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Los Angeles

Acidizing Oil Wells, a Sister-Technology to Hydraulic Fracturing:

Risks, Chemicals, and Regulations

A dissertation submitted in partial satisfaction of the requirements for the degree

Doctorate in Environmental Science and Engineering

by

Khadeeja Saba Abdullah

2016

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ABSTRACT OF THE DISSERTATION

Acidizing Oil Wells, a Sister-Technology to Hydraulic Fracturing: Risks, Chemicals, and Regulations

by

Khadeeja Saba Abdullah

Doctor of Environmental Science and Engineering

University of California, Los Angeles, 2016

Professor Irwin H. Suffet, Co-Chair

Professor Michael K. Stenstrom, Co-Chair

The United States has seen resurgence in petroleum production, mainly driven by technology improvements in unconventional oil and gas stimulation from shale formations. Hydraulic fracturing, one of the unconventional oil and gas stimulation technologies, has caught a lot of public attention that has led to more research on it and its impacts as well increased debate over more regulatory oversight. Other unconventional oil stimulation techniques have more or less been left out of the discussion. One of these less frequently discussed techniques is acidizing. Acidizing is a term used for all types of acid use that increase or keep up well productivity or injectivity. The use of these unconventional stimulation techniques has greatly increased over the past decade. The expansion of tight oil and shale gas extraction using unconventional oil stimulation has raised concerns about its potential

environmental and health impacts. These concerns include potential direct impacts to groundwater and surface water quality, water supplies, and air quality. Much attention has been on the impacts of hydraulic fracturing with little to no attention on acidizing. This research looks at the acidizing process and for the first time defines what the chemicals of acidization are, in what amount they are used, and what their toxicity is.

The analysis of the present data shows there have been over 600 instances of acidizing in urbanized Southern and Central California from April 2013 to August 2015. Although most of the chemicals of acidizing are similar to hydraulic fracturing, those used most frequently are different. There are close to 200 specific chemicals used in acidization, with at least 28 of them being F-graded hazardous chemicals, which are known carcinogens, mutagens, reproductive toxins, developmental toxins, endocrine disruptors, or high acute toxicity chemicals. Some are used frequently in the range of 100 - 1000 kg per treatment, such as hydrofluoric acid, xylene, diethylene glycol and ethyl benzene. Unlike hydraulic fracturing the chemical concentrations in acidizing are high, ranging from 6-18%, and the waste returns can be highly acidic, in the range of pH 0-3.

In addition to analyzing the chemicals and their potential impacts this research looks at the legal framework for regulating acidizing activities. Provisions of several federal environmental laws can apply to acidizing activities. The federal role in regulating O&G extraction activities has been the subject of considerable debate and

legislative proposals for several years. The Administration has pursued a number of regulatory initiatives related to unconventional O&G development, primarily hydraulic fracturing, under existing statutory authorities. Acidizing, however, has been almost entirely been left out of new proposals. This research sheds light on this topic and suggests areas where acidizing can be better regulated.

In addition to looking at the federal laws and state bills in place for regulating acidization, this research specifically looks at a better regulating scheme for stormwater runoff from oil and gas facilities. Contaminated stormwater runoff from oil and gas operations can pose a significant threat to surface waters. The research examines the extent of this threat and recommends more specific permitting requirements and best management practices to protect surface waters.

With increasing use of unconventional oil stimulation techniques like acidizing, it is important to understand the technology, the threats caused by them, and how to best protect the public and environment from any potential harm. This dissertation research attempts to shed light on these issues related to acidizing.

The dissertation of Khadeeja Saba Abdullah is approved.

Timothy Malloy

Keith Stolzenbach

Michael K. Stenstrom, Committee Co-Chair

Irwin H. Suffet, Committee Co-Chair

University of California, Los Angeles

2016

This dissertation is dedicated to

my parents Amtul Aziz and Aslam Abdullah

for their lifelong love, sacrifices, and commitment to my education

my mother and father-in-law Nafisa Syed and the late Mushtaq Syed

for their love, support, and encouragement

my husband Adeel Syed

for his support, without which I could not have reached my goals, and work ethic,

which inspires my own

my children Ameen and Zaynab

for their smiles and love that make every day a great day

and

my teachers

for their commitment to knowledge and giving me the tools to excel

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Acknowledgements

I thank the University of California, Los Angeles for providing me over a decade of support to achieve my goals. I thank Dr. Stolzenbach who first helped kindle the fire to start my path on environmental work my freshman year of college. I thank my host organization Rally, whose work around unconventional oil drilling is funded by the Schmidt Family Foundation, for introducing me to the work being done on unconventional oil and gas stimulation and giving me the space and funding to come up with my dissertation topic. I thank the National Water Research Institute for taking interest in my work and providing me with funds to research this topic.

There are many individuals at different agencies/companies to thank for answering my questions and directing me to the right resources: John Borkovich (PhD), Matthew Buffleben (D.Env), AliReza Rahmani (M.S.) at State Water Resources Control Board, Brett Bonotto (B.S.) at the Department of Oil Gas and Geothermal Resources, Ed Eckerle at the South Coast Air Quality Monitoring District, Christopher Gabelick (D.Env) at the Metropolitan District of Southern California, Robert Kleinberg (PhD) at Schlumberger-Doll Research and countless others. I wish to give a special thanks to Xavier Swamikannu (D.Env) at the State Water Resources Control Board for giving me the idea, guidance, and time to complete the oil and gas facility stormwater management piece.

I wish to thank my husband, Adeel Syed and brother Faisal Abdullah for proof reading my work and my good friend, Lena Khan for proof reading my work, pulling together material, and helping me find time to finish my work throughout this process. I wish to thank my fellow graduate students, Jennifer Taylor for helping me compile toxicity data and John Li for helping me with the GIS mapping.

Finally, I would like to thank Professor Mel Suffet and Michael Stenstrom, my committee chairs; and Professors Timothy Malloy and Keith Stolzenbach, members of my doctoral committee for their academic guidance, mentorship, and endless support. Without their support none of this would be possible.

EDUCATION

Master's in Public Health, Environmental Health Sciences - Industrial Hygiene (ABEST/ASAC)

University of California, Los Angeles (2008), 3.94 GPA

Hazardous Waste Minor

Bachelor of Science, Physiological Science

University of California, Los Angeles (2006), 3.6 GPA

Provost's Honor List

Dean's Honor List

Education Minor

PROFESSIONAL EXPERIENCE

Research Associate (February 2014-Present)

Rally

Research Associate (August 2014 – November 2015)

Heal the Bay

Project Developer (July 2013 – November 2013)

National Institute of Occupational Safety and Health (NIOSH)

Lecturer (Summer 2011)

California State University, San Bernardino

Graduate Researcher, Project Coordinator (June 2010 - June 2011)

California Consortium on Safe Handling of Nanomaterials in Research Labs

Project Developer, Trainer, and Researcher (June 2007 - August 2008)

American Occupational and Environmental Clinics and UCLA Institute of Research for Labor and Employment

Research Assistant I (June 2007 - Fall 2007)

Center for Occupational and Environmental Health (Dr. Froines)

GRANTS/AWARDS

California Endowment Award (2006-2007, 2007-2008)

American Industrial Hygiene Foundation Scholarship (2007)

Tony Norton Memorial Scholarship (2007)

Jim Koegh Scholarship (2007)

Cook/Snyder Memorial Scholarship Fund (2007)

Student Profile in UCLA's Public Health Magazine November issue (Climate Change and Our Health) (Nov 2007)

The Women's Environmental Council Fellowship Winner (2008)

Outstanding Graduating Student Dean's Award (2008)

Foreign Language and Asian Studies Fellowship (2008)

Eugene V. Cota-Robles Fellowship (2009-2016)

Charles Senn Scholarship (2010)

Gilbert Fellowship (2014)

National Water Research Institute Fellowship (2014-2016)

PRESENTATIONS/PUBLICATIONS

Abdullah, Khadeeja, Timothy Malloy, Michael K. Stenstrom, and I. H. (Mel) Suffet.
"Toxicity of Acidization Fluids Used in California Oil Exploration." *Toxicological & Environmental Chemistry* (2016): 1-17.

American Water Works Association (June 19-22, 2016)

The Chemicals Of Acidization And Their Impact On Drinking Water

American Chemical Society (March 14-17, 2016) San Diego, CA

Acidizing Oil Wells: The Chemicals and Their Impacts

American Chemical Society (March 22-25, 2015) Denver, Colorado

Toxicity and Fate and Transport of the Chemicals of Matrix Acidization

American Chemical Society (March 22-25, 2015) Denver, Colorado

Chemicals of Matrix Acidization and its Treatment Challenges

American Public Health Association Annual Conference (November 3-7, 2007) Washington D.C.

It's Hot: Heat Stress in California Farm Workers

Moving Forward Conference – Trade, Health and Environment Impact Project (Nov 30-Dec 1, 2007) Carson, CA

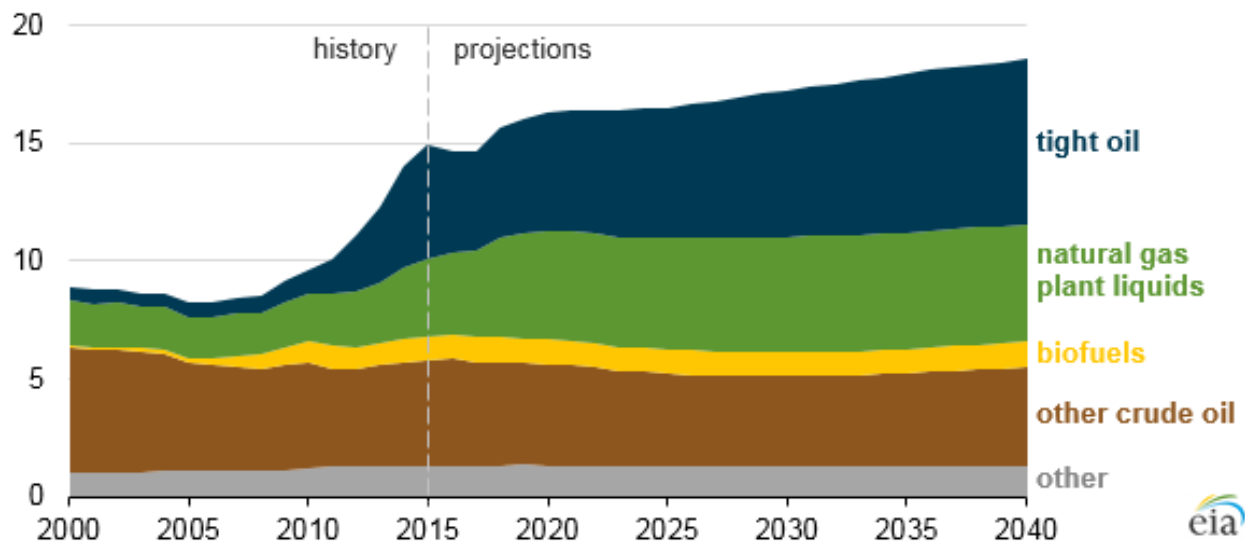
"Diesel Exposure at the Long Beach Port"

"Transport of Hazardous Waste through Local Communities"

I. Introduction

The United States has seen resurgence in petroleum production, mainly driven by technology improvements in unconventional oil and gas (UOG) stimulation from shale formations. Application of these technologies has enabled oil and natural gas to be economically produced from shale and other unconventional formations. This has contributed to the United States becoming the world's largest natural gas producer in 2009. Use of these technologies has also contributed to the rise in US oil production over the last few years. In 2009, for the first time since 1999, oil production increased annually. Between January 2008 and May 2014, U.S. monthly crude oil production rose by 3.2 million barrels per day, with about 85% of the increase coming from shale and related tight oil formations in Texas and North Dakota (Ratner and Tiemann, 2015). There had been a general increasing trend in production up until late 2014 when a drastic dip in oil prices pushed many companies to scale back their operations. However, since that time oil prices are recovering and the U.S. Energy Information Administration (EIA) recently projected that U.S. petroleum and other liquid fuels production will grow from 14.8 million barrels/day (b/d) in 2015 to 18.6 million b/d in 2040 in its *Annual Energy Outlook 2016* (AEO2016) Reference case.

Figure 1: U.S. Production of Petroleum and Other Liquids (2000-2040) in million barrels/day (Annual Energy Outlook, 2016)



The expansion of tight oil and shale gas extraction using UOG stimulation has raised concerns about its potential environmental and health impacts. These concerns include potential direct impacts to groundwater and surface water quality, water supplies, and air quality. Much of the research on the environmental and health impacts have been centered on only one type of UOG stimulation technique, hydraulic fracturing (HF). Stimulation techniques like acidizing have been grossly left out of the picture. This research is the first of its kind in that it discusses the different types of acidizing techniques and identifies the chemicals and amounts used in California and their toxicological impact.

Furthermore, this research looks at the legal framework available for regulating acidizing and identifies areas of improvement, both on the federal and California state level. States are the primary regulators of oil and gas (O&G) production on non-federal lands. With recent changes in production practices in tight oil, shale gas, and other unconventional hydrocarbon formations, many O&G producing states have revised laws and regulations governing O&G production. However, state rules vary considerably, leading to calls for

more federal oversight of UOG extraction activities. The federal role in regulating O&G extraction activities—specifically HF—has been the subject of considerable debate and legislative proposals for several years, but legislation has not been enacted. While congressional debate has continued, the Administration has pursued a number of regulatory initiatives related to unconventional O&G development under existing statutory authorities. Acidizing, however, has been almost entirely left out of new proposals. This research sheds light on this topic and suggests areas where acidizing can be better regulated.

The last portion of this research looks specifically at surface water protection from contaminated stormwater resulting from O&G activities as a whole. Contaminated stormwater runoff from O&G operations, acidizing included, can pose a significant threat to surface waters. This research examines the extent of this threat and recommends more specific permitting requirements and best management practices to protect surface waters from O&G stimulation activities.

While much of the research around UOG stimulation techniques has been focused on HF the focus of this dissertation is on the less discussed process of acidizing. With this research it is hoped that acidization becomes part of the larger discussion on concerns with O&G exploration and production as a whole and is evaluated by appropriate authorities.

References:

Annual Energy Outlook 2016. US Energy Information Administration.

Ratner, M., Tiemann, M., 2015. An Overview of Unconventional Oil and Natural Gas: Resources and Federal Actions. Congressional Research Service.

II. Background

A. What is Unconventional Oil and Gas Stimulation?

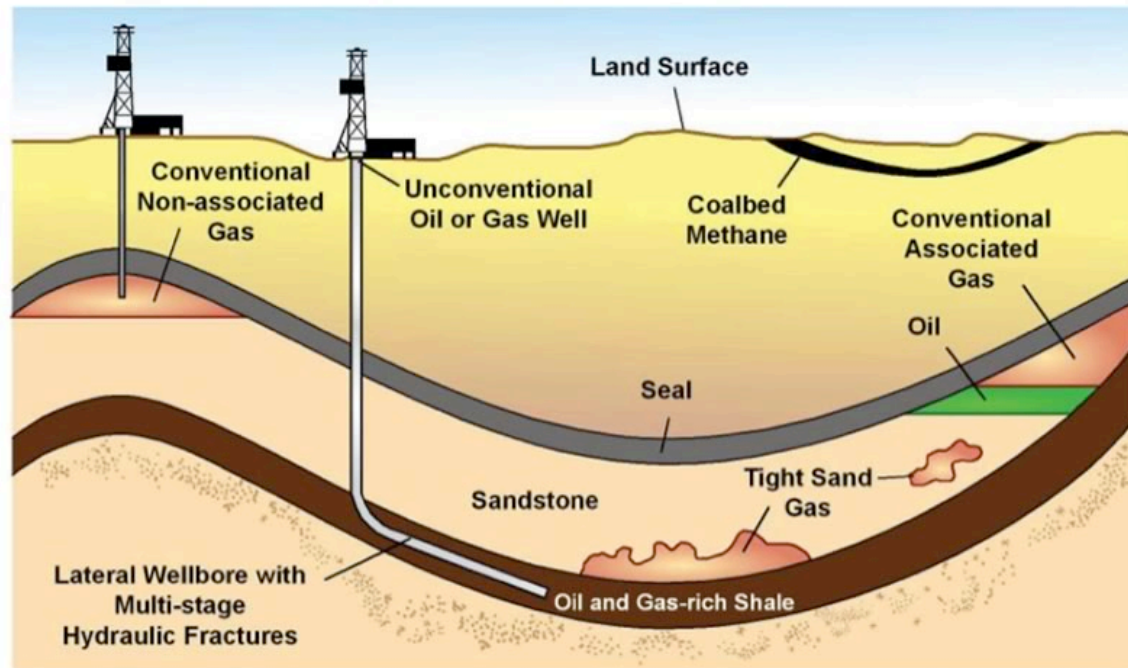
All of the O&G we use today began as microscopic plants and animals living in the ocean millions of years ago. As these microscopic plants and animals lived, they absorbed energy from the sun, which was stored as carbon molecules in their bodies. When they died, they sank to the bottom of the sea. Over millions of years, layer after layer of sediment and other plants and bacteria were formed.

As they became buried ever deeper, heat and pressure began to rise. The amount of pressure and the degree of heat, along with the type of biomass, determined if the material became oil or natural gas. More heat produced lighter oil. Even higher heat or biomass made predominantly of plant material produced natural gas.

After O&G were formed, they tended to migrate through tiny pores in the surrounding rock. Some O&G migrated all the way to the surface and escaped. Other O&G deposits migrated until they were caught under impermeable layers of rock or clay where they were trapped (Department of Energy). These trapped deposits are where we find conventional O&G today and are extracted by the known conventional techniques of oil drilling (See figure 2). Conventional O&G stimulation techniques are drilling operations that use the natural pressure of the wells as well as pumping or compression operations to extract crude oil and natural gas. Conventional O&G can be produced commercially without altering the rock permeability or fluid viscosity.

Figure 2: O&G Generation (EIA, 2011)

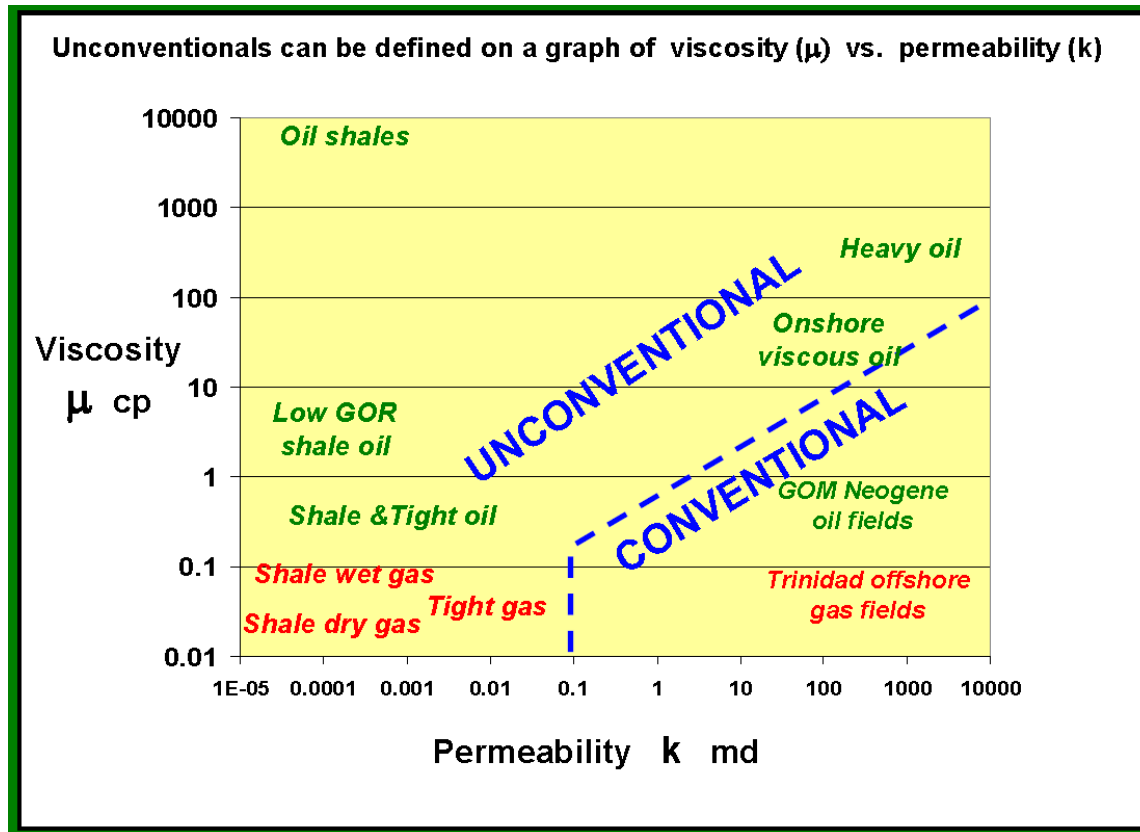
The Geology of Conventional and Unconventional Oil and Gas



Source: EIA

In addition to conventional O&G there is O&G that during the migration upwards got trapped in low-permeability rock, including sandstone, siltstone, shale, and carbonates, or gas trapped in fine-grained, organic-rich rock or coal. This O&G is referred to as unconventional resources, and require the use of technology to alter either the rock permeability or the fluid viscosity in order to produce the oil or gas (Cander, 2012). These techniques include but are not limited to horizontal drilling, hydraulic fracturing, matrix acidization, acid fracturing, steam injection, and carbon dioxide flooding (Zou, 2013). The figure below shows the difference in viscosity and permeability of different O&G resources.

Figure 3: Difference in Viscosity and Permeability of Conventional and Unconventional O&G (Cander, 2012)



More viscous oil and impermeable formations require UOG stimulation techniques to either make the oil more fluid or make the rock formation more permeable. Thermal methods are used to allow production of exceedingly viscous oil (Prats, 1982). Such hydrocarbons are called “viscous oil” or “heavy oil.” Thermal methods lower oil viscosity by heating the reservoir, most commonly through steam or hot water injection (Farouq, 2003).

Fracturing methods or worm holing methods increase permeability. There are three main stimulation techniques that increase permeability, hydraulic fracturing, acid fracturing, and matrix acidization (Economides and Nolte, 2000). Because these methods do not reduce oil viscosity, they are primarily targeted at tight (low permeability) rock formations containing gas or lower-viscosity oil, although they may be used in combination with thermal stimulation for heavy oil. Hydraulic fracturing is the injection of a pressured fluid,

containing water and chemicals, which fractures the formation. A proppant, like sand is used in the stimulation fluid to lodge itself in the fractures and keep it open to allow oil and gas to flow back through. Acidizing, which includes acid fracturing and matrix acidization, is the focus of this dissertation and will be discussed in the sections to follow.

B. What is Acidization?

Acids are used in a variety of ways for oil well stimulation. Acidizing, a term used for all types of acid use, is used to increase or keep up well productivity or injectivity. Chemicals are used to clean fractures and pores or to create new flow channels, thus increasing rock permeability. The acidizing techniques include acid maintenance, matrix acidization, and acid fracturing.

Acid maintenance is done very often and is used to remove scales in the wellbore. In acid maintenance, operators inject the acid solutions at a specific location in the wellbore or circulate it back and forth across the casing perforation or formation face to react with the scale. The scale is cleaned off of the surfaces of the wellbore and equipment without penetrating into the formation (Robertson et al., 1989).

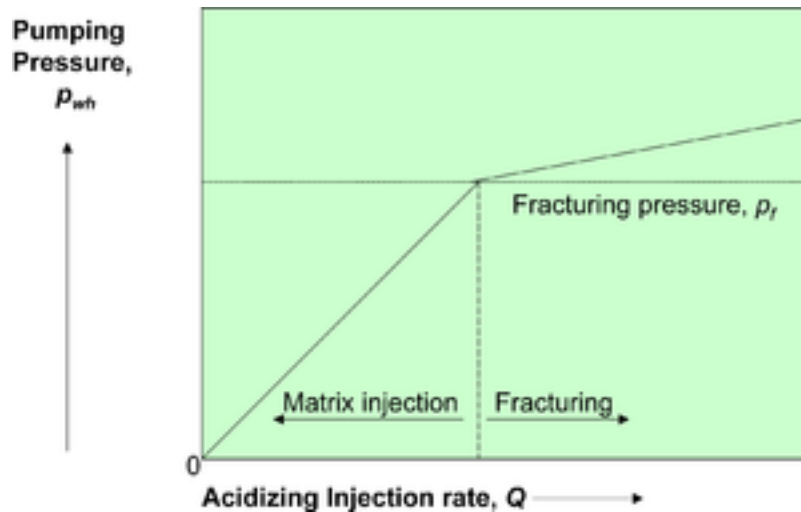
Matrix acidization is used to remove formation damage around the wellbore and/or increase reservoir permeability. Permeability is a characteristic that allows O&G to flow through the rock rather than be stuck in pores. Operators inject acid solutions into the well at pressures below the pressure required to fracture the rock, also known as fracture pressure (Robertson et al., 1986). Matrix acidization does not fracture the formation. Instead, acids etch away at the reservoir rock creating channels for O&G to flow through. The mechanisms involved include etching the mineral surfaces by dissolving the minerals

and mobilizing particles by decomposing the rock structure (McLeod, 1986). In California, matrix acidizing is done at depths ranging from 2000-11,000 feet. Matrix acidizing in carbonate formations can create small channels or tubes called wormholes that can propagate as much as 6.10 meters (20 feet) into the formation. This is similar to a small hydraulic fracturing treatment. However in sandstone, acid dissolution is limited to a much smaller distance of less than 0.3 to 0.6 m (one to two feet) into the formation. Matrix acidizing in sandstone primarily removes damaging solids that have reduced the near-well permeability of the reservoir. However, there are some instances of matrix acidizing using HF/HCl reported in the Monterey Formation in California that may have greater penetration because of the presence of natural fractures (CCST, 2014). Matrix acidization is primarily used to remove formation damage but can also increase reservoir permeability.

The last acidizing technique is acid fracturing. Acid fracturing is similar to HF in that a solution is injected into the wellbore above hydraulic pressure to fracture the formation. In acid fracturing an acid is used to “etch” channels in the fracture walls. The rock has to be partially soluble in acid, thus it is mainly used in carbonate formations. In these formations the acid reaction is quick; the acid excessively leaks into the formation, not being able to create long etched fractures (Williams et al., 1976). Both acid fracturing and matrix acidization used acids to etch the reservoir. The main difference is the injection rate. Injection rates resulting in pressures below the pressure needed to fracture are termed matrix acidizing, while those above fracture pressure are termed acid fracturing (McLeod, 1986). Figure 1 shows the difference between matrix acidization and acid fracturing. It shows that until the fracturing pressure is reached, pressure increases linearly with

injection rate. When fracturing pressure is reached the time rate can continue to increase with little change in pressure above fracturing pressure.

Figure 4: Pressure Changes with Increasing Acidizing Injection Rates (Acid Fracturing, 2013)



Acidizing is used in all oil exploration. Recently more attention has been given to UOG stimulation. These are techniques that alter the permeability of the reservoir or the viscosity of the stimulation fluid to extract once trapped oil/gas. HF is an UOG stimulation that alters the permeability of the reservoir, as are matrix acidization and acid fracturing (Zou, 2013). However, the composition of the stimulation fluids is different. In HF a solution consisting of 99.5% water and sand and 0.5% chemicals is used (US DoE, 2009). In both matrix acidization and acid fracturing a much higher concentration solution is used, as will be discussed later.

Table 1 highlights the differences between these three unconventional oil stimulation techniques used to alter permeability.

Table 1: Unconventional Oil Stimulation Techniques and their Differences

	Hydraulic Fracturing	Acid Fracturing	Matrix Acidization
Uses Pressurized Fluid	✓	✓	
Uses Propping Agent	✓	✓ (some cases)	
Uses Acid		✓	✓
Increases Reservoir Permeability via Fracturing	✓	✓	
Increases Reservoir Permeability via Acid Etching		✓	✓ (some cases)
Removes Formation Damage		✓	✓
Amount of Water Used	3-5 million gallons/well; 130,000-210,000 gallons/well (in California) (CCST 2014)	500,000 gallons/well (in California)	40,000 gallons/well (in California) (CCST 2014)

C. The History of Acidization

Acidizing is an old technique used in oil development. The details have changed but the principles remain the same. A Standard Oil patent for acidizing limestone with hydrochloric acid dates from 1896 (Frasch, 1896). The technique was first used a year earlier by the Ohio Oil Company. Reportedly, oil wells increased in production three times, and gas wells four times. At that time the acid severely corroded the well casing, and thus declined in popularity and wasn't used for about 30 years (Putman, 1933).

In 1928 acid use was brought back to remove scale in the oil wells with an added inhibitor to protect the iron casing from corrosion, but the decline in oil prices and the high cost of the acid made this treatment unused and unexplored (Champman, 1933).

The “modern era” of acidizing links back to events in the 1930s when arsenic was discovered to inhibit the action of hydrochloric acid on metal. Arsenic was used with

hydrochloric acid on a limestone reservoir, and a previously dead well started producing 16 barrels of oil per day (Newcombe, 1933). This sparked the interest of industry and acidizing came back into the market.

In 1933 hydrofluoric acid was used to treat a sandstone formation because hydrochloric acid doesn't react with silicate minerals in sandstone. Around the same time a mixture of hydrochloric and hydrofluoric acid was used to treat a well but commercial use didn't begin until the 1950s (Williams et al., 1979).

The principle of acidizing is still the same but additives used have changed quite a bit since the 1950s. Although the main drivers of this mechanism are the acids, there are hundreds of other chemicals used to enable this technique. In addition to the acids these other chemicals could potentially be the most harmful. The chemical makeup of the fluids used is dependent on the geology of the reservoir and the chemistry of the reactions. Although the science of how to extract oil has improved and continues to improve, the science of how it impacts our environment is unknown and is not being explored as rapidly. This research is an attempt to begin that discussion around the impacts to humans and the environment. In the next section we lay out the types of chemical that are used in acidization.

D. Fluid Makeup

Matrix acidizing fluid includes water, acids, and additives. Water is the main solvent and conduit of the chemicals to the wellbore damage and/or the reservoir. Acids are used for mineral dissolution and mobilization of mineral grains by decomposition of the rock structure. Additives are used for various purposes later outlined.

1. Acid Selection

Each type of acid has its own peculiar chemical and physical properties. The type of acid selected for stimulation of a particular oil well depends on various characteristics outlined below.

a) Rock-Dissolving Capacity

The rock-dissolving capacity of the acid refers to the volume of rock that can be dissolved by the acid. This is important when evaluating how much rock needs to be dissolved (Robertson et al., 1989).

b) Acid Spending Time

Operators also consider the spending time of the acid. The spending time of the acid is the time required for the acid to expend 85-90% of its dissolving capacity. After that, the acid reaction is very slow due to acid dilution. Acids with a high spending time are chosen so that they can be pushed away as far as possible from the wellbore into the formation before they are spent (Robertson et al., 1989).

c) Reaction Product Solubility

The acid selected is also dependent on the solubility of reaction products. Insoluble salts can precipitate and plug the formation channels and/or fractures. Thus, a prerequisite for any acid to be used is that the reaction salts must be soluble. Solubility of salts varies with temperature and quantity of similar salts already dissolved in the brine. An additional problem arises when the acid-reaction salts react with other ions present in the formation water to form insoluble salts (Robertson et al., 1989).

d) Acid Corrosion

Acid selection is also dependent on acid reaction with metals, also known as acid corrosion. For most acids, a chemical inhibitor is added to the solution to retard the corrosion process. In the case of many of these inhibitors, a protective thin film forms on the metal surface. This chemical film, which serves as a barrier between the reactive acid and the metal, tends to break down at high formation temperatures. Inhibitors don't produce 100% protection from corrosion for long periods of time (Robertson et al., 1989).

e) Emulsions

Another consideration is emulsion formation when the acids mix with water and oil. If formed in flow channels, the emulsions will increase the pressure gradient required to move fluids in those channels, as well as increase fluid viscosity, plug formation pore channels, and cause a well-fluid cleanup problem. Reaction between acid and oil, especially in the case of concentrated hydrochloric acid (28% and higher) may result in the formation of sludge, which can also plug the channels. Surfactants are used to prevent emulsification and the formation of sludge (Robertson et al., 1989).

f) Density and Viscosity of Spent Acid

Operators also think about the density and viscosity of spent acid water. The density and viscosity increases with increasing concentration of the initial acid. The increase in density makes it difficult to recover treating fluids (Robertson et al., 1989).

g) Etching Pattern

Another important consideration is the etching pattern of the acid. Generally stronger acids and acids of higher concentration produce better-etched flow channels with higher conductivities. These acids tend to etch more erratically and are more effective at

containing very small amounts of dispersed insoluble fine particles (Robertson et al., 1989).

h) Reservoir Geology

The choice of acid is also dependent on the geology of the oil reservoir. Matrix acidizing is used on different types of reservoirs including sandstone, carbonates, granites, and basalts and andesites. Each reservoir type has a distinct mineralogy and permeability which determines which acid(s) will be used. See table 2.

Table 2: Acid Selection for Different Minerals (Schieber, 2013)

Nearly all acids dissolve	HF, HCl/HF, HBF ₄ , dissolve
Carbonates:	Silicates:
Calcite CaCO ₃	Quartz SiO ₂
Dolomite CaMg(CO ₃) ₂	Feldspars (Plagioclase, Orthoclase, ...)
	Micas (Biotite, Muscovite)
	Clay minerals (Kaolinite, Smectite, Illite, Chlorite)
	and
	Oxides and Hydroxides:
	Hematite Fe ₂ O ₃
	Goethite FeOOH
	Magnetite Fe ₃ O ₄
Note: Sulfates (Gypsum [CaSO ₄ x 2H ₂ O], Anhydrite [CaSO ₄], and Barite [BaSO ₄]) have low solubility in acids.	

2. Types of Acids Used

The acids used in matrix acidizing can be inorganic, organic, or mixtures of the two.

Table 3: Types of Acids Used in Acidization (Schieber, 2013)

Inorganic	Organic	Mixtures
Hydrochloric acid (HCl)	Acetic acid (CH ₃ COOH)	Organic Acids/HBF ₄
Hydrofluoric acid (HF)	Formic Acid (HCOOH)	
Mud Acid (HCl/HF)	Citric Acid (C ₆ H ₈ O ₇)	
Tetrafluoroboric acid (HBF ₄)	Biodegradable acids	

3. Additives

Below are classes of common additives:

a) Corrosion Inhibitors

Corrosion inhibitors are used to reduce the reaction of acid with the metallic iron in the pipes. The inhibitor will form and maintain a film on the iron surface. Its effectiveness decreases at very high temperature (Robertson et al., 1989; Williams et al., 1979).

b) Surfactants

Surfactants are “surface-active” chemicals that contain at least two functional groups: one hydrophilic and the other hydrophobic. Surfactants are used in oil well acid treatments to 1) reduce interfacial tension, 2) demulsify acid-oil emulsions, 3) alter formations wettability, 4) prevent sludge formation in the case of concentrated acids (28% HCl or higher), 5) remove heavy hydrocarbon deposits, and/or 6) speed cleanup. Reduced surface tension is supposed to increase the acid’s spreading ability on the surfaces of oil or water-wet rocks. It can also facilitate the mixing of live or spent acid with formation waters, which makes removal of fluids easier. Cationic surfactants (organic amines and salts of quarternary amines) and nonionic surfactants (polyoxyethylated alkylphenols) are added as a demulsifying agent to stop the formation of acid-spent acid-crude oil emulsions. Ethylene glycol monobutyl ether is frequently used in sandstone acidizing as a mutual solvent to remove heavy hydrocarbons. It helps reduce interfacial tension between oil and water and acts as a solvent to solubilize oil in water (Kalfayan 2008)

c) Mutual Solvents

Solvents are used to improve solubility of additives and to remove hydrocarbons and different additives [Robertson et al., 1989; Kalfayan, 2008].

d) Friction Reducers

Friction reducers are typically high molecular weight polymers (5 to 30 million Dalton) that will uncoil when added in the aqueous solution to decrease pumping pressure losses. The drop in pressure reduces the horsepower required to pump the acid mixture. The most common friction reducers used in oil production are based on anionic polyacrylamide or other copolymers of polyacrylamide combined with different monomers.

e) Acid fluid-loss additives

Fluid-loss additives reduce the rate of fluid loss from an acid mixture. Without these additives water migrates into the permeable formation leaving the other fluid components behind. This happens more when pumping is stopped and the fluid is static, but not yet set. In addition water can be squeezed from the fluid as it passes through constrictions. Fluid loss additives keep the fluid intact and retain the mixture's key characteristics, including viscosity, thickening time, density and compressive strength development (Halliburton, 2014).

f) Diverting (Gelling) Agents

Diverting agents are a viscous gel or suspension of graded solids used to temporarily block off the most permeable sections of reservoir and force the acid into less permeable sections. Diverting agents used for acidizing include solid organic acids, finely divided inert organic resins, deformable solids, acid-sellable polymers, mixtures of waxes and oil-soluble

polymers, mixtures of water-soluble polymers (gum guar, gum karaya, cellulose, polyacrlamide, etc.) and inert solids (silica flour, calcium carbonate, rock salt, and oil-soluble resins) (Williams et al., 1979).

g) Iron Control Agents

Complexing agents are used to tie-up ions such as Fe^{3+} before they can precipitate out. Sources of ion include 1) corrosion products found on the walls of casing and other tubular goods, 2) pipe scale, and 3) iron in a mineralized form found in the formation (Williams et al., 1979).

h) Clay Stabilizer

Reservoir rock often contains clays with many different structures. The clays may swell, break off and migrate, or do both in the presence of water or acid-based fluid systems. The clay control additives adhere to the borehole wall, effectively sealing the surface and inhibiting their reaction with the fluid (Weatherford, 2014).

i) Calcium Sulfate Inhibitors

These are used in formations with high sulfate-ion content in the formation water (usually greater than 1,000 ppm) or rock containing anhydrite to prevent the formation of calcium sulfate.

j) Scale Inhibitor

Phosphonates, sulfonates, and polyacrylates are used to prevent formation of calcium scale (Kalfayan, 2008).

k) pH Adjusting Agent

Acids and bases are added to adjust the pH to the desired level.

l) Cleanup additives

Cleanup additives are used to remove spent acid in low-pressure reservoirs. Gaseous nitrogen, alcohols, or surfactants are used.

m) Biocides

Biocides are added to control bacterial growth during and after well stimulation.

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III. Toxicity of Acidization Fluids used in California Oil Exploration

Toxicity of acidization fluids used in California oil exploration

Khadeeja Abdullah, Timothy Malloy, Michael K. Stenstrom and I. H. (Mel) Suffet

Institute of the Environment and Sustainability, College of Letters and Science, University of California, Los Angeles, CA, USA

ABSTRACT

There has been considerable public interest regarding the toxicity of chemicals used in hydraulic fracturing, but little is known about its sister technique, acidizing. Little to no research has been done on what the chemicals of acidization are and what impact they could have on humans and the environment. This paper discusses the differences between three acidizing techniques (acid maintenance, matrix acidization, and acid fracturing) and quantifies the amounts of the chemicals used for each. Washington State's Quick Chemical Assessment Tool is used to identify F-graded toxins, which are known carcinogens, mutagens, reproductive toxins, developmental toxins, endocrine disruptors, or high acute toxicity chemicals. The analysis of the present data shows that there have been over 600 instances of acidizing in urbanized Southern and Central California from April 2013 to August 2015. Although most of the chemicals of acidizing are similar to hydraulic fracturing, those used most frequently are different. There are close to 200 specific chemicals used in acidization, with at least 28 of them being F-graded hazardous chemicals. Some are used frequently in the range of 100–1000 kg per treatment, such as hydrofluoric acid, xylene, diethylene glycol, and ethyl benzene. Close to 90 more chemicals are identified using non-specific names as trade secrets or reported with no quantity. Unlike hydraulic fracturing the chemical concentrations in acidizing are high, ranging from 6% to 18%, and the waste returns can be highly acidic, in the range of pH 0–3. With this paper it is hoped that acidization becomes part of the larger discussion on concerns with oil exploration and be evaluated by appropriate authorities.

ARTICLE HISTORY

Received 19 November 2015
Accepted 26 February 2016

KEYWORDS

Toxicity; acidizing; oil exploration; hydraulic fracturing; hazard assessment

1. Introduction

Unconventional oil exploration has led to greater energy independence for the USA. It has also raised concerns among the public, NGOs, and policymakers regarding harmful impacts. While researchers have begun exploring the potential impacts of hydraulic fracturing more seriously, impacts from acidizing are not being examined as closely. It is important that acidizing be a bigger part of the discussion to protect the public and environment from potential harm.

CONTACT Khadeeja Abdullah  Khadeeja@ucla.edu

 Supplemental data for this article can be accessed at <http://dx.doi.org/10.1080/02772248.2016.1160285>.

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The overall objective of this paper is to identify potential human health risks and environmental hazards associated with acidizing that require further evaluation for responsible decision-making. This paper discusses the differences between three acidizing techniques (acid maintenance, matrix acidization, and acid fracturing) and quantifies the type and amounts of the chemicals used in them. Washington State's Quick Chemical Assessment Tool (QCAT) is used to identify F-graded toxins, which are known carcinogens, mutagens, reproductive toxins, developmental toxins, endocrine disruptors, or high acute toxicity chemicals. QCAT is based on methodology developed by the United States Environmental Protection Agency's (EPA) Design for the Environment program. It looks at various toxicological endpoints (i.e. carcinogenicity, neurotoxicity, etc.) to assign chemicals a hazard grade.

Recently, the California Council on Science and Technology published chemical information for matrix acidization. This chemical information was gathered primarily from the California Department of Conservation's Division of Oil, Gas, and Geothermal Resources (DOGGR). Here, we will use the chemical information from DOGGR as well as the South Coast Air Quality Monitoring District (SCAQMD) to discuss all the acidizing treatment types as well as look at different toxicological endpoints to assign a QCAT hazard grade.

1.1. Description of acidizing techniques

The first use of acids in oil exploration was in 1895, but because of acid attack on metal in the wellbore it was not used much (Putman 1933). The modern-day use of acid in oil stimulation began in the 1930s when it was discovered that corrosion inhibitors could stop acid attack on metal. Commercial use of acids finally began in the 1950s (Williams, Gidley, and Schechter 1979). The idea of using acids for oil stimulation or cleaning a wellbore is an old concept, but the chemicals, volumes, and techniques used in acidizing have evolved.

Acid is used in oil wells as part of three different techniques: acid maintenance, matrix acidization, and acid fracturing. Acid maintenance is a routine procedure used to remove deposits formed on well surfaces, also known as scale. In acid maintenance, operators inject acid solutions at a specific location in the wellbore to react with the scale. The scale is thus cleaned off the surfaces of the wellbore and equipment without any acid penetrating into the formation (Robertson, Chilingarian, and Kumar 1989).

The second technique, matrix acidization, is used to remove formation damage (i.e. blocked oil/gas pathways) around the wellbore and/or increase reservoir rock permeability. Permeability is a characteristic that allows oil and gas to flow through the rock rather than be stuck in pores. Operators inject acid solutions into the well to etch away at the reservoir rock, creating channels for oil and gas to flow through. Matrix acidization does not fracture the formation. Solutions are injected at pressures below the pressure required to fracture the rock, also known as fracture pressure (Robertson, Chilingarian, and Kumar 1989). Matrix acidizing in carbonate formations can nonetheless create small channels or tubes called wormholes that can propagate as much as 6.1 m (20 feet) into the formation, as carbonates are easily dissolved by acids. This is similar to the result of a small hydraulic fracturing treatment (CCST 2014). However, in sandstone, acid dissolution is limited to a much smaller distance of 0.3–0.6 m (1–2 feet) into the formation because the silica

matrix is harder to dissolve. Matrix acidizing in sandstone is therefore primarily used to remove damaging solids that have reduced the near-well permeability of the reservoir. There are some instances of matrix acidizing using HF/HCl reported in the Monterey Formation in California that may have had greater penetration because of the presence of natural fractures (CCST 2014). In California, matrix acidizing is done at depths ranging from 2000 to 11,000 feet. The wells at the lower end of this range come close to drinking water aquifers.

The last acidizing technique is acid fracturing. Acid fracturing, like matrix acidization, uses acids to etch the reservoir. The main difference is the injection rate. Injection rates with pressures below the pressure needed to fracture are termed matrix acidizing, while those above fracture pressure are termed acid fracturing (McLeod 1986). Acid fracturing is similar to hydraulic fracturing in that a solution is injected into the wellbore at a high pressure to fracture the formation. The difference between acid fracturing and hydraulic fracturing is the composition of the stimulation fluids. Hydraulic fracturing uses a solution consisting of 99.5% water and sand and 0.5% chemicals (US DOE 2009), whereas, as determined from this research, in both matrix acidization and acid fracturing, the concentration of the solution used is 6%–18% chemicals. For acid fracturing to be able to etch channels in the fracture walls, the rock has to be soluble in acid, and the acid should not excessively leak off into the formation without reacting. Thus this technique is mainly used in carbonate formations (Williams, Gidley, and Schechter 1979).

1.2. Acidization fluid make up

Acidizing fluid includes water, acids, and additives. Water is the main solvent and conduit of the chemicals to the wellbore and/or reservoir. Acids are used to dissolve minerals and mobilize mineral grains by decomposing the rock structure. Many other chemicals are added for various purposes that are discussed in the appendix.

The most commonly used acids are listed in Table 1. In California, oil stimulations occur primarily in sandstone and some carbonate formations. Hydrofluoric acid (HF) in combination with other acids is used to dissolve silicates in sandstone. Hydrochloric acid (HCl) and other acids are used to dissolve carbonate minerals, such as limestone. See the supplemental section for more details on which acids are used for different minerals.

Table 1. Acids used in acidizing (Scheiber 2013).

Inorganic	Organic	Mixtures
Hydrochloric acid (HCl)	Acetic acid (CH ₃ COOH)	Organic acids/HBF ₄
Hydrofluoric acid (HF)	Formic acid (HCOOH)	
Mud acid (HCl/HF)	Citric acid (C ₆ H ₈ O ₇)	
Tetrafluoroboric acid (HBF ₄)	Biodegradable acids	

1.3. Chemical exposure pathways

There are many different types of chemicals used in acidizing, and the risk of each is dependent on the chemical's exposure, toxicity, fate and transport, transformation, and cumulative and synergistic effects with other chemicals. Many of these factors have not been studied. Here, we focus on the chemicals' human exposure pathways through water.

Table 2. Surface and subsurface chemical release mechanisms into waterways.

Surface	Subsurface
Percolation from unlined pit	Fractured/acid wormhole pathway
Siting of disposal well into aquifer	Deteriorated abandoned well
Inadequately treated wastewater for reuse or disposal	Failure of production or disposal well
Spills, leaks, and accidents	Fault pathway

Table 2 lists the surface and subsurface chemical release mechanisms into waterways from oil stimulation, production, and wastewater management and disposal activities in California. For a diagram of the surface and subsurface release mechanisms see the supplemental section.

The most likely source of water contamination comes from improper handling of wastewater at the surface. Surface release mechanisms include percolation from unlined pits, siting of a disposal well into an aquifer, reuse or disposal of inadequately treated wastewater, and spills, leaks, and accidents. More than half of the wastewater from fractured oil wells in California is disposed of in open, unlined pits and could contaminate groundwater. More than 900 such pits, many without proper permits from the state, lie in the oil fields of the San Joaquin Valley, and some atop usable aquifers (CCST 2015). Wastewater from the surface can also be directly injected into Underground Sources of Drinking Water and “Usable” Water defined under EPA and Bureau of Land Management regulations. The California State Water Board confirmed that at least nine wastewater disposal wells have been injecting waste into aquifers that contain high-quality water protected under federal and state law (Bishop 2014). This becomes a serious issue in drought-stricken places with a high water demand, like the Central Valley of California. Another surface exposure route is reusing or disposing inadequately treated wastewater. In California, about 25% of wastewater was injected into disposal wells or reused for oil/gas extraction. Some wastewater has also been permitted for irrigation in California (CCST 2015). Surface spills, another surface release mechanism, have contaminated both groundwater and surface water. According to the available data between January 2009 and February 2014, 423 surface spills at oil and gas fields in California released nearly 2.8 million gallons of wastewater, or an average of 6500 gallons per incident. Of these, 34 spills released a total of 88,000 gallons of wastewater into California waterways (CCST 2014).

Subsurface release mechanisms include acid wormhole pathways in the rock formation leading to aquifers, fault pathways leading to aquifers, deteriorated abandoned wells leaking into the subsurface, and the failure of production or disposal wells. Modeling work suggests that hydraulic fracturing stimulation fluid contaminating aquifers by connecting pathways is highly unlikely, happening on a 1000–100,000 year scale (Kissinger et al. 2013; Gassiat et al. 2013; Flewelling and Sharma 2014). It is even more unlikely for wormhole pathways to reach an aquifer, because they do not extend very far. However, it becomes a greater threat in California, where unconventional oil stimulation is occurring at relatively shallow depths closer to aquifers with usable water. Matrix acid stimulation has occurred in many fields at depths around 2000 feet (CCST 2014). In both the San Joaquin Valley and the densely populated Los Angeles Basin, oil stimulation has happened at depths less than 1000 feet (CCST 2015). Pathways created by the compromised or failed structural integrity of cement in oil and gas wells and wellbores are considered the most likely potential pathway for groundwater contamination.

2. Methods

2.1. Information sources

Information about the geographical location of acidizing sites in California, volume of water used per treatment, chemical names and chemical abstracts service (CAS) registry numbers, chemical purpose, and chemical amounts were collected, sorted, and analyzed from two California government databases: the Division of Oil, Gas, and Geothermal Resource's (DOGGR) Interim Senate Bill 4 (Interim SB 4) self-reporting portal (DOGGR 2015) and the South Coast Air Quality Monitoring District's (SCAQMD) Rule 1148.2 self-reporting portal (SCAQMD 2015). The data are inclusive of dates from the inception of the Interim SB 4 on 1 January 2014 and SCAQMD's Rule 1148.2 on 5 April 2013 to mid-August 2015.

The data from DOGGR's portal from January 2014 to June 2014 only included information on what operators are required by law to report what they considered as acid fracturing or matrix acidizing; it was not based on a generally applicable regulatory definition. Furthermore, it did not include treatments that used acid concentrations of 7% or less (DOGGR, 2014). After June 2014, operators self-reported matrix acidization or acid fracturing based on a uniform regulatory definition with no acid concentration exemption (DOGGR, 2014). As for SCAQMD's data, all chemical information on what operators considered as acidizing was collected. From April 2013 to March 2014 there was no way to determine whether what was reported was acid maintenance, matrix acidizing, or acid fracturing (SCAQMD, 2015), and the chemicals in use during this period could have been representative of any of the techniques. After March 2014, operators reported which acidizing techniques they were using. Information on acid maintenance and matrix acidization was collected from SCAQMD.

There are some clear limitations. Although information is required to be reported, self-reporting reduces transparency; there is no real-time way to validate information or that all information is being reported. Sometimes information is withheld because of trade secrets. Thus, the information may not be representative of consistent and transparent data collection. Furthermore, what was reported to SCAQMD as matrix acidization or acid fracturing should in theory also have been reported to DOGGR because SCAQMD is collecting information for Southern California and DOGGR for the whole state, but there is a lack of expected overlap. The data collected from DOGGR's portal came from only four operators for 100 wells, whereas SCAQMD received information from over 20 different operators for about 500 different wells.

2.2. Hazard assessment

Washington State's Ecology Department's QCAT was used to evaluate hazards associated with acidizing chemicals. The QCAT evaluation is a two-step process that assigns a grade to each chemical.

QCAT examines nine hazard endpoints; carcinogenicity, mutagenicity and genotoxicity, reproductive toxicity, developmental toxicity, endocrine toxicity, acute mammalian toxicity, acute aquatic toxicity, persistence, and bioaccumulation.

Step 1 uses authoritative sources to rank each chemical's hazard endpoints as very high, high, moderate, or low. The authoritative sources for Step 1 are toxicity characteristics

lists and databases generated by internationally recognized authoritative bodies or appropriate government agencies (US NIH, EC-REACH SVHS, IARC, Cal/EPA Prop 65, New Zealand HSNO, Lancet-Grandjean and Landrigan list, etc.). The chemical is ranked in accordance with the strength of the authority and the nature of the classification (Category 1, Priority list, etc.). Once each endpoint is ranked, a grade can be assigned. The grade is assigned on the basis of hazard endpoint-ranking combinations (see supplementary section for the process of assigning an initial grade). For example, a rank of high in carcinogenicity or reproductive toxicity automatically earns the chemical an F-grade.

If the hazard endpoints are found in Step 1 sources they are sufficient for assigning a grade. If however not all the hazard endpoints are found in Step 1 sources, one proceeds to the Step 2 sources. In some instances not all hazard endpoints are needed to assign an F-grade. For example, if a chemical is carcinogenic it is given an F-grade and no information from a Step 2 sources could give it a lower grade. Once the chemical is identified as an F-grade chemical in Step 1 there is no need to look further into Step 2 sources.

Step 2 requires more technical expertise. Its sources could include measured data from publicly available risk assessments and databases such as the Registry of Toxic Effects of Chemical Substances (RTECS) and the Hazardous Substances Data Bank (HSDB), or estimated data from PBT Profiler or other modeling tools. For the purposes of this paper only Step 1 sources were used. All F-graded chemicals have been identified only using Step 1 sources. More F-graded chemicals could be identified through Step 2 sources. Table 3 explains the meanings of the grade levels assigned by the QCAT assessment.

Table 3. Grade levels from the QCAT assessment process.

Grade A	Few concerns (i.e. relatively safe)	Preferable
Grade B	Slight concern	Improvement possible
Grade C	Moderate concern	Use but search for safer alternative
Grade F	High concern	Avoid

Because a QCAT assessment only looks at selected endpoints, chemicals of concerns could be missed during the evaluation process. The QCAT assessment is not as thorough an evaluation of the hazards posed by a chemical as other screening methods, like the GreenScreen® method. However, based on the level of technical expertise required to use it, it is a good starting point to identify hazardous chemicals (Washington State Department of Ecology 2015).

3. Results and discussion

3.1. Acidizing events

Well operators submitted chemical reports to DOGGR for matrix acidizing and acid fracturing only. DOGGR does not require acid maintenance activities to be reported. To SCAQMD, operators submitted chemical reports for acid maintenance and matrix acidizing only. There were no reported instances of acid fracturing to SCAQMD. However, it should be noted that these reports were submitted prior to the actual treatment, and it is not possible to distinguish matrix acidizing from acid fracturing without reviewing well completion reports to determine whether the fracture pressure was exceeded. Operators typically do not distinguish matrix acidizing from acid fracturing. From April 2013 to

March 2014, operators did not distinguish the type of acidizing to SCAQMD. After this time period, operators were required to identify which acidizing technique they would perform. But as stated before the distinction can only be made once an operation is completed. March 2014 onwards there were hundreds of reported instances of acid maintenance and only a handful of cases for matrix acidizing. It is thus likely that the instances of acidizing in the early time period were also mainly acid maintenance cases.

DOGGR acidizing events were primarily in Elk Hills Oil Field in Kern County, California, 40 miles east of Bakersfield, California. They represent 5% of the total unconventional oil stimulation techniques reported to DOGGR; 95% were hydraulic fracturing or listed as other stimulations.

SCAQMD acidizing events were in highly urbanized city centers of Southern California. They represent 65% of the total events reported to SCAQMD. A breakdown of the reported acidizing events can be seen in Table 4. Surprisingly, the SCAQMD matrix acidizing events did not show up in DOGGR's database, though based upon legal jurisdiction they should have. The way local and state authorities define matrix acidizing or an issue of enforcement could explain this discrepancy. There were few acid fracturing events reported to DOGGR and none to SCAQMD. This is probably due to the geology of the region. Acid fracturing is most effective in carbonate formations, whereas most of the oil-bearing formations in California are sandstone. Given the lack of oversight and enforcement and broad range of discretion afforded operators, it is possible that the acidizing events are under-reported.

Table 4. Reported acidizing events in California.

Treatment type	Submitted proposals as of mid-August 2015
SCAQMD acid maintenance	474
SCAQMD acid matrix	6
DOGGR acid matrix	90
DOGGR acid fracturing	10

3.2. Acidizing chemicals

There are many chemicals used in acidizing with data gaps. Many chemicals are listed as trade secrets; others have no toxicological or even basic chemical property information available. As for chemicals with known hazardous endpoints, the amounts used are substantial and create high toxic loads per treatment. The high acidity creates uncertainties as to how chemicals will transform or how much heavy metal will leach out.

This section details the composition and amount of chemicals in acidizing fluids and compares it with hydraulic fracturing. It also details the amounts of F-graded chemicals used in acidizing and what the toxicological load per treatment is – meaning what mass of carcinogens or reproductive toxins, for example, are used per treatment. Finally, it looks at the potential impacts of the acidic fluid.

3.2.1. Composition of acidizing fluids

There are about 200 different chemicals and around 90 chemical families, trade secrets, or chemicals of undefined amount used in acidizing in California. A list of all the chemicals and their amounts reported to DOGGR and SCAQMD, grouped by acidizing technique, is set out in the supplemental materials.

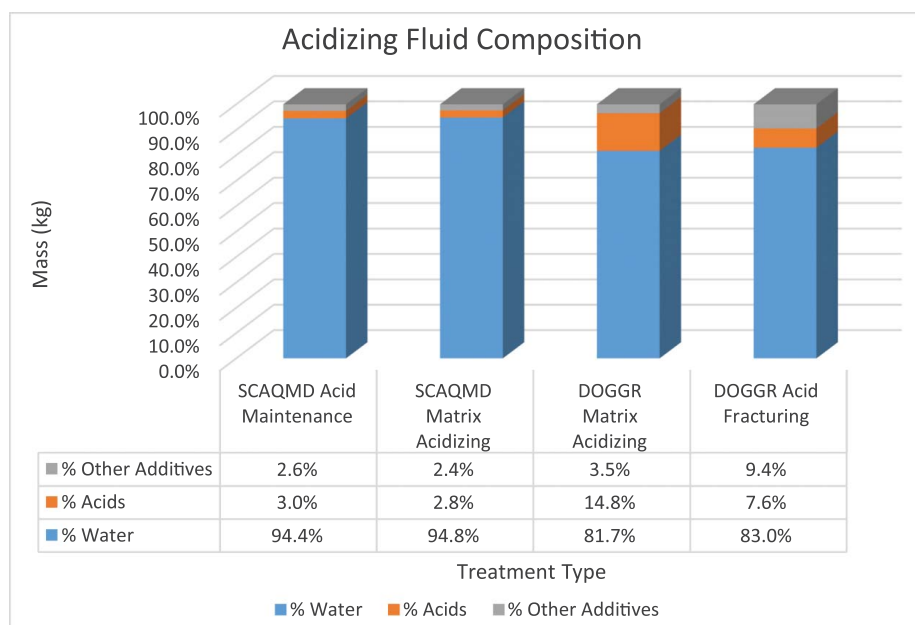


Figure 1. Acidizing fluid composition in California.

Unlike hydraulic fracturing fluid, where chemicals make up only 0.5% of the fluid (US DOE 2009), acidizing chemicals (acids and other chemicals, not including silica in acid fracturing) can make up 17% (acid fracturing), 5%–18% (matrix acidizing), or 6% (acid maintenance) of the fluid. Figure 1 shows a graphical representation of these percentages. Matrix acidizing as reported to DOGGR on average is the most concentrated with at least 81.7% being water and up to 18.3% other chemicals, of which 15% is acid. Acid fracturing as reported to DOGGR is about 8% acid and 9% other additives. In general, acidizing reported to SCAQMD had acids making up 3% of the fluid and other additives around 2.5% of the fluid.

These concentrated fluids have a greater impact than diluted hydraulic fracturing fluid. Microbes are not as effective at breaking down organic chemicals at higher concentrations, making them more persistent in the environment (Kekacs et al. 2015). Furthermore, new research is beginning to show that biocides that are used in unconventional oil stimulation techniques are also not effective at higher concentrations, possibly contributing to bacterial resistance to antibiotics (Kahrilas et al. 2015; Vikram, Bomberger, and Bibby 2015).

Although overall most of the chemicals used in acidizing are similar to the chemicals used in hydraulic fracturing (Stringfellow et al. 2014), those used most frequently in the two operations are different. If we compare the top 20 chemicals in Table 8 of the US EPA Report (2015) (20 most frequently reported additive ingredients in oil disclosures, ranked by frequency of occurrence) to the top 20 frequently used chemicals of acidizing techniques (Tables S4–S7), we see that only 10 of the most frequently used hydraulic fracturing chemicals are those that are used in acidizing treatments (the 10 most frequently used chemicals that are not among the most frequently used chemicals of hydraulic

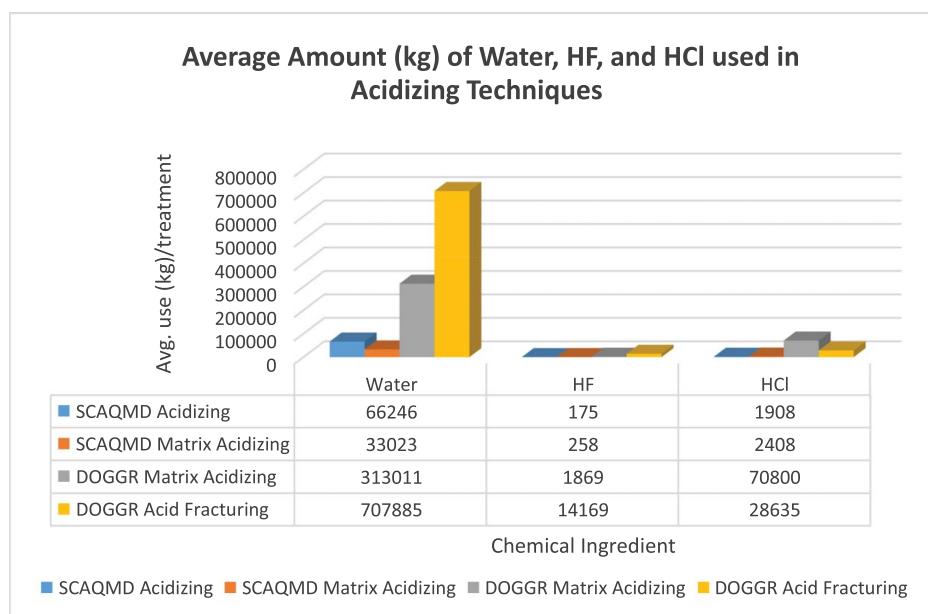


Figure 2. Average amount of water, HF, and HCl used in acidizing techniques.

fracturing are marked with an asterisks in the Tables S4–S7). In other words, 50% of the most frequently used chemicals of acidizing are different from the most frequently used chemicals of hydraulic fracturing, highlighting the need for increased research regarding the effects of acidizing.

Taking a closer look at water and acid use, Figure 2 shows the average amount of water, HF, and HCl used in acidizing.

The treatments reported to DOGGR, whether acid fracturing or matrix acidizing, used more water and acid. Acid fracturing used the most water, close to 700,000 kg/treatment. Acidizing is not as water intensive as hydraulic fracturing, and in general, California oil well stimulations use less water compared to other states. In other states hydraulic fracturing uses 4–12 million kg/well (CCST 2014), whereas in California the average use of water for the various acidizing techniques is between 60,000–700,000 kg/treatment.

Acid fracturing also used the most HF (~14,000 kg/treatment) of the treatments. Matrix acidizing as reported to DOGGR used the most HCl (~71,000 kg/treatment). The acidizing treatments reported to SCAQMD used the least HF (~200 kg/treatment) and HCl (~2300 kg/treatment).

HF is one of the more concerning chemicals, and is used in some of the largest quantities. HF is typically used in a combination with HCl and called mud acid (HF + HCl) to dissolve sandstone as well as remaining drilling mud. In Central California there is a greater use of mud acid. The average concentration by mass percentage (%w/w) of HF and HCl used in mud acid treatments is 0.5%–3% and 4%–15%, respectively (Scheiber 2013). Figure 2 shows that acid fracturing uses the most HF, more than 14,000 kg/treatment, followed by matrix acidizing (reported to DOGGR) at 1870 kg/treatment. All the treatments use more than the minimum reportable quantity of 45.4 kg, as set out by the

Emergency Planning and Notification Act, 40 CFR part 355. Even though acid maintenance uses on average 175 kg/treatment, it is such a common and routine procedure used in wells that the total accumulated load of HF in a region becomes significant. As for matrix acidization, more HF and HCl are used per treatment in Central California (reported to DOGGR) as opposed to Southern California (reported to SCAQMD). This difference could be because of geology or the scale of the activity in these regions. HF is primarily used to dissolve silicates and HCl for carbonates.

HF is of great concern because of its very high acute mammalian toxicity and neurotoxicity. Exposure to fumes or very short-term contact with liquid HF may cause severe and painful burns; it penetrates the skin to cause deep-seated ulceration that may lead to gangrene (National Center for Biotechnology Information 2015). Transport and storage of such large quantities of HF prior to use are serious concerns.

In addition, HF use in wells leaves fluoride behind which can also have detrimental impacts. Fluoride is beneficial in limited quantities for the mineralization of bones and formation of dental enamel. However, excessive fluoride is detrimental; 1.5–4 mg/L results in dental fluorosis, 4–10 mg/L results in skeletal fluorosis, and > 10 mg/L results in crippling fluorosis (Dissanayake 1991). If this excessive fluoride reaches drinking water sources, exposure becomes a serious concern.

The amount of HCl used also creates some concern. Individual reports show that HCl can be up to 270,000 kg/treatment. The %w/w of HCl reported in treatments other than mud acid mixtures is 15%–28%. HCl is corrosive to the eyes, skin, and mucous membranes. Chronic (long-term) occupational exposure to HCl has been reported to cause gastritis, chronic bronchitis, dermatitis, and photosensitization in workers. Prolonged exposure to low concentrations may also cause dental discoloration and erosion (US EPA 1999). Markey et al. (2014) also discuss the health and safety concerns of using HCl in oil drilling, as well as its corrosive impact on flow lines and equipment and environmental effects of the produced HCl.

3.2.2. F-graded chemicals

A main goal of this report was to identify the most toxic acidizing chemicals against a standard criterion. Table 5 lists the QCAT F-graded chemicals that are used in acidizing in California. They are listed in decreasing frequency of use. The primary hazardous toxicological endpoints of these chemicals are noted. These endpoints are detailed with references in the supplemental section.

There are at least 28 F-graded chemicals. The frequency of use and average amount per treatment gives an idea of exposure. However, information about the fate and transport of the chemicals, their transformations, synergistic and cumulative effects, as well as routes of exposure, are vital to understanding their true risk. The most commonly used F-graded chemicals in all acidizing treatments that were used on average in the 100's–1000's kg/treatment are methanol, HF, xylene, and diethylene glycol. These four chemicals are all neurotoxins and in some cases are also developmental or reproductive toxins. Methanol was used in almost all the treatments. HCl, although not listed as an F-rated chemical was also used in most treatments. HF, polyethylene glycol nonylphenyl ether, ethylene glycol, and formaldehyde were used in about half of the treatments. The amount used per treatment and how often a treatment is done are important in understanding the toxicological load put on a certain area.



Table 5. QCAT F-graded chemicals used in acidizing in California (ordered in decreasing frequency of use).

Chemical	CAS #	Maximum treatment (kg)	Average (kg)/ treatment	Frequency of use	Acid maintenance	Matrix acidizing	Purpose*	Primary QCAT I low grade reason**
Methanol	67-56-1	32,062.42	261.86	505	✓	✓	Corrosion inhibitor, non-emulsifier, anti-sludging agents, wetting surfactant, clay stabilizer, solvent acidizing, well stimulation	Developmental toxin, neurotoxin, persistent
Hydrofluoric acid	7664-39-3	24,974.71	850.50	290	✓	✓	Acidizing, well stimulation	Acute mammalian toxicity, persistent, neurotoxin
Polyethylene glycol nonylphenyl ether, poly (oxy-1,2-ethandiy), A-(nonylphenyl)-W-hydroxy	9016-45-9	147.32	30.29	256	✓	✓	Non-emulsifier, surfactant	Developmental toxin, endocrine disruptor, persistent
Ethylene glycol	107-21-1	404.31	11.90	201	✓	✓	Cleaner	Developmental toxin, neurotoxin
Formaldehyde	50-00-0	32.06	0.22	191	✓	✓	Corrosion inhibitor	Carcinogen
Xylene	1330-20-7	11,509.90	361.70	169	✓	✓	Surfactant, solvent, asphaltene dispersant, paraffin inhibitor, demulsifier, cleaner	Reproductive toxin, neurotoxin
Naphthalene	91-20-3	28.08	1.79	169	✓	✓	Surfactant, non-emulsifier, solvent	Carcinogen, acute aquatic toxicity
Ethylbenzene	100-41-4	2578.80	52.40	160	✓	✓	Surfactant, solvent, cleaner	Carcinogen, reproductive toxin, persistent
Cumene	98-82-8	1.39	0.33	146	✓	✓	Demulsifier, surfactant	Carcinogen, neurotoxin
Diethylene glycol	111-46-6	5013.96	1667.81	141	✓	✓	Corrosion inhibitor	Neurotoxin
Ethylene oxide	75-21-8	0.50	0.01	105	✓	✓		Carcinogen, mutagen, developmental toxin, reproductive toxin, neurotoxin, persistent
Silica, amorphous-fumed	7631-86-9	31,895.35	395.51	81	✓	✓	Proppant, friction reducer	Occupational carcinogen, persistent
Crystalline silica	14808-60-7	6769.86	537.70	28	✓	✓	Sand control, proppant	Carcinogen, very high acute mammalian toxicity, persistent
Nitrioltriacetic acid	139-13-9	3206.24	282.67	27	✓	✓	Iron control	Carcinogen, mutagen
Ethanol	64-17-5	857.11	84.12	26	✓	✓	Wellbore cleaner, clay control, iron control	Carcinogen, reproductive toxin, mutagen, persistent
Light aromatic naphtha	64742-95-6	62.23	12.98	21	✓	✓	Non-emulsifier	Carcinogen, mutagen
Cristobalite	14464-46-1	31,895.35	1993.54	16	✓	✓	Proppant, friction reducer	Carcinogen, occupational carcinogen, persistent
Diisopropyl naphthalene/bis (isopropyl) naphthalene	38640-62-9	2.50	1.90	14	✓	✓	Non-emulsifier	Carcinogen, persistent
Toluene	108-88-3	660.11	144.98	13	✓	✓	Solvent, asphaltene dispersant	Reproductive toxin, developmental toxin, persistent

(continued)

Table 5. (Continued)

Chemical	CAS #	Maximum (kg)/ treatment	Average (kg)/ treatment	Frequency of use	Acid maintenance	Matrix acidizing	Acid fracturing	Purpose*	Primary QCAT low grade reason**
Paraffinic petroleum distillate	64742-55-8	34.51	14.23	12		✓	✓		Carcinogen, persistent
Diethanolamine	111-42-2	27.43	5.30	9		✓	✓	Corrosion inhibitor, surfactant	Carcinogen
Methyl isobutyl ketone	108-10-1	27.43	5.30	9		✓	✓	Solvent	Carcinogen, developmental toxin, neurotoxin
Oxyalkylated alkylphenol; polyethylene glycol mono (branched P-nonylphenyl) ether	127087-87-0	12.23	7.45	6		✓	✓	Surfactant, wellbore cleaner, emulsifier, wetting agent	Developmental toxin, reproductive toxin, endocrine disruptor, persistent
Oxyalkylated alkylphenol; polyethylene glycol nonylphenyl ether; poly (oxy-1,2-ethandiyl), A- (nonylphenyl)-W-hydroxy	26027-38-3	12.23	6.90	5		✓	✓		Developmental toxin, reproductive toxin, endocrine disruptor, persistent
Boric acid (H3BO3)	10043-35-3	487.63	299.07	4		✓	✓		Developmental toxin, reproductive toxin, persistent
Cyclotetrasiloxane, 2,2,4,4,6,6,8,8- octamethyl-	556-67-2	0.02	0.02	2	✓			Friction reducer	Reproductive toxin, endocrine disruptor, very persistent
Acrylamide	79-06-1	0.06	0.06	1		✓			Carcinogen, mutagen, developmental toxin, reproductive toxin, neurotoxin
Acrylonitrile	107-13-1	0.0004	0.0004	1			✓		Carcinogen, persistent

*Chemical purposes listed are what the oil operator identifies.

**See the appendix for references for the toxicological endpoints.

The maximum reported use is also listed in Table 5. Some values are far above the average amounts used and may have been mis-reported. Methanol is reported to be used in up to 32,000 kg/treatment, HF up to 25,000 kg/treatment, xylene up to 12,000 kg/treatment, ethylbenzene up to 2600 kg/treatment, diethylene glycol up to 5000 kg/, and silica and cristobalite up to 32,000 kg/treatment. Their various toxicological endpoints can be seen in Table 5.

3.2.3. Toxicological load

In addition to identifying the F-rated chemicals, it is important to understand the toxicological load, or amount of carcinogens or reproductive toxins, for example, per acidizing treatment (see Figure 3).

In acid maintenance there is a high reproductive toxin load from xylene, ethylbenzene, and toluene. The high neurotoxin load is primarily from xylene and HF. Crystalline silica, ethylbenzene, and nitriloacetic acid are the main contributing carcinogens. HF and crystalline silica cause the high acute mammalian toxicity load.

In matrix acidizing as reported to SCAQMD there is a higher reproductive toxin load from xylene and ethylbenzene as well as a neurotoxin load from xylene, methanol, and HF. In matrix acidization reported to DOGGR the high developmental toxin and neurotoxin load are primarily from methanol. HF, xylene, and diethylene glycol also add substantially to the neurotoxin load. The acute mammalian toxicity is primarily from HF. Nitrotriatic acid is the main carcinogen accounting for the high load.

The acid fracturing treatments have the largest carcinogen load from silica use. The high neurotoxicity and high acute mammalian toxicity in acid fracturing are from HF.

There are between 7000–90,000 kg/treatment of these seven toxicological endpoint chemicals listed in any one acidizing treatment at one time. The actual amounts used in the treatment can be found in the supplemental section (Tables S4–S7). The weighted toxicological impact of these chemicals do not take into account any transformation, or

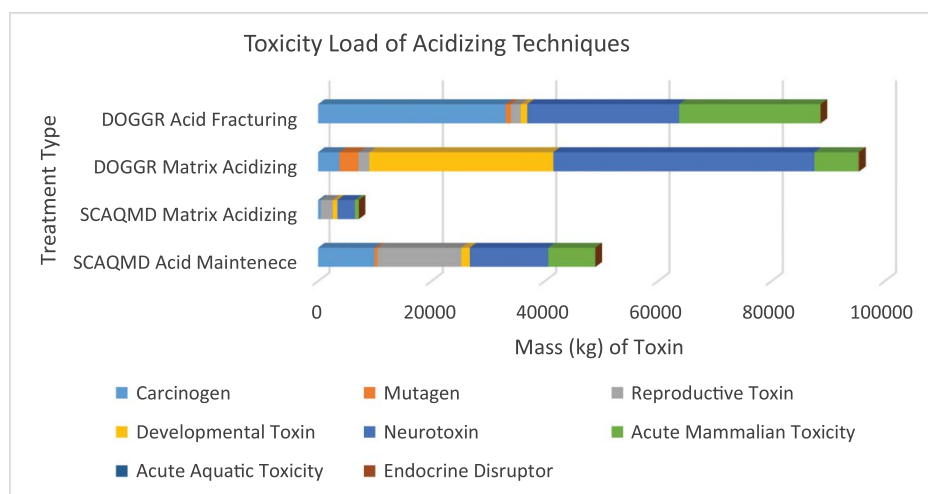


Figure 3. Toxicity load of acidizing techniques in California.

Table 6. Range of pH of matrix acidizing flowback water.

Treatment type	Range of pH of flowback	Time period or volume amount measured over	Reference
HCl/HF (5 diff. treatments)	0.5–3.5 (2.2–3.2)	200 min 500–700 bbl	Schuchart (1995)
15% HCl/1.5% HF	0–3	600 bbl	Gdanski and Peavy (1986)
15% HCl	0.2–5	5 h	Taylor, Nasr-El-Din, and Dajani (1999)

*bbl – oil barrel = 42 US gallon.

synergistic or cumulative impacts. In a highly acidic environment the stability and reactivity of the chemicals are unknown. The potential environmental impact of these chemicals and their byproducts is also unknown. Another problem of acidic solutions is the dissolution and mobilization of naturally occurring heavy metals and other pollutants from the oil-bearing formation, the extent of which is also unknown (CCST 2015).

It should be noted that not only is the acidizing fluid acidic, but the “flowback,” in the case of matrix acidization for example, can also be acidic. A few industry reports show that the pH of returning waste is mainly between 0 and 3 for the first few hours (see Table 6). It is unknown how much of the chemicals returns to the surface for acidizing, but recent data submitted to DOGGR by operators show that the volume of recovered fluids collected after matrix acidization is 50%–60% (CCST 2015)

4. Conclusions

The analysis of the present data shows that there have been 474 reported acid maintenance events in Southern California, 96 reported matrix acidization events in Central and Southern California, and 10 reported acid fracturing events in Central California from April 2013 to mid-August 2015. In Southern California, acidization events are occurring in highly urban areas around Los Angeles County. There are about 200 chemicals used in acidization, and 50% of the most commonly used acidizing chemicals are most commonly used hydraulic fracturing treatment chemicals. Unlike hydraulic fracturing, the chemical concentrations in the fluids for acidization are high, ranging from 6% to 18% chemicals, and the waste that returns can also be highly acidic.

The amounts of chemical used per treatment are anywhere between 100’s of milligrams and 100,000’s of kilograms. Some of the chemicals are known to be of concern for both human health and the environment. An initial hazard assessment was done, and 28 QCAT F-graded chemicals of concern have been identified. It should be noted that close to 90 other chemicals are identified by non-specific names, family classes, or chemicals of undefined amount.

Furthermore, the flowback conditions, pH of the fluid and what chemicals are returning are unknown. The toxicity, the chemical fate and transport, and exposure potential of all these chemicals should be understood, and if a hazard is noted then substitute chemicals should be suggested. Understanding where these chemicals are likely to end up in our environment is critical in predicting how vulnerable populations will be affected. Understanding the toxicity will help us to identify possible impacts we might see in the near to distant future on humans and other living organisms. The stability and reactivity of these chemicals under such strong acid conditions is also unknown. The potential hazard of these chemicals and their byproducts have unknown environmental impacts.

The aim of this paper was to present potential problems of acidizing that need to be investigated so that scientists and legislators can evaluate the environmental impact of acidization. There is a need for the most up-to-date information on what chemicals and quantities are being used and the specific uses of these chemicals. The information in this paper only includes self-reported information, which is limited. There needs to be a transparent way to gather information from industry. Even more important is the need for monitoring and reporting of what is returning as wastewater.

Future research should include identifying appropriate stable indicator chemicals or stable byproduct chemicals from the process that can be monitored in groundwater to track any leakage from wellbores or disposal wells and pits. Possible treatment techniques for chemicals of concern in the wastewater as well as the water remaining in the ground that can contaminate groundwater should also be researched. The feasibility of treatment needs to consider cost effectiveness. If acidization is to be used in oil exploration we need to be aware of the possible impacts and ways to prevent them, including appropriate treatment of residual water at the surface and in the ground. Finally, understanding the current regulatory framework and jurisdiction that is in place to regulate acidization effectively, as well as identifying the gaps that exist, are important in moving forward to safely regulate acidization.

Acknowledgments

We thank the National Water Research Institute and The Schmidt Family Foundation for supporting this research. A special thanks to Jennifer Taylor and Zhongtian Li for their help with this project.

Disclosure statement

No potential conflict of interest was reported by the authors.

Funding

National Water Research Institute; The Schmidt Family Foundation.

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Supplemental Section

Table S1: Acid Selection for Different Minerals (Scheiber 2013)

Nearly all acids dissolve	HF, HCl/HF, HBF ₄ , dissolve
Carbonates:	Silicates:
- Calcite CaCO ₃	- Quartz SiO ₂
- Dolomite CaMg(CO ₃) ₂	- Feldspars (Plagioclase, Orthoclase, ...)
	- Micas (Biotite, Muscovite)
	- Clay minerals (Kaolinite, Smectite, Illite, Chlorite)
And	
	Oxides and Hydroxides:
	- Hematite Fe ₂ O ₃
	- Goethite FeOOH
	- Magnetite Fe ₃ O ₄
Note: Sulfates (Gypsum [CaSO ₄ x 2H ₂ O], Anhydrite [CaSO ₄], and Barite [BaSO ₄]) have low solubility in acids.	

Table S2: Types of Additives Present in the Acid Solution

Acidizing Additives	Purpose
Corrosion Inhibitor	Corrosion inhibitors are used to reduce the reaction of acid with the metallic iron in the pipes. The inhibitor will form and maintain a film on the iron surface [Robertson, Chilingarian and Kumar 1989; Williams, Gidley and Schechter 1979].
Surfactants	Surfactants lower the surface tension or interfacial tension between fluids. They are used as wetting agents, penetrating agents, sludge preventers and foaming agents, acid solvent dispersants, mud dispersants, emulsion breakers, retarders, and suspending agents.
Iron-control Agents	These include iron complexing agents, iron reducing agents, and hydrogen sulfide scavengers to keep iron in solution without precipitating iron salts.
Mutual Solvent	Solvents are used to improve solubility of additives and to remove hydrocarbons and different additives [Robertson, Chilingarian and Kumar 1989; Kalfayan 2008].
Clay Stabilizer	These additives adhere to the borehole wall, effectively sealing the surface and inhibiting clay minerals or other fines from moving into the formation (Weatherford 2014).
Calcium Complexing Agents (Calcium Sulfate Inhibitors, scale inhibitors)	These are used in formations with high sulfate-ion content in the formation water (usually greater than 1,000 ppm) or rock containing anhydrite to prevent the formation of calcium sulfate precipitate. Phosphonates, sulfonates, and polyacrylates are used to prevent formation of calcium scale (Kalfayan 2008).
Diverting (Gelling) Agent	Diverting agents are a viscous gel or suspension of graded solids used to temporarily block off the most permeable sections of reservoir and force the acid into less

	permeable sections (Williams, Gidley and Schechter 1979).
Acid Fluid-loss Additive	Fluid-loss additives prevent water from migrating into the permeable formation leaving other fluid components behind (Halliburton 2014).
Cleanup Additive	Cleanup additives are used to remove spent acid in low-pressure reservoirs. Gaseous nitrogen, alcohols, or surfactants are used (Foshee and Hurst 1965; Howard and Fast 1970).
pH Adjusting Agent	Acids and bases are added to adjust the pH to the desired level.
Biocide	Biocides are added to control bacterial growth during and after well stimulation.
Proppant	A proppant is a solid material, typically silica, used to keep an induced fracture open.

The two diagrams below taken from the CCST (2015) report show surface and subsurface contamination pathways from oil stimulation activities.

Figure S1: Potential Contaminant Release Mechanisms that Originate at the Surface Related to Stimulation, Production, and Wastewater Management and Disposal Activities in California (CCST 2015).

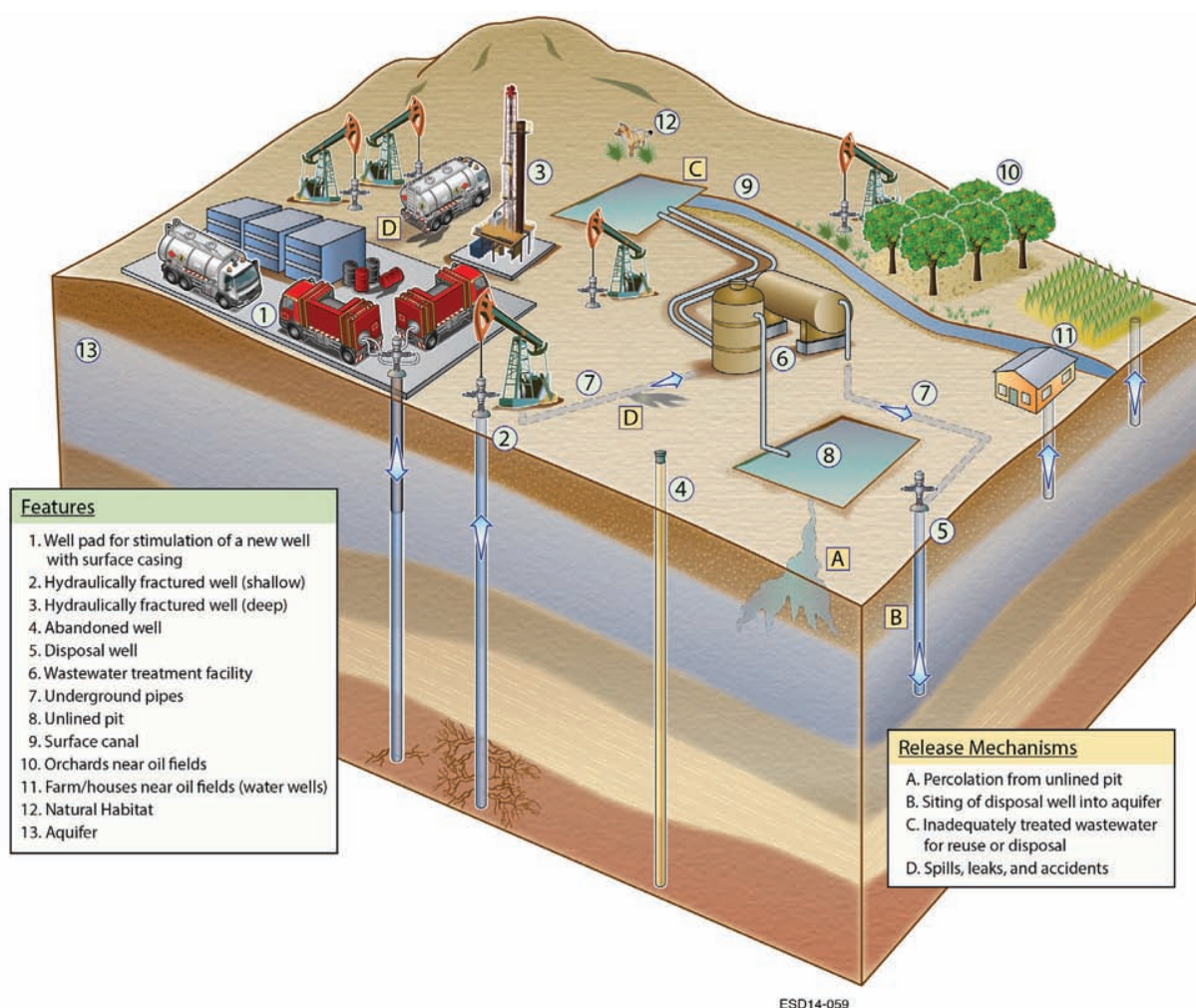


Figure S2: Potential Release Mechanisms and Transport Pathways in California that Could Originate in the Subsurface (CCST 2015).

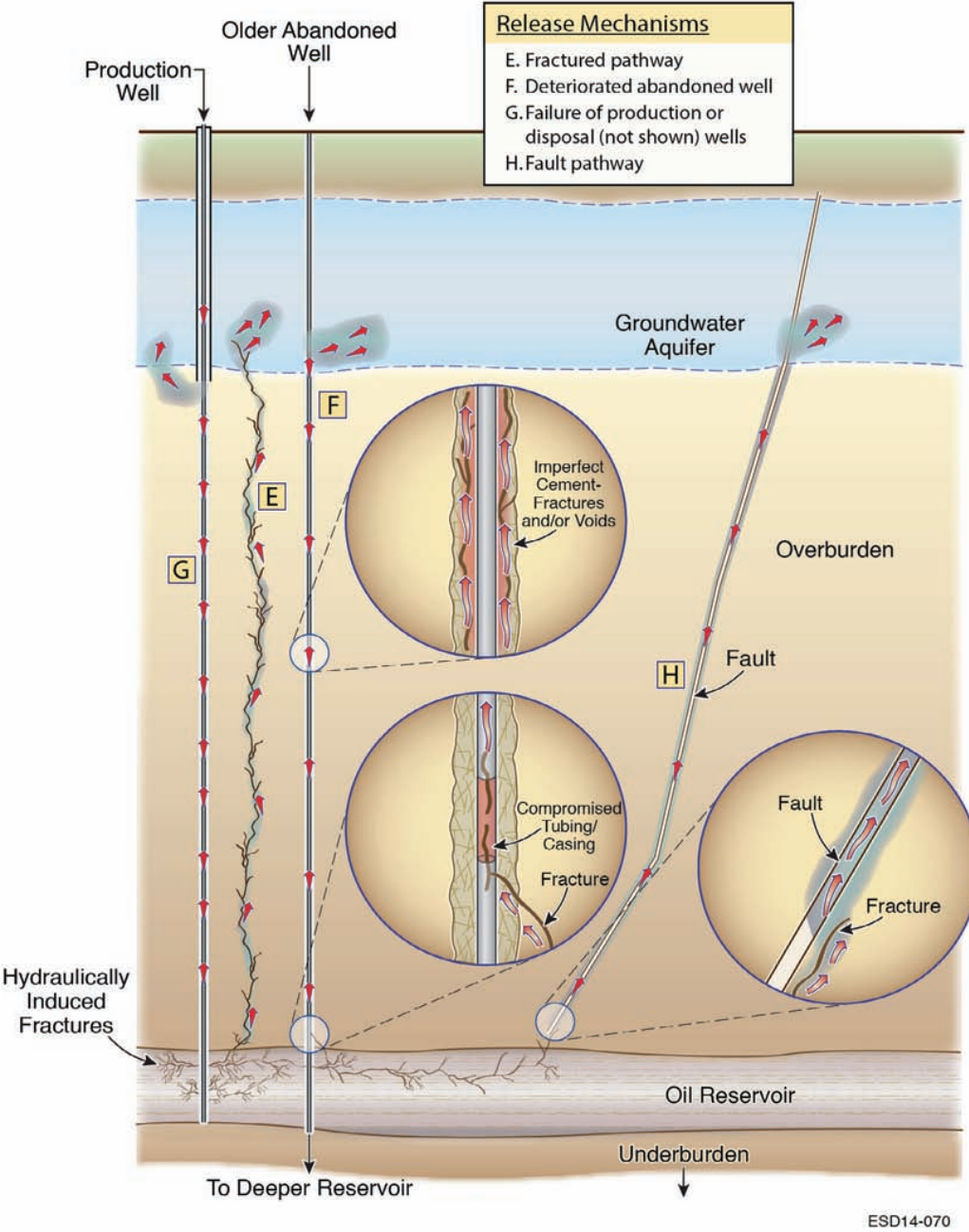


Table S3: QCAT Process for Assigning an Initial Grade

Grade A	1. Low P + Low T (AA, AT and all HH endpoints)
Grade B	1. Moderate P; or 2. Moderate B; or 3. Moderate AA; or 4. Moderate AT or one or more HH endpoints
Grade C	1. Moderate P + Moderate B + Moderate T (AA, AT, or any HH endpoint); or 2. High P & High B; or 3. High P + Moderate T (AA, AT, or any HH endpoint); or 4. High B + Moderate T (AA, AT, or any HH endpoint); or 5. Very High T (AA or AT)
Grade F	1. PBT = High P + High B + [Very High T (AA or AT) or High T (HH)]; or 2. vPvB = very High P + very High B; or 3. vPT = very High P + [very High T (AA or AT) or High T (HH)]; or 4. vBT = very High B + [very High T (AA or AT) or High T (HH)]; or 5. High T (HH)

Legend

AA = Acute Aquatic Toxicity	P = Persistence
AT = Acute Mammalian Toxicity	PBT = Persistent, Bioaccumulative, & Toxic
B = Bioaccumulation	R = Reproductive toxicity
C = Carcinogenicity	T = Toxic
D = Developmental Toxicity	vBT = very Bioaccumulative & Toxic
E = Endocrine Activity	vPT = very Persistent & Toxic
HH = Human Health (C, M/G, R, D & EA)	vPvB = very Persistent & very Bioaccumulative
M = Mutagenicity/Genotoxicity	

The following tables list chemicals and their amounts that are reported to be in use for the various acidizing techniques in California. Some of the chemicals listed under <1 kg/treatment are impurities that are not added alone but are often found with other chemicals. Impurities are common in industrial-grade chemicals, which are rarely 100% pure. Impurities are frequently residual feedstock materials from the manufacturing process or solvents and other materials added to control product consistency or handling properties.

The tables list the chemical name, purpose (as identified by the operator), CAS #, Maximum and Average mass used per treatment, frequency (number of times used), and for the SCAQMD lists whether it is an air toxic or not. The chemicals are ordered from most frequently used to least frequently used. The chemicals in red are the QCAT F-graded chemicals. CAS#'s that have an asterisk represent the most

frequently used chemicals of acidizing that are different than the 20 most frequently used chemicals of acidizing as reported in the US EPA report (2015) (Table 8: Twenty most frequently reported additive ingredients in oil disclosures, ranked by frequency of occurrence). The top 20 most frequently used chemicals of acidizing (Table S4-S7) were compared to Table 8 of the US EPA (2015) report.

Table S4: Chemicals Of Acid Maintenance (as reported to SCAQMD) Listed by Decreasing Frequency of Use

Name	Purpose	CAS #	Maximum (kg)/treatment	Average (kg)/treatment	Frequency of Uses	Air Toxic
Methanol	Corrosion Inhibitor, Non-Emulsifier, Anti-Sludging Agents, Wetting Surfactant, Clay Stabilizer, Solvent	67-56-1	811.10	79.50	321	Y
Water	Carrier	7732-18-5*	3,342,910.9	66,245.5	313	N
Hydrochloric Acid	Acidizing, Solvent, Well Stimulation	7647-01-0	12,051.80	1,907.90	313	Y
Citric Acid	Iron Control	77-92-9	423.70	111.02	292	N
Ammonium Chloride	Displacement Fluid, Salt, Clay Stabilizer	12125-02-9*	3,600.20	683.80	271	N
Hydrofluoric Acid	Acidizing, Well Stimulation	7664-39-3*	1,512.70	175.10	234	Y
Erythorbic Acid	Iron Control	89-65-6*	95.30	17.40	220	N
Heavy Aromatic Naphtha	Surfactant, Non-Emulsifier, Cleaner	64742-94-5	2,806.80	33.64	218	N
Citrus Terpenes	Solvent	94266-47-4*	813.50	96.40	213	N
Propargyl Alcohol	Wellbore Cleaner, Corrosion Inhibitor	107-19-1*	17.00	4.10	209	N
Terpene Hydrocarbon	Solvent	68956-56-9*	581.05	66.63	208	N
Thiourea, Polymer With Formaldehyde And 1-Phenylethanone	Corrosion Inhibitor	68527-49-1*	42.05	12.80	196	Y
Sodium Chloride	Corrosion Inhibitor	7647-14-5	161.80	20.10	195	N
Formaldehyde	Corrosion Inhibitor	50-00-0*	0.07	0.02	187	Y
Ethylene Glycol Monobutyl Ether	Clean Wellbore And Formation, Surfactant, Corrosion Inhibitor, Scale Inhibitor, Solvent Dispersant, Paraffin Inhibitor, Solvent, Cleaner	111-76-2*	3,453.00	190.49	161	Y
Xylene	Surfactant, Solvent, Asphaltene Dispersant,	1330-20-7	11,509.90	348.50	155	Y

	Paraffin Inhibitor, Demulsifier, Cleaner					
Ethylbenzene	Surfactant, Solvent, Cleaner	100-41-4	2,578.80	44.10	152	Y
Naphthalene	Surfactant, Non- Emulsifier, Solvent	91-20-3	28.08	1.30	144	Y
Cumene	Demulsifier, Surfactant	98-82-8	0.80	0.30	139	Y
Petroleum Naphtha	Surfactant, Gelling Agent	64742-47-8	50.08	19.95	134	N
Propargyl Alcohol	Corrosion Inhibitor	107-19-7	19.10	5.40	95	N
Nonyl Phenol Ethoxylate	Non-Emulsifier, Surfactant	9016-45-9*	34.10	6.11	77	N
Ethyl Octynol	Corrosion Inhibitor	5877-42-9	19.10	5.36	75	N
1,2-Ethanediaminium, N1,N2-Bis[2-[Bis (2- Hydroxyethyl)Methylammonio] Ethyl]- N1,N2-Bis(2-Hydroxyethyl)- N1,N2-Dimethyl-, Chloride (1:4)	Clay Control	138879-94-4	345.36	96.51	73	N
Quinaldine	Corrosion Inhibitor	91-63-4	19.10	5.50	73	N
Isoquinoline	Corrosion Inhibitor	119-65-3	19.10	5.40	73	N
D-Limonene	Solvent	138-86-3	690.70	184.58	62	N
Acetic Acid	Acid Reaction Retardant, Solvent, Iron Control, Acidizing	64-19-7	7,027.50	682.90	46	N
Pine Oil	Corrosion Inhibitor	80020-90-3	17.30	5.10	40	N
Pine Oil	Corrosion Inhibitor	'8002-09-3	19.10	5.57	35	N
3-Aminopropyl (Sileanetriol)	Clay Control	58160-99-9	175.95	30.70	31	N
Potassium Chloride	Paraffin Dispersant, Carrier Fluid	7447-40-7	3,026.73	2,240.60	29	N
Nitrilotriacetic Acid	Iron Control	139-13-9	521.60	151.10	25	Y
1,2,4 Trimethylbenzene	Wellbore Cleaner, Solvent, Demulsifier	95-63-6	21.80	3.70	22	Y
Isobutylmethylcarbinol	Solvent, Non-Emulsifier	108-11-2	11.50	2.55	16	N
Diisopropylnaphthalene	Non-Emulsifier	38640-62-9	2.50	1.90	14	N
Light Aromatic Naphtha	Non-Emulsifier	64742-95-6	1.27	0.90	14	N
Ethanol	Wellbore Cleaner, Clay Control, Iron Control	64-17-5	29.30	7.70	13	N
2-Ethyl Hexanol	Demulsifier	104-76-7	57.10	19.50	12	N
Toluene	Solvent, Asphaltene Dispersant	108-88-3	660.11	168.40	11	Y
Benzene, C10-16-Alkyl Derivs.	Solvent, Asphaltene Dispersant, Non- Emulsifier	68648-87-3	0.20	0.06	11	N
Ethylene Glycol	Cleaner	107-21-1	4.60	1.10	10	Y
Ethylene Oxide	Na	75-21-8	0.50	0.05	10	Y

Phosphoric Acid, Calcium Salt (2:3)	Na	7758-87-4	29.94	3.70	9	N
Alcohols, C14-15, Ethoxylated (7EO)	NA	68951-67-7	29.30	4.90	9	N
Oxyalkylated Alkylphenolic Resin	Solvent, Non-Emulsifier	63428-92-2	13.80	3.70	8	N
Cyclohexanamine, Sulfate (1:1)	Non-Emulsifier	19834-02-7	0.90	0.20	8	N
Etidronic Acid	Acidizing	2809-21-4	1,350.10	477.90	7	N
Phosphonic Acid	Acidizing	13598-36-2	405.05	143.40	7	N
Phosphoric Acid, Calcium Salt (2:3)	Scale Remover	7664-38-2	0.88	0.49	7	N
Formic Acid	Corrosion Inhibitor, Scale Removal	64-18-6	685.80	195.50	5	N
Isopropanol	Corrosion Inhibitor, Non-Emulsifier	67-63-0	195.95	47.80	5	Y
Alcohols, C10-14, Ethoxylated	Anti-Sludging Agents	66455-15-0	64.20	45.80	5	N
Morpholine	Anti-Sludging Agents	110-91-8	5.35	3.80	5	N
Amines, Hydrogenated Tallow Alkyl, Acetates	Na	61790-59-8	3.20	0.60	5	N
Crystalline Silica	Sand Control	14808-60-7	6,769.86	5,009.70	3	N
Alumina Oxide	Sand Control	1344-28-1	1,292.70	956.60	3	N
Iron Oxide (Fe2O3)	Sand Control	1309-37-1	136.08	100.70	3	N
Potassium Oxide (K2O)	Sand Control	12136-45-7	136.08	100.70	3	N
Calcium Oxide (CaO)	Sand Control	1305-78-8	74.80	55.40	3	N
Sodium Sulfate	Friction Reducer	7757-82-6	26.31	10.40	3	N
Petroleum Naphtha	Surfactant	68990-35-2	23.95	23.20	3	N
Mesitylene	DEMULSIFIER	108-67-8	3.07	2.40	3	N
2-Mercaptoethanol	Corrosion Inhibitor	60-24-2	2.50	2.10	3	N
1,2,3-Trimethylbenzene	Demulsifier	526-73-8	1.40	1.10	3	N
Sulfuric Acid	Asphaltene Dispersant	7664-93-9	0.18	0.17	3	N
Formaldehyde, Polymer With 4-(1,1-Dimethylethyl)Phenol, 2-Methyloxirane And Oxirane	Demulsifier	30704-64-4	0.05	0.04	3	N
Cyclopentasiloxane, 2,2,4,4,6,6,8,8,10,10-Decamethyl-	Friction Reducer	541-02-6	0.02	0.02	3	N
Sulfuric Acid Ammonium Salt (1:2)	Friction Reducer	7783-20-2	7.20	7.20	2	Y
Diethylene Glycol	Corrosion Inhibitor	111-46-6	0.50	0.40	2	Y
Silica, Amorphous - Fumed	Friction Reducer	7631-86-9	0.20	0.20	2	N
Siloxanes And Silicones, Di-Me, Reaction Products With Silica	Friction Reducer	67762-90-7	0.20	0.20	2	N
Silicone Oil	Friction Reducer	6314-86-29	0.20	0.20	2	N

Cyclotetrasiloxane, 2,2,4,4,6,6,8,8-Octamethyl-	Friction Reducer	556-67-2	0.02	0.02	2	N
Tetrasodium Ethylenediaminetetraacetate	Friction Reducer	64-02-8	0.02	0.02	2	N
Cyclohexasiloxane, 2,2,4,4,6,6,8,8,10,10,12,12-Dodecamethyl-	Friction Reducer	540-97-6	0.02	0.02	2	N
Sodium Hydroxide	Friction Reducer	1310-73-2	0.02	0.02	2	Y
Calcium Chloride (CaCl ₂)	Salt	10043-52-4	1,791.70	1,791.70	1	N
Hydrochloric Acid	Well Stimulation	6747-01-0	787.90	787.90	1	N
Amides, Tallow, N-[3-(Dimethylamino)Propyl], N-Oxides	Diverting Agents	68647-77-8	292.20	292.20	1	N
Propylene Glycol	Diverting Agents	57-55-6	179.80	179.80	1	N
Octane Sulfonic Acid	Other Ingredient	5324-84-5	157.40	157.40	1	N
Thioglycolic Acid	Corrosion Inhibitor	68-11-1	98.00	98.00	1	N
Dodecylbenzene Sulfonic Acid	Surfactant	27176-87-0	94.40	94.40	1	N
Propylene Glycol Monomethyl Ether (Pgme)	Surfactant	107-98-2	94.40	94.40	1	Y
2-Oxiranemethanaminium, N,N,N-Trimethyl-, Chloride (1:1), Homopolymer	Clay Stabilizer	51838-31-4	60.10	60.10	1	N
Ethanaminium, N,N,N-Trimethyl-2-[(2-Methyl-1-Oxo-2-Propen-1-yl)Oxy]-, Methyl Sulfate (1:1), Polymer With 2-Propenamide	Gelling Agent	26006-22-4	49.80	49.80	1	N
Aromatic Amine, Tofa Salt	Corrosion Inhibitor		24.30	24.30	1	N
Calcium Bromide	Salt	7789-41-5	17.90	17.90	1	N
Carbonic Acid Sodium Salt (1:2)	Na	497-19-8	13.60	13.60	1	N
Glycolic Acid	Scale Remover	79-14-1	9.80	9.80	1	N
Sulfonic Acids, C14-16-Alkane Hydroxy And C14-16-Alkene, Sodium Salts	Na	68439-57-6	5.40	5.40	1	N
Dodecylbenzene (Impurity)	NA	123-01-3	5.40	5.40	1	N
Acetone	Na	67-64-1	3.60	3.60	1	N
Glycerine	Surfactant	56-81-5	0.20	0.20	1	N
Acetophenone	Corrosion Inhibitor, Cleaner	98-86-2	0.01	0.01	1	Y

* Chemicals most frequently used in acidization and not frequently used in hydraulic fracturing

Table S5: Chemicals Of Matrix Acidization (as reported to SCAQMD) Listed by Decreasing Frequency of Use

Chemical Ingredient	Purpose	CAS	Maximum (kg)/treatment	Average (kg)/treatment	Frequency of Use	Air Toxic
Water	Carrier	7732-18-5*	76,820.90	33,023.40	6	N
Hydrochloric Acid	Well Stimulation	7647-01-0	5,491.80	2,408.40	6	Y
Ammonium Chloride ((Nh4)Cl)	Displacement Fluid	12125-02-9*	1,059.23	614.40	6	N
Methanol	Corrosion Inhibitor	67-56-1	790.50	293.00	6	Y
Hydrofluoric Acid	Well Cleanout	7664-39-3*	689.13	257.60	6	Y
Ethylene Glycol Monobutyl Ether	Solvent	111-76-2*	242.04	81.20	6	Y
Citric Acid	Iron Control	77-92-9	201.10	83.30	6	N
Heavy Aromatic Naphtha	Solvent Dispersant, Emulsifier	64742-94-5	142.61	39.60	6	N
Propargyl Alcohol	Corrosion Inhibitor	107-19-7	12.14	5.70	6	N
Ethyl Octynol	Corrosion Inhibitor	5877-42-9	12.10	5.38	6	N
Isoquinoline	Corrosion Inhibitor	119-65-3	12.10	5.40	6	N
D-Limonene	Solvent, Dissolves Parrafin And Asphaltene	138-86-3	157.94	89.80	5	N
Quinaldine	Corrosion Inhibitor	91-63-4	12.10	5.40	5	N
Pine Oil	Corrosion Inhibitor	80020-90-3	12.10	5.40	5	N
Xylene	Solvent	1330-20-7	1,613.61	1,613.61	2	N
Ethylbenzene	Solvent	100-41-4	484.08	484.08	2	N
Toluene	Solvent	108-88-3	16.14	16.14	2	N

* Chemicals most frequently used in acidization and not frequently used in hydraulic fracturing

Table S6: Chemicals of Matrix Acidization (as reported to DOGGR) Listed by Decreasing Frequency of Use

Purpose	Chemical Name	CAS #	Maximum (kg)/treatment	Average (kg)/treatment	Frequency of Use
Solvent, Cleaner	Ethylene Glycol Monobutyl Ether	111-76-2*	14,985.00	7,485.90	209
Base Fluid	Water	7732-18-5*	2,757,368.40	313,010.90	198
	Ethylene Glycol	107-21-1	56.35	10.40	190

Cleaner	Isopropanol	67-63-0	2,013.31	574.50	185
	Nonyl Phenol Ethoxylate	9016-45-9*	147.32	41.30	176
Corrosion Inhibitor	Methanol	67-56-1	32,062.42	603.72	174
Solvent	Hydrochloric Acid	7647-01-0	250,828.84	70,800.00	162
Anti-Sludging Agent	Dodecylbenzene Sulfonic Acid	27176-87-0	7,856.82	2,256.00	159
Intensifier	Formic Acid	64-18-6	16,106.47	3,768.00	145
Iron Reducing Agent	Citric Acid	77-92-9	13,553.01	2,023.50	144
	Ethoxylated Hexanol	68439-45-2	2,455.25	793.60	143
	Cinnamaldehyde	104-55-2	5,106.93	1,658.00	142
	Diethylene Glycol	111-46-6	5,013.96	1,691.80	139
	Poly(Oxy-1,2-Ethanediyl), Alpha-Hexyl-Omega-	31726-34-8	5,374.23	1,599.50	131
	2-Ethyl Hexanol	104-76-7	1,343.56	396.30	131
	Alcohols, C12-16, Ethoxylated	68551-12-2	3,433.03	985.80	115
	Ethylene Oxide	75-21-8	0.00	0.00	95
	Amine Oxides, Cocoalkyldimethyl	61788-90-7	1,312.06	513.60	89
	Sodium Iodide	7681-82-5	707.10	60.80	89
	Benzaldehyde	100-52-7	287.55	103.10	89
	Copper Dichloride	7447-39-4	1.87	0.71	89
Solvent	Acetic Acid	64-19-7	16,106.47	4,020.20	79
	Silica, Amorphous - Fumed	7631-86-9	8.04	1.80	78
	Ammonium Bifluoride	1341-49-7	72,443.94	17,194.50	77
	Hydroxylamine Hydrochloride	5470-11-1	651.99	221.40	62
	Hydrofluoric Acid	7664-39-3*	7,760.66	1,868.60	41
	Ammonium Chloride	12125-02-9*	64,124.85	19,678.80	37
	Polyethylene Oxide	25322-68-3	320.62	25.90	23
	Potassium Acetate	127-08-2	5.63	0.70	21
	Thiourea, Polymer With Formaldehyde and 1-Phenylethanone	685 27-49-1	6,483.16	845.00	20
	Fatty Acids, Tall-Oil	61790-12-3	6,483.16	845.00	20
	Alcohols, C14-15, Ethoxylated {7EO}	68951-67-7	3,206.24	299.60	20
	Propargyl Alcohol	107-19-7	3,206.24	294.30	20
	Alcohol, C11 Linear, Ethoxylated	34398-01-1	648.32	111.90	20
	Heavy Aromatic Naphtha	64742-94-5	64.83	15.10	20
	Propylene Glycol	57-55-6	7.86	1.60	20
	Naphtalene {Impurity}	91-20-3	1.71	5.83	20
	Alkenes, C>10 A-	64743-02-8	648.32	45.50	19
	Sodium Glycolate (Impurity)	2836-32-0	648.32	88.10	19
	Trisodium Ethylenediaminetetraacetate	150-38-9	563.50	57.40	19

	Impurity}				
	Sodium Hydroxide	1310-73-2	563.50	57.40	19
	Alcohol, C11-14, Ethoxylated	78330-21-9	320.62	30.70	19
	Alcohol, C9-11-Iso, C10, Ethoxylated	78330-20-8	320.62	30.70	19
	Alcohol, C7-9-Iso, C8, Ethoxylated	78330-19-5	320.62	30.70	19
	Quaternary Ammonium Compounds Chlorides Derivatives	68989-00-4	320.62	30.70	19
	Trisodium Nitrilotriacetate (Impurity)	5064-31-3	320.62	30.70	19
	Ethoxylated Propoxylated 4- Nonylphenol-Formaldehyde Resin	30846-35-6	320.62	30.70	19
	Disodium Ethylene Diamine Tetra Acetate {Impurity}	139-33-3	320.62	57.40	19
	Sulfuric Acid	7664-93-9	4.02	1.25	19
	Sodium Etythorbate	6381-77-7	3,206.24	292.80	18
	Alcohol, C9-C11, Ethoxylated	68439-46-3	648.32	61.70	18
	Methyl Oxirane Polymer With Oxirane	2594-62-8	407.99	26.40	18
	Potassium Oleate	143-18-0	5.63	0.57	18
	Linear/Branched Alcohol Ethoxylate (11eo)	127036-24-2	8,040.46	87.80	16
	Tetrasodium Ethylenediaminetetraacetate	64-02-8	170.95	88.50	16
	Coco-Amido-Propylamine Oxide	68155-09-9	17.10	8.85	16
	Alcohols, C10-14, Ethoxylated	66455-15-0	17.10	8.85	16
	Glycerol	56-81-5	17.10	141.50	16
	Diatomaceous Earth, Calcined	91053-39-3	10.26	8.85	16
	Dicoco Dimethyl Quaternary Ammonium Chloride	61789-77-3	1.71	0.88	16
	Dioctyl Sulfosuccinate Sodium Salt	577-11-7	1.71	0.88	16
	Magnesium Chloride	7786-30-3	1.03	0.88	16
	Crystalline Silica: Quartz (SiO ₂)	14808-60-7	0.94	0.14	16
	Dodecylbenzene (Impurity)	123-01-3	0.17	0.88	16
	Oleic Acid	112-80-1	0.17	0.09	16
	Crosslinked PO/EO-Block Polymer	68123-18-2	17.10	8.85	15
	5-Chloro-2-Methyl-2h-Isothiazol-3- One	26172-55-4	1.71	0.88	15
	Magnesium Nitrate	10377-60-3	1.71	0.88	15
	2-Methyl-2h-Isothiazol-3-One	2682-20-4	0.17	0.09	15
	Cristobalite	14464-46-1	0.10	0.09	15
	Hydroxylamine Hydrochloride	1304-22-2	674.96	249.30	14
	Etidronic Acid	2809-21-4	6,463.27	3,824.50	6
	Polyamines	68815-65-1	235.65	110.40	6
	Ethoxylated Alcohol C12-15	68131-39-5	563.50	118.10	5
	Guar Gum	9000-30-0	320.62	82.80	5
	Citrus Terpenes	94266-47-4*	39.27	22.46	5

	Tetrasodium Ethylenediaminetetraacetate	64-02-8	6,483.16	11,045.20	4
	Phosphonic Acid	13598-36-2	1,984.50	1,670.00	4
	Methyl Oxirane Polymer With Oxirane	9003-11-6	563.50	152.80	4
	1,2-Ethanediaminium, N1,N2-Bis[2-[Bis(2-Hydroxyethyl)Methylammonio]Ethyl]-N1,N2-Bis(2-Hydroxyethyl)-N1,N2-Dimethyl-, Chloride (1:4)	138879-94-4	479.90	321.50	4
	Erythorbic Acid	89-65-6*	478.82	210.70	4
	1-Octadecene (C18)	112-88-9	320.62	188.50	4
	Ethanol	64-17-5	138.20	103.50	4
	TRIETHYLENE GLYCOL	112-27-6	102.12	58.50	4
	Silanetrio; (3-Aminopropyl, Homopolymer)	68400-07-7	101.15	81.70	4
	Nonionic Alkoxylate	70559-25-0	78.55	45.00	4
	3-Aminopropyl (Sileanetriol)	58160-99-9	17.68	13.60	4
	Ethoxylated Castor Oil	61791-12-6	7.86	4.50	4
	Diethanolamine	111-42-2	4.02	3.00	4
	Methyl Isobutyl Ketone	108-10-1	4.02	3.00	4
	Xylene	1330-20-7	1,184.91	682.10	3
	Hydrocarbon Resin	12002-43-6	636.30	437.90	3
	Oxyalkylated Fatty Acid	61791-00-2	183.35	120.20	3
	2-Hydroxytrimethylene, Bis(Trimethylammonium) Dichloride	55636-09-4	87.23	60.50	3
	Triethanolamine	102-71-6	52.24	41.30	3
	Ethoxylated Alcohol	68603-25-8	40.18	31.80	3
	Formaldehyde	50-00-0*	32.06	12.70	3
	Quaternary Ammonium Compound	100765-57-9	22.92	15.00	3
	Oxyalkylated Alkylphenol	127087-87-0	12.23	10.20	3
	Paraffinic Petroleum Distillate	64742-55-8	11.30	8.02	3
	Potassium Iodide	7681-11-0	9.17	6.00	3
	1,2,4 Trimethylbenzene (Impurity)	95-63-6	5.63	4.69	3
	Polyalkylene	7756-94-7	4.58	3.00	3
	Isotridecanol, Ethoxylated	9043-30-5	0.94	0.79	3
	Hemicellulase Enzyme Concentrate	9025-56-3	0.33	0.27	3
	2-Butoxy-1-Propanol	15821-83-7	0.02	0.02	3
	Benzoic Acid	65-85-0	6,483.16	19,272.80	2
	Nitrilotriacetic Acid	139-13-9	3,206.24	1,927.30	2
	PETROLEUM NAPHTHA	64742-47-8	563.50	317.40	2
	Hexadec-1-Ene	629-7 3-2	563.50	442.10	2
	Ethylbenzene	100-41-4	355.47	306.90	2
	Benzyl lauryldimethylammonium Chloride	139-07-1	320.62	188.50	2

	Boric Acid (H3B03)	10043-35-3	205.21	189.40	2
	Tar Bases, Quinoline Derivs., Benzyl Chloride Quaternized	72480-70-7	137.51	118.70	2
	Ammonium, Diallyldimethyl-, Chloride, Polymers	26062-79-3	56.35	44.20	2
	Dimethylbenzylmyristylammonium Chloride	139-08-2	32.06	18.80	2
	Sulferized Polyolefin	68037-13-8	22.92	19.80	2
	Oxyalkylated Alkylphenol	26027-38-3	12.23	10.20	2
	Benzyltrimethylammonium Chloride	122-18-9	5.63	4.40	2
	Choline Chloride	67-48-1	32,062.42	32,062.42	1
	Sodium Chloride	7647-14-5	2,117.60	2,117.60	1
	Phthalic Acid	88-99-3	636.30	636.30	1
	Phthalic Anhydride	85-44-9	636.30	636.30	1
	Ethanaminium,N,N,N-Trimethyl-Methyl-Oxo, Chloride, Polymer With Propenamide	35429-19-7	563.50	563.50	1
	Vinyl Copolymer	38193-60-1	78.91	78.91	1
	Tetramethylammonium Chloride	75-57-0	64.83	64.83	1
	C14 Alpha Olein Ethoxylate	84133-50-6	56.35	56.35	1
	Oxyalkylated Alkylphenolic Resin	63428-92-2	51.44	51.44	1
	Sodium Bromate	7789-38-0	32.06	32.06	1
	Light Aromatic Naphtha	64742-95-6	8.04	8.04	1
	Diammonium Peroxidisulphate	7727-54-0	6.48	6.48	1
	Oxyalkylated Alcohol	68002-97-1	5.15	5.15	1
	Polyol Ester	1338-43-8	3.00	3.00	1
	Polyglycol Ester	9005-67-8	2.43	2.43	1
	Mesitylene	108-67-8	1.63	1.63	1
	1,2,3-Trimethylbenzene	526-73-8	0.82	0.82	1
	1-Butoxy-2-Propanol	5131-66-8	0.76	0.76	1
	Alkylaryl Sulfonate	68584-27-0	0.33	0.33	1
	Cumene	98-82-8	0.18	0.18	1
	Potassium Hydroxide	1310-58-3	0.11	0.11	1
	Acrylamide	79-06-1	0.06	0.06	1

* Chemicals most frequently used in acidization and not frequently used in hydraulic fracturing

Table S7: Chemicals of Acid Fracturing (as reported to DOGGR) Listed by Decreasing Frequency of Use

Chemical Name	CAS #	Maximum (kg)/treatment	Average (kg)/treatment	Frequency of Use
Water	7732-18-5*	1,317,796	707,884.80	10
Hydrochloric Acid	7647-01-0	57,839.04	28,635.40	10
Etidronic Acid	2809-21-4	24,974.71	8,065.20	10
Ethylene Glycol Monobutyl Ether	111-76-2*	10,921.66	4,715.80	10
Citrus Terpenes	94266-47-4*	6,262.52	2,470.60	10
Isopropanol	67-63-0	1,672.46	838.50	10
Polyoxyalkylenes	68439-45-2	832.78	139.25	10
Polyamines	68815-65-1	536.15	251.00	10
Hydrofluoric Acid	7664-39-3*	24,974.71	14,168.50	9
Phosphonic Acid	13598-36-2	7,668.21	4,339.40	9
Citric Acid	77-92-9	5,519.50	3,015.66	9
Oxyalkylated Amine Quat	138879-94-4	1,707.24	906.50	9
Erythorbic Acid	89-65-6*	1,075.17	596.80	9
Ethanol	64-17-5	857.11	185.90	9
Silanetrio; (3-Aminopropyl, Homopolymer)	68400-07-7	774.99	403.00	9
Xylene	1330-20-7	664.07	204.10	9
Cocamidopropyl Betaine	61789-40-0	424.81	360.00	9
TRIETHYLENE GLYCOL	112-27-6	233.18	128.70	9
Nonionic Alkoxylate	70559-25-0	179.36	99.00	9
3-Aminopropyl (Sileanetriol)	58160-99-9	129.17	67.18	9
Guar Gum	9000-30-0	69.03	32.60	9
Paraffinic Petroleum Distillate	64742-55-8	34.51	16.30	9
PETROLEUM NAPHTHA	64742-47-8	34.51	16.30	9
Crystalline Silica, Quartz	14808-60-7	5.75	2.70	9
Isotridecanol, Ethoxylated	9043-30-5	5.75	2.70	9
1-Butoxy-2-Propanol	5131-66-8	4.18	2.72	9
Hemicellulase Enzyme Concentrate	9025-56-3	1.09	0.59	9
2-Butoxy-1-Propanol	15821-83-7	0.13	0.06	9
Formic Acid	64-18-6	6,099.53	3,011.90	8
Hydrocarbon Resin	12002-43-6	2,324.69	1,257.00	8
Oxyalkylated Fatty Acid	61791-00-2	1,140.63	630.00	8
Tar Bases, Quinoline Derivs., Benzyl Chloride Quaternized	72480-70-7	855.52	472.52	8

Cinnamaldehyde	104-55-2	855.52	472.50	8
Sulferized Polyolefin	68037-13-8	142.59	78.80	8
Quaternary Ammonium Compound	100765-57-9	142.59	78.80	8
Potassium Iodide	7681-11-0	57.03	31.50	8
Polyalkylene	7756-94-7	28.51	15.70	8
Potassium Acetate	127-08-2	14.26	7.90	8
Acetic Acid	64-19-7	3,809.41	2,384.30	7
Sodium Chloride	7647-14-5	654.80	535.10	7
Triethanolamine	102-71-6	3,970.44	738.90	6
Oxyalkylated Alkylphenolic Resin	63428-92-2	398.17	268.60	6
Light Aromatic Naphtha	64742-95-6	62.23	42.00	6
1,2,4-Trimethylbenzene	95-63-6	40.44	27.31	6
Mesitylene	108-67-8	12.63	51.01	6
1,2,3-Trimethylbenzene	526-73-8	6.32	4.26	6
Alkylaryl Sulfonate	68584-27-0	2.52	1.71	6
Cumene	98-82-8	1.39	0.94	6
Ammonium Chloride	12125-02-9*	20,932.35	17,260.03	5
Dodecylbenzene Sulfonic Acid	27176-87-0	820.83	213.70	5
Methanol	67-56-1	715.51	159.90	5
Ethoxylated Alcohol	68603-25-8	273.46	71.20	5
Methyl Oxirane Polymer With Oxirane	9003-11-6	136.73	35.60	5
Caprylamidopropyl Betaine	73772-46-0	42.48	36.63	5
Glycerol	56-81-5	42.48	36.60	5
Diethanolamine	111-42-2	27.43	7.14	5
Methyl Isobutyl Ketone	108-10-1	27.43	7.14	5
Sulfuric Acid	7664-93-9	27.43	7.20	5
Polyethylene Oxide	25322-68-3	27.43	7.20	5
Ethoxylated Alcohol C12-15	68131-39-5	9.66	4.49	5
Potassium Hydroxide	1310-58-3	0.83	0.50	5
Naphthalene	91-20-3	0.03	0.02	5
Phthalic Acid	88-99-3	2,324.69	2,251.40	4
Phthalic Anhydride	85-44-9	2,324.69	2,251.40	4
Ethylbenzene	100-41-4	199.22	136.90	4
2- Hydroxytrimethylene,Bis(Trimethylamm Onium) Dichloride	55636-09-4	120.08	54.80	4
Ethoxylated Castor Oil	61791-12-6	6.44	2.94	4
Propylene Glycol	57-55-6	6.44	2.90	4
Terpene Hydrocarbon	68956-56-9*	4,473.23	4,290.80	3
Nonyl Phenol Ethoxylate	9016-45-9*	6.20	4.70	3
Oxyalkylated Alkylphenol	26027-38-3	6.20	4.70	3

Oxyalkylated Alkylphenol	127087-87-0	6.20	4.70	3
Boric Acid (H3BO3)	10043-35-3	487.63	408.73	2
Mixture Of Dimer And Trimer Fatty Acids Of Indefinite Composition Derived From Tall Oil	61790-12-3	289.39	145.65	2
Propargyl Alcohol	107-19-7	96.46	48.40	2
Silica, Amorphous - Fumed	7631-86-9	31,895.35	31,895.35	1
Crystalline Silica, Cristobalite	14464-46-1	31,895.35	31,895.35	1
Benzoic Acid	65-85-0	2,408.50	2,408.50	1
Ethylene Glycol	107-21-1	404.31	404.31	1
Polyoxyalkylenes	68951-67-7	289.39	289.39	1
Thiourea Polymer	68527-49-1	289.39	289.39	1
Acrylamide Acrylate Copolymer	'9003-06-9	154.53	154.53	1
Alkylbenzene Sulfonate Compd. With 2-Propanamine	68584-25-8	26.70	26.70	1
Alkylbenzene Sulfonate Compd. With Triethanolamine	68584-24-7	26.70	26.70	1
Bentonite, Benzyl(Hydrogenate D Tallow Alkyl) Dimethylammonium Stearate Complex	121888-68-4	10.70	10.70	1
Alcohols, C14-15, Ethoxylated (7EO)	68951-67-7	1.91	1.91	1
Sodium Polyacrylate	'9003-04-7	0.45	0.45	1
Xanthan Gum	11138-66-2	0.45	0.45	1
Formaldehyde	50-00-0*	0.44	0.44	1
Silica Gel	112926-00-8	0.43	0.43	1
Sodium Sulfite	7757-83-7	0.11	0.11	1
Sodium Sulfate	7757-82-6	0.11	0.11	1
2-Monobromo-3- Nitrilopropionamide	1113-55-9	0.07	0.07	1
1-Hexadecene	629-73-2	0.06	0.06	1
1-Octadecene	112-88-9	0.06	0.06	1
1-Eicosene	'3452-07-1	0.0019	0.0019	1
1-Tetradecene	1120-36-1	0.0019	0.0019	1
Acrylonitrile	107-13-1	0.0004	0.0004	1

* Chemicals most frequently used in acidization and not frequently used in hydraulic fracturing

Table S8: QCAT F-graded Chemicals used in Acidizing in California (arranged by decreasing frequency of use)

Chemical	CAS #	Maximum (kg)/Treatment	Average (kg)/Treatment	Frequency of Use	Acid Maintenance	Matrix Acidizing	Acid Fracturing	Purpose*	Primary QCAT Low Grade Reason
Methanol	67-56-1	32,062.42	261.86	505	✓	✓	✓	Corrosion Inhibitor, Non-Emulsifier, Anti-Sludging Agents, Wetting Surfactant, Clay Stabilizer, Solvent	Developmental Toxin (US NIH, Cal EPA) Neurotoxin (Lancet - Grandjean & Landrigan) Persistent (Environment Canada)
Hydrofluoric Acid	7664-39-3	24,974.71	850.50	290	✓	✓	✓	Acidizing, Well Stimulation	Fatal if swallowed (H300), inhaled (H310), in contact with skin (H330) (European Commission (EC)) Neurotoxin (Lancet - Grandjean & Landrigan) Persistent (Environment Canada)
Polyethylene Glycol Nonylphenyl Ether; Poly (Oxy-1,2-Ethandiyl), A-(Nonylphenyl)-W-Hydroxy	9016-45-9*	147.32	30.29	256	✓	✓	✓	Non-Emulsifier, Surfactant	Developmental Toxin (US EPA, TSCA Criteria met), Endocrine Disruptor (US EPA, TSCA Criteria met) Persistent (EC/Oslo-Paris Conv)
Ethylene Glycol	107-21-1	404.31	11.90	201	✓	✓	✓	Cleaner	Developmental Toxin (US NIH) Neurotoxin (Lancet - Grandjean & Landrigan)
Formaldehyde	50-00-0*	32.06	0.22	191	✓	✓	✓	Corrosion Inhibitor	Carcinogen (International Agency for Research on Cancer, US EPA, US NIH, Cal EPA...)
Xylene	1330-20-7	11,509.90	361.70	169	✓	✓	✓	Surfactant, Solvent,	Reproductive Toxin (Category 1B - Japan METI/MOE)

								Asphaltene Dispersant, Paraffin Inhibitor, Demulsifier, Cleaner	Neurotoxin (Lancet - Grandjean & Landrigan)
Naphthalene	91-20-3	28.08	1.79	169	✓	✓	✓	Surfactant, Non-Emulsifier, Solvent	Carcinogen (US NIH, Cal EPA) Acute Aquatic Toxicity (EC H400)
Ethylbenzene	100-41-4	2,578.80	52.40	160	✓	✓	✓	Surfactant, Solvent, Cleaner	Carcinogen (Cal EPA) Reproductive Toxin (Category 1B - Japan METI/MOE) Persistent (Environment Canada)
Cumene	98-82-8	1.39	0.33	146	✓	✓	✓	Demulsifier, Surfactant	Carcinogen (US NIH, Cal EPA) Neurotoxin (Lancet - Grandjean & Landrigan)
Diethylene Glycol	111-46-6	5,013.96	1,667.81	141	✓	✓	✓	Corrosion Inhibitor	Neurotoxin (Lancet - Grandjean & Landrigan)
Ethylene Oxide	75-21-8	0.50	0.01	105	✓	✓			Carcinogen (International Agency for Research on Cancer, US EPA, US NIH, Cal EPA...) Mutagen (EC R46) Developmental Toxin (US NIH, Cal EPA) Reproductive Toxin (US NIH, Cal EPA) Neurotoxin (Lancet - Grandjean & Landrigan) Persistent (Environment Canada)
Silica, Amorphous-Fumed	7631-86-9	31,895.35	395.51	81	✓	✓	✓	Proppant, Friction Reducer	Occupational Carcinogen (US CDC) Persistent (Environment Canada)
Crystalline Silica	14808-60-7	6,769.86	537.70	28	✓	✓	✓	Sand Control, Proppant	Carcinogen - Respirable (International Agency for Research on Cancer)
Nitrilotriacetic Acid	139-13-9	3,206.24	282.67	27	✓	✓		Iron Control	Carcinogen (US NIH, Cal EPA) Mutagen (Category 1B - Japan METI/MOE)
Ethanol	64-17-5	857.11	84.12	26	✓	✓	✓	Wellbore Cleaner, Clay Control, Iron Control	Carcinogen (International Agency for Research on Cancer) Reproductive Toxin (Category 1B -

									Japan METI/MOE), Mutagen (Category 1B - Japan METI/MOE) Persistent (Environment Canada)
Light Aromatic Naphtha	64742-95-6	62.23	12.98	21	✓	✓	✓	Non-Emulsifier	Carcinogen (EC H350, R45) Mutagen (EC R46, H340)
Cristobalite	14464-46-1	31,895.35	1,993.54	16		✓	✓	Proppant, Friction Reducer	Occupational Carcinogen (US CDC) Persistent (Environment Canada)
DiisopropylNaphthalene/ Bis(Isopropyl)Naphthalene	38640-62-9	2.50	1.90	14	✓			Non-Emulsifier	Carcinogen (US NIH) Persistent (EC/Oslo-Paris Conv, Environment Canada)
Toluene	108-88-3	660.11	144.98	13	✓	✓		Solvent, Asphaltene Dispersant	Developmental Toxin (Cal EPA) Reproductive Toxin (Cal EPA) Persistent (Environment Canada)
Paraffinic Petroleum Distillate	64742-55-8	34.51	14.23	12		✓	✓		Carcinogen (EC – REACH Annex XVII) Persistent (Environment Canada)
Diethanolamine	111-42-2	27.43	5.30	9		✓	✓	(Corrosion Inhibitor, Surfactant)	Carcinogen (Cal EPA)
Methyl Isobutyl Ketone	108-10-1	27.43	5.30	9		✓	✓	(Solvent)	Carcinogen (Cal EPA) Developmental Toxin (Cal EPA) Neurotoxin (Lancet - Grandjean & Landrigan)
Oxyalkylated Alkylphenol; Polyethylene Glycol Mono(Branched P-Nonylphenyl) Ether	127087-87-0	12.23	7.45	6		✓	✓	(Surfactant, Wellbore Cleaner, Emulsifier, Wetting Agent)	Developmental Toxin (US EPA, TSCA Criteria met) Reproductive Toxin (US EPA, TSCA Criteria met) Endocrine Disruptor (EC/Oslo-Paris Conv) Persistent (EC/Oslo-Paris Conv)
Oxyalkylated Alkylphenol; Polyethylene Glycol Nonylphenyl Ether; Poly (Oxy-1,2-Ethandiyl), A-(Nonylphenyl)-W-Hydroxy	26027-38-3	12.23	6.90	5		✓	✓		Developmental Toxin (US EPA, TSCA Criteria met), Endocrine Disruptor (US EPA, TSCA Criteria met) Endocrine Disruptor (EC/Oslo-Paris Conv) Persistent (EC/Oslo-Paris Conv)

Boric Acid (H3B03)	10043-35-3	487.63	299.07	4		✓	✓		Developmental Toxin (EC R61) Reproductive Toxin (EC R60) Persistent (Environment Canada)
Cyclotetrasiloxane, 2,2,4,4,6,6,8,8-Octamethyl-	556-67-2	0.02	0.02	2	✓			Friction Reducer	Reproductive Toxin (US EPA, TSCA Criteria met) Endocrine Disruptor (EC Cat. 1) Very Persistent (Oregon P3)
Acrylamide	79-06-1	0.06	0.06	1		✓			Carcinogen (International Agency for Research on Cancer, US EPA, US NIH, Cal EPA...) Mutagen (EC R46) Developmental Toxin (US NIH, Cal EPA) Reproductive Toxin (US NIH, Cal EPA) Neurotoxin (Lancet - Grandjean & Landrigan)
Acrylonitrile	107-13-1	0.0004	0.0004	1			✓		Carcinogen (International Agency for Research on Cancer, US EPA, US NIH, Cal EPA...) Neurotoxin (Lancet - Grandjean & Landrigan) Persistent (EPA)

*Chemical purposes listed are what the oil operator identifies. Those listed in parenthesis are the authors suggestion.

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IV. Federal Framework For Regulating Acidization

A. Abstract

Whereas hydraulic fracturing has received increased regulatory attention after rising concerns about health and environmental impacts, other “sister” techniques such as, acidizing have gone unnoticed. Acidizing, a general term for acid use in oil and gas exploration, is used as frequently as hydraulic fracturing but with hazardous chemical concentrations higher than hydraulic fracturing. It is important that acidizing be addressed when discussing how best to protect the public and environment from potential impacts of oil and gas exploration. This paper discusses the legal framework that is currently in place to regulate acidizing at the federal level. In some cases where hydraulic fracturing is exempt from regulation – acidizing is not – as in the Safe Drinking Water Act. The Safe Drinking Water Act will prove to be an important regulation in controlling acidization activities but probably not without a legal battle. In other cases, like the Clean Air Act or Toxic Substances Control Act, there is proposed rulemaking for hydraulic fracturing but none for other unconventional oil and gas stimulation techniques like acidizing. The proposed rules must include acidizing. Under the Clean Water Act, the chemicals used in acidizing warrant classification as hazardous waste and should be disposed of appropriately and require stormwater permits. All unconventional oil and gas exploration techniques, not just hydraulic fracturing, should be considered when thinking about regulating these practices to best protect the public and environment from harm.

B. Introduction

Hydraulic fracturing (HF) is an unconventional oil and gas (UOG) well stimulation technique that pumps pressurized fluid with a propping agent into the ground to fracture a rock formation, allowing oil or gas to flow. A propping agent is a substance like sand that can lodge itself into a fracture and keep it open. Whereas HF has received increased regulatory attention after rising concerns about health and environmental impacts, other “sister” techniques to HF such as acidizing have gone unnoticed. Acidizing, a general term for acid use in oil and gas (O&G) exploration and production, is used as frequently as HF but with hazardous chemical concentrations higher than HF. It is important that acidizing be dealt with in any regulatory program focused upon UOG production methods. This paper outlines the legal framework currently in place at the federal level to regulate acidizing and examines potential revisions.

Acidizing, a term used for all types of acid use, can refer to acid maintenance, matrix acidizing, and acid fracturing processes. These processes are used to increase or keep up well productivity or increase rock permeability (Robertson, Chilingarian, and Kumar, 1989).

In acid maintenance, acid solutions are used to remove scales. Operators either inject the acid solution at a specific location into the wellbore, or it is circulated back and forth across the casing perforation or formation face to react with the scale. The scale is cleaned off of the surfaces of the wellbore and equipment without acid

penetrating into the formation (Robertson, Chilingarian, and Kumar, 1989). Acid maintenance is not considered a well stimulation technique.

Matrix acidizing and acid fracturing are different than acid maintenance in that the acid solution is not restricted to the wellbore. Rather, it is intended to reach the formation. In matrix acidizing the acid solution is injected into the formation below fracturing pressure. The acid etches its way through the formation, creating new pathways several centimeters to a meter around the borehole. The increase in the cross-sectional area of channels leads to an increase in permeability and porosity of the reservoir rock (Robertson, Chilingarian, and Kumar, 1989).

In acid fracturing, acid solutions are injected into the wellbore above hydraulic fracturing pressure to fracture the formation and create new flow channels or widen existing fractures (McLoed, 1986). As fluid continues to be injected, the fracture length and width increase, eventually allowing the fluid to enter the fracture, dissolving the minerals and widening the fracture further (Williams et al., 1979).

The main difference between acid fracturing and matrix acidization is the injection pressure. Injection rates resulting in pressures below fracture pressure are termed matrix acidizing, while those above fracture pressure are termed acid fracturing (Williams et al., 1979). Often one cannot determine which technique occurred until after well completion. If the pressure chosen caused the formation to fracture it is considered acid fracturing and if it did not, it is considered matrix acidization.

Although acidizing has been used for decades, and was first introduced over a hundred years ago (Williams et al., 1979), we have only recently started examining its potential impacts. In California acidizing chemicals include at least 22 toxic chemicals, and some of these are used in the 100,000's kg/treatment. The health and environmental impacts linked to HF apply to acidizing as well because many of the chemicals used are the same, and in some cases the process is very similar (Abdullah et al., 2016). Some occupational stressors of UOG stimulation include mortality, exposure to hazardous materials and increased risk of industrial accidents. For communities near E&P sites the major stressors are air pollutants, ground and surface water contamination, truck traffic and noise pollution, accidents and malfunctions, and psychosocial stress associated with community change (Adgate, 2014). There is a growing amount of literature on the impacts from UOG stimulation techniques, such as the EPA report on impacts of HF on drinking water sources (*Assessment of the potential impacts of hydraulic fracturing for oil and gas on drinking water resources: Executive Summary*, 2015). However, long-term environmental and health impacts are not considered.

There has been considerable focus on the impacts of HF and how best to regulate it. Acid fracturing is very similar to HF, the main difference being how the fracture conductivity is created. Yet while a few papers have been published discussing the legal framework for regulating HF (Rahm, 2011; Brady and Crannell, 2013; Kiparsky and Foley Hein, 2013; Konschnik and Dayalu, 2016), none discuss the legal

framework for regulating acidizing. A recently published paper showing the types and amounts of hazardous chemicals used in acidizing revealed higher concentrations in acidizing than what is used in HF (Abdullah et al., 2016). It is therefore increasingly important to understand the legal framework for regulating acidization.

The overall objective of this paper is to outline the legal framework currently in place at the federal level to regulate acidizing and examines potential revisions. Thus, this paper defines areas of public concern where better policy is needed. The paper outlines existing relevant laws that regulate acidizing operations at the federal level, highlights the differences in treatment of acidizing operations as compared to HF, and identifies those areas in which new policies or laws are needed.

C. Existing Federal Regulations

The federal government interacts with the O&G industry in two ways: as a landowner and as a regulator.

As a landowner, the Bureau of Land Management (BLM), a federal agency in the Department of the Interior, is charged with administering O&G operations in a manner that protects Federal and Indian lands while allowing for appropriate development of the resource. The BLM oversees approximately 700 million subsurface acres of Federal mineral estate. Currently, nearly 36 million acres of

Federal land are under lease for potential O&G development in 33 states. As of June 30, 2014, there were approximately 47,000 active O&G leases on public lands, and approximately 95,000 O&G wells (Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 2015).

As a regulator, the Environmental Protection Agency (EPA) is tasked with protecting human health and the environment by writing and enforcing regulations based on laws passed by Congress. There are multiple federal laws that could regulate acidization. Some exempt acidizing altogether and others have conditions for regulating it. This section outlines the federal laws that BLM and EPA are tasked with upholding to regulate acidizing operations.

1. Federal Acts Upheld by the Bureau of Land Management

a) The Federal Land Policy and Management Act (1976) (FLPMA)

Regulating how public lands are managed and where certain activities like acidizing are allowed is important for protecting the public and environment. The Federal Land Policy and Management Act (FLPMA) governs the way in which the public lands administered by the BLM are managed.

Section 202 of the FLPMA requires the BLM to develop and maintain land use plans or Resource Management Plans (RMPs). These plans are the basis for all land use decisions the BLM makes, including decisions to allow O&G leasing, allow O&G

leasing under certain conditions, or prohibit O&G leasing altogether. The RMP applies to public lands, including the Federal mineral estate; however, it does not apply to Indian land or to surface estates managed by other Federal agencies such as the USDA Forest Service.

The BLM seeks public feedback to identify the issues to consider and address in the RMP. The public must be able to participate in the development, maintenance, and revision of land use plans. If, for example, the public identifies areas as recreational or environmentally important, the BLM may prohibit or restrict O&G development.

Given the nature of acidization activities and the large quantities of toxic chemicals brought on site, leasing of public lands in close proximity to residential developments or sensitive environmental receptors should not be allowed for acidizing under the FLPMA. The BLM is charged with responsibly developing and maintaining land use to protect the public and environment; allowing acidizing activities to occur within feet of sensitive receptors goes against this goal.

b) The National Environmental Policy Act (1969) (NEPA)

Prior to finalizing any RMP, the BLM must conduct a full-scale environmental analysis. This is a requirement of the National Environmental Policy Act (NEPA). NEPA requires federal agencies to review environmental impacts of a proposed action and possible alternatives for actions that involves federal funding, work performed by the federal government, or permits issued by a federal agency. An

action can be either exempt, categorically exempt, or require an Environmental Assessment (EA). As a final step, if there are significant anticipated effects, an Environmental Impact Statement (EIS) is prepared, and if there are no significant impacts then a Findings of No Significant Impact (FONSI) is prepared.

Although an environmental analysis is done prior to the RMP being finalized, the BLM generally analyzes the environmental impacts of the alternatives through an Environmental Impact Statement (EIS) once lands are considered appropriate for leasing. Traditionally the BLM has not done a full-scale NEPA review for a specific parcel prior to leasing it. That is usually done once a lessee requests to drill a well or conduct other surface activities. However, in some cases BLM is required to do a full-scale NEPA EIS prior to issuing a lease (*Background for Nepa Reviewers: Crude Oil and Natural Gas Exploration, Development, and Production*, 1992).

The BLM is required to post notices of Applications for a Permit to Drill (APD) for O&G development on public lands for public inspection for 30 days. During this time the public may express any concerns as the agency conducts a site-specific environmental analysis. These concerns and analysis may result in conditions of approval on the operator's drilling permit that require, forbid, or control specified activities or disturbances (*Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands*, 2015).

There are some O&G development activities that are categorically excluded from conducting a full-scale NEPA review. These exclusions were enacted in the 2005 Energy Policy Act. The excluded activities are presumed to have no significant environmental impact, unless the public can prove “extraordinary circumstances in which a normally excluded action may have a significant environmental effect.”

Section 390 categorical exclusions (CX) as stated in the legislature are as follows:

1. Individual surface disturbances of less than five acres so long as the total surface disturbance on the lease is not greater than 150 acres and site-specific analysis in a document prepared pursuant to the NEPA has been previously completed.
2. Drilling an O&G well at a location or well pad site at which drilling has occurred within five years prior to the date of spudding the well.
3. Drilling an oil or gas well within a developed field for which an approved land use plan or any environmental document prepared pursuant to NEPA analyzed drilling as a reasonably foreseeable activity, so long as such plan or document was approved within five years prior to the date of spudding the well.
4. Placement of a pipeline in an approved right-of-way corridor, so long as the corridor was approved within five years prior to the date of placement of the pipeline.
5. Maintenance of a minor activity, other than any construction or major renovation of a building or facility.

These exclusions indicate that some environmental assessment was done during the land acquisition process and/or within a certain time frame of activity, and unless there is an extraordinary circumstance, there should be no significant environmental impact. This may be true for some types of activities considered in the CX's, but the nature of oil drilling has changed in recent years and an environmental assessment at an early stage might not include unstudied O&G exploration technology impacts.

Numerous questions were raised about how and when BLM should use these CXs. In 2009 the United State Government Accountability Office (GAO) was asked to report on these issues. GAO found several types of violations of the law, including “approving more than one oil or gas well under a single decision document, approving projects inconsistent with the law’s criteria, and drilling a new well after time frames had lapsed (Nazzaro, 2009).” GAO also found in 85% of the field offices sampled that officers did not adequately justify the use of a categorical exclusion. The GAO recommended that BLM improve the implementation of the CXs by “clarifying agency guidance, standardizing decision documents, and ensuring compliance through more oversight.”

In addition to ensuring compliance and clarity, it’s important to revisit the CXs and see if UOG stimulation techniques of HF and acidizing result in significant environmental impacts.

*c) Bureau of Land Management Proposed Rule to Address
Hydraulic Fracturing (HF)*

The BLM has made an attempt to address HF. Pursuant to the Federal Land Policy and Management Act (FLPMA), Indian mineral leasing laws, and other statutes, and in response to significant public interest in HF, BLM proposed a rule titled Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands. This proposed rule was published May 2012 under the Mineral Leasing Act. In May 2013, the BLM published a supplemental notice of proposed rulemaking and request for comments. After the comment period the final rule was published in March of 2015 and effective June 24th, of 2015.

Like other BLM regulations, this final rule applies to O&G operations on public lands, as well as operations on Indian lands. The rule establishes new requirements to ensure wellbore integrity, protect water quality, and enhance public disclosure of chemicals and other details of HF operations. (Oil and Gas; Hydraulic Fracturing on Federal and Indian Lands, 2015).

The rule however has not gone unchallenged. In June 21, 2016 a federal district court judge in Wyoming ruled that BLM lacked statutory authority to promulgate the rule (State of North Dakota, State of Utah, and UTE Indian Tribe vs. United States Department of the Interior, 2016). They cited that hydraulic fracturing is exempt under the Underground Injection Control Program in the Safe Drinking Water Act

(SDWA), and since EPA does not have authority to regulate HF neither does the BLM. This ruling will most likely be appealed.

Whether this rule is promulgated or not, it still grossly overlooks other UOG stimulation practices. These practices should be covered, for they involve much of the same best practice protocol as HF. Ensuring wellbore integrity, protecting water quality, and enhancing public disclosure of chemicals and other details of acidizing operations must be required. The basis on which the BLM's new rule has been struck down may not apply to acidizing. Later in this chapter there is a discussion on the SDWA and what is intended by the hydraulic fracturing exemption. Acidizing could be considered a different technique than hydraulic fracturing and thus not exempt. So if a similar rule were to be passed for acidizing the same argument might not hold true. Nevertheless BLM is attempting to keep up with the changing O&G development technologies but a limited coverage of what is regulated will not accomplish what BLM is tasked to do.

2. Federal Acts Upheld by the Environmental Protection Agency

a) The Clean Air Act (1970) (CAA)

Acidizing operations use many volatile compounds that can be a source of air pollution. A local governing body in Southern California, the South Coast Air Quality Monitoring District, requires reporting of acidizing techniques. Some of the air toxics listed in use for acid maintenance and matrix acidizing include:

- 1,2,4 Trimethylbenzene
- 1-Methoxy-2-Propanol

- 2-Butoxy Ethanol
- Acetophenone
- Aminotriacetic Acid
- Cumene
- Diethylene Glycol
- Ethyl Benzene
- Ethylbenzene
- Ethylene Glycol
- Ethylene Glycol Monobutyl Ether
- Ethylene Oxide
- Formaldehyde
- Hydrochloric Acid
- Hydrofluoric Acid
- Isopropanol
- Methanol
- Naphthalene
- Sodium Hydroxide
- Sulfuric Acid Ammonium Salt (1:2)
- Thiourea, Polymer with Formaldehyde and 1-Phenylethanone
- Toluene
- Xylene

The Clean Air Act (CAA) regulates air emissions of such chemicals from stationary and mobile sources. The CAA defines enforceable emission limitations for hazardous air pollutants (HAPs), National Emissions Standards for Hazardous Airborne Pollutants (NESHAPs), from “major source” and “area source” categories under section 112. Major sources are defined as a “stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.” An area source is “any stationary source of hazardous air pollution that is not a major source.” For major sources, the statute requires the EPA to establish standards that reflect the maximum degree of reduction in HAP emissions through application of maximum achievable control technology (MACT).

There has been some confusion in determining what is considered a “stationary source” and “major source.” As of June 2016 the EPA is finalizing a revision to regulations applicable to permitting of stationary sources of air pollution under the

New Source Review (NSR) and title V programs in the Clean Air Act (CAA or Act). The rule clarifies the meaning of the term “adjacent” that is used to determine the scope of a “stationary source” (for purposes of the Prevention of Significant Deterioration (PSD) and Nonattainment NSR (NNSR) preconstruction permitting programs) and the scope of a “major source” (in the title V operating permit program in the onshore oil and natural gas sector). The revised definitions now consider proximity of emitting activities and whether the activities share equipment (Source Determination for Certain Emission Units in the Oil and Natural Gas Sector, 2016).

It should be noted though that section 112(n)(4) of the Act prohibits aggregating emissions from O&G exploration or production wells (and their associated equipment) and emissions from pipeline compressor or pump stations with emissions from other similar units. Since most O&G wells, on their own, do not emit the threshold limit of HAPs under the statutory definition, many O&G exploration and production facilities aren’t considered major sources.

For those facilities considered major sources and area sources the EPA promulgated NESHAP limit emissions from O&G facilities that process, upgrade or store hydrocarbon liquids in 1999 and 2007. Both of these rules do not include sources of air pollution from UOG operations. Both of these standards also exclude facilities that exclusively handle black oil. Black oil is defined in the final rule as a hydrocarbon liquid with an initial gas-to-oil ratio (GOR) less than 0.31 cubic meters

per liter (m3/liter) and an American Petroleum Institute (API) gravity less than 40 degrees. Most of the onshore oil extraction in California is black oil (Sheridan, 2006), and thus wouldn't be covered.

The CAA also sets forth allowable emissions for new major sources and major modifications to existing sources through New Source Performance Standards (NSPS). NSPS can extend to pollutants not included in the NAAQS and the NESHAPs.

The EPA in 2012 and 2016 issued NSPSs (Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 2012; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources, 2016) to regulate methane emission from natural gas wells and natural gas processing plants. These rules also regulate emissions of GHG and VOCs from new, reconstructed and modified O&G sources. These emission sources include HF oil well completions and potentially acid fracturing well completions. According to these rules HF is defined as "the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions." This could potentially include acid fracturing but not matrix acidizing.

With these newer rules in place, natural gas extraction, HF, and potentially acid fracturing are better regulated, but matrix acidizing and acid maintenance are not included. The NESHAPs established in 1999 and 2007 do not cover UOG operations. The 2012 NSPS rule mainly includes natural gas wells that are hydraulically fractured, whereas in California most of the UOG operations are for crude oil, not natural gas (CCST, 2015). In the 2016 NSPS rule, HF and potentially acid fracturing, are included for both oil and gas wells. However, as noted above there are many air toxins used in matrix acidizing and acid maintenance, and these practices are not regulated. The chemicals of acidizing must be reviewed to see what constituents could be problematic. All acidizing should also be included in the new rules set forth.

b) The Safe Drinking Water Act (1974) (SDWA)

In addition to protecting our air, protecting our water sources from acidizing chemical contamination is crucial. Water contamination has been one of the biggest issues raised over UOG exploration. The Safe Drinking Water Act (SDWA) protects public drinking water supplies by setting standards for drinking water quality and implementing various technical and financial programs to ensure drinking water safety. SDWA controls the injection of wastes into groundwater through the Underground Injection Control (UIC) program. For the O&G industry this includes underground injection used for enhanced oil recovery, but not production wells that are used only to bring O&G to the surface, without injection. The UIC program sets requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water.

Originally, the SDWA defined “underground injection” as “the subsurface emplacement of fluids by well injection,” without any exceptions (Safe Drinking Water Act, 1974). Surprisingly, at that time EPA considered HF as exempt under the SDWA. In 1997, however, the U.S. Court of Appeals for the 11th Circuit ruled that HF activities constitute ‘underground injection’ under Part C of the SDWA (LEAF. v. U.S. EPA, 1997). Thus, the EPA and State UIC Programs were required to regulate HF under the SDWA. In response, the EPA initiated a study of the potential for contamination of public water supplies from the HF of coal seams for methane production and concluded in 2004 that HF poses little or no threat to underground sources of drinking water (Evaluation of Impacts to Underground Sources Of Drinking Water By Hydraulic Fracturing Of Coalbed Methane Reservoirs, 2004).

Despite questions over the report’s accuracy, Congress amended the SDWA in 2005 with the passage of the Energy Policy Act. The Act added two exclusions to the definition of underground injection:

1. The underground injection of natural gas for purposes of storage
2. The underground injection of fluids or propping agents (other than diesel fuels) pursuant to HF operations related to oil, gas, or geothermal production activities.

An important question arises—what is intended by HF in the Energy Policy Act?

Matrix acidization and acid fracturing involve injecting fluids for enhanced oil

recovery and operationally are not considered HF by those in the O&G industry. This becomes a very important question to answer to know if matrix acidization and acid fracturing must be regulated. To determine what was meant by the HF exemption we looked at:

- The bill language and definitions in the Energy Policy Act of 2005
- The legislative history of the Act including the committee reports, conference report, legislative debates, hearings, committee prints, house and senate documents
- EPA guidance
- Law review articles

The more authoritative sources in determining what is intended by HF in the Act are the bill language itself and committee reports. The committee debates are not as defining because they are exactly that—debates. EPA provides guidance but it isn't binding by law. These are all discussed below.

The bill language itself does not define HF. Looking through the committee reports on the Energy Policy Act of 2005, HF is defined as “a technique used to enhance the recovery of methane gas from coalbeds (H. Rept. 109-215, 2005; H. Rept. 108-65, 2003).” The EPA defines HF as a “temporary and intermittent process in which fluids are injected underground at high pressures to create fractures in the coals seam that enhance the recovery of methane gas by creating pathways for the gas to flow to the surface (H. Rept. 109-215, 2005; H. Rept. 108-65, 2003).” This EPA

definition likely goes back to the 2004 EPA report, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*. There is no concise definition provided in the report. Rather, there is a general description of pressurized fluid used to create an initial fracture, followed by fracture propagation, proppant placement, and the subsequent fracturing fluid recovery/groundwater extraction stage of the coalbed methane (CBM) production process. HF concerns today extend to far more than CBM production. The Energy Policy Act of 2005 includes HF operations related to oil, gas, and geothermal production activities, not just CBM.

From the Committee Report and 2004 EPA report that provided the proof to enact the exemption, it seems as though the HF exemption does not include matrix acidization and acid fracturing in the definitions.

If we look at the congressional records/debates, there are a few different definitions of HF mentioned:

- “HF is a drilling technique that injects chemicals into the ground during O&G development.” (149 Cong. Rec 167, 2003)
- “HF is a process by which water, sand, and toxic chemicals are injected into rock so the oil and natural gas that they contain can be extracted.” (149 Cong. Rec 168, 2003)
- “Involves injecting diesel fuel or potentially hazardous substances such as benzene, toluene, and MTBE underground to fracture rock and release O&G.”

(151 Cong. Rec 106, 2005)

- “Involves injecting a fluid under pressure into the ground in order to create fractures in rock and capture methane.” (151 Cong. Rec 106, 2005)
- “Involves injecting diesel fuel into groundwater supplied/aquifers/water supply” (151 Cong. Rec 106, 2005)
- “An invasive O&G extracting technique” (151 Cong. Rec 52, 2005)

Some of these definitions are very general. For example “an invasive O&G extracting technique.” This definition can include any O&G extracting technique. Other definitions are more specific and in line with how industry defines HF as the use of pressurized fluid, containing a proppant like sand to keep created fractures open and extract the trapped oil or gas.

There are a few EPA guidance documents that describe HF. The first one is EPA’s permitting guidance on HF using diesel fuels (Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels: Underground Injection Control Program Guidance #84, 2014). Page 3 of the guidance contains the following description of HF:

“HF is a technique used to produce economically viable quantities of oil and natural gas, especially from unconventional reservoirs, such as shale, tight sands, coalbeds and other formations. HF involves the injection of fluids (commonly a mixture of water, chemical additives and proppants) under pressures great enough to open

and enlarge fractures within the oil-and gas-producing formations. The resulting fractures are held open using propping agents, such as fine grains of sand or ceramic beads, to allow O&G to flow to the production well. The types and concentrations of chemical additives and proppants used in the HF fluids vary depending on site-specific conditions and are usually tailored to the properties of the formation and the needs of the project.”

The second document is EPA’s Draft Assessment on the impacts of HF on drinking water resources (*Assessment of the potential impacts of hydraulic fracturing for O&G on drinking water resources: Executive summary*, 2015). Chapter 2 of the document includes a description of HF: “HF is a stimulation technique used to increase production of O&G. HF involves the injection of fluids under pressures great enough to fracture the O&G production formations. HF fluid transfers the pressure generated by equipment at the surface into the subsurface to create fractures, and it carries and places the proppant into the fractures so that they remain ‘propped’ open after the injection pumping pressure is terminated (Gupta and Valko, 2007).”

In the same report acid fracturing is mentioned under Alternative Fracturing Fluids. It is described as follows: “Acid fracturing removes the need for a proppant and is generally used in carbonate formations. Fractures are initiated with a viscous fracturing fluid, and the acid (gelled, foamed, or emulsified) is added to irregularly etch the wall of the fracture and prop open the formation for a higher conductivity fracture (Spellman, 2012; Gupta and Valko, 2007).”

In these EPA guidance documents acid fracturing may be considered to be a type of HF. Matrix acidization though is not considered a type of fracturing stimulation. Acid fluid is injected below fracturing pressure, and acid etches its way through the formation.

Going beyond just the literal definition in the law and regulations, it is also important to see if there were any underlying reasons for exempting HF that can be extended out to other UOG stimulations. The legislative history and discussions around HF show that there was a narrow scope intended. And it seems that the exclusion was a political response to interest groups lobbying to congress. For these reasons acidizing should be seen as a different operation since there were no policy underlying reasons for excluding HF.

This is a debatable topic in which legislators must determine what is intended by the HF exemption. The current regulatory language hints toward both acid fracturing and matrix acidization not being exempt and thus regulated under the SDWA. SDWA may prove to be a powerful legislation in regulating the two acidizing techniques, matrix acidizing and acid fracturing. Under the UIC program this would mean requirements for proper well siting, construction, and operation to minimize risks to underground sources of drinking water from acidizing activities.

c) The Clean Water Act (1977)

In addition to protecting ground water sources, protecting our surface waters from acidizing chemical pollution is also important. The Clean Water Act regulates the treatment and discharge of wastewater into surface waters of the United States. It sets national standards for industrial wastewater discharges to surface waters and municipal sewage treatment plants (also known as publicly owned treatment works or POTWs) based on the performance of treatment and control technologies. There are two types of regulated discharges: direct and indirect. Direct discharge refers to wastewater discharged directly into a stream or other receiving body.

Indirect discharge refers to wastewater that is sent to a POTW. On June 28, 2016, EPA finalized pretreatment standards for O&G extraction. The standard calls for zero discharge of wastewater pollutants associated with onshore UOG extraction facilities to POTWs. This is because industry is already disposing of UOG wastewater via other methods; disposal in UIC wells, wastewater reuse/recycling to fracture another well, or management by centralized waste treatment (CWT) facilities—none of which involve sending wastewater to POTWs. UOG waste is not typical of POTW influent wastewater, some of the wastewater constituents can be discharged, untreated, from the POTW to surface water. The wastewater can also disrupt the operation of the POTW by; inhibiting biological treatment; accumulating in biosolids (also called sewage sludge), limiting their use; and facilitating the formation of harmful disinfection by-products (Natural Gas Extraction - Hydraulic Fracturing, 2016). Treating for these things would be quite costly.

Direct discharges from onshore UOG extraction are subject to NPDES permit regulations, with the exception of CBM. There can be no discharge of water pollutants from any source associated with production, field exploration, drilling, well completion, or well treatment, except for wastewater that is of good enough quality for use in agricultural and wildlife propagation. The program requires permits for the discharge of pollutants from any point source into waters of the United States. However, stormwater from O&G operations is exempted from the NPDES requirement, unless a facility has a discharge of Reportable Quantity (RQ) or contributes to a violation of a water quality standard. Reportable Quantity is a determined limit for specific hazardous chemicals pursuant to section 311 of The Clean Water Act. Certain acidization chemicals are included in this list (Abdullah et. al., 2016):

- | | |
|--------------------------------|---------------------|
| • Acetic acid | • Formic acid |
| • Ammonium bifluoride | • Hydrochloric acid |
| • Ammonium chloride | • Hydrofluoric acid |
| • Benzoic acid | • Sodium hydroxide |
| • Dodecylbenzene sulfonic acid | • Xylene (mixed) |

Proving a discharge of RQ or even noting a violation of a water quality standard is a very difficult task. Monitoring at the right time and place is necessary to note if stormwater with RQ or violating a water quality standard was released. Such monitoring only happens if a facility is enrolled in the NPDES program.

What can be assumed is that contaminated stormwater does leave acidizing operation sites. Acidizing waste is often stored in unlined impoundments (CCST, 2015). During rain events the waste is undoubtedly released. Furthermore, acidizing operations use chemicals that are listed in the hazardous chemical list well above RQ limits (Abdullah et al., 2016). Stormwater discharge from UOG facilities must require at the least an Industrial Stormwater General Permit under the National Pollutant Discharge Elimination System (NPDES). Specific best management practices for acidizing operations must be identified, and in cases when certain facilities are polluting surface waters from spills, industry-specific or individual permits must be enforced.

d) Toxic Substances Control Act (1976) (TSCA)

The chemicals used in acidizing number over 200 and are used in large quantities, up to 100,000 kg/treatment (Abdullah et al., 2016). Currently we only have self-reported information about the chemicals used in select acidizing techniques in California. There is no requirement to provide information on the chemicals used in acid maintenance in California. In other states there is no requirement to provide information on any of the acidizing techniques.

The Toxic Substances Control Act (TSCA) provides EPA with authority to require reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and/or mixtures. It is likely that many of the chemicals of acidization were in use at the time the TSCA Inventory was created, so they were

grandfathered in and not reviewed. On June 7, 2016 Congress passed the Frank R. Lautenberg Chemical Safety for the 21st Century Act, the first time the Toxic Substances Control Act (TSCA) has been substantively amended since its enactment in 1976. The new legislation will significantly change the way EPA approaches chemical management under TSCA. Some of these changes include; an up-to-date inventory of all chemicals in active commerce in the U.S.; a risk screening based on health, hazard, use and exposure information; proof of businesses claiming confidentiality; testing or submission of information through an order rather than a rule. These changes don't directly impact rules regarding UOG but will amend the way chemicals are managed.

On May 9, 2014, however EPA issued an Advance Notice of Proposed Rulemaking (ANPR) under Section 8 of TSCA for HF chemicals and mixtures. EPA is developing an approach to obtain information on chemical substances and mixtures used in HF. This was in response to a citizen petition submitted under section 21 of TSCA. As a first step EPA has sought public input to determine the types of chemical information that could be reported and disclosed under TSCA and the approaches to obtain this information, including non-regulatory approaches. HF activities include the injection of water, chemicals, proppant, and/or tracers to prepare geologic formations for HF, complete an HF stimulation stage, evaluate the extent of resulting fractures, or ensure future ability to continue enhancement of production through stimulation by HF. The notice defines HF as pressurized fluids containing carrier fluids such as water or gas and any combination of proppant and chemicals that are

injected into wells to fracture portions of the formation surrounding a selected well section. It is uncertain if acid fracturing is included in the definition of HF.

The EPA has also sought comments on ways to minimize reporting burdens and costs and avoid duplication of state and other federal agency information collections, while at the same time maximizing data available for EPA risk characterization, external transparency, and public understanding. Furthermore, EPA wants incentives and recognition programs that could be used to develop safer chemicals in HF. They have received over 200,000 comments and will finalize a rule by 2017 (Advance Notice of Proposed Rulemaking: Hydraulic Fracturing Chemicals and Mixtures, 2014).

Under TSCA more appropriate steps are being taken to gather chemical information, improve access to information, and promote safer chemical use for HF and potentially acid fracturing. Chemical information, access to information, and promoting safer chemical use for matrix acidizing and acid maintenance is an obvious inclusion that is needed in the ANPR. Improving transparency from industry by focusing on one technology and ignoring an associated sister technology falls short of protecting the public.

*e) The Emergency Planning and Community Right-To-Know
Act (1986) (EPCRA)*

Access to information about acidizing and its chemicals is crucial in having accountability and protecting the public. The Emergency Planning and Community Right-To-Know Act (EPCRA) is focused on community safety and is designed to help communities protect public health, safety, and the environment from chemical hazards. It includes emergency planning, emergency notification of spills above Reportable Quantities defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to state and local officials, and "Community Right-to-Know" reporting on hazardous and toxic chemicals. Under Sections 311 and 312 of EPCRA, facilities that manufacture, process, or store designated hazardous chemicals must make Material Safety Data Sheets (MSDS), describing the properties and health effects of these chemicals available to state and local officials and local fire departments. Facilities must also provide state and local officials and local fire departments with inventories of all on-site chemicals for which MSDS exist. Information about chemical inventories at facilities and MSDS must be available to the public. Facilities that store over 10,000 pounds of hazardous chemicals are subject to this requirement. Any hazardous chemicals above the threshold stored at O&G production and processing sites must be reported in this manner.

Section 313 of EPCRA authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and

waste management activities reported annually by certain industries as well as federal facilities. A special form must be submitted for each of the over 600 TRI chemicals that are manufactured or otherwise used above the applicable threshold quantities. Some acidizing chemicals are on this list. EPA issues a list of industries that must report releases for the database. To date, EPA has not included O&G extraction as an industry that must report under TRI. This is not an exemption in the law. Rather it is a decision by EPA that this industry is not a high priority for reporting under TRI.

EPA has the authority to designate O&G extraction a high priority industry.

Operators acidizing wells should submit information on the TRI chemicals that are manufactured or used above the applicable threshold quantities. The acidizing chemicals reported in California that appear on the list are:

- 1,2,4-trimethylbenzene
- acetophenone
- acrylamide
- acrylonitrile
- benzene
- cumene
- ethylbenzene
- ethylene glycol
- ethylene oxide
- formaldehyde
- formic acid
- hydrofluoric acid
- methanol
- naphthalene
- nitrilotriacetic acid
- quinaldine
- sulfuric acid
- toluene
- xylene

Many of these are used far above the applicable threshold quantities in the 1000's kg/treatment (Abdullah et al., 2016). UOG stimulation activities, including HF and acidizing, undoubtedly should make O&G a high priority

industry that must report annually on the TRI chemicals used above threshold quantities.

f) The Resource Conservation and Recovery Act (1976) (RCRA)

The Resource Conservation and Recovery Act (RCRA) creates the framework for properly managing hazardous and non-hazardous solid waste. Subtitle C gives EPA the authority to regulate the generation, transportation, treatment, storage, and disposal of hazardous waste. This is commonly referred to as a “cradle-to-grave” regulatory program. Subtitle D provides a framework for regulating non-hazardous solid waste.

The definition of hazardous waste under RCRA is “a solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical, or infectious characteristics may cause or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness or pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.” If a waste is classified as a hazardous waste, there are more stringent requirements.

Many O&G wastes are exempt from regulation as hazardous waste. These wastes are generally subject to non-hazardous waste regulation under RCRA Subtitle D and applicable state regulations. Many state governments have specific regulations and guidance for O&G wastes.

As the use of UOG stimulation has increased, it is crucial that wastes from O&G activities be managed properly. O&G waste has changed from 1988, when the EPA determined that O&G field wastes were not hazardous wastes. Chemicals information about HF and acidizing show the use of dozens of hazardous chemicals in large quantities (CCST, 2014; Stringfellow et al., 2014; Abdullah et al., 2016). Besides the chemicals that are injected, the formation water contains many chemicals. Much of the stimulation fluid that returns is saltier than seawater (~35,000 mg/L), and can be >300,000 mg/L; it contains oil and grease, inorganic and organic toxic chemicals, and naturally occurring radioactive material. During 2012, 21.2 billion barrels of produced water were generated in the United States (Veil, 2015). The waste constituents have changed as well as the volumes. States and other federal agencies (BLM) are trying to address the waste management issue, but wastes from acidizing and other UOG stimulations must be considered hazardous waste and regulated under Subtitle C.

g) The Comprehensive Environmental Response, Compensation, and Liability Act (1980) (CERCLA)

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) regulates the clean up of hazardous substance releases. It requires the reporting of hazardous substance releases, as well as the location of hazardous storage, treatment, and disposal sites. The statute also establishes the Superfund, a trust fund to pay for hazardous waste clean up, derived from taxes imposed on oil and chemicals, as well as fines and penalties levied by the EPA. CERCLA is a remedial statute that covers clean up from spills of hazardous substances and thus does not regulate acidization operations directly.

D. Discussion

Table 4 summarizes the federal acts discussed and defines if acidization is regulated.

Table 4: Summary of Regulations

Regulation	Description	Is Acidization Covered?
The Federal Land Policy and Management Act (FLPMA)	Governs the way in which the public lands administered by the Bureau of Land Management are managed.	Yes
The National Environmental Policy Act (NEPA)	Requires federal agencies to review environmental impacts of a proposed action and possible alternatives for actions that involves federal funding, work performed by the federal government, or permits issued by a federal agency.	Yes, but there are certain O&G categorical exemptions.
The Clean Air Act (CAA)	Regulates air emissions from stationary and mobile sources.	Yes, but limited applicability because acidizing operations not considered a “major source,” and there are no New Source Performance Standards (NSPS) addressing all acidizing techniques.
The Safe Drinking Water Act (SDWA)	Sets standards for drinking water quality and implements various technical and financial programs to ensure drinking water safety. Controls the injection of wastes into groundwater through the Underground Injection Control (UIC) program.	Possibly covered under UIC program (HF is exempt, but matrix acidizing and acid fracturing may still be covered).
The Clean Water Act (CWA)	Regulates the treatment and discharge of wastewater into surface waters of the United States. Sets national standards for industrial wastewater discharges to surface waters and municipal sewage treatment plants.	Indirect and direct discharges are regulated. However there is no permit required for stormwater run-off from acidizing operation sites.

The Toxic Substances Control Act (TSCA)	Requires reporting, record-keeping and testing requirements, and restrictions relating to chemical substances and/or mixtures.	Yes, but limited applicability (may cover acid fracturing).
The Emergency Planning and Community Right-To-Know Act (EPCRA)	Requires emergency planning, emergency notification of spills above Reportable Quantities defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to state and local officials, and "Community Right-to-Know" reporting on hazardous and toxic chemicals (Toxic Release Inventory (TRI)).	Yes, larger facilities are subject to the requirements but under the TRI O&G is not required to report.
The Resource Conservation and Recovery Act (RCRA)	Creates the framework for properly managing hazardous and non-hazardous solid waste.	Yes, but acidizing waste considered a non-hazardous waste with less stringent management requirements.
The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	Requires reporting of hazardous substance releases as well as the location of hazardous storage, treatment, and disposal sites. The statute also establishes the Superfund.	N/A, does not regulate acidizing but retroactively addresses damage.

From the outlined research in this paper we see that some federal bills exempt or have limited oversight over O&G operations. There have been recent concerns over the impacts of HF on human health and the environment, and recent discussions have called for increased regulatory oversight. Some acidizing well stimulations operationally are very similar to HF but have not received the same attention. Acidizing techniques use hazardous chemicals in higher concentrations than HF and should be better regulated.

As outlined in the table, we see that the FLPMA gives authority to BLM to determine if acidization can take place on leased land. The public has input in this process. The BLM had proposed new requirements that were challenged by the courts, to ensure wellbore integrity, protect water quality, and enhance public disclosure of chemicals and other details of HF operations under FLPMA but acidizing is not included. NEPA requires an environmental review of proposed acidizing activities if it is not under one of the categorical exclusions (CXs). The CXs can exclude acidizing activities if an environmental assessment occurred at an early stage. The nature of oil drilling, however, has changed in recent years and an environmental assessment at an early stage might not include unstudied O&G exploration technology impacts.

The CAA has limited applicability for acidizing because acidizing operations are not considered a “major source,” and there are no New Source Performance Standards for it. The CWA has successfully called for pretreatment standards for indirect UOG wastes going to POWTs but direct discharges from stormwater coming from acidizing sites are still unregulated. Under TSCA EPA issued an Advance Notice of Proposed Rulemaking to obtain information on chemical substances and mixtures used in HF. Acid fracturing may be part of the definition of HF, but matrix acidizing isn’t. Under the EPCRA EPA has not included O&G extraction as an industry that must report under Toxic Release Inventory. Thus acidizing is exempt. RCRA governs acidizing waste management, but acidizing waste is considered a non-hazardous waste with less stringent management requirements. Finally CERCLA is a remedial statute that deals with hazardous substance releases and so it doesn’t regulate acidizing activity but retroactively addresses damage.

On the federal level there are a few opportunities to better regulate acidization:

- The Bureau of Land Management has proposed a new rule when permitting HF wells. The Clean Air Act has New Source Performance Standards (NSPS) for hydraulically drilled wells. Under section 8 of the Toxic Substance Control Act, EPA issued an Advance Notice of Proposed Rulemaking (ANPR) for HF chemicals and mixtures. In all these cases acidization should be included in new rules.
- The Safe Drinking Water Act may prove to be an effective way to regulate acidization activities. Although the Energy Policy Act of 2005 exempts HF, except where diesel is used, from its underground injection definition, acid fracturing and more likely matrix acidization, are not exempt. This finding will prove to be an area of great debate in the courts.
- A new rule under the Clean Water Act has established pretreatment standards for O&G extraction. This is a positive step. However, currently under the Clean Water Act stormwater discharge from O&G facilities do not require an Industrial Stormwater General Permit, unless a Reportable Quantity of a hazardous chemical is released or there is a violation of a water quality standard. Hazardous acidizing chemicals are used above the RQ limits. This in combination with acidizing waste being stored in surface impoundments creates a threat for surface water contamination. Stormwater discharges from acidizing operations should require permits and specific best management practices for the oil/gas industry should be

recommended.

- Section 313 under The Emergency Planning and Community Right-To-Know Act (1986) authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste management activities reported annually by certain industries as well as federal facilities. To date, EPA has not included O&G extraction as an industry that must report under TRI because it is not considered a high priority. There are close to a dozen acidizing chemicals that appear on the TRI inventory list. This should warrant reporting.

With increased oversight for HF, it is important that O&G development and production be reviewed as a whole. Some of the concerns that exist for HF apply to all of O&G exploration. For example, chemical waste returns, chemicals stored on site, and stormwater discharge of chemical laden fluid is a concern for most O&G exploration activities. Chemicals reaching USDWs are concerns for all UOG techniques, including acid fracturing and matrix acidization. These activities should not be ignored, especially when discussions are happening on how to effectively protect the public and the environment from potential harmful impacts of HF. New York State can be taken as an example. They conducted a study on the impacts from hydraulic fracturing and implemented a statewide ban. Although this research is not calling for such a ban, similar studies are being done across the US indicating potential impacts and it is necessary that a national framework be in place to ensure a consistent minimum level of protection for the public and environment.

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V. California State Regulations for Acidization

A. Introduction

At the state level, California does not regulate all acidizing techniques, just matrix acidizing and acid fracturing. Acid maintenance, although not a “well stimulating” technique uses the same types of chemicals in similar amounts as regulated operations, and deals with more concentrated waste streams at the surface. In the previous chapter, federal regulations that govern acidizing operations were discussed. This section outlines the California state laws that regulate acidization and protect the public and environment from harmful impacts.

B. California State Bills and Regulations

1. The California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA), the state’s implementation of NEPA, requires that the State look at the environmental impacts of a proposed action and possible alternatives. It applies to discretionary projects carried out or approved by a public agency in California. Well stimulation projects are subject to the California Environmental Quality Act. An Environmental Impact Report (EIR) to evaluate the impacts of all existing and potential future O&G well stimulation, including matrix acidizing and acid fracturing in California, was completed in July 2015.

2. Senate Bill 1281

Senate Bill 1281 established the requirement for a quarterly water report, which must be filed online by all O&G well owners. This includes the source and volume of any water reported, along with water used to generate or make up the composition of any injected

fluid or gas, as well as the treatment of water. This would include all acidizing techniques. It also requires the Division of Oil Gas and Geothermal Resources (DOGGR) to use a standardized form or format to facilitate reporting, and to use non-custom software, as feasible, to implement online reporting. DOGGR has developed a quarterly water report form in Microsoft Excel. The law provides that a person who fails to comply with specific laws relating to the regulation of oil or gas operations, including failing to furnish a report or record, is guilty of a misdemeanor.

3. Senate Bill 83 Section 45

Section 45 of SB 83 requires that the State Water Resources Control Board (SWRCB) report on the regulation of oil field produced water ponds (surface impoundments) within each region by January 30, 2016, and every six months thereafter. A produced water pond is a surface impoundment used to store and/or dispose of produced water. Acidizing waste can be stored in surface impoundments in California, and are predominantly unlined and used to dispose of produced water through evaporation and/or percolation (CCST, 2015).

4. Senate Bill 4

Senate Bill 4 requires oil companies seeking to “stimulate” wells after January 1, 2014 to file satisfactory certifications of compliance with key safeguards of groundwater testing (before/after), neighbor notification, and public disclosure of chemicals, well history, and locations online. For the public disclosure of chemicals, operators are allowed to withhold certain information if they deem it a trade secret. Acid fracturing and matrix acidizing are considered stimulation techniques covered by this bill. Acid maintenance is not included.

In addition to these requirements for operators, the bill requires that the Secretary of California's Natural Resources Agency complete an independent scientific study on well stimulation treatments, and the State Water Resources Control Board develop model criteria for groundwater monitoring and regional or well specific groundwater monitoring criteria by July 15, 2015.

The model criteria for groundwater monitoring has three main components:

- Area-specific required groundwater monitoring near stimulation wells by operators
- Requirements for designated contractor sampling and testing
- Regional scale groundwater monitoring to be implemented by the State Water Board

For area-specific monitoring the operators are required to submit an approved groundwater monitoring plan or a letter from the State Water Board staff concurring that there is no protected water to monitor for their well stimulation permit.

Table 5: Groundwater Monitoring Model Criteria

Scale	Responsibility	What
Well by well (supply well)	Well operator (permit)	Water supply well within 1 mile of oil and gas (O&G) well
Well by well (protected groundwater)	Well operator (permit)	Protected groundwater in close proximity to an individual or small set of O&G wells
Regional	Water Board	Groundwater basin O&G field

5. New California Industrial Stormwater General Permit Order

Effective July 2015, the new NPDES General Permit requires that O&G exploration facilities that discharge stormwater contaminated by contact with or that has come into contact with

any overburden, raw material, intermediate products located on the site of such operations are now covered by the General Permit. At the federal level under the Clean Water Act O&G exploration facilities are not required to file for a permit for stormwater discharges unless there is a water quality violation. In California the O&G industry must obtain a permit or they can apply for a No Exposure Certification if they meet very specific criteria.

C. Conclusion

On the California state level, acid fracturing and matrix acidization operations are being regulated like hydraulic fracturing under Senate Bill 4. Acid maintenance is not regulated. Only recently has DOGGR also begun collecting information on acid maintenance activities but a full chemical disclosure is not required. Acid maintenance uses similar amounts and high concentrations of certain chemicals. The waste that returns is highly concentrated. It should be regulated under SB 4.

Another area that could be improved is how the chemical information is collected under SB4. Currently, operators are allowed to withhold certain information if it is a trade secret. Recent studies have shown that if a “systems approach” is used to collect chemical information operators are much more likely to share chemical information. Companies using the “systems approach” list all chemical ingredients added to the stimulation fluid, rather than linking those ingredients to particular fracturing/etching fluid products. Commentators have recommended this approach believing it enables companies to share more information without fear of reverse engineering by competitors (Konschnik and Dayalu, 2016).

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VI. Regulating Oil and Gas Facility Stormwater Discharge

A. Abstract

Contaminated stormwater runoff from oil and gas (O&G) operations can pose a significant threat to surface waters. The purpose of this study is to examine the extent of this threat and recommend more specific permitting requirements and best management practices to protect surface waters. By eliminating the exposure of oil and gas operations to stormwater runoff and controlling pollutants in discharges, surface water is better protected. To determine if a significant threat exists, this paper analyzes spill reports and stormwater permit compliance in two California counties. It also reviews selected spill cases and associated Spill Prevention, Control and Countermeasure Plans and Stormwater Pollution Prevention Plans to identify the adequacy of current industry practices.

The analysis shows that on the federal level stormwater contamination from O&G facilities is not well regulated. The U.S. Environmental Protection Agency does not require O&G facilities to file for an Industrial Stormwater General Permit even though many O&G industry practices have the potential to contaminate stormwater runoff from the site. When O&G facilities discharge a Reportable Quantity of a hazardous chemical or violate a water quality standard they are required to enroll in the National Pollutant Discharge Elimination System permit program. Spills, although not a direct indication of stormwater runoff, can illustrate the risk of potential polluted runoff discharges that should be regulated. The medium and large spills that reached waterways discussed in this paper potentially violated a water quality standard but did not file for a permit. In California new filing requirements for oil and gas industry require all facilities that discharge stormwater

that has come into contact with any overburden, raw material, or intermediate products located on the site, to file for an Industrial Stormwater General Permit. As this study shows, the new requirements in California are capturing a larger pool of facilities within a regulatory framework for the protection of water quality. The federal government should consider such an approach. A further step would be to compel the industry to implement more specific pollution control practices than the current general permit requires.

There is growing evidence that regulatory protocols must be in place to protect surface waters from stormwater runoff pollutants from oil and gas facilities. There are too many spills that are not being contained, and even after spills have occurred, facilities are not complying with regulations that require greater scrutiny over their actions. There is a need to both understand the potential threat from oil and gas activities to surface waters from contaminated stormwater, as well as have the regulations in place to prevent any contamination. The purpose of this paper is to shed light on the threat and the need for appropriate regulations.

B. Introduction

O&G exploration and development is a large global industry, and it is likely to expand in the near future due to technological advances and the increased cost-effectiveness of unconventional oil stimulation techniques. With increased activity, there are a variety of ways in which pollutants can get into our waterways, especially if the activity goes unregulated. Stormwater runoff from these sites has largely been unregulated. Stormwater transports debris, chemicals, sediment and other pollutants, and if those pollutants get into

our waterways, they can adversely impact wildlife, cause algae blooms and increase flooding (Stormwater Quality, 2016).

1. Oil and Gas Contamination of Stormwater

There are many O&G field operations that can contribute to contamination of stormwater. They include but are not limited to drilling and production equipment and other machinery, raw materials, waste products and by-products, O&G treatment units, finished products, storage areas, fuels and lubricants, and waste treatment areas (EPA, 2006). The activities, pollutant sources, and pollutants detailed in Table 1 are commonly found at O&G extraction facilities.

Construction activity is a major source of pollutant discharge, both from sediment and also the equipment and materials used. O&G construction sites have the potential to produce as much sediment as other types of construction sites (McBroom et al., 2012; Williams et al., 2008). Well drilling, well stimulations, and well production are all sources of increased total suspended solids (TSS) and total dissolved solids (TDS), and pollutants including oil and grease as well as a large variety of hazardous chemicals listed as chemicals requiring reporting under the Clean Water Act.

In California, surface impoundments are often used to store produced water from unconventional oil stimulation activities. Although no studies have looked at the impact of stormwater runoff from surface impoundments, these impoundments are potentially a source of contaminated stormwater runoff during rain events if not contained.

Vehicles and equipment on site are another source of TSS, TDS, oil and grease, and pH alterations. Oil fields with more wells are greater threats to stormwater pollution. Well density is positively correlated with in-stream turbidity measurements (Entrekin et al., 2011) and increased TSS concentrations (Olmstead et al., 2013).

Table 6: Common Activities, Pollutant Sources, and Associated Pollutants at Oil and Gas Extraction Facilities (EPA, 2006)

Activity	Pollutant Source	Pollutant/Altered Condition
Construction of: access roads drill pads mud/reserve pits personnel quarters surface impoundments storage tanks pipelines	Soil/dirt, leaking equipment, and vehicles	Total suspended solids (TSS), total dissolved solids (TDS), oil and grease
Well drilling	Drilling fluid, lubricants, mud, cuttings, and produced water	TSS, TDS, oil and grease, chemical oxygen demand (COD), chlorides, barium, naphthalene, benzene, lead, arsenic, fluoride
Well completion/ stimulation	Fluids (used to control pressure in well), cement, residual oil, acids, surfactants, solvents, produced water, and sand	TSS, TDS, oil and grease, COD, acid, acetone, toluene, ethanol, xylenes
Production	Produced water, oil, waste sludge, tank bottoms, acids, oily debris, and emulsions	Chlorides, TDS, oil and grease, TSS, pH, benzene, phenanthrene, barium, arsenic, lead, antimony
Vehicle and equipment cleaning and repairing	Cleaning solvents, lubricants, and chemical additives	TSS, TDS, oil and grease, pH
Site closures	Residual muds and oily debris	TSS, TDS, oil and grease, pH
Vehicle fueling	Diesel fuel	TSS, TDS, oil and grease

2. Oil and Gas Exploration and Production Stormwater Regulations

The Clean Water Act regulates the treatment and discharge of wastewater into surface waters of the United States. It sets national standards for industrial wastewater discharges to surface waters – which is known as direct discharge – and municipal sewage treatment plants (also known as publicly owned treatment works or POTWs) – which is known as indirect discharge – based on the performance of treatment and control technologies.

Direct discharges are subject to the National Pollutant Discharge Elimination System (NPDES) permit program. The permit contains limits on what can be discharged, monitoring and reporting requirements, and other provisions to ensure that the discharge does not hurt water quality or people's health. There are two basic types of NPDES permits issued: an individual permit and a general permit. An individual permit is a permit specifically tailored to an individual facility, and a general permit covers a group of dischargers with similar qualities within a given geographical location. In certain cases there are more sector/industry specific permits/requirements, such as the Washington States boatyard permit (Boatyard General Permit) or California Regional Water Quality Control Board Santa Ana Region's sector-specific general permit for storm water runoff associated with industrial activities from scrap metal recycling facilities (General Permit Exec. Order No. NPDES NO CAS618001).

Stormwater runoff is a direct discharge. Common requirements for the Industrial Stormwater General Permit include development of a written Stormwater Pollution Prevention Plan (SWPPP), implementation of control measures, and submittal of a request

for permit coverage, usually referred to as the Notice of Intent or NOI. The SWPPP is a written assessment of potential sources of pollutants in stormwater runoff and measures that will be implemented at the facility to minimize the discharge of these pollutants in runoff from the site. These measures include site-specific best management practices (BMPs), maintenance plans, inspections, employee training, and reporting. The procedures detailed in the SWPPP must be implemented by the facility and updated as necessary, with a copy of the SWPPP kept on-site. The Industrial Stormwater General Permit also requires collection of visual, analytical, and/or compliance monitoring data to determine the effectiveness of implemented BMPs (EPA).

Direct discharges from O&G sites are subject to the NPDES permit program, with the exception of coal bed methane. There can be no discharge of water pollutants from any source associated with production, field exploration, drilling, well completion, or well treatment, except for wastewater that is of good enough quality for use in agricultural and wildlife propagation.

Stormwater, however, has largely gone unregulated at O&G sites. O&G site runoff is exempted from the NPDES program, unless a facility has a discharge of Reportable Quantity (RQ) or contributes to a violation of a water quality standard (*40 CFR 122.26(a)(2)*). This includes discharges that cause a film or sheen, or a discoloration of the water surface or adjoining shorelines, or causes a sludge or emulsion to be deposited beneath the water surface or upon adjoining shorelines. Reportable Quantity is a determined limit for specific hazardous chemicals pursuant to section 311 of The Clean Water Act.

Proving a discharge of RQ or even noting a violation of a water quality standard is a very difficult task. Monitoring at the right time and place is necessary to note if stormwater of such conditions was released. Such monitoring only happens if a facility is enrolled in the NPDES program.

The stormwater discharge exemption proves challenging when trying to prevent waterway contamination from O&G sites. Although this exemption exists there is Residual Designation Authority in the CWA that allows for regulating an activity that may adversely impact surface waters. A delegated state such as California also has this authority. It states that, “the EPA Regional Administrator may designate additional stormwater discharges as requiring NPDES permits where he determines that the discharge, or category of discharges within a geographic area, contributes to a violation of a water quality standard or is a significant contributor of pollutants to waters of the United States (40 CFR 122.26).”

Effective July 2015, California has designated that all O&G facilities that discharge stormwater contaminated by contact with, or that has come into contact with any overburden, raw material, intermediate products located on the site of such operations, must file for an Industrial Stormwater (General Permit Exec. Order No. NPDES NO. CAS000001, 2014). O&G exploration and production facilities that drain to waterways must now submit an application to be covered by the Industrial Stormwater General Permit or file a No Exposure Certification. A No Exposure Certification means that the entity identified does not require permit authorization for its stormwater discharges associated

with industrial activity due to the existence of a condition of no exposure. In the new order it also states, “when developing the next reissuance of this General Permit, the State Water Board expects to have a better understanding of the feasibility and benefits of sector-specific and watershed based permitting alternatives, which may include technology – or water quality based numeric effluent limitation (Exec. Order No. NPDES NO. CAS000001, 2014).” This means that the State Water Board recognizes that sector-specific permitting may be a necessary for certain industries, O&G included.

As part of the CWA, EPA also requires certain oil drilling facilities to prepare and implement Spill Prevention, Control and Countermeasure (SPCC) plans to prevent discharge of oil into navigable waters or adjoining shorelines. Facilities that must prepare and implement SPCC plans include: non-transportation related facilities; facilities that have an aggregate above ground storage capacity over 1,320 gallons or a buried storage capacity over 42,000 gallons; and facilities that have a reasonable expectation of discharging into or upon navigable waters or adjoining shorelines (40 CFR 122).

The SPCC plan and the NPDES permit program are intended to capture potential sources of pollutants that may contaminate surface water. However, often the suggested protocol and measures taken are too generic for them to be effective for the specific industry. With no industry specific permits there is no guidance as to where and how representative and effective monitoring should take place, what industry specific constituents should be monitored, or which BMPs serve that industries needs. With no industry specific recommendations, it is left up to operators to implement or not implement measures. If

appropriate monitoring is not happening it is not capturing any violations. As this paper will show in the results section there is only a very small fraction of O&G operators that are enrolled in the NPDES permit program.

At the national level, only spills that exceed a Reportable Quantity or contribute to a water quality violation require notification to be covered by the general permit for stormwater discharges. In California, all O&G exploration and production facilities that drain to waterways must submit an application to be covered by the Industrial Stormwater General Permit or file for a No Exposure Certification. At issue is the fact that an important industry is either not being regulated at the federal level or being regulated with very general pollution prevention and control requirements when more specific control measures would be appropriate to reduce the risk of contamination of waterways.

The purpose of this study is to examine if O&G exploration and production operations present a significant threat to surface water and recommend more specific permitting requirements and custom tailored BMPs to eliminate the exposure of O&G operations to stormwater runoff and/or to control pollutants in discharges to protect surface waters. To determine if a significant threat exists—

which if does exist, the EPA Regional Administrator may designate additional stormwater discharges as requiring NPDES permits— this paper analyzes spill reports, Industrial Stormwater General Permit compliance, and current unconventional oil stimulation stormwater permit compliance given the increase in this practice in two California Counties. It also reviews selected spill cases and associated SWPP and SPCC plans to

identify adequacy of current industry practices. Finally, the paper looks at waste surface impoundments at O&G facilities in California and the operation and maintenance practices to assess if they too pose a threat. Surface impoundments are used to store a variety of potentially toxic, as well as non-hazardous liquid and solid wastes associated with O&G development. The chemicals may leach into groundwater; contaminate soils and vegetation; or overflow from the sides of the impoundment—either during a rain event, or due to inadequate storage—and pollute soil and surface waters. Drilling fluids and wastes, production chemicals and wastes, and produced water are some of the fluids stored in surface impoundments (*Managing industrial solid wastes from manufacturing, mining, O&G production, and utility coal combustion, 1992*).

C. Methods

There is no one decisive way to determine if stormwater from O&G exploration and production poses a significant threat. Contaminated stormwater quality and volumes from oil and gas exploration and production sites depends on site-specific consideration including overall housekeeping and spill prevention practices, rainfall, and total runoff area. This study conducted a survey of O&G spills and O&G stormwater permit compliance in Kern County and Ventura County, California for the time period of 2010-2016. Reviewing the types and sizes of spills at oil fields can inform on whether the current industry practices pose a significant threat to the environment. For the larger spills (those above 10,000 gallons), reviewing corresponding facility SPCC and SWPP plans will give a better understanding if written plans are specific enough to prevent such spills. O&G facilities that spill chemicals of Reportable Quantity (RQ) or contribute to a violation of a water quality standard must enroll in the NPDES permit program. Looking at permit compliance would

be useful in determining the effectiveness of the current regulatory framework that is being implemented to mitigate stormwater pollution.

The use of unconventional oil and gas (UOG) stimulation techniques has increased dramatically over the last 5 years. Most of the reporting on UOG stimulation in California has really only begun in the last 2 years. Given the new NPDES Industrial Stormwater General Permit requirements for O&G facilities that went into effect July 2015, it would be useful to see how permit compliance has changed in relation to UOG exploration. The analysis will be done for Kern County and Ventura County, California. Kern County is the main hub of UOG stimulation techniques in California; much of the county is oil fields. Ventura County has O&G activity but to a lesser extent than Kern County. Ventura County is more representative of an area that has residential, commercial, and industrial areas spread out over a county. The following sections describe the methods used for the various analyses.

1. Oil and Gas Exploration and Production Spill Analysis

We used data from the California Office of Emergency Services (Cal OES) for hazardous material release information. The data was downloaded in March 2016 from the Cal OES website for the years 2010-2016. The Excel sheets provide spill details including, date, time, location, substance type, amount spilled, and a general description of the cause of the spill. It also provides information on the type of immediate impact, including surface water contamination or fatalities and injuries involved. The responsible party and the agency reported to are also listed.

The data was filtered to include only spills that occurred on oil fields in Kern and Ventura counties. The assumption is that spills entail runoff. The spills were classified by size. There are no standard definitions for small, medium, or large spills. A variation of the United States Coastal Guard (USCG) threshold cutoffs was used. USCG classifies a small spill as less than 24 oil barrels (bbl), a medium spill as less than 240 bbl, and a large spill as greater than or equal to 240 bbl (Anderson, Mayes, LaBelle, 2012). One bbl represents 42 gallons. Ten bbl was used as the lower end of a small spill because according to the Department of Oil, Gas, and Geothermal Resources (DOGGR) it is considered significant for spill management purposes (Department of Conservation, 1998). The study also determined which spills reached waterways.

Table 7: Spill Classification

Spill Size	Spill Amount
Small	10 - < 24 bbl (< 1000 gallons)
Medium	24 - < 240 bbl (1000-10,000 gallons)
Large	≥ 240 bbl (>10,000 gallons)

* 1 bbl (oil barrel) = 42 US gallons

Once the information on oil field spills in Kern County and Ventura County was collected, the State Water Resources Control Board's (SWRCB) Stormwater Multiple Application and Report Tracking System (SMARTS) was used to see which facilities filed for an Industrial Stormwater General Permit. SMARTS was developed as an online database for dischargers to electronically file their stormwater permit documents. The database was searched using the Standard Industrial Code (SIC) 13xx; this applies to the O&G industry. The time frame of the study was from 2010-2016. Some of the information included in the database is the application type (Industrial, No Exposure Certification, etc.), its status (active or

terminated), status date, and the operator/owner name and address. As the regulation states, prior to July 2015 in California “when a facility has a discharge of reportable quantity for which notification is required or contributes to a violation of a water quality standard” they are required to be enrolled in the NPDES permit program. Post July 2015, all O&G facilities are required to enroll in the Industrial Stormwater General Permit program if they “discharge stormwater contaminated by contact with or that has come into contact with any overburden, raw material, intermediate products located on the site”(General Permit Exec. Order No. NPDES NO. CAS000001, 2014).

2. Analysis of Selected Spill Cases and Associated SPCC and SWPP Plans

The largest spills in Kern County and Ventura County were identified as case studies to understand the adequacy of current industry practices. SPCC plans for these facilities were sought out. Representatives from DOGGR were contacted to obtain the SPCC plans. The SMARTS site was used to find the associated SWPP Plans.

3. Oil and Gas Facility Industrial Stormwater General Permit Compliance

Analysis

This analysis looked at how many O&G facilities filed for an Industrial Stormwater General Permit pre/post the new Industrial Stormwater General Permit requirements for O&G in California. The analysis determined how many facilities had a permit prior to and after July 2015 for Kern and Ventura County. The analysis also focused on UOG stimulation operations to see how many facilities filed for an Industrial Stormwater General Permit pre/post the new Industrial Stormwater General Permit requirements. Reporting on UOG stimulation techniques, including HF, acid fracturing, and matrix acidization, began in 2014

in California through the interim Senate Bill 4 (SB4) and is now required through the SB4 bill as of July 2015. The analysis looked at how many UOG stimulation facilities filed with DOGGR also filed for the Industrial Stormwater General Permit, and how many more were prompted to register after the new requirements. This might give an idea of whether the new permit requirement promoted O&G to file for a permit. Unless a facility is entirely contained it is likely that all operators would need to be covered by the Industrial Stormwater General Permit post July 2015.

Industrial Stormwater General Permit information was obtained from the California State Water Board's SMARTS system using SIC 13xx to narrow down to O&G industry up until April of 2016. To get information on UOG stimulation facilities, a representative at DOGGR gave a list of all the disclosures submitted to them.

4. Surface Impoundments

Section 45 of California Senate Bill 83 requires that the State Water Resources Control Board report on the regulation of oil field produced water ponds within each region by January 30, 2016, and every six months thereafter. This report was reviewed to understand surface impoundment use and makeup in the State of California. The literature was searched to see in what capacity surface impoundments are used and what the operation entails.

D. Results

1. Oil and Gas Exploration and Production Spill Analysis Results

The results for the spill analysis for both counties are below.

Table 8: Oil Field Spill Analysis for Ventura and Kern County, California (January 2010 - March 2016)

	Ventura County	Kern County
# of spills	61	316
# of medium spills (24-240bbl)	7	47
# of large spills (≥ 240 bbl)	0	10
# in contact w/waterways	22	34
# of different facilities/entities reporting spills	14	70
Which facility/entity was covered by NPDES permit	California Resources Production Corp (Industrial)	Inergy (Industrial) Schlumberger (Notice of non-applicability) Chevron (Notice of non-applicability)

There are fewer spills in Ventura County compared to Kern County because it is not as active an oil-producing county. There were a total of 61 reported spills from January 2010 - March 2016. Of those 61 spills, 7 were of medium size (24 – 240 bbl) and the rest were small spills. For the medium sized spill, only 1 of the 4 entities responsible had an active permit. There were 22 spills that came in contact with waterways, of which only 1 entity of the 6 responsible had an active permit. There were 14 different entities that reported the 61 spills, meaning the same entities had repeated spill instances. The only entity that was covered by the Industrial Stormwater General Permit was California Resources Production Corp. If one assumes that the spills met the reporting requirements, few to no facilities filed for a permit.

There were 316 spills in Kern County during the study time frame. Of those 316, 47 were medium sized spills (24 – 240 bbl) with only one of the 14 entities responsible for the spills having a Notice of Non-Applicability. A Notice of Non-Applicability would indicate that the site was either enclosed, there was no stormwater discharge/exposure, they were not required to be permitted by federal regulation, they were regulated by another permit, there was a new facility operator or they never operated the facility. There were 10 large spills (> 240 bbl) and only one of the 5 entities responsible had a Notice of Non-applicability. Of the 34 spills that reached waterways, only one of 20 entities responsible had a Notice of Non-applicability. There were a total of 70 entities responsible for the 316 spills, only 3 filed in the NPDES program; Inergy had an Industrial Stormwater General Permit; Schlumberger and Chevron submitted a Notice of Non-Applicability, Chevron being responsible for one of the large, medium, and contact with waterway spills. In Kern County as well only a very small percentage filed for a permit.

For the medium/large spills and/or those that reached waterways, the responsible entity most likely would have needed to notify the Water board and have been enrolled in the NPDES program. However, there is very little overlap between who the polluters were and who is covered by the NPDES permit.

2. Analysis of Selected Spill Cases and Associated SPCC and SWPP Plans

After sorting through the Ventura and Kern County oil field spills, the 3 largest spills were chosen in each county as case studies. Information about the spills is taken directly from the Cal OES site and is in the tables below.

Table 9: Ventura County Medium Sized Spills

Entity	Permit Status	Spill Size	Spill Description
California Resources Production Corp.	Active Industrial Stormwater General Permit	100 bbl produced water	A hole in a 4" pipe spilled onto a private road on the leased property (oil production lease); some release entered a nearby metal culvert and then into a soil ravine.
Vintage Productions California	Terminated Permit	65 bbl crude oil	During hydrotesting of a line, built up pressure caused a spray of oil and water onto trees over a dry creek bed.
Vintage Production LLC	Terminated Permit	60 bbl produced water/crude oil	A broken hose caused this release.

The largest spills in Ventura County were of medium size. The 3 case studies involved spills of 60-100bbls of produced water and/or crude oil. Produced water contains many chemicals either from the injected fluid or formation waters (CCST, 2014), and it accounts for 96 to 98 percent of all O&G wastes (*Managing industrial solid wastes from manufacturing, mining, O&G production, and utility coal combustion*, 1992). These medium sized spills were either caused by a faulty pipe/hose, or build up of pressure; in two of the releases, waterways were reached. California Resources Production Corp was the only entity covered by the NPDES general industrial permit.

Ventura County Facility SPCC and SWPP Plans:

There were no SPCC plans obtained for these three sites. California Resources Production Corp. was the only one with a SWPP plan on file (See Supplemental Section). The SWPP plan had specific best management practices listed. Of particular interest were the general BMPs. These included; containing all stored non-solid industrial materials or wastes that

can be transported or dispersed by the wind or contact with stormwater during handling; and covering industrial waste disposal containers and industrial material storage containers that contain industrial materials when not in use. The advanced BMP used was berming/containment around tank batteries and well pads. Tank batteries are constructed with secondary means of containment with the volume capacity of the containment designed to exceed the contents of the largest tank within the facility and with sufficient freeboard to contain precipitation. Well pads are constructed of earthen berms and/or well cellars to contain liquids on location. There are open drains within the site, which collect miscellaneous fluids from the containment areas. These drains are piped and transported to a central sump from which they are pumped for proper disposal. Containment structures are inspected regularly for deficiencies and repairs are made as necessary.

Table 10: Kern County Large Sized Spills

Entity	Permit Status	Spill Size	Spill Description
Berry Petroleum	No Permit	700 bbl Water – Produced type used for well kill	A rain event occurred over the area and filled a concrete cellar that a well sits in and floated residual oil to the surface, resulting in the release of crude oil on a dry, unknown creek bed.
Plains All American Pipeline	No Permit	600 bbl Produced Water	Produced water line failure caused the release of approximately 5 gallons of crude oil into a dry waterway; the rest of the release went to land only, impacting no waterway.
Chevron USA Inc.	Notice of Non-Applicability	500 bbl Produced Water	Corrosion on a 3" flow line caused a release to a blue line (stream).

The largest spills in Kern County were 500-700bbl of produced water; the largest of these spills occurring after a rain event. This is just one case that shows that rain events can cause stormwater pollution issues from O&G facilities. Preventing overflows from rain

events is possible if the facility is entirely covered or contained. The remaining two spills were caused by faulty pipes lines. Only one operator, Chevron USA Inc. had a Notice of Non-Applicability.

Kern County Facility SPCC and SWPP Plans:

There were two associated SPCC plans obtained; one for the Plains All American Pipeline site and the other for Chevron site. The first SPCC plan had an annual pipeline inspection plan and monthly facility maintenance plan for primarily checking equipment integrity. In addition there was a general spill protocol outlined. There was no discussion of any secondary containment. The SPCC plan was not very specific in its prevention protocol. Chevron's SPCC plan had similar spill and maintenance protocol, but the site was designed with containment berms and had a valve shut-off protocol. Because the facilities was entirely contained Chevron appropriately filed for a Notice of Non-Applicability. In this case the site was contained and the spill did not cause a threat to surface waters. As for SWPP plans there were none found for the spill sites of concern.

From the limited information it seems as though SWPP plans include more specific BMPs to manage stormwater and protect surface water than the SPCC plans. The reason for this may be that an assessment of potential sources of pollutants in stormwater runoff is required in the NPDES program, as are measures to minimize the discharge of these pollutants in runoff from the site. The Industrial Stormwater General Permit also requires collection of visual, analytical, and/or compliance monitoring data to determine the effectiveness of implemented BMPs.

Ideally, there needs to be specific guidance and requirements for O&G facilities to prevent spill and overflow. Currently there are no industry specific requirements. EPA has a list of BMPS for potential pollutant sources at oil and gas extraction facilities that will be discussed later (EPA, 2006), as well as more specific guidance for oil and gas construction sites provided by the Independent Petroleum Association of America (Reasonable and Prudent Practices for Stabilization (RAPPS) of Oil and Gas Construction Sites, 2004).

3. Oil and Gas Exploration and Production Industrial Stormwater General Permit Compliance Analysis

This study also looked at Ventura and Kern County's active O&G facilities to see how many filed for an Industrial Stormwater General Permit pre/post the new requirements. This covered until March of 2016. In Ventura County there were 36 Active permits, 10 of those filed post July 2015. This is a substantial percentage (28%) that enrolled in a short time frame of 8 months (July 2015 – March 2016) after the new permit requirements. In Kern County there were 45 Active NPDES permits; 27 of those were post the new requirements. In Kern County 60% enrolled after the new order. The new Industrial Stormwater General Permit requirements had a large proportion of operators enroll in the program in a short time span. Surprisingly, facilities where spills occurred did not file for permits.

Table 11: O&G Facilities Filing for NPDES Permit Pre/Post New NPDES Permit Order

County	# of NPDES Permit Before July 2015	# of NPDES Permits After July 2015
Ventura	36	10
Kern	45	27

There were 9 different UOG stimulation facilities filing for well stimulation permits with DOGGR prior to the new Industrial Stormwater General Permit requirements and only one applied for a Notice of Non-applicability. About 10% of operators filed for a permit. After the new requirements, there were five different entities filing for well stimulation permits with DOGGR; two filed for a Industrial Stormwater General Permit, and one filed a Notice of Non-applicability. Post new requirements, 60% of the UOG facilities filed for a permit.

Table 12: UOG Facilities Filing for NPDES Permit Pre/Post New NPDES Order

	Before July 2015	After July 2015
# DOGGR UOG facilities	9	5
# DOGGR UOG facilities w/NPDES permit	1	3
% UOG facilities obtaining NPDES permit	10%	60%

This analysis shows that the new requirements for O&G facilities to file for a Industrial Stormwater General Permit in California is encouraging more O&G facilities to enroll in the NPDES permit program. This however does not mean better regulatory control or pollution reduction. There needs be specific best management practices for O&G as well as specific requirements for known polluters. However having all O&G at least enroll in the program is a first step that that the federal government can follow California's example in.

4. Surface Impoundments Analysis

Surface impoundments, sometimes referred to as ponds, can be another source of contaminated runoff. They are used for temporarily storing drilling fluids for use in drilling operations, settling/skimming of solids and separation of residual oil, storage of produced waters prior to injection or off-site transport, percolation of liquids via drainage or seepage

into surrounding soil, and evaporation of produced waters into the atmosphere (Karami et. al., 2013).

In California, surface impoundments are permitted by the Regional Water Quality Control Boards. In California, surface impoundments are predominantly unlined and used to dispose of produced water through evaporation and/or percolation. Produced waters account for 96 to 98 percent of all O&G wastes (*Managing industrial solid wastes from manufacturing, mining, O&G production, and utility coal combustion*, 1992). An estimated 1.9 billion barrels of water were produced during oil extraction in the Central Valley in 2013. Approximately 12% (12 billion gallons) was disposed into sumps or recycled (Zinky, 2016).

Section 45 of California Senate Bill 83 requires that the State Water Board report on the regulation of oil field produced water ponds within each region by January 30, 2016, and every six months thereafter. The first report contains information from the Central Coast and Central Valley Water Boards, and includes the total number of ponds in each region, the number of permitted and unpermitted ponds, enforcement actions, and the status of permitting the unpermitted ponds. Enforcement Actions include Informational Orders (13267), Notices of Violations and Cleanup and Abatement Orders.

Table 13: SWRCB Oil Field Produced Water Ponds Report as of January 30, 2016

Regional Water Board	Active Ponds		Inactive Ponds		Total Ponds		Enforcement Actions
	Permitted	Un-permitted	Permitted	Un-permitted	Permitted	Un-permitted	
Central Coast	3	41	0	8	3	49	52
Central	530	162	101	269	631	431	1062

Valley							
Total	533	203	101	277	634	480	1114

In the Central Coast most of the active and inactive ponds were unpermitted and there were enforcement actions against most of them. In the Central Valley about 40% of the ponds were unpermitted, and almost all the ponds had enforcement actions against them. The use of ponds is very pervasive, especially in the Central Valley where most of the O&G exploration and production takes place. Unpermitted ponds and ponds violating code indicate that best protocol to protect surface waters from improper containment practices are not in place.

A survey of the literature concluded that there are no current reports on surface impoundments. The EPA produced a few reports in the 70s and early 80s but none published recently. There were no articles found on surface impoundments and surface water threats.

5. Best Management Practices

Currently the requirements in place for the O&G industry to prevent surface water contamination from stormwater runoff are very general. Ideally, having specific BMPs tailored to the industry would provide better protection. There are a few guidance documents with more specific recommendations for O&G facilities. Two were developed by the US EPA, one looking at BMPs for potential pollutant source (EPA, 2010) and the other providing voluntary practices for oil and gas wastes (EPA, 2014). Another document by the Independent Petroleum Association of America (IPAA) identifies practices for stabilization

of O&G construction sites. These documents could be sources to establish requirements for a more industry specific stormwater permit. Currently most of the BMPs recommended in these documents don't have defined performance standards. The guidance provided by the IPAA provides more details for scoping the BMPs to stabilize O&G construction sites. The table below lists the BMPs the EPA recommends. Although many are general recommendations there is specific guidance that could be used in the permitting process.

Table 14: BMPs for Potential Pollutant Sources at O&G Extraction Facilities (EPA, 2010)

Pollutant Source	BMPs
Construction	• Limit the amount of land disturbed during construction of access roads and facilities and preserve existing vegetation. • Implement erosion and sediment controls such as vegetated swales, diversion berms, or dikes to limit or isolate land disturbance and process areas to retain/detain flows and limit stormwater run-on in these areas. • Divert stormwater away from contaminated areas. Inspect the area regularly to ensure BMPs are implemented and maintained.
Well drilling	• Use diking and other forms of containment and diversion around storage tanks, oil drums, acid, production chemicals and liquids, reserve pits, and impoundments. • Use diking and other forms of containment and diversion around material handling and processing areas. • Use porous pads under drum and tank storage areas. • Use covers and/or lining for waste reserve and sludge pits to avoid overflows and leaks. • Use drip pans, catch basins, or liners during handling of materials such as tank bottoms. • Re-use collected stormwater for industrial process or as an irrigation source. • Develop and implement spill plans for pipelines, tanks, drums, etc. • Recycle oily wastes, drilling fluids and other materials on-site, or dispose offsite. • Use oil - water separators. • Inspect the area regularly to ensure BMPs are implemented and maintained.
Well completion	• Utilize diking and other forms of containment and diversion around storage tanks, oil drums, acid, production chemicals and liquids, reserve pits, and impoundments. • Use diking and other forms of containment and diversion around material handling and processing areas. • Use porous pads under drum and tank storage areas.

	• Use covers and/or lining for waste reserve and sludge pits to avoid overflows and leaks. • Use drip pans, catch basins, or liners during handling of materials such as tank bottoms. • Re-inject or treat produced water instead of discharging it. • Re-use collected stormwater for industrial process or as an irrigation source. • Develop and implement spill plans for pipelines, tanks, drums, etc. • Recycle oily wastes, drilling fluids and other materials on-site, or dispose of offsite. • Use oil water separators. • Inspect the area regularly to ensure BMPs are implemented and maintained.
Vehicle and equipment cleaning and maintenance	Good Housekeeping • Eliminate floor drains that are connected to the storm or sanitary sewer; if necessary, install a sump that is pumped regularly. Collected wastes should be properly treated or disposed of by a licensed waste disposal company. • Prevent and contain spills and drips. • Do all cleaning at a centralized station so the solvents stay in one area. • If parts are dipped in liquid, remove them slowly to avoid spills. • Use drip pans, drain boards, and drying racks to direct drips back into a fluid holding tank for reuse. • Drain all parts of fluids prior to disposal. Oil filters can be crushed and recycled. • Promptly transfer used fluids to the proper container; do not leave full drip pans or other open containers around the shop. Empty and clean drip pans and containers. • Clean up leaks, drips, and other spills without using large amounts of water. Use absorbents for dry cleanup whenever possible. • Prohibit the practice of hosing down an area where the practice would result in the discharge of pollutants to a stormwater system. • Do not pour liquid waste into floor drains, sinks, outdoor storm drain inlets, or other storm drains or sewer connections. • Maintain an organized inventory of materials. Eliminate or reduce the number and amount of hazardous materials and waste by substituting nonhazardous or less hazardous materials. • Label and track the recycling of waste material (e.g., used oil, spent solvents, batteries). • Store batteries and other significant materials inside. • Dispose of greasy rags, oil filters, air filters, batteries, spent coolant, and degreasers in compliance with RCRA regulations. Minimizing Exposure • Perform all cleaning operations indoors or under covering when possible. Conduct the cleaning operations in an area with a concrete floor with no floor drainage other than to sanitary sewers or treatment facilities.

	• If operations are uncovered, perform them on a concrete pad that is impervious and contained. Park vehicles and equipment indoors or under a roof whenever possible and maintain proper control of oil leaks/spills. • Check vehicles closely for leaks and use pans to collect fluid when leaks occur. Management of Runoff • Use berms, curbs, or grassed swales other diversion measures to ensure that stormwater runoff from other parts of the facility does not flow over the maintenance area. • Collect the stormwater runoff from the cleaning area and provide treatment or recycling. • Discharge vehicle wash or rinse water to the sanitary sewer (if allowed by sewer authority), wastewater treatment, a land application site, or recycle on-site. DO NOT discharge washwater to a storm drain or to surface water. Inspections and Training • Inspect the maintenance area regularly to ensure BMPs are implemented. • Train employees on waste control and disposal procedures.
Vehicle fueling	Stationary fueling areas • Conduct fueling operations (including the transfer of fuel from tank trucks) on an impervious or contained pad and under a roof or canopy where possible. Covering should extend beyond spill containment pad to prevent rain from entering. • When fueling in uncovered area, use concrete pad (asphalt is not chemically resistant to the fuels being handled). • Use drip pans where leaks or spills of fuel can occur and where making and breaking hose connections. • Use fueling hoses with check valves to prevent hose drainage after filling. • Keep spill cleanup materials readily available. • Clean up spills and leaks immediately. • Use dry cleanup methods for fuel area rather than hosing down the fuel area. Sweep up absorbents as soon as spilled substances have been absorbed. • Do not “top-off” fuel tanks. • Use spill and overflow protection devices. • Minimize/eliminate run-on into fueling areas with diversion dikes, berms, curbing, surface grading or other equivalent measures. • Collect stormwater runoff and provide treatment or recycling. • Provide curbing or posts around fuel pumps to prevent collisions from vehicles. • Regularly inspect and perform preventive maintenance on fuel storage tanks to detect potential leaks before they occur. • Inspect the fueling area for leaks and spills. Train personnel on vehicle fueling BMPs. Mobile fueling areas

	• Use drip pan under the transfer hose. • Use fueling hoses with check valves to prevent hose drainage after filling. • Ensure the fueling vehicle is equipped with a manual shutoff valve. • Do not allow topping off of the fuel in the receiving equipment. • Train personnel on vehicle fueling BMPs.
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E. Discussion

The analysis shows that on the federal level stormwater contamination from O&G facilities is not well regulated. At the federal level O&G facilities do not need to file for an Industrial Stormwater General Permit even though many O&G industry practices contaminate stormwater runoff from the site. When O&G facilities discharge a RQ or violate a water quality standard they are required to enroll in the NPDES program. Spills, although not a direct indication of stormwater runoff, can give some idea of potential polluted runoff that should be regulated. If we assume the medium and large spills in this study that reached waterways violated a water quality standard then those facilities must have an active permit on file. However, what we see is that most of those facilities are not filing for a permit. In California new filing requirements for oil and gas industry require all facilities that discharge stormwater contaminated by contact with, or that has come into contact with any overburden, raw material, intermediate products located on the site of such operations, to file for an Industrial Stormwater General Permit. The new requirements have captured a larger pool of facilities in the program. The federal government should follow suit in requiring similar permitting of all O&G facilities. Nonetheless, the permit is general in nature and may not provide the industry with the more specific requirements that it needs. There is a need for industry tailored stormwater permit requirements.

For the Ventura County and Kern County medium and large sized spill case studies, there were only two associated SPCC plans and one SWPP plan that were obtained. One site's SPCC plans show that measures in place are very general; they may be able to detect faulty equipment but do not address containment issues. The other SPCC plan was for an enclosed facility whose spill did not reach waterways. The SWPP plan provides more specific recommendations for sites that are in contact with waterways. From this limited sample it seems like being enrolled in the NPDES permit program ensures better BMPs to prevent contaminated stormwater releases. Having even more specific BMPs would be more protective.

Surface impoundments at O&G facilities can be a serious threat to waterways. In California there are thousands of these impoundments, currently most are unlined and many are unpermitted. Almost all are in some sort of violation. Proper oversight and development of surface impoundments is needed. Many states have banned the use of surface impoundments for the many problems associated with them, overflows being one of them.

Given the sources of runoff contamination from O&G industry practices, problems with spills, and surface impoundments, all O&G facilities should be covered under the Industrial Stormwater General Permit, which is the current California approach. It should not be left up to facilities to identify when a violation has occurred and then file for a permit. The authors recommend a tiered permitting approach nationally. The tiers should relate to spills as well as toxicity of chemicals used. All O&G facilities should file for the Industrial Stormwater General Permit for potential stormwater discharges as the first tier. The next

tier of facilities would be regulated more strictly in cases of spills or use of toxic chemicals. If there is a medium sized spill (24 - 240 bbls) or hazardous chemicals are used that appear on the Reportable Quantity list or have a toxicity grade of an F, as identified in the second chapter, the operator must file for a sector specific permit as the second tier, which calls for more specific protocols for the O&G sector. The BMPs identified in this paper can be incorporated in such a permit. If there is a large sized spill (> 240 bbls) or hazardous chemicals (identified in the second tier of reporting) are used in quantities above identified thresholds the operator must file for a site-specific individual permit under the third tier. This allows for more scrutiny and oversight. A tiered approach gives operators an incentive to prevent spills, use safer chemicals, and employ BMPs.

At the California State level all O&G are required to file for an NPDES permit. To ensure that this happens it can be a requirement for all facilities obtaining a drilling permit from DOGGR to file for a permit with the Water Board. There can be a permit block from DOGGR stating that no O&G stimulation will be permitted until an NPDES permit has been filed for. Such inter-agency dependency can enhance the effectiveness of rules and better protect the public and environment.

There is growing evidence that regulatory protocols must be in place to protect surface waters from contamination from O&G facilities. In California there are too many spills that are not being contained, and even after spills have occurred, facilities are not complying with regulations that require greater scrutiny over their actions. There is a need to both understand the potential threat from O&G activities to surface waters from contaminated

stormwater as well as have the regulations in place to prevent any contamination. It is hoped that this paper sheds light on the threat and the need for appropriate regulations concerning O&G stormwater management.

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VII. Conclusion

The use of unconventional oil and gas stimulation is projected to rise in the next decades.

The research and regulatory communities are starting to address some of the concerns regarding potential impacts to the public and environment. A greater focus has been on hydraulic fracturing (HF), both on its potential impacts and how to best regulate the practice. Acidizing, though a sister-technology, has mostly been ignored. The research shows that it is being used quite frequently, and the concerns that have arisen for HF also hold true for acidizing.

Taking a closer look at its use in California, the analysis shows that there have been 474 reported acid maintenance events in Southern California, 96 reported matrix acidization events in Central and Southern California, and 10 reported acid fracturing events in Central California from April 2013 to mid-August 2015. In Southern California, acidization events are occurring in highly urban areas around Los Angeles County. There are about 200 chemicals used in acidization, and 50% of the most commonly used chemicals are the most commonly used HF treatment chemicals. Unlike HF, the chemical concentrations in the fluids for acidization are high, ranging from 6-18% chemicals, and the waste that returns is also highly acidic.

The amounts of chemical used per treatment are anywhere between 100's of milligrams to 100,000's of kilograms. Some of the chemicals are known to be of concern for both human health and the environment. An initial hazard assessment was done, and 28 QCAT F-graded chemicals of concern have been identified.

Furthermore the flow back conditions, pH of the fluid and what chemicals are returning are unknown. The toxicity, the chemical fate and transport, and exposure potential of all these chemicals should be understood, and if a hazard is noted then substitute chemicals should be suggested. Understanding where these chemicals are likely to end up in our environment is critical in predicting how vulnerable populations will be affected. Understanding the toxicity will help us identify possible impacts we might see in the near to distant future on humans and other living organisms.

Regulating acidizing is also crucial in protecting the public and environment from any unintended consequences. From the outlined research in this dissertation we see that many federal bills exempt O&G operations from regulatory oversight. There have been recent concerns over the impacts of HF on human health and the environment. Recent discussions have called for increased regulatory oversight for HF events. Some acidizing well stimulations operationally are very similar to HF but have not received the same attention. Acidizing techniques use hazardous chemicals in higher concentrations than HF and should be better regulated.

On the federal level there are a few opportunities to better regulate acidization:

- The Bureau of Land Management has proposed a new rule when permitting HF wells.

The Clean Air Act has New Source Performance Standards (NSPS) for hydraulically drilled wells. Under section 8 of the Toxic Substance Control Act, EPA issued an Advance Notice of Proposed Rulemaking (ANPR) for HF chemicals and mixtures. In

all these cases acidization should be included in new rules.

- The Safe Drinking Water Act may prove to be an effective way to regulate acidization activities. Although the Energy Policy Act of 2005 exempts HF, except where diesel is used, from its underground injection definition acid fracturing and more likely matrix acidization, are not exempt. This finding will prove to be an area of great debate in the courts.
- A new proposed rule under the Clean Water Act is establishing pretreatment standards for O&G extraction. This is a positive step and the acidizing chemicals should be looked at when setting the standards. Currently under the Clean Water Act, stormwater discharge from O&G facilities do not require an Industrial Stormwater General Permit, unless a Reportable Quantity of a hazardous chemical is released or there is a violation of a water quality standard. Hazardous acidizing chemicals are used above the RQ limits. In combination with acidizing waste being stored in surface impoundments creates a threat for surface water contamination. Stormwater discharges from acidizing operations should require permits and specific best management practices for the oil/gas industry should be recommended.
- Section 313 under The Emergency Planning and Community Right-To-Know Act (1986) authorizes EPA's Toxics Release Inventory (TRI), which is a publicly available database that contains information on toxic chemical releases and waste

management activities reported annually by certain industries as well as federal facilities. To date, EPA has not included O&G extraction as an industry that must report under TRI because it is not considered a high priority. There are close to a dozen acidizing chemicals that appear on the TRI inventory list. This should warrant reporting.

Taking a more detailed look at protecting surface waters from O&G stormwater, the analysis shows that on the federal level stormwater contamination from O&G facilities is not well regulated. At the federal level, O&G facilities do not need to file for an Industrial Stormwater General Permit even though many O&G industry practices contaminate stormwater runoff from the site. When O&G facilities discharge a RQ or violate a water quality standard they are required to enroll in the NPDES program. The research shows that medium and large spills that reached waterways may have violated a water quality standard but only a few filed for a permit. In California new filing requirements for oil and gas industry require all facilities that discharge stormwater contaminated by contact with or that has come into contact with any overburden, raw material, intermediate products located on the site of such operations to file for an Industrial Stormwater General Permit. The new requirements have captured a larger pool of facilities in the program. The federal government should follow suit in requiring similar permitting of all O&G facilities. Nonetheless, the permit is general in nature and may not provide the industry with the more specific requirements that it needs. There is a need for industry tailored stormwater permit requirements.

There is growing evidence that regulatory protocols must be in place to protect surface waters from contamination from O&G facilities. There are too many spills that are not being contained, and even after spills have occurred, facilities are not following regulations that require greater scrutiny over their actions. There is a need to both understand the potential threat from O&G activities to surface waters from contaminated stormwater as well as have the regulations in place to prevent any contamination.

It's important that O&G development and production be reviewed as a whole. Some of the concerns that exist for HF apply to all of O&G exploration. For example, chemical waste returns, chemicals stored on site, and stormwater discharge of chemical laden fluid is a concern for most O&G exploration activities. Chemicals reaching USDWs are concerns for all UOG techniques, including acid fracturing and matrix acidization. These activities should not be ignored, especially when discussions are happening on how to effectively protect the public and the environment from potential harmful impacts of HF. A national framework is needed to ensure a consistent minimum level of protection for the public and environment.

What is evident from the research of this dissertation on acidization – the chemicals used, their toxicity, the regulatory oversight – is that a narrow scope of looking at just one oil and gas operation like HF is not enough to protect the public and environment. The O&G industry as a whole has evolved and is evolving substantially. Having a comprehensive approach at looking at impacts from all unconventional oil stimulation techniques, like acidizing, is crucial in protecting the public and environment from any future harm. It is

hoped that with this research acidization becomes part of the larger discussion on concerns with oil exploration and is evaluated by appropriate authorities.

VIII. Appendix

A. Spill Prevention Control and Countermeasure Plans; Stormwater Pollution Prevention Plan



STORM WATER POLLUTION PREVENTION PLAN (SWPPP)

MONITORING AND REPORTING PLAN

California Resources Production Corporation
Ojai Field
12720 Ojai Santa Paula Road
Santa Paula, California 93060
WDID # 4 561025652

July 1, 2015

STORM WATER POLLUTION PREVENTION PLAN

Facility Operator Information:

California Resources Production Corporation
270 Quail Court, Suite 201
Santa Paula, California 93060

Facility Site Information:

California Resources Production Corporation
Ojai Field
12720 Ojai Santa Paula Road
Santa Paula, California 93060
SIC Code: 1311
WDID # 4 561025652

Date:

July 1, 2015

ACRONYMS

BBL	Barrel
BMP	Best Management Practice
BOD	Biochemical Oxygen Demand
CASQA	California Stormwater Quality Association
CoC	Chain of Custody
COD	Chemical Oxygen Demand
CRPC	California Resources Production Corporation
DA	Drainage Area
DAR	Duly Authorized Representative
ERA	Exceedance Response Action
LRP	Legally Responsible Person
MDL	Method Detection Limit
MIP	Monitoring Implementation Plan
NAL	Numeric Action Level
NOAA	National Oceanographic and Atmospheric Administration
NOI	Notice of Intent
NOT	Notice of Termination
NPDES	National Pollutant Discharge Elimination Systems
NSWDs	Non-Stormwater Discharges
O&G	Total Oil and Grease
PRDs	Permit Registration Documents
PRI	Pacific Ridgeline, Inc
QA/QC	Quality Assurance and Quality Control
QCS	Qualified Combined Samples
QISP	Qualified Industrial Stormwater Practitioner
QSE	Qualified Storm Event
RSR	Representative Sample Reduction
SPCC	Spill Pollution Control and Countermeasure Plan
SMARTS	Stormwater Multi Application and Report Tracking System
SWPPP	Stormwater Pollution Prevention Plan
TDS	Total Dissolved Solids
TMDLs	Total Maximum Daily Loads
TSS	Total Suspended Solids
USDA	United States Department of Agriculture
VOC	Volatile Organic Compounds
WDID	Waste Discharge Identification

STORM WATER POLLUTION PREVENTION PLAN

Ojai Field
WDID # 4 56I025652

1.0 SWPPP REQUIREMENTS

1.1 INTRODUCTION

This Storm Water Pollution Prevention Plan (SWPPP) was prepared for California Resources Production Corporation's (CRPC) Ojai Field ("Site"). The Site is comprised of five leases (Ojai, Silverthread, Hamp, Ferndale and Timber Canyon) within the Ojai area, which are situated between Sulfur Mountain and Santa Paula Peak, and bisected by Highway 150 (Ojai-Santa Paula Road). The Ojai Oil Field is located 2.5-miles north of Santa Paula and 10.5-miles east of Ojai in Ventura County, California. The combined total acreage for the Site is approximately 3,400 acres. The Site locations are presented on the site maps included in Appendix A.

The objective of this SWPPP is to satisfy the requirements of California's General Permit for Storm Water Discharges Associated with Industrial Activities Order No. 2014-0057-DWQ, NPDES No. #CAS000001 (General Permit). The General Permit and the following plan is applicable to areas engaged in industrial activities, which encompasses approximately 100-acres of the approximately 3,400-acre lease property. This SWPPP has been prepared following a combination of internal documents and the template provided in the *California Stormwater Quality Association Stormwater Best Management Practice Handbook Portal: Industrial and Commercial* (CASQA 2014).

In accordance with the General Permit, Section X.A, this SWPPP contains the following required elements:

- Site Name and Contact Information;
- Site Maps;
- List of Significant Industrial Materials;
- Description of Potential Pollution Sources;
- Assessment of Potential Pollutant Sources;
- Minimum Best Management Practice (BMP);
- Advanced BMPs, if applicable;
- Monitoring Implementation Plan (MIP);
- Annual Comprehensive Facility Compliance Evaluation (Annual Evaluation); and,
- Date that SWPPP was Initially Prepared and the Date of Each SWPPP Amendment, if Applicable.

Due to the natural soil conditions of the Site, it is anticipated that collected storm water samples would exceed Numeric Action Levels (NALs) set forth in the General Permit. Therefore, California Resources Production Corporation proactively prepared a Natural Background Demonstration Technical Report (NBDTR). The results of the demonstration are presented in Appendix B.

1.2 PERMIT REGISTRATION DOCUMENTS

Required Permit Registration Documents (PRDs) were submitted to the State Water Resources Control Board (Water Board) via the Stormwater Multi Application and Report Tracking System (SMARTS) by the Legally Responsible Person (LRP), or authorized personnel (i.e., Approved Signatory) under the direction of the LRP. The project-specific PRDs include:

1. Notice of Intent (NOI);
 2. Signed Certification Statement (LRP Certification is provided electronically with SMARTS PRD submittal);
 3. Site Map(s);
 4. SWPPP; and
 5. Annual Fee.
- The Site Map(s) can be found in Appendix A. A copy of the submitted PRDs will also be kept in Appendix C of the SWPPP along with the Waste Discharge Identification (WDID) confirmation.
 - The SWPPP uploaded into SMARTS should not include a copy of the General Permit.
 - In the event of future significant changes to the facility layout, the Discharger will certify and submit new PRDs via SMARTS.

1.3 PLAN AUTHORIZATION AND IMPLEMENTATION

A complete copy of this SWPPP shall be maintained at the Site, and will be made available for review by facility employees and State or Municipal inspectors upon request. The SWPPP will be implemented by July 1, 2015.

The CRPC Operations Superintendent is the Legally Responsible Person (LRP) and will be responsible for overseeing the SWPPP program, ensuring that employees at the Site become familiar with the contents of this SWPPP, and ensuring that all SWPPP monitoring program and sampling activities are conducted. The CRPC Field Operations Supervisor is a Duly Authorized Representative (DAR) and will perform SWPPP activities when the LRP is absent or unavailable. This table will be updated as needed when there are changes to staff and staff responsibilities. See Appendix D for the Storm Water Pollution Prevention Team.

All team members will be trained to perform the duties assigned to them, and all pertinent employees will be trained on the general contents of this plan. Employee training logs are provided in Appendix E. Written authorization(s) from the LRP for the DAR(s) is included in Appendix F. Individual personnel responsibilities are presented below.

If the Site reports a Numeric Action Level (NAL) exceedance, a Qualified Industrial Stormwater Practitioner (QISP) will be required. The QISP will provide additional training and facility evaluations as needed to maintain compliance with the General Permit.

1.4 PERMITS AND GOVERNING DOCUMENTS

In addition to the General Permit, the following documents have been taken into account while preparing this SWPPP:

- Regional Water Board requirements;
- Basin Plan requirements;
- TMDL Requirements;
- Spill Prevention Control and Countermeasures Plan (SPCC);
- Hazardous Material Business Plan (HMBP);
- Hazardous Waste Regulations and Permits;
- Natural Background Pollutant Source Demonstration; and
- Air Quality Regulations and Permits.

1.5 SWPPP AMENDMENTS

This SWPPP will be amended or revised as needed. A list of amendments (Amendment Log) is included in the front of this SWPPP, and amendment certifications are included in Appendix G. The Amendment Log will include the date of initial preparation and the date of each amendment. The SWPPP should be revised when:

- There is a General Permit violation;
- There is a reduction or increase in the total industrial area exposed to stormwater;
- BMPs do not meet the objectives of reducing or eliminating pollutants in stormwater discharges;
- There is a change in industrial operations which may affect the discharge of pollutants to surface waters, groundwater(s), or a municipal separate storm sewer system (MS4);
- There is a change to the parties responsible for implementing the SWPPP; or
- Otherwise deemed necessary by the QISP.

The following items will be included in each amendment:

- Who requested the amendment;
- The location of proposed change;
- The reason for change;
- The original BMP(s) proposed, if any; and
- The new BMP(s) proposed.

Amendments will be logged at the front of the SWPPP and certification kept in Appendix G. The SWPPP text will be revised, replaced, and/or hand annotated as necessary to properly convey the amendment. SWPPP amendments must be certified and submitted by the LRP or their designated DAR via SMARTS within 30 days whenever the SWPPP contains significant revisions. With the exception of significant revisions, SWPPP changes will be certified and uploaded to SMARTS once every three (3) months in the reporting year.

1.6 RECORDKEEPING

In accordance with the General Permit, paper and electronic records required by this SWPPP shall be retained for a minimum of five (5) years from the date generated or submitted, whichever is later, for the following items:

- Employee Training Records;
- BMP Implementation Records;
- Spill and Clean-up Related Records;
- Records of Sampling and Analysis Information
 - The date, exact location, and time of sampling or measurement;
 - The date(s) analyses were performed;
 - The individual(s) that performed the analyses;
 - The analytical techniques or methods used; and
 - The results of such analyses;
- Records of Visual Observations
 - The date
 - The industrial areas/drainage areas of the Site observed during the inspection (Location);
 - The approximate time of the observation;
 - Presence and probable source of observed pollutants; and
 - Name of the individual(s) that conducted the observations;
- Response to the observations including identification of SWPPP revisions if needed.
- Level 1 Exceedance Response Action (ERA) Reports;
- Level 2 ERA Action Plan;
- Level 2 ERA Technical Report; and
- Annual Reports from SMARTS (checklist and any explanations).

Copies of these records will be available for review by the Water Board's staff at the Site during scheduled operating hours. Upon written request by U.S. EPA or the local MS4, Dischargers will provide paper or electronic copies of requested records to the Water Board, U.S. EPA, or local MS4 within ten (10) working days from receipt of the request.

1.7 EXCEEDANCE RESPONSE ACTIONS

NAL values, test methods, and reporting units are presented in Table 1.1. If a General Permit NAL exceedance occurs in a given reporting year, a Level 1 ERA Evaluation and a Level 1 ERA Report will be required in the following year. If a second General Permit NAL exceedance occurs in the subsequent year, a Level 2 ERA Action Plan and a Level 2 ERA Report will be required in accordance with the General Permit. The results of either of the ERA reports may require that the SWPPP be amended.

Table 1.1 outlines the anticipated parameters to be sampled at the Site under this plan.

Table 1.1 – Parameter NAL Values and Test Methods

Parameter	Test Method	Annual NAL (mg/L)	Inst. Max. NAL (mg/L)
pH*	Field	n/a	<6.0, >9.0
Suspended Solids (TSS)*, Total	SM 2540-D	100	400
Oil and Grease (O&G)*, Total	EPA 1664A	15	25

* Minimum parameters required by the General Permit

1.8 ANNUAL COMPREHENSIVE FACILITY COMPLIANCE EVALUATION

The General Permit (Section XV) requires the Site to conduct one Annual Comprehensive Facility Compliance Evaluation (Annual Evaluation) for each reporting year (July 1 to June 30). Annual Evaluations will be conducted at least eight (8) months and not more than sixteen (16) months after the previous Annual Evaluation. The planned window for conducting the Annual Evaluation is between April and June of each year. The SWPPP will be revised, as appropriate based on the results of the Annual Evaluation, and the revisions will be implemented within 90 days of the Annual Evaluation.

At a minimum, Annual Evaluations will consist of:

- A review of all sampling, visual observation, inspection and monitoring records and sampling and analysis results conducted during the previous reporting year;
- A visual inspection of all areas of industrial activity and associated potential pollutant sources for evidence of, or the potential for, pollutants entering the stormwater conveyance system;
- A visual inspection of all drainage areas previously identified as having no exposure to industrial activities and materials in accordance with the definitions in Section XVII;
- A visual inspection of equipment needed to implement the BMPs;
- A visual inspection of any BMPs;
- A review and effectiveness assessment of all BMPs for each area of industrial activity and associated potential pollutant sources to determine if the BMPs are properly designed, implemented, and are effective in reducing and preventing pollutants in industrial stormwater discharges and authorized NSWDS; and
- An assessment of any other factors needed to comply with the Annual Reporting requirements in General Permit Section XVI.B.

1.9 ANNUAL REPORT

The Annual Report will be prepared, certified, and electronically submitted no later than July 15th following each reporting year using the standardized format and checklists in SMARTS. Reports will be based on the reporting requirements identified in Section XVI of the General Permit. Annual reports will be submitted in SMARTS and in accordance with information required by the on-line forms.

1.10 TERMINATIONS AND CHANGES TO GENERAL PERMIT COVERAGE

When any of the following conditions occur;

- Operation of the facility has been transferred to another entity;
- The facility has ceased operations, completed closure activities, and removed all industrial related pollutant generating sources;
- The facility's operations have changed and are no longer subject to the General Permit.

Termination of coverage under the General Permit will be requested by certifying and submitting a Notice of Termination (NOT) via SMARTS.

The SWPPP and all of the provisions of the General Permit will be complied with until a valid NOT is received and accepted by the Board.

If ownership changes, the new owner of the facility will be notified of the General Permit and regulatory requirements for permit coverage.

2.0 FACILITY INFORMATION

2.1 FACILITY DESCRIPTION

2.1.1 Facility Location

The Ojai Oilfield is an onshore crude oil and natural gas production facility. The Ojai Oil Field is comprised of five leases within the Ojai area, which are situated between Sulfur Mountain and Santa Paula Peak, and bisected by Highway 150 (Ojai-Santa Paula Road). The Ojai Oil Field is located 2.5-miles north of Santa Paula and 10.5-miles east of Ojai in Ventura County, California and is situated within extreme topographic relief with active landslides. An estimated 1% of the property is considered impervious. The Operator engages in Industrial Activities consisting of oil and gas mining operation on approximately 3,400 acres.

Note that while the facility leaseholds encompass approximately 3,400 acres, only roughly 100 acres are used for industrial activities.

The annual average precipitation within the vicinity of the project (Santa Paula, California) is approximately 18.38 inches (<http://www.usclimatedata.com/climate/santa-paula/california/united-states/usca1025>).

The Ojai Field is situated within extreme topographic relief with active landslides. Drainage of the Site is toward Sisar Creek and Santa Paula Creek. Sisar Creek and Santa Paula Creek have not adopted TMDLs and are not listed on the most recent 303(d) list for any water quality impairments.

2.1.2 Facility Operations

The Ojai Field is an operating oil field and all activities are related to the production, transportation and temporary storage of crude oil. Preliminary treatment of the crude oil, such as separating oil from production waters, is also conducted onsite. There are five (5) active tank settings associated with the Site where crude oil collection and temporary storage occurs: Ojai Tank Battery 1, Silverthread, Hamp and Timber Canyon (Clark and Clark/West). Producing wells are scattered throughout the Site.

Crude oil and natural gas are extracted from the subsurface through wells, which are piped to a water-separator and the oil and natural gas is piped to storage containers, while the produced water is re-injected to the producing formation to facilitate further oil and natural gas production. Produced water, oil, and natural gas are all piped directly from the wellheads to storage tanks for separation and distribution.

Primary Facility operation is Monday through Friday (5 days a week) from the hours of 7:00am to 4:00pm.

2.1.3 Existing Conditions

This SWPPP addresses storm water discharges from the industrial land uses only. While the Facility leaseholds encompass approximately 3,400 acres, only approximately 100 acres are used for oil and gas production and distribution (industrial activities), as shown on the Facility site maps. Existing BMPs at this facility are described in Section 3.

A Natural Background Demonstration Technical Report (NBDTR) was prepared proactively for CRPC. Naturally occurring background chemicals were demonstrated to be present within the soil of the Site, as summarized and concluded in the NBDTR. Due to the fine-grained nature of the sediments discussed above within the steep hillsides, erosion and/or landsliding contributes fine-grained sediment to storm water discharges from the site. The fine-grained nature of the marine-derived sediments is responsible for the elevated TSS, SC, and TDS concentrations within storm water discharges in the Ojai Field. These chemical constituents are not associated with Operator's oil and gas production and are not subject to NAL regulation under the CWA, or the IGP.

Additionally, naturally occurring oil seeps are common in the vicinity. These seeps are not a result of CRPC's industrial activities.

2.1.4 Required Map Information

The facility's Site Maps are provided in Appendix A. The maps include information regarding the Site boundary and stormwater drainage areas, nearby water bodies, locations of stormwater collection and conveyance systems.

2.1.5 Geology

Based on review of the Geologic Map of the Santa Paula Peak 7.5-Minute Quadrangles (Dibblee, 1990) and at http://gmw.consrv.ca.gov/shmp/download/evalrpt/spp_eval.pdf, the Site geology includes the following geologic units:

- Miocene Monterey Formation (Tm);
- Miocene Sisquoc Shale (Ts);
- Pliocene Pico Formation (QTpm and Tp); and
- Pleistocene Older Dissected Surficial Sediments (Qoa and Qof).

Many active landslides are also present and shown on the Santa Paula Peak 7.5-Minute Geologic Map. Natural erosion of these less competent formations results in large sediment loads being transported by the drainages to Santa Paula Creek, which flows near Highway 150. Mass-wasting (landsliding) conditions at this site result in excessive TSS loads into the drainages listed above, and into Santa Paula Creek, then into Santa

Clara River and the Pacific Ocean.

Bedrock units of the Santa Paula Peak 7.5-Minute Quadrangle range from Miocene - to Pleistocene-aged marine deposits, except for the non-marine Older Dissected Surficial Sediments (Qoa and Qof), which represent eroded older alluvial fan deposits. Surficial deposits are limited to areas along active stream channels, elevated terraces, alluvial and fan gravels, shallow landslides and debris flows (Dibblee, 1990).

The oldest exposed unit in the Santa Paula Peak 7.5-Minute Quadrangle is predominantly Miocene marine Monterey Formation (Tm) and Miocene-Pliocene marine Sisquoc Shale (Tmq), followed by the Pliocene-Pleistocene marine Pico Formation (Tp and QTpm).

The early to late Miocene marine Monterey Formation (Modelo Formation), and has two members exposed in the Santa Paula Peak 7.5-Minute Quadrangle. The lower shale unit (Tml) consists of white-weathering, soft, fissile clay shale, with interbeds of hard siliceous shale and thin limestone strata. The upper shale unit (Tm) consists of thin-bedded, hard, and platy to brittle, siliceous shale. These units are widespread in a series of eastern-plunging anticlinal and synclinal folds associated with the Sesar and Cayentano Fault zones, and are also very susceptible to landsliding, especially along northern-facing slopes, especially during a moderate to severe earthquake event and/or extreme rainfall event.

Early Miocene marine The Sisquoc Formation (Tsq) conformably overlies the Monterey Formation and is a sedimentary geologic unit widespread in Southern California, both on the coast and in mountains near the coast. Overlying the Monterey Formation, it is of upper Miocene and lower Pliocene age (from about 4 to 6 million years old). The formation consists of claystone, mudstone, siltstone, shale, diatomite, and conglomerates, with considerable regional variation, and was deposited in a moderately deep marine environment at a depth of approximately 500–5,000 feet (150–1,520 meters). Since some of its diatomites, along with those of the underlying Monterey Formation, are of unusual purity and extent, they can be mined as diatomaceous earth. France-based Imerys operates a mine in the Sisquoc and Monterey Formations in the hills south of Lompoc, California, the largest such operation in the world (Dibblee, 1990). Sisquoc Shale consists of a light-gray silty shale or claystone, which is locally slightly siliceous and diatomaceous (Vedder and others, 1969).

The Pliocene Pico formation consists chiefly of six units, five of which consist of light olive-gray and medium bluish-gray siltstone and fine-grained silty sandstone, containing

small reddish-brown concretions, and light-colored sandstone and conglomerate (Winterer et al., 1962). In the western part of the area the sandstone and conglomerate constitute a minor portion of the formation. In the easternmost part of the area the converse is true; there the formation consists largely of sandstone and conglomerate. The Pico Formation is distinguished largely by the presence in the Pico of olive-gray soft siltstone, which generally contains small limonite concretions.

The sixth member of the Pico Formation (QTpm) is also known as the "Mudpit Claystone" Member of the Santa Barbara Formation (Yerkes and others 1987; Yeats and Grigsby, 1987; Grigsby, 1988), and is reportedly of early Pleistocene to possibly late Pliocene age. This member is massive to vaguely bedded, gray claystone or mudstone, and may include the QTpmc member. Pleistocene to Holocene surficial units unconformably overlie the Tertiary bedrock units. The oldest Quaternary units in the Santa Paula Peak Quadrangle are dissected gravel and sand sediments along stream channels, older alluvial deposits (Qoa), and older cobble-boulder fan and conglomerate deposits (Qog). Younger deposits consist of alluvium (Qa) in stream and lowland environments, colluvium, and stream wash, and landslide deposits (Qls). Minor artificial fill (af) units also exist within the Santa Paula Peak 7.5-Minute Quadrangle, and is relative to anthropogenic activities, such as roads and structures.

Most of the source materials comprising the sedimentary rocks at the Site are consistent with eroded plutonic rocks (diorite and granite), chert, metamorphosed igneous and sedimentary rocks, and limestone. Detailed analyses of the geology and slope-failure at the Santa Paula Peak 7.5-Minute Quadrangle can be reviewed at http://gwm.consrv.ca.gov/shmp/download/evalrpt/spp_eval.pdf.

Due to the fine-grained nature of the sediments discussed above within the steep hillsides, erosion and/or landsliding contributes fine-grained sediment to storm water discharges from the site. The fine-grained nature of the marine-derived sediments is responsible for the elevated TSS, SC, and TDS concentrations within storm water discharges in the Ojai Lease.

2.2 DRAINAGE CHARACTERISTICS

2.2.1 Description of Drainage Areas

Drainage is topographically dependent; however, all drainages have the potential to flow towards Sesar and Santa Paula Creeks. The Site is divided into two (2) 12-digit Hydrologic Units (HUC12), as defined by the United State Environmental Protection Agency, "My WATERs Mapper":

HUC12 Area 1: San Antonio Creek
HUC12 Area 2: Santa Paula Creek

The Site Maps (Appendix A) show the hydrologic unit area layout.

2.2.2 Stormwater Run-On from Offsite Areas

There is no anticipated offsite industrial run-on to the facility. Any potential offsite run-on would be natural erodible surfaces, undisturbed by human or industrial activities. Additionally, natural oil seeps occur in the area. There is a potential of storm water discharge coming into contact with these seeps. Berms, channels, sumps and drains are in place to minimize and direct offsite stormwater run-on to the extent practicable.

2.3 POLLUTANT SOURCE ASSESSMENT

Potential sources of pollution to surface waters include unauthorized non-storm water discharges to the storm drain and pollutants contained in storm water runoff from source areas located on the property. This section presents a list of all industrial materials and potential pollutant sources at the Site. It identifies specific pollutants associated with these sources and pollutant sources that are most susceptible to stormwater exposure.

2.3.1 Description of Potential Pollutant Sources

Potential sources of pollution related to the Site activities are described in Table 2.1. The activities and associated pollutants provided in the table are the basis for selecting and implementing the BMPs for the Site as described in Section 3. Locations of referenced activities are shown on the Site Maps in Appendix A.

2.3.1.1 Industrial Processes

The Site is an operating oil field and all activities are related to the production, transportation and temporary storage of crude oil. Separation of crude oil from production waters and natural gas is also conducted onsite. Production facilities are scattered throughout the property. Each storage tank location is constructed with a secondary containment structure with a volume capacity designed to exceed the contents of the largest tank within each location in accordance with CRPC's SPCC Plan and 40 CFR Part 112.

Crude oil and natural gas are extracted from the subsurface through wells, which are piped to a water-separator and the oil and natural gas is piped to storage containers, while the produced water is re-injected to the producing formation to facilitate further oil and natural gas production. Produced water, oil, and natural gas are all piped directly from the wellheads to storage tanks for separation and distribution. Crude oil is then shipped via pipeline or trucked offsite for processing and refining.

2.3.1.3 Dust and Particulate Generating Activities

A percentage of the roads used for access to the tank battery facilities are paved. However, a majority of the roads and well pads located on the Site not paved. Dust generated from driving on these unpaved roads would be associated with minor erosion. Dust-control via watering the roadways retards dust generation on dirt roadways. Water used for dust control purposes is infiltrated into the soil adjacent to the roads and does not create any non-storm water discharges. This SWPPP does not address areas not impacted by Industrial Activities on the Site.

2.3.2 Significant Spills and Leaks

There is the potential for a crude oil or produced water spill to occur at the Site. In the event of a spill, the spilled material is removed as quickly as possible and to the extent practicable. If the quantity spilled is a reportable amount, appropriate agencies will be notified accordingly. Spills and leaks will be prevented by implementing the BMPs described in Section 3, specifically through the implementation of the Spill Prevention, Control, and Countermeasures Plan (SPCC).

Historical spills and leaks that were of reportable quantities within the previous five (5) years are presented below in Table 2.2.

Table 2.2 – Historical Spills/Leaks

Material	Date	Location	Quantity Spilled	Remaining Quantity
Produced Water	8/22/10	Ojai-Hamp	30 bbl	None, remediated
Crude Oil	11/21/11	Ojai	3 bbl	None, remediated
Crude Oil	2/20/15	Ojai-Hamp	10 bbl	None, remediated
Crude Oil	3/16/15	Ojai-Silverthread	2 bbl	None, remediated

2.4 NON-STORM WATER DISCHARGES

Non-stormwater discharges (NSWDs) consist of discharges which do not originate from precipitation events. The General Permit provides allowances for specified NSWDs provided they:

- Do not cause erosion;
- Do not carry other pollutants;
- Are not prohibited by the local MS4; and
- Do not require a separate NPDES Permit from the Regional Water Board.

NSWDs into storm drainage systems or waterways which are not authorized under the General Permit and listed in the SWPPP, or authorized under a separate NPDES permit, are prohibited.

2:

Currently the Site does not release any NSWDS from the property boundary. Steps will be taken, including the implementation of appropriate BMPs as defined in Section 3, to ensure that unauthorized NSWDS are eliminated, controlled, disposed off-site, or treated on-site.

Monthly visual observations will be conducted according to the General Permit (Section XI.A.1) for NSWDS and sources to ensure adequate BMP implementation and effectiveness. Monthly visual observations include observations for evidence of unauthorized NSWDS.

2.5 SOIL EROSION

The Ojai Oil Field is located 2.5-miles north of Santa Paula and 10.5-miles east of Ojai in Ventura County, California and is situated within extreme topographic relief with active landslides. The subject property consists of approximately 3,400 acres. An estimated 1% of the property is considered impervious.

Extreme erosion is occurring along most slopes and drainages; however, the majority of the landsliding is along the southwesterly sloping Santa Paula Peak ridgeline and the northerly-sloping Sulfur Mountain ridgeline, which were within and immediately above the lease boundary. Sediment loading initiates from the elevated hill-tops and accelerates down slope and funnels into the drainages, which discharge into Santa Paula Creek. Due to the fine-grained nature of the sediments discussed above within the steep hillsides, erosion and/or landsliding contributes fine-grained sediment to storm water discharges from the site. The fine-grained nature of the marine-derived sediments is responsible for the elevated TSS, SC, and TDS concentrations within storm water discharges in the Ojai Lease.

It is estimated that the combined roadway and industrial land area soil loss is estimated at 5,738 tons of soil per year (Appendix B).

3.0 BEST MANAGEMENT PRACTICES

3.1 MINIMUM BMPS

All minimum BMPs that are required by the General Permit and necessary to meet the Site conditions will be implemented. Guidance for BMP implementation is provided in the CASQA Stormwater BMP Handbook Portal: Industrial and Commercial Fact Sheets and the relevant fact sheets are included in Appendix I. Sections 3.1.1 through 3.1.5 list the requirements for each of these minimum BMPs. Minimum BMPs will be implemented for additional targeted industrial activities, equipment, and materials as necessary. If any of the required minimum BMPs are applicable but cannot be implemented, an explanation and alternative approach will be provided in the following sections.

Table 3.1 provides a list of the five minimum General Permit BMP elements that are included in the relevant BMP fact sheets and indicates which BMPs are implemented at the facility. The BMP fact sheets are provided as guidelines for the facility to assist with compliance with the required BMPs in the general permit, and are not necessarily line-by-line descriptions of everything done at the facility.

Employee Training, described in Section 3.1.6, and Quality Assurance and Record Keeping, described in Section 3.1.7, are additional minimum BMPs that will be implemented.

As required by the General Permit, a summary of all implemented BMPs is included in Section 3.3. The schedule for BMP implementation and the requirements for inspection and maintenance are contained in Section 4.

Table 3.1 Minimum BMPs

CASQA Fact Sheet Number	CASQA BMP Fact Sheet Name	Addresses Minimum General Permit BMP Requirements						BMP to be Implemented?	
		Good Housekeeping	Preventative Maintenance	Spill and Leak Prevention and Response	Material Handling and Waste Management	Erosion and Sediment Control	YES	NO	Not Applicable
SC-10	Non-Stormwater Discharges	✓		✓			✓		
SC-11	Spill Prevention, Control, & Cleanup			✓			✓		
SC-22	Vehicle & Equipment Maintenance and Repair	✓	✓	✓	✓		✓		
SC-30	Outdoor Loading & Unloading	✓		✓	✓		✓		
SC-31	Outdoor Liquid Container Storage	✓	✓	✓	✓		✓		
SC-32	Outdoor Equipment Operations	✓	✓	✓	✓		✓		
SC-33	Outdoor Storage of Raw Materials	✓	✓	✓			✓		
SC-34	Waste Handling & Disposal	✓	✓	✓	✓		✓		
SC-40	Contaminated or Erodible Surfaces					✓	✓		
SC-41	Building & Grounds Maintenance	✓		✓	✓		✓		
SC-43	Parking Area Maintenance	✓	✓	✓			✓		
SC-44	Drainage System Maintenance	✓	✓	✓			✓		
Additional BMPs Implemented:									
Spill Prevention Control and Countermeasures Plan									
Equipment Preventative Maintenance Program									

3.1.1 *Good Housekeeping*

The following good housekeeping measures will be implemented in accordance with the General Permit (Section X.H.1.a):

- Observe all outdoor areas associated with industrial activity including stormwater discharge locations, drainage areas, conveyance systems, waste handling/disposal areas, and perimeter areas impacted by off-facility materials or stormwater run-on to determine housekeeping needs. Any identified debris, waste, spills, tracked materials, or leaked materials will be cleaned and disposed of properly;
- Minimize or prevent material tracking;
- Minimize dust generated from industrial materials or activities;
- Ensure that all facility areas impacted by rinse/wash waters are cleaned as soon as possible;
- Cover all stored industrial materials that can be readily mobilized by contact with stormwater;
- Contain all stored non-solid industrial materials or wastes (e.g., particulates, powders, shredded paper, etc.) that can be transported or dispersed via by the wind or contact with stormwater;
- Prevent disposal of any rinse/wash waters or industrial materials into the stormwater conveyance system;
- Minimize stormwater discharges from non-industrial areas (e.g., stormwater flows from employee parking area) that contact industrial areas of the facility; and
- Minimize authorized NSWs from non-industrial areas (e.g., potable water, fire hydrant testing, etc.) that contact industrial areas of the facility.

General BMPs to be implemented at the Site are summarized in Table 3.1, and the BMP fact sheets associated with the general BMPs are included in Appendix I.

3.1.2 Preventative Maintenance

The following preventative maintenance measures will be implemented in accordance with the General Permit (Section X.H.1.b):

- Identify all equipment and systems used outdoors that may spill or leak pollutants;
- Observe the identified equipment and systems to detect leaks, or identify conditions that may result in the development of leaks;
- Observe a pipeline management plan;
- Observe DOGGR pipeline hydrotest program;
- Observe DOGGR AB 1960 monthly tank inspection program;
- Observe a preventative maintenance of identified equipment and systems; and
- Establish procedures for prompt maintenance and repair of equipment, and maintenance of systems when conditions exist that may result in the development of spills or leaks.

Specific preventative maintenance BMPs to be implemented at the Site are provided in Table 3.1 and the BMP fact sheets are included in Appendix I.

3.1.3 Spill and Leak Prevention and Response

The following spill and leak prevention and response measures will be implemented in accordance with the General Permit (Section X.H.1.c):

- Establish procedures and/or controls to minimize spills and leaks;
- Develop and implement spill and leak response procedures to prevent industrial materials from discharging through the stormwater conveyance system. Spilled or leaked industrial materials will be cleaned promptly and disposed of properly;
- Identify and describe all necessary and appropriate spill and leak response equipment, location(s) of spill and leak response equipment, and spill or leak response equipment maintenance procedures;
- Identify and train appropriate spill and leak response personnel; and
- Observe annual spill drills with appropriate personnel, contract responders and regulatory agencies in accordance with the Facility Oil Spill Contingency Plan (OSCP).

Specific spill and leak prevention and response BMPs to be implemented at the Site are provided in Table 3.1 and the BMP fact sheets are included in Appendix I.

A written SPCC was prepared in accordance with 40 CFR Part 112 and is in effect at the Site. In addition, the HMBP provides plot plans of hazardous material storage facilities, inventories and emergency procedures to be observed in the event of a release involving hazardous materials. Both the SPCC and the HMBP are incorporated into this SWPPP by reference.

3.1.4 Material Handling and Waste Management

The following material handling and waste management measures will be implemented in accordance with the General Permit (Section X.H.1.d):

- Prevent or minimize handling of industrial materials or wastes that can be readily mobilized by contact with stormwater during a storm event;
- Contain all stored non-solid industrial materials or wastes (e.g., particulates, powders, shredded paper, etc.) that can be transported or dispersed by the wind or contact with stormwater during handling;
- Cover industrial waste disposal containers and industrial material storage containers that contain industrial materials when not in use;
- Divert run-on and stormwater generated from within the facility away from all stockpiled materials;
- Clean all spills of industrial materials or wastes that occur during handling in accordance with the spill response procedures (Section X.H.1.c); and
- Observe and clean as appropriate, any outdoor material or waste handling equipment or containers that can be contaminated by contact with industrial materials or wastes.

Specific material handling and waste management BMPs to be implemented at the Site are provided in Table 3.1 and the BMP fact sheets are included in Appendix I.

3.1.5 Erosion and Sediment Controls

The following erosion and sediment control measures will be implemented in accordance with the General Permit (Section X.H.1.e):

- Implement effective wind erosion controls;
- Provide effective stabilization for all disturbed soils and other erodible areas prior to a forecasted storm event;
- Maintain effective perimeter controls and stabilize all site entrances and exits to sufficiently control discharges of erodible materials from discharging or being tracked off the site;
- Divert run-on and stormwater generated from within the facility away from all erodible materials; and
- If sediment basins are implemented, ensure compliance with the design storm standards in Section X.H.6. of the General Permit.

Specific erosion and sediment control BMPs to be implemented at the Site are provided in Table 3.1 and the BMP fact sheets are included in Appendix I.

3.1.6 Employee Training Program

An employee training program will be implemented in accordance with the following requirements in the General Permit (Section X.H.1.f):

- Ensure that all team members implementing the various compliance activities of this SWPPP are properly trained in topics including but not limited to: BMP implementation, BMP effectiveness evaluations, visual observations, and monitoring activities;
- Prepare or acquire appropriate training manuals or training materials;
- Identify which personnel need to be trained, their responsibilities, and the type of training they will receive;
- Provide a training schedule; and
- Maintain documentation of all completed training classes and the personnel that received training in the SWPPP.

The Pollution Prevention Team will be trained in implementing the various compliance activities specified in this SWPPP, and documentation of training activities is retained in SWPPP Appendix E. To promote stormwater management awareness specific for this facility, refresher training will be provided annually.

Task specific training for all employees engaged in activities that have the potential to cause stormwater pollution will be conducted when new employees are hired and refresher training will be provided annually.

This Site is currently at the Baseline Level, and training will be performed by a qualified team member. If the facility enters Level 1 status, a QISP will be hired to provide additional training. The qualified team member and/or QISP will be responsible for providing information during training sessions and subsequently completing the training logs shown in Appendix E, which identifies the site-specific stormwater topics covered as well as the names of site personnel who attended the meeting. Each team member will be trained in the specific role they are responsible to undertake.

3.1.7 Quality Assurance and Record Keeping

The following quality assurance and record keeping activities will be performed in accordance with the requirements in the General Permit (Section X.H.1.g):

- Develop and implement management procedures to ensure that appropriate staff implements all elements of the SWPPP, including the Monitoring Implementation Plan (SWPPP Section 5);
- Develop a method of tracking and recording the implementation of BMPs identified in the SWPPP; and
- Maintain the BMP implementation records, training records, and records related to any spills and clean-up related response activities for a minimum of five (5) years as required in the General Permit (Section XXI.J.4).

BMPs will be implemented according to the schedule and procedures presented in SWPPP Section 4. BMPs will be implemented by or under the supervision of properly trained team members as documented in Appendix E.

Visual observations will be performed as described in SWPPP Section 5.5. Potential pollutant sources and BMPs will be inspected during visual observations, and new BMPs will be implemented as needed. Records of visual observations of BMP implementation will be retained in Appendix J.

Paper or electronic records of documents required by this SWPPP will be retained for a minimum of five (5) years from the date generated or date submitted, whichever is later, for the following items:

- Employee Training Records;
- BMP Implementation Records;
- Spill and Clean-up Related Records;
- Records of Monitoring Information
 - The date, exact location, and time of sampling or measurement;
 - The date(s) analyses were performed;
 - The individual(s) that performed the analyses;
 - The analytical techniques or methods used; and
 - The results of such analyses;
- Level 1 ERA Reports;
- Level 2 ERA Action Plan;
- Level 2 ERA Technical Report; and

- Annual Reports.

3.2 ADVANCED BMPS

In cases where the minimum BMPs listed in Section 3.1 are not adequate to reduce or prevent pollutants in stormwater, the General Permit requires the discharger to implement and maintain advanced BMPs, where feasible. The following represents advanced BMPs that are currently in place at the Site.

3.2.1 Exposure Minimization BMPs

Extracted crude oil and natural gas is contained in a closed system from the time of extraction, through storage and eventual transfer off-site. At no time are raw materials exposed to the environment during standard operations at the Site.

3.2.2 Stormwater Containment and Discharge Reduction BMPs

Stormwater containment and discharge reduction BMPs include BMPs that divert, reuse, contain, or reduce the volume of stormwater runoff. The primary BMP implemented on location to contain and reduce discharge is berming/containment around tank batteries and well pads. Tank batteries are constructed with secondary means of containment with the volume capacity of the containment designed to exceed the contents of the largest tank within the facility and with sufficient freeboard to contain precipitation. Well pads are constructed of earthen berms and/or well cellars to contain liquids on location. There are open drains within the Site which collect miscellaneous fluids from the containment areas. These drains are piped and transported to a central sump from which they are pumped for proper disposal. Containment structures are inspected regularly for deficiencies and repairs are made as necessary.

3.2.3 Treatment Control BMPs

Treatment control BMPs include one or more mechanical, chemical, biologic, physical, or any other treatment process technology and is sized to meet the treatment control design storm standard. Currently, there are no treatment control BMPs installed on the property. Currently, there are no treatment control BMPs installed on the property. This section was included in the document to be easily changed in the future, should additional BMPs be required.

3.2.4 Other Advanced BMPs

Currently, there are no other advanced BMPs installed on the property. This section was included in the document to be easily changed in the future, should additional BMPs be required.

3.3 BMP SUMMARY

Table 3.2 summarizes the industrial activities, materials, pollutant sources, potential pollutants, and BMPs being implemented to prevent discharge of pollutants in stormwater runoff. Descriptions of the specific BMPs being implemented were provided in previous subsections. Implementation and maintenance of BMPs is described in Section 4.

Table 3.2 BMP Summary Table

Industrial Activity/Material	Pollutant Sources	Potential Pollutants	BMPs Implemented	CASQA BMP Fact Sheet Number
Crude Oil Storage	Crude Oil	Oil and Grease	SPCC, PMP, Spill/Leak Prevention Response	SC-11, SC-30, SC-31, SC-33, SC-34, SC-40
Well Pads/Well Cellars	Crude Oil, Erosion	Oil and Grease, TSS	SPCC, PMP, Erosion & Sediment Control	SC-11, SC-30, SC-31, SC-33, SC-34, SC-40
Old Equipment Storage Areas	Crude Oil, Lube Oil, Diesel	Oil and Grease	SPCC, Spill/Leak Prevention Response	SC-10, SC-22, SC-34
Compressors and Machinery	Crude Oil, Lube Oil, Diesel	Oil and Grease	SPCC, PMP, Spill/Leak Prevention Response	SC-10, SC-22, SC-31, SC-44
Equipment Maintenance	Crude Oil, Lube Oil, Diesel, Motor Oil	Oil and Grease	SPCC, PMP, Spill/Leak Prevention Response	SC-10, SC-11, SC-22
Loading and Unloading	Crude Oil	Oil and Grease	SPCC, PMP, Spill/Leak Prevention Response	SC-10, SC-11, SC-30, SC-34
Chemical Storage	Varies	Varies	SPCC, PMP, Spill/Leak Prevention Response	SC-10, SC-11, SC-33

4.0 BMP IMPLEMENTATION

4.1 BMP IMPLEMENTATION SCHEDULE

The schedule for implementing all minimum and advanced BMPs is presented in Table 4.1. BMPs will be implemented as necessary to reduce or prevent transport of industrial pollutants in stormwater runoff. Slight modifications to this schedule may be necessary to achieve this goal. Records of BMP implementation will be included in Appendix I.

Table 4.1 *BMP Implementation Schedule*

Industrial Activity/Material and Location	BMP Description	Department Responsible for Implementing BMP	Date and Time of Implementation	Implementation Duration

4.2 BMP INSPECTION AND MAINTENANCE

The General Permit requires, at a minimum, monthly observations of BMPs, along with inspections during sampling events. Monthly observations will be conducted during daylight hours of scheduled facility operating hours and on days without precipitation. A BMP observation checklist must be filled out for and maintained on-site with the SWPPP. The observation checklist includes the necessary information as discussed in Section 5.5. Completed checklists will be kept in an accompanying file/binder associated with the SWPPP and readily accessible on site.

BMPs will be maintained regularly to ensure proper and effective functionality. If necessary, corrective actions will be implemented when deficiencies are identified. These action items will be documented in the SWPPP.

Specific guidance for maintenance, observation, and repair of advanced BMPs can be found in the BMP Factsheets in Appendix I.

5.0 MONITORING IMPLEMENTATION PLAN

The intent of a Monitoring and Reporting Program is to ensure that storm water discharges are in compliance with elements of the General Permit, and to assess facility BMPs so they are evaluated and modified, as necessary.

This Monitoring Implementation Plan (MIP) was developed to address the following objectives:

1. Identify the monitoring team;
2. Describe weather and rain event tracking procedures;
3. Describe discharge locations, visual observations procedures
4. Describe visual observation response procedures;
5. Describe sample collection and handling procedures;
6. Describe field instrumentation calibration instructions and intervals;
7. Provide justification for alternative discharge locations, Representative Sample Reduction (RSR), and Qualified Combined Samples (QCS), as applicable; and
8. Provide an example Chain of Custody form to be used when handling and shipping water quality samples to the laboratory.

5.1 VISUAL MONITORING AND SAMPLING PERSONNEL

Visual monitoring and sampling will be conducted by trained team members or subcontractors. The name(s) and contact number(s) of the site visual monitoring and sampling personnel are listed below and their training qualifications are provided in Appendix E.

Assigned inspector: Pacific Ridgeline, Inc.	Contact phone: (805) 933-1770
Alternate inspector: CRPC	Contact phone: (805) 525-8008

5.2 WEATHER AND RAIN EVENT TRACKING

Stormwater sampling and visual observations will be conducted during Qualified Storm Events (QSEs). A QSE is defined as any precipitation event that produces a discharge for at least one drainage area and is preceded by 48 hours with no discharge from any drainage area. Weather and precipitation forecasts will be tracked to identify potential QSEs.

When targeting a QSE for stormwater sampling, the appropriate team member will weekly consult the National Oceanographic and Atmospheric Administration (NOAA) for weather forecasts. These forecasts can be obtained at <http://www.wrh.noaa.gov/>. If weekly forecasts indicate potential for significant precipitation, the weather forecast will

be closely monitored during the 48 hours preceding the event. Weather reports with precipitation data should be printed and maintained with the SWPPP in MIP Attachment 1 "Weather Reports" to document precipitation totals and antecedent conditions.

5.3 ALTERNATIVE DISCHARGE LOCATIONS

As discussed in Section 2, the majority of the land area at the Ojai Field is open space, with only approximately 3% of the land disturbed by industrial activities conducted by CRPC. The entire facility encompasses approximately 3,400 acres, and encompasses two (2) HUC12 areas and has two (2) streams that run in the vicinity of the facility and ultimately discharge from property boundaries. Although industrial areas exposed to stormwater do drain to these streams, the majority of the stormwater flows in the basins are from uncontrolled surrounding areas that are not covered by this permit or have any sort of disturbances caused by CRPC.

As reported in the Natural Background Demonstration Technical Report (Appendix B), the land area of the Facility is highly prone to erosion, and natural levels of salinity, Total Dissolved Solids (TDS) and Total Suspended Solids (TSS) are expected discharging from the site sediments associated with storm water discharges in the area. These levels are not indicative of stormwater being released directly by CRPC.

In order to collect stormwater samples that are that are not affected by open space land outside of control of CRPC, all samples will be collected directly from discharges off of areas that have been disturbed by industrial activities under direct control of CRPC. Examples of areas to be sampled are tank pads, well pads, and equipment storage areas.

5.4 REPRESENTATIVE SAMPLING REDUCTION

As described in Section 2.2, the Facility encompasses two (2) HUC12 areas and has two (2) minor streams that run in the vicinity of the Site and ultimately discharge from property boundaries. For the purpose of this MIP, these HUC12 areas are considered to be the drainage areas for the property. Within these areas, CRPC operates on approximately 3% of the land space. The primary discharge locations for each HUC12 are presented on the figures in Appendix A.

Each of the drainage areas have substantially similar industrial activities, with oil and gas production being the sole industrial operation conducted by CRPC. Typically, areas inside of the oil field are graded flat to make pad locations. These pads contain tanks, processing and transmission equipment, and/or well pumping units, and are connected via pipelines and roadways. Many of the pad locations are remote and not easily accessible from public roads.

The BMPs listed in Section 3.1 are implemented universally throughout the entire Site. All of the drainage areas are similar in BMP implementation.

The physical characteristics of each drainage area and the Site as a whole are described in Section 2 and in the Natural Background Demonstration Technical Report in Appendix B.

As described above, there is not a significant difference between industrial activities, BMP implementation, or physical characteristics in any of the drainage areas or general discharges from industrial land operated by CRPC. Currently, CRPC operates on numerous pad locations throughout the Site, each which has its own discharge point(s). Sampling from the main outfalls of the Site would not be indicative of discharges from industrial activities, and sampling each discharge from every pad is not possible or practical due to the number and wide distribution of the pad locations. CRPC proposes to collect a total of four (4) samples directly from various pad locations throughout the Site to represent discharges from typical industrial activities at the field.

Sampling locations were selected from the three primary tank battery facilities (Ojai, Hamp, Silverthread) and a well pad location at Ferndale. The Ferndale tank battery is currently not in operation and all storage/processing equipment has been taken out of service. Timber Canyon was not selected to have a storm water sampling location due to safety concerns accessing the facility during rain events. The locations of the representative sampling locations are presented on the Site Map(s) in Appendix A, and are discussed in further detail below.

5.5 VISUAL MONITORING AND SAMPLING LOCATIONS

Visual monitoring and sampling locations, as discussed in the following sections, are shown on the Site Map(s) in Appendix A. Visual monitoring locations are described in Section 5.7, and sampling locations are described in Section 5.8.

Due to the size of the Site, not every discharge location from all pad locations will be inspected during visual monitoring events. Operators and technicians routinely inspect the entire Site daily for leaks, spills, or any other unauthorized discharges, and immediately stop any detected leaks. Monthly visual observation will focus on discharge areas as a whole, including BMPs, major outfalls of the Site, and observations of pad locations selected as representative of the Site as a whole. Sampling event visual observations will focus on the representative sampling locations during times that sampling occurs, along with general observations of the surrounding areas.

Whenever changes in Site operations might affect the appropriateness of representative discharge and sampling locations, locations will be revised accordingly. All such revisions will be implemented as soon as feasible and the SWPPP amended.

5.6 VISUAL MONITORING AND SAMPLING EXEMPTIONS

The collection of samples or conduct visual observations is not required under the following conditions:

- During dangerous weather conditions such as flooding and electrical storms.
- During any conditions deemed unsafe by the site manager, including natural disasters.
- Outside of standard site business hours (typical business hours are between 7:00AM to 4:00PM).

If monitoring (visual observations or sample collection) of the Site is unsafe because of the dangerous conditions noted above then the appropriate team member will document the conditions and explain why an exception to performing the monitoring was necessary. The exception documentation will be filed in MIP Attachment 2 "Monitoring Records".

5.7 VISUAL OBSERVATION PROCEDURES

Visual observations include observations of drainage areas, BMPs, and discharge locations.

- Observations of BMPs are required to identify and record BMPs that need maintenance to operate effectively, that have failed, or that could fail to operate as intended.
- Observations of the drainage areas are required to identify any spills, leaks, uncontrolled pollutant sources, and non-stormwater discharges.

- Observations of discharge locations are required to identify the presence of visible pollutants that are or could be mobilized in stormwater discharged from the facility.

Operators and technicians inspect the Site daily for leaks and spills. Formal visual observations will be performed at least once every calendar month during dry conditions and during all stormwater sampling events when discharge is occurring.

Visual observations will be documented on the *Visual Observation Log – Monthly or Sampling Event* (see MIP Attachment 3 “Example Forms”). Visual observations will be supplemented with a site specific BMP inspection checklist when necessary. Photographs used to document observations will be referenced on the *Visual Observation Log* and maintained with the Monitoring Records in MIP Attachment 2.

The completed logs and checklists will be kept in MIP Attachment 2 “Monitoring Records”.

5.7.1 Monthly Visual Observations

Monthly visual observations are to be conducted on days without precipitation, and will be recorded on the *Visual Observation Log – Monthly*. Observations are to be conducted twelve months a year. Although not required by the General Permit, monthly visual observations should be scheduled and conducted prior to rain events in order to assess any current issues with BMPs at the Site prior to stormwater discharge.

Monthly visual observations are to be conducted throughout each drainage area at the facility. Drainage areas are shown on the Site Map(s) in Appendix A.

Monthly visual observations are necessary to document the presence of and to identify the source of any pollutants and non-stormwater flows. These should consist of observations of the outdoor facility operations, BMPs, and NSWDC observations, as described below.

In the event that monthly visual observations are not performed, an explanation must be provided in the annual report.

5.7.1.1 Outdoor Facility Operations Observations

Observe potential sources of industrial pollutants including industrial equipment and storage areas and outdoor industrial activities. Record observations of:

- Spills or leaks; and
- Uncontrolled pollutant sources

5.7.1.2 BMP Observations

Observe BMPs to identify and record:

- BMPs that are properly implemented;
- BMPs that need maintenance to operate effectively;
- BMPs that have failed; or
- BMPs that could fail to operate as intended.

5.7.1.3 Non-Stormwater Discharge Observations

Observe each drainage area for the presence of or indications of prior unauthorized and authorized non-stormwater discharges. Record:

- Presence or evidence of any non-stormwater discharge (authorized or unauthorized);
- Pollutant characteristics (floating and suspended material, sheen, discoloration, turbidity, odor, etc.); and
- Source of discharge.

For authorized non-stormwater discharges, also document whether BMPs are in place and are functioning to prevent contact with materials or equipment that could introduce pollutants.

5.7.2 Stormwater Sampling Event Visual Observations

Sampling event visual observations evaluate the general appearance of the stormwater as an indicator of potential pollutants. These observations will be conducted at the same time sampling occurs at the representative sampling locations identified in Section 5.8.2. At each discharge location where a sample is obtained, record observations of:

- Floating and suspended materials;
- Oil and grease;
- Discoloration;
- Turbidity;
- Odors; and
- Trash.

Discharge locations that were not chosen to be representative discharge locations for sampling will also be intermittently observed during sampling events for pollutants listed above. If pollutants are observed, the location and observations will be recorded on the

Visual Observation Log – Sampling Event. When pollutants are observed in the discharged stormwater, follow-up observations of the drainage area will be conducted to identify the probable source of the pollutants.

In the event that a representative discharge location is not visually observed during the sampling event, the location of the discharge and reasoning for not obtaining observations must be recorded.

5.8 SAMPLING AND ANALYSIS PROCEDURES

This section describes the methods and procedures that will be followed for stormwater sampling and analysis. It contains information for sampling schedule, sampling locations, monitoring preparation, analytical constituents, sample collection, sample analysis, and data evaluation and reporting.

5.8.1 Sampling Schedule

Stormwater samples at each representative discharge location will be collected and analyzed from two (2) QSEs within the first half of each reporting year (July 1 to December 31), and two (2) QSEs within the second half of each reporting year (January 1 to June 30). If the Facility does not report concentrations of pollutants above NALs for four (4) consecutive sampling events and maintains complete compliance with this SWPPP, a Sampling Frequency Reduction Certificate will be submitted. If approved, the sampling schedule will be reduced to one (1) QSEs within the first half of each reporting year (July 1 to December 31), and one (1) QSEs within the second half of each reporting year (January 1 to June 30).

A QSE is a precipitation event that:

- Produces a discharge for at least one drainage area; and
- Is preceded by 48 hours with no discharge from any drainage area.

5.8.2 Sampling Locations

Sampling locations were chosen according to the representative sampling reduction discussed in Section 5.4. Sampling locations are shown on the Site Map(s) in Appendix A.

A total of four (4) representative sampling location(s) have been identified on the project site for the collection of stormwater runoff samples.

Sample Location Number	Sample Location Description
Ojai 1	Ojai Tank Battery 1
Ojai 2	Located downgradient of Hamp Tank Battery, loading facility and well pad
Ojai 3	Located adjacent/downgradient to Silverthread Tank Battery
Ojai 4	Located adjacent to Ferndale well pad

5.8.3 Sampling Preparation

Samples will be collected by the personnel outlined in Section 5.1.

An adequate stock of monitoring supplies and equipment for sampling will be available onsite prior to a sampling event. Monitoring supplies and equipment will be stored in a cool temperature environment that will not come into contact with rain or direct sunlight. Sampling personnel will be available to collect samples in accordance with the sampling schedule. Supplies maintained at the facility will include, but are not limited to: clean powder-free nitrile gloves; sample collection equipment; coolers; appropriate number and volume of sample containers; identification labels; re-sealable storage bags; paper towels; personal rain gear; ice; and *Sampling Field Log Sheets* and Chain of Custody (CoC) forms, which are provided in MIP Attachment 3 "Example Forms".

5.8.4 Sample Collection

Samples of discharge will be collected at the designated representative sampling locations shown on the Site Map(s) in Appendix A. Samples from each discharge location will attempted to be collected within four (4) hours of:

- The anticipated start of the discharge; or
- The start of facility operations if the QSE occurs within the previous 12 hour period.

Sample collection is required during scheduled facility operating hours and when sampling conditions are safe. Please note that the locations of representative sampling locations are not manned at all times, and the start of discharge will not be able to be observed visually for every location. CRPC and/or its stormwater sampling contractor, will use professional judgement, knowledge of the area, and weather reports to determine the appropriate times to initiate sampling events for the area. All reasonable efforts will be undertaken to ensure samples are collected within a timely manner from the anticipated times of discharge.

Grab samples will be collected and preserved in accordance with the methods identified in Table 5.2, "Sample Collection, Preservation and Analysis for Water Quality Samples" provided in Section 5.8.5. Only team members properly trained in water quality sampling will collect samples.

Grab samples will be collected and analyzed for pH using a portable pH meter. Manufacturer information and equipment calibration requirements are included MIP Attachment 4, "Field Meter Instructions." The pH analysis will be performed as soon as practicable, but no later than 15 minutes after sample collection.

Samples from different discharge locations will not be combined or composited prior to shipment to the analytical laboratory. Sample collection and handling requirements are described in Section 5.9.

5.8.5 Sampling Analytical

The Site analyzes for the basic required constituents in the General Permit, there are no additional TMDLs which would apply to a crude oil and natural gas facility.

Table 5.2 lists the sampling parameters, along with their respective reporting limits, holding times, and sampling containers.

TABLE 5.2 - Sample Collection, Preservation and Analysis for Water Quality Samples

Analytical Test and Method	Detection Limit (MDL)	Holding Time	Container
Total Suspended Solids by SM 2540D	1 mg/L	7 days	1-L Plastic Unpreserved
pH by SM 4500-HB	None	immediate	250-ml Plastic Unpreserved
Oil and Grease by EPA 1664A	0.5 mg/L	28 days	1-L Amber Glass H ₂ SO ₄ (Sulfuric Acid) Preservation

5.8.6 Data Evaluation and Reporting

The designated member of the Pollution Prevention Team will complete an evaluation of the water quality sample analytical results.

All sampling and analytical results for all individual samples will be submitted via SMARTS within 30 days of obtaining all results for each sampling event.

Values from laboratory analytical results from samples will be reported as less than the Method Detection Limits (MDL; i.e. <MDL). A value of zero or "ND" will not be reported.

Analytical results that are reported by the laboratory as below the minimum level (often referred to as the reporting limit) but above the method detection limit will be provided.

Reported analytical results will be averaged automatically by SMARTS at the end of the reporting year. For any calculations required by the General Permit a value of zero shall be used for all effluent sampling analytical results that are reported by the laboratory as "non-detect" or less than the MDL.

5.9 SAMPLE COLLECTION AND HANDLING

Sample collection and handling is performed in Accordance with Attachment H of the General Permit, and generally follows the "Industrial Stormwater Monitoring and Sampling Guide" (US EPA 2009) and "NPDES Storm Water Sampling Guidance Document" (U.S. EPA 1992).

5.9.1 Sample Collection

Samples will be collected at the designated representative sampling locations shown on the Site Map(s) and listed in the preceding sections. Samples will be collected, maintained and shipped in accordance with the requirements in the following sections.

Grab samples will be collected and preserved in accordance with the methods identified in preceding sections. Automatic sampling devices will not be used at the facility. There are currently no Qualified Combined Samples.

To maintain sample integrity and prevent cross-contamination, sample collection personnel will follow the protocols below.

- Collect samples (for laboratory analysis) only in analytical laboratory-provided sample containers;
- Do not touch the inside of sampling containers, or put anything into sampling containers prior to sampling;
- Wear clean, powder-free nitrile gloves when collecting samples;
- Change gloves whenever something not known to be clean has been touched, and change gloves between sites;
- Decontaminate all equipment (e.g. bucket, tubing) prior to sample collection using a proper environmental decontaminant water wash, distilled water rinse, and final rinse with distilled water. (Dispose of wash and rinse water appropriately, i.e., do not discharge to storm drain or receiving water). Do not decontaminate laboratory provided sample containers;
- Do not smoke during sampling events;
- Never sample near a running vehicle;
- Do not park vehicles in the immediate sample collection area (even non-running vehicles);
- Do not eat or drink during sample collection;
- Do not overfill sampling containers, and;
- Do not breathe, sneeze, or cough in the direction of an open sample container.

The most important aspect of grab sampling is to collect a sample that represents the entire runoff stream. Typically, samples are collected by dipping the collection container in the runoff flow paths and streams as noted below.

- For small streams and flow paths, simply dip the bottle facing upstream until full.
- For larger stream that can be safely accessed, collect a sample in the middle of the flow stream by directly dipping the mouth of the bottle. Once again making sure that the opening of the bottle is facing upstream as to avoid any contamination by the sampler.
- For larger streams that cannot be safely waded, pole-samplers may be needed to safely access the representative flow.
- Avoid collecting samples from ponded, sluggish or stagnant water.
- Avoid collecting samples directly downstream from a bridge as the samples can be affected by the bridge structure or runoff from the road surface.
- Do not stand upstream of the sampling point within the flow path.

In the case of sheet flow from the runoff of a site, direct submersion of the intermediate container may not be possible. In this case, a collection device will be used to collect water to directly fill the sample containers. The intermediate sample container will be pre-cleaned prior to sample collection, and will be decontaminated in between sampling events. Clean nitrile gloves will be worn at all times. The container could consist of a bucket, a dipping stick, or something that consists of the same composition as the sample containers, depending on site-specific conditions. The intermediate container will be filled through direct submersion, rinsed with sampling water, re-filled, and the sample will be transferred to the appropriate pre-labeled sample containers as quickly as possible.

Note, that depending upon the specific analytical test, some containers may contain preservatives. These containers should **never** be dipped directly into the flow of stormwater, but filled indirectly from a secondary collection container.

5.9.2 Sample Handling

Field pH measurements must be conducted immediately. Do not store pH samples for later measurement.

Samples for laboratory analysis must be handled as follows. Immediately following sample collection:

- Tightly cap sample containers;
- Complete sample container labels;
- Sealed containers in a re-sealable storage bag;
- Place sample containers into an ice-chilled cooler;
- Document sample information on the Sampling Field Log Sheet; and
- Complete the CoC.

All samples for laboratory analysis must be maintained on ice during delivery to the laboratory. Samples must be kept on ice, or refrigerated, from sample collection through delivery to the laboratory. Do not freeze samples. Place samples to be shipped inside coolers with ice. Make sure the sample bottles are well packaged to prevent breakage and secure cooler lids with packaging tape.

Ship samples that will be laboratory analyzed to the analytical laboratory right away. Hold times are measured from the time the sample is collected to the time the sample is analyzed. The General Permit requires that samples be received by the analytical laboratory within 48 hours of the physical sampling (unless required sooner by the analytical laboratory).

5.9.3 Sample Documentation

All original data documented on sample bottle identification labels, *Sampling Log*, and CoCs will be recorded using waterproof ink. If an error is made on a document, sampling personnel will make corrections by lining through the error and entering the correct information. The erroneous information will not be obliterated. All corrections will be initialed and dated.

Duplicate samples will be identified consistent with the numbering system for other samples to prevent the laboratory from identifying duplicate samples. Duplicate samples will be identified in the Sampling Log.

Sample documentation procedures include the following:

Sample Bottle Identification Labels: Sampling personnel will attach an identification label to each sample bottle. Sample identification will uniquely identify each sample location, the date and time of sample collection, and the person collecting the sample.

Field Log Sheets: Sampling personnel will complete the *Effluent Sampling Field Log Sheet* and *Receiving Water Sampling Field Log Sheet* for each sampling event, as appropriate.

Chain of Custody: Sampling personnel will complete the CoC for each sampling event for which samples are collected for laboratory analysis. The CoC will include the discharges name, address, phone number, identification of samples, the identification of the person collecting the sample, dates and times of sampling, and the required analysis. The sampler will sign the CoC when the sample(s) is turned over to the testing laboratory or courier.

5.10 QUALITY ASSURANCE AND QUALITY CONTROL

An effective Quality Assurance and Quality Control (QA/QC) plan will be implemented as part of the IMP to ensure that analytical data can be used with confidence. QA/QC procedures to be initiated include the following:

- Field logs;
- Clean sampling techniques;
- CoCs;
- QA/QC Samples; and
- Data verification.

Each of these procedures is discussed in more detail in the following sections.

5.10.1 Field Logs

The purpose of field logs is to record sampling information and field observations during monitoring that may explain any uncharacteristic analytical results. Sampling information to be included in the field log include the date and time of water quality sample collection, sampling personnel, sample container identification numbers, and types of samples that were collected. Field observations should be noted in the field log for any abnormalities at the sampling location (color, odor, BMPs, etc.). Field measurements for pH and turbidity should also be recorded in the field log. Field logs are included in MIP Attachment 3 "Example Forms".

5.10.2 Clean Sampling Techniques

Clean sampling techniques involve the use of certified clean containers for sample collection and clean powder-free nitrile gloves during sample collection and handling.

As discussed in Section 6.8, adoption of a clean sampling approach will minimize the chance of field contamination and questionable data results.

5.10.3 Chain of Custody

The sample CoC is an important documentation step that tracks samples from collection through analysis to ensure the validity of the sample. Sample CoC procedures include the following:

- Proper labeling of samples;
- Use of CoC forms for all samples; and
- Prompt sample delivery to the analytical laboratory.

Analytical laboratories usually provide CoC forms to be filled out for sample containers. An example CoC is included in MIP Attachment 3 "Example Forms".

5.10.4 Laboratory QA/QC

Laboratories contracted for the project will be State-Certified and follow internal QA/QC measures, as stipulated by the individual laboratory QA/QC document. Generally, quality control samples will consist of method blanks, laboratory duplicates, laboratory control samples, and matrix spikes.

5.10.5 QA/QC Samples

No QA/QC samples are anticipated for sampling at the Site, due to the small number of sampling locations.

5.10.6 Data Verification

After results are received from the analytical laboratory, the discharger will verify the data to ensure that it is complete, accurate, and the appropriate QA/QC requirements were met. Data must be verified as soon as the data reports are received. Data verification will include:

- Check the CoC and laboratory reports.
Make sure all requested analyses were performed and all samples are accounted for in the reports.
- Check laboratory reports to make sure hold times were met and that the reporting levels meet or are lower than the reporting levels agreed to in the contract.
- Check data for outlier values and follow up with the laboratory.
Occasionally typographical errors, unit reporting errors, or incomplete results are reported and should be easily detected. These errors need to be identified, clarified, and corrected quickly by the laboratory. Especially note data that is an

order of magnitude or more different than similar locations, or is inconsistent with previous data from the same location.

- Check laboratory QA/QC results.
EPA establishes QA/QC checks and acceptable criteria for laboratory analyses. These data are typically reported along with the sample results. Evaluate the reported QA/QC data to check for contamination (method, field, and equipment blanks), precision (laboratory matrix spike duplicates), and accuracy (matrix spikes and laboratory control samples). When QA/QC checks are outside acceptable ranges, the laboratory must flag the data, and usually provides an explanation of the potential impact to the sample results.
- Check the data set for outlier values and accordingly, confirm results and re-analyze samples where appropriate.
Sample re-analysis should only be undertaken when it appears that some part of the QA/QC resulted in a value out of the accepted range. Sample results may not be discounted unless the analytical laboratory identifies the required QA/QC criteria were not met and confirms this in writing.

Field data including pH measurements and visual observations must be verified as soon as the Visual Observation and Sampling Logs are received, typically at the end of the monitoring event. Field data verification will include:

- Check logs to make sure all required measurements were completed and appropriately documented;
- Check reported values that appear out of the typical range or inconsistent; Follow-up immediately to identify potential reporting or equipment problems, if appropriate, recalibrate equipment after sampling;
- Verify equipment calibrations;
- Review observations noted on the logs; and
- Review notations of any errors and actions taken to correct the equipment or recording errors.

5.11 RECORDS RETENTION

Records of stormwater monitoring information and copies of reports (including Annual Reports) must be retained for a period of at least five (5) years from date of submittal or longer if required by the Water Board.

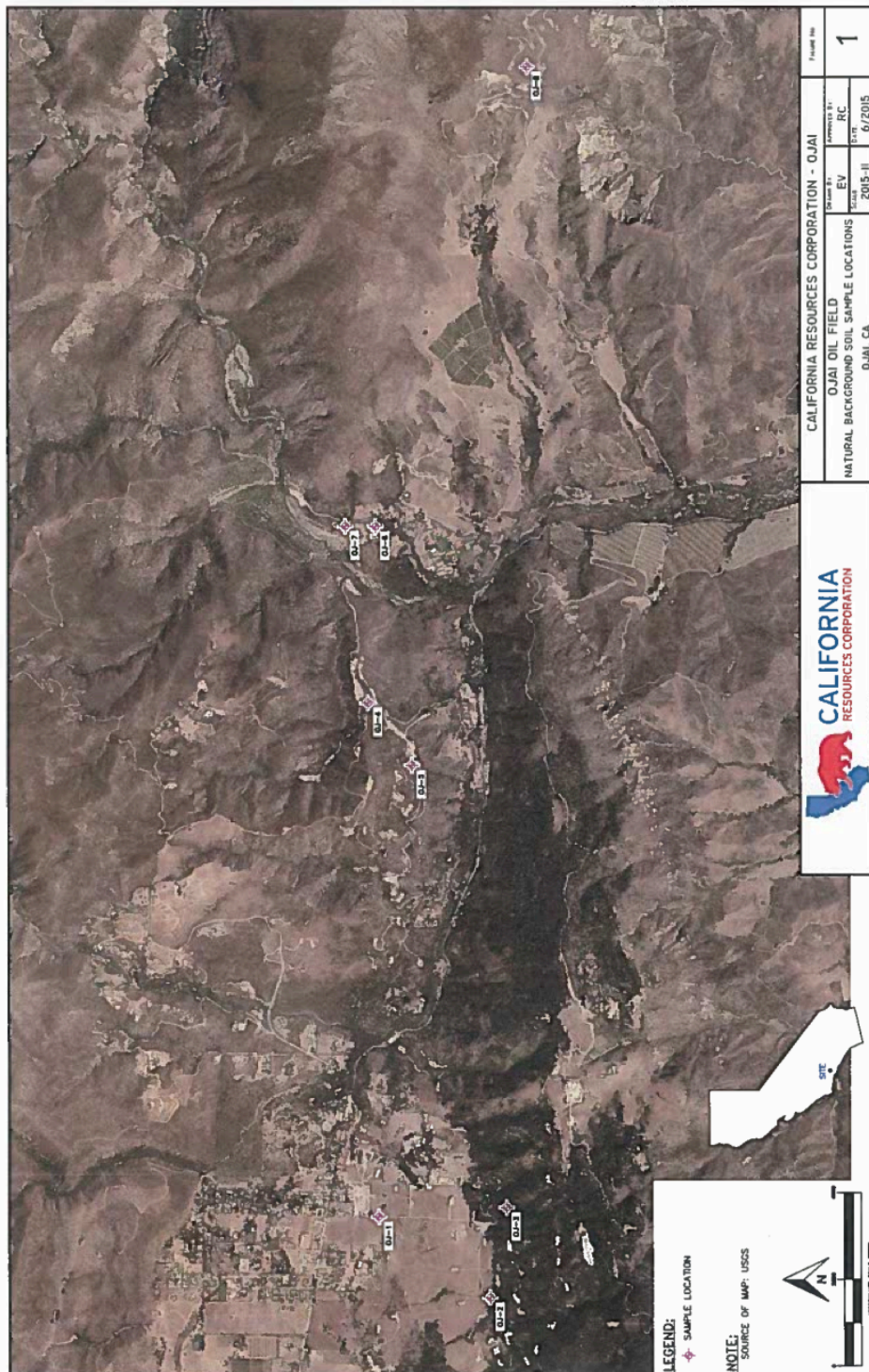
Results of visual observations, field measurements, and laboratory analyses must be kept in the SWPPP along with CoCs, and other documentation related to the monitoring.

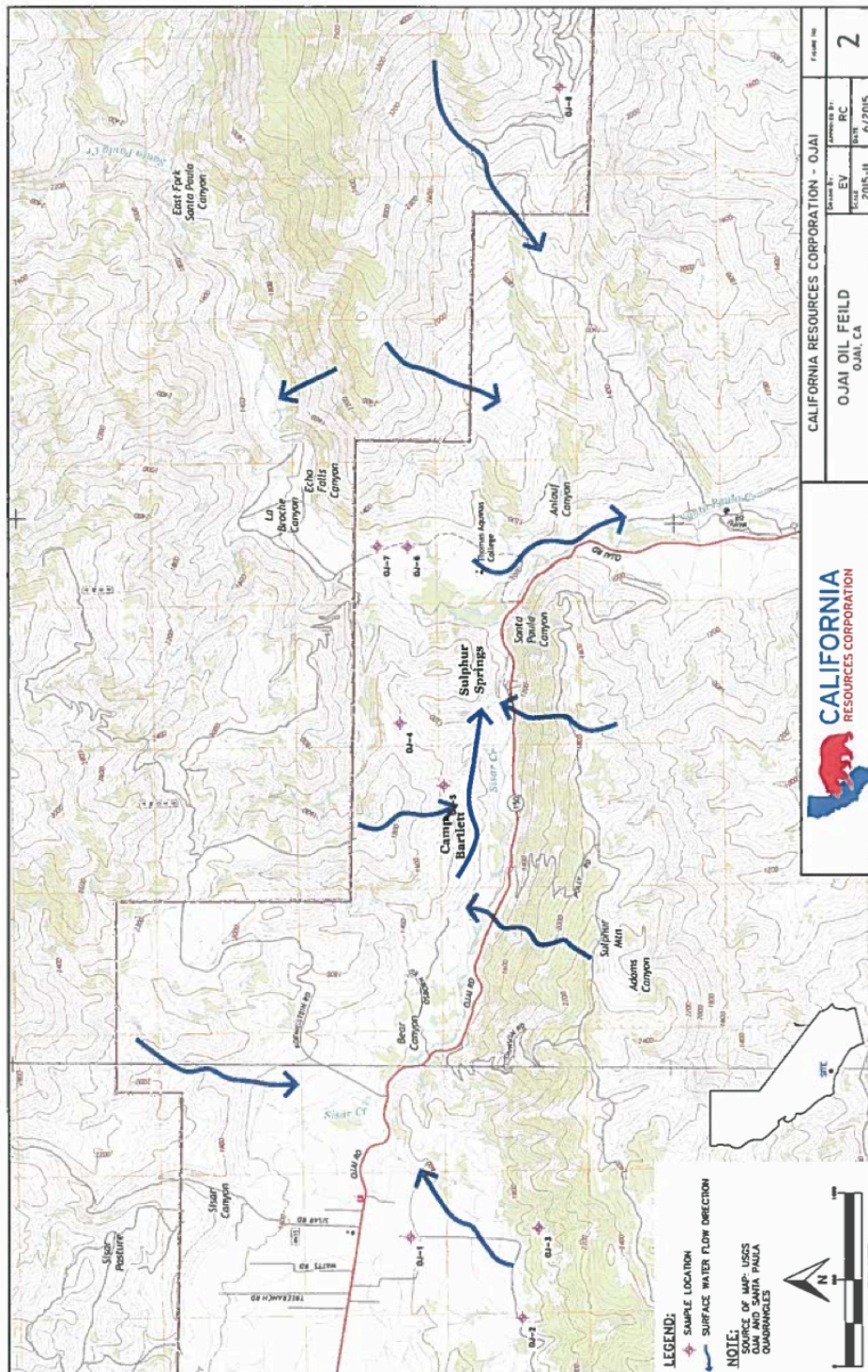
Records to be retained include:

- The date, place, and time of inspections, sampling, visual observations, and/or measurements, including precipitation;
- The individual(s) who performed the inspections, sampling, visual observation, and/or field measurements;
- The date and approximate time of field measurements and laboratory analyses;
- The individual(s) who performed the laboratory analyses;
- A summary of all analytical results, the method detection limits and reporting limits, and the analytical techniques or methods used;
- Weather reports;
- QA/QC records and results;
- Calibration records;
- Visual observation and sample collection exception records; and

The records of any corrective actions and follow-up activities that resulted from analytical results, visual observations, or inspections.

APPENDIX A
SITE LOCATION MAP AND SITE MAP





APPENDIX B
NATURAL BACKGROUND DEMONSTRATION TECHNICAL REPORT



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CALIFORNIA RESOURCES CORPORATION, LLC

OJAI OIL FIELD

**Natural Background Demonstration Technical Report
For Stormwater Compliance
Ventura County, California**

Project No. 2015-11

Prepared By:

GeoSolve, Inc.

1807 Santa Rita Road, Suite D165
Pleasanton, California 94566

June 30, 2015

Prepared By:



Robert D. Campbell, M.S., P.G., C.E.G., Q.S.D., Q.S.I.P. III
Principal Engineering Geologist

1807 Santa Rita Road, Suite D-165 • Pleasanton, CA 94566
rcampbell@geosolve-inc.com • (925) 963-1198

Committed to solving your environmental, geological and hydrogeological concerns.



1.0 Introduction

The Ojai Oil Field ("Site") is comprised of four leases within the Ojai area, which are situated between Sulfur Mountain and Santa Paula Peak, and bisected by Highway 150 (Ojai-Santa Paula Road). The Ojai Oil Field is located 2.5-miles north of Santa Paula and 10.5-miles east of Ojai in Ventura County, California and is situated within extreme topographic relief with active landslides. The Ojai Oil Field Lease boundary is shown on Figure 1, Site Vicinity Map. This Natural Background Demonstration Technical Report (Report) for the Site was prepared in conformity with the provisions set forth in the California State Water Resources Control Board (SWRCB) Order Number 2014-0057-DWQ, or the Industrial General Permit ("IGP"). The purpose of this Report is to demonstrate the Numeric Action Levels (NALs) reported in storm water discharges were solely from natural background conditions, as summarized in this Report.

The SWRCB issued an IGP associated with discharge of storm water from permitted facilities, which superseded the former Order Number 97-03-DWQ. Details of the current IGP are available at the SWRCB website http://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2014/wqo2014_0057_dwq.pdf.

Oil and gas extraction is covered under the IGP as *Item 3. Oil and Gas/Mining Facilities, which includes Facilities SICs 10XX through 14XX, including oil and gas exploration, production, processing, or treatment operations; or transmission facilities that discharge storm water contaminated by contact with or that has come into contact with any overburden, raw material, intermediate products, finished products, by-products, or waste products located on the site of such operations.* In the IGP Fact Sheet and IGP, Demonstration Technical Reports for covered sites must be prepared by a Qualified Industrial Storm Water Practitioner (QISP III) to demonstrate Level 2 Exceedance Response Actions (ERAs) were caused by natural background sources.

This Report demonstrates:

1. Exceedances of discharge standards or receiving water quality objects in the runoff from the Site are caused solely and exclusively by naturally occurring conditions on the site.
2. Exceedances of discharge standards are not related to industrial operations at the Site including any legacy pollutants from prior human activities.
3. That the levels of pollutants of concern measured in the runoff at the site are comparable to the reference site which exhibits similar natural conditions and for which there had been no history of anthropogenic activity

Pursuant to the provisions of the IGP, this report specifically addresses the following nine Permit Provisions:

1. A statement that the Discharger has determined that the exceedance of any NAL is attributable solely to the presences of the pollutant in the natural background.
2. A summary of all data previously collected by the Discharger or others that describe the levels of natural background pollutants in the storm water discharge.
3. A summary of any research and published literature that relates the pollutants evaluated at the facility as part of the Natural Background.
4. A map showing reference site location in relation to the Site along with available land cover information.
5. Reference site and Site elevation
6. Available geology and soil information from the Reference Site and the Site.
7. Photographs showing Site vegetation.
8. Site reconnaissance survey data regarding the presences of roads, outfalls, or other human-made structures.
9. Records from relevant state or federal agencies indicating no known mining, forestry, or other human activities upstream of the proposed reference site.

A certified copy of this report has been submitted via SMARTs and a hard copy has been provided to the Regional Water Quality Control Board for the Los Angeles Region (RWQCB).

Any exceedances of discharge standards or water receiving water quality objects in the runoff from the Site are caused solely and exclusively by naturally occurring conditions on the site.

Annual industrial storm water sampling and reporting pursuant to Industrial Permit No. 2014-0057-DWQ, revealed historic elevated Specific Conductance ("SC") levels and concentrations of Total Dissolved Solids ("TDS"), and concentrations of Total Suspended Solids ("TSS") in storm water samples collected from the Site. The sampling points were randomly selected to depict Site conditions rather than the aggregate of the surface run-off from the entire lease. The sampling locations are shown on Sample Location Map, Figure 1. Although the RWQCB has noted exceedances of water quality benchmarks and receiving water objectives in prior sample data, this portion of this Report demonstrates the exceedances are the result of natural background at the site, and are not due to any industrial operations at the Site. This conclusion is based on the unique marine sedimentary geologic units eroding into the drainage channels, close proximity of the Site to the Pacific Ocean and consistent deposition of sea salt aerosols on the ground surface.

Laboratory analytical and material testing results of eight randomly collected shallow-soil samples indicated the shallow soil is slightly alkaline, and contains elevated concentrations of soluble salts. Minor concentrations of metals were also detected in the soil samples.

The laboratory analytical results were averaged and statistically calculated to obtain 95% upper confidence levels (UCL). The range between the mean averages and 95% UCL concentrations was established as background concentrations for shallow soil at the site. Particle size analyses of four soil samples indicated the shallow soil consists mostly of silt and fine- to medium-grained sand with minor clay and gravel. As described in detail below, averaged soil erodibility factor (K) was calculated at 0.29 and an average soil-loss calculation was performed indicating approximately 1,021 tons of sediment per acre per year is being eroded from the 3,400 acres not associated with industrial activities at the Site and approximately 64 tons of soil per acre per year from the 50 acres of operational areas at the site. Thus, 99.8% of all silt and sediment originating from the Site is associated with undisturbed areas with no industrial activities.

2.0 Site-Specific Soil Loss Calculations using Site Specific Factors

Using the Revised Universal Soil Loss Equation (RUSLE, Equation 1) and the SWQCB's storm water website, the following soil loss was calculated for an average one acre area the site:

$$A = R * LS * K * C * P \quad (1)$$

Where:

A	=	soil loss in tons per acre per year
R	=	rainfall-runoff erosivity factor
LS	=	length and slope factors
K	=	erodibility factor
C	=	cover factor
P	=	practice factor

P and C were equal to 1.0 for this calculation

R was calculated at 78.84 for one year using the EPA's Rainfall Erosivity Factor Calculator for Small Construction Sites (<http://water.epa.gov/polwaste/npdes/stormwater/Rainfall-Erosivity-Factor-Calculator.cfm>).

Sulfur Mountain is approximately 11 miles from the Pacific Ocean and is approximately 2,530 feet above sea level. Using the length of 1,000 feet and the slope percent was 37.5%. Using the LS Table, the LS Factor was determined to be 44.70.

The average K Factor was calculated at 0.29 using Nomograph from Erickson (1977) and Goldman et al. (1986).

Therefore, $K * LS = 12.96$

$$\begin{aligned}\text{Using Equation (1)} \quad A &= 78.84 * 12.96 * 1 * 1 \\ &= \quad \quad \quad \mathbf{1,021.76 \text{ tons/acre per year}}\end{aligned}$$

At least 1,021 tons of sediment per year is estimated as being eroded from each acre at the site. The size of the entire Site is approximately 3,400 acres (minus the 65-acres used for industrial activities), which is 3,300. Therefore, approximately 3,371,808 tons of sediment is being eroded from the non-industrial portions of the site each year.

The industrial activities as the Site only occupy approximately 100-acres of land (approximately 50 acres are roadways and the other 50 acres consist of well pads, buildings, and tank areas). From the 50 acres of roadways, 25 percent of the roadways are paved and minimal erosion is occurring at the edges of the roadways. From the 50 acres of facilities, 50% of the facilities are paved. To account for the industrial area, the following calculation was performed using the RUSLE, as discussed below.

2.1 Roadway Soil Loss

Since C for the industrial area is significantly less than vacant ground due to the roadways and paved areas, C for this site is estimated at 0.01 for 25% of the site and 0.10 for 75% of the roadways, while P is equal to 1.

Using Equation (1)

$$A = 78.84 * 12.96 * 0.01 * 1 \text{ (25\% of the industrialized area)}$$

$$A = 10.22 \text{ tons of soil per acre per year for 25\% for the paved roadway areas.}$$

$$A = 78.84 * 12.96 * 0.1 * 1 \text{ (75\% of the unpaved roadway areas)}$$

$$A = 102.17 \text{ tons of soil per acre per year for 75\% of the unpaved roadway areas}$$

Therefore, 25% of 50 acres is 12.5 acres and 75% of 50 acres is 37.5 acres.

$$A = 12.5 \text{ acres} * 10.22 \text{ tons per acre} = 127.75 \text{ tons of soil per year}$$

$$A = 37.5 \text{ acres} * 102.17 \text{ tons per acre} = 3,831 \text{ tons of soil per year}$$

Therefore, approximately 3,959 tons of soil is eroded per year from the industrial portions of the Site on the roadways.

2.2 Facility Soil Loss

Since C for the industrial area is significantly less than vacant ground due to the paved areas, C for this site is estimated at 0.01 for 25% of the paved industrial areas and 0.8 for 75% for the unpaved areas of the roadways, while P is equal to 1. Most of the facilities are flatter in topography, and a K * LS factor was calculated at 0.749 (0.29 * 2.55).

Using Equation (1) $A = 78.84 * 0.749 * 0.01 * 1$ (25% of the paved industrialized area)

$A = 0.59$ tons of soil per acre per year for 25% of the paved industrialized area

$A = 78.84 * 0.749 * 0.8 * 1$ (75% of the unpaved industrialized area)

$A = 47.24$ tons of soil per acre per year for 75% of the unpaved industrialized area

Therefore, 25% of 50 acres is 12.5 acres and 75% of 50 acres is 37.5 acres.

$A = 12.5 \text{ acres} * 0.59 \text{ tons per acre} = 7.375 \text{ tons of soil per year}$

$A = 37.5 \text{ acres} * 47.24 \text{ tons per acre} = 1,771.5 \text{ tons of soil per year}$

Therefore, approximately 1,778.88 tons of soil is eroded per year from the industrial areas at the Site.

The total combined soil loss for the 50 acres of industrial area is estimated at 1,779 tons of soil per year (17.79 tons of soil per acre per year). The combined roadway and industrial land leased area soil loss is estimated at 5,738 tons of soil per year.

Compared to the remaining area (3,300 acres) of the non-industrial area, the soil loss is estimated at 3,371,808 tons of soil per year. The soil loss on the industrial 100 acres of leased land accounts for only 0.1 percent (%) of the entire soil loss of the entire 3,400 acre facility. As demonstrated below, 0.1% of the concentrations of TSS, TDS and SC readings are well within the benchmarks established by the RWQCB and State Water Resources Control Board.

3.0 Site Location

The Ojai Oil Field ("Site") is comprised of four leases within Ojai area, as listed below, which are situated between Sulfur Mountain and Santa Paula Peak, and bisected by Highway 150 (Ojai-Santa Paula Road). The Ojai Oil Field is located 2.5-miles north of Santa Paula and 10.5-miles east of Ojai in Ventura County, California and is situated within extreme topographic relief with active landslides. The Ojai Oil Field Lease boundary is shown on Figure 1, Site Vicinity Map. The Site consists of approximately 3,400 acres that extend up to 2,535 feet above mean seal level (AMSL) and is situated approximately 11-miles from the Pacific Ocean. Only an estimated 0.1% of the property is considered impervious. Many active landslides are also shown on the Santa Paula Peak geologic map. Mass-wasting (landsliding) conditions at this site result in

excessive TSS, TDS, and SC in the discharged storm water from the Site. Drainage is topographically dependent; however, all drainages flow into the Santa Paula Creek, which flows south into the Santa Clara River and to the Pacific Ocean. The four leases at the Site include the following:

- Silverthread Lease
- Hamp Lease
- Ferndale Lease, and
- Timber Lease

4.0 Sources of Naturally Occurring Background Pollutants in Storm Water Discharges and Related Research and Published Literature

4.1 Regional Geology Results in High Concentrations of TSS, SC, and TDS

Based on review of the Geologic Map of the Santa Paula Peak 7.5-Minute Quadrangles (Dibblee, 1990) and at http://gmw.consrv.ca.gov/shmp/download/evalrpt/spp_eval.pdf, the Site geology includes the following geologic units:

- Miocene Monterey Formation (Tm);
- Miocene Sisquoc Shale (Ts);
- Pliocene Pico Formation (QTpm and Tp); and
- Pleistocene Older Dissected Surficial Sediments (Qoa and Qof).

Many active landslides are also present and shown on the Santa Paula Peak 7.5-Minute Geologic Map. Natural erosion of these less competent formations results in large sediment loads being transported by the drainages to Santa Paula Creek, which flows near Highway 150. Mass-wasting (landsliding) conditions at this site result in excessive TSS loads into the drainages listed above, and into Santa Paula Creek, then into Santa Clara River and the Pacific Ocean.

Bedrock units of the Santa Paula Peak 7.5-Minute Quadrangle range from Miocene - to Pleistocene-aged marine deposits, except for the non-marine Older Dissected Surficial Sediments (Qoa and Qof), which represent eroded older alluvial fan deposits. Surficial deposits are limited to areas along active stream channels, elevated terraces, alluvial and fan gravels, shallow landslides and debris flows (Dibblee, 1990).

The oldest exposed unit in the Santa Paula Peak 7.5-Minute Quadrangle is predominantly Miocene marine Monterey Formation (Tm) and Miocene-Pliocene marine Sisquoc Shale (Tmq), followed by the Pliocene-Pleistocene marine Pico Formation (Tp and QTpm).

The early to late Miocene marine Monterey Formation (Modelo Formation), and has two members exposed in the Santa Paula Peak 7.5-Minute Quadrangle. The lower shale unit (Tml) consists of white-weathering, soft, fissile clay shale, with interbeds of hard siliceous shale and

thin limestone strata. The upper shale unit (Tm) consists of thin-bedded, hard, and platy to brittle, siliceous shale. These units are widespread in a series of eastern-plunging anticlinal and synclinal folds associated with the Sisar and Cayetano Fault zones, and are also very susceptible to landsliding, especially along northern-facing slopes, especially during a moderate to severe earthquake event and/or extreme rainfall event.

Early Miocene marine The Sisquoc Formation (Ts_q) conformably overlies the Monterey Formation and is a sedimentary geologic unit widespread in Southern California, both on the coast and in mountains near the coast. Overlying the Monterey Formation, it is of upper Miocene and lower Pliocene age (from about 4 to 6 million years old). The formation consists of claystone, mudstone, siltstone, shale, diatomite, and conglomerates, with considerable regional variation, and was deposited in a moderately deep marine environment at a depth of approximately 500–5,000 feet (150–1,520 meters). Since some of its diatomites, along with those of the underlying Monterey Formation, are of unusual purity and extent, they can be mined as diatomaceous earth. France-based Imerys operates a mine in the Sisquoc and Monterey Formations in the hills south of Lompoc, California, the largest such operation in the world (Dibblee, 1990). Sisquoc Shale consists of a light-gray silty shale or claystone, which is locally slightly siliceous and diatomaceous (Vedder and others, 1969).

The Pliocene Pico formation consists chiefly of six units, five of which consist of light olive-gray and medium bluish-gray siltstone and fine-grained silty sandstone, containing small reddish-brown concretions, and light-colored sandstone and conglomerate (Winterer et al., 1962). In the western part of the area the sandstone and conglomerate constitute a minor portion of the formation. In the easternmost part of the area the converse is true; there the formation consists largely of sandstone and conglomerate. The Pico Formation is distinguished largely by the presence in the Pico of olive-gray soft siltstone, which generally contains small limonite concretions.

The sixth member of the Pico Formation (QT_{pm}) is also known as the “Mudpit Claystone” Member of the Santa Barbara Formation (Yerkes and others 1987; Yeats and Grigsby, 1987; Grigsby, 1988), and is reportedly of early Pleistocene to possibly late Pliocene age. This member is massive to vaguely bedded, gray claystone or mudstone, and may include the QT_{pmc} member. Pleistocene to Holocene surficial units unconformably overlie the Tertiary bedrock units. The oldest Quaternary units in the Santa Paula Peak Quadrangle are dissected gravel and sand sediments along stream channels, older alluvial deposits (Qoa), and older cobble-boulder fan and conglomerate deposits (Qog). Younger deposits consist of alluvium (Qa) in stream and lowland environments, colluvium, and stream wash, and landslide deposits (Qls). Minor artificial fill (af) units also exist within the Santa Paula Peak 7.5-Minute Quadrangle, and is relative to anthropogenic activities, such as roads and structures.

Most of the source materials comprising the sedimentary rocks at the Site are consistent with eroded plutonic rocks (diorite and granite), chert, metamorphosed igneous and sedimentary rocks, and limestone. Detailed analyses of the geology and slope-failure at the Santa Paula Peak 7.5-Minute Quadrangle can be reviewed at http://gmw.consrv.ca.gov/shmp/download/evalrpt/spp_eval.pdf.

Due to the fine-grained nature of the sediments discussed above within the steep hillsides, erosion and/or landsliding contributes fine-grained sediment to storm water discharges from the site. The fine-grained nature of the marine-derived sediments is responsible for the elevated TSS, SC, and TDS concentrations within storm water discharges in the Ojai Lease.

4.2 Site Geochemistry and Atmospheric Deposition Results in Elevated SC and pH readings as well as Higher Concentrations of TDS and Dissolved Metals

As discussed in the regional geology section above, most of the bedrock at the Site consists of marine sandstone and shale, with the exception of the Sespe Formation, which is terrestrial in origin. The majority of the site bedrock is of marine origin, with very high concentrations of soluble salts, including halite or table salt (NaCl), Drever (1988), and most of the sedimentary rocks contain calcium carbonate cement, as both dolomite and limestone (Tan et al., 2003 and Dibblee, 1988).

SC is the measurement of the electrical conductivity or salinity of the saturated soil and/or runoff water. Conductivity is the reciprocal of electrical resistivity. The more ions a solution contains, the lower its resistivity and hence the higher its conductivity (Drever, 1988). Soluble salts including NaCl and carbonates from eroded bedrock dissolve into the stormwater at the Site and significantly increase SC. The levels of SC are further exacerbated by droplets of sea water that are deposited on the ground surface by on-shore winds at the Site (Drever, 1988). When the soluble salts such as NaCl and carbonates present within the eroded bedrock and saline soil at the Site become dissolved by rainwater, stormwater runoff results in high SC and TDS concentrations.

Soil alkalinity is a function of the concentration of carbonate (CO_3) and sodium carbonate (Na_2CO_3) as a result of natural weathering of the feldspar-rich silt and fine sand present at the subject site (Nesse, 1986). Feldspar and quartz-rich sediments are present within the sedimentary rocks are arkosic and fine-grained in nature. The primary source of sodium in sedimentary rocks is sodium-rich feldspars, mica, and pyroxenes, such as plagioclase, nepheline, sodalite, biotite, and hornblende, common minerals in rhyolite and dioritic granites, and metamorphosed diorites and granites (Nesse, 1986). The non-marine and marine bedrock units contain remnants of eroded diorites and granite bedrock from igneous and metamorphic rocks, based on the arkosic sandstone mapped at the Site. When these minerals chemically weather in the presence of lime or carbonates, they form Na_2CO_3 . When Na_2CO_3 dissolves in water, it dissociates into 2Na^+ and CO_3^{2-} . The sodium carbonate reacts with water to produce carbon dioxide (CO_2) and sodium hydroxide (Na^+OH^-), which is alkaline and generates high pH values, often in excess of 8.5.

In a study conducted by Dixon et al. (2009), research was focused on linked climate, Saprolite (chemically weathered rock) weathering, and erosion within the Sierra Nevada in non-glaciated areas to quantify chemical weathering in both the soil and Saprolite, and link weather to rates and process of down-slope soil transport. Since the provenance of the sediments within the sedimentary rocks was derived from plutonic eroded rocks, such as granite, the Dixon et al. study

was compared to the Site. In the elevated terrain with steep slopes, their findings indicated a strong relationship between physical erosion and chemical weathering. Others (Rieber et al., 2004) suggest physical erosion sets the pace of chemical weathering in soil-mantled terrain.

Iron compounds are the primary coloring agents in Saprolites (and the eroded sediments derived from Saprolites) at most outcrops. The color is directly related to the mineralogy and particle size of the sediment (Hurst, 1977). Submicron-sized goethite [$\text{FeO}(\text{OH})$] is yellow and coarse goethite is brown. Submicron-sized hematite [Fe_2O_3] is red and coarse hematite is gray to black in color (Hurst, 1977). The light red to gray tan color of the soil suggests iron is present within the soil from weathered minerals.

Fine-grained sediments found at the Site such as silt and fine-sand contain naturally-occurring metals, especially arsenic, cobalt, copper, iron, lead, nickel, vanadium, and zinc as weathered products from erosion of granitic bedrock mass. As the rock and water cycles work together to erode the Earth's surface through mass wasting processes, bedrock is mechanically and chemically weathered to become clay, silt, sand, and gravel, while the minerals with the bedrock are released into the environment as ions and chemical cements (Drever, 1988).

The soil samples collected as part of this study were from near the ground surface, where reduction-oxidation buffering is occurring. A system is buffered with respect to reduction and oxidation processes if oxidizable or reducible compounds are present, which prevent a significant change in potential energy (pe) in response to additions of small amounts of strong oxidizing or reducing agents (Drever, 1988). As long as free oxygen is present, pe remains high, which creates an oxygenated environment; therefore, the ground surface at the site is oxygenated. During rainfall events, the pH of the rainwater varies from 5.8 to 6 (slightly acidic), which aids in chemical weathering of the bedrock and sediments. The resulting weathered sediments are then incorporated into the stormwater run-off as dissolved ions or finely divided particulates. Addition of organics into the process (leaves, dead animals, etc.), can remove excess oxygen in the water and increases the dissolution of salts, carbonates, and metals into the run-off (Drever, 1988).

Precipitation falling onto the near-shore ground surface consists of H_2O containing a wide range of dissolved substances. The main dissolved material is sea salt. In addition, when waves break on shore, fine droplets of seawater are dispersed into the atmosphere. The water evaporates, leaving a solid aerosol particle, which is transported by winds until either deposited onto the on-shore ground and/or dissolved by rain (Drever, 1988). The low pH (acidic) rainwater dissolves adsorbed NaCl and carbonates within Marine bedrock and increases the NaCl concentrations within the rainwater run-off, which also increases the SC and TDS concentrations of stormwater runoff, since TDS is the summation of all dissolved ions in solution (Fetter, 1994).

5.0 Site Reconnaissance, Sampling and Analytical Results

5.1 Site Reconnaissance

On May 20, 2015, a *GeoSolve, Inc.* field geologist and the Site operator conducted a site reconnaissance of the Site in order to visually document vegetation, roads, drainages, landslides and other soil erosional features, and Site facilities. Digital pictures of the site reconnaissance are attached as Appendix A.

Mass wasting was observed along the vegetated hillsides as massive deep-seated active landslides. Adverse bedding of the geologic units appeared to exacerbate landsliding; however, landsliding was also observed along bedding of sedimentary rocks dipping into the hillsides.

Rill-type erosion was also observed along naturally occurring slopes greater than 2:1 (vertical:horizontal), especially on steep slopes near drainages. Most of the sediment observed along the channels and drainages appeared to be silt to fine- and medium-grained sand. Very minor amounts of clay were observed along the hill-slopes and minor clay was observed within the base of the drainages, especially within the catch basins as a thin crust overlying the sandy sediment.

Extreme erosion was observed along most slopes and drainages; however, the majority of the landsliding was observed along the southwesterly sloping Santa Paula Peak ridgeline and the northerly-sloping Sulfur Mountain ridgeline, which were within and immediately above the lease boundary. Sediment loading initiates from the elevated hill-tops and accelerates down slope and funnels into the drainages, which discharge into Santa Paula Creek. The NALs detected within storm water discharges occurring at the Site is naturally occurring and will continue unabated due to the low cohesion of granular soil, natural springs, and gravitational force of steep slopes at the Site. The active landsliding observed at the Site was somewhat mitigated by vegetated slopes.

5.2 Sampling Activities

On May 20, 2015, a *GeoSolve, Inc.* field geologist visited the site in order to randomly collect eleven (11) surficial-soil samples from the Site. The soil samples were randomly collected by *GeoSolve, Inc.* at variable locations to depict different geological settings and native or non-native conditions. Eight of the soil samples were collected using laboratory supplied and clean glass 4 ounce jars and stainless steel liners for laboratory analyses and three (3) of the soil samples were placed within zip-lock plastic bags for material testing. Each sample location was recorded using a portable GPS device. Sample locations are more fully described in Table 1 below and are shown on Figures 1 and 2.

Soil samples OJ-1 through OJ-8 were capped, labeled, and placed in a pre-chilled ice chest for temporary storage. The three split-soil samples collected for material testing (OJ-1, OJ-4, and OJ-6) were sealed, labeled and placed within a box for temporary storage.

Table 1
Soil Sample Locations

Sample ID	Latitude	Longitude	Sample Area Description
OJ-1	N34.433053	W119.138031	Ojai Tank Battery – Hamp Lease
OJ-2	N34.425896	W119.144101	Ojai Tank Battery – Hamp Lease
OJ-3	N34.424934	W119.137200	Hamp Lease
OJ-4	N34.434038	W119.098745	Hamp Lease
OJ-5	N34.431232	W119.103470	Silverthread Lease
OJ-6	N34.433687	W119.080861	Ferndale Lease
OJ-7	N34.435594	W119.085264	Ferndale Lease
OJ-8	N34.424384	W119.049937	Timber Lease

During soil sampling activities, the exposed soil and bedrock at the Site was observed to be dark brown sandy clay with organics to brown gravelly sand with silt with bedrock fragments.

5.3 Laboratory Methods

Soil samples OJ-1 through OJ-8 were transported under chain-of-custody documentation to McCampbell Analytical, Inc., a California State-certified hazardous waste testing laboratory (Certification No. 1644), of Pittsburg, California and split soil samples OJ-1, OJ-4, and OJ-6 were submitted under chain-of-custody documentation to Berlogar Stevens and Associates in Pleasanton, California. Soil samples OJ-1 through OJ-8 were analyzed by McCampbell Analytical, Inc. for specific conductivity, salinity, pH, chloride, and metals antimony, arsenic, barium, beryllium, beryllium, cadmium, chromium, cobalt, copper, lead, mercury, molybdenum, nickel, selenium, silver, sodium, thallium, vanadium, and zinc using Environmental Protection Agency (EPA) Methods CATest424m, SM2520B, SW9045D, E300.0, and SW6020.

Split soil samples OJ-1, OJ-4, and OJ-6 were submitted for grain size distribution with hydrometer to Berlogar Stevens and Associates of Pleasanton, California, using ASTM D422.

5.4 Laboratory Analytical and Material Testing Results

Laboratory analytical results are summarized on Table 2, Summary of Analytical Results of Soil Samples, and the McCampbell Analytical, Inc. Laboratory Analytical Reports are attached to this report as Appendix B.

Specific conductivity ranged from 35.6 microhms per centimeter ($\mu\text{mhs/cm}$) to 690 $\mu\text{mhs/cm}$ in sample OJ-5; chloride ranged from not detected (less than 10 milligrams per kilogram [mg/Kg]) to 36 mg/Kg; and pH values ranged from 3.76 (sample OJ-5) to 8.39 (sample OJ-3). Silver was not detected in any sample analyzed (less than 0.5 mg/Kg). Antimony was detected at concentrations ranging from not detected (less than 0.5 mg/Kg) to 7.1 mg/Kg (in sample OJ-2). Arsenic was detected at concentrations ranging from 2.7 mg/Kg to 14 mg/Kg. Barium was detected at concentrations ranging from 33 mg/Kg to 800 (sample OJ-7). Beryllium was

detected at concentrations ranging from 0.55 mg/Kg to 1.3 mg/Kg (sample OJ-6). Cadmium was detected at concentrations ranging from not detected (less than 0.25 mg/Kg) to 40 mg/Kg (sample OJ-2). Chromium was detected at concentrations ranging from 9.2 mg/Kg to 130 mg/Kg (sample OJ-2). Cobalt was detected at concentrations ranging from 5 mg/Kg to 17 mg/Kg (sample OJ-6). Copper was detected at concentrations ranging from 9.2 mg/Kg to 46 mg/Kg (sample OJ-2). Lead was detected at concentrations ranging from 6 mg/Kg to 17 mg/Kg (sample OJ-6). Mercury was detected at concentrations ranging from not detected (less than 0.05 mg/Kg) to 0.083 mg/Kg (sample OJ-3). Nickel was detected at concentrations ranging from 8 mg/Kg to 210 mg/Kg (sample OJ-2). Selenium was detected at concentrations ranging from not detected (less than 0.5 mg/Kg) to 2.7 mg/Kg (sample OJ-5). Sodium was detected at concentrations ranging from not detected (less than 100 mg/Kg) to 1,300 mg/Kg (sample OJ-5). Thallium was detected at concentrations ranging from not detected (less than 0.5 mg/Kg) to 0.97 mg/Kg (sample OJ-2). Vanadium was detected at concentrations ranging from 25 mg/Kg to 410 mg/Kg (sample OJ-2) and Zinc was detected at concentrations ranging from 28 mg/Kg to 270 mg/Kg (sample OJ-2).

The particle size distribution using sieve and hydrometer analyses indicated the soil samples were sandy clay (OJ-1) to silty sand (OJ-4 and OJ-6). Minor gravel was realized in sample OJ-6. Erodibility factors were calculated for each sample and are summarized on Table 3, Soil Erodibility Factors. Copies of the sieve – hydrometer analyses are attached to this report as Appendix C.

Table 3
Soil Erodibility Factors

Sample ID	ASTM – USCS Scale	Erodibility Factor (K)	% Clay
OJ-1	Sandy Clay (CL)	0.28	32.4
OJ-4	Silty Sand (SM)	0.32	11.4
OJ-6	Silty Gravelly Sand (SM)	0.28	28.7
<i>Average</i>	---	<i>0.29</i>	<i>24.2</i>

6.0 Discussion of Results

The chemical constituents analyzed were averaged and 95% upper confidence levels (UCLs) were calculated using the EPA computer program ProUCL Version 4.02 for the chemical constituents' salinity, pH, chloride, SC, sodium and CAM 17 metals. The 95% UCL values for antimony, beryllium, molybdenum, selenium, silver, and thallium were not calculated since these chemical constituents were not detected in all sixteen soil-samples analyzed. In addition, the 95% UCL for barium was not calculated since barium is a ubiquitous element.

The averaged concentrations and 95% UCL concentrations are shown on Table 2 and the calculation sheets are attached to this report. Generally, averaged results were slightly too moderately lower in concentration than calculated 95% UCL concentrations. The 95% UCL concentrations are the statistically calculated values generated for the ProUCL computer

program and the averaged concentrations are simply the calculated mean. The variance between the average concentration and 95% UCL concentrations are the background concentration ranges for the chemicals analyzed at the site. Averaged and 95% UCL concentrations are shown on Table 4.

Table 4
Averaged and 95% UCL Concentrations of Salinity, pH, SC and Metals

Chemical Constituent	Average (mean)	95% UCL
Salinity (mg/Kg)	136.49	280.3
pH	6.85	7.80
Chloride	16.38	25.22
SC (µmhos/cm)	222.4	375.3
Antimony (mg/Kg)	1.78	---
Arsenic (mg/Kg)	6.64	7.81
Barium (mg/Kg)	290.5	453.7
Beryllium (mg/Kg)	0.83	0.99
Cadmium (mg/Kg)	8.78	24.24
Chromium (mg/Kg)	46.02	72.8
Cobalt (mg/Kg)	8.23	11.32
Copper (mg/Kg)	25.65	33.44
Lead (mg/Kg)	9.76	12.04
Molybdenum (mg/Kg)	13.12	43.72
Nickel (mg/Kg)	66.83	115
Selenium (mg/Kg)	1.03	2.12
Sodium (mg/Kg)	225	1,386
Thallium (mg/Kg)	0.27	---
Vanadium (mg/Kg)	128.88	218.1
Zinc (mg/Kg)	105.63	159

The most significant findings of these calculations are the elevated concentrations of cadmium, molybdenum, salinity, SC and sodium concentrations within the soil at the Site, along with moderate concentrations of arsenic, chloride, nickel, vanadium and zinc. Low concentrations of metals beryllium, chromium, cobalt, copper, lead, selenium, and trace concentrations of antimony and thallium. Based on the study by Hurst (1977), the sediment and bedrock were gray to modeled yellow to red in color, which indicates high ferric concentrations. The naturally occurring iron in the sediment is most likely generated from chemical weathering of distant plutonic source bedrock.

The background concentration of SC for the Site was calculated at concentrations ranging from 35.6 µmhos/cm to 3690 µmhos/cm in soil. Once the rainwater, containing dissolved NaCl, carbonates, and dissolved ion solutes from the eroded bedrock, combine to increase the SC, which would be much more elevated than detected in soil.

Antimony, beryllium, molybdenum, and especially selenium, according to the United States Geological Survey (<http://energy.cr.usgs.gov/TraceElements/monterey.html>), are associated with high carbon sources in bedrock, such as petroleum hydrocarbons. These trace metals were detected at very low to moderate concentration in all surficial soil sample analyzed, suggesting the hydrocarbon source bedrock unit, the Monterey (Modelo) Formation, has natural oil seeps in the Monterey Formation. Oil seeps were observed near the Hamp Lease along Highway 150. The other detected metals indicate the presence of natural background concentrations of chemically weathered minerals in soil, which are incorporated into storm water run-off discharges from the site.

Based on the particle size analyses conducted on samples OJ-1, OJ-4, and OJ-6, and summarized in Table 3, clay was present in all samples at percentages ranging from 11 to 32. The majority of the sediments sieved from the Site contain silt and fine sand, with minor gravel in OJ-6. Since the surficial soil is mostly comprised of silt and fine to medium sand, soil erodibility is high to very high. An average soil erodibility factor (K) was calculated at 0.29 and the average percent clay in the soil was calculated at 24.2%. The low to moderate percentage of clay with the surficial soil will provide low cohesion of the soil, and result in the observed significant erosion and landsliding at the site.

Based on the analytical data summarized above in soil samples OJ-1 through OJ-8, rainwater flowing over the exposed soil at the Site has an acidic and basic pH, which dissolves soluble salts in the soil matrix. As the rainwater continues to flow over soil surfaces at the site and quickly becomes storm water run-off, additional soluble salts are dissolved into the discharge, resulting in excessive SC and TDS concentrations from natural sources. Since the soil is granular in nature, storm water run-off also contains excessive TSS, as further discussed below.

In addition to the high levels of soluble salts in eroded soil discussed above, the constant influx of sea salt from sea water as an aerosol particle also increases the SC concentrations in surficial storm water run-off. In moderately to highly alkaline soil solutions, pH rises to values above neutral (>7) and the run-off water remains alkaline (Drever, 1988). The alkaline nature of the soil solutions buffers storm water run-off discharges and creates a stable solution for elevated SC and TDS concentrations, which does not react with other solutes to reduce these naturally occurring elevated concentrations of SC and TDS.

If soil contains both calcium (Ca^{2+}) and aluminum (Al^{3+}), cation-exchange reactions strongly affect the relationships amount partial pressure of carbon dioxide (PCO_2), pH, and Alkalinity (Drever, 1988). If any hydrogen ions (H^+) are introduced by dissolution of acids and hydroxyl compounds (such as carbonic acid [H_2CO_3] in rainwater or Gibbsite [$\text{Al}(\text{OH})_3$], a by-product of weathered aluminous minerals such as feldspar), they tend to be removed by ion exchange, generating Ca^{2+} ions in solution. Thus, the introduced H^+ ions would be largely converted into Ca^{2+} ions, and the change in pH would be minor, as long as ample supply of weathered feldspars and calcium carbonates are available in a buffered solution (Drever, 1988).

Excess Ca^{2+} ions, with carbonate ions, sodium ions (Na^+) and chloride ions (Cl^-) significantly increase the SC and TDS concentrations within storm water run-off effluent discharges from the subject site as discussed by Dixon et al. (2009). The slightly alkaline storm water discharge from

the site supports this observation, along with the ample supply of sediments derived from plutonic and calcium-carbonate rich rocks. SC provides a general indication of TDS concentrations in most clear water conditions; however, storm water discharges from the Site generates very high TSS concentrations, which increases both SC and TDS concentrations.

Erosion of the steep slopes and subsequent landsliding of the fine-grained sediments discussed above delivers fine-grained sediment to storm water discharges at the site. It is estimated that at least 431 tons of sediment per acre per year is generated from landsliding processes and other erosion-process at the Site in the non-industrial areas. The fine-grained natural (silt to medium grained-sand) generated from natural erosion due to landsliding is responsible for the TSS concentrations within storm water discharges. The following is a conservative calculation of soil loss and rainfall contributing to TSS discharging from the Site.

Using the average rainfall data for Ojai, California (<http://www.idcide.com/weather/ca/ojai.htm>), the average rainfall is 21.79 inches per year. Over one acre of land, this constitutes approximately 79,097.7 cubic feet of water, or 591,651 gallons of water. Gallons can easily be converted into liters by multiplying gallons by 3.785 to obtain 2,239,399 liters of water. As for the sediment loss, 1,021 tons is equal to 2,042,000 pounds or 926,235 Kg of soil, which is also equivalent to 926,235,000,000 milligrams (mg) of soil. The anticipated TSS concentration for a daily discharge at the Site is realized by dividing by 365. Therefore, using the following equation below, the average TSS via soil loss per acre per year discharging from non-industrial occupied areas at the Site is as follows:

$$\frac{926,235,000,000 \text{ mg}}{2,239,399 \text{ L} * 365 \text{ days}} = 1,133 \text{ mg/L of TSS per acre/year.}$$

Naturally occurring SC and TDS concentrations generated from naturally occurring conditions has been documented in a nearby reference site, the Malibu Creek watershed, which is discussed below.

Any exceedances of discharge standards are not related to industrial operations at the Site including any legacy pollutants from prior human activities.

Most of the roadways on the Site were unpaved and approximately 75% of the roadways were not paved, but covered with gravel. Minor rilling was observed along the lower grade of roadways apparently due to the extreme topographic relief, sandy nature of the soil, and less rilling was observed in clay-rich soil.

The industrial facilities situated on the Site appeared to be either cut into or on-top of hillsides, or on naturally level areas. No significant rilling and/or erosion were observed associated with the oil and gas field development. Minor to moderate erosion was observed along the paved roadways along steep slopes (greater than 33 percent grade) as side accessory rilling. Furthermore, the CAM 17 metals and sodium detected within soil samples OJ-1 through OJ-8 (summarized on Table 2), indicate the metals are derived from the site's geology and soil mineralogy related to chemical weathering of bedrock and natural oil seeps.

The levels of pollutants of concern measured at the site are comparable to the reference site which exhibits similar natural conditions and for which there had been no history of anthropogenic activities.

The Malibu watershed was used as a Reference Site, which is situated near the Site. Historic concentration data for SC, pH, and TDS obtained from storm water sampling along creeks within the Malibu watershed were compared between the Reference Site and the subject Site. The Monterey (Modelo) Formation was determined to impact stream-water by significantly increasing SC levels and TDS concentrations compared to other streams traversing volcanic and metamorphic rocks. The authors of this Report conclude elevated TSS concentrations at both Sites are the result of naturally occurring high erosion rates of the tectonically uplifted mountains by mass wasting processes, and not caused by any surface industrial activities at the Site.

The Analysis of Malibu Creek Watershed report is attached to Appendix D, which includes study location maps. Elevation ranges are similar to the subject Site, as well as extensive landsliding. The main difference between the Malibu Creek watershed and the subject Site is geology. Igneous and metamorphic rocks outcrop along the Malibu Creek watershed. According to the Las Virgenes Municipal Water District (LVMWD), the Malibu Creek watershed is not exposed to mining, forestry, or other anthropogenic activities.

The LVMWD conducted a study comparing the geology of the Monterey (Modelo) Formation to water quality within the nearby Malibu Creek watershed (<http://www.lvmwd.com/Home/ShowDocument?id=2273>). The Malibu Creek watershed is situated east and southeast of the subject site near Thousand Oaks, California, and is similar in geologic setting, climate, and topography to the Site. The Malibu Creek watershed area is geologically complex, with volcanic and Tertiary marine and non-marine sedimentary rock units. According to the LVMWD, several studies have attempted to quantify anthropogenic pollutant sources and their impact on aquatic life by comparisons to more-natural reference sites in undeveloped areas within the watershed or nearby coastal streams. However, aside from noting geology can affect water quality, none of these studies included any analysis of local geology or evaluated its effects on their water quality results. A recent regional water quality study by Stein and Yoon (2007) did note differences in native water quality in drainages with sedimentary versus those with igneous or metamorphic rock. However, their study did not investigate differences in water quality between drainages with different types of sedimentary rock such as marine and non-marine sedimentary rock, or sedimentary petroleum source rock, all of which have substantial deposits and exposures in the Malibu Creek watershed. The LVMWD assessment found clear evidence of sub-standard water quality associated with one geologic formation in particular, the Monterey/Modelo Formation.

The LVMWD assessment evaluated the elemental composition of Monterey/Modelo Formation rocks indicates the composition of major and minor elements and some other constituents of four samples of freshly-exposed (graded) Monterey/Modelo Formation rock from the upper watershed north of Thousand Oaks Boulevard on undeveloped land in the foothills north of the City of Westlake Village. Of the 34 elements analyzed, 13 varied across the analyzed rock samples by 1-2 orders of magnitude in samples deliberately selected on the basis of large visual

differences in the field and widely separated stratigraphic sections. Both the magnitude of variation and the elements exhibiting increased concentration are consistent with exposure to the Monterey Formation in Ventura County. With the exception of cadmium, samples of local Monterey/Modelo Formation rock tended to be lower in metals than in Monterey/Modelo Formation rock sampled in Santa Barbara County, where the Monterey/Modelo Formation is actively tapped for petroleum.

In the LVMWD study, Malibu Creek SC was the highest of any measured among Santa Monica Mountain coastal streams, and was brackish year-round ($SC > 1,500$ [microsiemens per centimeter $\{\mu S/cm\}$, which are equivalent to $\mu mhos/cm$; Masters and Ela, 2007] over the 1998 – 2009 period of record from the highest northern tributaries in the foothills north of the Highway 101 to the lower reaches in the City of Malibu, except during large rain events, when SC fell to $\sim 1,200 \mu S/cm$. Average SC from 1998 to 2009 ranged from $\sim 3,300 \mu S/cm$ in the creek's northern headwaters (range 2,150 - 5,200 $\mu S/cm$) to $\sim 1,890 \mu S/cm$ (range 1,090 to 3,690) in the lower creek about $\frac{1}{2}$ mile above Malibu Lagoon. Even during three large rain events in February 2001, 2005 and 2009, SC in Malibu Creek did not fall below 1,200 $\mu S/cm$ at any station. Two tributaries to Malibu Creek, Carlisle Creek and upper Cold Creek (located on the western and eastern limits of the watershed, respectively) are exceptions to the high SC levels and large seasonal variation found in other tributaries to Malibu Creek. They drain areas with no known exposures of the Monterey/Modelo Formation). Carlisle Creek's drainage consists almost entirely of Conejo Volcanics with average SC of 510 $\mu S/cm$ (range 272 – 780). Mean SC in upper Cold Creek (which drains primarily the Conejo Volcanics and Topanga Canyon and Calabasas Formations) was 686 $\mu S/cm$ (range 230 – 762) from 1998-2009. Cold Creek SC was similar to SC in Arroyo Sesquit Creek, a small coastal drainage with no known Monterey Formation exposures, where mean SC during 1998 – 2009 was 989 $\mu S/cm$ (range 752 – 1,162). Mean SC was higher in two other Santa Monica Mountains creeks (Lachusa and Solstice Creeks) that drain some Monterey/Modelo Formation rock. There is a strong seasonal component to SC in Malibu Creek, peaking at the end of the dry season in any given year. From 1998 to 2009, SC in the lower reaches below Rindge Dam peaked in September to early November at between 2,200 to 2,700 $\mu S/cm$, depending on the year. Late summer SC levels in the upper creek and its northern tributaries was significantly higher than SC in non-Monterey Formation tributaries, with peak values $> 3,500 \mu S/cm$. For comparison, SC in municipal potable and recycled water in the watershed rarely exceeds about 300 and 800 $\mu S/cm$, respectively (LVMWD records).

The LVMWD identified unusually high SC and metals are associated with large exposures of Monterey/Modelo Formation, compared to relatively low concentrations of SC and metals in non-Monterey/Modelo Formation exposures. These findings are similar to those detected in soil at the subject Site, which suggests soluble salts are entrained in storm water run-off from exposed soil containing elevated salt and metal concentrations.

7.0 History of Anthropogenic Activities Up-Stream from Site

According to Mindat.org, one existing gypsum mine is situated up-stream from the subject Site (<http://www.mindat.org/loc-98419.html>). This mine is named the Ojai Gypsum Mine and mines gypsum, which has the chemical mineral formula of $CaSO_4 \cdot H_2O$. Weathering of gypsum can

significantly decrease pH in the soil and surface water due to the formation of hydrochloric acid during rain events. Furthermore, no logging has been or is being conducted up-stream of the Site according to the United States Department of Agriculture – Department of Forestry (<http://www.fs.usda.gov/lpnf/>).

8.0 Conclusions

Laboratory analytical results of randomly collected soil samples OJ-1 through OJ-8, and the particle size testing results of soil samples OJ-1, OJ-4, and OJ-6 compared to the natural geologic conditions at the Site yielded the following:

- Background pH of the shallow soil samples was calculated between 6.85 and 7.80, with a low pH of 3.76 in sample OJ-5 (near the Ojai Gypsum Mine) and a pH of 8.39 in sample OJ-3;
- Background SC concentrations of the shallow soil samples was calculated between 222 $\mu\text{mhos/cm}$ to 375 $\mu\text{mhos/cm}$, with a low concentration of 35.6 $\mu\text{mhos/cm}$ at sample OJ-8 and a higher SC concentration of 690 $\mu\text{mhos/cm}$ at sample OJ-5;
- Moderate concentrations of chloride and moderate to high concentrations of sodium in the shallow soil indicated the presence of salt within eroded bedrock due to erosion and weathering activities. These dissolved solutes will increase TDS during a storm water event.
- Soil loss on the industrial areas (100 acres) accounts for only 0.1% of the total soil loss on the entire 3,400-acre Site;
- Approximately 1,133 mg/L of TSS is anticipated to be naturally discharged per acre per daily discharge at the non-industrial occupied areas at the Site; and
- Background metal concentrations of the shallow soil samples summarized in Tables 2 and 4 indicated elevated concentrations of molybdenum,
- The most significant findings of the laboratory analyses of shallow soil samples were the elevated concentrations of cadmium, molybdenum, salinity, SC and sodium at the Site, along with moderate concentrations of arsenic, chloride, nickel, vanadium and zinc. Low concentrations of metals beryllium, chromium, cobalt, copper, lead, selenium, and trace concentrations of antimony and thallium were also detected. These metal, chlorite, pH, salinity, and SC concentrations indicate the presence of natural oil seeps, along with the chemical weathering of marine sedimentary rocks and gypsum, which account for the variability of the chemical constituents analyzed in the shallow soil samples from the Site. Other background metals are summarized on Table 2 and averaged concentrations on Table 4.

GeoSolve, Inc. concludes the following from this investigation:

1. Based on the moderate to elevated SC concentrations in soil, which has been demonstrated to be generated by erosion and weathering of marine sedimentary rocks of Miocene to Pliocene age, which were deposited in shallow and deep ancient marine environments. Erosion and weathering of these marine sedimentary rocks have generated elevated soluble salts in exposed soil. Natural chemical weathering of feldspar-, and calcium-sulfates (gypsum), and NaCl-rich sediments, the SC readings in storm water run-off are anticipated to be significantly elevated.
2. As demonstrated in this Report, the Site is subject to natural erosion at excessive rates, which generates elevated natural concentrations of SC, TDS, and TSS, which are not associated with anthropogenic activities.
3. The elevated concentrations of SC and TDS is similar to the Malibu Creek watershed bisecting the Monterey (Modelo) Formation, and although significantly elevated concentrations of SC and TDS have been historically recorded for storm water discharges from the Site, these data are similar to those conditions at the Malibu Creek watershed and represent background concentrations.
4. Elevated molybdenum concentrations and low selenium concentration detected in shallow soil samples from natural background locations around the Site indicate the presence of natural oil seeps on the Site.

NBDTR Investigation Conclusions

Any exceedances of discharge standards are not related to industrial operations at the Site including any legacy pollutants from prior human activities.

The levels of pollutants of concern measured at the site are comparable to the reference site which exhibits similar natural conditions and for which there had been no history of anthropogenic activities, with the exception of Ojai Gypsum Mine and natural oil seeps.

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<http://www.fs.usda.gov/lpnf/>



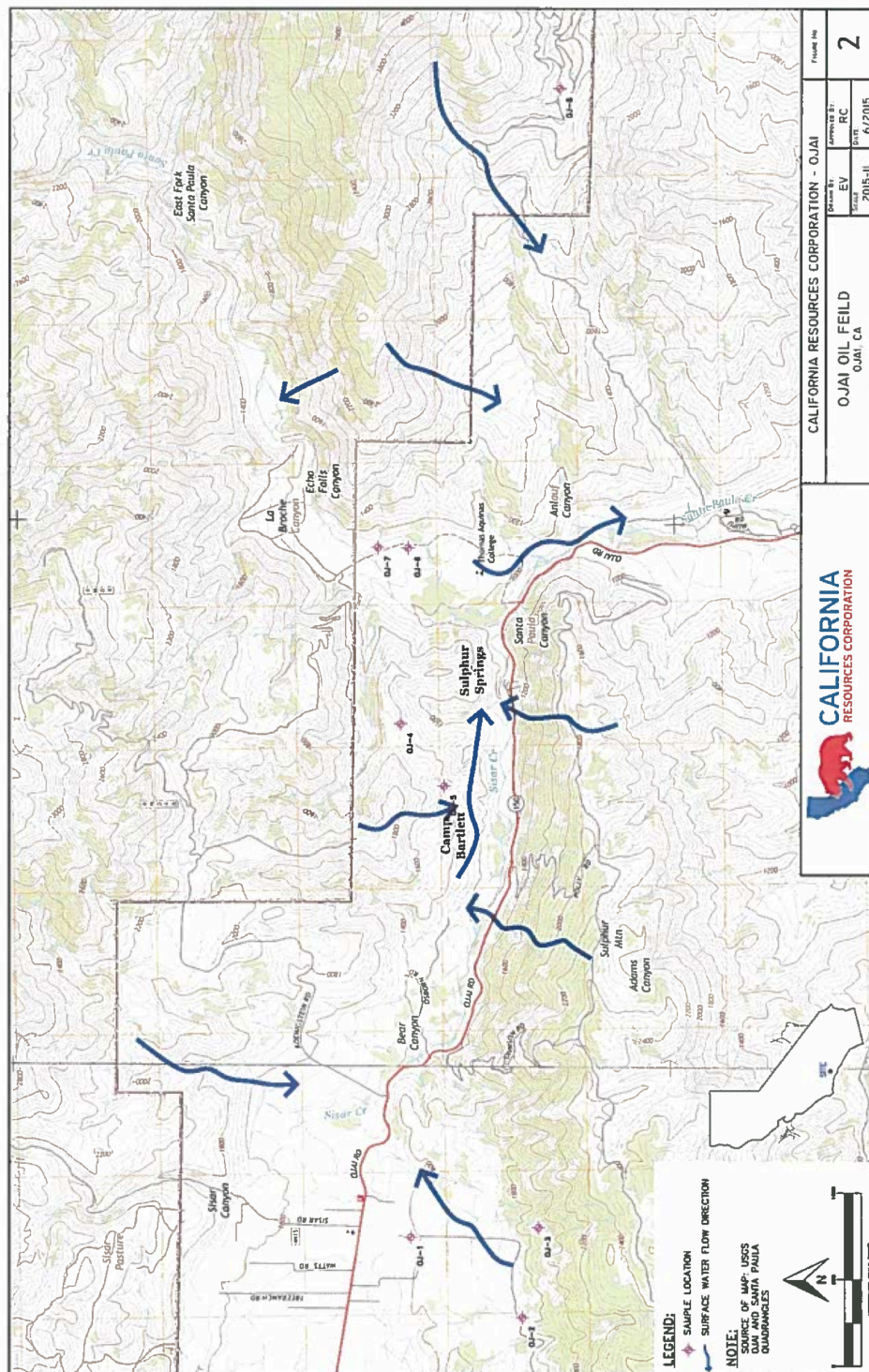


Table 2 - Laboratory Analytical Results of Soil Samples - May 20, 2015

CRC - Qjai Lease												
Sample ID	Salinity (mg/Kg)	pH	Conductivity (umhos/cm)	Chloride (mg/Kg)	Antimony (mg/Kg)	Arsenic (mg/Kg)	Barium (mg/Kg)	Beryllium (mg/Kg)	Cadmium (mg/Kg)	Chromium (mg/Kg)	Cobalt (mg/Kg)	
OJ-1	123	6.85	193	23	1.5	7.5	320	0.78	6.2	42	10	
OJ-2	45.5	7.73	71.1	17	7.1	14	350	1	40	130	7.2	
OJ-3	46.4	8.39	72.4	12	3.6	11	360	0.81	16	64	6	
OJ-4	195	6.38	305	36	<0.5	4.1	100	0.55	<0.25	9.2	6.8	
OJ-5	441	3.76	690	20	2.1	14	280	0.66	7.5	62	5	
OJ-6	<25	6.53	36.1	<10	<0.5	6.3	81	1.3	<0.25	19	17	
OJ-7	241	7.46	376	11	<0.5	6.6	800	0.87	0.59	31	9	
OJ-8	<25	7.71	35.6	12	<0.5	2.7	33	0.71	<0.25	11	4.8	
Average	136.49	6.85	222.40	16.38	1.7875	8.28	290.5	0.835	8.78625	46.03	8.23	
95% UCL	280.3	7.8	375.3	25.22	—	11.15	453.7	0.99	24.24	72.8	11.32	

Sample ID	Copper (mg/Kg)	Lead (mg/Kg)	Mercury (mg/Kg)	Molybdenum (mg/Kg)	Nickel (mg/Kg)	Selenium (mg/Kg)	Silver (mg/Kg)	Sodium (mg/Kg)	Thallium (mg/Kg)	Vanadium (mg/Kg)	Zinc (mg/Kg)	
OJ-1	29	11	0.055	4.8	90	1.8	<0.5	120	<0.5	120	100	
OJ-2	46	7.6	0.07	38	210	1.6	<0.5	190	0.97	410	270	
OJ-3	30	6	0.083	18	130	1.6	<0.5	270	0.59	210	170	
OJ-4	12	9.3	<0.05	2.2	9.6	<0.5	<0.5	<0.5	<0.5	19	28	
OJ-5	30	8.7	<0.05	40	39	2.7	<0.5	1300	0.59	160	80	
OJ-6	28	17	<0.05	0.91	20	<0.5	<0.5	<100	<0.5	41	87	
OJ-7	21	11	<0.05	1.1	28	0.56	<0.5	160	<0.5	46	79	
OJ-8	9.2	7.5	0.068	<0.5	8	<0.5	<0.5	<100	<0.5	25	31	
Average	25.65	9.76	0.0085	13.12625	66.83	1.0325	<0.5	255	0.26875	128.88	105.63	
95% UCL	33.44	12.04	—	43.72	115	2.12	—	1386	—	218.1	159	

APPENDIX A
SITE RECONASSIANCE PICTURES



Photo 1A: Ojai Oil Field – Ojai Lease Tank Battery (viewing northeast)

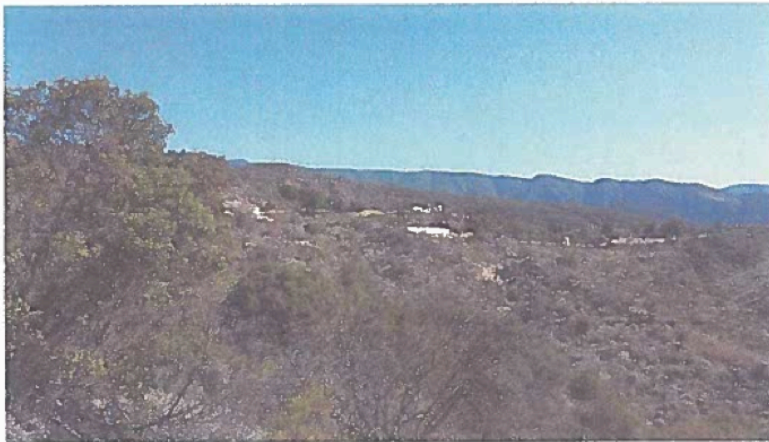


Photo 1B: Ojai Oil Field – Silverthread Lease (viewing east)





Photo 2A: Ojai Oil Field – Hamp Lease oil well (viewing north)



Photo 2B: Ojai Oil Field – Ferndale Lease oil well (viewing south)



Photo 3A: Ojai Oil Field – Timber Canyon Lease (note oil seeps in hillside)

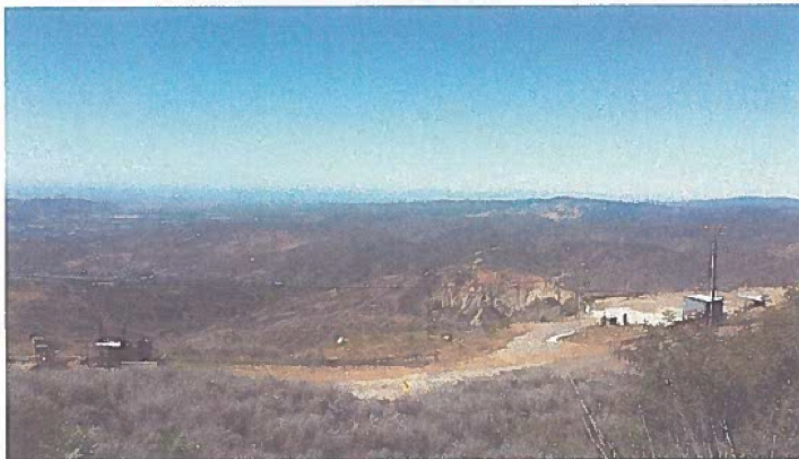


Photo 3B: Ojai Oil Field – Timber Canyon Lease (viewing west)

Regulatory, Update, & Contact Information Regarding This Plan

This spill contingency plan has been prepared pursuant to California Code of Regulations Title 14, Division 2, Chapter 4, Section 1722.9.

Printed copies and/or maps will be updated annually or upon request of the Division of Oil & Gas & Geothermal Resources (DOG/GR).

Any questions or comments regarding this plan should be directed to:

**Mr. Lonnie Brummett
Environmental Specialist
Aera Energy LLC
25401 Hwy 33
Fellows, CA 93224**

Phone 661-665-3102

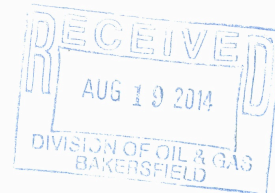
The following Pre-Incident Planning and Emergency Response (PIPER) guidelines are designed for use as a guide for managing specific emergency incidents and for training response personnel. These guidelines have been selected as credible facility events. This list is, however, not all-inclusive. Most incidents will not occur exactly as outlined in the PIPER guidelines and may require changes in response actions.

Each PIPER guideline, along with any attached supporting documentation, should be used for **initial emergency action**. Each PIPER is composed of the following sections (using the acronym **HAZARDS**):

- **H:** Hazard Identification and Recognition.
- **A:** Assessment of Hazards.
- **Z:** Zone of Impact / Zoning.
- **A:** Action Planning.
- **R:** Resources / Reporting
- **D:** Decontamination / Disposal / Documentation
- **S:** Safety Concerns.

This Section includes the following PIPER guidelines:

- 50% Caustic Leak / Release.
- 35% (Moco) Hydrochloric Acid Leak / Release.
- Condensate / Oil Leak / Release.
- Confined Space Rescue.
- DOT Emergency Action Plan Natural Gas Pipelines.
- Earthquake.
- Emergency Medical Incident.
- Hydrogen Sulfide Leak / Release.
- Light Oil Leak / Release.
- Methanol Leak / Release.
- Natural Gas Pipeline Leak / Release.
- Oil Leak / Release.
- Process Fire / Explosion.
- Security Incident.



Section 2

Personal Safety Equipment

Personal Safety Equipment is comprised primarily of hazardous atmosphere detectors and personal protective equipment (PPE) appropriate to the exposure hazards of any emergency response incident and must be available and utilized at all times while potential or actual exposures exist. Except in special circumstances, Aera does not provide hazardous atmosphere detectors or PPE to third-party responders.

Hazardous atmosphere detectors in the form of personal H₂S monitors are components of the basic work uniform at Aera field in the San Joaquin Valley. Meters for the detection of other hazardous atmospheres (reduced O₂, flammable gasses, etc.) are available for checkout from the Safety Department and teams have monitors assigned to operators. PPE for Aera responders is available in warehouses, at select production facility control rooms, carried in company vehicles or from Response Contractors.

For large-scale response operations, PPE (as described in the response event Site Safety Plan) is supplied by the Response Contractor for all responders. Aera's Safety Advisor will verify that sufficient PPE is provided to the workforce by the Response Contractors.

Hazardous Atmosphere Detectors are tested and maintained and most PPE is maintained in accordance with manufacturer's recommendations. Certain consumables (e.g. glasses, goggles, Tyvec suits, etc.) are discarded rather than being the subject of a maintenance program.

Table 2.1 – List of typical Personal Safety Equipment

Hazardous Atmosphere Detectors	Personal Protective Equipment
Personal H ₂ S Detector	Hardhat
Pent-meter (LEL, O ₂ , H ₂ S, CO, SO ₂)	Safety shoes
Color metric Tubes	Coveralls
Photo Ionizer Detector	Safety glasses or chemical splash goggles
	Full-time two-way communications devices
	Chemical resistant gloves
	Chemical resistant clothing
	Chemical resistant safety shoes/boots
	Half face piece, air purifying respirator with appropriate canister or cartridges
	Pressure demand (positive pressure), full face SCBA or airline unit with escape SCBA
	Encapsulating chemical protective suite (TECPS)

**Aera Energy LLC – Well Stimulation Treatment Contingency Plan
Well Failure or Surface Release – Initial Action Checklist**

PRIORITY	ACTION
1	Assess the situation. If safe: - Identify source of release and its potential toxic or combustible nature. - Sound alarm, warn people, and evacuate site, facility, or field if required.
2	Save lives and prevent injuries. - Dial (661)765-1133 (Belridge) or 911 (Ventura/MWSS/Coalinga) to report a serious injury or fire, and obtain assistance as needed. - Don required PPE if necessary. Assist in evacuation of person(s). Provide first aid.
3	Initiate response actions when deemed safe. - Take immediate actions to try to stop the flow of released substances, and contain them if it can be done safely and quickly. Protect public and wildlife and minimize damage. - Report the event to the Manager of Operations or On Duty Supervisor. - Notify cleanup contractor(s) to assist or stand by. - Activate the Incident Response Team. Set up (a) command post(s). - Initiate ICS for a sustained response.
4	Assess situation and make required notifications. - Within 48 hours notify the required agencies. Required Agencies <u>Ventura</u> - District 2 DOGGR - Phone: (805) 654-4761 - State Water Resources Control Board – Phone: (916) 341-5779 - Los Angeles RWQCB – Phone: (213) 576-6600 <u>Belridge / Lost Hills / MWSS</u> - District 4 DOGGR – Phone: (661) 322-4031 - State Water Resources Control Board – Phone: (916) 341-5779 - Central Valley RWQCB – Phone (559) 445-5116 <u>Coalinga</u> - District 5 DOGGR – Phone: (559) 935-2941 - State Water Resources Control Board – Phone: (916) 341-5779 - Central Valley RWQCB – Phone (559) 445-5116 <u>San Ardo</u> - District 3 DOGGR - (805) 937-7246 - State Water Resources Control Board – Phone: (916) 341-5779 - Central Coast RWQCB – Phone: (805) 549 3147 Describe the following information pertaining to the event: - Sequence of events leading to well failure or unintended event. - Depth interval(s) for subsurface well failure or release location (surface). - Chemical composition of treatment fluid being utilized, fluid in the well at the time of failure (subsurface) or composition of fluid released at the surface. - Estimate of the volume lost (subsurface) or released/recovered for surface releases.
5	Minimize damage to the environment. Over-respond and stand down if necessary.
6	Clean up the affected area. Prepare and submit cleanup and restoration plans for government approval.
7	Prepare and submit all spill report forms, as required by the Company and/or agencies, in a timely manner, and consistent with State and federal regulations.

Section 5

Control Equipment

Spill response equipment is comprised primarily of collection, storage, and clean-up equipment. Aera's daily construction and maintenance operations involve the use of multiple pieces of heavy equipment that can be utilized to create temporary collection impoundments for localized spill control and vacuum trucks for collection and temporary storage of spilled fluids. In addition, to utilizing trained, on-site maintenance and construction personnel to respond to spills, Aera contracts with Double Barrel Environmental Services to provide trained spill response personnel and clean-up equipment for larger events.

Table 5.1 lists types of equipment and materials available to Aera personnel for spill response and clean-up activities.

Table 5.1 – List of typical spill response equipment available to Aera

Heavy Equipment	Consumable Response Equipment
Backhoes	Spill Boom
Graders	Sorbent Pads
Bulldozers	Personal Protective Equipment
Vacuum Trucks	Multi-ply trash bags
Portable (Baker) Tanks	Shovels/Hoes/Garden Shears
Dump Trucks	Chemical resistant gloves

Section 8

Inspection Procedures

Following are generic inspection templates for piping and facility inspections. The templates are shortened by operating personnel to include only the sections appropriate for the assigned inspection (e.g. Well String, Dehydration Facility, Water Plant, etc) and entries are only made on the forms when an exception (e.g. leakage requiring a repair that cannot be performed by the inspector, excessive corrosion requiring follow-up by the locations' reliability engineer, etc.) are discovered. Inspection forms are retained onsite in the System of Operating Excellence (SOE) file system.

Annual Pipe Visual Inspection Standard Checklist

Operator performing Line Walk: _____ Pipeline Inspected: _____
 Date of Line Walk: _____ Revision 0.4 9/9/10

Piping Defects		Circle one		Piping Defects (continued)		Circle one	
A.	Any evidence of external corrosion?	Yes	No	T.	Any evidence of missing bolts?	Yes	No
B.	Any evidence of pipe to soil contact?	Yes	No	U.	Any evidence of soil erosion at pipe supports?	Yes	No
C.	Any evidence of external wrap or coating damage	Yes	No	V.	Any evidence of improperly abandoned lines?	Yes	No
D.	Number of road crossings? (enter number in space to right)			W.	Any evidence of other defects?	Yes	No
E.	Any evidence of a crimp or bend in pipe?	Yes	No	X.	Any evidence of missing gas pipeline labels?	Yes	No
F.	Any evidence of improper structural support or improper sleeper support?	Yes	No	Y.	Any evidence of dead legs?	Yes	No
G.	Any evidence of a leak in pipe or fitting?	Yes	No	Buried Section of Piping			
H.	Any evidence of a dent, cuts or gouges in pipe?	Yes	No	A.	Any evidence of missing or broken CP test stations?	Yes	No
I.	Any evidence of clamps installed on pipe?	Yes	No	B.	Any evidence of broken CP straps?	Yes	No
J.	Number of clamps installed? (enter number in space to right and location in comments section)			C.	Any evidence of broken or disconnected CP wires?	Yes	No
K.	Any evidence of irregular fittings?	Yes	No	D.	Any evidence of damage to PVC watering system?	Yes	No
L.	Any evidence of improper line size changes?	Yes	No	E.	Any evidence of missing of damaged pipeline markers?	Yes	No
M.	Any evidence of weld patch?	Yes	No	F.	Any evidence of missing or damaged flange isolation at locations that are protected by CP system?	Yes	No
N.	Any evidence of water ponding with contact with pipe has or could occur?	Yes	No	Pipe Appurtenances			
O.	Any evidence of improper wall thickness pipe or fittings installed in line?	Yes	No	A.	Any evidence of leaks at valves?	Yes	No
P.	Any evidence of weed encroachment?	Yes	No	B.	Any evidence of leaks at chemical injection assemblies?	Yes	No
Q.	Any evidence of pipe strain?	Yes	No	C.	Any evidence of leaks at flange connections?	Yes	No
R.	Any evidence of insulation damage?	Yes	No				
S.	Any evidence of soil placed over pipe?	Yes	No				

Comments:

MONTHLY PRODUCITON FACILITY INSPECTION CHECKSHEET							
Aera Energy LLC Equipment: Location: Facility Name: Date of Inspection: Inspected by:							
Equipment Type	Y = Yes, N = No, NA = Not Applicable						
Berms & Drainage	Items	1	2	3	4	5	Specify Defect & Location
		Evidence of integrity issues in walls or berms (cracks, openings, erosion)					
		Vegetation and weed clearance needed					
		Drain valves in bad condition or not functioning properly					
		Drain valves not locked or sealed					
		Not Adequate capacity remaining - rain filled					
Tanks/Vessels	Items	Sub-team is proposing that this portion of the Prod Facility Checklist be used to satisfy the requirement in AB-1960, 1777.3 for reporting purposes for Monthly Tank Inspections.					
Heater/Treaters		1	2	3	4	5	6
Separators		Evidence of drips, leaks, weeps (Heads, Roof, Shell, & Bottom, Appurtences, and Piping)					
FWKO		Evidence of Corrosion (Heads, Roof, Shell, & Bottom, Appurtences, and Piping)					
ISFs		Evidence Integrity Issues such as cracks, bulges, distortions, or warping					
WEMCOs		Evidence of foundation issues -such as gaps between tank and damaged foundation					
Filters		Evidence of Adequate Drainage (no standing water).					
Fin Fans		Condition of the Insulation Satisfactory (No tears, No evidence of oil, CUI).					
		Inspection of Grounding System (adequately grounded, no leads disconnected)					
		Condition of Associated Piping (Satisfactory)					
		Appurtences (i.e. Manways, Thief Hatch, Gas Blanket, Dikes, Trash Vegetation, CP, Ladders and stairways, Platforms and walkways, Anchor bolts).					
		Signs of Settlement (Foundation)					
Pumps, Piping, Valves, Fittings	Items	1	2	3	4	5	
Manifold		Evidence of drips, seepage, leak, or spill					
Piping		Evidence of inadequate supports, footings, foundations					
Valves		Evidence of Corrosion					
Fittings		Evidence of inadequate pipe coating at soil surfaces and through walls and dikes					
		Piping not properly labeled, Required locks or seals not in place					
Oil/ Injection flowline	Items	Determine if Title 8 covers these lines					
Oil Flow Lines		1	2	3	4	5	
Oil Group Lines		Evidence of leaks or weeps					
Injection Flow Lines		Evidence of Corrosion					
Injection Group Lines							
Gas Gathering/Distribution							
Portable Equipment	Items	1	2	3	4	5	
AWT well test vessel		Drainage pathway is not boomed, bermed or contained to prevent drainage to water or offsite					
Pressure Drain Tank		Evidence of drips or leaks					
ADT Liquid Seal for the ADT		Signs of corrosion					
Fire Water Pump Engine		Drainage path to the deck drain is not clear					
Satellite Drip Tank							
Compressors Stations	Items	1	2	3	4	5	6
Compressors		Evidence of Corrosion					
Inlet/Discharge Separators		Excessive vibration					
Blow Case vessels		Evidence of leaks or weeps (i.e. coupling, probes, seals, rotors, gear box)					
Filters		Evidence of cracks in foundation					
Glycol Tanks		Inspection of Grounding System (adequately grounded, no leads disconnected)					
Lube Oil Tanks		Condition of Associated Piping Satisfactory (No leaks)					
Air Compressors							
Transformers	Items	1	2	3	4	5	
		Evidence of drips, leaks, weeps					
		Evidence of Corrosion					
		Evidence of foundation integrity issues					
		Drainage path leads towards property fence line, water bodies, streets, or storm drains					
Wells & Well Cellars	Items	1	2	3	4	5	
		(Aera HB performs daily surveillance of wells for stuffing box leaks - under a separate program - see CLAM surveillance log)					
		(AERA HB performs and records weekly well cellar inspections under a separate program - see Rule 1148.1 Logs)					
WellHead	Items	1	2	3	4	5	
		Evidence of Corrosion					
		Evidence of dripps, leak, weep					



Midway Sunset Operations

www.aeraenergy.com

North Midway Sunset Unit
25401 Highway 33
Fellows, CA 93224
(661) 665-3141

South Midway Sunset Unit
29235 Highway 33
Maricopa, CA 93252
(661) 665-3141

The oilfield operations of Aera Energy LLC in the Midway Sunset Field are centered in the company's North Midway Sunset Unit and South Midway Sunset Unit. Midway Sunset is the largest producing onshore oilfield in the lower 48 states. Aera and Chevron are the largest producers in the field, with Aera accounting for approximately 35 percent of the field's production.

The North Midway Sunset Unit is located along Highway 33 north of the town of Fellows. Oil production averages 13,000 barrels of oil per day (BOPD). Operations consist of 1,900 producing wells and 200 steam injector wells. Approximately 85 employees and 200 contractors work on site.

Aera's South Midway Sunset Unit is located between Taft and Maricopa. The unit produces a daily average of 16,000 BOPD from 1,600 producing wells and 340 steam injector wells. Over 75 employees and 200 contractors work on site.

In 2004 North Midway Sunset won the prestigious North American Maintenance Excellence (NAME) Award for its maintenance and reliability program and results. Aera is the first exploration and production company to win the award previously given only to manufacturing organizations, and North Midway Sunset is the second Aera unit to earn the honor. In the manufacturing industry, the NAME Award has been compared to the Malcolm Baldrige National Quality Award.

Employees assigned to Aera's Midway Sunset units are actively involved in the local community. Community activities include partnerships with Roosevelt Elementary School and the Taft Union High School Oil -Technology Academy, and a holiday outreach program that provides food baskets and gifts to dozens of needy families. Employees have also adopted a two-mile stretch of Highway 33. Aera is a "Black Gold" sponsor of the Oilworkers Monument, dedicated during the Centennial 2010 Oildorado Celebration. In 2007, in recognition of Aera's 10th anniversary, employees sponsored a commemorative legacy donation to underwrite the construction of a lighted information kiosk in historic downtown Taft.

Aera Energy LLC is one of California's largest oil producers, accounting for about 25 percent of the state's production. With headquarters in Bakersfield, most of Aera's production is centered in the San Joaquin Valley. Aera also has operations in the L.A. Basin and in Monterey and Ventura Counties. The work force needs of Aera are provided by Aera Energy Services Company (Aera Services). Aera and Aera Services provide employment for 1,200 people and hundreds of contractor companies. Aera is jointly owned by affiliates of Shell and ExxonMobil.

03/11

Section 10 Corrosion Prevention & Monitoring Techniques

Depending on site conditions, Aera utilizes some combination of the following corrosion prevention and monitoring techniques:

Prevention	Monitoring
Adding chemical corrosion inhibitors	Intrusive:
Removing corrosive gasses, e.g. O ₂ , H ₂ S, CO ₂	System profile for Fe, Mn
Controlling bacteria activity	Water quality testing
Line pigging (can include corrosion inhibitor and/or biocide)	Internal visual inspection
Applying protective coatings	Smart pigging
Applying cathodic protection	Coupons
Using corrosion resistant alloys	Corrosion probes
Using non-metallic materials	
Normalizing weld areas	Non-Intrusive:
	External visual inspection
	Ultrasonic (UT)
	Radiography
	C-span

Section 11

Sensors and Alarms

In addition to employing typical passive spill prevention techniques such as adequate container size to prevent overfill, equalizing lines between containers and overpressure/vacuum relief devices, Aera employs some combination of the sensors and alarms described in Table 11.1 to detect/report process upsets.

Table 11.1 lists types of sensors and alarms utilized by Aera.

Table 11.1 – List of typical sensors and alarms used by Aera

Sensor or Alarm	Used for:
High/Low Level	Maintaining proper fluid levels
High/Low Pressure	Reporting pressure anomalies on select pipelines (including steam systems) and pressure vessel
Fire Sensors	Steam generator shutdowns, gas turbine enclosures, occupied buildings, electrical control rooms
Fixed H ₂ S Detectors	Monitoring H ₂ S levels at critical process locations
Fixed Gas Detectors	Critical process equipment locations, gas turbine enclosures

PRODUCTION FACILITY SPILL CONTINGENCY PLAN
CCR 1722.9

Operator Name, Address, Phone, Contact

Name: Chevron Corporation
Address: 9525 Camino Media
City, State, Zip: Bakersfield, CA 93313
Phone: (661) 654-7122
Contact: Jim Waldron
email: jwaldron@Chevron.com
Field/Lease: San Joaquin Valley Business Unit
Sec. _____ **Twn.** _____ **Rge.** _____

Facility Name, Address, Phone, Contact

Name: Midway Sunset, Temblor Thermal Area
Address: 26251 Highway 33
City, State, Zip: Fellows, CA
Phone: (661) 768-3672
Contact: Tom Porter
email: TomPorter@Chevron.com
County: Kern
Offshore: Y ☒ N (circle one)

Additional Facilities, Fields, Leases, Sections, Townships, Ranges, etc.:

26 C Unit III (T32S/R23E/S26)
2F-Oil Cleaning Plant (T11N/R24W/S2f)
26C-Oil Cleaning Plant (T32S/R23E/S26)
26C-Water Plant (T32S/R23E/S26)
26 C. Cogen (T32/R23/S26)
29D-Oil Cleaning Plant (T32S/R24E/S29d)
31E-Oil Cleaning Plant (T12N/R23E/S31e)
31E-Water Plant (T12N/R23W/S31e)
36L- Oil Plant (T12N/R24W/S36L)
Station 1-09 (T32S/R/23E/S9)
Station 2-22 (T32S/R/23E/S9)
Station 31 (T31S/R23E/S31)

PRODUCTION FACILITY SPILL CONTINGENCY PLAN
CCR 1722.9

A 24-Hour Emergency Contact Information - all calls to 2-22 (661-768-5416) who will contact the following:

[Contact needs to be prepared to provide Division Staff with complete Facility Emergency Shutdown Procedures. Reference CCR 1722.9(a)]

Name	Job Title	Telephone/Cell Number
1 26 C. Unit III: Call Bob Allen/Robert Price Jr. to shut down wells feeding into facility. Facility would be operated manually by operators on duty 24/7 at 26 C. Water Plant	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
2 2 F Oil Cleaning Plant: Call Bob Allen/Robert Price Jr. to shut down wells feeding into facility. Facility would be operated manually by operators on duty 24/7 at 26 C. Water Plant	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
3 31 E. Water Plant: Water comes into plant from 26 C. Water Plant. Water Plant operator on duty would be contacted, and if there was a need to shut-in production, it would be done	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
4 31 E. OCP: oil/water comes in from field: Call Bob Allen/Robert Price Jr. to shut down wells feeding into facility. Facility would be operated manually by operators on duty 24/7 at 26 C. Water Plant	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
5 36L. Mixing Plant: call 26 W. Water Plant operators to secure plant and restrict truck off-loading	Plant operator on duty at 26C. Water Plant, Facilities Supervisor Troy Latham or Operations Supervisor Kenny White	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White)
6 29D. OCP: Operator working from 26C. Water Plant would route incoming wastewater from 31 E. OCP to Valley Waste instead, Robby Price/Bob Allen would be contacted to shut down incoming wells into this facility	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
7 26 C. OCP: shut down south production wells feeding into 26 C. Unit III and Gauge Setting 13. Plant operated manually by operators on duty 24/7 at 26 C. Water Plant	Plant operator on duty at 26C. Water Plant/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, Bob Allen - Operations Supervisor for Midway South Production, Robert Price - PT for Midway South Production	661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)

PRODUCTION FACILITY SPILL CONTINGENCY PLAN		
CCR 1722.9		
26 C. Water Plant: Operator manning 26C OCP would need to re-route water to Valley Waste's section 17D percolation ponds, and the operator at Station 1-09 would need to re-route water that is normally routed to those ponds via disposal line to an alternate disposal site or possibly shut in some wells	Plant operator on duty for 26 C. OCP at 26 C. Water and plant operator on duty at Station 1-09, Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, North Midway Production Supervisor Chris Hansen	661-768-3336 (26 C. WP), 661-768-4222 (Station 1-09), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-2527 (Hansen)
26 C. Cogen: Thermal Supervisor will contact Co-gen operator on-duty who would activate the plant ESD, lock the gates, preventing entry, notify 26 C. Water plant to re-route water normally coming to your drain tank, and notify production regarding loss of steam to 21 S. and 26 C.	Thermal Supervisor Joe McNeely, 26 C. Water Plant Operator/Facilities Supervisor Troy Latham or Operations Supervisor Kenny White, and South Midway Production Supervisor Bob Allen	661-478-5096 (McNeely), 661-768-3336 (26 C. WP), 661-348-2256 (Latham), 661-340-8591 (White), 661-331-7178 (Allen), 661-332-2507 (Price)
Station 31: Operator at plant would notify plant operators at Station 2-22 and Station 1-09 to stop incoming flow if oil storage capacity at the plant could not allow for any further oil into plant while emergency situation is being addressed. May also contact Plant Supervisor Troy Latham and/or Kenny White, Operations Supervisor	Operator on duty at Station 2-22, 1-09, Plant Supervisor Troy Latham and Operations Supervisor Kenny White	661-768-4635 (Station 31 Operator), 661-768-4222 (1-09), 661-768-5416 (2-22), 661-348-2256 (Latham), 661-340-8591 (White)
Station 1-09: The operator on duty 24/7 at 1-09 would contact Production Supervisor Bob Allen/Robby Price to have incoming production shut down for Production area 3, contact the Thermal Supervisor Joe McNeely to notify them that water normally routed to 17 S. Steam Plant, 21 S. Steam Plant, and the multiphase would not be coming for steam production, notify Station 31 operator on duty 24/7 that oil to facility may be reduced, and contact the operator at Station 2-22 if incoming soft water from that plant needs to be re-routed	Operator on duty at 1-09, Production Supervisor Bob Allen/Production Technologist Robby Price, Thermal Supervisor Joe McNeely, plant operator at Station 31, plant operator on duty at 2-22, and Plant Supervisor Troy Latham or Operations Supervisor Kenny White	661-768-4222 (1-09), 661-331-7178 (Allen), 661-332-2507 (Price), 661-478-5096 (McNeely), 661-348-2256 (Latham), 661-340-8591 (White), 661-768-4635 (Station 31), 661-768-5416 (Station 2-22)
Station 2-22: Operator on duty 24/7 at the plant would notify Chris Hansen, Operations Supervisor for the North Midway Production fields to shut-in production, then Thermal Supervisor Joe McNeely regarding possible reduction in water for steam to north Midway steam plants, and notify Station 31 operator regarding possible reduction in shipping oil to facility	Operator on duty 24/7 at 2-22, Production Supervisor for North Midway wells Chris Hansen, Thermal Supervisor Joe McNeely, and plant operator at Station 31	661-768-5416 (Station 2-22), 661-331-2527 (Hansen), 661-478-5096 (McNeely), 661-768-4635 (Station 31)

B Available Personal Protective/Safety Equipment

Type	Location	Maintenance Frequency
26C, Unit III: Unmanned facility - Fire extinguisher, first aid kit kept in company vehicle for easy access (annual inspections/maintenance)		
2F OCP: Fire extinguisher, first aid kit, respiratory protection, eyewash stations, fresh water hose connection (Annual inspections/maintenance)		
31 E. Water: Fire extinguisher, eye wash/safety shower, first aid kit in vehicle (annual inspections/maintenance)		
31 E. OCP: Respiratory protection, full and emergency eye wash stations, fire extinguisher, first aid kit (annual inspections/maintenance)		
36L Mixing Plant: Fire extinguisher, first aid kit in vehicle (annual inspections/maintenance)		
29D, OCP: first aid kit and fire extinguisher in company vehicles (annual inspections/maintenance)		

PRODUCTION FACILITY SPILL CONTINGENCY PLAN

CCR 1722.9	
26 C. OCP: Respiratory protection (annual inspections), first aid and fire extinguishers in vehicle (annual inspections/maintenance)	
26 C. Water Plant: Eye wash stations, respiratory protection, first aid kit (annual inspections/maintenance)	
26 C. Cogen: Eye wash stations, respiratory protection, fire water systems, fire extinguishers, first aid kit (annual inspections/maintenance)	
Station 1-09: Respiratory protection, fire extinguishers, eye wash stations, first aid kit and AED in control room (annual inspections/maintenance)	
Station 2-22: Fire extinguishers, eye wash station, fixed H2S alarm, respiratory protection, first aid kit (annual inspections/maintenance)	
Station 31: Fire extinguishers, eye wash station, first aid kit (annual maintenance/inspections)	

C Initial Quick Action Checklist - see attached

D Government Agency Notification List

(All examples may not apply)

	Telephone Number
1 National Response Center (NRC)	800-424-8802
2 BOEMRE/OEMM (formerly MMS)	800-672-2627
3 Bureau of Land Management (BLM)	661-391-6130
4 United States Coast Guard (USCG)	800-221-8724
5 Environmental Protection Agency (EPA)	800-300-2193
6 California Emergency Management Agency (CEMA)	800-852-7550
7 Division of Oil, Gas and Geothermal Resources	661-322-4031
8 Department of Fish and Game (OSPR)	800-852-7550 or 800-OILS-911
9 Dept. Toxic Substances Control (DTSC)	800-698-6942
10 State Lands Commission (SLC)	562-590-5201
11 State Fire Marshall	N/A
12 California Highway Patrol	(661)-864-4400
13 Regional Water Quality Control Board	(559) 445-5116
14 County Health Department	(661) 862-8700
15 Fire Department	(661)324-6551 (emergency 24 Hr)
16 Local Police	Taft 661 763-3101
17 Certified Unified Program Agencies (CUPA's)	661-861-2521

CUPA's are often fire departments, environmental health departments, or emergency services departments. They may provide resources and liaison functions during oil spills.

PRODUCTION FACILITY SPILL CONTINGENCY PLAN
CCR 1722.9

E Spill Control/Cleanup Equipment Available Either Onsite or in Another Location

(If at other location, please describe contact/requisition procedures)

- Equipment
- 1 26C. Unit III: Drain sump holding 7,793 bbls
- 2 2F OCP: Sump holding 3,627 bbls; Earthen berms holding 4,516 bbls and 5,557 bbls
- 3 31 E. Water plant sump holds 22,178 bbls
- 4 31 E. OCP sump holds 9,948 bbls
- 5 36 L. Mixing plant: sump holding 5,515 bbls and sump holding 2,911 bbls
- 6 29D. OCP berms around facility and sump holds 30,998 bbls
- 7 26 C. OCP berms and sump hold 14,392 bbls
- 8 26 C. Water plant earthen basin holding 14,732 bbls
- 9 26 C. Cogen has earthen berm around facility, drain tank has berm
- 10 Station 1-09: earthen basin holding 8,183 bbls and additional one holding 14,934 bbls. Storm drain valve locked closed unless high precipitation
- 11 Station 2-22: Earthen Berm holding 141,000 bbls around facility and Earthen Berm holding 31,631 bbls around Tanks 75-01 and 75-02
- Station 31: Berms around facility holding 50,193 bbls and holding 32,842 bbls and holding 38,134 bbls and sump holding 4,719 bbls

Onsite Location or Contact/Requisition Procedures

Emergency Response Service Provider: Spill Response & Earthmoving Business Partners	
MSRC	1-800-OIL-SPILL (1-800-645-7745), 1-800-259-6772
Clean Harbors	1 800 OIL TANK (1 800 645 8265)
Browns Backhoe Service (Bakersfield)	661-366-3818
Demo Construction (Bakersfield)	661-324-4705
Kern Small Construction, Inc. (Oildale)	661-393-6678
Kern Environmental Services (Bakersfield)	661-589-5220
Kern Vacuum Service (Rosedale)	661-589-5220
M.P. Vacuum Truck Service (Oildale)	661-393-1151
Pool Vacuum Service (Oildale)	661-588-6140
BOOTS AND COOTS EMERGENCY RESPONSE SERVICES	1-800-BLOWOUT (USA) or 1-800-256-9688

F Map of Production Facilities Including the Location and Labeling of:

- 1 See attached

Note: Operators may need to supply maps with all well locations listed. Refer to "Production Facility" definition, CCR 1760.

G Chemicals that Require a Material Safety Data Sheet and the Location of those Sheets

A separate sheet(s) may be needed to fulfill this requirement.

Chemical MSDS Location

MSDS sheets are located online at the Midway Sunset Home Page and many facilities have them at the site and in the Right to Know Center. Please see attached spreadsheet

H Procedures for Making Regular Facility Inspections and Maintenance of Inspection Records

- 1 Description of Inspection Procedures: [reference CCR 1773.3(b)]

26C. Unit III: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

PRODUCTION FACILITY SPILL CONTINGENCY PLAN
CCR 1722.9

2F OCP: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

31 E. Water: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

31 E. OCP: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

36 L. Mixing: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

29 D OCP: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

26 C. OCP: Visual verification during AM and PM shift and continuous remote alarm monitoring from 26C Water Plant

26 C. Water plant: Visual verification during AM and PM shift and continuous remote alarm monitoring from control room

26 C. Cogen: During AM and PM shift, and alarm monitoring from control room

Station 1-09: visual verification every 3 hours and continuous remote alarm monitoring from control room

Station 2-22: visual verification every 3-4 hours and continuous remote alarm monitoring from control room

Station 31: visual verification every 3 hours and continuous remote alarm monitoring from control room

H Procedures for Making Regular Facility Inspections and Maintenance of Inspection Records (continued)

Maximum Rate

- 2 Maintenance of Inspection Records: [reference CCR 1777.3]

26C. Unit III: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

2F OCP: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

31 E. Water Plant: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

31 E. OCP: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

36 L. Mixing: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

29 D. OCP: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

26 C. OCP: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

26 C. Water Plant: At 26C Water Plant and/or on intranet (O:\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2F, 26C, 29D, 31E\2011\2011 Deep South Process Check.xlsx

26 C. Cogen: Documentation of day shift surveillance in log books in control room. Night shift surveillance is visual only

Station 1-09: At the plant or via the intranet at <\\BDONTDFS1.BDO.CHEVRONTXACO.NET\SHARE\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 1-09\2011\2011 Station 109 Plant Process Check.xlsx>

Station 2-22: at the plant or via the intranet at <\\BDONTDFS1.BDO.CHEVRONTXACO.NET\SHARE\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 2-22\2011\2011 - 222 Plant Process Check.xlsx>

Station 31: at the plant or via the intranet at <\\BDONTDFS1.BDO.CHEVRONTXACO.NET\SHARE\MidwaySunset\Operations\Plants\MWSS FACILITIES\Station 31\2011\2011 Station 31 Plant Process Check.xlsx>

I Produced Fluid Processing Rates

PRODUCTION FACILITY SPILL CONTINGENCY PLAN					
Facility	Typical Rate	Maximum rate	CCR 1722.9 Facility	Typical Rate	Maximum rate
1 26C. Unit III - Oil			7 26 C. OCP	16450 bbl/day	18,400 bbl/day
2 2F OCP	20,000	48,000 bbl/day	8 26 C. Water	25,000 bbl/day	75,000 bbl/day
3 31 E. Water	5,000	20,000 bbl/day	9 26 C. Cogen	12,800 bbl/day	16,000 bbl/day
4 31 E. OCP	3,500	23,500 bbl/day	10 Station 1-09:	63,500 bbl/day	120,000 bbl/day
5 36L Mixing	600	2,000 bbl/day	11 Station 2-22:	80,000 bbl/day	175,000 bbl/day
6 29 D. OCP	2,500	48,000 bbl/day	12 Station 31:	25,152 bbl/day	120,000 bbl/day

J Typical Volumes of Liquids Stored at the Facility

Facility		Typical Volume			Typical Volume		
1	26C. Unit III	250 bbl		7	26 C. OCP		8000 bbl
2	2F OCP	3,500 bbl		8	26 C. Water		5000 bbl
3	31 E. Water Plant	3,500 bbl		9	26 C. cogen		350 bbl
4	31 E. OCP	3,500 bbl		10	Station 1-09:		15,800 bbl
5	36 L. Mixing	1200 bbl		11	Station 2-22:		30,000 bbl
6	29 D. OCP		3,000	12	Station 31:		20,000-30,000 bbl/day

K List of additional containment features for production facilities in drainages with direct access to waterways or urban areas as determined by the Supervisor.

Facility: Direct access to a waterway ☒ Is in an urban area ☐

Additional Containment Feature(s)

- 1 26 C. Unit III Has culvert pipe alongside it to route storm water into ditch, not into plant
- 2 Station 1-09: storm drain valve and line locked closed to prevent entry into blue line. Only opened during periods of high precipitation ☒

L Corrosion Prevention or Corrosion Monitoring Techniques Utilized

- 1 26C. Unit III: Tank maintenance every 3 years
- 2 2 F OCP: scale inhibitor for boilers
- 3 31 E. Water Plant: Corrosion inhibitor injection
- 4 31 E. OCP: Corrosion inhibitor injection
- 5 36 L. Mixing: scale inhibitor for boilers
- 6 26 C. Water: scale inhibitor and corrosion inhibitor injection
- 7 26 C. OCP: Corrosion inhibitor and scale inhibitor injection

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PRODUCTION FACILITY SPILL CONTINGENCY PLAN	
8 Station 1-09: Scale inhibitor injection	CCR 1722.9
9 Station 31: Scale inhibitor injection	
10 Station 2-22: Corrosion inhibitor injection	

In addition to specific plant chemical injections, tank and pipe testing is performed according to regulation and inspection records by facility and equipment are kept at the corporate office located at 9525 Camino Media in Bakersfield.

M Description of All Installed Sensor and Alarm Systems

These may include alarms or sensors for Tank Overfill, High and Low Pressure for Pipelines, Fire, H₂S, Gas, etc...
A separate sheet(s) may be needed to fulfill this requirement.

- 1 26 C. Unit III: Tanks have level alarms monitored by remote at 26 C. Water Plant (T-1: high level, low level, high interface, low interface, high temp and low temp; T-2: high interface, low interface, high temp and low temp; T-5: high interface and low interface)
- 2 2F OCP: T-1 has high level, low level, high interface, low interface, high temp and low temp (a few more than T-2 due to it can be used as a FWKO). T-2 has high interface, low interface, high temp and low temp. T-5 has high interface and low interface.
- 3 31 E. Water Plant: T-1 has level high and level high high alarms
- 4 31 E. OCP: T1-A & B has HL AND HHL ALARMS. T-2 has high interface. T-3 has HL and HHL alarms. T-4 has HL and HHL alarms. T-6 has HL and HHL alarms. T-8 has HL and HHL alarms.
- 5 36L Mixing: T-6 High Level, High High Level and Low Level; T-4 High Level, High High Level; T-5 High Level, High High Level and Low Level; T-7 high level; Upper tanks have common high level alarm (T-1, 2, 6, 10)
- 6 29 D OCP: T-1 High Level, High High Level, Low Level, Hi & Lo interface; T-2 High Level, High High Level, Low Level, Hi & Lo interface; T-3 High Level, High High Level and Low Level; T-4 High Level, High High Level and Low Level (This the drain tank-if it gets a HL, it shuts down all wells with a POC)
- 7 26 C. OCP: T-1 & T-2 HL, HHL, LL, Hi & Lo interface; T-3 & T-4 Hi & Lo interface, Hi & Lo temp; T-5 & T-6 HL, HHL, LL, Hi & Lo temp; T-8 Hi & Lo interface, Hi & Lo temp; T900 Hi & Lo interface; T903 HL, HHL, L and LL; T904 HL & LL; T905A/B Hi & Lo interface; T905C HL & LL
- 8 26 C. Water Plant: T600 High Level, High High Level, Level Alarm Low and LALow Low; T620 HL; T640 HL, HHL, LAL and LALow Low; T650 HL; T651 HL; T655 Low Low; T680 HL & Low Low; T681 HL & Low Low
- 9 26 C. Cogen: T-517 and T-50 have Level Alarms High, Level Alarms High High, Level Alarms Low, Level Alarms Low Low; Ammonia tank has high level alarm and switch with light and horn and external ammonia leak detector; every Ammonia System skid has an Ammonia Leak Detector with light; steam system has high pressure alarms and automatic shutdowns; each steam generator system has a fire water system
- 10 Station 1-09: Tanks T-101, T-102, T103, PWT-105, PWT-106, T-127, T-128, T-129, T-130, and T-131 all have level high alarms, level high high alarms, level low alarms, and level low low alarms; RWT and SWT have high level and low level alarms, and T-1500 has High level alarms, high high level alarms, and low level alarms. Fixed H₂S monitor is located at the VRU system location
- 11 Station 2-22: T-200-1,2,3,4 all have level alarms high and level alarms low and low low; T-100-1,2,3,4 all have level alarms high and level alarms low and low low; T-50-1,3,4 all have level alarms high and low; T-200-5, 6, 7 have level alarms high and high high and level alarms low and low low; T-100-A,B and T-200-A,B all have level alarms high and high high, and T-75-1,2 have level alarms high, low, and high and low interface alarms
- 12 Station 31: All tanks have level high and level high high alarms

N Description of the Training Provided to Implement the Spill Contingency Plan

New hire operations and maintenance training on equipment and components to include: hazard awareness orientation, heat illness prevention, H₂S, California oil producers video, basic steam flood operations, injury and illness prevention plan, stop work authority and OE tenets, defensive driving, hazard communication, pumping units, piping and auxiliary equipment, valves, actuators, pumps, pump performance and inspection, overhead power lines safety, instrumentation and control, Plant science -- heat, heat exchanger - introduction, intro to compressors and positive displacement, airfield compliance, AWT operations, tanks, standard operating procedures, hazard identification, managing safe work, isolation of hazardous energy, hot work permitting, confined space work, excavation trenching, working at heights, qualified gas testing, lifting and rigging, work management, instrumentation and control, piping and instrumentation diagrams, hand tools, fire extinguisher training, first responder operations

PRODUCTION FACILITY SPILL CONTINGENCY PLAN

Information sharing regarding the AB1960 DOGGR Spill Contingency Plan, Quick Action Checklist, reinforcement of MSDS location, and review of emergency procedures in the event of a spill

Site specific plant training with mentors, annual SPCC training (including reference to Initial Responder's Guide for spills), training on How to Pass an Environmental Audit with Flying Colors, Wildlife and Plant life annual CBT, waste management, management of process change, and Spill Prevention CBT w/tabletop exercise

Additions, Additional Comments: