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Shaping the Future

Hydraulic Fracturing Study

PXP Inglewood Oil Field

October 10, 2012

Prepared For

Plains Exploration & Production Company

Hydraulic Fracturing Study

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Prepared for

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Acronyms and Abbreviations

µg/L	micrograms per liter
µS/cm	microSiemens per centimeter
AML	acute myelogenous leukemia
AOR	area of review
API	American Petroleum Institute
bgs	below ground surface
BOD	biological oxygen demand
BOD_5	nitrate, nitrite, metals and biological oxygen demand
BOGM	Bureau of Oil and Gas Management
BTEX	benzene, toluene, ethylbenzenes and xylenes
BWPM	barrels of water per month
Cal-Tech	California Institute of Technology
CARB	California Air Resources Board
CAP	Community Advisory Panel
CBM	coalbed methane
CCAR	California Climate Action Registry
CCR	California Code of Regulations
CDMG	California Department of Conservation, Division of Mines and Geology
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	methane
CML	chronic myelogenous leukemia
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalents
COGA	Colorado Oil & Gas Association
C-PM_{10}	dust particles 10 microns or less in size
C-$PM_{2.5}$	dust particles 2.5 microns or less in size
CSD	Community Standards District
dB	decibels
dBA	A-weighted decibels
DEP	Department of Environmental Protection

DMRM	Divisions of Mineral Resource Management
DOGGR	California Department of Conservation, Division of Oil, Gas and Geothermal Resources
DTSC	California Department of Toxic Substance Control
DWR	California Department of Water Resources
EIR	Environmental Impact Report
EQAP	Environmental Quality Assurance Program
FRAC Act	Fracturing Responsibility and Awareness of Chemicals Act
GEIS	Generic Environmental Impact Statement
GHG	greenhouse gasses
GPS	global positioning system
GWP	Global Warming Potential
GWPC	Ground Water Protection Council
H_2S	hydrogen sulfide
HBO®	Home Box Office
Hz	hertz
IEA	International Energy Association
in/sec	inches per second
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
LAC DPH	Los Angeles County Department of Public Health
LARWQCB	Los Angeles Regional Water Quality Control Board
lbs	pounds
LNG	liquefied natural gas
MCL	California maximum contaminant level
Mg/L	milligrams per liter
MIT	mechanical integrity test
MRRP	monitoring, recordkeeping and reporting protocol
MTBE	methyl tert-butyl ether
MUN	municipal supply
N_2O	nitrogen dioxide
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGO	non-governmental organization

NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRC	National Research Council
NSPS	new source pollutant standards
NYCDEP	New York City Department of Environmental Protection
ODNR	Ohio Department of Natural Resources
OGCD	Oil and Gas Conservation Division
PAW	Petroleum Association of Wyoming
ppb	parts per billion
ppm	parts per million
ppmv	parts per million by volume
psi	pounds per square inch
PXP	Plains Exploration and Production Company
RWQCB	Regional Water Quality Control Board
SCAQMD	South Coast Air Quality Management District
SDWA	Safe Drinking Water Act
SGEIS	Supplemental Generic Environmental Impact Statement
SO_X	sulfur oxides
SPCC	Spill Prevention, Control, and Countermeasures
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
TDS	Total Dissolved Solids
TOC	toxic organic compound
TPH	Total Petroleum Hydrocarbons
TPH-DRO	Total Petroleum Hydrocarbons – Diesel Range Organics
TRPH	Total Recoverable Petroleum Hydrocarbons
UIC	underground injection control
USDOE	U.S. Department of Energy
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
USDW	underground sources of drinking water
VOC	volatile organic compounds

Executive Summary

ES.1 Hydraulic Fracturing Study Objectives

The Inglewood Oil Field was discovered in 1924 by Standard Oil, and encompasses an approximate 1,000-acre area of the Baldwin Hills of Los Angeles County (Figure ES-1). Plains Exploration & Production Company (PXP) has operated the oil field since December 2002.

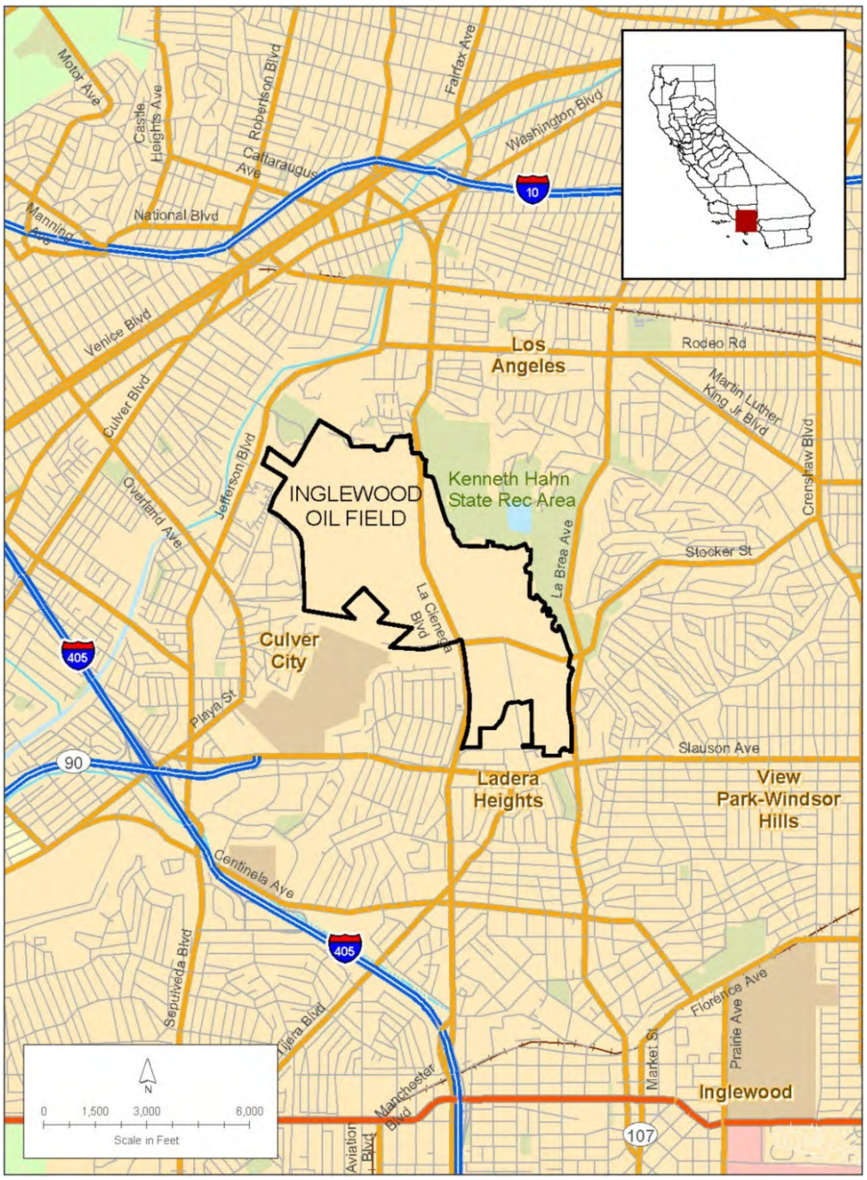


Figure ES-1 Regional Location Map

In October 2008, the County of Los Angeles (County) approved the Baldwin Hills Community Standards District (CSD), creating a supplemental district to improve the compatibility of oil production with adjacent urban land use. A lawsuit was filed in late 2008 against the County and PXP challenging the validity of the CSD. The lawsuit was settled July 15, 2011. This Hydraulic Fracturing Study is the direct result of Term 13 of the Settlement, which states:

> *PXP shall pay for an independent consultant to conduct a study of the feasibility and potential impacts (including impacts to groundwater and subsidence) of the types of fracturing operations PXP may conduct in the Oil Field. The study will also consider PXP's historic and current use of gravel packing. Such study will be completed within twelve (12) months of the date of this Agreement. Such study and all the back-up information for such study shall be provided to a qualified peer reviewer selected by the County and PXP, who shall review the study, back-up materials, and conclusions for completeness and accuracy. PXP must provide the independent expert with all materials requested and reasonably necessary for an accurate and verifiable study. The peer reviewer will be provided with access to all the data and materials provided to the independent expert. The peer reviewer shall agree to keep all proprietary information confidential. If the peer reviewer determines that the study is materially inadequate, incomplete or inaccurate, it shall so advise PXP's consultant who will complete the study as reasonably recommended by the peer reviewer and provide the revised study to the peer reviewer within 90 days. Upon acceptance by the peer reviewer, the study and all supporting material, including comments by the peer reviewer, shall be forwarded to the County, DOGGR, the Regional Water Quality Control Board ("RWQCB"), CAP and Petitioners and be available to the public, with any proprietary information redacted.*

This study draws on several sources, including sources in the peer-reviewed literature, the Inglewood Oil Field CSD, the 2008 Environmental Impact Report (EIR) conducted for the CSD, data and analyses provided by the contractor who conducted the recent hydraulic fracturing and high-rate gravel packing operations at the field, and from numerous contractors performing monitoring studies before, during, and after the recent hydraulic fracturing and high-rate gravel packing operations at the field.

In accordance with the Settlement Agreement, this study was reviewed by peer reviewers, jointly selected by the County and PXP. The peer reviewers, John Martin, Ph.D. and Peter Muller, Ph.D., C.P.G., were provided with the draft study and all reference materials. The peer reviewer's comments on the study, and their statement indicating that the revised study addressed all comments adequately and completely, thereby determining the study compete, is provided in Appendix A.

ES.2 Summary of Findings

The following are the primary findings of the Hydraulic Fracturing Study:

1. **Microseismic Monitoring:** The microseismic monitoring of high-volume hydraulic fracturing indicated that proppant-filled fractures were confined within the deep shale formations beneath the Inglewood Oil Field. Microseismic monitoring showed all fractures

were separated from the designated base of fresh water by 7,700 feet (1.5 miles) or more. Monitoring also showed all high-rate gravel packs stayed within their target zones.

2. **Groundwater:** Groundwater beneath the Inglewood Oil Field is not a source of drinking water, although the water quality must meet the standards for such a source. Groundwater beneath the Baldwin Hills is geologically isolated from the surrounding Los Angeles Basin and any water supply wells. Routine tests by the water purveyor show the community's water supply meets drinking water standards, including the period of high-rate gravel packs and conventional hydraulic fracturing, as well as the first high-volume hydraulic fracture in September 2011. In addition, the Inglewood Oil Field has an array of groundwater monitoring wells to measure water quality. Apart from arsenic, which is naturally high in groundwater of the Los Angeles Basin, the analyzed constituents meet drinking water standards. Before-and-after monitoring of groundwater quality in monitor wells did not show impacts from high-volume hydraulic fracturing and high-rate gravel packing.

3. **Well Integrity:** Tests conducted before, during and after the use of hydraulic fracturing and high-rate gravel packing showed no effects on the integrity of the steel and cement casings that enclose oil wells. There is also an ongoing program of well integrity tests at the Inglewood Oil Field.

4. **Methane:** Methane analyzed in soil gas and groundwater, as well as carbon and hydrogen isotopic rations in methane, at the Inglewood Oil Field did not show levels of concern. There was no indication of impacts from high-volume hydraulic fracturing or high-rate gravel packing.

5. **Ground Movement and Subsidence:** Before-and-after studies of high-volume hydraulic fracturing and high-rate gravel packing at the Inglewood Oil Field showed no detectable effect on ground movement or subsidence.

6. **Induced Earthquakes:** Before-during-and-after measurements of vibration and seismicity, including analysis of data from the permanently installed California Institute of Technology accelerometer at the Baldwin Hills, indicates that the high-volume hydraulic fracturing and high-rate gravel packs had no detectable effects on vibration, and did not induce seismicity (earthquakes).

7. **Noise and Vibration:** Noise and vibration associated with high-volume hydraulic fracturing and high-rate gravel packing operations at the Inglewood Oil Field were within the limits set forth in the CSD.

8. **Air Emissions:** Emissions associated with high-volume hydraulic fracturing were within standards set by the regional air quality regulations of the South Coast Air Quality Management District.

9. **Community Health:** The Los Angeles County Department of Public Health conducted a community health assessment that found no statistical difference of the health of the local community compared to Los Angeles County as a whole. Conventional hydraulic fracturing and high-rate gravel packs operations took place at the oil field, within the period addressed by the health assessment. Given the fact that public health trends in the area surrounding the

field were consistent with public health trends throughout the L.A. Basin it is reasonable to conclude that the conduct of hydraulic fracturing during the analyzed period did not contribute or create abnormal health risks

The Baldwin Hills CSD, and the associated Environmental Impact Report (EIR), together addresses the issues that are part of a hydraulic fracturing operation, such as truck traffic, water use, community compatibility (noise, light and glare, etc.), air emissions from vehicles and equipment used during the well development process, and other environmental resource categories. In addition, the EIR evaluates cumulative impacts, and environmental justice. These two documents support this Hydraulic Fracturing Study, which evaluates the effects measured and monitored during the high-volume hydraulic hydraulic fracturing and high rate gravel packing operations conducted in 2011 and 2012, as well as past activities of this type. The Hydraulic Fracturing Study did not identify a new impact not analyzed in the EIR, nor did it identify impacts greater in significance than those analyzed in the EIR.

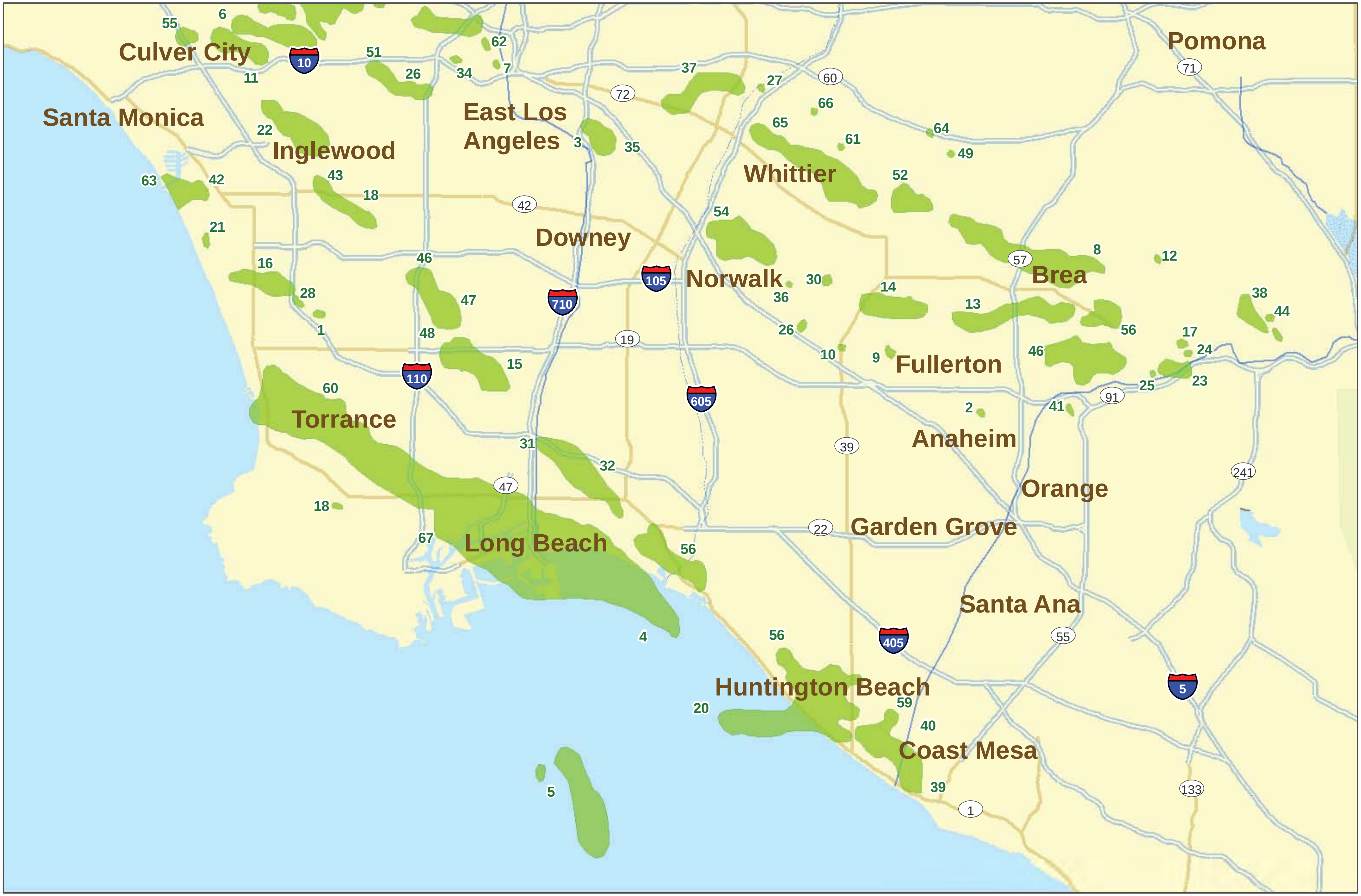
Exacting protective measures and close monitoring are required by the Baldwin Hills CSD and by county, regional and federal agencies. These field-specific reviews and public and agency interactions compel PXP to enforce real-time compliance with all environmental standards in the Inglewood Oil Field. The long history of oil production in the area provides operators with an excellent understanding of the local subsurface conditions and reduces standard risks and uncertainties that would be present in new operations.

ES.3 Oil Production in the Los Angeles Basin and the Inglewood Oil Field

California is the fourth largest oil producing state in the U.S. (U.S. Energy Information Agency 2012), and the Los Angeles Basin is the richest oil basin in the world based on the volume of hydrocarbons per volume of sedimentary fill (Biddle 1991). Oil was first discovered in the area at the Brea-Olinda Oil Field in 1880, followed by numerous fields, including the Inglewood Oil Field in 1924 (Figure ES-2). As of this writing, there are 42 active fields in the Los Angeles Basin.

The Los Angeles Basin represents, from a global perspective, the ideal conditions for the generation and accumulation of hydrocarbons (Barbat 1958, Gardett 1971, Wright 1987a). The relatively recent geologic, tectonic, and structural history of the region has provided a thermal history that brings the organic-rich material into the “oil window”; the thermal regime that is optimum for development of oil and gas from organic precursors.

Discovery and development of the Los Angeles Basin oil fields accompanied rapid urbanization. Many oil fields were later covered by residential or commercial development, sometimes with continuing oil production. Chilingar and Endres (2005) evaluated urban encroachment on active and inactive oil fields, primarily in the Southern California area. They conclude that “a clear case is made for the urgent need for closer coordination and education by the petroleum industry of the local government planning departments…and in establishing mitigation measures for dealing with long-term environmental hazards.” The Inglewood Oil Field CSD, the associated EIR, and this Hydraulic Fracturing Study are coordinated processes that are meant to address such concerns.



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Legend

Oil Field

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Figure ES-2
Location of Los Angeles Basin Oil Fields
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The approximately 1,000-acre Inglewood Oil Field is one of the largest contiguous urban oil fields in the United States, with an estimated recovery of 400 million barrels of oil. Oil and natural gas produced from the field is sold and used entirely in California. The oil field is adjacent to the County of Los Angeles communities of Baldwin Hills, View Park, Windsor Hills, Blair Hills and Ladera Heights, as well as the City of Culver City.

The Baldwin Hills consist of rolling hills up to 511 feet above sea level, cut by canyons and gullies, and form part of a chain of low hills along the Newport-Inglewood Fault Zone. The Baldwin Hills have been uplifted above the Los Angeles basin by folding and faulting of the underlying geological formations.

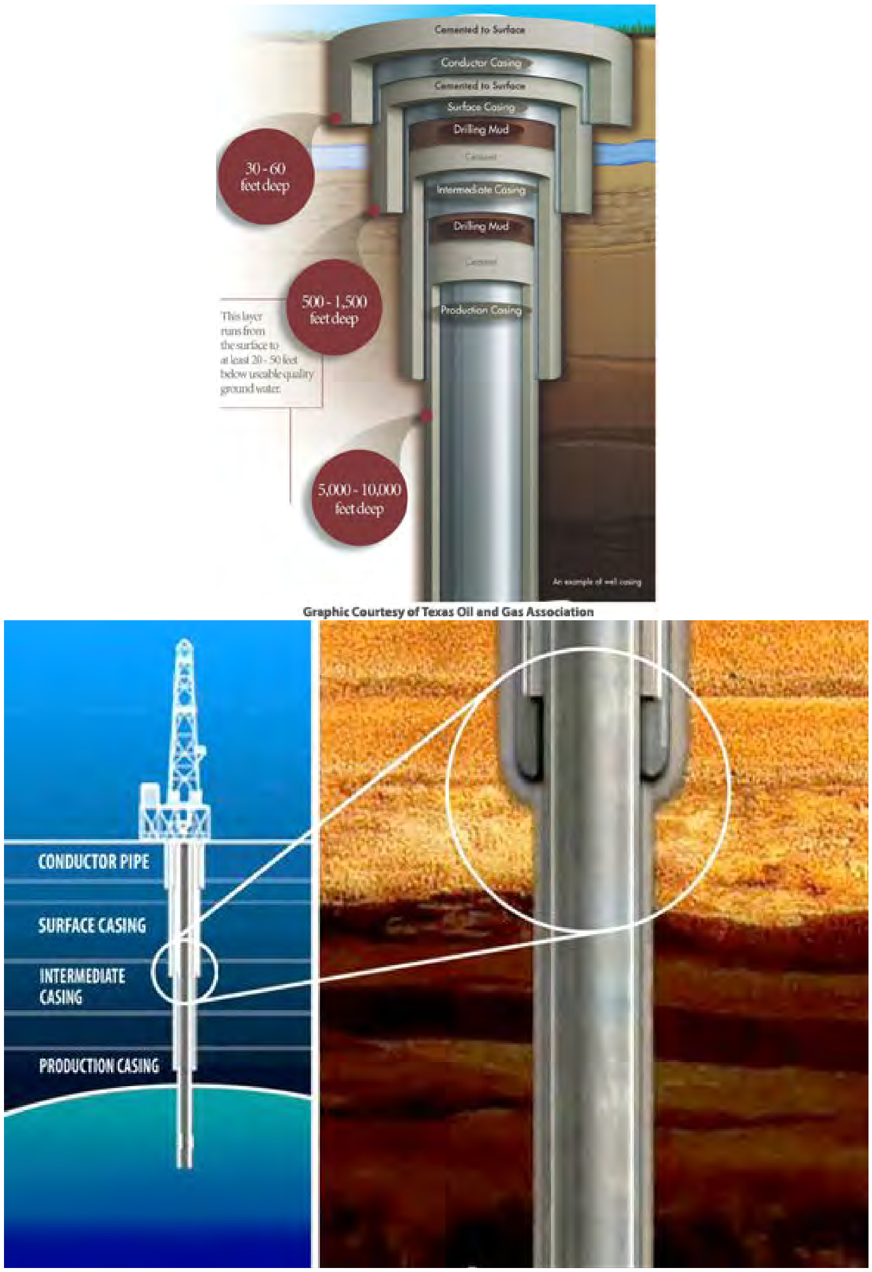
The petroleum producing zones in the Inglewood Oil Field comprise nine strata that range in depth from approximately 900 to 10,000 feet below the ground surface. In order of increasing depth and geologic age, the producing formations are: Investment, Vickers, Rindge, Rubel, Upper and Lower Moynier, Bradna, City of Inglewood, Nodular Shale, and Sentous. Water that is recovered along with the oil and gas, known as produced water, can make up to 90 percent or more of the total fluids pumped. The produced water has been reinjected in to the shallow depressurized Vickers and Rindge zones (known as a waterflood for enhanced oil recovery) since 1954, with much lesser amounts injected into the deeper Rubel and Moynier zones.

A total of 1,475 wells have been drilled over the life of the oil field; currently these are active, idle, or plugged. Many have been directionally drilled and are non-vertical. As of this writing, there are approximately 469 active production wells and 168 active waterflood injection wells operating at the Inglewood Oil Field.

ES.4 Well Drilling and Completion

Well drilling is the process of drilling a hole in the ground for the purposes of extracting a natural substance (e.g., water, oil, or gas). Oil wells are drilled using a drill string which consists of a drill bit, drill collars (heavy weight pipes that put weight on the bit), and a drill pipe. As the well is drilled and drilling fluid (i.e. mud, water and soil) is removed by the cementing process, a series of steel pipes known as casings are inserted and cemented to prevent the boring from closing in on itself (Figure ES-3). Cemented casing also serves to isolate the well from the surrounding formation. Each length of casing along the well is commonly referred to as a casing string. Cemented steel casing strings are a key part of a well design and are essential to isolating the formation zones and ensuring integrity of the well. Cemented casing strings protect against migration of methane, fugitive gas, and any formation fluid and protect potential groundwater resources by isolating these shallow resources from the oil, gas, and produced water inside of the well.

When initial drilling extends just below the base of fresh water, which is typically isolated from deeper saline formation water with an impermeable confining layer below it, the casing is placed into the drilled hole. The casing used in wells at the Inglewood Oil Field meets the State of California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) regulations and American Petroleum Institute (API) standards, which include requirements for compression, tension, collapse and burst resistance, quality, and consistency so that it is able to withstand the anticipated pressure from completing and producing the well (API 2009).



Source: Halliburton 2012

Figure ES-3 Depiction of Casing Strings

The space between this casing and the drilled hole (wellbore) is called the annulus. The annulus is filled with cement, permanently holding the casing in place and further sealing off the interior of the well from the surrounding formation. Cement serves two purposes: (1) it protects and structurally supports the well; and (2) it provides zonal isolation between different formations, including full isolation of the groundwater. Cement is fundamental in maintaining integrity throughout the life of the well, and after the well is idled and abandoned. It also protects the casing from corrosion. This bonding and the absence of voids stops the development of migration paths and isolates the production zone (Halliburton 2012, API 2009).

The final steps to install an oil-producing well are collectively known as well completion. Well completion includes the application of techniques such as sand control and well stimulation, including hydraulic fracturing, and installation of the production tubing and other downhole tools.

Well completions are not a part of the drilling process, but are applied after the well is drilled, sealed, and the drilling equipment has been removed. The first step to complete a well is to perforate the casing to allow the fluid from the producing formation to enter the well. Perforations are simply holes that are made through the casing. Once the casing is perforated, the well stimulation or sand control process is then initiated, depending on which technique is required. There are four types of well completion techniques described in this study that have occurred or may occur at the Inglewood Oil Field: conventional hydraulic fracturing and high-volume hydraulic fracturing, to stimulate and enhance production; and high-rate gravel packing and gravel packing, for sand control.

ES.4.1 Hydraulic Fracturing

In general, the process of hydraulic fracturing consists of injecting water, sand, and chemical additives into the well over a short period of time (typically less than one hour) at pressures sufficient to fracture the rocks to enhance fluid movement through the perforations and into the wellbore. Water and small granular solids such as sands and ceramic beads, called proppants, make up approximately 99.5 percent of the fluid used in hydraulic fracturing (Halliburton 2012). The flow of water acts as a delivery mechanism for the sand, which enters the newly-created fractures and props them open. These proppant-filled fractures allow oil and gas to be produced from reservoir formations that are otherwise too tight to allow flow. If proppant does not enter a new fracture, then the pressure of the overlying rocks forces the fracture closed once the overpressure is stopped, typically in less than one hour.

The chemical additives consist of a blend of common chemicals that increase water viscosity and help the sand and water mixture be carried further out into the fracture network. Additives include gels, foams, and other compounds. Additives have two primary functions: (1) to open and extend the fracture; and (2) to transport the proppant down the length of the fracture to maintain the permeability. Additives also perform critical safety functions such as controlling bacterial growth and inhibiting corrosion to help maintain the integrity of the well, which in turn protects groundwater. Most of the additives are recovered in the water that flows back after the hydraulic fracture (15 to 80 percent depending on the completion), and the remainder is recovered once the oil well is brought on to production and begins pumping fluids from the zone that was fractured (Halliburton 2012, USEPA 2010).

Hydraulic fracturing applied in oil and gas completions typically takes one of two forms, although some hybrid approaches are also in use. As indicated in the descriptions below, the process of fracturing in both forms are the same; the difference generally lies in the type of reservoir where the fracturing is occurring.

ES.4.1.1 Conventional Hydraulic Fracturing

This completion approach uses water, sand, and additives to fracture and stimulate the producing formation itself to a distance of up to several hundred feet from the well. This method is intended to affect the formation surrounding the perforated zone of the well, and enhance the permeability of the target producing zone itself. It is typically applied in sandstone, limestone, or dolomite formations.

ES.4.1.2 High-Volume Hydraulic Fracturing

This higher energy completion approach is generally applied to shales rather than sandstones that typically require a greater pressure to fracture. Sand and additives are used in the process, similar to conventional hydraulic fracturing; however, the primary distinguishing factor is the amount of fluid used in the process.

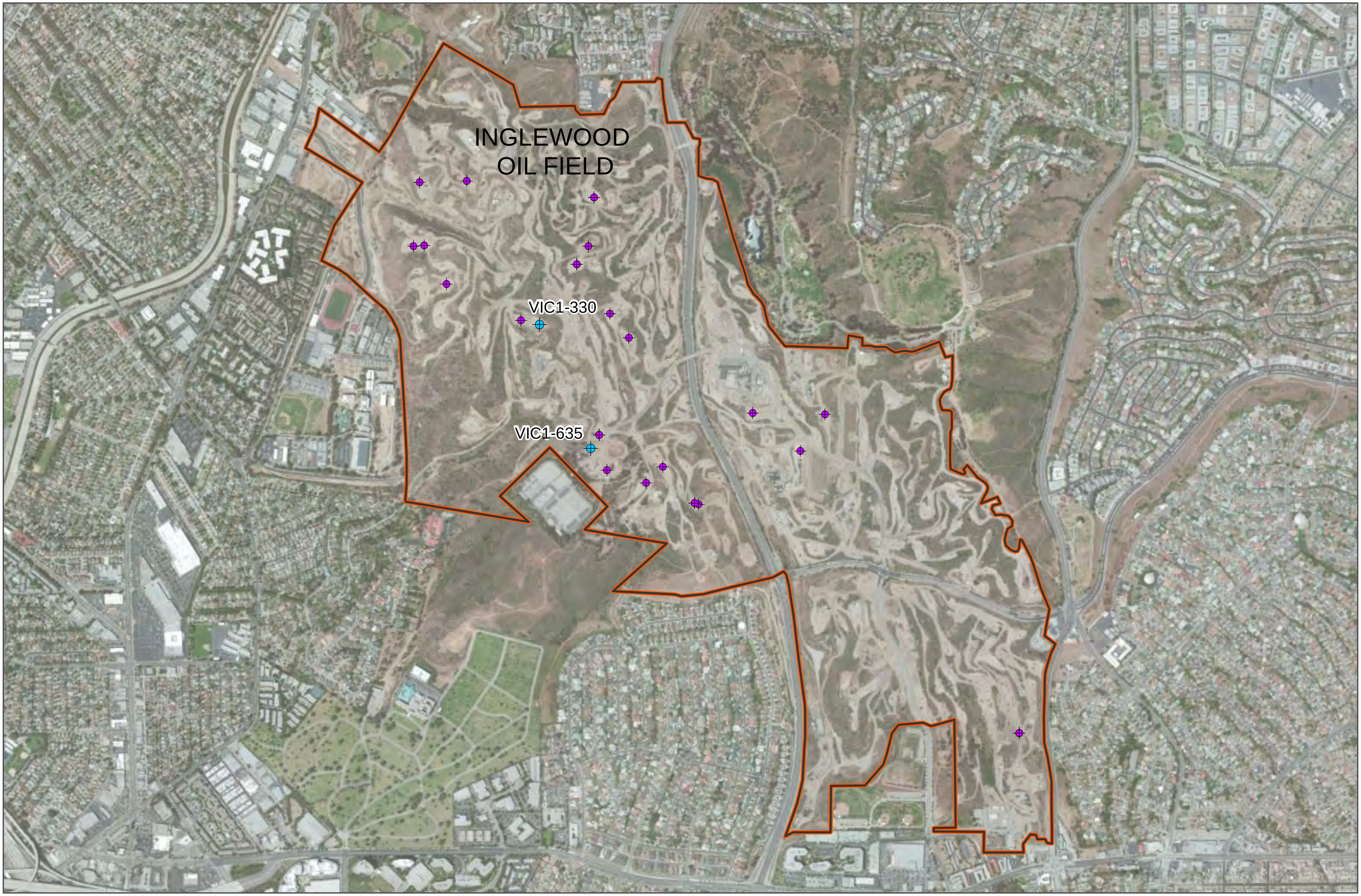
ES.4.2 High-Rate Gravel Packing

This completion approach uses water, gravel, and additives to place sand and gravel near the well itself with the objective of limiting entry of formation sands and fine-grained material into the wellbore, i.e., sand control. In this process, the space between the formation and the outer casing of the well is packed, at a high-rate, with gravel that is small enough to prevent formation grains (sand) and fine particles from mixing and entering the wellbore with the produced fluids, but large enough to be held in place by the well perforations. This relatively low-energy completion approach creates a fracture using water, sand, and additives that improve the proper placement of the gravel filter. This process is not intended to increase the permeability of the producing formation, and it only affects the area near the well itself.

Gravel packing, in contrast to high-rate gravel packing, does not exceed the local geological fracture pressure. In gravel packing operations, a steel screen is placed in the wellbore and the surrounding annulus packed with prepared gravel of a specific size designed to prevent the passage of formation sand. The primary objective is to stabilize the formation while causing minimal impairment to well productivity (Schlumberger 2012a). The gravel is circulated into place rather than pumped in under high pressure.

ES.5 Summary of Past and Future Hydraulic Fracturing and High-Rate Gravel Packing at the Inglewood Oil Field

Both conventional and high-volume hydraulic fracturing have been used at the Inglewood Oil Field. Figure ES-4 shows the location of Inglewood Oil Field wells that have either been completed by high-volume hydraulic fracturing or conventional hydraulic fracturing since 2003 when PXP began operating the field. All of the hydraulic fracturing has been completed on producing wells, that is, on pumping wells rather than injection wells. After the completion, flowback water brings back most of the additives used during the hydraulic fracturing operation to the surface. After the stimulation operation is completed, the well is brought on line and begins pumping, and any residual hydraulic fracturing fluids are drawn towards the well during pumping.



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0 500 1,000 2,000 Feet

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LEGEND

Conventional Hydraulic Fracture

High Volume Hydraulic Fracture

Inglewood Oil Field Boundary

PLAINS EXPLORATION & PRODUCTION COMPANY

Figure ES-4

Locations of Hydraulic Fracturing Operations at Inglewood Oil Field

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In conjunction with this Hydraulic Fracturing Study, PXP conducted high-volume hydraulic fracturing tests at two wells at the Inglewood Oil Field (VIC1-330 and VIC1-635). Only one stage was conducted as part of each of these tests. These are the only two high-volume hydraulic fracture jobs known to have been performed on the Inglewood Oil Field. The stages are representative of anticipated future hydraulic fracturing in terms of pressure, water use, and other factors.

Conventional hydraulic fracturing has been conducted on 21 wells in the deep Sentous, Rubel, Moynier, Bradna, City of Inglewood, and/or the Nodular Shale formations. Combined, a total of approximately 65 stages of conventional hydraulic fracturing have occurred at the Inglewood Oil Field since 2003.

PXP expects that, in the future, high-volume hydraulic fracturing and conventional hydraulic fracturing may be conducted in the deeper Rubel, Bradna, Moynier, City of Inglewood, Nodular, and Sentous zones (all located greater than 6,000 feet below ground surface).

PXP expects that, in the future, high-volume hydraulic fracturing and conventional hydraulic fracturing may be conducted in the deeper Bradna, City of Inglewood, Nodular, and Sentous zones (all located greater than 6,000 feet below ground surface).

PXP has operated the Inglewood Oil Filed since December 2002, and since that time, has conducted high-rate gravel pack completions on approximately 166 wells, in the Vickers and the Rindge formations, and one completion in the Investment Zone. Each high-rate gravel pack included an average of 5 stages per well. Approximately 830 stages of high-rate gravel packs have been completed at the Inglewood Oil Field since PXP began operating the field.

It is anticipated that high-rate gravel packing operations may be conducted on as many as 90 percent of all future production wells drilled within sandstones on the Inglewood Oil Field. This procedure results in less sand being drawn into the well during pumping, and reduces the amount of formation sand that must be managed at the surface. High-rate gravel pack operations use less water (~1,000 barrels vs. ~3,000 barrels) and lower pressures (~1,900 psi vs. ~9,000 psi) than hydraulic fracturing operations.

ES.5.1 Recent Hydraulic Fracturing Completions

PXP conducted two high-volume hydraulic fracture jobs at separate wells on the Inglewood Oil Field for the purposes of this study. The first hydraulic fracture completion was conducted on September 15 and 16, 2011, at the VIC1-330 well. The second completion was conducted on January 5 and 6, 2012, at the VIC1-635 well. Only one stage was completed during each operation.

Both of these operations were conducted in the Nodular Shale, a subunit of the Monterey Shale, approximately 8,000 to 9,000 feet below ground surface. The hydraulic fracture completions were conducted by Halliburton Energy Services with PXP oversight. Microseismic monitoring and fracture mapping was conducted by Schlumberger on the VIC1-330 and by Pinnacle (a Halliburton Company) on the VIC1-635. Halliburton (2012) contains a full report of both operations.

The applied pressure, water use, and monitored effects are expected to be similar between these two high-volume hydraulic fracture jobs and any future high-volume hydraulic fracture jobs to be conducted at the field. However, future high-volume hydraulic fracturing completions would likely utilize more than one fracturing stage each. In hydraulic fracture jobs that consist of more than one stage, each stage is conducted one after the other, never simultaneously. Therefore any one stage will be similar to those described in this section. The amount of water and chemicals used would be proportional to the number of stages.

Although both VIC1-330 and VIC1-635 are vertical wells, in the future, hydraulic fracturing may be conducted using horizontal wells, and with more stages. The high-volume hydraulic hydraulic fracturing job itself and the monitored effects would be the same in each stage as those measured during this study. The intent of the two high-volume hydraulic fracture jobs was to bound the potential effects of this process on the field. In the future, the only difference between these two jobs could be the construction of the well, including the number of stages applied. Each stage would be an isolated event, and each stage would be similar to the two analyzed in this Study. Although a horizontal well can be much longer than a vertical well in the same formation, the hydraulic fracture completion targets an individual zone, and so the amount of water, sand, and additives used would be the same, stage for stage. Horizontal wells, by drilling along the producing zone itself at depth, significantly reduce the number of wells needed to produce the same formation. As such, horizontal wells minimize the surface footprint of the oil production operation.

Water for the hydraulic fracturing operations at the Inglewood Oil Field is provided either from produced water at the field or, if a potassium-chloride gel is used, fresh water provided by California American Water Company, the provider of all fresh water used at the Inglewood Oil Field. For both of the high-volume hydraulic fracturing operations on the field, PXP used fresh water. Water produced from the target reservoirs during hydraulic fracturing operations, known as flowback water or flush water, is transported by pipeline to the field water treatment plant where it is mixed with other produced water generated on the field and processed. The treated water is then reinjected into the oil and gas producing formations as part of the waterflood process. This operation is in accordance with CSD Condition E.2(i), which requires that all produced water and oil associated with production, processing, and storage be contained within closed systems at all times. This process substantially reduced air emissions from the fluids. The total volume of additives is small and is diluted in the fluids of the producing zone.

ES.5.2 Recent High-Rate Gravel Pack Completions

PXP also conducted high-rate gravel pack jobs at two wells on the Inglewood Oil Field to collect data for this study. The first high-rate gravel pack was a five-stage completion performed on January 9, 2012, at the TVIC-221 well. The second high-rate gravel pack was a six-stage completion performed on the same day at a different well, TVIC-3254. Both of these operations were conducted in the Vickers and Rindge formations. The high-rate gravel pack operations were conducted by Halliburton with PXP oversight. The conditions of the high-rate gravel packs are representative of other high-rate gravel packs previously conducted across the field, and are also representative of future high-rate gravel pack jobs that could be expected to be conducted at the oil field.

The maximum applied pressure during both high-rate gravel packs was 1,900 pounds per square inch (psi). In comparison the high-volume hydraulic fracturing projects described in ES.6.1, had an average treatment pressure of 2,971 psi (VIC1-330) and 6,914 psi (VIC1- 635). The high-rate gravel pack influenced the zone within 125 feet of the well within the target oil-producing zone;

whereas, the high-volume hydraulic hydraulic fractures affected areas up to 1,100 horizontal feet from the subject wells (2,200 feet in length tip to tip, Halliburton 2012).

ES.6 Monitoring Conducted During Hydraulic Fracturing and High-Rate Gravel Packing at Inglewood Oil Field

ES.6.1 Hydrogeology, Water Quantity and Quality

In all parts of the world, fresh (not salty) groundwater lies at relatively shallow depths. At greater depths the water is saline, not drinkable, and is sometimes called formation water. The United States Environmental Protection Agency (USEPA) recognizes this distinction in the Safe Drinking Water Act which requires that the shallow, fresh water is protected from contamination by deeper, saline formation water. In most of the Los Angeles Basin, the base of the fresh water zone, below which saline formation water is found, is defined by the top of a marine geological unit called the Pico Formation. The zone at the Baldwin Hills considered to potentially contain fresh groundwater is from the ground surface to a depth of approximately 500 feet. Below approximately 500 feet, a “hydrocarbon seal” (or a nearly impermeable geologic formation) separates the fresh water zone from the oil producing zones and saline water containing formations below.

Nineteen groundwater borings have been drilled on the Inglewood Oil Field since 1992, only eleven of which encountered any water. Where water is encountered, it can range from 30 to 500 feet below ground surface, in zones less than 10 feet thick. The four deepest wells were installed to reach the “base of the fresh water zone,” that is, the top of the Pico Formation. As such, current understanding of groundwater hydrogeology and water quality at the Inglewood Oil Field is based on a well-documented investigation of the entire zone beneath the surface that has any potential to contain fresh water. Although many borings for wells did not encounter any water, those that did were found to pump dry rapidly at low flow rates and recharge slowly. These data indicate that the water bearing zone from which they draw is limited in extent and not suitable for a water supply that could serve the oil field or the surrounding community.

None of these thin, discontinuous water-bearing zones within the Inglewood Oil Field connect to the aquifers of the Los Angeles Basin (USGS 2003, DWR 1961, this Study). The observed zones are perched within the folded and faulted confines of the field. In groundwater models of freshwater flow in the Los Angeles Basin aquifer systems prepared by the U.S. Geological Survey (USGS 2003), the Baldwin Hills are modeled as a “no flow” zone since the sediments beneath the Baldwin Hills are disconnected from the regional aquifers and groundwater flow is discontinuous across the Baldwin Hills. The California Department of Water Resources (DWR 1961) states “the Baldwin Hills form a complete barrier to groundwater movement, where the essentially non-water bearing Pico Formation crops out” (DWR 1961). The findings of the studies and ongoing groundwater monitoring of the Baldwin Hills commissioned by PXP and summarized in this study are in complete agreement with the findings of the USGS and DWR. Due to this lack of water in the geological formations beneath the Baldwin Hills, groundwater in the area is not suitable as a water supply (DWR 1961, USGS 2003, County of Los Angeles 2008).

The local community does not receive water from any formations beneath the Baldwin Hills, or from any well within 1.5 miles of the Baldwin Hills. Rather, approximately two-thirds of the community’s water is delivered from sources in northern California (the Sacramento - San Joaquin River Delta) or sources such as the Colorado River. The nearest groundwater supplies outside the

Baldwin Hills are all very limited in supply and are geologically separated from the subsurface geologic formations of the Inglewood Oil Field. Therefore, activities associated with oil and gas development in the Baldwin Hills do not affect the community's drinking water supply.

All of the water service providers to the communities surrounding the Baldwin Hills must test their water from local wells at least four times a year and report the results to the water users. These reports indicate that the community receives water that meets USEPA's drinking water standards. Ongoing (four times per year) monitoring corroborates that this portion of the water supply meets these standards. The most recent data posted by the water purveyor covers the high-volume hydraulic fracturing that occurred in September 2011, as well as earlier conventional hydraulic fracturing and high-rate gravel packs. All public water supplies in California must also meet these requirements.

ES.6.1.1 Groundwater Monitoring Before and After Hydraulic Fracturing and High-Rate Gravel Packing

The Los Angeles Regional Water Quality Control Board (LARWQCB) Water Quality Control Plan, or Basin Plan, establishes beneficial uses of surface and groundwater in the Los Angeles Basin. Based on the State Board Resolution No. 88-63, "Sources of Drinking Water Policy", all groundwater in the state must be considered a potential source of drinking water, and carry a beneficial use designation of Municipal Supply (or MUN). This designation does not imply that the groundwater has sufficient capacity to support a municipal supply, presently or in the future. The designation addresses requirements to maintain groundwater quality in the sense of meeting drinking water standards.

As such, any water that may be encountered beneath the Inglewood Oil Field, regardless of its ability to actually supply water, must carry the beneficial use designation of MUN. Groundwater is collected from monitoring wells within the oil field, and is analyzed on a quarterly basis. A review of quarterly groundwater monitoring reports for 2010 and 2011 indicates that the perched, isolated groundwater meets the water quality requirements for MUN waters with the exception of arsenic, the concentrations of which are likely due to the high background level that naturally occurs in Southern California (Chernoff et al. 2008, Welch et al. 2000). As documented by USEPA, when "compared to the rest of the United States, western states have more systems with arsenic levels greater than USEPA's standard of 10 parts per billion (ppb)" (USEPA 2012a). Arsenic delineation maps produced by the USGS in 2011 have documented increased levels of arsenic in both the County of Los Angeles and Southern California as a whole (Gronberg 2011).

These data are also consistent with soils data from the 2008 California Department of Toxic Substance Control (DTSC) memo "Determination of a Southern California Regional Background Arsenic Concentration in Soil" (Chernoff et al. 2008). Areas in Southern California have been shown to have higher than average levels of arsenic present in soil and thus, through the release of naturally occurring arsenic in sediments, levels can be inferred to also be higher than average in groundwater resources throughout Southern California.

Monitoring was also conducted in April and August, three months and seven months after high-volume hydraulic fracturing and high-rate gravel packs conducted in January. The water was analyzed for the following constituents: pH, total petroleum hydrocarbons (TPH), benzene, toluene, ethylbenzene, total xylenes, methyl tertiary butyl ether (MTBE), total recoverable petroleum hydrocarbons (TRPH), total dissolved solids (TDS), nitrate, nitrite, metals, and biological oxygen demand (BOD5). These compounds include those used in hydraulic fracturing. The results of this monitoring were consistent with past groundwater monitoring and results. Groundwater will continue to be collected, analyzed, and reported consistent with the CSD and irrespective of when hydraulic fracturing and high rate gravel pack operations are conducted in the future.

Based on comparison of two sampling rounds after the high-volume hydraulic fracturing operations and high-rate gravel pack operations with the quarterly sampling rounds conducted prior to the operations, none of the analytical results indicated constituents above the state drinking water standard, with the exception of arsenic, which occurs naturally in soil and rock formations in Southern California. For the compounds detected, the concentrations after hydraulic fracturing were within the range of concentrations detected during the baseline period before hydraulic fracturing. The only exception was a minor increase in chromium from one well, MW-7 (2.7 to 3.0 µg/L, both results were well below the 50 µg/L state standard). Chromium is not associated with hydraulic fracturing additives.

Several new groundwater monitoring wells were installed after high-volume hydraulic hydraulic fracturing and high-rate gravel packing operations were conducted. Accordingly, the pre and post-hydraulic fracturing and high-rate gravel packing data in these specific wells cannot be compared. However, we can compare the results in the new wells with the pre- and post-hydraulic fracturing and high-rate gravel packing results from the pre-existing wells. In comparing the results of groundwater collected from new wells installed after hydraulic fracturing and high-rate gravel packing with the existing wells, the results were also consistent. No compounds violated the drinking water standard except for arsenic, as was the case with the pre-existing wells. The new wells were within the ranges of values detected in the pre-existing wells, with the new wells ranging to slightly higher total dissolved solids, zinc, and biological oxygen demand. The total dissolved solids and zinc may be due to conditions at depth, closer to the saline formation water. The biological oxygen demand is not associated with hydraulic fracturing additives.

Groundwater monitoring shows similar groundwater quality results before and after high-volume hydraulic fracturing and high-rate gravel packing. The Inglewood Oil Field's groundwater is not a source of drinking water. The groundwater bearing water bodies of the Baldwin Hills are geologically isolated from the nearest groundwater wells used for the municipal supply; and, two-thirds of the community water supply is from Northern California (the Sacramento-San Joaquin Delta) or the Colorado River. The local community does not receive water from closer than 1.5 miles to the Baldwin Hills. Community water supply is tested on a quarterly basis by the water purveyor, meets drinking water standards, and the results are publicly available.

ES.6.2 Well Integrity

During each stage of the hydraulic fracturing and high-rate gravel pack operations, the well casing of the subject well is tested in order to ensure integrity prior to injection of fracturing fluids (Halliburton 2012). Information about the well integrity tests is described in the post job reports. Well integrity testing is done by pressure testing the well up to 70 percent of the strength of the casing, in conformance with field rules established by the DOGGR. Offset wells, production wells, and injection wells are also tested for proper zonal isolation (i.e., annular cement) prior to any hydraulic fracturing operations. All measurements of well integrity during the hydraulic fracture and high-rate gravel pack operations conducted for this study indicated that there were no losses in pressure. The offset wells easily withstood the pressures of high-volume hydraulic fracturing; and no evidence of damage to the offset well was demonstrated by the pressure testing. The applied energy of the high-volume hydraulic fracturing rapidly decreases away from the completed well, and as such surrounding wells would not be adversely affected by the operation.

In addition to the well-integrity tests conducted for the high-volume hydraulic fracturing and high-rate gravel pack operations, active injection wells at the Inglewood Oil Field are surveyed annually (and pressure tested after each well work) per DOGGR requirements pursuant to CCR, Chapter 4, Article 3, §1724.10(j)3. PXP also monitors active injection wells weekly for injection rates and pressures (what also indicates the integrity of the wellbore and confinement of fluids to the injection zone) and reports to DOGGR on a monthly basis, pursuant to CCR Chapter 4, Article 3, §1724.10(c).

Tests conducted before, during and after the use of high-volume hydraulic hydraulic fracturing and high-rate gravel packing showed no impacts on the integrity of the steel and cement casings that enclose oil and gas wells.

ES.6.3 Containment of High-Rate Gravel Packs and High-Volume Hydraulic Fractures to the Target Zones

The measured distribution of fractures caused by the high-rate gravel pack completions were all less than 250 feet from the well, and were confined to the perforated zone within the Vickers and Rindge formations. The measured distribution of fractures from the high-volume hydraulic fracture completions were less than 1,100 feet in length from the well, and, with minor exceptions, were contained within the target zone (Halliburton 2012). For the few fractures that were outside the Nodular Shale target zone, they were deeper (with the oil-bearing Sentous Shale) and not filled with proppant. They therefore would reseal after the cessation of the increased pressure of hydraulic fracturing. Fractures grew either horizontally from the well or at angles less than 20 degrees depending on the local angle of the geological formations. Vertical fracture growth was very limited. The high-volume hydraulic fracture completions were conducted between 8,000 and 9,000 feet below the ground surface, and fractures did not form at shallower depths than approximately 8,000 feet below the ground surface. By comparison, the deepest groundwater encountered that had relatively low salinity was at a depth of 500 feet below the ground surface, corresponding to the base of fresh water beneath the Inglewood Oil Field, 1.5 miles above the hydraulic fracturing.

The results of microseismic monitoring indicate that fractures created during the high-volume hydraulic hydraulic fracturing operations were contained to the deep Nodular Shale with the exception of a minor few that were not filled with proppant. The fractures were all greater than 7,500 feet below the designated base of fresh water. The fractures created during all high-rate gravel packs were confined to the target zones.

ES.6.4 Subsurface Occurrence of Methane

Most of the oil and natural gas in the Los Angeles Basin lies trapped beneath both shales and faults, allowing it to accumulate at depth. However, some surface seeps do occur, as at the La Brea Tar Pits, and were the initial targets in the development of the Los Angeles Basin fields. In accordance with the CSD, field-wide methane monitoring is conducted at the Inglewood Oil Field on an annual basis to gauge for shallow occurrences of methane, and detections are investigated to determine the cause and remediate it.

Due to the potential of methane gas migration from the naturally occurring, prolific oil and gas province underlying the entire Los Angeles Basin, the City of Los Angeles has established a zoning ordinance identifying two zones, a Methane Zone and a Methane Buffer Zone, with special requirements for new construction, existing construction, and methane monitoring. The Baldwin Hills are outside the City of Los Angeles, and therefore are not classified on the methane map; however, they are adjacent to such zones. Although past methane detections have either been low or associated with a well to be re-abandoned, methane concentrations beneath portions of the field would reflect the relatively high background levels of methane in the Los Angeles Basin. All shallow detections of methane associated with the monitoring have been biogenic, based either on the composition (almost pure methane) or isotopic composition. Monitoring of shallow methane after high-volume hydraulic fracturing and high-rate gravel packing did not detect increases in soil gas methane concentrations.

Groundwater was not measured for methane prior to high-volume hydraulic fracturing or high-rate gravel packing. Samples collected after high-volume hydraulic fracturing detected dissolved methane in all but one well (MW-7), with concentrations up to 9.7 mg/L methane; all but two of the detections were less than 0.2 mg/L. Methane is not toxic and so there is not a drinking water standard established for it in water. There are few standards that have been promulgated for the nuisance effects of methane; the most widely applied are those of the U.S. Office of Surface Mining and the U.S. Bureau of Land Management. The highest value measured in groundwater at the Inglewood Oil Field is within the levels considered safe (10 mg/L), and well within levels that would actually trigger contingency actions (28 mg/L). The City of Los Angeles methane zoning ordinance does not address methane in groundwater; the ordinance only addresses levels in soil gas and applies construction standards as contingencies. Based on isotopic analysis of the dissolved methane in groundwater, it is thermogenic (from the oil-bearing formations) in origin, whereas detections in shallow soil gas are biogenic in origin. There are shallow occurrences of oil in the Investment Zone, within the Pico Formation. Since these zones are in closest proximity to the water bearing zones, and the occurrence of methane is pervasive in the monitoring results, it does not appear to be related to oil and gas production activity but to the natural occurrence of the underlying oil and gas. The occurrence is also not correlated to the locations of high-volume hydraulic fracturing or high-rate gravel packing.

The results of methane testing in soil and groundwater showed no influence from high-volume hydraulic fracturing or high-rate gravel packing.

ES.6.5 Slope Stability, Subsidence, Vibration, and Induced Seismicity

Slope stability is a primary geologic concern in the Baldwin Hills, and is addressed by conditions in the CSD that require ongoing monitoring. The California Department of Conservation, Division of Mines and Geology (CDMG), has studied the occurrence of slope instabilities and related geological issues of the Baldwin Hills (CDMG 1982). The study notes widespread damage from slope failures caused by rains in 1969, 1978, and 1980, and less widespread damage in other years. The study concludes that slope stability is a substantial problem in the Baldwin Hills because the terrain that has been developed for residential use consists mostly of steep natural slopes underlain by soft sedimentary rocks that are prone to land sliding and erosion. In addition, many of the communities in the Baldwin Hills were developed prior to the enactment of strict grading codes by local government, and therefore lack adequate protections against these natural geological conditions. The CDMG study notes that the Inglewood Formation is particularly susceptible to slope instability because the surficial soils developed on the formation are clay-rich. The study also notes that the Culver Sands are particularly susceptible to erosion. Monitoring for vibration and subsidence did not detect a change due to hydraulic fracturing or high-rate gravel packing. As such, hydraulic fracturing and high-rate gravel packing would not affect surface slope stability.

Subsidence is another geological concern in the Baldwin Hills. As described in the Baldwin Hills CSD EIR, prior to 1971, the maximum cumulative subsidence of any of the areas along the Newport-Inglewood fault zone was centered over the Inglewood Oil Field. Injection of produced water into the active producing zones began in 1957 to counteract this subsidence, and since 1971, water injection into the shallow production horizons has effectively eliminated subsidence associated with oil and gas production. The oil field has an ongoing program of annual subsidence monitoring that is reported in the framework of the CSD. To date, no changes in ground surface are attributed to oil and gas production activities. In evaluating pre- and post-hydraulic fracturing and high-rate gravel packing subsidence, none were attributed to the hydraulic fracturing or high-rate gravel packing.

ES.6.5.1 Subsidence and Ground Movement Monitoring during Hydraulic Fracturing

The CSD requires an annual ground movement survey at the Inglewood Oil Field. Surveying for both vertical and horizontal ground movement is accomplished using satellite-based GPS technology. Accumulated subsidence or uplift is measured using repeat pass Differentially Interferometric Synthetic Aperture Radar technology. The data are then evaluated to determine whether oil field operations (oil production and/or produced water injection volumes) are related to any detected ground motions or subsidence. Baseline survey points were collected in 2010 and then resurveyed in January 2011 and February 2012 (following the hydraulic fracturing operations of VIC1-330 and VIC1-635 and the high-rate gravel packing operations of TVIC 221 and TVIC 3254) to calculate annual subsidence or uplift at each point (Fugro NPA 2011, Psomas 2012). Based on a comparison of the ground movement survey results in 2011 and 2012 to operations production and injection records over the same time periods, there is no correlation between measured elevation changes and field activities.

The high-volume hydraulic fracturing and high-rate gravel packing had no detectable effect on ground movement, vibration, seismicity or subsidence, based on the results of studies conducted before and after the activities. As such, there would also be no detectable effect on slope stability.

ES.6.5.2 Vibration and Induced Seismicity

PXP retained Matheson Mining Consultants, Inc. to conduct vibration and ground surface monitoring during the high-volume hydraulic fracturing operations at the VIC1-330 and VIC1-635 wells, and at TVIC-221 and TVIC-3254 for the high-rate gravel pack jobs.

Vibration records for the VIC1-330 and VIC1-635 wells were collected using four and eight seismographs, respectively, installed at different locations in relation to the high-volume hydraulic fracture operations. The TVIC-221 and TVIC-3254 wells are directly adjacent to one another; therefore, the same seismographs were used to monitor the high-rate gravel packs on these wells. Based on analysis of the seismograph data, Matheson Mining Consultants, Inc. concluded that no seismic activity was produced by any of the high-volume hydraulic fracturing or high-rate gravel pack operations. In addition to the seismic monitoring conducted by Matheson Mining Consultants, Inc., seismic data collected by the permanently installed California Institute of Technology (Cal-Tech) accelerometer (seismometer) at the Baldwin Hills was reviewed for the time periods before and during the high-volume hydraulic fracturing and high-rate gravel pack operations. Background levels range from 0.0003 to 0.0006 inch per second (ips); however, random spikes occur in the record approximately every two to three hours. These spikes are likely related to local traffic or some other passing noise source, and are common in urban areas. The data collected from the seismograph during the VIC1-635 operation showed two minor spikes during the time period reviewed (the largest measuring 0.0012 ips). Analysis of the data by Dr. Hauksson, a Senior Research Associate in Geophysics with the Cal-Tech Seismological Laboratory, concludes that these spikes are not indicative of any seismic events above background levels were recorded (Matheson Mining Consultants, Inc. 2012a). The data collected from the seismograph during the TVIC high-rate gravel pack operations showed some spikes during the time period reviewed but no significant signals above the background levels. No data above background levels were recorded on the Cal-Tech seismograph during the VIC1-330 operation.

Petersen and Wesnousky (1994) evaluated all seismic events greater than Magnitude 2 on the Newport-Inglewood Fault zone, and determined that most epicenters are located at depths between 3.5 miles and 12 miles deep (Petersen and Wesnousky 1994, Hauksson 1987). In comparison, the waterflood operation at the Inglewood Oil Field extends to depths of up to 3,000 feet (0.57 mile) and the deepest hydraulic fracturing occurs at less than 10,000 feet depth (1.9 miles). Therefore, oil field operations are much shallower than the zones typically associated with earthquake epicenters along the Newport-Inglewood Fault zone.

Results of studies conducted before and after high-volume hydraulic fracturing and high-rate gravel packing operations indicate that the operations had no detectable effect on vibration, and did not induce seismicity at the surface.

ES.6.6 Noise and Vibration

To address concerns regarding perceptible vibration and noise during high-volume hydraulic fracturing operations, PXP commissioned Behrens and Associates, Inc., a firm specializing in noise and vibration studies, to measure produced vibration during the VIC1-330 and VIC1-635 high-volume hydraulic fractures and the TVIC-221 and TVIC-3254 high-rate gravel pack events. The ground-borne vibration survey for each event was completed while all equipment was operated under normal loads and conditions.

The high-volume hydraulic fracturing treatment on September 16, 2011, was completed on the VIC1-330 well, located in the northwestern portion of the field. Measured levels indicate that the maximum ground-borne vibration produced during the operation was 0.006 inch per second, as measured 40 feet from the operation. At 160 feet from the operation, measured vibration was 0.001 inch per second. Both of these levels are imperceptible to humans (Behrens and Associates, Inc. 2011).

In addition to ground-borne vibration measurements, Behrens and Associates, Inc. also took sound level measurements during the high-volume hydraulic fracturing operation at VIC1-635 and the high-rate gravel pack operations at TVIC-221 and TVIC-3254 using a calibrated sound level meter. The microphone was set at 5 feet above ground surface. The measured noise level at 100 and 200 feet from the operation at VIC1-635 was 68.9 and 68.4 decibels (dBA), respectively (Behrens and Associates, Inc. 2012a), The measured noise level at 100 and 200 feet from the TVIC-221 and TVIC-3254 operations was 68.1 dBA and 63.5 dBA, respectively (Behrens and Associates, Inc. 2012b). These measured noise levels are all in compliance with CSD limits.

The noise and vibration associated with the high-volume hydraulic fracturing and high-rate gravel pack operations did not exceed CSD limits.

ES.6.7 Air Emissions

Air emissions on the Inglewood Oil Field are monitored as described in an Air Monitoring Plan in accordance with Section E.2(d) of the Baldwin Hills CSD. This plan requires monitoring for hydrogen sulfide and total hydrocarbon vapors. It also requires that drilling or completions operations shut down if monitoring detects concentrations of hydrogen sulfide greater than 10 ppm or hydrocarbon concentration of 1,000 ppm or greater. Vehicle use for on-road and off-road vehicles and construction equipment is also regulated by the CSD under Sections E.2(j) through E.2(n).

Mass emissions of criteria pollutants and greenhouse gases (GHG) for off-road equipment and on-road vehicles were calculated using emission factors published by the South Coast Air Quality Management District (SCAQMD 2008) and USEPA (2011a, 2011b). The project schedule and equipment/vehicle list provided by PXP and Halliburton served as the basis for the analysis. The results of the analysis are presented in the emissions summary tables contained in section 4.7 of this study. These levels are consistent with those considered in the CSD.

Air emissions associated with high-volume hydraulic fracturing and high-rate gravel packing were compliant with the regulations of the South Coast Air Quality Management District and the CSD.

ES.6.8 County of Los Angeles Department of Public Health Study

The County of Los Angeles Department of Public Health (LAC DPH) conducted a community health assessment on the population living in communities surrounding the Inglewood Oil Field in 2011. The assessment was designed to determine if health concerns in the communities surrounding the Inglewood Oil Field reflect a higher than expected rate or an unusual pattern of disease. The report was sent to three external peer reviewers who found it to be technically sound.

The conclusions of the health assessment indicate that the health of the community adjacent to the Baldwin Hills is not statistically different from that of Los Angeles County as a whole, including cancer rates in the community. The report acknowledges that the data cannot determine adverse health effect below its detection limit, nor can the data address the contribution of other, non-quantifiable health-related issues such as smoking, lack of exercise, and social determinants of health.

Conventional hydraulic fracturing and high-rate gravel packing have occurred at the field since 2003, along with other oil and gas development activity. Based on the results of the health assessment, these activities had no detectable adverse effect on the health of the local community.

The health assessment recommends careful monitoring of the oil field operations to ensure compliance with regulations and standards to protect community health and safety. In compliance with the CSD, such monitoring occurs via Environmental Compliance Coordinator weekly inspections and an annual Environmental Quality Assurance Program (EQAP) audit.

The Los Angeles County Health Study found no detectable health consequences to the local community from oil and gas development (including hydraulic fracturing and high-rate gravel packing) at the Inglewood Oil Field. The study recommends careful monitoring of the oil field operations to ensure compliance with regulations and standards to protect community health and safety.

ES.6.9 Issues Associated with Hydraulic Fracturing in Shale Gas and Relevance of Inglewood Oil Field Hydraulic Fracturing Study Results

Since high-volume hydraulic fracturing has been used for shale gas development in the northeastern United States, there has been extensive media coverage of controversies surrounding its use. Although most of the news has been about the development of shale gas, tight sands and coalbed methane deposits rather than the type of oil and natural gas development that occurs at the Inglewood Oil Field, community outreach conducted as part of this study has indicated that many of the concerns surrounding shale gas development are shared by the local community and applied to oil development. The primary environmental and health issues of concern associated with hydraulic fracturing operations include:

- Potential for contamination of groundwater, including drinking water supplies, and gas migration;
- Environmental hazards associated with the chemical additives used during hydraulic fracturing operations;
- Potential for hydraulic fracturing operations to cause earthquakes;
- Issues related to well integrity; and,
- Air emissions and greenhouse gas emissions of hydraulic fracturing operations in comparison to regular oil field operations.

A description of each of these issues as they relate to hydraulic fracturing operations is provided in the study, along with the direct measurements taken at the Inglewood Oil Field to determine their relevance.

ES.7 Regulatory Perspective on the Inglewood Oil Field

The federal, state, and local laws, ordinances, regulations, and standards that govern oil field development throughout the United States require protections against the potential environmental impacts of the entire development process. These protections range from provisions in the Clean Air Act, Clean Water Act, Safe Drinking Water Act, Endangered Species Act, and through extensive California regulation addressing air quality, water resources, biological resources, and cultural resources, and at the local level. The Inglewood Oil Field is unusual in that it has much greater regulation and oversight of its operations than most other onshore oil fields as a result of the County of Los Angeles CSD.

The current national regulatory framework and government-sponsored studies of hydraulic fracturing are summarized in Section 5 of this Study to provide a national perspective to this Hydraulic Fracturing Study. Most of these studies address hydraulic fracturing associated with the development of shale gas, which is different than oil and gas development. Although the Inglewood Oil Field is not a shale gas field, and many of the concerns associated with the development of shale gas do not apply to the Inglewood Oil Field, the findings presented in Section 5 are intended to place concerns commonly seen in the news media in the local context of the Inglewood Oil Field.

The Baldwin Hills CSD, and the associated EIR, together address most of the issues that are part of a hydraulic fracturing operation, such as truck traffic, water use, community compatibility (noise, light and glare, etc.), air quality, and other environmental resource categories. In addition, the EIR evaluates cumulative impacts, and environmental justice. These two documents support this Hydraulic Fracturing Study, which evaluates the effects measured and monitored during the high-volume hydraulic hydraulic fracturing and high rate gravel packing operations conducted in 2011 and 2012, as well as past activities of this type. The Hydraulic Fracturing Study did not identify a new impact not analyzed in the EIR, nor did it identify impacts greater in significance than those analyzed in the EIR.

Exacting protective measures and close monitoring are required by the Baldwin Hills CSD and by county, regional and federal agencies. These field-specific reviews and public and agency interactions compel PXP to enforce real-time compliance with all environmental standards in the Inglewood Oil Field. The long history of oil production in the area provides operators with an excellent understanding of the local subsurface conditions and reduces standard risks and uncertainties that would be present in new operations.

Chapter 1

Introduction

Plains Exploration & Production Company (PXP) operates the Inglewood Oil Field, an approximately 1,000 acre area of the Baldwin Hills in Los Angeles County (Figure 1-1). Oil was discovered in the Baldwin Hills in 1924 by Standard Oil, and the oil field was operated by Chevron (successor company to Standard Oil), followed in 1990 by Stocker Resources, Inc., which was then acquired by Plains Resources, Inc. in 1992. PXP was incorporated in September 2002, and acquired all of Plains Resources, Inc.'s California operations, including the Inglewood Oil Field, in December 2002. PXP has operated the oil field since late 2002.

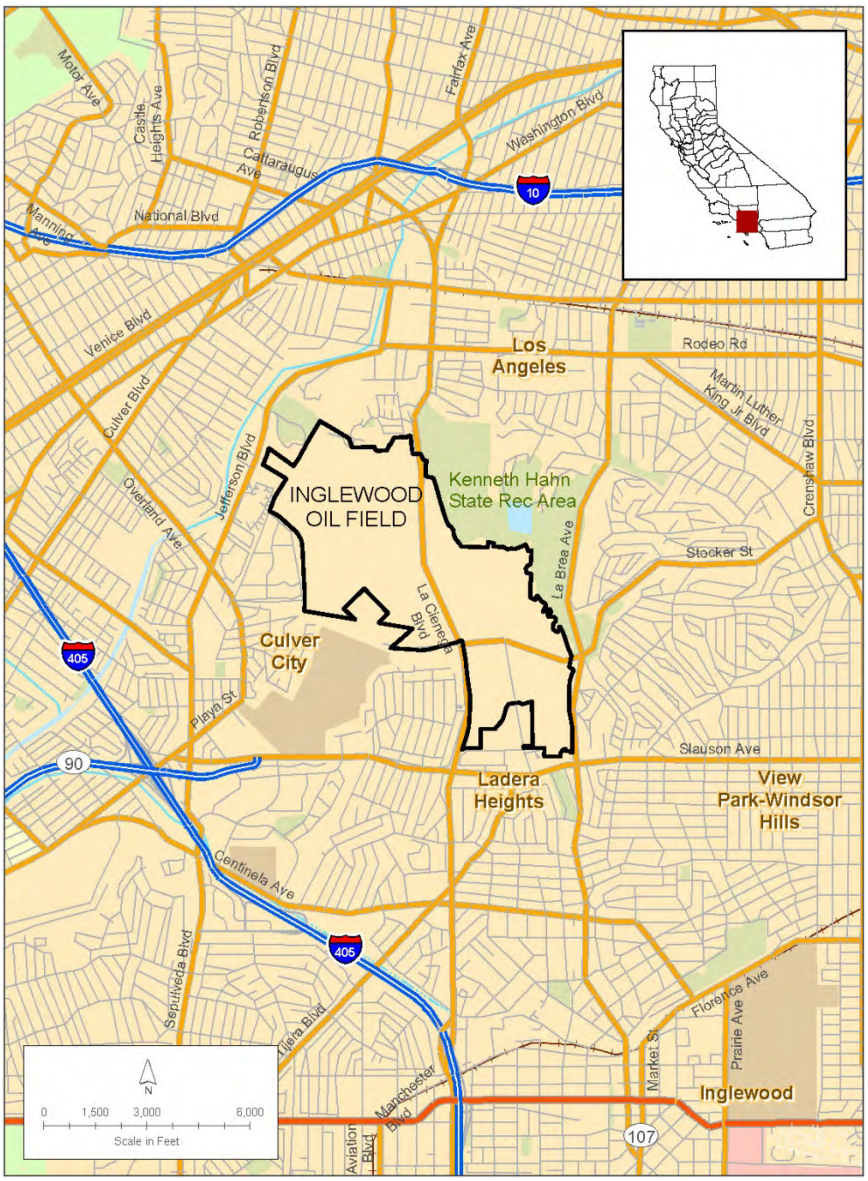

Figure 1-1 Regional Location Map

In October 2008, the County of Los Angeles (County) approved the Baldwin Hills Community Standards District (CSD), which created a supplemental district within the County to address the compatibility of oil production with adjacent urban land use. The CSD established permanent development standards, operating requirements, and procedures for the Los Angeles County portion of the Inglewood Oil Field. The northernmost areas of the field are within the city limits of Culver City, and PXP has voluntarily complied with the provisions of the CSD in that portion of the oil field as well.

Following adoption of the CSD, a lawsuit was filed against the County and PXP in late 2008, challenging the validity of the ordinance. The lawsuit was resolved through a Settlement Agreement that was signed on July 15, 2011 by the City of Culver City, Natural Resources Defense Council, Concerned Citizens of South Los Angeles, Citizens Coalition for a Safe Community, Community Health Council, the California Attorney General's Office, PXP, and the County of Los Angeles. The Settlement Agreement augments the protections contained in the CSD with 15 additional terms. This Hydraulic Fracturing Study is the direct result of Term 13, which states:

> *PXP shall pay for an independent consultant to conduct a study of the feasibility and potential impacts (including impacts to groundwater and subsidence) of the types of fracturing operations PXP may conduct in the Oil Field. The study will also consider PXP's historic and current use of gravel packing. Such study will be completed within twelve (12) months of the date of this Agreement. Such study and all the back-up information for such study shall be provided to a qualified peer reviewer selected by the County and PXP, who shall review the study, back-up materials, and conclusions for completeness and accuracy. PXP must provide the independent expert with all materials requested and reasonably necessary for an accurate and verifiable study. The peer reviewer will be provided with access to all the data and materials provided to the independent expert. The peer reviewer shall agree to keep all proprietary information confidential. If the peer reviewer determines that the study is materially inadequate, incomplete or inaccurate, it shall so advise PXP's consultant who will complete the study as reasonably recommended by the peer reviewer and provide the revised study to the peer reviewer within 90 days. Upon acceptance by the peer reviewer, the study and all supporting material, including comments by the peer reviewer, shall be forwarded to the County, DOGGR, the Regional Water Quality Control Board ("RWQCB"), CAP and Petitioners and be available to the public, with any proprietary information redacted.*

The Settlement Agreement Term 13 requires that the practice of high-rate gravel packing be included in this Hydraulic Fracturing Study. The process of high-rate gravel packing does not serve the same purpose as hydraulic fracturing and is a different process. Nonetheless, the practice is fully discussed in this study, in compliance with the agreement.

This study draws on several sources, including peer-reviewed literature, the Inglewood Oil Field CSD, the 2008 Environmental Impact Report (EIR) conducted for the CSD, data and analyses provided by Halliburton, who conducted the recent hydraulic fracturing operations at the field, and from numerous contractors performing monitoring studies before, during, and after the recent hydraulic fracturing and high-rate gravel pack test operations at the field.

In accordance with the Settlement Agreement, this study was reviewed by peer reviewers, jointly selected by the County and PXP. The peer reviewers, John Martin, Ph.D. and Peter Muller, Ph.D., C.P.G., were provided with the draft study and all reference materials. The peer reviewer's comments on the study, and their statement indicating that the revised study addressed all comments adequately and completely, thereby determining the study complete, is provided in Appendix A.

This Hydraulic Fracturing Study is organized as follows:

- **Chapter 1** presents the Study objectives.
- **Chapter 2** presents a brief summary of the distribution of oil production in the Los Angeles Basin providing regional perspective for the Hydraulic Fracturing Study. Chapter 2 also describes the geological setting at the Inglewood Oil Field, including the results of a 3-D depiction of the subsurface geology.
- **Chapter 3** describes oil and gas well drilling and completion methods. Hydraulic fracturing is a completion method and is described in the context of the overall well drilling and completion process. This Chapter describes hydraulic fracturing jobs performed at the Inglewood Oil Field by PXP, including a discussion of past, current, and potential future methods of hydraulic fracturing that have occurred, or may occur, at the field, and the two high-volume hydraulic fracture tests and two high-rate gravel pack tests conducted in 2011 and 2012.
- **Chapter 4** describes the setting, methods and results of extensive environmental monitoring conducted in conjunction with the hydraulic fracturing and high-rate gravel pack tests. Chapter 4 also includes a discussion of each environmental issue as raised in regulatory proceedings, agency studies, university studies, and in the media regarding high-volume hydraulic fracturing as applied in shale gas and tight sands reservoirs, principally in the northeastern United States, Texas, New Mexico and Colorado. Although exploration and development of shale gas differs from oil and gas production at the Inglewood Oil Field, the issues and concerns in states like Pennsylvania have helped shape public perceptions in the local community surrounding the oil field. The relevance of these issues to the Inglewood Oil Field is addressed in the context of the environmental monitoring conducted at the Inglewood Oil Field.
- **Chapter 5** describes the regulatory framework that governs hydraulic fracturing, drawing on information from across the country. This chapter also summarizes recent and ongoing studies by federal and state agencies on the environmental effects of hydraulic fracturing.
- **Chapter 6** provides the qualifications of the preparers of this document.
- **Chapter 7** provides supporting material and references, with complete citations and internet addresses for all sources used in this study.

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Chapter 2

Oil Production in the Los Angeles Basin and at the Inglewood Oil Field

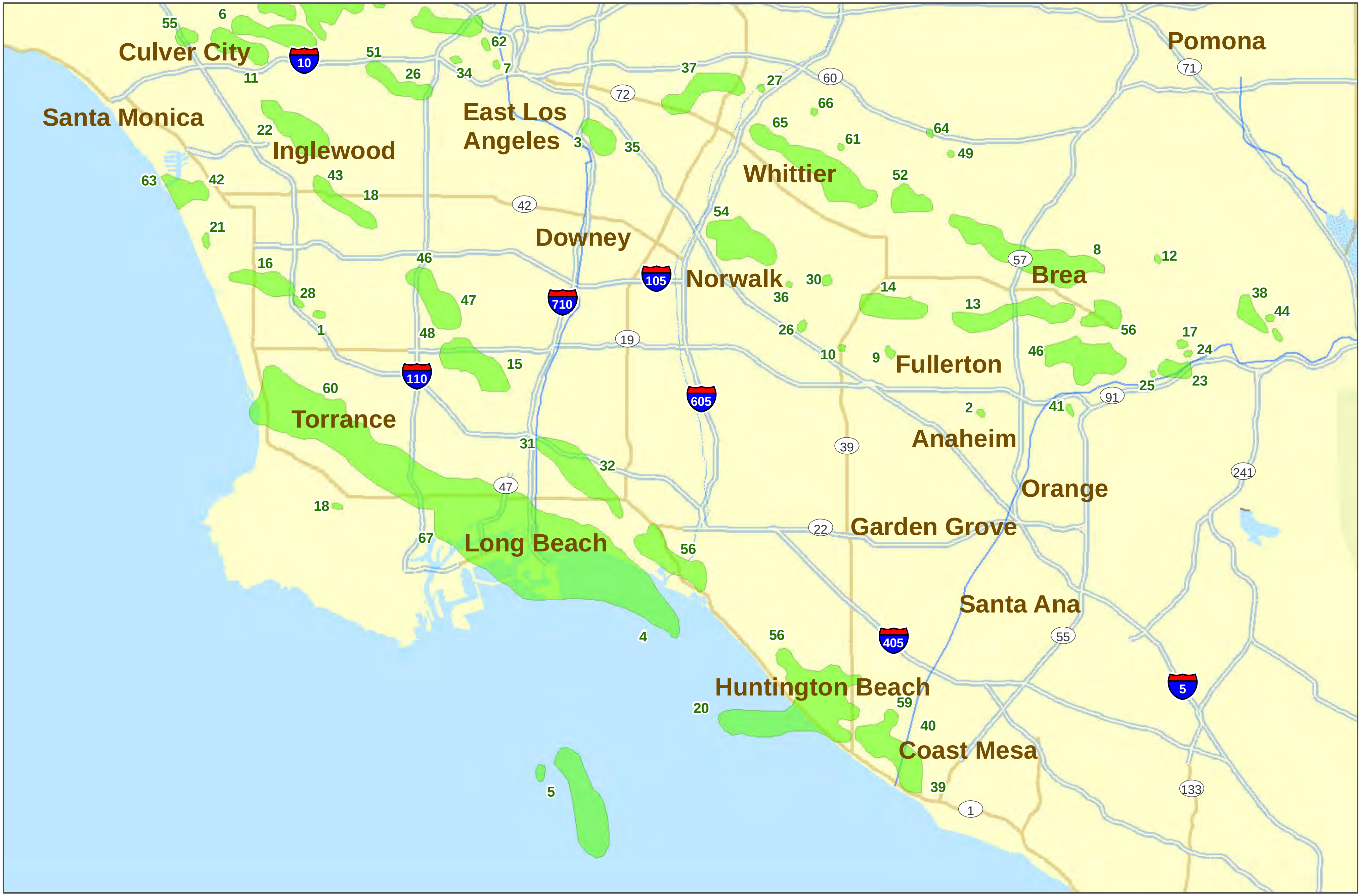
2.1 Introduction

California is the fourth largest oil producing state in the U.S. (U.S. Energy Information Agency 2012), and the Los Angeles Basin is the richest oil basin in the world based on the volume of hydrocarbons per volume of sedimentary fill (Biddle 1991). Oil was first discovered in the area at the Brea-Olinda Oil Field in 1880, followed by the development of the Los Angeles City Oil Field in 1893, the Beverly Hills Oil Field in 1900, the Salt Lake Oil Field in 1902, the Long Beach Oil Field in 1921, the Inglewood Oil Field in 1924, the Wilmington Oil Field in 1932, and many others. Figure 2-1 shows the distribution of major oil fields in the Los Angeles Basin (refer to Table 2-1 for the names of each oil field corresponding to the numbers on the figure). The size of this province, and its continuing potential for new discoveries and technologies, ensure its continued development into the future.

The Los Angeles Basin represents, from a global perspective, the optimum conditions for the generation and entrapment of hydrocarbons (Barbat 1958, Gardett 1971, Wright 1987a). Barbat, in particular, considered eight major controls on the occurrence and amount of oil in different basins around the world. He concluded that, "no matter how the Los Angeles Basin may differ from other oil-producing areas, the differences favor the Los Angeles Basin" (Barbat 1958).

The unique abundance of oil in the Los Angeles Basin derives from a thick section of layered sediments and organic-rich materials. The relatively recent geologic, tectonic, and structural history of the region has provided an optimal thermal history to bring the organic-rich material into the "oil window," the thermal regime that is ideal for oil production. This means that as the sediments and organic materials were buried, these source rocks reached high enough pressures and temperatures that they transformed to oil and natural gas.

The oil and natural gas migrated then from the source rocks, typically the Monterey shale formation, into overlying sandstones. The sandstones acted as reservoir rocks, accumulating and holding the oil and natural gas underground. The Los Angeles Basin is folded and faulted, and as a result, after migrating into the sandstone reservoir rocks, the oil and gas deposits become trapped by the folds and faults which are impermeable (do not allow for the passage of fluid), as well as relatively impermeable shale rocks which are also present. Therefore, the traps allow oil in the reservoir rocks to continue to accumulate at depth and not continue to migrate up to the surface. These traps are not ubiquitous, and in some locations oil continued to rise to the surface as seeps. The most famous local surface seep of oil is the La Brea Tar Pits.



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Legend

Oil Field

PLAINS EXPLORATION & PRODUCTION COMPANY

Figure 2-1

Location of Los Angeles Basin Oil Fields

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Table 2-1 Los Angeles Basin Oil and Gas Field

Number as shown on Figure 2-1	Field Name	Discovery Year	Estimated Ultimate Recovery		
			Oil[1] (kbbl mcf)	Gas[1] (mcf)	Oil-equivalent barrels (kbbl)
1	Alondra	1946	2,154	1,408	2,406
2	Anaheim (abd)	1951	4	--	4
3	Bandni	1953	5,969	15,469	8,738
4	Belmont Offshore	1948	68,500	41,931	76,006
5	Beta	1976	214,272	21,866	218,186
6	Beverly Hills	1900	164,131	215,163	202,645
7	Boyle Heights (abd)	1955	273	113	293
8	Brea-Olinda	1880	439,691	481,986	524,967
9	Buena Park, East (abd)	1942	197	20	201
10	Buena Park, West (abd)	1944	50	17	53
11	Cheviot Hills	1958	26,180	142,492	51,686
12	Chino-Soquel	1950	324	349	387
13	Coyote, East	1909	121,829	60,804	132,713
14	Coyote, West	1909	257,522	271,005	306,032
15	Dominguez	1923	276,846	387,394	346,190
16	El Segundo	1935	14,744	34,725	20,960
17	Esperanza	1956	1,331	699	1,456
18	Gaffey (abd)	1955	10	--	10
19	Howard Townsite	1947	6,162	27,810	11,140
20	Huntington Beach	1920	1,138,034	861,117	1,291,805
21	Hyperion	1944	798	209	835
22	Inglewood	1924	400,048	285,002	451,063
23	Kraemer	1918	3,925	1,078	4,118
24	Kraemer, Northeast (abd)	1953	unknown	--	--
25	Kraemer, West (abd)	1956	10	--	10
26	La Mirada (abd)	1946	25	10	27
27	Lapworth	1935	55	--	55
28	Las Cienegas	1960	36,349	55,550	75,293
29	Lawndale	1928	3,747	6,729	4,958
30	Leffingwell (abd)	1946	763	2,460	1,203
31	Long Beach	1921	927,428	1,087,440	1,121,773
32	Long Beach Airport	1954	11,572	35,003	17,838
33	Los Angeles City	1892	23,575	--	23,575
34	Los Angeles Downtown	1964	15,233	22,922	19,336
35	Los Angeles, East	1946	6,936	12,401	9,156
36	Mahala	1920	4,077	1,586	4,361

Table 2-1 Los Angeles Basin Oil and Gas Field

Number as shown on Figure 2-1	Field Name	Discovery Year	Estimated Ultimate Recovery		
			Oil[1] (kbbl mcf)	Gas[1] (mcf)	Oil-equivalent barrels (kbbl)
37	Montebello	1917	202,004	234,712	243,917
38	Newgate	1956	296	370	362
39	Newport	1922	187	259	233
40	Newport, west	1923	77,647	8,371	79,145
41	Olive	1953	3,020	1,209	3,236
42	Playa del Rey	1929	63,008	62,061	74,118
43	Portrero	1928	15,672	72,967	28,733
44	Prado-Corona	1966	1,632	5,192	2,561
45	Richfield	1919	217,340	173,067	248,319
46	Rosecrans	1924	83,339	166,330	113,112
47	Rosecrans, East	1959	202	234	243
48	Rosecrans, South	1940	8,835	20,661	12,533
49	Rowland (abd)	1931	2	--	2
50	Salt Lake	1902	53,683	211,894	91,612
51	Salt Lake, South	1970	10,091	4,503	10,897
52	Sansinena	1898	60,840	74,661	74,204
53	San Vicente	1968	21,043	19,433	24,522
54	Santa Fe Springs	1919	622,254	836,512	771,990
55	Sawtelle	1965	15,274	13,100	17,619
56	Seal Beach	1924	217,236	219,786	256,484
57	Sherman (abd)	1965	93	50	102
58	Sunset Beach	1954	6,910	9,591	8,627
59	Talbert (abd)	1947	126	4	127
60	Torrance	1922	247,562	162,573	276,593
61	Turnbell (abd)	1941	766	582	870
62	Union Station	1967	1,895	5,298	2,843
63	Venice Beach	1966	4,030	2,678	4,508
64	Walnut	1948	131	25	135
65	Whittier	1898	55,731	52,193	65,074
66	Whittier Heights, North (abd)	1944	85	84	235
67	Wilmington	1932	2,788,158	1,192,802	3,001,670
68	Yorba Linda	1930	94,781	2,174	95,170
Totals			9,074,637	7,628,134	10,439,275

SOURCE: Biddle 1991
[1]EUR = estimated ultimate recovery
kbbl = thousand barrels
mcf = million cubic feet
abd = abandoned

2.2 Petroleum Geology of the Los Angeles Basin

The Los Angeles Basin is approximately 70 miles long and 10 miles wide. It is a coastal sediment-filled trough located between the Peninsular Mountain Ranges and the Transverse Mountain Ranges in southern California. The Los Angeles Basin contains the central part of the city of Los Angeles as well as its southern and southeastern suburbs (both in Los Angeles and Orange counties).

The Los Angeles Basin was formed in a strike-slip tectonic setting (crust generally sliding side-to-side along faults). Two different phases of motion were involved: early extension overlain on the strike-slip motion, followed by more recent compression overlain on a weakening strike-slip system. These phases of evolution are in part illustrated by the number of faults that cut other faults in the subsurface (Biddle 1991). The following paragraphs describe this history in greater detail.

The Los Angeles Basin originated as a depositional basin caused by crustal extension overlapping with the regional, right-lateral strike-slip movement. Prior to five million years ago the Los Angeles Basin was submerged approximately 5,000 feet under the waters of the Pacific Ocean. During this period the marine basin collected sand, silt, and clay sediment from the surrounding upland areas. As surrounding mountain ranges (including the San Gabriel and Santa Monica mountains) rotated clockwise, the crust cracked, extended, and released molten rock from below. Over time the crust thinned and formed a basin, or bowl, with boundaries formed by the San Gabriel Mountains, Santa Monica Mountains, Santa Ana Mountains, and the Palos Verdes Peninsula. Sand, silt and clay from the sea and ancient rivers poured into the bowl-shaped depression. The sedimentary formations resulting from this deposition extend more than 30,000 feet downward before reaching bedrock.

The more recent history of faulting represents shortening of the basin caused by compression (counteracting the earlier extension), and a reduction in the amount of strike-slip motion, beginning approximately five million years ago. Compression of the basin created thrust faults. A thrust fault is a type of a break in the earth's crust in which older rock is uplifted over younger rock material. In the Los Angeles Basin, faults of this type uplifted the sediments and rock that had once lain at the ocean floor and brought them to the surface. This rock from the ocean floor consisted of alternating layers of sandstones and shales that had also previously folded and faulted. As it rose above sea level, this pile of sediment began forming the Los Angeles Basin.

Each of these phases of activity affected the oil producing characteristics of the basin. The extensional phases created a container into which sediments poured: both the Monterey shale, which is the source of the hydrocarbons, and the overlying sedimentary rocks that acted as the reservoir rocks once the oil formed and rose towards the surface. The more recent shortening of the basin has changed the overall shape of the basin, and modified the traps that allowed oil to accumulate in the reservoir sediments. The rapidly-subsiding, deep, Los Angeles Basin formed at the right time, and in the right place, with an appropriate geometry and thermal history, to form this uniquely rich oil province (Biddle 1991).

2.3 Petroleum Production in the Los Angeles Basin

The Los Angeles Basin is one of California's most prolific crude oil and natural gas regions. Figure 2-2 shows the amount of oil produced from Southern California oil fields since the discovery of the first field, Brea Olinda. Table 2-1, taken from Biddle (1991), summarizes the oilfields of the area, including the year of discovery and amount of oil and gas produced.

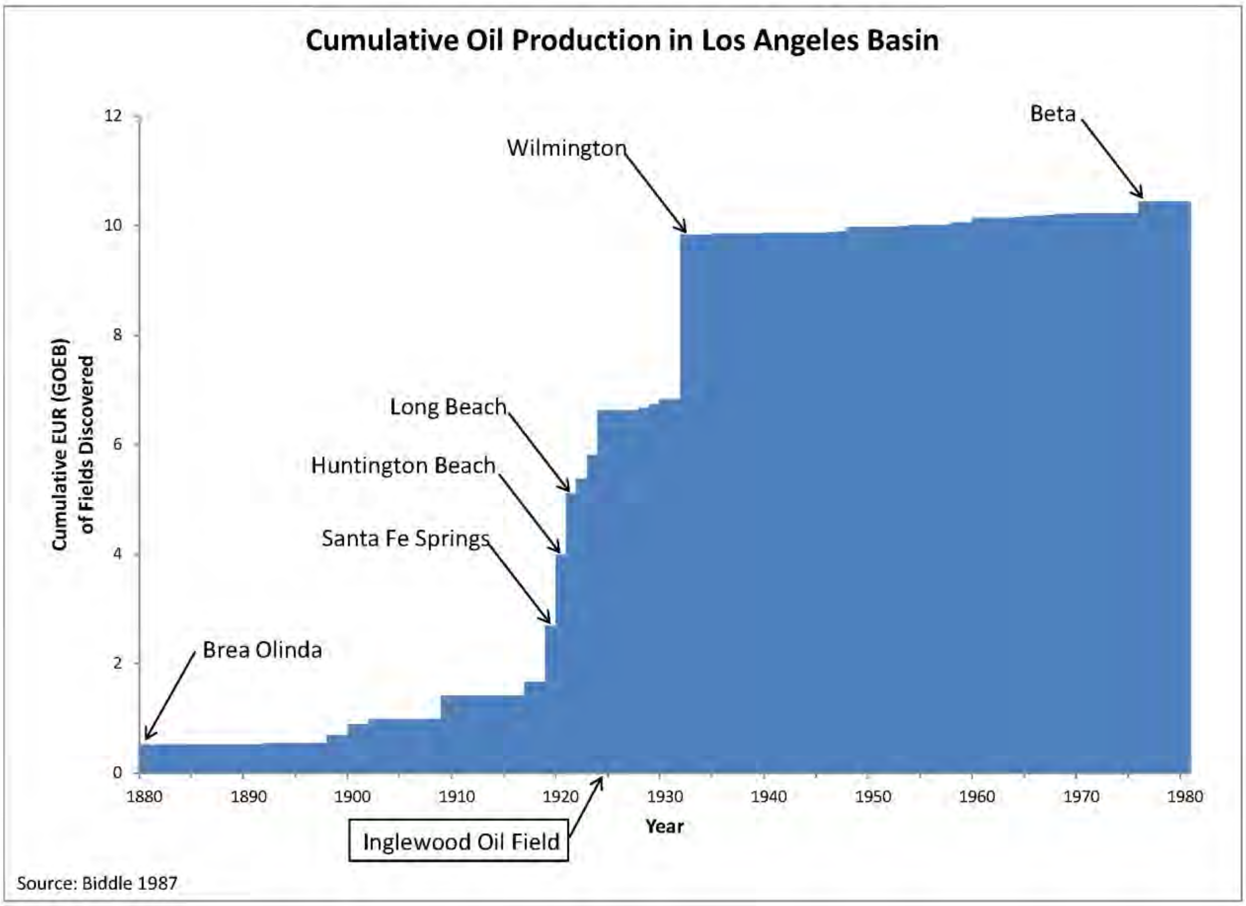


Figure 2-2 Cumulative Oil Production in the Los Angeles Basin

As of 2011, there are currently 42 active fields in the Los Angeles Basin. In 2011, the combined onshore and offshore oil production in California totaled approximately 197 million barrels, of which the Los Angeles Basin accounted for approximately 18 percent. Since 2007, an average of 2,700 wells has been drilled statewide annually (DOGGR 2011). Figure 2-3 shows the number of barrels of oil produced annually in California over the past decade (DOGGR 2007, 2011).

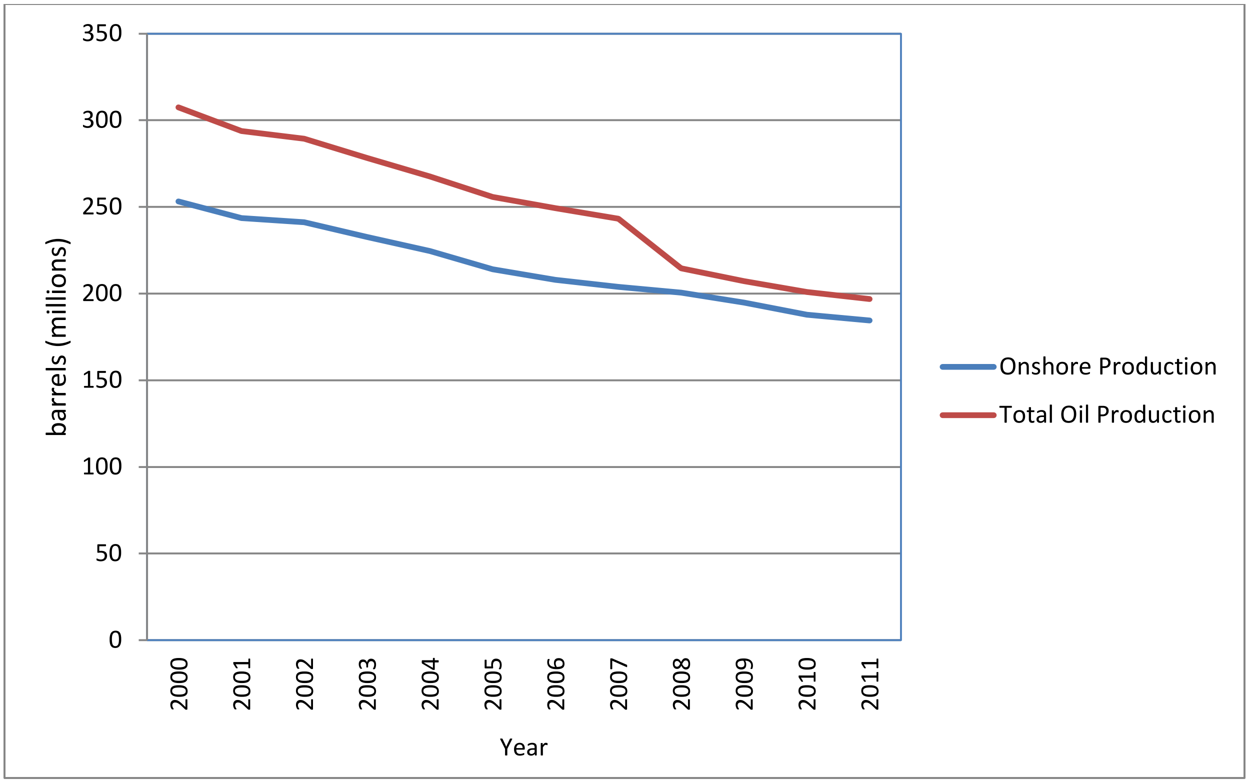


Figure 2-3 California Oil Production Since 2000

2.4 Petroleum Geology and Production at the Inglewood Oil Field

The approximately 1,000-acre Inglewood Oil Field is one of the largest contiguous urban oil fields in the United States. The Inglewood Field was discovered in 1924 and has produced an estimated cumulative production of 400 million barrels of oil. Oil and natural gas produced from the field is sold and used entirely in California. The oil field is adjacent to Culver City and the Los Angeles County communities of Baldwin Hills, View Park, Windsor Hills, Blair Hills and Ladera Heights. As of 2010, the U.S. Census Bureau estimated Los Angeles County's population to be 9.8 million. The area surrounding the field had a population of 65,892 in 2000. The population of this area has since remained relatively stable in comparison to the 2000 census data (U.S. Census Bureau 2010).

The Inglewood Oil Field was first commercially produced by Standard Oil in 1924, when livestock grazing (primarily by sheep) was the prevailing economic use of the land. The cultivated croplands had been reclaimed from the low-lying swampy terrain (cienegas) in the gently sloping portions of the Los Angeles Basin that surrounded the Baldwin Hills. Many of these lands were gradually converted to residential suburbs. With the incorporation of the City of Inglewood, residential development was spurred by transportation improvements, including the growth of highway network that transformed farmlands and displaced brick making industrial areas to the south of the Baldwin Hills.

In Culver City, both residential development and the foundation of movie studios and their associated supporting industries encroached upon the foothill slopes of the Baldwin Hills from the west and northwest. The northeastern and eastern sides of the Baldwin Hills were encroached upon by the westerly spread of the suburban growth of the City of Los Angeles (County of Los

Angeles 2008). Chilingar and Endres (2005) evaluate urban encroachment on active and inactive oil fields, primarily in the Southern California area. They conclude that "*a clear case is made for the urgent need for closer coordination and education by the petroleum industry of the local government planning departments…and in establishing mitigation measures for dealing with long-term environmental hazards*". The Baldwin Hills CSD, the associated EIR, and this Hydraulic Fracturing Study are examples of this advice put into practice.

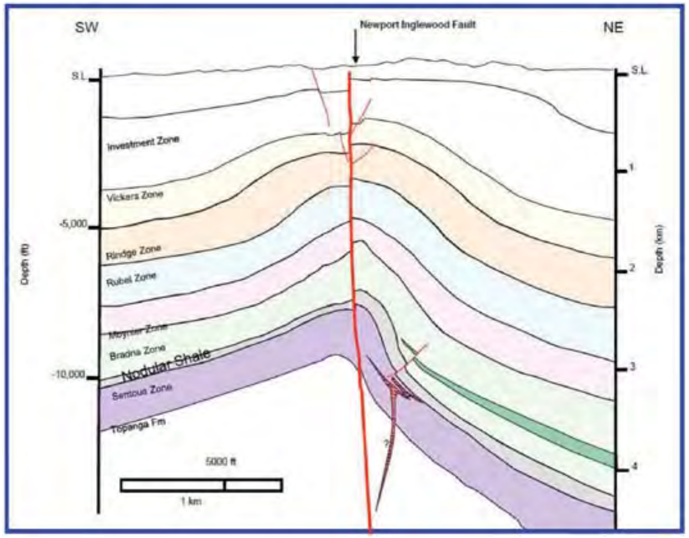
2.4.1 Inglewood Oil Field Geology

Overview

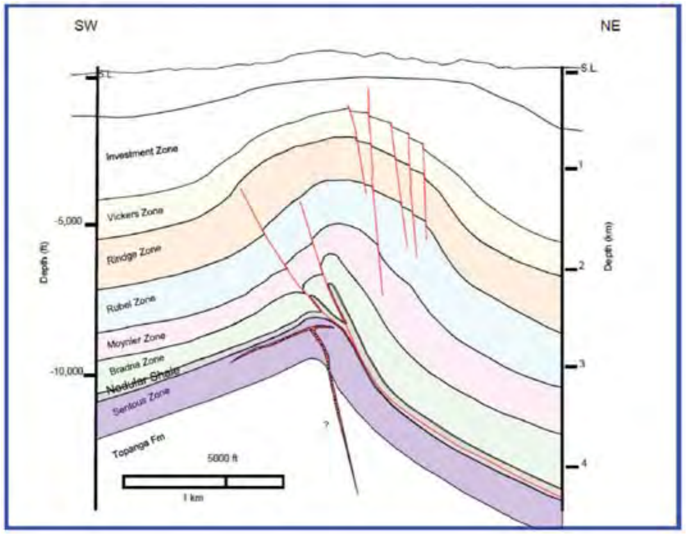
The Baldwin Hills form part of a chain of low hills along the Newport-Inglewood Fault Zone. The Baldwin Hills are the highest of these hills, reaching an elevation of 511 feet above mean sea level. The hills are in sharp relief against the relatively flat Los Angeles Basin, and include rolling hills cut by canyons and gullies. The northern flank of the Baldwin Hills has been deeply incised by erosion while the southern flank slopes gently to the Torrance Plain and Rosecrans Hills.

Figure 2-4 provides three geologic cross sections illustrating the sub-surface geology (cross section locations shown in Figure 2-6), while Table 2-2 provides details regarding the thickness of each formation. The southernmost cross section in Figure 2-4 shows the Newport-Inglewood Fault as cutting all the petroleum-producing units at the field. Moving north to the central part of the field, the cross section depicts the dissipation of the Newport-Inglewood Fault as it approaches the relatively east-west Santa Monica fault further to the north. At depth, the Newport-Inglewood Fault transitions to the series of folds and thrust faults at depth. Moving to the northernmost cross section, the Newport-Inglewood Fault is no longer present, and the movement here and further to the north is likely accommodated by a combination of folds and thrust faults. This depiction of the geology is based on the data collected by well drilling and by seismic surveys, and is described in Wright (1991).

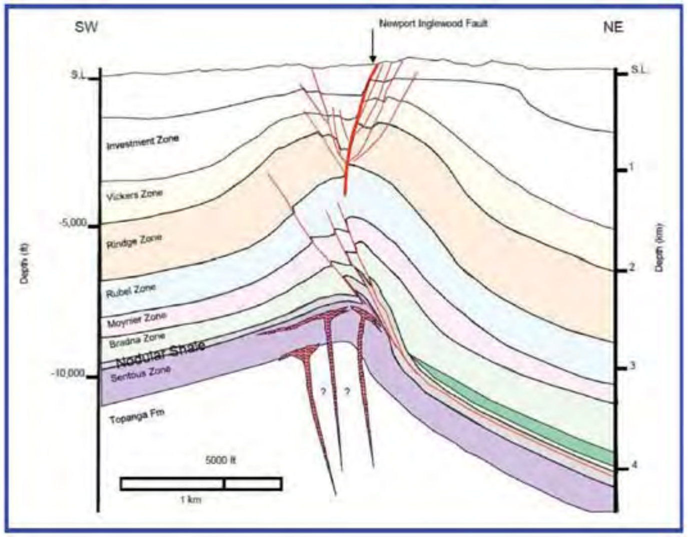
The Baldwin Hills have been uplifted by folding and faulting of the underlying geological formations. A northwest-trending anticline (upward-directed fold) is developed in sediments of Tertiary and Pleistocene age (23 million to 1.8 million years ago–see Table 2-3) beneath the Baldwin Hills. Two principal northwesterly trending, nearly parallel faults offset the central portion of the hills, developing a down-dropped trench, or graben, across the crest of the anticline. The more easterly of the two structures is the Newport-Inglewood Fault; the other fault is unnamed. Both faults are offset by secondary cross faults which trend northeast. The block east of the Newport-Inglewood Fault is composed of sediments of Pliocene age (approximately 5 million years ago) and older and is cut by several small unnamed faults. The modified geological timescale (Figure 2-5) summarizes the intensity of tectonic activity with time, as well as the major units that formed during each phase and the principal biological markers used to identify the units.



Schematic cross section of Inglewood Field, southern portion (Elliot 2009)



Schematic cross section of Inglewood Field, northern portion (Elliot 2009)



Schematic cross section of Inglewood Field, central portion (Elliott 2009)

Source: Wright, 1991

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Figure 2-4

Cross Section of Structure and Geologic Formation

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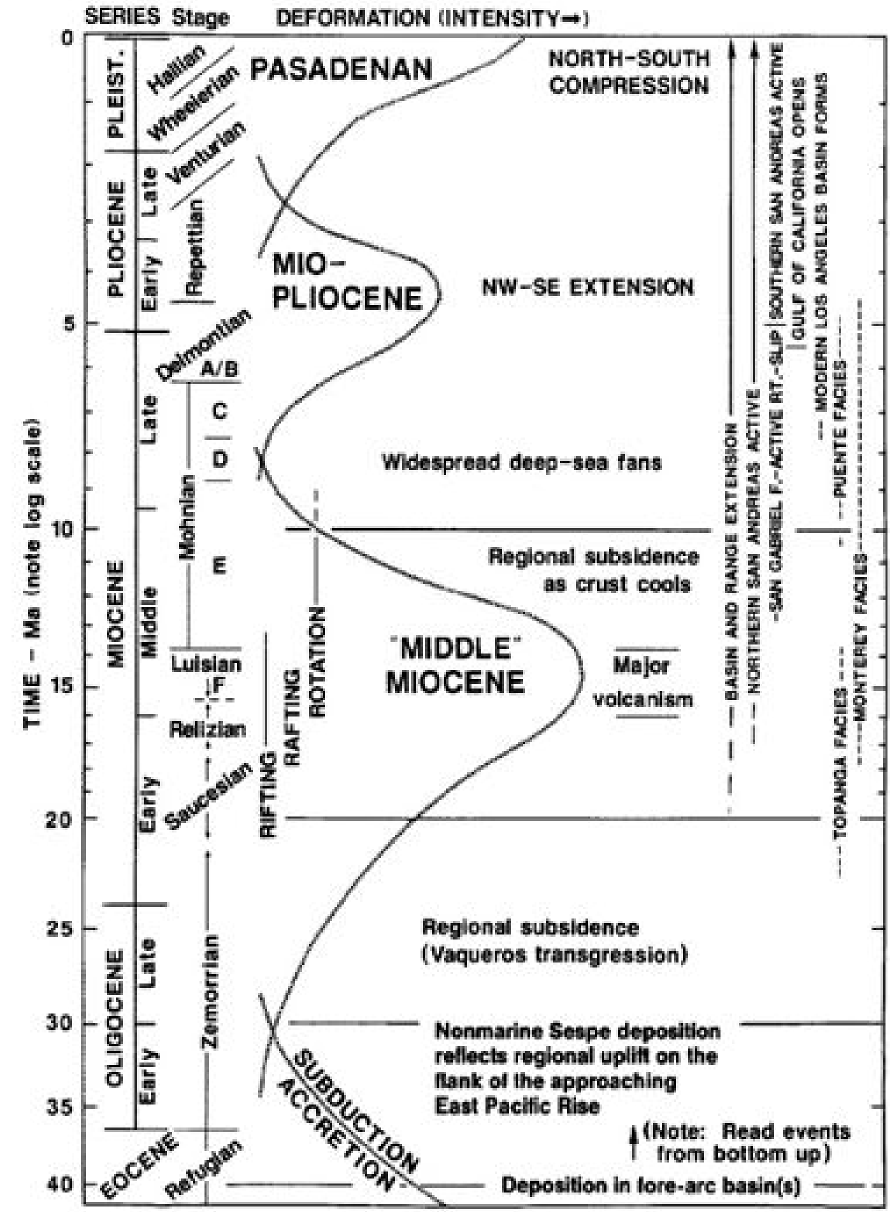
Table 2-2 Stratigraphy of the Inglewood Oil Field

<table>
<tr><th>Epoch</th><th colspan="2">Formation</th><th>Reservoir</th><th>Thickness</th></tr>
<tr><td rowspan="3">Pleistocene</td><td colspan="2">San Pedro</td><td></td><td>0' - 200'</td></tr>
<tr><td colspan="2">Inglewood</td><td></td><td>150' - 300'</td></tr>
<tr><td rowspan="4">Pico</td><td>Upper</td><td></td><td>150' - 300'</td></tr>
<tr><td rowspan="3">Upper Pliocene</td><td rowspan="2">Middle</td><td>Investment</td><td>200' - 600'</td></tr>
<tr><td rowspan="3">Vickers</td><td rowspan="3">1500' - 1700'</td></tr>
<tr><td>Lower</td></tr>
<tr><td rowspan="6">Lower Pliocene</td><td rowspan="6">Repetto</td><td rowspan="2">Upper</td></tr>
<tr><td>Rindge</td><td>900' - 1000'</td></tr>
<tr><td rowspan="2">Middle</td><td>Upper Rubel</td><td>250' - 300'</td></tr>
<tr><td>Lower Rubel</td><td>600' - 700'</td></tr>
<tr><td rowspan="2">Lower</td><td>Upper Moynier</td><td>300' - 400'</td></tr>
<tr><td>Lower Moynier</td><td>600' - 700'</td></tr>
<tr><td>Upper Miocene</td><td rowspan="4">Puente</td><td></td><td>Bradna</td><td>700' - 1800'</td></tr>
<tr><td rowspan="5">Middle Miocene</td><td rowspan="2"></td><td>City of Inglewood</td><td>0' - 250'</td></tr>
<tr><td>Nodular Shale</td><td>150' - 175'</td></tr>
<tr><td rowspan="2"></td><td>Sentous</td><td>200' - 1000'</td></tr>
<tr><td rowspan="2">Topanga</td><td rowspan="2">Topanga</td><td rowspan="2">1500'</td></tr>
<tr><td></td></tr>
</table>

Table 2-3 Geologic Time Scale

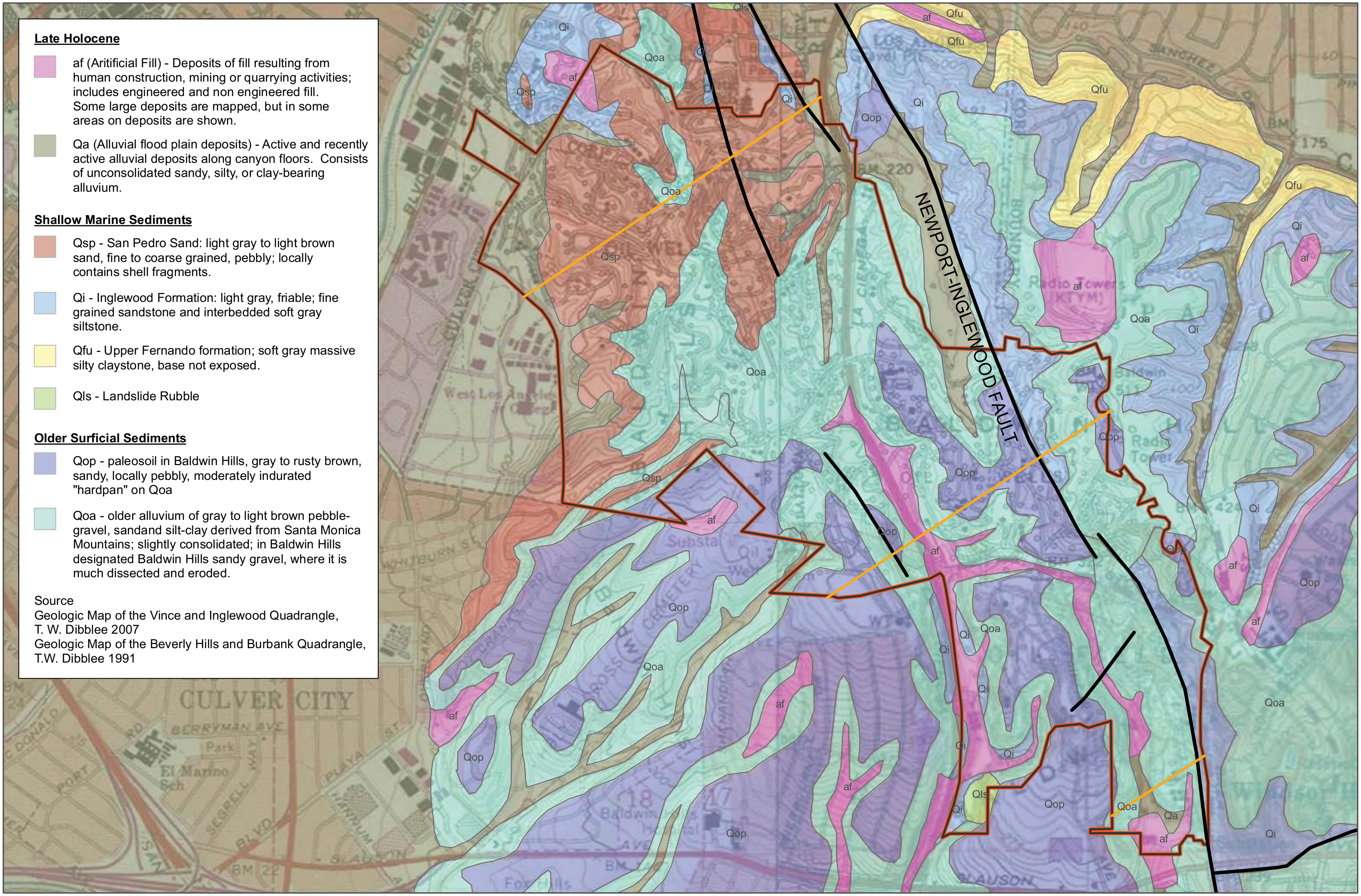
Era	Period	Epoch	Years Before Present
Cenozoic	Quaternary	Holocene	10 thousand
		Pleistocene	1.8 million
	Tertiary	Pliocene	5 million
		Miocene	23.5 million
		Oligocene	39 million
		Eocene	53.5 million
		Paleocene	65 million
Mesozoic	Cretaceous		144 million
	Jurassic		208 million
	Triassic		245 million
Paleozoic	Permian		286 million
	Pennsylvanian		320 million
	Mississippian		360 million
	Devonian		408 million
	Silurian		438 million
	Ordovician		505 million
	Cambrian		570 million
	Ediacarian		700 million



Source: Wright 1991

Figure 2-5 Chronology of Major Cenozoic Events in the Los Angeles Region

Figure 2-6 depicts the surface geology. Compared to the surrounding Los Angeles Basin, the geology of the Baldwin Hills exposes older and deeper geological formations. In addition, the Newport-Inglewood Fault and other related faults are shown as they are interpreted to occur near the surface. This structural discontinuity between the Baldwin Hills and the surrounding basin in part explains the occurrence of oil and gas at this location, and the discontinuity of shallow groundwater with deeper groundwater formations in the Los Angeles Basin (USGS 2003).



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LEGEND

Fault Line

Inglewood Oil Field Boundary

Approximate location of cross sections displayed in Figure 2-4

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Figure 2-6

Geologic Formations Present at the Inglewood Oil Field and Vicinity

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3-D Depiction of Inglewood Oil Field Geology

As part of the development of this study, Halliburton was retained to develop a three-dimensional (3-D) geological depiction of the subsurface of the Baldwin Hills, from the depth of the Sentous, the lowest known formation (10,000 feet below ground surface), up to the surface. The 3-D depiction is based on geological and structural data from drilling oil wells. The objective was to assist in the interpretation of the results of the high-volume hydraulic fracturing operation, and to better understand the relationship between the deep oil-producing formations and the shallow subsurface including the occurrence and distribution of shallow groundwater. The following discussion describes each formation, ending in the present-day land surface. The final 3-D model is used to depict the results of hydraulic fracturing, and of the discontinuous, fragmented water-bearing zones at shallow depths beneath the field, and the units that constitute the hydrocarbon seal that traps oil and gas in the deep subsurface (Figure 2-7).

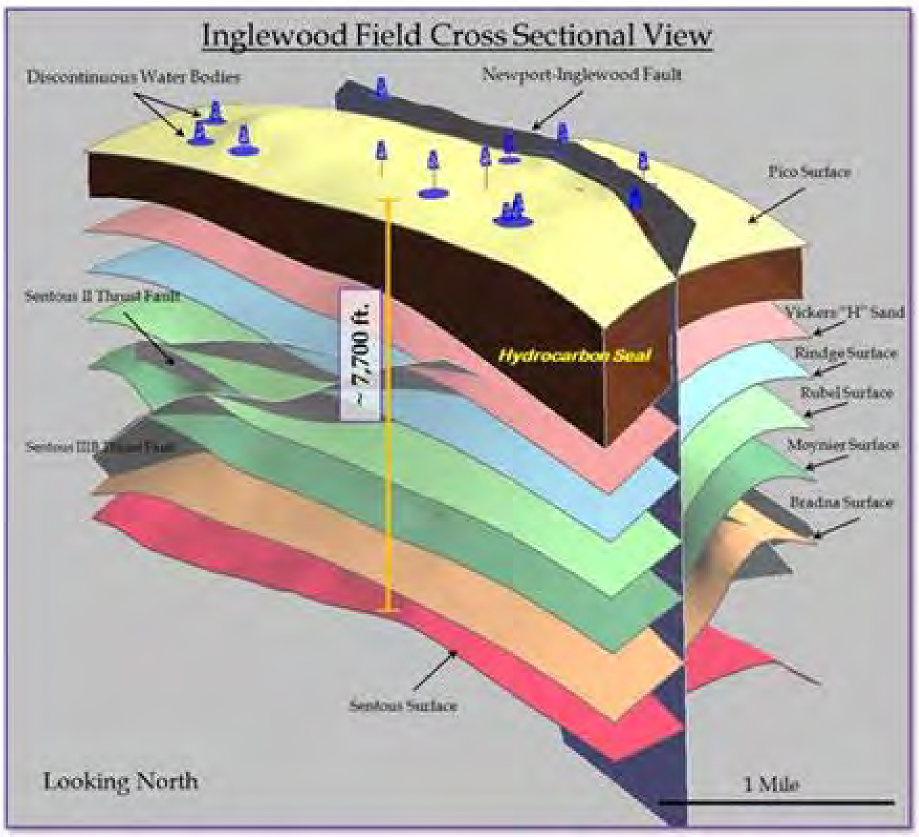


Figure 2-7 Cross Section of the Inglewood Oil Field Earth Model

In the following, each figure shows the progressive development of the field, starting with the deepest, oldest unit evaluated, the Sentous Sandstone. This presentation is used to show the growth of the formations and the folding and faulting specific to the area beneath the Inglewood Oil Field, as it is currently understood. Once constructed, this 3-D depiction is used to illustrate some of the study results later in the study.

Also shown for reference are the two wells that had high-volume hydraulic fracturing (VIC1-330 and VIC1-635), four wells that had conventional hydraulic fracturing in the past in the Sentous formation, and the two wells that had high-rate gravel packs (TVIC-221 and TVIC-3254). The yellow marker is the surface location of the well, and the red line is the length of the well. Each layer represents the top of one of the formations described above, and the space in between would be filled with that particular geologic formation (shale or sandstone). The fault planes are shown as colored layers cross-cutting the geologic formations. All the depictions are constrained by geological and structural data for the oil field.

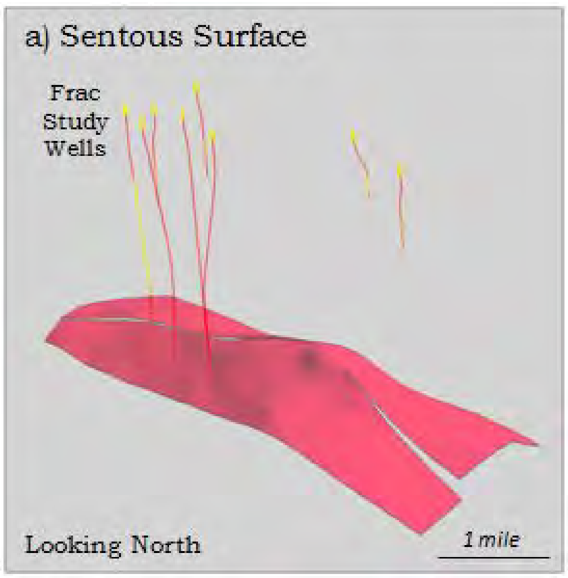


Figure 2-8A Sentous Surface

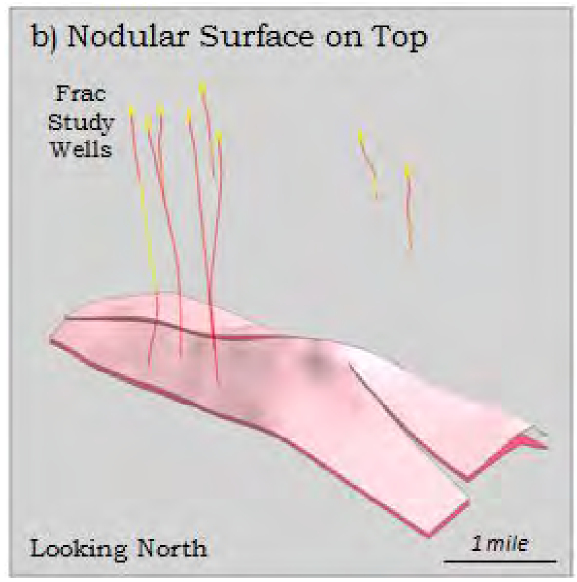


Figure 2-8B Nodular Surface on Top

The top of the Sentous sandstone is shown in Figure 2-8A. The Sentous is also known as the Topanga Formation elsewhere in the Los Angeles Basin. This was a period of active volcanic activity; the basin was under an extensional regime and a strike-slip regime, forming a pull-apart basin that was actively subsiding. The volcanic intrusions into the sediments filled from the bottom, and at the same time erosion from distant land areas fed sandy sediments to form the Sentous sandstone. The microfauna indicate a depth of 3,000 to 4,000 feet below the ocean surface during this time. There are similar microfauna now in the Gulf of California, indicating that water temperatures were higher than today. All of the volcanic deposits are found below this layer.

The base of the Nodular Shale is also the top of the Sentous (Figure 2-8B). The Nodular Shale grades directly from the Sentous sandstone. This organic rich shale that is the source rock for much of the oil found here, and is approximately 150 feet thick; at the time of deposition, it may have been as much as 400 feet thick but has since been compressed. The mineralogy of the shale includes plagioclase derived from the volcanic rocks, and clay from the distant landmass depositing in the basin. The grain size became finer because of a decrease in the land-based sediment, leading to dominantly marine shale deposit. The Nodular Shale was deposited across the Los Angeles Basin. The subsidence of the Los Angeles Basin ceased approximately 2 million years ago.

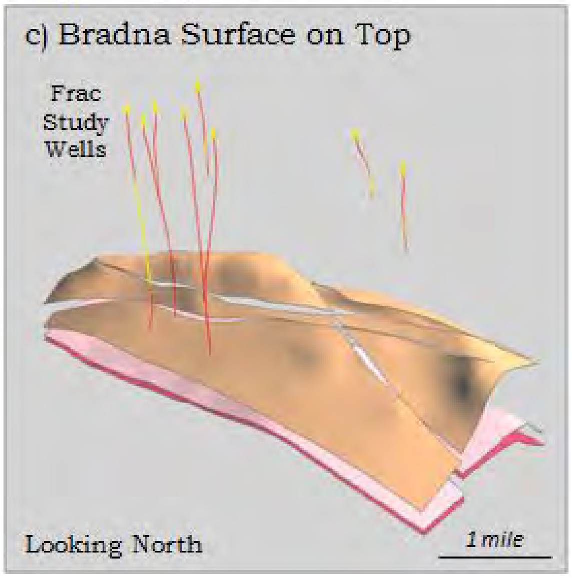


Figure 2-8C Bradna Surface on Top

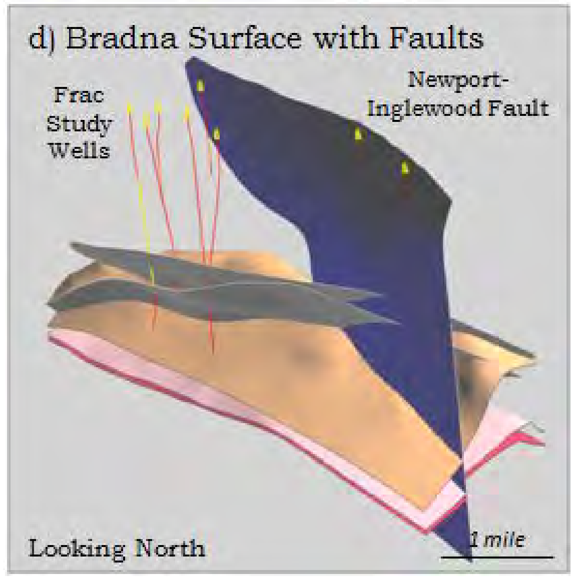


Figure 2-8D Bradna Surface with Faults

The Pasadenan Orogeny (mountain building) began about 2 million years ago. The activity led to uplift and rotation of plates, and a transition from a strike slip and extensional regime to a strike slip and compressive regime. Compaction and uplift forms the Baldwin Hills at this time, and is ongoing today. During this time period, the traps started to form; the folds and faults act as impermeable zones that allow oil to accumulate beneath them. It is believed that the Newport-Inglewood Fault may have originated as a normal fault giving it a steep angle, and accommodated the strike-slip motion. The two grey faults in Figure 2-8D are thrust faults accommodating the compression. This block was likely oriented NW-SE, but has rotated to E-W.

The Newport-Inglewood Fault is also shown in Figure 2-8D. The Newport-Inglewood Fault terminates in the northern portion of the field, as depicted in Figure 2-4, and Figure 2-8D expands on that termination. The fault likely transitions to folds or thrust faults as it approaches the Santa Monica Fault to the north.

The interval above the Nodular Shale at Inglewood includes the Bradna Shale. In other Los Angeles Basin fields, such as Long Beach and Beverly Hills, sands were deposited instead of the Bradna Shales. It is thought that the Inglewood area at the time formed a topographic high, such as a submarine knoll.

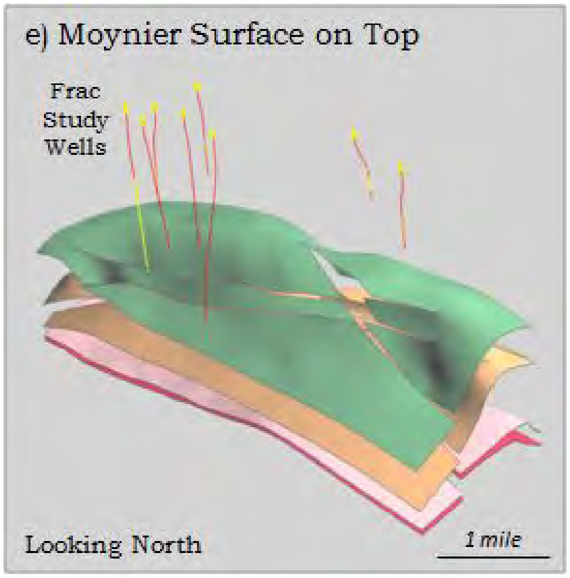


Figure 2-8E Moynier Surface on Top

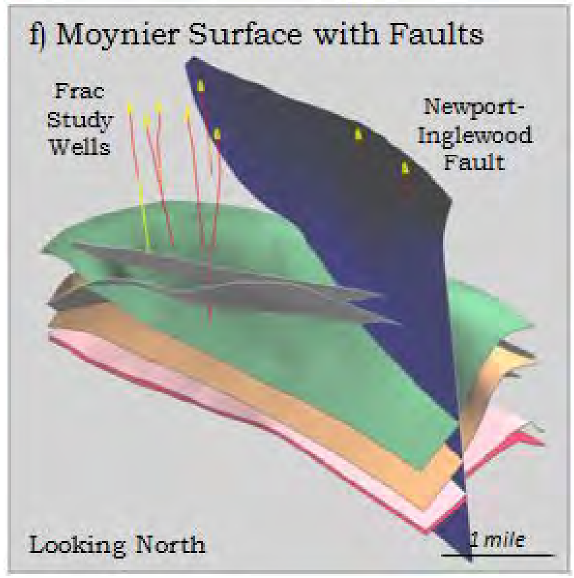


Figure 2-8F Moynier Surface with Faults

The Moynier formation is shale, likely reflecting the submarine knoll that is more or less unique to the Inglewood Oil Field compared to other parts of the Los Angeles Basin. Some sand channels begin to appear in Moynier time, but they are minor.

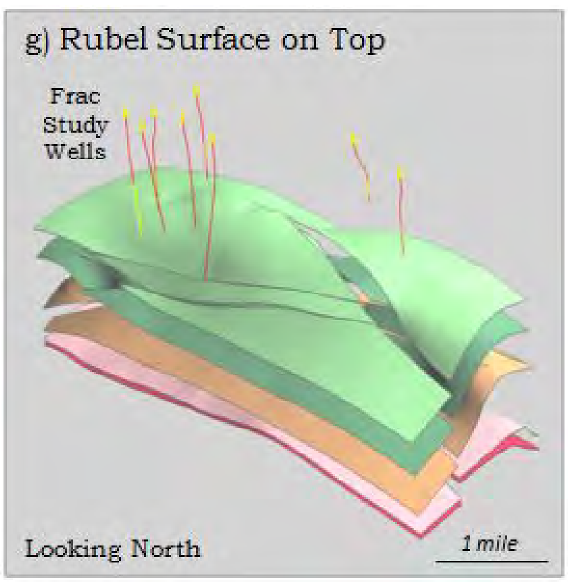


Figure 2-8G Rubel Surface on Top

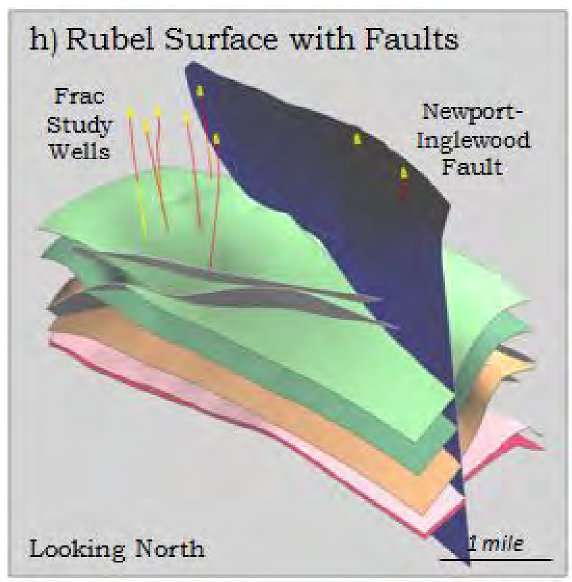


Figure 2-8H Rubel Surface with Faults

The Rubel marks the return of sand after the Sentous sandstone. It is the first major sand unit, and is the first major petroliferous zone at Inglewood. Approximately 90 percent of oil production is from the sandy submarine debris flow deposits (turbidities), first represented by the Rubel formation. These are deep-sea fans that funnel land-derived sands down to the deep ocean area. These formations are overlapping fans, and are currently active offshore of Southern California.

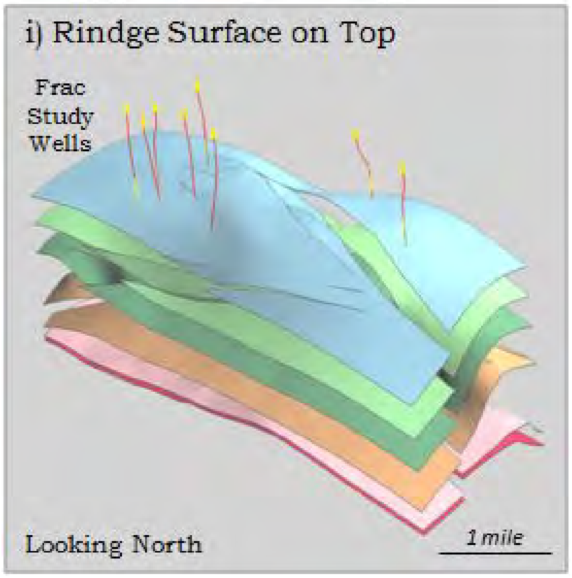


Figure 2-8I Rindge Surface on Top

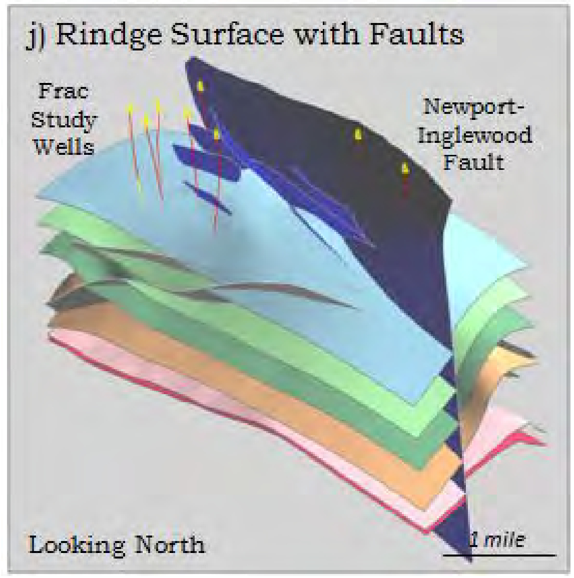


Figure 2-8J Rindge Surface with Faults

The Rindge Formation is another productive sandstone for oil development. New structures are represented here in Figure 2-8J. These are interpreted as normal faults. The area was still dominantly strike slip with compression, but we interpret these as relatively shallow normal faults. These form the graben structure in the southeastern portion of the field. These could also be dominantly strike-slip faults with a normal component.

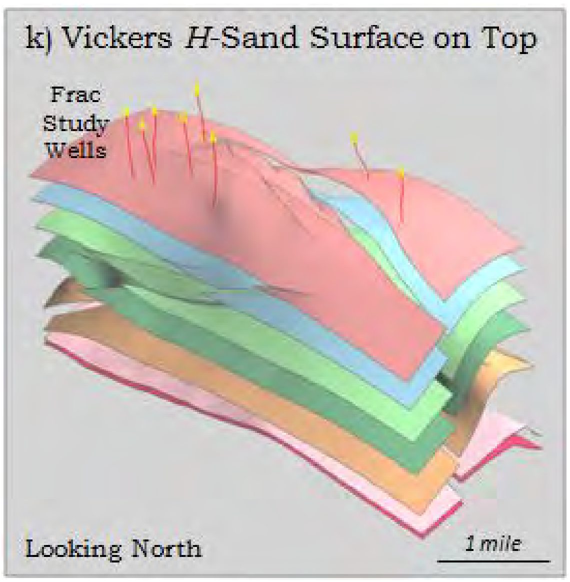


Figure 2-8K Vickers H-Sand Surface on Top

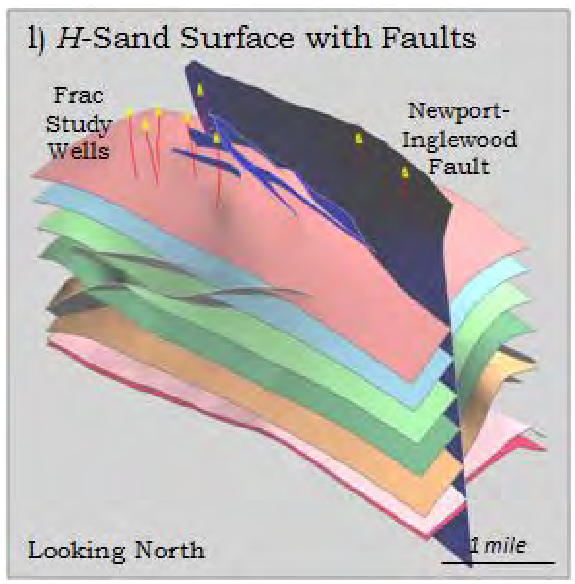


Figure 2-8L H-Sand Surface with Faults

The Vickers unit is another productive sandstone, similar to the description for the Rindge.

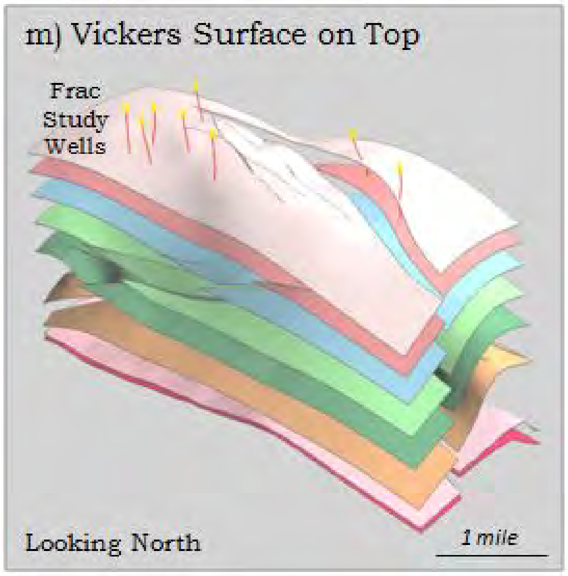


Figure 2-8M Vickers Surface on Top

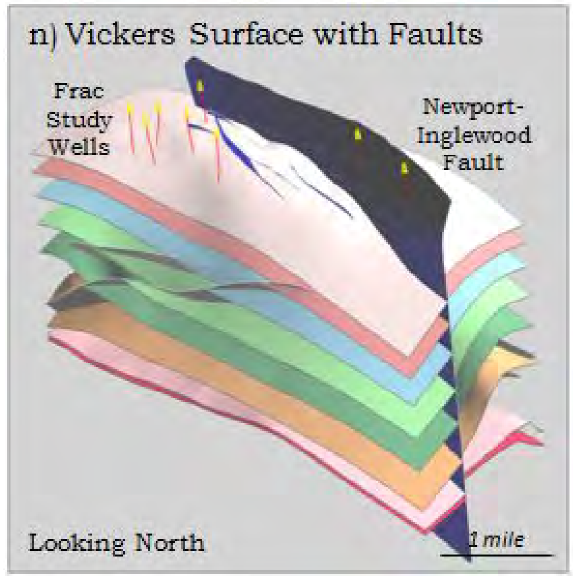


Figure 2-8N Vickers Surface with Faults

Figure 2-8O UIHZ Surface on Top

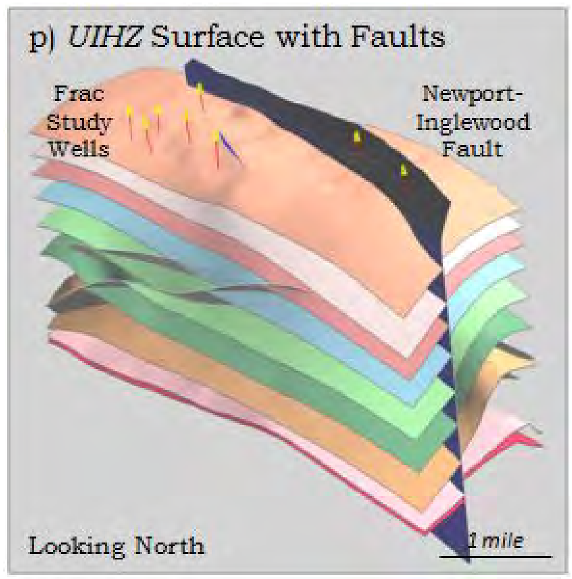


Figure 2-8P UIHZ Surface with Faults

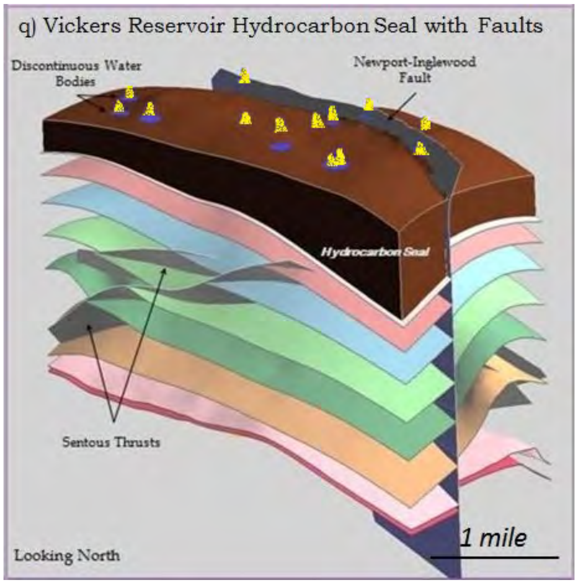


Figure 2-8Q Vickers Reservoir Hydrocarbon Seal with Faults

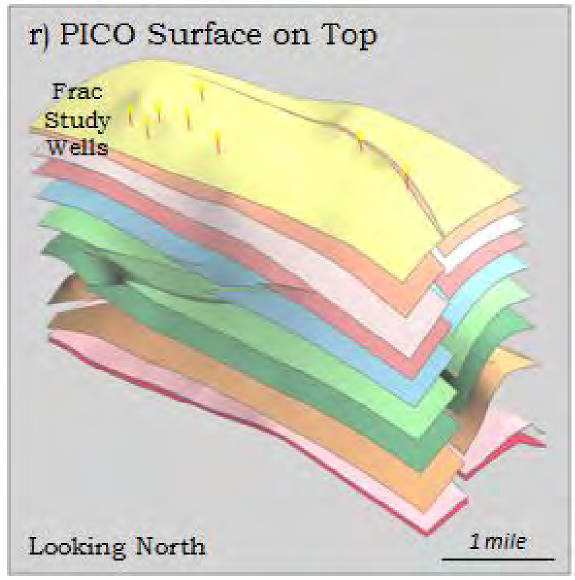


Figure 2-8R PICO Surface on Top

There is a prominent, relatively impermeable layer at the top of the Vickers, within the upper portion of the Pico Formation. The impermeable layer is more shale-rich than the underlying sandstones and forms a seal, inhibiting further upward migration of oil and gas. There are limited oil and gas deposits in the lowermost portion of the hydrocarbon seal; these are known as the Investment Zone. The folded and faulted units below act as traps beneath this seal. The depositional environment is still similar to that of the sandstones: submarine turbidite fans. However, this time may have been relatively less active, so the deposits are finer grained and formed a relatively impermeable shale instead of a sandstone.

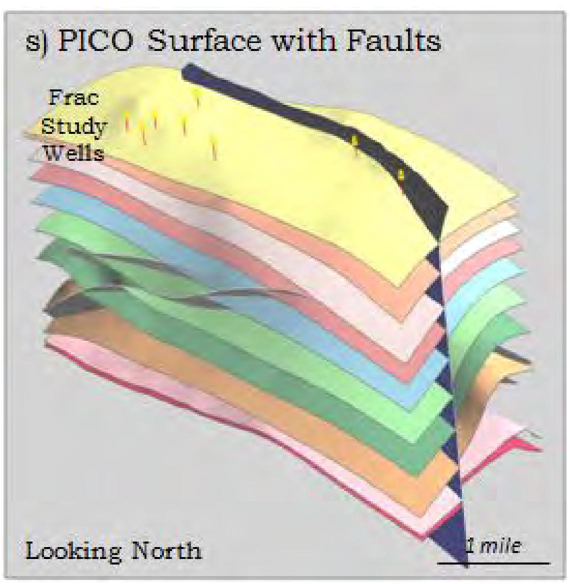


Figure 2-8S PICO Surface with Faults

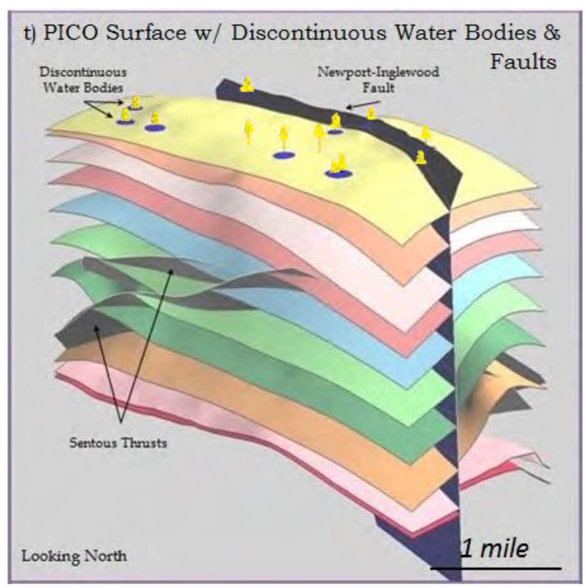


Figure 2-8T PICO Surface w/ Discontinuous Water Bodies & Faults

The top of the Pico Formation is also considered the Base of Fresh Water across much of the Los Angeles Basin. The Pico is a marine formation similar to the underlying units, and the formation water is salty. At shallower depths, above the Pico (Figure 2-8T), water is relatively fresh, but occurs in isolated, discontinuous water bearing zones that do not provide a sufficient yield for water supply, and are separated from the water-bearing zones elsewhere in the Los Angeles Basin. The aerial photograph of the Inglewood Oil Field is overlain on the geologic strata to provide reference (Figure 2-8U).

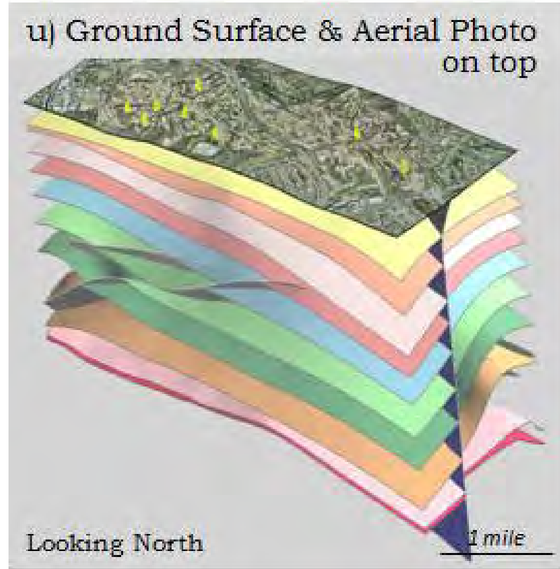


Figure 2-8U Ground Surface & Aerial Photo on Top

2.4.2 Petroleum Producing Zones

The field produces oil, natural gas, and saline water from interbedded sandstone and shale sediments ranging from Miocene Upper Topanga Formation (approximately 15 million years in age) to late Pliocene Upper Pico Formation (approximately 2 million years in age). See Table 2-3 for Geologic Time Scale. Production within the field is from nine zones that range in depth from about 900 to 10,000 feet. In order of increasing depth and increasing geologic age, the producing horizons are: Upper Investment-Investment, Vickers, Rindge, Rubel, Upper and Lower Moynier, Bradna, City of Inglewood, Nodular Shale, and the Sentous (refer to Figure 2-4, which illustrates the geology of the Baldwin Hills). The shallow reservoir zones (Vickers and Rindge zones) have been undergoing waterflood treatment since 1954. Each of the producing formations, along with the active wells completed in each zone, is summarized in Table 2-4.

Table 2-4 Summary of Active and Idle Wells within Each Oil and Gas-bearing Formation on the Inglewood Oil Field

Series	Formation	Average Depth Below Ground Surface	Number of Active Wells		Number of Idle Wells	
			Producer	Injector	Producer	Injector
Upper Pico	Upper Investment-Investment	1,000 feet	5		9	
	Vickers	2,000 feet	188	83	45	28
	Vickers-Rindge[1]	2,000 – 3,000 feet	167	67	27	33
Lower Repetto	Rindge	3,000 feet	10	3	5	1
	Rubel	4,000 feet	8	4	6	3
	Rubel-Moynier[2]	4,000 – 5,000 feet	16	5	5	
	Upper Moynier	5,000 feet	22	4	28	4
	Lower Moynier	5,500 feet				
Upper Puente	Bradna	6,000 feet	1			
	City of Inglewood	7,000 feet	1		2	1
	Nodular Shale	8,000 feet				
Upper Topanga	Sentous	8,500 feet	12			
Wells drilled within other transition areas between formations			39	2	14	1
		Total	469	168	141	73

Source: Fugro Consultants 2011, PXP 2012

[1]These wells are completed in both the Vickers and Rindge formations
[2]These wells are completed in both the Rubel and Moynier formations

A total of 1,475 oil wells have been drilled on the Inglewood Oil Field; these are active, idle, or plugged. Many have been directionally drilled and are non-vertical (i.e., drilled on a slant or angle). There were 469 active production wells and 168 active waterflood injection wells operating as of the writing of this study. Table 2-4 identifies the number of producing (pumping) well and injection wells in each zone, divided between active and idle wells. Plugged and abandoned wells are not included in Table 2-4.

Vickers and Rindge Formations

The Vickers and Rindge zones accounted for more than 74 percent of the total cumulative production at the Inglewood Oil Field in 2011 and 2012 (to date). Overall, the shallow and extensive Vickers and Rindge zones have produced more than half of all the oil produced over the life of the Inglewood Oil Field. In the context of this study, all of the high-rate gravel packs have been completed in these two zones.

The primary development focus in the Vickers and Rindge zones occurs between 2,000 and 4,000 feet below the ground surface; limited production from the Investment Zone occurs at approximately 1,000 feet. The formations are cut by faults, which act as barriers to fluid flow because they cut off permeable sand formations.

Nodular Shale Formation

The Nodular Shale is the name given to that portion of the Upper and Middle Miocene rocks of the Western part of the Los Angeles Basin that carry large phosphatic nodules. It is a subunit of the Monterey Formation. The Nodular Shale is known to underlie several oil fields of the Los Angeles Basin including Playa Del Rey (Hoots 1931, Wissler 1943), El Segundo (Porter 1938, Wissler 1943), Inglewood (Wissler 1943), Torrance (Wissler 1943), and Wilmington (Wissler 1943). It is also suspected to underlie the Beverly Oil Field (Hoots 1931) and the Lawndale Oil Field. In the context of this Hydraulic Fracturing Study, the only two high-volume hydraulic fracture completions that have occurred at the Inglewood Oil Field have been done within this formation.

The Nodular Shale is a highly organic, dark brown to black shale, and has produced small amounts of oil in several wells at Inglewood. This distinctive unit was deposited on deeply submerged offshore ridges and slopes through the slow accumulation of biological debris, diluted by clay particles carried in suspension by circulating ocean currents. The high organic content of the Nodular Shale indicates the presence of anaerobic conditions seen in the northern area of the Nodular deposition.

Sentous Formation

The Sentous Formation is the deepest unit produced at the Inglewood Oil Field, and is below the Nodular Formation at greater than 9,000 feet below the ground surface. The Sentous is the geologically oldest producing zone in the Inglewood Oil Field and also along the Newport-Inglewood Fault trend. Since the early 1990s, the exploration and development focus in the Inglewood Oil Field has been on the Lower Pliocene and Upper and Middle Miocene, particularly the Sentous. Sentous sands were deposited in approximately 1,000 feet water depth during the opening of the rifted basins of the Southern California continental borderland. Oil accumulated in the Sentous sands down the northwest plunge of the Inglewood anticline; however, the sands become impermeable higher up on the anticlinal crest due to filling of the pore spaces with calcite cement. This loss of permeability has created a stratigraphic trap for this reservoir (Halliburton 2012). In the context of the Hydraulic Fracturing Study, the conventional hydraulic fracture completions have been conducted either solely in the Sentous zone or combined in the Sentous and either the Moynier or the Bradna.

2.5 Future of Oil and Gas Development in the Los Angeles Basin

The Monterey Shale is the primary source of oil and natural gas found in Southern California. The organic-rich shale was heated and compressed during tectonic activity, producing oil and gas. Some of the oil and natural gas migrated upwards into the overlying, more permeable, sandstone layers, where the hydrocarbons were then trapped by overlying impermeable shales and faults. Across Southern California, the deep source rocks, approximately 2 miles below the ground surface, of the Monterey Formation are now an exploration objective. High-volume hydraulic fracturing is being explored as a possible well completion method to allow the extraction of oil and natural gas from this geologic formation.

At a 2012 meeting of the American Association of Petroleum Geologists, the U.S. Geological Survey presented an assessment of the amount of oil remaining in the Los Angeles Basin. They note that, during much of the twentieth century, discovery and development of the Los Angeles Basin oil fields went hand in hand with rapid urbanization, which impacted field development from the first day of drilling. In spite of one of the world's greatest concentrations of oil per unit area, the oil recovery efficiency in the major fields continues to decrease (Gautier et al. 2012). Many small fields have been covered by residential or commercial development while still in primary production. For example, along the Wilmington Anticline and Newport-Inglewood Fault Zone, at least six fields have estimated original oil volumes in excess of one billion barrels. These fields have been in production for about 90 years. However, future recovery in such major fields could reasonably be expected to almost equal the total amount of oil recovered so far. It is predicted that oil volumes well in excess of one billion barrels could be recovered going forward from existing fields in the Los Angeles Basin through widespread application of current best practice industry technology such as improved imaging, advanced directional drilling, and other techniques (Gautier et al. 2012).

Along with continued oil and gas development in the Los Angeles Basin, hydraulic fracturing has been occurring to explore the resource potential of the Monterey Shale throughout California and in the Los Angeles Basin. Hydraulic fracturing is likely to continue to be utilized during recovery of the remaining petroleum resources. Figure 2-9 displays the location of wells in the southern California where hydraulic fracturing was reported in either 2011 or 2012 (as reported on www.fracfocus.org).

Cardno ENTRIX

LEGEND

- Well Completed by Hydraulic Fracturing
- XXX Well Name
- (XX) Multiple Wells Completed by Hydraulic Fracturing

PLAINS EXPLORATION & PRODUCTION COMPANY

Figure 2-9

2011 and 2012 Reported Hydraulic Fracturing Operations in Southern California

09 | 12 | 12

Chapter 3

Hydraulic Fracturing at Inglewood Oil Field: Past, Present, and Future

3.1 Oil and Gas Well Drilling, Including Hydraulic Fracturing Completions

Well drilling is the process of drilling a hole in the ground for the purposes of extracting a natural substance (e.g., water, oil, or natural gas). Drilling and completing a well consists of several sequential activities, which are listed below in order (note that these activities may be conducted multiple times during the drilling of a well, or be already completed and not needed for a particular well):

- Building the well pad and installing fluid handling equipment;
- Setting up the drilling rig and ancillary equipment and testing all equipment;
- Drilling the hole;
- Running formation evaluation logs and other instruments down the well;
- Running casing (steel pipe) to line the wellbore;
- Cementing the casing;
- Removing the drilling rig and ancillary equipment;
- Logging the casing to ensure bonding of cement to the formation and casing;
- Perforating the casing;
- Stimulating the well;
- Installing surface production equipment;
- Beginning production of the well;
- Monitoring well performance and integrity; and
- Reclaiming the parts of the drilling location that are no longer needed and removing equipment no longer used.

In the exploration and development of oil and natural gas fields, wells must be designed to carry the extracted fluids directly from the producing zone at depth to the surface completely within the well, without allowing fluid to escape into surrounding formations. Wells are designed and constructed to prevent any communication (migration and/or transport of fluids) between these subsurface layers, which have acted as a barrier for millions of years (API 2009).

In most parts of the Los Angeles Basin, including the Inglewood Oil Field, there are impermeable rock formations that lie between the hydrocarbon producing formations and shallow zones including groundwater-bearing formations and the land surface. These formations provide additional, natural protection against migration of oil and gas to the shallower formations. These impermeable formations and confining faults at the Inglewood Oil Field isolate, or trap, the hydrocarbons from the near surface formations. If these impermeable formations did not exist, the naturally buoyant oil would continue rising until reaching the surface, similar to areas such as the La Brea Tar Pits.

3.1.1 Drilling, Casing, and Cementing

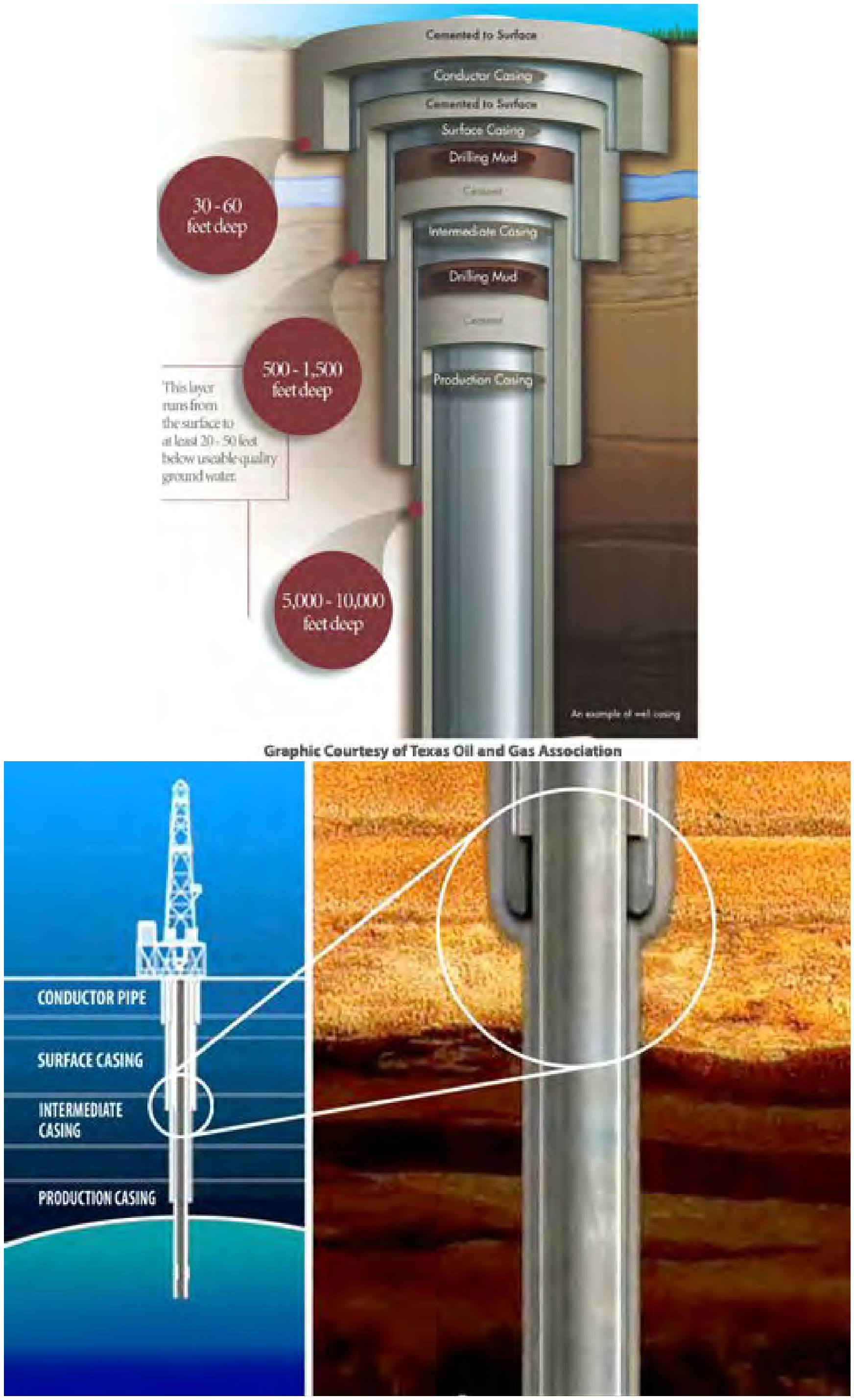
This section describes the methods used during drilling to ensure oil, natural gas, and water that are pumped from the deeper formations are brought to the surface without loss to shallower zones.

Wells are drilled using a drilling rig equipped with a drill string. The drill string consists of a drill bit, drill collars (heavy weight pipes that put weight on the bit so that it cuts through the formation), and a drill pipe. The drill string is assembled and suspended at the surface on a drilling derrick and run into the hole in the ground. It is then rotated using a turntable, or motor, in order to cause the drill bit to advance downward through the formations and thereby extend the hole deeper into the ground.

While the hole is drilled, fluid (drilling mud) is circulated down the drill string and up the space between the drill string and the hole. This drilling fluid serves to lubricate the drilling assembly, remove the sediments that are drilled, maintain pressure control of the well and stabilize the hole being drilled (prevent collapse of sediments back into the hole). Drilling fluid is generally a mixture of water, clays, and additives that prevent fluid loss, control density, and suspend the drilled cuttings. The first hole drilled is for installation of the surface protection casing. This is followed by sequentially deeper holes so that the well can be completed (API 2009).

The first step in completing a well is to case the hole (Figure 3-1). As the well is drilled and drilling fluid is removed, a series of steel pipes known as casings are inserted to prevent the boring from closing in on itself. Cemented casing also serves to isolate the well from the surrounding formation. Each length of casing along the well is often referred to as a casing string. The steel casing strings are a key part of well design and essential to isolating the formation zones and ensuring integrity of the well. Cemented casing strings protect against methane migration and protect groundwater resources (if present) by isolating these shallow resources from the oil, natural gas, and produced water (water produced during operation of a well) inside of the well. It is important to note that the shallow portions of the well have multiple strings of steel casing installed (Halliburton 2012, API 2009).

When drilling nears the base of fresh water, typically sealed naturally from deeper saline water by an impermeable confining layer, as at the Inglewood Oil Field, the casing is placed into the drilled hole. The design and selection of the casing is important since the casing has to be able to withstand various forces (for example compression by surrounding formation), as well as any pressure it might be subjected to during the well's life. The casing is threaded on each end that allows it to join to the next pipe. When several joints of casing are screwed together, they form a continuous string that isolates the hole.



Source: Halliburton 2012

Figure 3-1 Depiction of Casing Strings

The casing used in wells at the Inglewood Oil Field meet the American Petroleum Institute (API) standards. API standards entail strict requirements for compression, tension, collapse, burst resistance, quality, and consistency so that casing is able to withstand the anticipated pressure from well completion, fracturing and production, as well as environmental conditions that could cause corrosion (API 2009).

The space between the casing and the drilled hole (wellbore), called the annulus, is filled with cement, permanently holding the casing in place and further sealing off the interior of the well from the surrounding formation. Cementing is accomplished by pumping the cement (commonly known as slurry) down the inside of the casing into the well to displace the existing drilling fluids and to fill in the space between the casing and the actual sides of the drilled well. Once the cement has set, drilling continues to the next depth. This process is repeated, using smaller steel casing each time, until the targeted oil and gas-bearing reservoir is reached and cement is no longer used.

Oilfield cements are carefully designed products, formulated to meet the requirements of individual well designs. Cementing serves two purposes — it provides protection and structural support to the well while also providing zonal isolation between different formations, including full isolation of the groundwater. Cement is fundamental in maintaining integrity throughout the life of the well and protecting the casing from corrosion. Placement of the cement completely around the casing and at the proper height above the bottom of the drilled hole are two of the primary factors in achieving successful zone isolation and integrity. Proper isolation requires complete filling of the annulus and tight cement bonding to both the casing and the surrounding geologic formation. This bonding and the absence of voids prevents the development of migration pathways and isolates the production zone (Halliburton 2012, API 2009).

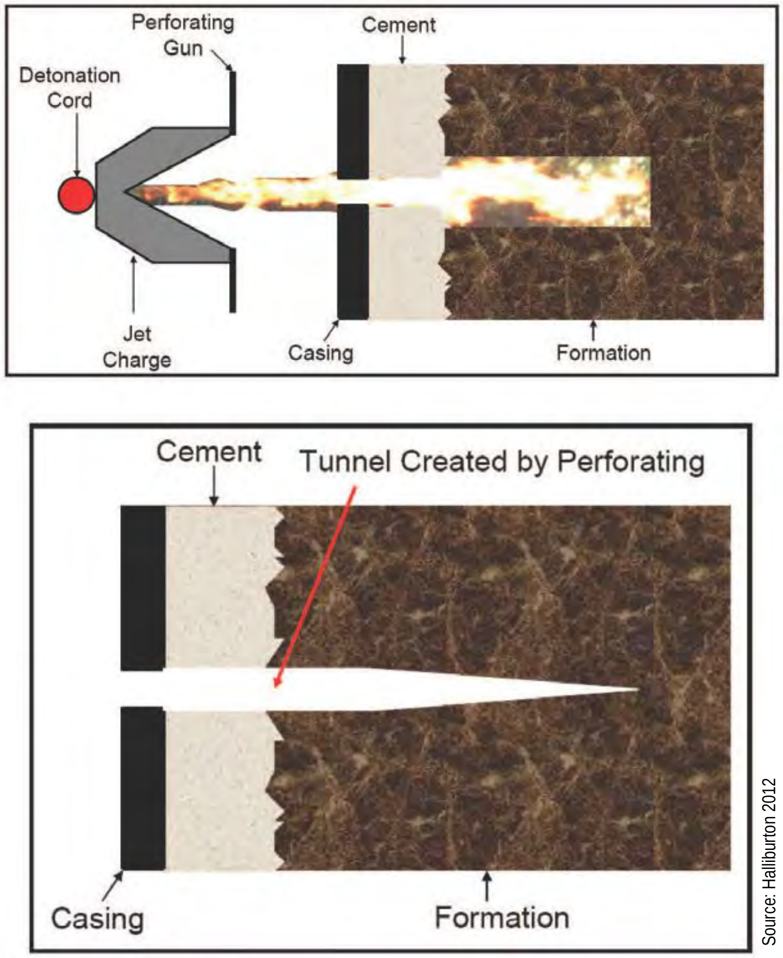
3.1.2 Hydraulic Fracturing as a Completion Technique

The final steps to a producing well are known as "well completion." Well completion includes perforations and any sort of well stimulation techniques, including hydraulic fracturing, sand control measures, installing the production tubing, and other downhole tools.

Perforating

Once the well is drilled to the target producing zone, cased and cemented in place, the areas outside the well are sealed off by the casing and cement. At this point in the process, there is a solid steel casing across the target producing zone. In order to pump out oil, natural gas, and water from this zone, a mesh of open space must be made in the casing. The process of creating the open holes within the target producing zone is called perforating; perforations are simply holes that are made through the casing. Perforating uses a series of small, specially designed shaped charges, which are lowered to the desired depth in the well and activated (Figure 3-2). These shaped charges create the holes in the steel casing that connect the inside of the production casing to the geological formation.

The perforations are isolated by the cement. Additionally, the producing zone itself is isolated outside the production casing by the cement above and below the zone. This isolation ensures that hydrocarbons and other fluids are unable to migrate anywhere except between the perforations and the wellbore.



Source: Halliburton 2012

Figure 3-2 Perforation Process

Hydraulic Fracturing Process

Hydraulic fracturing is not part of the drilling process, but is a completion technique applied after the well is drilled, sealed, and perforated and the drilling rig has moved to another site. It is a well completion technology that results in the creation of fractures in rocks that allows oil and gas in the source rock to move more freely through the rock into the well. Hydraulic fracturing is a well stimulation process used to maximize the extraction of underground resources. Hydraulic fracturing is sometimes referred to as "fracking."

Hydraulic fracturing for stimulation of oil and natural gas wells was first tested in the United States in 1947. It was first used commercially in 1949, and was rapidly adopted because of increased well performance and increased yields of oil and gas from relatively impermeable rock units. It is now used worldwide in tens of thousands of oil and natural gas wells annually. The method has also been used at more shallow depths to assist in cleanup of contaminated industrial sites that have relatively impermeable zones.

In general, the process of hydraulic fracturing consists of injecting water, sand, and additives into the well over a short period of time (typically less than an hour) at pressures sufficient to fracture the rocks of a formation. Water and small granular solids such as sands and ceramic beads, called proppants, make up approximately 99 percent or more of the fluid used in a typical hydraulic fracturing operation (Halliburton 2012). This is consistent for both conventional and high-volume hydraulic fracturing. The flow of water acts as a delivery mechanism for the sand, which enters the newly-created fractures and props them open. If proppant does not enter a new fracture, then the pressure of the overlying rocks forces the fracture closed. These proppant-filled fractures allow oil and gas to be produced from reservoir formations that are otherwise too tight to allow flow.

The additives in the water help the sand to be carried farther into the fracture network. Such additives used to increase the viscosity of the water include gelling materials and/or foaming agents. Other liquid and solid additives that may be incorporated in the fracturing fluid are surfactants, a soap-like product designed to enhance water recovery, friction reducers, biocides to prevent microorganism growth, oxygen scavengers and other stabilizers to prevent corrosion of metal pipes, and acids to remove drilling mud damage. Figure 3-3 illustrates the composition of a typical fluid used in high-volume hydraulic fracturing. The specific products used at Inglewood Oil Field are described in Section 3.2.

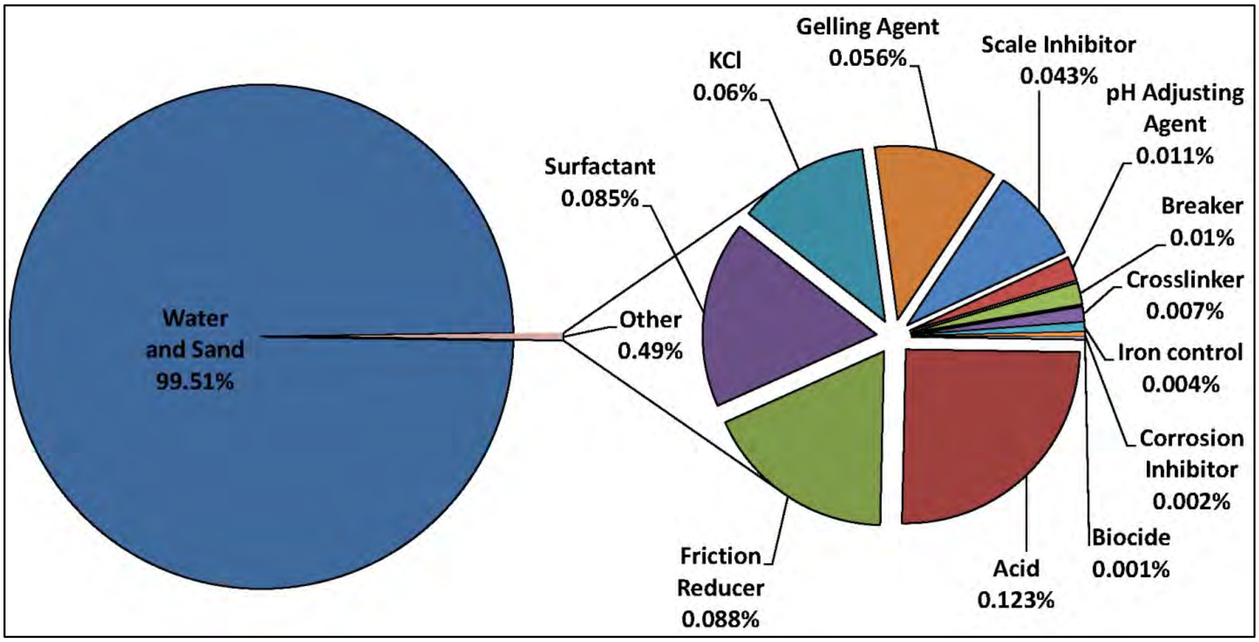


Figure 3-3 Composition of a Typical Fracturing Fluid

There are several steps during the hydraulic fracturing process. Taken together, these steps constitute one stage. Horizontal wells that are completed by hydraulic fracturing typically have several stages. Stages are not completed simultaneously. After the first stage is complete, the pressure is reduced, and the downhole equipment is moved to setup the second stage. When ready, the pressure is increased for the second stage. The following describes the steps that can be conducted during a hydraulic fracturing stage.

- **Step 1.** This optional step places water mixed with a dilute acid such as hydrochloric or muriatic acid into the sealed well. The volume of acid used is low and it is spent (used up) within inches of the fracture entry point and yields calcium chloride, water and small amount of CO_2. No acid is returned to the surface (King 2012). This step serves to clear cement debris in the wellbore and provide an open conduit for other hydraulic fracturing fluids by dissolving carbonate minerals and opening fractures near the wellbore. This step is not always performed, depending on the characteristics of the well and the formation.

- **Step 2.** The hydraulic fracturing fluid pad step (water with friction reducing additives) helps initiate and then propagate the fracture and assist in the placement of proppant material.
- **Step 3.** A proppant concentration step consists of several steps of adding water combined with proppant material (sand) to the well. This step may collectively use several hundred thousand gallons or more of water. Proppant material may vary from a finer particle size to a coarser particle size throughout this sequence and the proppant concentrations will vary during the treatment – starting with a lower concentration and then ramping to a higher concentration.
- **Step 4.** A flush step consists of a volume of fresh water or brine sufficient to flush the excess proppant from the wellbore.
- **Step 5.** Most of the fluid used for hydraulic fracturing is heated in the deep formation, becomes less viscous, flows more readily, and is recovered as it comes back up the well to the surface; this fluid is known as flowback. The amount recovered depends on the characteristics of the formation, and of the fluid used for hydraulic fracturing. The fluid that does not flow out of the well as flowback remains in the formation until the well is brought on production to pump and recover oil and gas. Any remaining fracturing fluids are also pumped out of the ground. Therefore, any remaining hydraulic fracturing fluid that does not return as flowback is captured by the pumping of the well. The only period of elevated pressure is during the brief (typically less than an hour) hydraulic fracturing operation itself (Halliburton 2012).

Uses of Hydraulic Fracturing

Within the last decade, the combination of horizontal wells installed with GPS-mounted drill heads to precisely guide the drill bit through relatively thin reservoir formations, and high-volume hydraulic fracturing completions has allowed the production of natural gas and oil from deep shale and tight sands deposits. Previously, the oil and gas-bearing shales were thought of as the source rocks of petroleum, from which oil and gas could not be economically produced directly. With the advent of new technology, companies now have the ability to precisely drill a horizontal well to be entirely within a relatively thin shale and tight sand bed using GPS technology, and then to precisely fracture that shale and prop open the fractures with sand to produce hydrocarbons from formations that previously were not economical.

This ability to capture hydrocarbon resources from zones that previously could not be produced is one form of development of “unconventional sources of oil and gas”. As applied to shale gas, this technique has completely changed the estimate of economic natural gas reserves. U.S. natural gas reserves had previously been thought to be in decline. To supply the nation’s energy needs, numerous plans to import gas from overseas as liquefied natural gas (LNG) were proposed between 2000 and 2005. Now, however, development of shale gas has led to the U.S. becoming the world’s largest producer of natural gas, surpassing Russia in 2009. The abundance of this relatively clean-burning fuel is beginning to displace the use of coal in U.S. generating stations, thus reducing greenhouse gas emissions.

At the Inglewood Oil Field, the uses of hydraulic fracturing are to create a permeable channel (propped fracture) within the shale and sandstone units so that the oil can be produced economically from these deeper formations. All activity occurs on an active, closely monitored oil and gas field using existing cleared areas for new wells whenever feasible. The activity differs from other parts of the country where areas not located in active oil and gas developments are converted to this use, and where the principal target is natural gas.

Types of Hydraulic Fracturing and Gravel Packing

Hydraulic Fracturing

Hydraulic fracturing as applied in oil and natural gas completions can take one of two forms, although some hybrid approaches are also in use. The process of fracturing in both forms is the same; the difference generally lies in the type of reservoir in which the fracturing is occurring, either tight sandstone or shale. The two forms are as follows:

- **Conventional Hydraulic Fracturing.** This completion approach uses water, sand, and additives to fracture and stimulate the producing formation to a distance of up to several hundred feet from the well. This method is intended to enhance the permeability of the target producing zone itself, and stimulate the reservoir. It is typically applied in tight sandstone formations and some shales.
- **High-Volume Hydraulic Fracturing.** This higher energy completion approach is generally applied to shales rather than sandstones. Sand and additives are used in the process similar to how they are used in conventional hydraulic fracturing; however, the primary distinguishing factor is the amount of fluid and pressure used in the process. Since shales have extremely low permeability, it is essential to increase the formation surface area contact with a permeable fracture channel. The high-volume hydraulic hydraulic fracturing process accomplishes this by increased treatment rates and material volumes.

Gravel Packing

In addition to hydraulic fracturing, the Settlement Agreement requires that gravel packing also be described and evaluated in this study. Gravel packing differs from hydraulic fracturing in that it is not intended to create fractures in the producing formation in order to pump out more water, oil, and gas. Rather, it is intended to place sand and gravel outside and adjacent to the well itself, with the intention of limiting the amount of fine-grained material that is pumped from the formation along with the fluids. As such, the purpose and techniques of gravel packing are distinctly different from hydraulic fracturing. Although the objective and techniques of gravel packing are very different from hydraulic fracturing, they are described in this study in accordance with the Settlement Agreement:

- **High-Rate Gravel Pack.** Since 2003, high-rate gravel packing has been conducted above the fracture pressure to improve well production performance through sand control. This operation uses much lower pressures than conventional and high-volume hydraulic fracturing. This completion approach, which is sometimes referred to as a “frack pack,” uses water, gravel, and additives to place sand and gravel near the well itself with the objective of limiting entry of formation sands and fine-grained material into the wellbore. In this process, the space between the formation and the outer casing of the well is packed, at a high-rate, with gravel that is small enough to prevent formation grains (sand) and fine particles from mixing and entering the wellbore with the produced fluids, but large enough to be held in place by the well perforations. This relatively low-energy completion approach can create limited fractures, using water, sand, and additives that improve the proper placement of the gravel filter. This process is not intended to increase the permeability of the producing formation, and it only affects the area near the well itself. Sand and finer particles that are entrained from the formation by pumping reduce the life of surface equipment such as valves, pipelines, and separators. In addition, produced sand can reduce oil production and impair the performance of injection wells.

- **Gravel Pack.** Prior to 2003, gravel packing was done at lower rates and lower applied pressures. The objective was the same as high-rate gravel packing, and the methods were also very similar, but the gravel packing process was always conducted at pressures less than the fracture pressure. In the past, some gravel packing was conducted using produced crude oil as part of the fluid mixture (a total of 11 completions); this oil was injected into the oil-producing formations themselves and not into shallow formations. Although PXP does not use oil as a fluid in gravel packing any more, it is noteworthy that such activity would not require an Underground Injection Control (UIC) permit since the operation did not use diesel fuel.

3.2 Hydraulic Fracturing at the Inglewood Oil Field

Conventional hydraulic fracturing has been conducted on 21 wells in the past at the Inglewood Oil Field. These completions were conducted in the Sentous Moynier, , Bradna ,City of Inglewood, Rubel, and Nodular shale formations. Combined, a total of approximately 65 stages of conventional hydraulic fracturing have occurred at the Inglewood Oil Field since 2003 when PXP began operating the field.

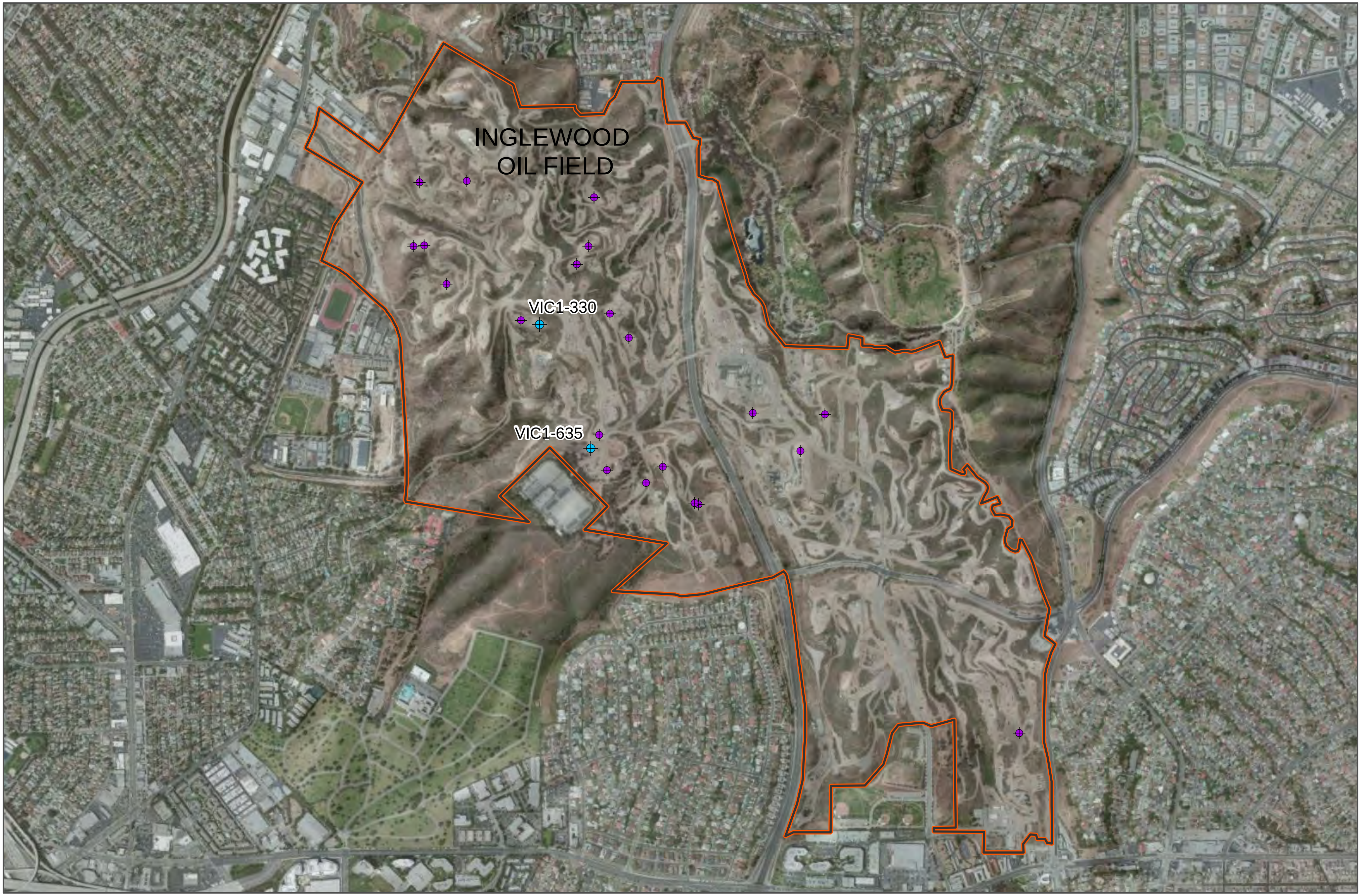
In conjunction with this Hydraulic Fracturing Study, PXP conducted high-volume hydraulic fracturing tests at two wells at the Inglewood Oil Field (VIC1-330 and VIC1-635). These are the only two high-volume hydraulic fracture jobs that have been performed on the Inglewood Oil Field.

Figure 3-4 shows the location of Inglewood Oil Field wells that have either been completed by high-volume hydraulic fracturing or conventional hydraulic fracturing since PXP took over field operations. All of the hydraulic fracturing has been completed on producing wells, that is, on pumping wells rather than injection wells.

3.2.1 Conventional Hydraulic Fracturing

Halliburton (2012) analyzed data from the past conventional hydraulic fracturing in the Sentous formation at the Inglewood Oil Field. The results of this analysis are summarized in this chapter to provide an indication of the feasibility and effectiveness of this technique at the Inglewood Oil Field.

Conventional hydraulic fracturing uses water, sand, and additives to fracture and stimulate the producing formation to a distance of up to several hundred feet from the well. This method is intended to affect the formation surrounding the perforated zone of the well, and enhance the hydrocarbon production of the target zone. It is typically applied in sandstone and some shale formations.



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LEGEND

- Conventional Hydraulic Fracture
- High Volume Hydraulic Fracture
- Inglewood Oil Field Boundary

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Figure 3-4

Locations of Hydraulic Fracturing Operations at Inglewood Oil Field

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In this type of treatment, water is mixed with a polymer to increase the viscosity to the range of 10 to 40 centipoise (cp); for comparison, water viscosity is 1 cp. When ready to pump into the well, the water and polymer blend referred to as the "base gel" is blended further with a liquid additive that binds the polymer chains in the base gel increasing the viscosity to several thousand cp which aids in the suspension of the solids. This process is referred to as "cross-linking" the base gel. The cross-linked gel is mixed with the proppant and pumped into the well as slurry. The proppant, either natural (sand) or manmade (ceramic beads), is pumped along with the fluid and remains in the created fractures to hold it open. Additives designed to delay the degradation of the cross-linked gel are pumped along with the cross-linked gel and, in combination with the elevated temperature in the formation, return the cross-linked gel to a viscosity approaching that of water so that it can be recovered, or "flowed back" from the formation.

Conventional hydraulic fracturing has been used for every producing formation deeper than the Vickers and the Rindge at the Inglewood Oil Field. Most conventional hydraulic fracturing jobs were completed in the Sentous, the deepest producing formation at approximately 10,000 feet beneath the ground surface. Halliburton (2012) contains an analysis of the outcomes of hydraulic fracturing in the Sentous zone based on detailed analysis of two wells: TVIC-1033 and VIC2-1133. Figures 3-5A and 3-5B present different visualizations of the fracture geometries determined from the hydraulic fracturing treatments. The small rectangular area at the base of the diagram represents the calculated volume that received proppant. The figures include the relevant formation surfaces, ground surface, geologic structure, including major faults; water-bearing bodies near the surface are also depicted. The area affected by the conventional hydraulic fracturing remained in the Sentous formation, greater than 9,000 feet below the ground surface.

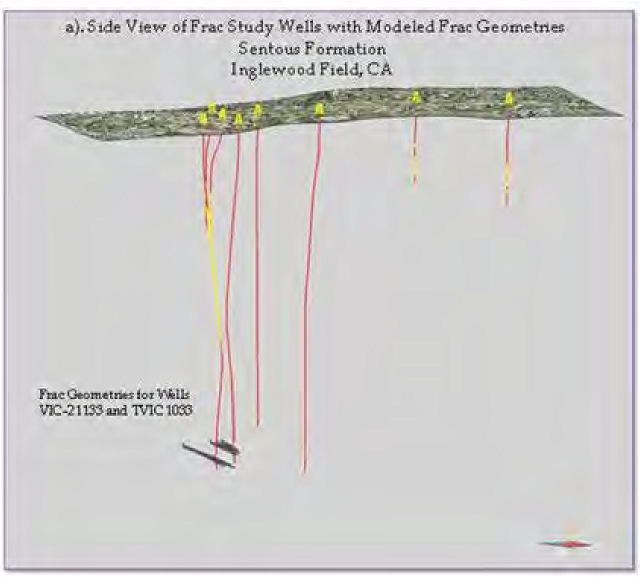

Figure 3-5A Side View of the Sentous Zone Modeled Fracture Geometries

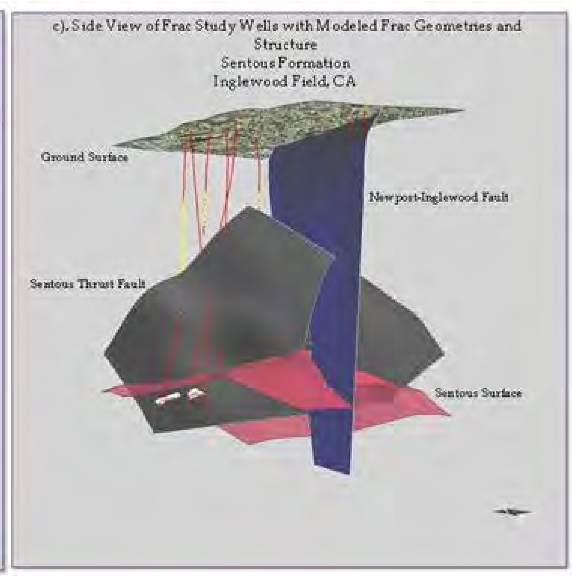

Figure 3-5B Side View Showing Modeled Fracture Geometries for Study Well in the Sentous Zone Together with Structural Features (Faults)

3.2.2 High-Volume Hydraulic Fracturing

PXP contracted Halliburton Energy Services to conduct two high-volume hydraulic fracture jobs at separate wells on the Inglewood Oil Field for the purposes of addressing feasibility and potential impacts of hydraulic fracturing. The first hydraulic fracture completion was conducted on September 15 and 16, 2011, at the VIC1-330 well. The second completion was conducted on January 5 and 6, 2012, at the VIC1-635 well.

Only one hydraulically fractured stage was completed on each well during the operations. Both of these operations were conducted in the Nodular Shale, a subunit of the Monterey Shale, approximately 8,000 to 9,000 feet below ground surface. Halliburton (2012) contains a full report of these operations.

The conditions of the hydraulic fracture jobs are the same as those expected for any other future high-volume hydraulic fracturing to be conducted at the field. Therefore, the applied pressure, water use, and monitored effects are expected to be similar between these two stages of high-volume hydraulic fracture jobs and any future stages of high-volume hydraulic fracture jobs.

Future high-volume hydraulic fracturing completions would likely utilize more than one stage per well in the future. That is, any single hydraulic fracture job in the future could consist of more than one individual fracturing event. In hydraulic fracture jobs that consist of more than one stage, each stage would be conducted one after the other, never simultaneously. Therefore, any one stage will be similar to those stages described in this section. Cumulatively, the amount of water and chemicals used would be greater for a multi-stage completion than for a single-stage completion. However, the volumes required are still much less than the overall water usage at the field.

Although VIC1-330 and VIC1-635 are both vertical wells, PXP reports that in the future, high-volume hydraulic fracturing may be conducted via horizontal wells. This difference would not lead to any variation in the hydraulic fracture stage, or to the monitored effects; the only difference would be the construction of the well itself. Although a horizontal well can be much longer than a vertical well in the same formation, the hydraulic fracture completion targets an individual zone, and so the amount of water, sand, and additives used would be the same, stage for stage. A longer, horizontal well would also result in more than one stage, which as described above, would result in the use of greater volumes of water and chemicals.

This section describes the conditions and results of high-volume hydraulic fracturing of the VIC1-330 and VIC1-635 wells. Both hydraulic fracturing events were in the Nodular shale, at depths in excess of 8,000 feet below ground surface. Microseismic data are fist used to describe the hydraulic fracturing. Next, water demand, water reuse, and chemical use are described for both jobs.

Microseismic Monitoring Methods

A hydraulic fracture job generates microseismic events when the rock develops cracks. During the hydraulic fracturing treatment, these microseismic events are measured with seismic receivers or geophones placed at depth within a nearby well or wells. The events are so imperceptible, even by this sensitive equipment, that it must be placed at or near the depth of fracturing to detect them. Figure 3-6 shows the locations of the four wells, and the nearby wells used for microseismic monitoring of VIC1-330 and VIC1-635.

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LEGEND

High Rate Gravel Pack

High Volume Hydraulic Fracture

Monitoring Location

Inglewood Oil Field Boundary

PLAINS EXPLORATION & PRODUCTION COMPANY

Figure 3-6

High-Volume Hydraulic Fracturing Operations with Microseismic Monitoring Locations

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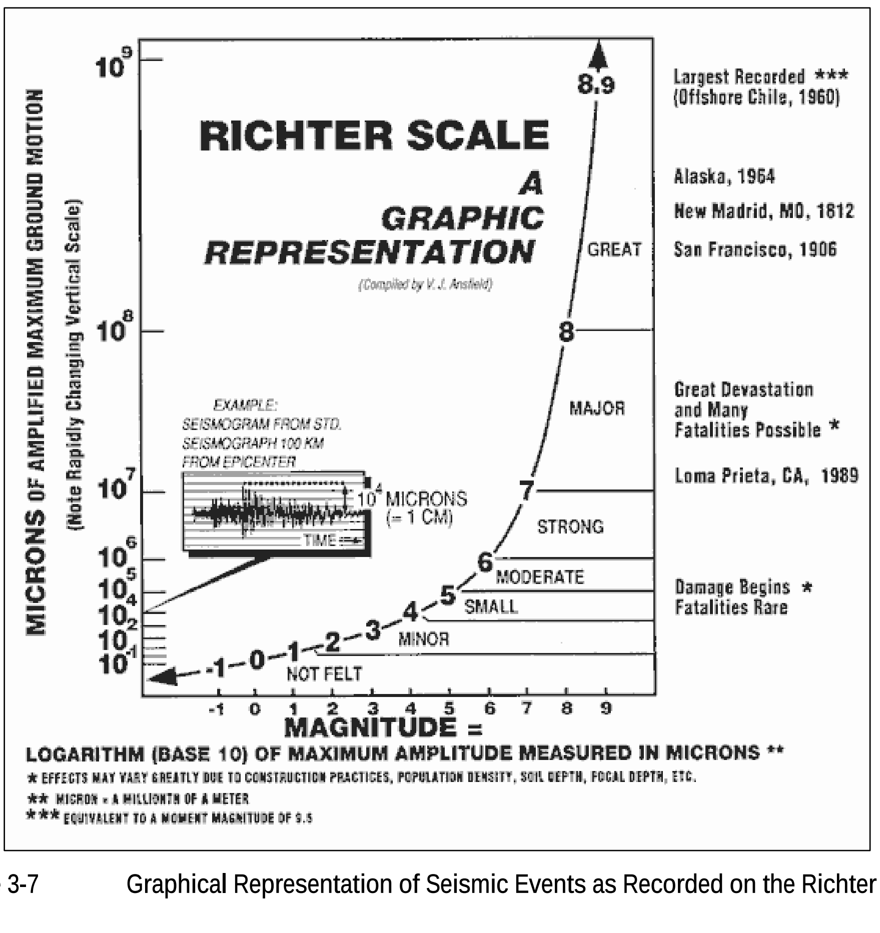
Earthquakes and other seismic events are commonly measured using the Richter scale (Figure 3-7). The Richter scale is based on Magnitude; that is, an earthquake of Magnitude 6 is ten times stronger than an earthquake of Magnitude 5, as a result of the amplification of ground movements (e.g., soft soils overlying bedrock will strengthen the intensity of the ground movement). Events of Magnitude 3 to 4 are similar to vibrations caused by heavy traffic. Events of Magnitude 2 to 3 are typically not noticed by people. Events of Magnitude 1 to 2 are only detectable by seismographs and are not felt by people. For context, the Northridge earthquake of 1994 was Magnitude 6.4, and the San Fernando earthquake of 1970 was Magnitude 6.9.

During hydraulic fracturing, the microseismic events are generally less than Magnitude -2 or -3 on the Richter scale (Halliburton 2012). That is, they are about 1,000,000 times weaker than events that are typically felt by people. Although the pressures used in hydraulic fracturing are, by definition, high enough to fracture rock, the effects are very localized and do not induce further seismic effects. As discussed further in Section 4.5.6, recent studies by the U.S. Geological Survey and other organizations have consistently concluded that the forces generated by hydraulic fracturing do not cause earthquakes. These studies have shown that, under some conditions, injection of water or other fluids associated with wastewater disposal can, however, induce small tremors less than Richter Magnitude 3 or 4.



Source: South Dakota Geologic Survey 2012

Figure 3-7 Graphical Representation of Seismic Events as Recorded on the Richter Scale

Microseismic monitoring was conducted during hydraulic fracturing treatments for both VIC1-330 and VIC1-635. The results are used to determine the extent of fractured rock resulting from the treatment by mapping the locations of induced microseismic events. Figure 3-8A presents a detailed earth model side view visualization showing the locations of microseismic events detected during the mainstage fracture treatment. Each dot shown is a microseismic event, corresponding to a fracture. The rectangular area within the microseismic events represents the calculated volume that received proppant. The color of the microseismic events represents the time that they occurred. Taken together, the area affected by the microfractures is the zone affected by high-volume hydraulic fracturing. As depicted in Figure 3-8A, a few microseismic events occurred in the underlying Sentous Formation. However, the rectangular areas indicate that the proppant remained in the Nodular Shale, so the deeper fractures would seal after the high-volume hydraulic fracturing. Descriptions of fracture height and fracture length refer to the overall zone affected by fracturing; these are not the heights and lengths of individual fractures.

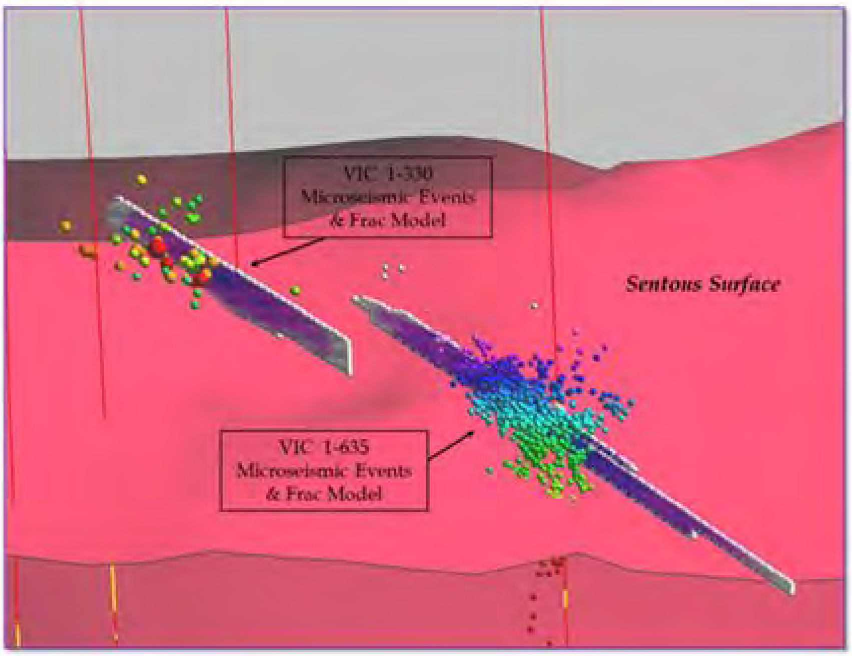


Figure 3-8A Microseismic Events Detected During the Hydraulic Treatments in the Sentous Zone in Wells VIC1-330 and VIC1-635

Figure 3-8B presents the 3-D model visualization of the microseismic events recorded during hydraulic fracture treatments in the Nodular Shale zone in wells VIC1-330 and VIC1-635. The distance between the top of the created fracture and the near-surface water bodies is approximately 7,700 feet. As shown in Figure 3-8B and described in the following sections, the fracture treatment stayed predominantly within the zone, and all proppant applied stayed within the zone (Halliburton 2012).

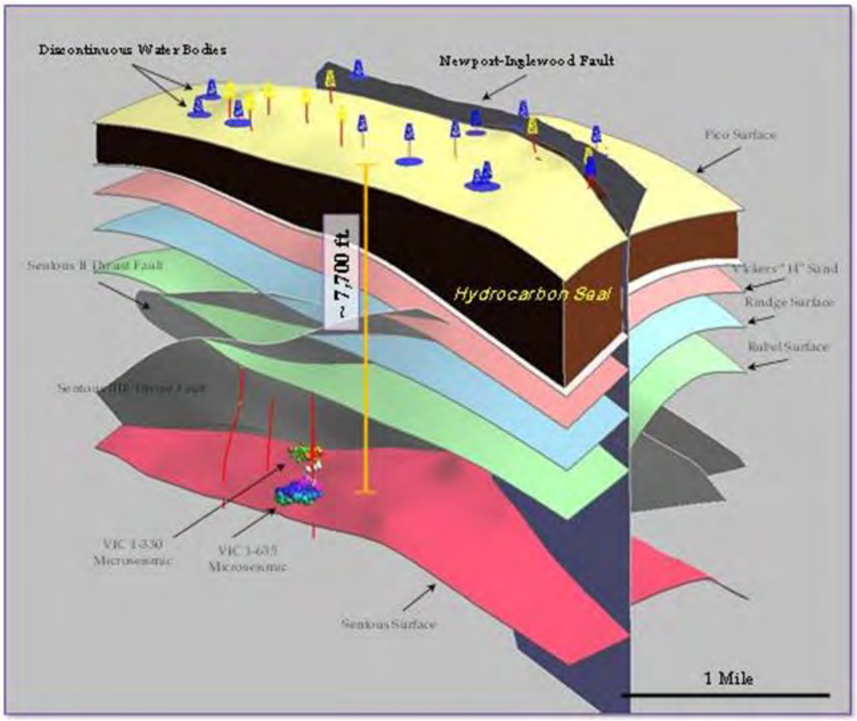


Figure 3-8B Earth Model Visualization Showing the Microseismic Events Recorded during Hydraulic Fracture Treatment in the Nodular Shale Zone in Wells VIC1-330 and VIC1-635

Well VIC1-330 Hydraulic Fracturing and Microseismic Monitoring

VIC1-330 well was hydraulically fractured between the depths of 8,030 to 8,050 feet below ground surface. The target formation was the Nodular Shale. The microseismic monitoring of VIC1-330 well was done from the VIC1-934 well using an array of geophones spaced 100 feet apart. The distance from the center of the geophone array to the perforations in the VIC1-330 treatment well is approximately 700 feet.

A total of 47 microseismic events were located during the hydraulic fracturing (Figure 3-9) operation. Based on the microseismic monitoring, the fractures are not radially distributed around the well, but follow three primary directions corresponding to the structure of the reservoir. Some fractures occur outside of the Nodular Shale, although most lie within the target unit (Schlumberger 2012b). Halliburton (2012) also models the distribution of proppant applied to the fractures in the target zone. Based on this model, all of the proppant stayed within the target zone of the Nodular Shale. The minor fractures that occurred outside the Nodular Shale did not receive proppant, and as such the minor fractures sealed based on the overburden pressure.

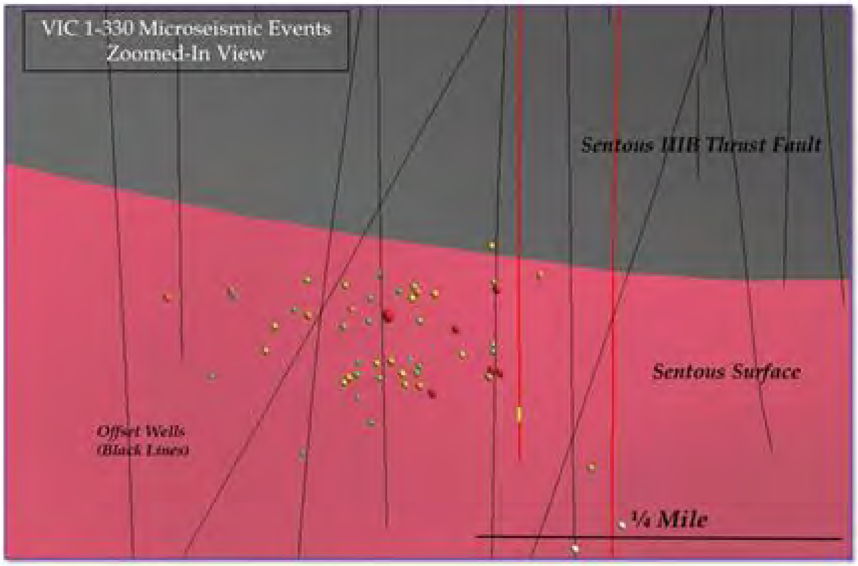


Figure 3-9 Detailed Zoomed in Side View Visualization of the Microseismic Events Recorded during Fracture Treatment in the Sentous Zone in Well VIC1-330

Well VIC1-635 Hydraulic Fracturing and Microseismic Monitoring

VIC1-635 well was hydraulically fractured between the depths of 8,430 to 8,450 feet below ground surface. The target formation was the Nodular Shale. The microseismic monitoring of VIC1-635 well was done from wells VIC1-735 and VIC1-935 using an array of geophones spaced 100 feet apart. Figure 3-10 depicts the microseismic events that were observed during the hydraulic fracturing treatment.

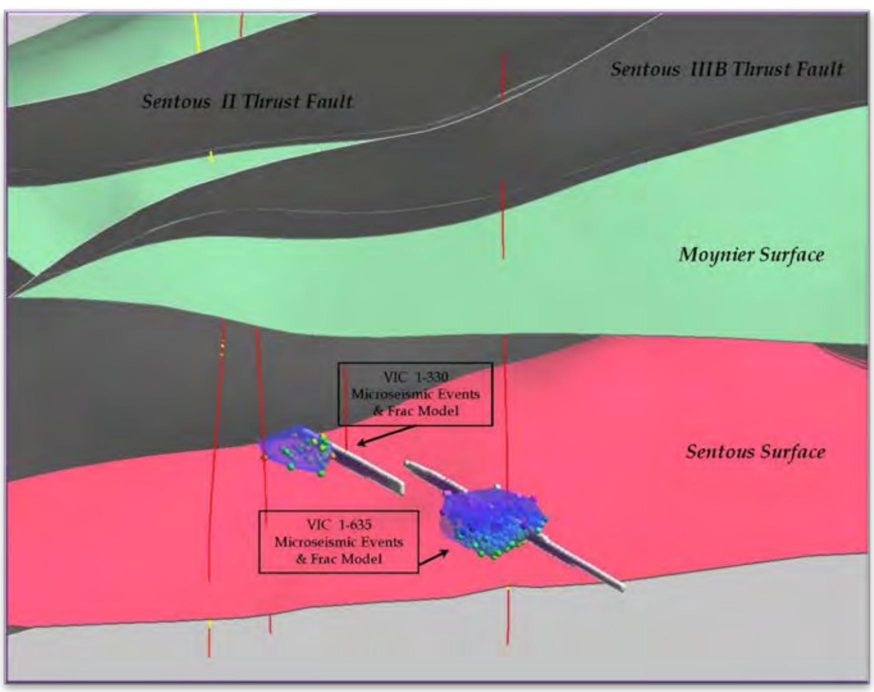


Figure 3-10 Microseismic Events Detected during Mainstage Fracture Treatment, Top View

Figure 3-11 shows the map view (left) and 2D Depth view (right) of the Mainstage high-volume hydraulic fracture treatment along with the microseismic events for the hydraulic fracture in well VIC1-635.

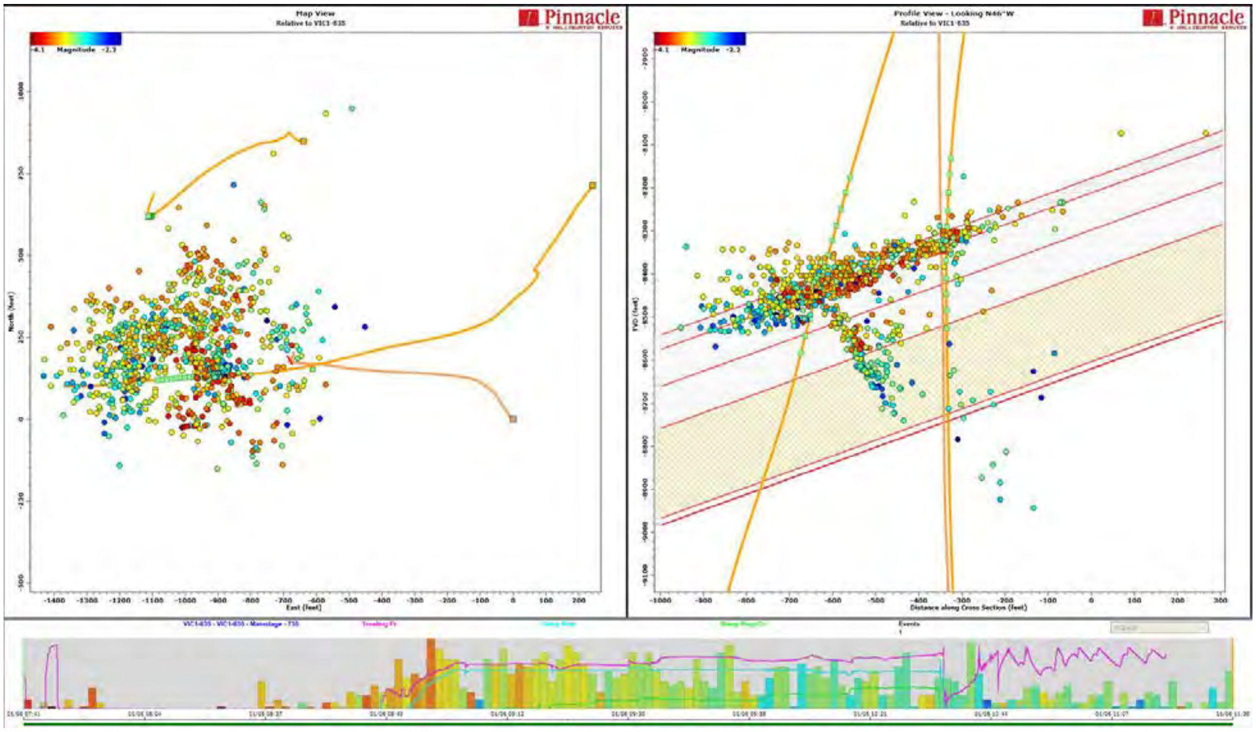


Figure 3-11 2D VIC1-635, VIC1-735 and VIC1-935 Surface Locations with Events Mapped

Earlier geologic control from well logs and structural mapping in the area indicated the Nodular Shale has dipping beds (~20°) from the northeast to the southwest. Based on the microseismic monitoring, the primary fracture network direction is considered east-west for the single stage mapped in the VIC1-635 well with a secondary fracture direction of N45°E. The microseismic mapping results indicate that the target zone of the Nodular Shale was effectively stimulated and fracture growth occurred along the formation dip of approximately 20 degrees. Growth appears to be asymmetric to the west based on the geophone array locations. The fracture network half-length was measured to be 750 feet. Fracture height was approximately 230 feet.

Almost all of the microseismic events occurred in the Nodular Shale; however, some microseismic events occurred outside the Nodular Shale and affected the Sentous Shale, underlying the Nodular. This appears to be related to pre-existing structure. Halliburton (2012) also models the distribution of proppant applied to the fractures in the target zone. Based on this model, all of the proppant stayed within the target zone of the Nodular Shale. Therefore the minor events (corresponding to microfractures) that occurred outside the Nodular Shale did not receive proppant, and as such they sealed based on the overburden pressure.

Water and Chemical Use during High-Volume Hydraulic Fracturing

Water Use and Source

Water for the hydraulic fracturing operations at the Inglewood Oil Field is provided from either produced water the field or, if a potassium chloride gel is used, fresh water provided by California American Water Company, the provider of all fresh water used at the Inglewood Oil Field. For both of the high-volume operations on the field, PXP used fresh water. Table 3-1 provides the volumes of water used during the high-volume hydraulic fracturing at the Inglewood Oil Field.

Table 3-1 Volumes of Water Used During High-Volume Hydraulic Fracturing Operations at the Inglewood Oil Field

Operation Type	Date	Well	Volume Water Used (gallons)	Water Source
High Volume	September 15-16, 2011	VIC1-330	123,354	Fresh Water
High Volume	January 5-6, 2012	VIC1-635	94,248	Fresh Water

Water Disposal

Water produced during hydraulic fracturing operations, known as flowback water and flush water, is transported by pipeline to the field water treatment plant where it is mixed with other produced water generated on the field. The treated water is then reinjected into the oil and gas producing formations as part of the waterflood process. This operation is in accordance with CSD Condition E.2.(i), which requires that all produced water and oil associated with production, processing, and storage be contained within closed systems at all times. The volume of water in the oil and gas producing zones is much greater than the volumes used for hydraulic fracturing and as such any residual additives are greatly diluted. In addition, many of the chemicals are soluble in oil and would be removed from the subsurface when the oil is sold.

Chemical Listing

Table 3-2 lists the additives that were mixed with the water and sand and injected into the formation during the two high-volume hydraulic fracture operations at the Inglewood Oil Field. Please refer to Appendix B for more detailed information regarding these additives, including volume injected and concentration.

Table 3-2 List of Additives Used During High-Volume Hydraulic Fracture Operations at the Inglewood Oil Field

Additive Type	Trade Name	Typical Main Compound Listed on Material Safety Data Sheet	Purpose
Water		Water	Base fluid carries proppant, also can be present in some additives
Biocide	BE-3S	Propionamide	Prevents or limits growth of bacteria which can cause formation of hydrogen sulfide and physically plug flow or oil and gas into the well
Gel	LGC-38 UC	Guar Gum	Thickens the water in order to suspend the sand
		Naptha hydrotreated heavy	
Breaker	SP Breaker	Sodium Persulfate	Allows for a delayed breakdown of the gel
Crosslinker	BC-140	Borate	Maintains fluid viscosity as a temperature increases

Table 3-2 List of Additives Used During High-Volume Hydraulic Fracture Operations at the Inglewood Oil Field

Additive Type	Trade Name	Typical Main Compound Listed on Material Safety Data Sheet	Purpose
pH Adjusting Agent	MO-67	Sodium Hydroxide	Adjusts pH to proper range for fluid to maintain the effectiveness of other fluid components
Surfactant	Losurf-300M	Ethanol	Aids in recovery of water used during fracturing operation by reducing surface tension
Clay control	Clayfix II Plus	Alkylated quaternary chloride	Clay-stabilization additive which helps prevent fluid interaction with formation clays
		Potassium chloride	
Proppant		Silica	Holds open fracture to allow oil and gas to flow to well

3.2.3 Images from January 2012 Completion Operations

This section presents photographs taken during high-rate gravel packing and high-volume hydraulic fracturing operations conducted at the Inglewood Oil Field in January 2012. The first photo above shows the overall requirements for a high-rate gravel pack completion; they are setting up near the wellhead.

After bringing the vehicles and equipment to the wellhead, hoses and pipes are connected to the various components of the test. The hydraulic fracturing is conducted at elevated pressure, so all components that bear pressure are steep pipes with wall thickness that provides a margin of safety. Hoses are used to connect water, sand, and chemicals prior to mixing and injection.

The blender unit is located behind the trailers in this image. The blender mixes the water, sand, and additives prior to introduction into the well for the completion process.

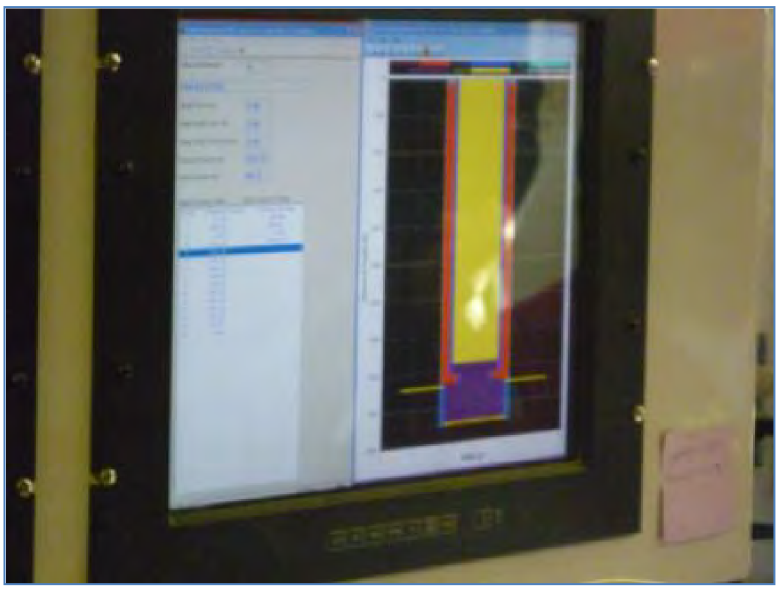
This is an image of the mixture of water, sand and additives used for the high-volume hydraulic fracturing at VIC1-635. This sample of the proppant/gelled water mixture is used to test for consistency with project specifications; samples are taken frequently during the course of the hydraulic fracture treatment for quality control purposes. Note that the food-grade gelling agents hold the sand in suspension, allowing the sand to be introduced into the fractures away from the well. Without the gel, the sand would settle out and not prop open the fractures formed by the completion process. The compound that causes this thickening, guar gum, is an additive used to thicken ice creams for human consumption (Halliburton 2012).

This image shows the VIC1-635 wellhead with a device for isolating the wellhead from the hydraulic fracturing equipment, set up to begin hydraulic fracturing. The green vertical pipe is the wellhead, and the two red pipes attached to the wellhead deliver the water-sand-additive fluid mixture down the well under pressure.

This image shows the VIC1-635 wellhead set up to begin hydraulic fracturing, looking the other direction from the previous image. The water-sand-additive fluid mixture is delivered down the well through the red pipes connected to the top of the well. The image shows the above-ground pumping unit to be connected after the well completion process (hydraulic fracturing), and the amount of equipment needed at the wellhead for hydraulic fracturing job.

A mobile Control Room is placed on site adjacent to the well to be hydraulically fractured at the Inglewood Oil Field. The control room has connections to all of the monitoring, allowing real-time adjustment of the hydraulic fracturing conditions as the job progresses. This control ensures that well integrity, pressures, proppant delivery, and all other attributes of the process can be adjusted to meet downhole conditions. The control room also has a small lab for testing the samples of gelled water and proppant material that are collected for quality control.

This image depicts a screen in the on-site mobile control room, monitoring downhole characteristics of the early stages of the VIC1-635 hydraulic fracture job in progress.



This image shows a graphical display of part of the VIC1-635 hydraulic fracture job in the mobile control room. The image on the screen shows the progress of adding the water-sand-additive mixture; the real-time monitoring using both numerical and graphical displays allows for modification or cessation of the hydraulic fracturing job if the performance does not meet the project design specifications.

3.3 Gravel Packs at the Inglewood Oil Field

In addition to hydraulic fracturing, the Settlement Agreement requires that gravel packing also be described and evaluated in this study. High-rate gravel packing uses water, gravel, and additives to limit entry of formation particles and sand into the wellbore. High-rate gravel packing is a technique that is used for sand control. High-rate gravel packing is ideal in formations that are already permeable. The gravel pack method uses a metal screen placed in the wellbore. The surrounding annulus, or the space between the well and the outer casing, is packed with gravel, water, and additives to limit entry of formation fines and sand into the wellbore. In this process, the space between the formation and the outer casing is packed, at a high-rate, with gravel that is sized small enough to prevent formation grains and fine particles from mixing and entering the wellbore with the produced fluids, but large enough to be held in place by screens. Sand and finer particles reduce the life of surface equipment such as valves, pipelines, and separators. In addition, produced sand can reduce oil production and impair the performance of injection wells.

3.3.1 Past Gravel Packs

Gravel packing is a completion approach that is specifically designed to prevent non-consolidated formation sands from flowing into the wellbore and preventing hydrocarbon production. In gravel packing operations, a steel screen is placed in the wellbore and the surrounding annulus packed with prepared gravel of a specific size designed to prevent the passage of formation sand. The primary objective is to stabilize the formation while causing minimal impairment to well productivity (Schlumberger 2012a). The gravel is circulated into place rather than pumped in under high pressure. Gravel packing does not exceed the fracture gradient.

The process of introducing a gravel pack has gone through several changes over time at the field. Prior to 2003, all of the gravel packs were conducted at pressures below the fracture gradient of the formation. Open hole gravel packs were used until 2003 in the Vickers-Rindge formation and were never installed above the fracture gradient of the surrounding formation. From the mid-1990s to 2003 in the Vickers-Rindge, the technique was modified to a cased-hole gravel pack; this improvement allowed the completion to target the specific producing zone. This had the effect of isolating high saline water producing zones so that the more oil-rich zones could be targeted. This method was also used in the Vickers-Rindge, and was never installed above the fracture gradient of the surrounding formation.

High-rate gravel packs were first used in 2003. At that time, this technique used the cased hole as before, and was limited to a 200-foot target interval as before. This method, however, was the first to exceed the fracture gradient in the surrounding formation, as well as introducing the gravel pack. The fractures would typically be less than 250 feet from the well. Eleven of the initial completions in 2004 used produced crude oil in the fluids in order to be more consistent with the oil in the formation, and potentially yield better well performance; however, analysis of well performance indicated that this was not the case and the use of oil was subsequently stopped. The crude oil had been previously pumped from the formation, and was only used for high-rate gravel packs targeting the oil producing zones. That is, crude oil was never used above, or near, the base of fresh water, but only in oil-bearing formations.

Table 3-3 lists the primary differences between high-rate gravel packs and conventional and high-volume hydraulic fracturing.

Table 3-3 Comparison of High-Rate Gravel Packs to Conventional Hydraulic Fracturing

High-Rate Gravel Packs	Hydraulic Fracturing
Wire wrapped screen is installed in the well	No wire wrapped screen in the well
Goal is not to pump entire sand / proppant volume in the formation but to prevent the entrance of sand into the wellbore	Goal is to pump entire sand / proppant volume into the formation
Sand and water mixture is placed within a short radius of the wellbore (normally 10-50 feet but can reach 250 feet)	Sand and water mixture can be pushed out well in excess of 500 feet from the wellbore

Source: Halliburton 2012

In addition, high-rate gravel pack treatments are usually smaller in terms of sand and fluid volumes and require less time to pump than an average conventional hydraulic fracturing treatment. To illustrate this difference, Table 3-4 provides a comparison of actual sand and fluid volumes pumped in the Inglewood Oil Field during a high-rate gravel pack treatment and the high-volume hydraulic fracturing treatments that were the subject of this study.

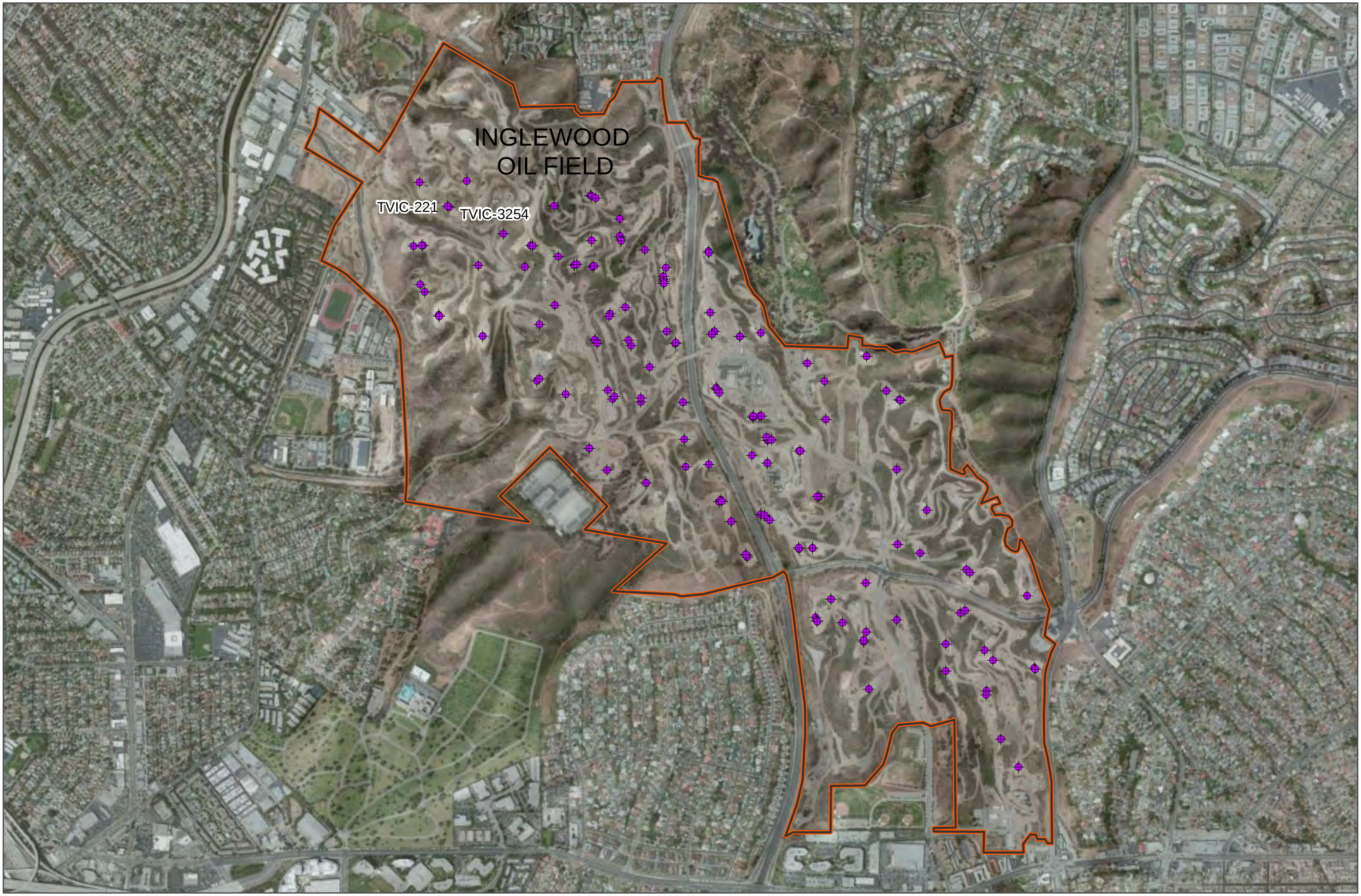
Table 3-4 Comparison of Sand and Fluid Volumes between High-Rate Gravel Pack and High-Volume Hydraulic Fracturing at the Inglewood Oil Field

Parameters	High-Rate Gravel Pack	Hydraulic Fracturing
Pump Time (minutes)	27.68	141.87
Clean Volume (bbl)	418.45	2992.18
Slurry Volume (bbl)	458.89	3210.35
Average Treating Pressure (psi)	768	6914
Max Treating Pressure (psi)	1343	8,818
Proppant Mass (100* lb)	373.79	2013.48

Source: Halliburton 2012

Since 2003, PXP has conducted high-rate gravel pack completions on approximately 166 wells in the Inglewood Oil Field, all in the Vickers and the Rindge formation, with a single completion in the Investment Zone (Figure 3-12). Each high-rate gravel pack includes an average of five stages per well; therefore, approximately 830 stages have been completed at the Inglewood Oil Field since 2003.

Halliburton (2012) studied four recent high-rate gravel pack completions in the Vickers and Rindge formations to assess applicability and feasibility: VRU-4243, TVIC-274, Stocker 461, and BC-285. The wells were selected because of their location within the field, including presence on both sides of the Newport-Inglewood Fault. Twenty-one independent high-rate gravel pack treatments from the four wells selected in the Vickers and Rindge zones were analyzed (Halliburton 2012).



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N

0 500 1,000 2,000 Feet

LEGEND

High-rate Gravel Pack

Inglewood Oil Field Boundary

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Figure 3-12

High-Rate Gravel Pack Completions
at the Inglewood Oil Field

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The results of the analysis showed the following:

- The fracture height created by the high-rate gravel packs in the Vickers and Rindge formations was, on average, in the range of 100 to 170 feet for the majority of the stages. The fracture height in several stages was around 200 to 240 feet.
- Fracture height is very small in relation to the depth of the fracture.
- The top of the created fracture is at least 1,000 feet below the bottom of the deepest perched water zones in the area that includes the Inglewood Oil Field.

Figures 3-13A and 3-13B present different visualizations of the fracture geometries produced by the high-rate gravel packs. The figures also show the relevant formation surfaces, ground surface, geologic structure including major faults, and groundwater-bearing bodies near the surface.

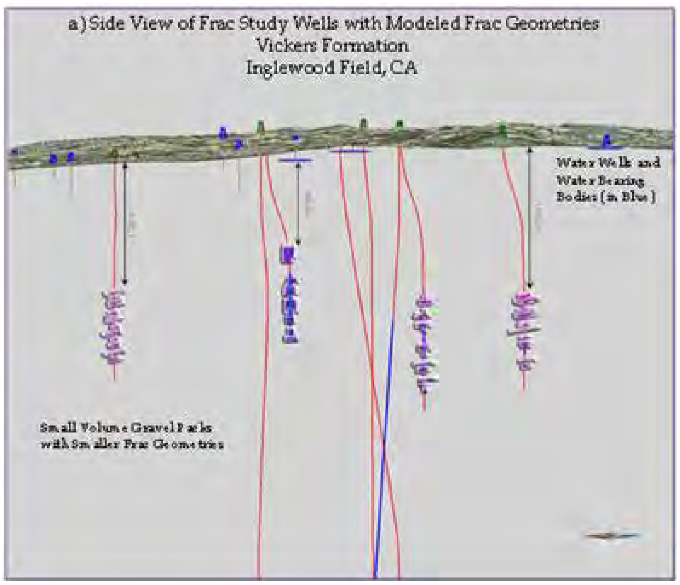

Figure 3-13A Side View Showing Modeled Fracture Geometries in the Vickers Zone

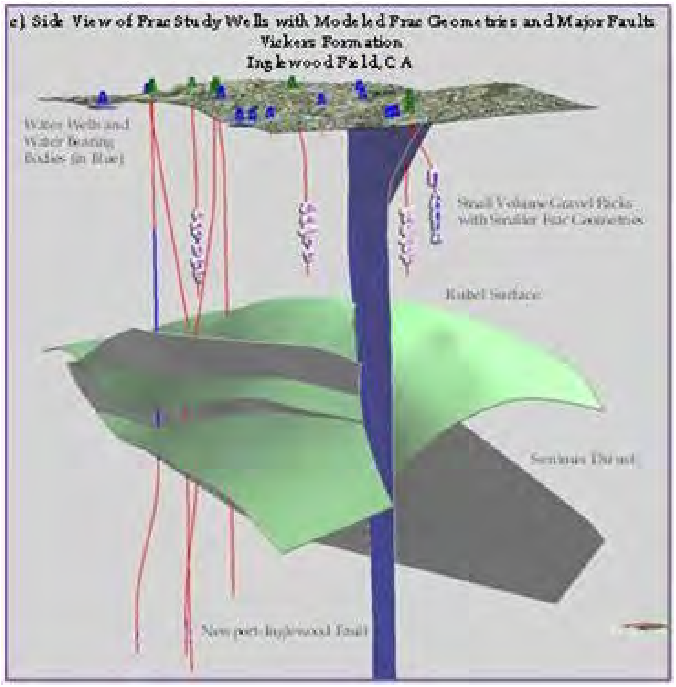

Figure 3-13B Side View Showing Modeled Fracture Geometries in the Vickers Zone and Structure (Faults)

3.3.2 Recent High-Rate Gravel Pack Completions

PXP also conducted high-rate gravel pack jobs at two wells on the Inglewood Oil Field to assess feasibility and potential impacts. The first high-rate gravel pack involving a five-stage completion was conducted on January 9, 2012, at the TVIC-221 well. The second high-rate gravel pack involved a six-stage completion and was conducted on the same day at a different well, TVIC-3254. Both of these operations were conducted in the Vickers and Rindge formations. The high-rate gravel pack operations were conducted by Halliburton with PXP oversight. The conditions of the high-rate gravel packs are similar to the well completions previously conducted across the field, and are also similar for any future high-rate gravel pack jobs that would be expected to be conducted at the oil field.

The maximum applied pressure during both high-rate gravel packs was 1,900 psi. In comparison the high-volume hydraulic fracturing projects had an average treatment pressure of 2,971 psi (VIC1-330) and 6,914 psi (VIC1-635). The high-rate gravel pack fracturing influences the zone within 100 to 250 feet of the well within the target oil-producing zone, compared to in excess of 500 feet for hydraulic fracturing.

Water and Chemical Use during High-Rate Gravel Pack

Water Demand/Source

Water for high-rate gravel packs at the Inglewood Oil Field has been provided either from produced water at the field or, if a potassium-chloride gel is used, fresh water provided by California American Water Company (the water service provider for all fresh water on the oil field). The majority of the high-rate gravel pack operations that have occurred since April 2011 have used produced water from the lease, including the two high-rate gravel pack examined in this study. Table 3-5 provides the volumes of water used during the two high-rate gravel pack fracture jobs at the Inglewood Oil Field.

Table 3-5 Volumes of Water Used During High-Rate Gravel Pack Hydraulic Fracturing Operations at the Inglewood Oil Field

Operation Type	Date	Well	Volume Water Used (gallons)	Water Source
High-rate gravel pack	January 5-6, 2012	TVIC 3254	33,357	Produced Water
High-rate gravel pack	January 5-6, 2012	TVIC 221	55,247	Produced Water

Chemical Listing

Table 3-6 below, lists the materials that have been injected into the formation during the high-rate gravel pack operations at the Inglewood Oil Field.

Table 3-6 List of Additives at Used During High-Rate Gravel Pack Operations at the Inglewood Oil Field

Additive Type	Trade Name	Typical Main Compound	Purpose
Water		▪ Water	Base fluid carries proppant, also can be present in some additives
Buffering Agent	BA-40L	▪ Potassium carbonate	pH buffer
Gel	LGC-36 UC	▪ Guar Gum ▪ Naphtha hydrotreated heavy	Thickens the water in order to suspend the sand
Breaker	SP Breaker	▪ Sodium Persulfate	Allows for a delayed breakdown of the gel
Crosslinker	K-38	▪ Disodium octoborate tetrahydrate	Maintains fluid viscosity as a temperature increases
pH Adjusting Agent	MO-67	▪ Sodium Hydroxide	Adjusts pH to proper range for fluid to maintain the effectiveness of other fluid components
Activator	CAT-3	▪ Copper chelate	Reduces viscosity
Surfactant	Losurf-300M	▪ Ethanol	Aids in recovery of water used during fracturing operation by reducing surface tension
Clay control	Clayfix II Plus	▪ Alkylated quaternary chloride ▪ Potassium chloride	Clay-stabilization additive which helps prevent fluid interaction with formation clays
Proppant		▪ Silica	Holds open fracture to allow oil and gas to flow to well

Water Reuse

As described for the high-volume hydraulic fracture operations, water produced during high-rate gravel pack operations is transported by pipeline to the field water treatment plant where it is mixed with other produced water generated on the field. The treated water is then reinjected into the oil and natural gas producing formations as part of the waterflood process. This operation is in accordance with CSD Condition E.2.(i) which requires that all produced water and oil associated with production, processing, and storage are contained within closed systems at all times. The volume of water in the oil and gas producing zones is much greater than the volumes used for hydraulic fracturing and as such any residual additives would be greatly diluted. In addition, many of the chemicals are soluble in oil and would be removed from the subsurface when the oil is sold.

3.4 Anticipated Future Use of Hydraulic Fracturing and Gravel Packing at the Inglewood Oil Field

PXP expects that, in the future, high-volume hydraulic fracturing and conventional hydraulic fracturing may be conducted in the relatively deep Rubel, Moynier, Bradna, City of Inglewood, Nodular, and Sentous zones (all located deeper than 4,000 feet below ground surface).

It is anticipated that high-rate gravel packing operations may be conducted on as many as 90 percent of all future production wells drilled in the Vickers and Rindge formations on the Inglewood Oil Field, as well as other permeable sandstone completions. This procedure results in less formation sand being drawn into the well during pumping, thus, the amount of formation sand that requires management at the surface is reduced and the procedure provides a longer life to the well.

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Chapter 4

Environmental Effects Monitored in Conjunction with Hydraulic Fracturing Tests

4.1 Introduction

As described in Chapter 4, the Inglewood Oil Field has an ongoing program of environmental monitoring and reporting for environmental factors such as water quality, air quality, and others. As part of this Hydraulic Fracturing Study, these ongoing monitoring programs were augmented to include other monitoring of environmental factors of importance. This chapter summarizes the results of this comprehensive environmental monitoring, as follows:

- Hydrogeology, Water Quantity and Quality
- Containment of Fractures to the Desired Zone
- Well Integrity
- Slope Stability, Subsidence, Ground Movement, Induced Seismicity
- Methane
- Other Emissions to Air
- Noise and Vibration
- Los Angeles County Department of Public Health Study

In addition, since high-volume hydraulic fracturing was first used for shale gas development in the northeastern United States and tight sands development in the Intermountain West, there has been extensive coverage of controversies surrounding its use. Although most of the news has been about the development of shale gas, tight sands and coalbed methane deposits rather than the type of oil and natural gas development that occurs at the Inglewood Oil Field, community outreach conducted as part of this study indicated that many of the concerns surrounding shale gas development are shared by the local community. Therefore, in this chapter we present the methods and results of environmental monitoring conducted at the Inglewood Oil Field, and we provide context by describing how these issues have been described as they relate to shale gas development. Although the focus of this chapter is the Inglewood Oil Field, the issues have been framed by the national attention given to shale gas development elsewhere in the country; thus, the context is relevant to the Inglewood Oil Field.

4.2 Hydrogeology, Water Quantity and Quality

4.2.1 Geologic Control on the Distribution of Groundwater-Bearing Zones

The geology of the Baldwin Hills constrains the occurrence and movement of groundwater, as described in the USGS groundwater model of the Los Angeles Basin (USGS 2003), the California Department of Water Resources groundwater assessment of the Los Angeles Basin

(DWR 1961), and studies specific to the Inglewood Oil Field summarized in this study. The USGS excludes the Baldwin Hills from the model domain, separating it by a no-flow boundary. The no-flow boundary condition means that groundwater neither flows in to or out of the Baldwin Hills; it is isolated from the remainder of the Los Angeles groundwater basin (Figure 4-1). In the definitive account of the groundwater geology of the Los Angeles Basin, the Department of Water Resources concludes that “the Baldwin Hills form a complete barrier to groundwater movement, where the essentially non-water bearing Pico Formation crops out” (DWR 1961). The results of the extensive site-specific study of the Baldwin Hills, including a groundwater monitoring array that traverses the entire zone of potential fresh water, summarized in this section, are in complete agreement with the findings of the USGS and DWR.

Figure 4-2 presents the standard model of the geology of the Baldwin Hills (Wright 1991), from the surface to a depth in excess of two miles. The center of the figure has a small area labeled “*See Figure 4-3C*” which represents the uppermost 500 feet at the Baldwin Hills; this area will be magnified in stages from Figure 4-3B to 4-3C.

Figure 4-3A shows the locations of all of the groundwater monitoring wells installed on the Inglewood Oil Field. All the oil producing formations, from the Investment Zone downwards, contain water too saline for direct use at the surface. Only the upper 500 feet, above the top of the Pico Formation, has any fresh water, albeit limited in extent and yield. For this reason, the top of the Pico Formation is known as the base of fresh water.

Figure 4-3B is the first level of magnification and shows the freshwater zones. In all parts of the world, fresh (not salty) groundwater lies at relatively shallow depths. At greater depths the water is saline, not drinkable, and is sometimes called formation water. The USEPA makes this distinction in the Safe Drinking Water Act by protecting the shallow, fresh water from contamination by deeper, saline formation water. In most of the Los Angeles Basin, the base of the fresh water zone, below which saline formation water is found, is defined by a geological unit called the Pico Formation, a marine unit shown in Figure 4-3B (developed from USGS 2003). Overlying the Pico Formation are the aquifer systems in the Los Angeles Basin located away from the Baldwin Hills: the Inglewood Formation, the Silverado Formation, and the Lakewood Formation. In many parts of the Los Angeles Basin, these formations are aquifers for water supply wells. The box labeled “*See Figure 4-3C*” depicts how these formations became folded and faulted in the geological uplift of the Baldwin Hills (within the labeled box). As a result of this uplift, these formations are not water-bearing beneath the Baldwin Hills, and are in fact exposed at the surface. Their disruption by the uplift of the Baldwin Hills has disconnected them from the groundwater-bearing formations of the Los Angeles Basin (USGS 2003, DWR 1961).

Finally, Figure 4-3C shows the uppermost 500 feet beneath the Baldwin Hills. The ground surface is shown as the undulatory line at the top of the figure. The vertical black lines represent groundwater wells drilled at the Inglewood Oil Field from 1993 to present. Although they are shown along a single line in the figure, the wells are distributed across the oil field; their locations have been projected to a single line to aid in the presentation of the results. The length of the line shows the depth of drilling. If any groundwater was detected, the depth is shown with an upside-down triangle and the estimated extent of the groundwater is shown with the blue color surrounding the well (black line). If no groundwater was detected, that observation is noted with an upside-down triangle with a red circle around it, and a red cross-out.

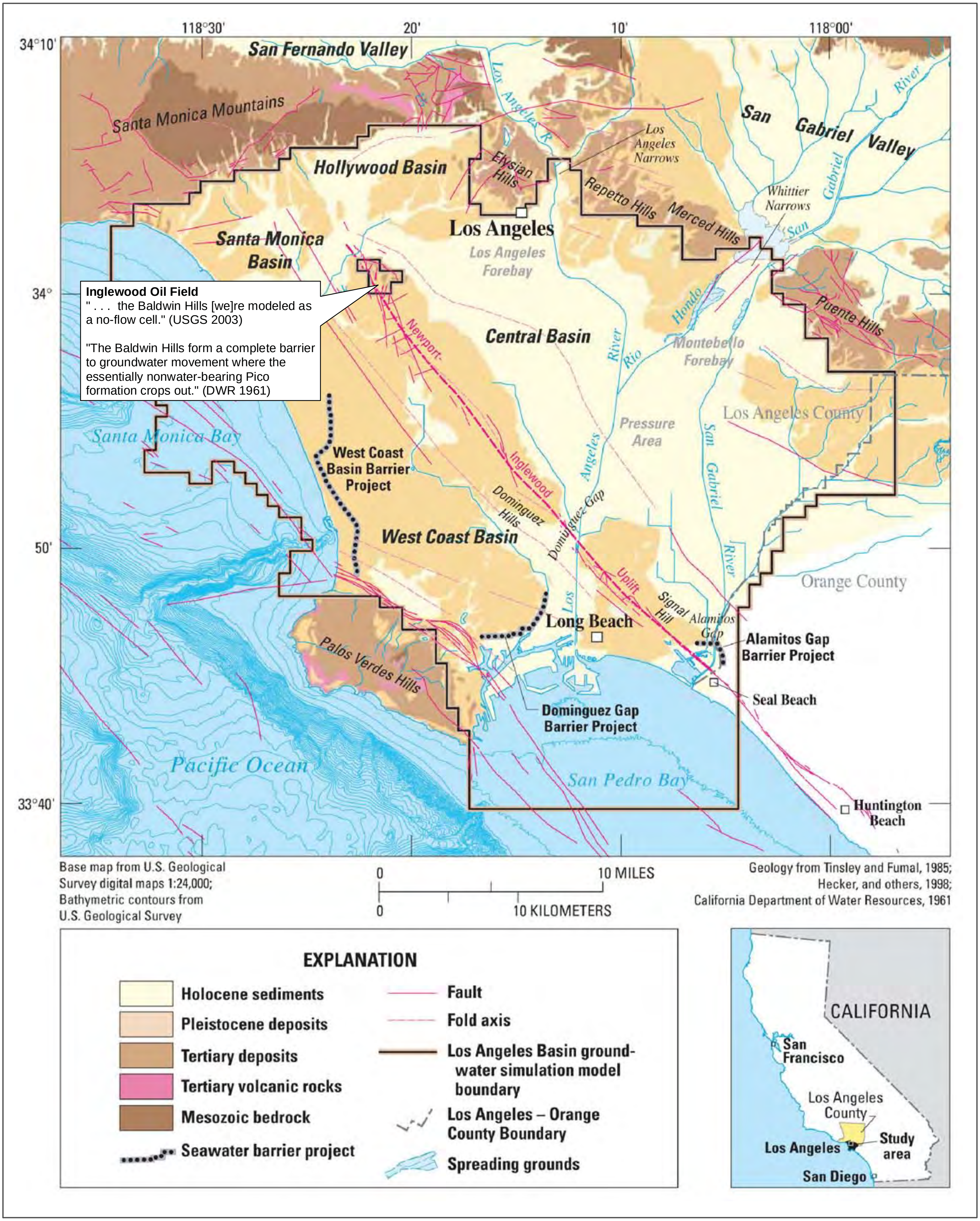

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Figure 4-1
Groundwater Basins in the Vicinity of the Inglewood Oil Field
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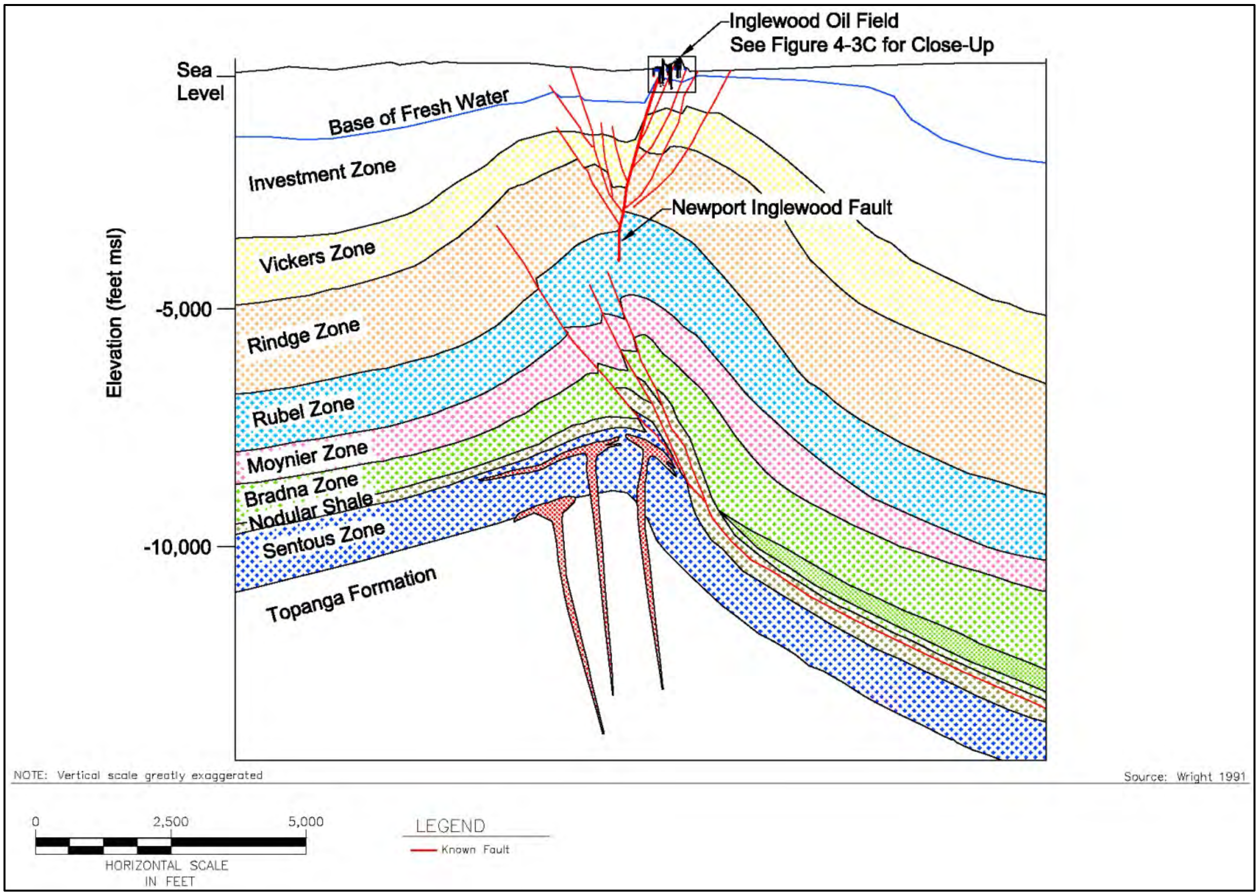
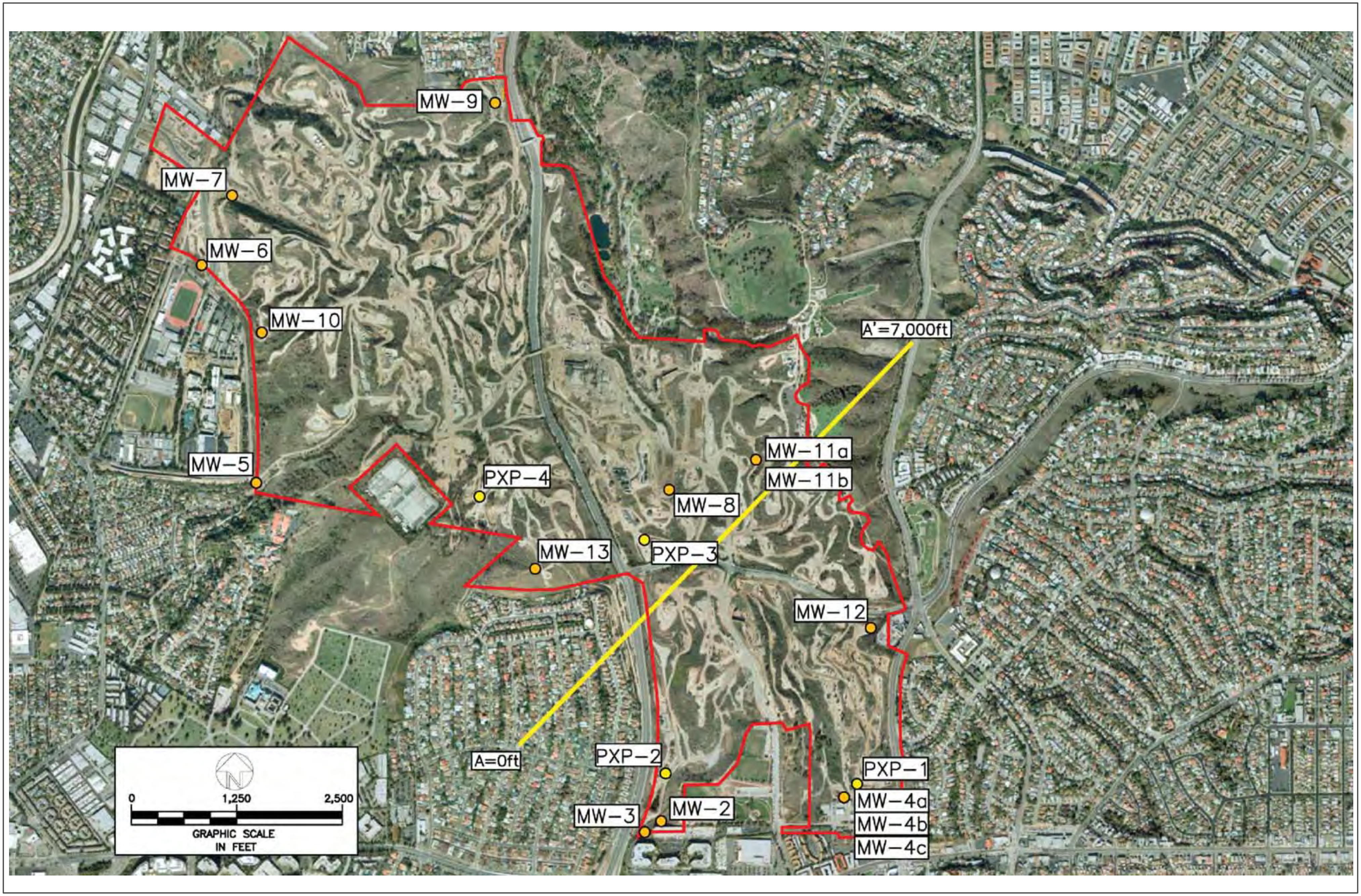


Figure 4-2 Location of Inglewood Oil Field in Relation to Known Fault Lines



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- (MW) Monitoring Well Location
- PXP Dry Borehole
- Active Surface Field Boundary
- Cross-Section

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Figure 4-3A

Cross Section Location

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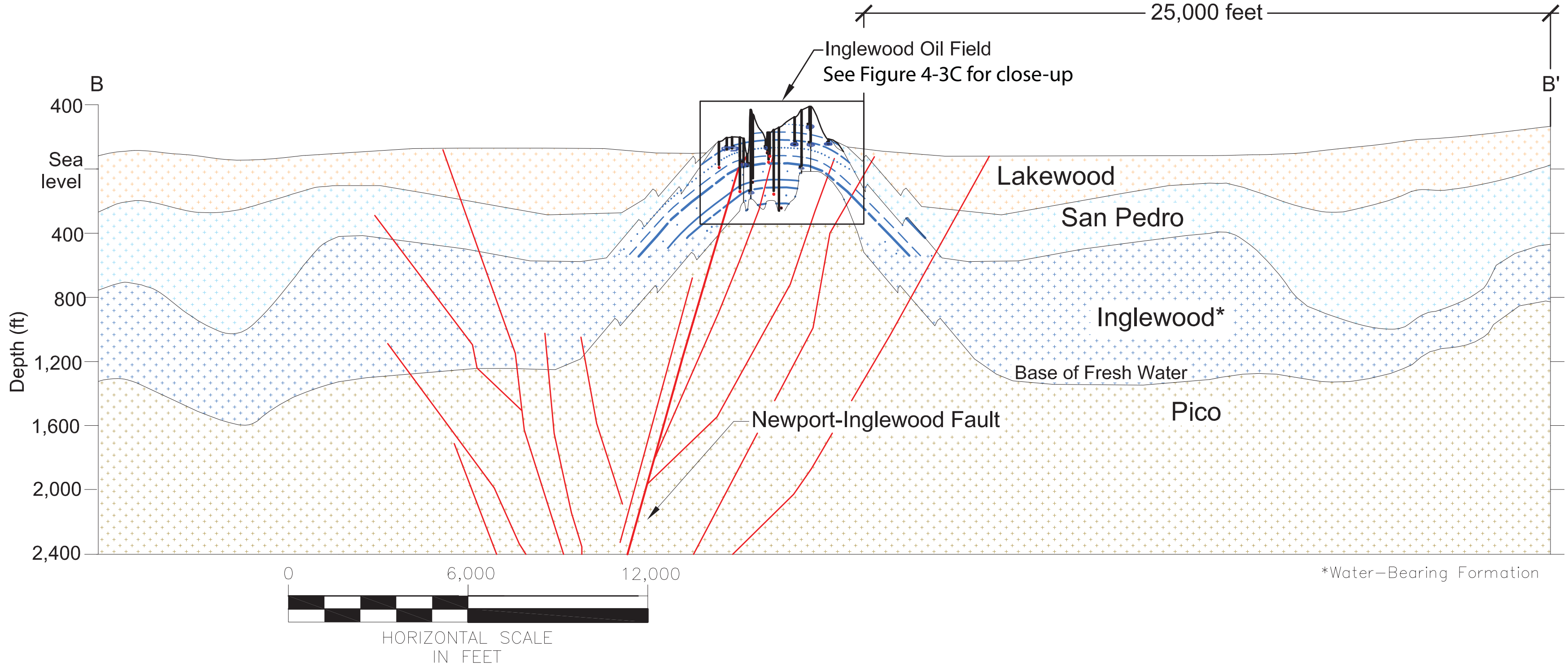

LEGEND

- Fault
- Fold Axis
- Geologic Formation
- Cross–Section

NOTES: 1. Vertical scale greatly exaggerated.
2. Both San Pedro and Inglewood formations are present at the oil field. Depiction is an estimate, as both formations crop out and have complex folds.
3. Cross–section depicted located as shown in inset map.

Source: USGS 2003

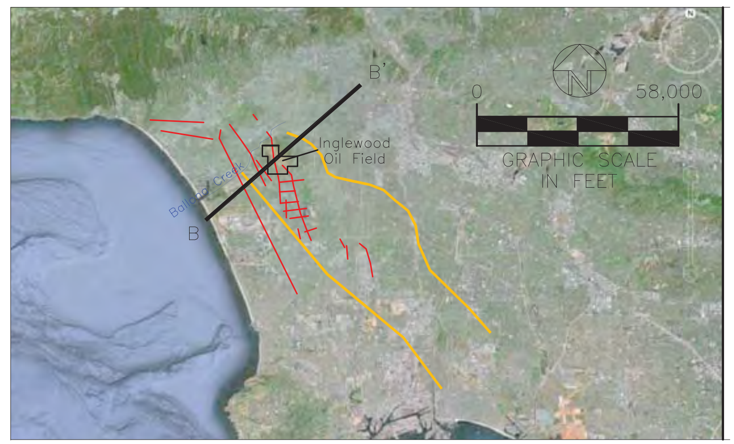

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Figure 4-3B

Monitoring and Drinking Water Wells in the Vicinity of the Inglewood Oil Field

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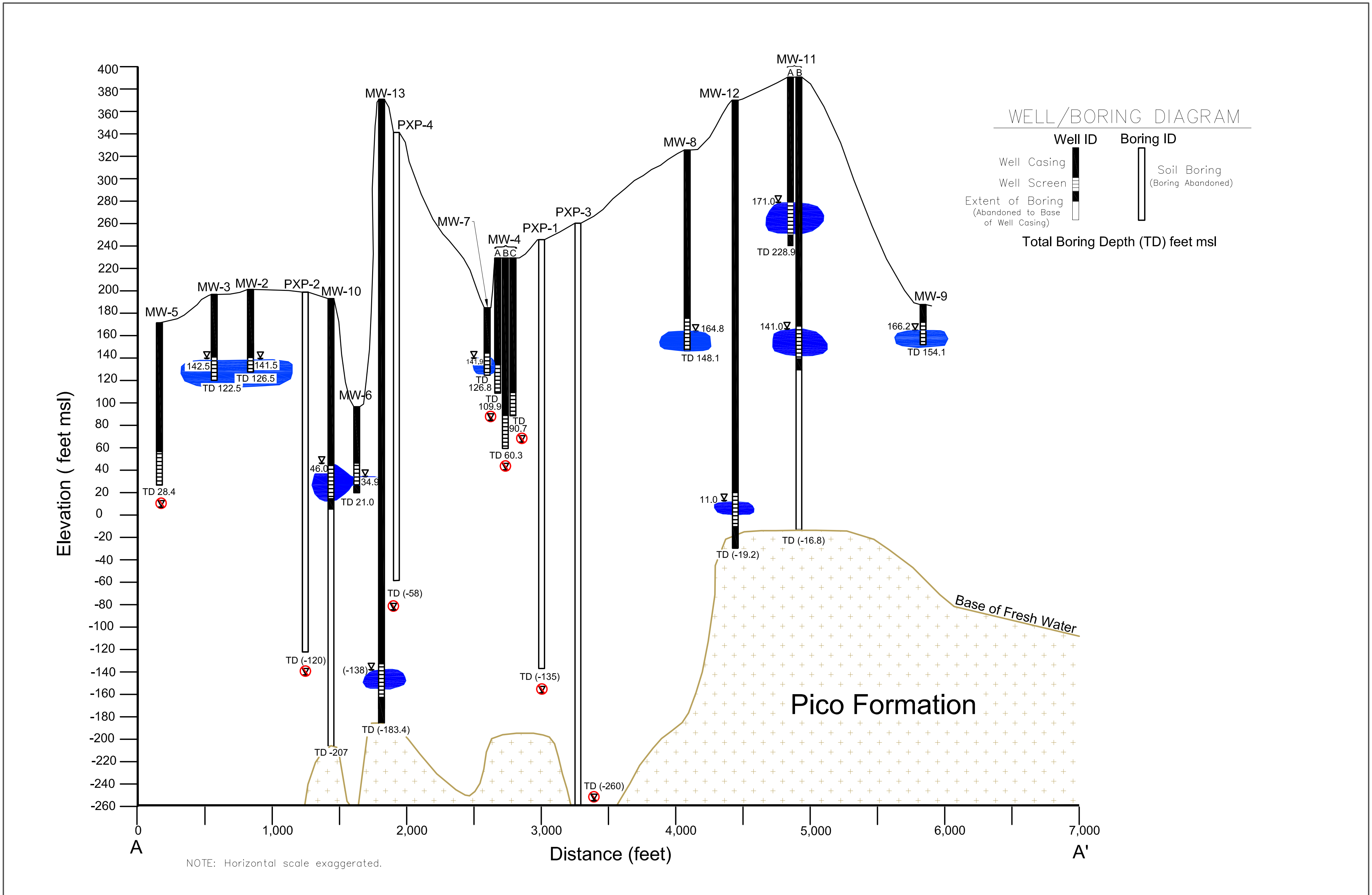

LEGEND

No Groundwater Found

Static Groundwater Level (feet msl)

Groundwater

Pico Geologic Formation

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Figure 4-3C

Groundwater Beneath the Oil Field

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Figure 4-3C is based on measured conditions beneath the field, with 15 groundwater monitoring wells and four deep supply wells that were attempted by PXP, but that did not encounter water and were abandoned. Note that the same characteristics shown in Figure 4-3C are also shown in more detail by the 3-D model prepared by Halliburton in Figure 2-8H. The data show that the water bearing zones are not continuous across the field because they occur at different depths, or do not occur at all.

All of the wells have very low yield; the shallow wells and all but two of the deeper wells pump dry in less than 30 minutes at low pumping rates. The two that can sustain higher initial pumping rates show declining yields when pumped for more than a day, indicating that the water bearing zone from which they draw is limited in extent. None of the units show evidence of a connection to the aquifers of the Los Angeles Basin (shown in Figure 4-3C).

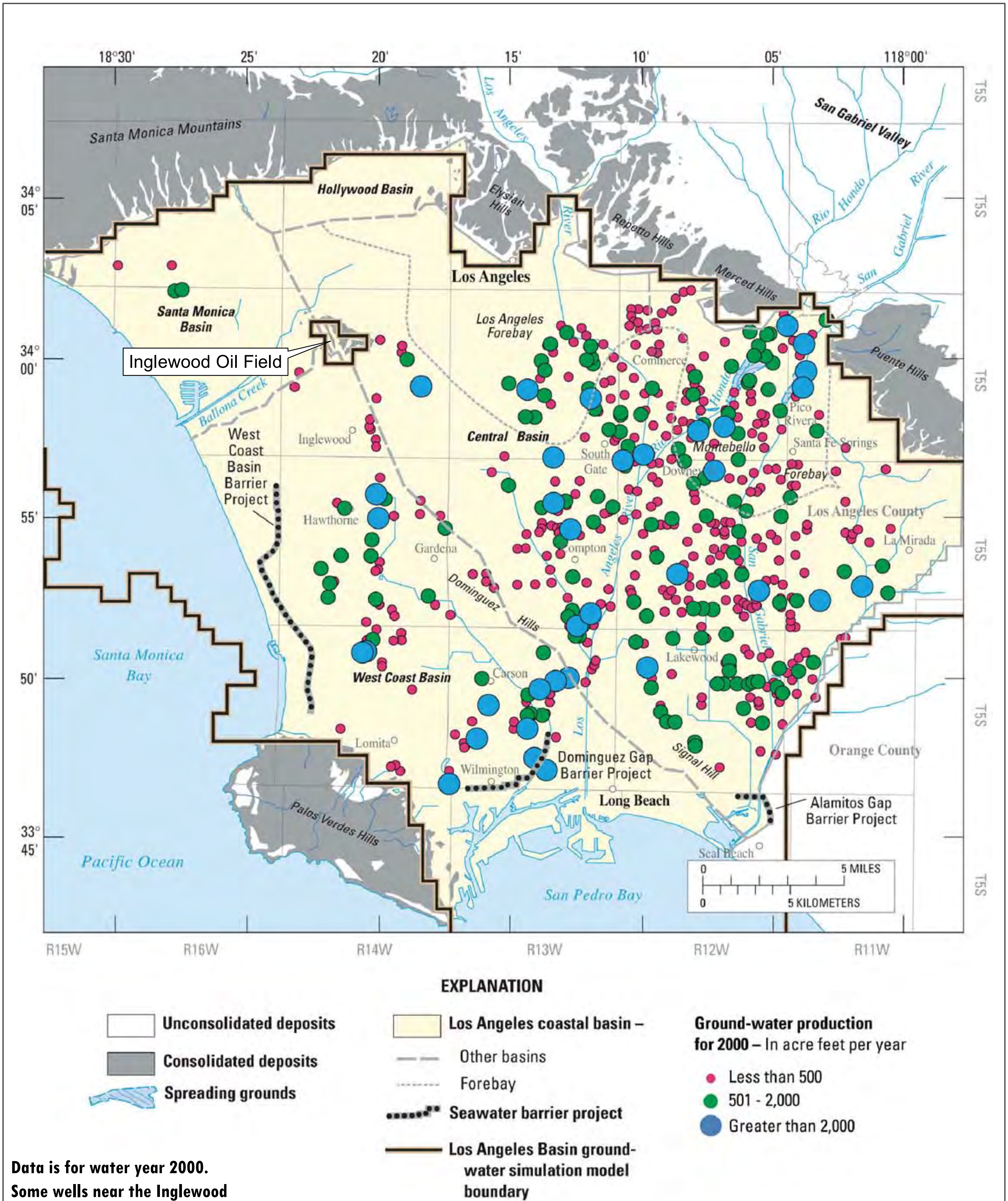
4.2.2 Hydrogeology

The description of conditions beneath the Inglewood Oil Field depicted in Figure 4-3C and described in the previous section is based on data collected from 15 groundwater monitoring wells installed to test for the presence and quality of groundwater beneath the site, ranging in depth from 30 feet to 500 feet beneath the ground surface. The four deepest wells were installed to reach the "base of the fresh water zone", that is, the top of the Pico Formation. As such, the understanding of groundwater hydrogeology and water quality is based on investigation of the *entire* zone beneath the surface that has any potential to contain fresh water.

The Baldwin Hills are generally comprised of non-water-bearing rock layers that straddle the West Coast, Central, and Santa Monica groundwater basins (Figure 4-4). As shown in this figure, where groundwater is pumped for groundwater supply, it is principally in areas to the east of the Baldwin Hills. The data used by the USGS to construct this figure were based on water year 2000; currently, the only wells in the vicinity of the Inglewood Oil Field are either no longer active (Environmental Data Resources, Inc. 2012) or located greater than 1.5 miles from the field boundary.

Studies of the Baldwin Hills have concluded that the tectonic uplift of the Baldwin Hills by folding and faulting has disconnected water-bearing sediments from groundwater supplies in the Los Angeles Basin (USGS 2003, DWR 1961). The geological formations that may produce usable quantities of groundwater from aquifers elsewhere in the Los Angeles Basin are folded, faulted, and either dry or have practically no water supply potential beneath the Baldwin Hills. Because of a lack of water, the geological formations beneath the Baldwin Hills are not suitable for water supply (DWR 1961, USGS 2003, County of Los Angeles 2008).

For example, the prominent aquifers in some portions of the Los Angeles Basin, which lie greater than 100 feet below the surface in the flat portion of the Los Angeles Basin (refer to Figure 4-1, Figure 4-3B), have been brought to the surface by folding and faulting of the Baldwin Hills. The units are exposed at the surface, do not contain water, and are not connected to the surrounding basin. In groundwater models of freshwater flow in the Los Angeles Basin aquifer systems recently prepared by the U.S. Geological Survey (USGS 2003), the Baldwin Hills is modeled as a "no flow" zone; that is, since the sediments beneath the Baldwin Hills are disconnected from the regional aquifers, groundwater flow is discontinuous across the Baldwin Hills.



Data is for water year 2000.
Some wells near the Inglewood Oil Field are no longer active.

Source: USGS 2003

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Figure 4-4
Groundwater Production in the Los Angeles Basin in 2000

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The five water wells (MW-10, MW-11A, MW-11B, MW-12, and MW-13) drilled down to the base of fresh water in 2012 are intended to provide data for the deepest freshwater zones in the Baldwin Hills. Only two encountered water at the deepest levels, and were completed in the only zones containing water. Maps showing the top of the Pico used for oil exploration defined the top of the Pico Formation, and drilling progressed to that depth, in some places up to 500 feet below the ground surface. In addition, geophysical logs were run after drilling to thoroughly search for water. Two of the locations had only a single thin water-bearing zone, and the wells quickly pumped dry at low flow rates. One location had water near the top of the Pico Formation and was initially capable of sustaining pumping rates of eight gallons per minute. Over three days of pumping the yield diminished significantly, indicating a limited areal extent of the water-bearing zone. The fourth location of the deep water wells identified two thin water-bearing zones. One pumped dry readily, while the other well initially sustained pumping rates of one gallon per minute. Over three days of pumping the yield diminished significantly indicating a limited areal extent of the water-bearing zone.

At the Inglewood Oil Field perched groundwater (groundwater that is discontinuous and occurs in small pores within the rock layers) has been measured at depths ranging from approximately 45 to 500 feet below ground surface (Figure 4-3C). Groundwater monitoring on the field suggests that rainfall and irrigation water from nearby residences appear to be the only source of this groundwater because water levels respond to the presence of water in catch basins.

4.2.3 Water Quality

Regulatory Limits

The LARWQCB Water Quality Control Plan, or Basin Plan, establishes beneficial uses of surface and groundwater in the Los Angeles Basin. Based on the State Board Resolution No. 88-63, “Sources of Drinking Water Policy”, all groundwater in the state must be considered a potential source of drinking water, and carry a beneficial use designation of Municipal Supply (or MUN). The only exceptions are as follows:

- Total Dissolved Solids (TDS) exceeds 3,000 mg/l (5,000 µS/cm electrical conductivity);
- Contamination exists, that cannot reasonably be treated for domestic use; and
- The source is not sufficient to supply an average sustained yield of 200 gallons per day.

The LARWQCB would also require that, for any groundwater to have the MUN designation removed that there be a formal process to de-designate the aquifer. There are only two de-designated areas in the LARWQCB jurisdiction: limited coastal areas beneath the Port of Los Angeles and the Port of Long Beach, and a limited area of El Segundo seaward of a series of injection wells to limit saltwater intrusion. Because the Inglewood Oil Field has not gone through a de-designation process, any water that may be encountered beneath the field has the beneficial use designation of MUN, and the drinking water standards are applied regardless of the low yield.

Chemical Disclosure and Environmental Effects of Chemical Additives

When new oil and natural gas development using high-volume hydraulic fracturing was initially introduced in the northeastern United States (areas dependent on shallow groundwater resources or water from relatively pristine watersheds), public concern was initially related to the policy of oilfield service companies to maintain confidentiality of the precise chemical names and concentrations used in hydraulic fracturing fluids. The initial lack of full disclosure on the part of the oilfield service companies increased public concerns about the chemicals. As a result of these concerns, several states initiated independent reviews of the environmental impacts of hydraulic fracturing with an emphasis on water quality and chemical disclosure. In addition, USEPA initiated two ongoing reviews, one focused on the potential effects of hydraulic fracturing on drinking water supplies, and the other focused on the definition of "diesel fuel" as part of a review of the 2005 EPAct provisions (USEPA 2011c, USEPA 2011d). The 2005 EPAct reaffirmed that hydraulic fracturing is a well completion process regulated at the state level, and therefore does not require an underground injection control permit under the Safe Drinking Water Act. The 2005 EPAct did require a UIC permit in cases where diesel fuel is used in hydraulic fracturing fluid.

Since the passage of the EPAct, many states have adopted regulations or passed legislation requiring operators to disclose the composition of the fluids used in the hydraulic fracturing process. In California, legislation (AB 591 - Wieckowski) requiring operators to post a complete list of the chemical constituents used in the hydraulic fracturing process was introduced during the 2011 – 2012 legislative session but failed to pass. The bill would have required that operators involved in hydraulic fracturing provide a complete list of the chemical constituents used in the hydraulic fracturing fluid, as well as the following additional information to DOGGR:

- the source and amount of water used in the exploration or production of the well;
- data on the use, recovery and disposal of any radiological components or tracers injected into the well; and
- if hydraulic fracturing is used, disclosure of the chemical information data described above.

The chemical additives used in hydraulic fracturing, typically 0.5 percent of the total fluids, are necessary to ensure that the fracturing job is as effective and efficient as possible. The various chemicals are used as friction reducers, biocides to prevent microorganism growth, oxygen scavengers and other stabilizers to prevent corrosion of metal pipes, and acids to remove drilling mud damage. The consequences of not using additives in the fluids include higher engine emissions as a result of greater loads, increasing pipe corrosion (and, in turn, compromised integrity of the well), increased water use, and decreased hydrocarbon recovery.

PXP reported the full chemical listing of the two recent high-volume hydraulic fracture operations on the FracFocus.org website. This website offers the opportunity to comply with the standard chemical disclosure regulations in effect in other parts the country. The level of disclosure used in this Hydraulic Fracturing Study would comply with the terms of AB 591 as drafted at the time this study was prepared. Diesel fuel is not used as a chemical additive for the hydraulic fracturing conducted at the Inglewood Oil Field; therefore, a UIC permit is not required.

Quarterly Water Quality Testing Prior to High-Volume Hydraulic Fracturing

Fifteen groundwater wells to test for the presence and quality of groundwater beneath the Inglewood Oil Field have been drilled since 1993. These vary in depth from 30 feet to 500 feet below the ground surface. In addition to the 15 groundwater monitoring wells, four wells were drilled as potential water supply wells for the oil field, but because they were dry, the wells were abandoned and sealed. Of the fifteen wells, six did not encounter groundwater but the wells remain in place. Four were installed in 2012 and were drilled to the base of fresh water in order to characterize the entire fresh water zone. The remaining five all sample the shallowest water on the field and are monitored on a quarterly basis, in accordance with CSD Condition 19.

Quarterly monitoring reports for 2010 and 2011 provide a baseline indication of existing groundwater quality. Prior to the hydraulic fracturing operations of January 2012, a total of nine monitoring wells were tested as part of the groundwater monitoring effort that took place on November 22, 2011. Specifically, the monitoring effort involved wells MW-2, MW-3, MW-4A, MW-4B, MW-4C, and MW-5, MW-6, MW-7, and MW-8 as part of the monitoring program. The sampling involved the collection of depth-to-water measurements and groundwater samples from monitor wells MW-2, MW-6, MW-7, and MW-8. Monitor wells MW-3, MW-4A, MW-4B, MW-4C and MW-5 were not sampled since they were dry or contained insufficient water at the time the monitoring was conducted.

Groundwater analytical results indicated no results were above the California Maximum Contaminant Level (MCL), with the exception of arsenic. Arsenic levels are believed to correspond to naturally occurring arsenic found in soil and rock formations throughout the Los Angeles Basin. As documented by USEPA, when “compared to the rest of the United States, western states have more systems with arsenic levels greater than the [US]EPA’s standard of 10 parts per billion (ppb)” (USEPA 2012a). Arsenic delineation maps produced by the USGS in 2011 have documented increased levels of arsenic in both Los Angeles County and Southern California as a whole (Gronberg 2011). These data are also consistent with soils data from the 2008 California Department of Toxic Substance Control (DTSC) memo “Determination of a Southern California Regional Background Arsenic Concentration in Soil” (Chernoff et al. 2008). Areas in Southern California have been shown to have higher than average levels of arsenic present in soil and thus, through the release of naturally occurring arsenic in sediments, levels can be inferred to also be higher than average in groundwater resources throughout Southern California.

A summary of the baseline groundwater analytical results is as follows:

- TDS was measured at 590 mg/L in MW-2, 2,000 mg/L in MW-6, 2,500 mg/L in MW-7, and 1,500 mg/L in MW-8.
- pH was measured at 7.5 in MW-2, 7.0 in MW-6, 7.0 in MW-7, and 7.0 in MW-8.
- BOD_5 was measured at 38.5 mg/L in MW-2, 30.4 mg/L in MW-6, 25.6 mg/L in MW-7, and 15.7 mg/L in MW-8.
- Low levels of TPH in MW-2, MW-6 and MW-7. The silica gel filtering method, which removes nonpetroleum materials such as fats, was run on all groundwater samples. Results indicate TPH concentration of 0.35 mg/L in MW-2, and below the detectable limit of

0.10 mg/L in wells MW-6 and MW-7. These levels are within the range of drinking water standards for taste and odor commonly applied for TPH (between 0.050 and 1 mg/L).

- TRPH were below the detection limit of 0.50 mg/L in all samples.
- BTEX and MTBE were below detection limits in all samples.
- Nitrate was detected at a concentration of 0.34 mg/L in MW-2 and 3.8 mg/L in MW-7, both below the state MCL of 45 mg/L.
- Barium was detected in MW-6 at a concentration of 56 µg/L, MW-7 at a concentration of 60 µg/L, and in MW-8 at a concentration of 170 µg/L. These levels are all below the state MCL of 1,000 µg/L.
- Arsenic was detected at a concentration of 37 µg/L in MW-2 and 4.2 µg/L in MW-8. The concentration of arsenic in MW-2 is above the state MCL of 10 µg/L and is likely due to naturally occurring arsenic found in soil and rock formations as described previously in this section.

4.2.4 Groundwater Monitoring Associated with High-Volume Hydraulic Fracturing

The groundwater monitoring wells have been sampled twice since the high-volume hydraulic fracturing was completed. Results from baseline (pre-hydraulic fracturing) groundwater sampling are compared with results of sampling the same wells after hydraulic fracturing. Since the deep wells do not have a baseline, the results of two rounds of sampling the deep wells are compared to the same two rounds of the pre-existing wells.

The Inglewood Oil Field is required to sample and analyze groundwater on a quarterly basis in compliance with CSD Section E.19. This sampling will continue irrespective of whether hydraulic fracturing operations are conducted in the future, but this study focuses on the sample rounds at the end of 2011 (pre-hydraulic fracturing) compared to the two rounds of samples collected so far in 2012 (post-hydraulic fracturing).

Comparison of Baseline to Post-Hydraulic Fracturing Operation Water Quality

The monitoring wells with sample results prior to 2012 were sampled for the same analytes after the occurrence of hydraulic fracturing in January. The water was analyzed for the following constituents: pH, TPH, benzene, toluene, ethylbenzene, total xylenes, methyl-tributyl ethylene (MTBE), total recoverable petroleum hydrocarbons (TRPH), total dissolved solids (TDS), nitrate, nitrite, metals, and biological oxygen demand (BOD_5). These chemicals include compounds in the hydraulic fracturing fluids.

Analysis of samples taken post-fracturing (April and August 2012) indicated no results above the state MCL for any constituents, with the exception of arsenic, which is likely due to naturally occurring arsenic found in soil and rock formations that was present prior to fracturing. These results are consistent with earlier, pre-hydraulic fracturing sample results from these wells.

In most cases there were either no changes in the concentrations of the analytes sampled for, or there was a decrease in concentration after hydraulic fracturing. One of the wells, MW-7, had an increase of one compound, chromium, in the samples after the hydraulic fracturing (2.7 µg/L to

3.0 µg/L, both results well below the 50 µg/L state standard). Chromium is not associated with hydraulic fracturing additives.

The following analytes showed no major changes in concentration when comparing the data that was obtained prior to and after hydraulic fracturing:

- pH
- TPH-DRO[1]
- TRPH
- TDS
- Nitrite
- Cobalt

The following analytes were below detection prior to the hydraulic fracturing, and then showed concentrations above the detection limit in January 2012, with levels returning to below detection in April 2012 and remaining below detection in August 2012. All analytes were below the state MCL.

- MW-6 and MW-7 TPH-DRO (with Silica Gel)
- MW-3 Benzene, Toluene, Ethylbenzene, Total Xylenes, and MW-8 Toluene
- MW-2 and MW-6 Zinc

The following analytes showed an instance where there was a slight concentration increase after the hydraulic fracturing:

- MW-7 Chromium showed an increase from 2.7 to 3.0 µg/L. Both results are well below the 50 µg/L state standard. Chromium is not associated with hydraulic fracturing additives.

The following analytes showed a decrease after hydraulic fracturing:

- MW-2 and MW-6 Nitrate
- MW-7 Barium
- MW-8 Arsenic
- MW-7 Copper showed below detection limit immediately after wells were installed, then had a slight increase in concentration 6 months later, before returning to below the detection limit.
- MW-8 Lead showed below detection limit immediately after wells were installed, then had a slight increase in concentration 6 months later before returning to below the detection limit.

In summary, the hydraulic fracturing did not have a detectable change to groundwater quality based on the comparison of baseline results to post-hydraulic fracturing results. Any variations are within the ranges detected over the course of the monitoring. Figure 4-5 summarizes the monitoring results. The horizontal axis lists any detected compounds. The vertical axis divides the amount detected by the drinking water standard for that compound; a value of 1 means that the detected amount equaled the drinking water standard. The horizontal line corresponding to 1 on the vertical axis divides the chart between detections that meet the drinking water standard

[1] With the exception of MW-8, which showed below the detection limit after the well was installed in February 2012 then a slight increase to .34 mg/L in April 2012, before returning to below the detection limit in August 2012.

(all compounds except arsenic) from arsenic, which has a high background in Southern California that exceeds the drinking water standard.

Comparison of New Wells to Pre-Existing Wells

In addition to the existing monitor well array prior to hydraulic fracturing, five new wells (MW-10, MW-11A, MW-11B, MW-12, MW-13) were installed at the field in order to fully investigate the occurrence and quality of groundwater from the base of fresh water (the top of the Pico Formation at approximately 500 feet below ground surface) to the shallowest occurrence of water (approximately 30 feet below ground surface).

Groundwater sampled from these wells was analyzed for the following constituents: pH, TPH, benzene, toluene, ethylbenzene, total xylenes, MTBE, TRPH, TDS, nitrate, nitrite, metals, and BOD_5. A comparison of the sample results from the pre-existing wells to the new deeper wells show generally consistent results. In most cases, the results for the new deeper wells were within the ranges found at the pre-existing wells. All analytes were below the state MCL for Drinking Water Standards, with the exception of arsenic, which is likely due to naturally occurring arsenic found in soil and rock formations as described previously in this section.

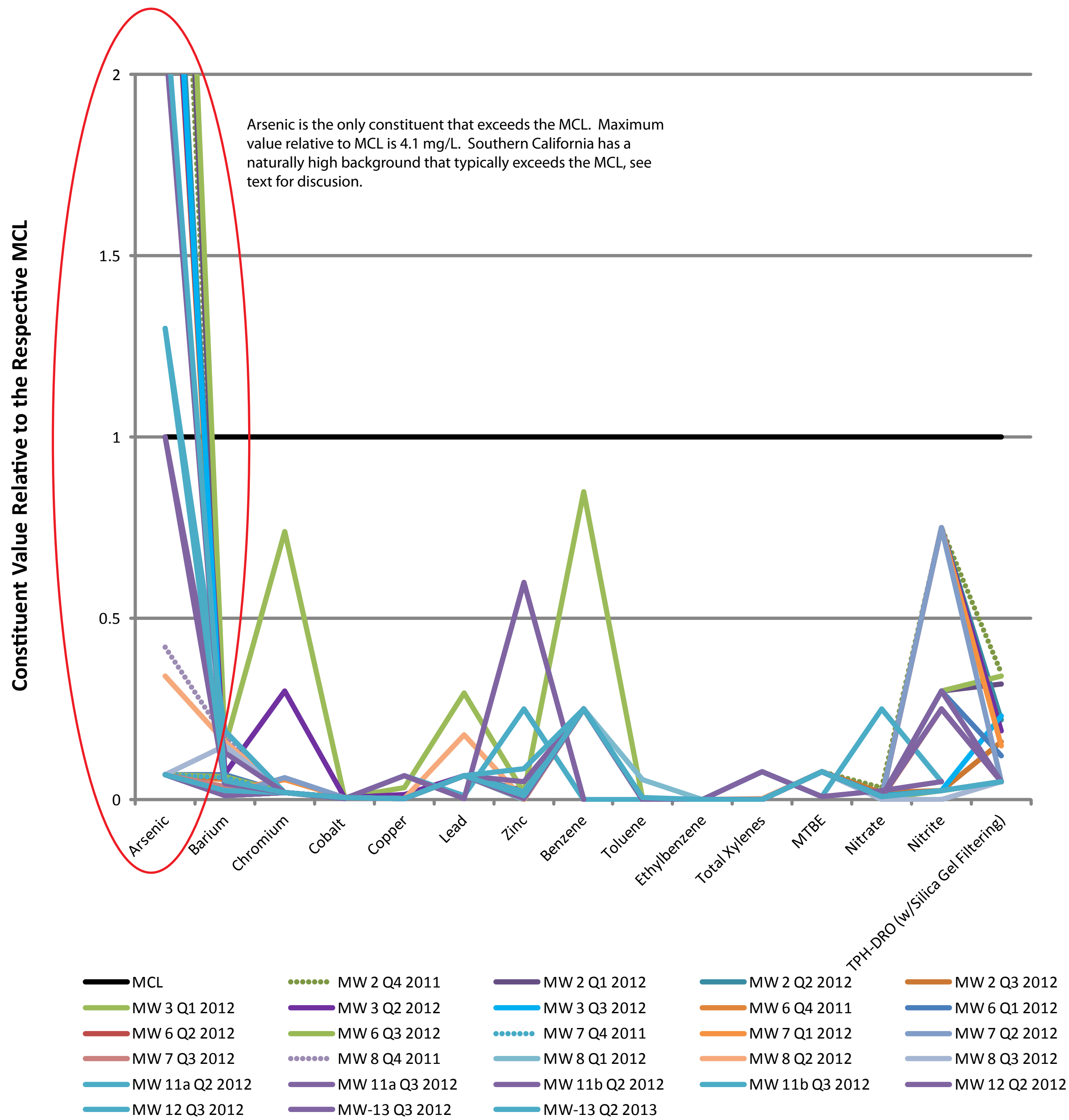
The following analytes showed no major changes in concentration:

- pH
- Benzene, toluene, ethylbenzene, total xylenes, MTBE
- TRPH
- Nitrate and nitrite
- Cobalt
- Lead
- Barium
- Copper, below detection in most cases, but had similar ranges for those analytes that showed above detection.

The following analytes showed ranges that were greater in the new deep wells in comparison to pre-existing wells; all ranges were below the state MCL:

- TDS in the shallow wells showed a concentration range of 510 to 2,500 mg/L vs. 1,400 to 3,900 mg/L for deep wells.
- Zinc in the shallow wells showed a concentration range of 18 to 120 µg/L vs. 20 to 280 µg/L for deep wells.
- BOD in the shallow wells showed a concentration range of 9.91 to 43.4 mg/L vs. 11.5 to 92.6 mg/L for deep wells.

Groundwater Sampling Results for All Monitoring Wells from 4th Quarter 2011-3rd Quarter 2012 Compared to MCL



The following chemical concentrations in the new deep wells were lower than the concentration in the pre-existing wells. As a note, all ranges were below the state MCL with the exception of arsenic, which is likely due to naturally occurring arsenic found in soil and rock formations:

- Arsenic in the shallow wells showed a concentration range of up to 37 µg/L vs. 21 µg/L for deep wells.
- TPH DRO in the shallow wells showed a concentration range of up to 2.1 mg/L vs. 0.77 mg/L for deep wells.
- Chromium in the shallow wells showed a concentration rage of up to 32 mg/L vs. 12 mg/L for deep wells.

In summary, the new wells, intended to investigate the deepest zones of fresh water beneath the Baldwin Hills, had similar groundwater quality results compared to the pre-existing wells that have been sampled on a quarterly basis prior to high-volume hydraulic fracturing. Accordingly, the new wells do not show a detectable environmental effect of high-volume hydraulic fracturing. The values are within the ranges detected over the course of the monitoring (Cardno ENTRIX 2012).

4.2.5 Surface Water

No perennial or intermittent streams as defined by the USGS are present at the Inglewood Oil Field (County of Los Angeles 2008), although Ballona Creek lies to the north and west. Surface runoff occurs primarily as sheet flow across the land surface, eventually flowing into ephemeral gullies and drainage ditches to six surface water detention basins. Runoff from these basins is discharged to the Los Angeles County stormwater system near the boundaries of the field in accordance with protections, sampling and analysis, and monitoring overseen by the LARWQCB (NPDES No. CA0057827). No discharge of surface water occurred during hydraulic fracturing operations; thus, there was no effect on surface waters draining from the oil field.

4.2.6 Sources of Drinking Water to the Local Community

West Basin Water District (District) provides water to the City of Inglewood, Culver City, and the unincorporated communities of South Ladera Heights, Lennox, Athens, Howard and Ross-Sexon, View Park, Windsor Hills, and others near the Inglewood Oil Field, either itself or through sale of water to retail service provides such as California American Water Company, California Water Service Company, and Golden State Water Company, among others.

Approximately 66 percent of the District's water supply is imported from either the Colorado River or from the San Joaquin Delta in Northern California. Approximately 20 percent of the District's supply is from groundwater; however, the nearest active supply well is 1.5 miles from the Inglewood Oil Field, and most of the groundwater supply is from significantly further than 1.5 miles from the Inglewood Oil Field (USGS 2003, West Basin Municipal Water District 2011).

Among the other communities in the vicinity of the Baldwin Hills, the City of Culver City relies on imported sources of water and does not have a groundwater supply (Culver City 2010). The City of Inglewood has four groundwater supply wells in the West Basin, all of which are greater than 1.5 miles from the oil field. None of these wells serve the community around the field (City of Inglewood 2010). Golden State Water Company has 13 wells within the West Basin groundwater basin with the closest one located 1.5 miles from the Inglewood Oil Field (Golden

State Water Company 2011). California American Water Company which services the Baldwin Hills provides water purchased from West Basin Water District as well as groundwater pumped from the Central Basin (California American Water 2011b).

All of the water service providers to the communities surrounding the Baldwin Hills must test their water at least 4 times a year and report the results to the water users. The constituents that are tested include, but are not limited to, the following:

- Turbidity
- Aluminum
- Arsenic
- Fluoride
- Nitrate
- Gross Alpha Activity
- Gross Beta Activity
- Uranium
- Color
- Chloride
- Odor
- Specific Conductance
- Sulfate
- Total Dissolved Solids
- N-nitrosodimethylamine
- Alkalinity
- Calcium
- Hardness
- Magnesium
- pH
- Potassium
- Sodium
- Total Coliform Bacteria
- Bromate
- Chlorine Haloacetic acids
- TTHMs
- Copper

A review of the 2011 Annual Water Quality Reports for the local community (which includes testing in the 4th quarter following the high-volume hydraulic fracture of VIC1-330), indicate that the community receives water that meets USEPA and California drinking water standards. The continued monitoring four times per year ensures that the water supply will continue to meet these standards (California American Water 2011a, Golden State Water Company 2012). The data for 2012 has not yet been posted as of the time of this study, and is expected to be posted in January 2013.

There are no domestic or industrial water supply wells located within the active surface oil field boundary. Potable water aquifers nearest to the Baldwin Hills include the Silverado Aquifer, which is located along the north-northwest boundary of the Baldwin Hills and extends to depths between 200 and 450 feet below ground surface, and several aquifers to the east of the Field including (in descending order) the Exposition, Gage, Lynwood, Silverado, and Sunnyside aquifers that extend to depths of approximately 800 feet. These aquifers are underlain by the non-water-bearing Pico Formation (see Figure 4-3C, DWR 1961). As described in Section 4.2.1, the USGS (2003), DWR (1961) and this study have determined that because the Baldwin Hills are uplifted, the formations do not allow groundwater to flow in to or out of the Baldwin Hills; it is isolated from the remainder of the Los Angeles groundwater basin and are considered to form a complete barrier to groundwater movement. The groundwater monitoring and analysis has shown that hydraulic fracturing did not have a discernible effect on groundwater quality beneath the Baldwin Hills; the isolated nature of this groundwater further indicates that there would be no effect on the groundwater in surrounding aquifers of the Los Angeles Basin.

In summary, over much of the Baldwin Hills there is limited or no groundwater within the freshwater interval above the Pico Formation, and where groundwater does occur, it is not connected to the aquifers of the Los Angeles basin. The groundwater is not used for water supply of any type, nor is it present in sufficient quantity to provide a water supply. The local community receives most of its water from sources in northern California (the Delta) or the Colorado River. Therefore, activities associated with oil and gas development in the Baldwin Hills do not affect the community's drinking water supply. The water supplied to the local community (as well as any community in California) must be sampled on a quarterly basis, with the results reported to the community.

4.2.7 Water Supply Concerns Related to Shale Gas Development Elsewhere in the United States

National Issue

There have been several studies published in 2011 and 2012 that examine the potential effects of hydraulic fracturing and shale gas development on private water wells in their respective study areas. Specific concerns with regard to groundwater contamination include: risk of migration and contamination from fracturing fluids; and, risk of migration and contamination from gas, oil, or other compounds (e.g., arsenic, methane).

2011 Duke Study: Methane Contamination of Drinking Water

The first Duke University study was conducted in response to the widespread public concern in Pennsylvania about drinking water contamination from drilling and fracturing, and lack of scientific evidence as to whether these activities posed an actual risk. The study described itself as the first scientific review of water contamination near hydraulic fracturing operations. The study, which collected and analyzed samples from 68 drinking water wells in the Marcellus and Utica formations in Pennsylvania and New York, aimed to evaluate the potential impacts of natural gas drilling and hydraulic fracturing on shallow groundwater quality by comparing areas with active drilling and fracturing to areas that are not currently being drilled. This study found that methane contamination in private drinking wells systematically occurred in areas where hydraulic fracturing of shale gas takes place (Osborn et al. 2011).

The study also indicated that methane was detected in 85 percent of the drinking water wells across the region, regardless of gas industry operations, thus demonstrating a regional background in this area of natural gas. The concentration of methane in water collected from the drinking water wells in areas with active natural gas drilling and extraction were approximately 17 times higher on average than those further away. Average and maximum methane concentrations were found to be higher in wells located within approximately 1,000 meters (3,280 feet) of active drilling sites. Although methane gas is known to occur naturally in shallow groundwater aquifers in both of these regions, the testing determined that the gas found in the wells was consistent with methane gas that originated at depths associated with the reservoirs that were drilled. However, although the testing showed elevated methane levels in the wells, isotopic analyses conducted on the same wells did not find any indication that hydraulic fracturing fluids or saline produced water had polluted the groundwater aquifers (Osborn et al. 2011).

Critiques of the study cite the lack of baseline data. While the study finds higher methane concentrations near active wells and concludes that these increases are the result of hydraulic fracturing operations, it does not compare its data to wells sampled prior to the occurrence of hydraulic fracturing. Other criticisms have asserted that the data set is not large enough to draw any definitive conclusions, and that the results are likely to vary regionally. Furthermore, critiques point to areas without drilling where methane was detected in wells, suggesting that claims that hydraulic fracturing caused methane contamination are not scientifically supportable (Bauers 2011).

2012 Duke Study: Natural Migration of Brines

Researchers at Duke University published a second study in response to continued concerns related to reports of potential drinking water contamination related to hydraulic fracturing in Pennsylvania. The study aimed to examine hydraulic conductivity between shale gas formations and the shallower drinking water aquifers in Pennsylvania.

The study analyzed the chemical content of 426 groundwater samples collected from six counties in Northeastern Pennsylvania that did not have links to drilling activities. The study then compared the salts present in the samples to the salts present in brine water from the Marcellus Shale. For some samples, they found that the salts in the groundwater had the same chemical composition as the salts in the Marcellus Shale brine, suggesting that there are naturally occurring hydrogeological pathways in the Marcellus shale that could allow migration from the shale to shallower aquifers. The authors report that there is no link between the salinity of the samples and proximity to Marcellus Shale gas wells, stating that "it is unlikely that hydraulic fracturing for shale gas caused this salinization and that it is instead a naturally occurring phenomenon that occurs over longer timescales." The report speculates that "these areas could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations" (Warner et al. 2012).

2011 Pennsylvania Methane Study

Cabot Oil and Gas Corporation (Cabot) conducted baseline "pre-drill" groundwater sampling and analysis throughout Susquehanna County, PA for various water quality parameters, including dissolved gases and other water quality parameters related to drinking water standards. The baseline analysis was performed in advance of proposed drilling in accordance with Pennsylvania regulations or anticipated regulations. The study concluded that (1) there is consistent evidence of elevated methane in shallow groundwater, (2) concentrations of methane seem to correlate with surface topography (i.e. more methane was found in wells that were in lowland valleys than on hilltops), (3) there was no relationship between methane concentrations in non-productions areas versus historical gas production areas (i.e. higher methane concentrations were not related to gas well drilling) (Molofsky et al. 2011).

In addition, a smaller subset of wells was sampled to conduct an isotope analysis, which helps distinguish between sources of natural gas. This portion of the study was initiated by the Pennsylvania Department of Environmental Protection (DEP) and Cabot. The study concluded that the methane is naturally occurring, unrelated to gas drilling, and not from the shale gas-producing Marcellus shale (Molofsky et al. 2011).

Finally, the report criticized the 2011 Duke study of methane contamination, arguing against the conclusion by the Duke researchers that the thermogenic methane identified in their water samples was consistent with the Marcellus shale. Instead, the isotopic fingerprints of the Duke samples, and other hydrogeological evidence, suggested that the methane found may have been from shallower sources rather than the deeper Marcellus formation and are not related to hydraulic fracturing activities (Molofsky et al. 2011).

2012 Dimock Study

Dimock, Pennsylvania was portrayed in the 2010 movie "Gasland," and included interviews with residents who feared their water was contaminated by natural gas drilling. In early January 2012, USEPA responded to complaints of drinking water quality in Dimock. Residents complained of cloudy, foul smelling water since 2009 after Cabot Oil & Gas Corporation began hydraulic fracturing operations to extract natural gas from reserves near the Marcellus Shale. The USEPA sampled waters from 64 homes in Dimock and concluded the set of samples did not indicate levels of contaminants that would foster further action by USEPA. The USEPA released the final data set on May 11, 2012, of 59 homes. Since USEPA sampling began, contaminants were found in some wells, but USEPA stated the levels of contamination in the wells were considered safe and did not pose a threat to human health. The USEPA also resampled four wells where previous data showed contamination. At one of those wells, USEPA found elevated levels of manganese (a naturally-occurring substance) in untreated well water, but the two homes serviced by that well had water treatment systems the reduced the level of manganese to sage levels. None of the other wells contained levels of contaminants that would require action. The USEPA did find one well containing hits for methane, but USEPA declined to verify the source of pollution, as methane is documented to be a naturally occurring gas in the surrounding area. USEPA has released all sampling results to residents in Dimock and has no further plans to conduct additional sampling (USEPA 2012b). Representatives for Cabot have publicly contended the contaminants found in some of the wells are likely from background levels or other activities unrelated to hydraulic fracturing activities (Gardner 2012).

2008 Bainbridge Township, Ohio Study

In December 2007, the Ohio Department of Natural Resource, Division of Mineral Resources Management (DMRM) initiated an investigation after there was an explosion at a house. Responders quickly recognized that natural gas was entering homes through water wells; either unvented water wells located in basements, abandoned and unplugged water wells in basements, or wells with indoor well pumps. The Ohio Valley Energy Systems Corp, which had recently completed a nearby oil and gas well, English No. 1, assumed responsibility for the natural gas contamination and resulting explosion.

Further investigation by DMRM concluded that three factors were likely to have contributed to the gas invasion of the shallow aquifers: (1) inadequate cementing of the production casing around that well, (2) proceeding with hydraulic fracturing without addressing the casing deficiencies, and (3) the month long period after hydraulic fracturing during which the annular space between the surface and the production casing was shut in, confining high-pressure gas in the restricted space. The over-pressurized condition cause the migration of natural gas from the well annulus into the natural fractures in the bedrock located below the base of the cemented surface casing. It is believed that the natural gas traveled vertically through the fractures into overlying aquifers and into local water wells (ODNR 2008).

2011 Pavilion Study

The USEPA released a draft report in December 2011 examining the potential of a link between groundwater contamination in Pavillion, Wyoming and local hydraulic fracturing operations. The USEPA's draft report found that groundwater samples taken from two deep test wells contained benzene and at least 10 other compounds known to be used in hydraulic fracturing fluid. The draft report theorized that the fluids seeped up from improperly sealed gas wells. Several months after the USEPA issued its draft report, reviews by both critics and proponents of hydraulic fracturing provided additional expert opinion on the draft. The critical reviews contend that the data collection processes were faulty and accordingly no valid conclusions could be drawn from USEPA's study. Notable criticisms of USEPA's draft report are as follows:

- The pollution detected by USEPA that was linked to hydraulic fracturing was found in deep water monitoring wells, not the shallower monitoring wells that are more comparable to the drinking water supply wells. The link between pollution in deep monitoring wells and shallow water wells is uncertain.
- Contamination in shallow monitoring wells was strongly linked to contamination from waste disposal pits, rather than migration of deeper sources of contamination.
- USEPA's monitoring wells were drilled directly into gas bearing zones; approximately 200 to 275 meters bgs (656 to 902 feet); therefore, reviewers suggest that it is not unusual that elevated levels of methane, hydrocarbons, and benzene were detected (Petroleum Association of Wyoming 2011). Along the same line, methane is naturally occurring near the surface of the Wind River Formation and many residents recall the presence of methane in well water prior to the occurrence of energy production activities in Pavillion (EnCana Oil & Gas Inc. 2009)
- To the extent that drilling chemicals were detected in deep monitoring wells, USEPA acknowledges the possibility of poor wellbore design and integrity, resulting in vertical and lateral movement of contaminants to surrounding groundwater. The study stated that only two gas production wells in the Wind River Formation have surface casings that extend below the depth of domestic wells. Shallow surface casings in conjunction with little or no cement or sporadic bonding of production casings can facilitate upward gas and fluid migration. In addition, poorly sealed domestic water wells are a known concern in Pavillion and an improper seal can create a migration pathway for gas and fluids into domestic wells.

Another subsequent study of USEPA's draft report commissioned by NRDC, the Wyoming Outdoor Council, Sierra Club and the Oil and Gas Accountability Project largely supported the agency's findings. The report, by Nevada-based hydrologic consultant Tom Myers, was careful to state that more testing is needed, though he said USEPA's preliminary conclusion that hydraulic fracturing had polluted the area's groundwater was sound. Myers said hydraulic fracturing fluids could move up a number of ways in the region — from compromised gas wells, past thin layers of sandstone, or through out-of-formation rock fissures. The natural gas wells in the area, he stated, often lack metal casings or cement, allowing natural gas and fluids to travel up into groundwater. The USEPA, Myers said, also found a number of compounds during testing that aren't found naturally, including isopropanol and diethylene glycol. "*The [US]EPA is correct in its conclusion that there is no acceptable alternative explanation and the most likely source of these contaminants is fracking fluid*," Myers wrote. Myers also disputed that cement and drilling mud contaminated water samples, stating that neither could raise the pH level to the range found — between 11.2 and 12.0. Myers recommended that USEPA should continue collecting data, including from new and deeper monitoring wells, to try to replicate and verify its findings (Myers 2012b).

While USEPA's draft report identified potential links between hydraulic fracturing and contamination in the Pavillion water wells, the report remains a draft and USEPA is continuing its review. At a hearing before the House Subcommittee on Energy and Environment, in February 2012, USEPA Region 8 administrator Jim Martin stated the following in response to mischaracterizations of the draft report: "*We make clear that the causal link [of water contamination] to hydraulic fracturing has not been demonstrated conclusively,*" adding that USEPA's draft report "*should not be assumed to apply to fracturing in other geologic settings*" (Martin 2012).

In March 2012, USEPA agreed that additional testing was needed in the Pavillion before a final report could be issued. The USEPA in conjunction with the State of Wyoming is currently conducting further sampling of water wells in the area. In a joint statement, USEPA Administrator Lisa Jackson, Wyoming Governor Matt Mead, and the Northern Arapaho and Eastern Shoshone Tribes said: "*The USEPA, the State of Wyoming, and the Tribes recognize that further sampling of the deep monitoring wells drilled for the Agency's groundwater study is important to clarify questions about the initial monitoring results*" (USEPA 2012c).

2012 Myers Model Study of the Marcellus Shale

Tom Myers, a Nevada-based hydrologic consultant, published a study in spring 2012, which uses a model to characterize the risks associated with contaminants travelling through natural vertical pathways from fractured shale to shallower drinking water aquifers. The study analyzes two potential hydrogeological pathways – advective transport through bedrock and preferential flow through fractures. Myers assigned various factors to model contaminant flow including groundwater flow, conductivity of the substrate, and changes in conductivity of the substrates based on regional shale hydrogeology, high density fracturing, and faulting; and high-volume injection.

The study acknowledges that the model simplifies a complex underground system, but the results suggest that a combination of the factors described above could decrease transport times from the Marcellus Shale to shallower aquifers from geological times scales to only tens of years, and that preferential flow through natural and hydraulic fracturing induced fractures could further reduce transport times to as little as just a few years (Myers 2012a). However, the study is a modeling exercise that is theoretical in nature and specific to contaminant transport in the Marcellus shale. Following publication of this study, Syracuse University hydrogeology Dr. Don Siegel released a critique of its assumptions and conclusions. Myers developed "an implausible model" that produced "completely wrong results," Siegel wrote. According to Siegel, the Myers model is based on mistaken assumptions about the kind of rock that lies above the Marcellus Shale, the way groundwater moves through sedimentary basins, and the length of the fissures created by hydraulic fracturing (Siegel 2012).

Relevance to Inglewood Oil Field

Of the studies noted above, USEPA's ongoing study of Pavillion, Wyoming has received the most media attention nationally and continues to be the subject of varying interpretations. In evaluating the draft report it is important to note that hydraulic fracturing operations and geology at the Pavillion Natural Gas Field are distinctly different from those under consideration at the Inglewood Oil Field. For comparison purposes, the drinking water aquifer sits directly atop the production zone at the Pavillion Natural Gas Field and high-volume hydraulic fracturing is used to extract gas from as shallow as 372 meters (1,220 feet) bgs, in close range to the domestic water wells that are screened as deep as 244 meters (800 feet) bgs. Consequently, there is a negligible separation between the hydraulic fracturing operations and groundwater. In contrast, the high-volume hydraulic fracturing jobs PXP conducted occurred over 2,500 meters (8,202 feet) bgs to retrieve shale oil, while the perched water formation is located approximately 120 meters (393 feet) bgs, a separation of over one mile.

Furthermore, as noted in Section 4.2.1, there is no groundwater that can sustain a water supply beneath the Baldwin Hills. The supply to the local area is primarily from sources outside of Los Angeles, whereas in Pavillion groundwater is integral to the community's water supply. The water supply in Los Angeles is subject to quarterly testing and public reporting. Due to uplift in the Baldwin Hills and associated folding and faulting, water tables are sporadic and shallow throughout the production zone on the oil field itself and there is no sustainable groundwater resources located within perimeters of the oil field. In groundwater models of freshwater flow in the Los Angeles Basin aquifer systems (USGS 2003), the Baldwin Hills is modeled as a "no flow" zone; that is, since the sediments beneath the Baldwin Hills are disconnected from the regional aquifers, groundwater flow is discontinuous across the Baldwin Hills (see Figures 4-1 and 4-3C).

4.3 Containment of Hydraulic Fractures to the Desired Zone

A significant amount of discussion has taken place about the vertical growth of hydraulic fractures, particularly in gas shales, tight sands, and shallow reservoirs in regards to whether these hydraulic fractures can create pathways for the fracturing fluids or hydrocarbons to migrate upward and contaminate groundwater supplies.

The vertical extent that a created fracture can propagate is controlled by the upper confining zone or formation, and the volume, rate, and pressure of the fluid that is pumped. The confining zone will limit the vertical growth of a fracture because it either possesses sufficient strength or elasticity to contain the pressure of the injected fluids or an insufficient volume of fluid has been pumped. This is important to note because the greater the distance between the fractured formation and the groundwater or water-bearing zones, the more likely it is that multiple formations will possess the qualities necessary to impede the growth of hydraulic fractures.

Microseismic and micro-deformation mapping has been conducted on thousands of hydraulic fracturing jobs nationwide (Fisher and Warpinski 2011) and indicate that the growth of fractures vertically is relatively well-contained. Figure 4-6 is taken from Fisher and Warpinski (2011) and depicts the depth and vertical height affected by hydraulic fracture jobs conducted in the Barnett Shale of Texas (inclined multi-colored lines), compared to the depth of water (blue horizontal line at top of chart). This relationship was validated during observations of microseismic results at the Inglewood Oil Field (see Figure 3-11).

Fracture lengths of a typical hydraulic fracture operation can sometimes exceed 1,000 feet when contained within a relatively homogenous layer, but fracture heights, because of the layered geological environment and other physical parameters are typically much smaller, usually measured in ten-foot or hundred-foot intervals (Warpinski et al. 2011).

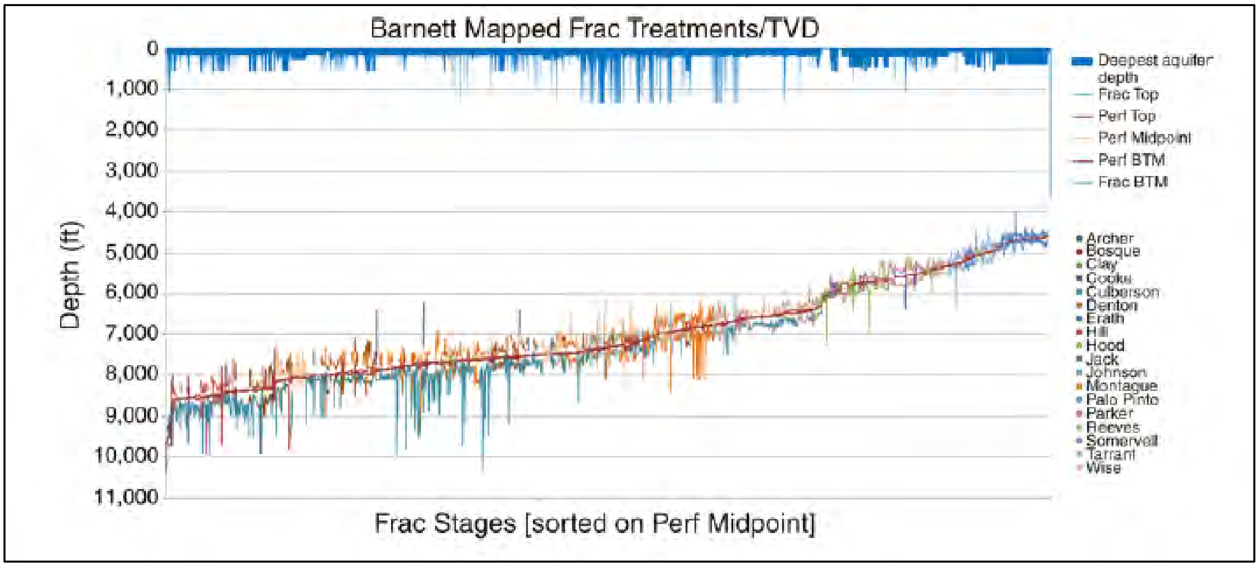


Figure 4-6 Barnett Mapped Frac Treatments/TVD

Similar results have been found by Fisher and Warpinski (2011) in their study of the real fracture growth data mapped during thousands of fracturing treatments in tight sands and shales. They supplemented their data with an in-depth discussion of fracture-growth limited mechanisms augmented by mine back tests and other studies. They also note that fractures and fracture networks tend to be complex; the complexity tends to shorten the network as the energy dissipates.

At the Inglewood Oil Field, the measured distribution of fractures caused by the hydraulic fracture completions at VIC1-330 and VIC1-635 were less than 1,000 feet horizontally from the well, and were almost entirely within the target zone with limited vertical fracture growth (less than 250 feet). Fractures grew either horizontally from the well or at angles less than 20 degrees depending on the local dip angle of the geological formations. The high-volume hydraulic fracture completions were conducted between 8,000 and 9,000 feet below the ground surface and microseismic analysis of the operations indicate that fractures did not form at shallower depths than approximately 8,000 feet below the ground surface (see Section 3.2.2). By comparison, the deepest groundwater encountered that had relatively low salinity was at a depth of 500 feet below the ground surface, corresponding to the base of fresh water beneath the Inglewood Oil Field.

During hydraulic fracturing, the pressure applied to the rock by the water/sand/additive mixture exceeds the fracture strength of the rock, and portions of the rock fractures. As measured by the microseismic data in Section 3.2.2, the induced fractures follow the bedding planes at approximately 20-degree angles. Halliburton (2012) also models the distribution of proppant applied to the fractures in the target zone. Based on this model, all of the proppant stayed within the target zone of the Nodular Shale. The minor fractures indicated by the microseismic data that occurred outside the Nodular Shale were in the underlying, oil-bearing Sentous Formation. These fractures did not receive proppant, and as such they sealed based on the overburden pressure.

4.4 Well Integrity

The proper construction of active oil wells and the condition of idle, plugged, and abandoned wells ensures that protections to fresh water-bearing zones are intact. As described in Section 4.2.1, the water-bearing zones above the base of fresh water beneath the Baldwin Hills do not have sufficient yield to support a water supply, and the local community receives their water supply primarily from sources that are distant from the Los Angeles Basin. However, well integrity was still investigated as part of this study at the scale of the wells subject to hydraulic fracturing, as well as at the scale of the entire oil field.

The term “well integrity” refers to the containment of hydrocarbons within a well from the producing formation all the way to the surface. The rock formations that lie between the hydrocarbon producing formations and the groundwater have isolated the groundwater over millions of years. The well construction process uses a combination of steel casing, cement sheaths, and other mechanical isolation devices to prevent the migration and transport of fluids between these subsurface layers. These construction and engineering controls provide multiple layers of groundwater protection throughout the life of the well. The wells within injection zones at Inglewood Oil Field are constructed in accordance with API guidelines, ensuring that all Federal and State regulations are met and groundwater is protected (API 2009).DOGGR well integrity regulations require a facility to keep records of the size, weight, grade, and condition of all casings and any equipment attached to the casing, pursuant to California Code of Regulations (CCR), Chapter 4, Article 3, §1724.

To supplement more broadly applicable statutory and regulatory requirements, the State Oil and Gas Supervisor may establish Field Rules for any oil and gas pool or zone in a field when sufficient geologic and engineering data are available from previous drilling operations, pursuant to CCR Title 14, Division 2, Chapter 4, § 1722 (k). Each Field Rule is specific to a field, and in many cases, specific to Areas and Zones or Pools within a field. DOGGR has established Field Rules for those fields where geologic and engineering information is available to accurately describe subsurface conditions. These Field Rules identify downhole conditions and well construction information that oil and gas operators should consider when drilling and completing onshore oil and gas wells. Field Rules have been established for the Inglewood Oil Field in two areas – west of the Newport-Inglewood fault and east of the Newport-Inglewood fault (DOGGR 2007).

With regard to abandoned wells, Term 10 of the Settlement Agreement requires PXP to install a 150-foot cement plug at the surface of the well, which exceeds DOGGR standards 6-fold (DOGGR requires only installation of a 25-foot plug). This supplemental requirement provides enhanced protection of any surface resources.

Based on review of records maintained by PXP, the active wells at the Inglewood Oil Field meet modern well construction and casing standards, which protect against releases to the environment, pursuant to State Regulations and Field Rules. Idle wells are tested annually and reports are submitted to DOGGR, in accordance with CCR, Chapter 4, Article 3, §1723.9.

Prior to commencing injection operations, each injection well must pass pressure tests to confirm the integrity of the casing. A Mechanical Integrity Test (MIT) must be performed on all injection wells to verify that injected fluid is confined to the approved zone(s). California regulations mandate that "data shall be maintained to show performance of the project and to establish that no damage to health, life, property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons. All project data shall be available for periodic inspection by Division personnel" (CCR 1724.10 (h)).

Active injection wells at the Inglewood Oil Field are surveyed annually (and pressure tested after each well work) per DOGGR requirements pursuant to CCR, Chapter 4, Article 3, §1724.10(j)3. In addition, PXP monitors active injection wells weekly for injection rates and pressures (what also indicates the integrity of the wellbore and confinement of fluids to the injection zone) and reports to DOGGR on a monthly basis, pursuant to CCR Chapter 4, Article 3, §1724.10(c).

PXP also measures the pressure of the annulus after they idle production or injection at a well and reports this data to DOGGR, as required by Chapter 4, Article 3, §1724.1. Each idle well (production or injection) is subject to DOGGR Idle Wells Testing program according to California Code of Regulations. The testing is done in two parts. Initially it is determined if wellbore fluids (i.e. formation fluids) are above or below the designated base of fresh water. If the fluids are below, then no further testing is required until the next testing cycle. If the fluid in the wellbore is at or above the designated base of fresh water, thus creating a potential for migrating into the designated fresh water formation, then the next part of testing takes place. The integrity of the casing (steel pipe and cement) at this time is evaluated by one of the following methods: running static temperature and spinner surveys, pressure testing the casing, or a nitrogen fluid level depression tests. Both fluid level in the wellbore location determination, and subsequent (if needed) integrity testing are subject to DOGGR witnessing. Any problems determined during an annual Idle Wells Testing are addressed by either repairing or abandoning the well.

Additional well integrity monitoring is provided through PXP's active production well monitoring. In accordance with Public Resources Code Division 3, Article 1, Section 3227, PXP provides monthly production reports that indicate the amount of oil/gas produced from each well, composition of produced water (e.g., salinity), amount of injection fluid, and any other information requested by the Division. While reports are only produced on a monthly basis, PXP monitors active production wells daily for oil and water production rates and pump behavior. Although PXP reports that this is not intended to be a well integrity monitoring program, PXP notes that this monitoring allows them to quickly identify, isolate, and correct any potential problems.

Well integrity is further monitored prior to and during each stage of the hydraulic fracturing operations. The well casing of the subject well is tested to ensure integrity prior to injection of fracturing fluids (Halliburton 2012). This is accomplished by pressure testing the well up to 70 percent of the strength of the casing. Offset wells, production wells, and injection wells are also tested for proper zonal isolation (i.e., annular cement) prior to any hydraulic fracturing operations. Halliburton's post-job reports for hydraulic fracturing operations indicate that all measurements of well integrity conducted for this study show that there were no losses in pressure. Furthermore, as shown in the microseismic results (see Section 3.6), none of the fractures encroach on nearby wells. The applied energy of the hydraulic fracturing rapidly decreases away from the completed well, and as such, surrounding wells would not be adversely affected by the operation.

Prior to issuing a permit for any new injection well, or converting an existing production well to an injection well, DOGGR conducts an Area of Review (AOR) as required by the Underground

Injection Control Program (see Section 5.4.1 for greater discussion of this program). The AOR investigates the condition of every well within one-quarter mile radius of the proposed new injection well. The AOR includes all active, idle, plugged, and abandoned wells and determines the casing and cement intervals. The purpose of the review is to ensure that all wells in the area are completed or abandoned in such a way as to contain injected fluids within the zones that are approved for injection and isolate freshwater zones from the injected fluids.

4.5 Slope Stability, Subsidence, Ground Movement, Seismicity

4.5.1 Slope Stability

Slope stability is a primary geologic concern in the Baldwin Hills. The California Department of Conservation, Division of Mines and Geology, has previously reported on slope stability and geological issues of the Baldwin Hills (CDMG 1982). The purpose of the program was to identify the nature and cause of slope failures across the state, and to provide the information to local governments within whose jurisdictions the failures occurred so that they can plan action to mitigate the problems. The 1982 study was solely focused on the Baldwin Hills and included investigations starting in 1969. The study included detailed mapping of areas with slope instability in the Baldwin Hills, investigation into the causes of the failures, and recommended mitigation.

The study notes widespread damage from slope failures caused by rains in 1969, 1978, and 1980, and less widespread damage in other years. The study concludes that there are two reasons why slope stability is a substantial problem in the Baldwin Hills:

- The terrain that has been developed consists mostly of steep natural slopes underlain by soft sedimentary rocks. This combination will lead to slope instabilities. The result is that graded and natural slopes with slope angles up to 45 degrees or steeper occur without proper drainage devices and retaining walls.
- Much of the Baldwin Hills were developed prior to the enactment of strict grading codes by local government, and as such lack adequate protections. These protections include lower slope angles, requirements for compaction of fills, and structural requirements.

The study notes that the Inglewood Formation is susceptible to slope instability because the surficial soils developed on the formation are clay-rich, while the Culver Sands are particularly susceptible to erosion. The study also notes the presence of ancient, apparently large, landslides. Most of the mapped slope failures damaged more than one property.

The study also notes that in the three most densely developed portions of the Baldwin Hills, approximately 21 percent of the properties have been damaged by rainfall-induced slope failures. As described in the CDMG report, approximately 93 percent of the residential properties have the potential for at least minor damage from slopes failure during or after large storms in the future (CDMG 1982).

Monitoring for vibration and subsidence did not detect a change due to hydraulic fracturing. As such, hydraulic fracturing would not affect surface slope stability.

4.5.2 Subsidence

Subsidence is another geological concern in the Baldwin Hills. As described in the Baldwin Hills CSD EIR, prior to 1971 the maximum cumulative subsidence of any of the areas along the Newport-Inglewood fault zone was centered over the Inglewood Oil Field, where 67,000 acre-feet of oil, water, and sand had been withdrawn from shallow production horizons. Water injection into the shallow production horizons began in 1957 and as of 1971, effectively eliminated subsidence associated with oil and gas production (County of Los Angeles 2008). The Inglewood Oil Field has an ongoing program of annual subsidence monitoring that is reported in the framework of the CSD. To date, although minor subsidence has been detected, no changes in ground surface are attributed to oil and gas production activities (Fugro Consultants 2012). Measurements of subsidence before and after high-volume hydraulic fracturing did not detect a measurable change.

Subsidence has also been theorized to be one factor associated with the failure of the former 20-acre Baldwin Hills Reservoir in 1963. The north embankment of the Baldwin Hills Reservoir failed causing property damage and loss of life. One of the leading theories for the reservoir's failure is that it was undermined by seepage along a fault which was known prior to construction of the reservoir, and which is related to the active Inglewood fault system. The dam's failure has been attributed to different causes: oil-field subsidence (Castle and Yerkes 1969); tectonic faulting (Hudson and Scott 1965); water injection in the nearby oil field (Hamilton and Meehan 1971); and construction related factors (Wright 1987). An innovative design was intended to prevent tectonic subsidence and water injection from jeopardizing the reservoir. In a study of the reservoir failure, Wright (1987b) presents records that document that a field change to the design during construction undermined most of the features intended to accommodate the original design protections. As such, it has been theorized that the design changes also played a role in the dam's eventual collapse (Casagrande et al. 1972).

4.5.3 Monitoring of Ground Movement

The CSD requires an annual ground movement survey at the Inglewood Oil Field. Surveying for both vertical and horizontal ground movement is accomplished using satellite-based Global Positioning System (GPS) technology. Accumulated subsidence or uplift is measured using repeat pass Differentially Interferometric Synthetic Aperture Radar (inSAR) technology. The data are then evaluated to determine whether Inglewood Oil Field operations are related to any detected ground motions or subsidence. According to the ground movement survey covering the 2011/2012 monitoring period there is no correlation between measured elevation changes and field activities (Fugro Consultants 2012, Fugro NPA 2012, Psomas 2012). For this period, inSAR imagery was collected on January 15, 2012, and elevation data at each survey location was collected in February 2012. Note that hydraulic fracturing operations occurred in September 2011 and January 5-6, 2012, and were captured in this survey period. Fugro Consultants compiled a list of the Inglewood Oil Field production and injection wells within a 1,000-foot radius of each survey location and PXP supplied the annual production and injection volumes from all active wells across the field. The database included 456 production wells and 213 waterflood injection wells. Some stations recorded settlement where the injected fluid exceeded the produced volume, some monuments recorded elevation gains where the produced water volume exceeded injected volume, and others showed changes where no active wells are within a 1,000-foot radius. The majority of movements is less than the 0.05 foot measurement threshold and, therefore, at or less than the limit that can be detected (Fugro Consultants 2012, Fugro NPA 2012, Psomas 2012). None of the ground movement was attributable to high-volume hydraulic fracturing.

4.5.4 Vibration and Seismicity During Hydraulic Fracturing

PXP retained Matheson Mining Consultants, Inc. to conduct vibration and ground surface monitoring during the high-volume hydraulic fracturing operations at the VIC1-330 well on September 15 and 16; the VIC1-635 well on January 5 and 6; and at TVIC-221 and TVIC-3254 high-rate gravel pack operations on January 7, 9, 10, and 11.

Vibration records for the VIC1-330 and VIC1-635 wells were collected using four and eight seismographs, respectively, installed at different locations in relation to the high-volume hydraulic fracture operations. The TVIC-221 and TVIC-3254 wells are directly adjacent to one another; therefore, the same seismographs were used to monitor the high-rate gravel pack operations at these wells. Vibration records for these wells were collected using eight seismographs installed at different locations between 218 and 1,000 feet from the wells. Seismographs were placed near the subject wells. All of the seismographs were put in place early enough to allow the collection of 24 hours of baseline data prior to recording vibrations of the hydraulic fracturing operation and high-rate gravel pack operation. Each device was set to the lowest trigger level possible (0.005 in/sec) in order to detect all vibrations.

Seismic events (imperceptible to humans and below the limit which could cause any structural damage) caused by vehicles and other oil field activities at the surface were noted during the baseline period conducted prior to each hydraulic fracture event. These events were then compared to events recorded during both the pumping test and hydraulic fracturing time periods. Table 4-1 displays the highest level vibration recorded during the baseline period and each hydraulic fracture operation. Based on this comparison, Matheson Mining concluded that no seismic activity was produced by any of the high-volume hydraulic fracturing or high-rate gravel pack operations for which seismicity was recorded (Matheson Mining 2012a, b, c).

Table 4-1 Comparison of Vibration Levels Recorded During Baseline Monitoring and Hydraulic Fracturing Operations

	Maximum Vibration Record (in/sec)	
Subject Well	Baseline Monitoring	During Hydraulic Fracturing Operation
VIC1-330	0.0062	0.0119
VIC1-635	0.0075	0.0162
TVIC-221 and 3254	0.025	0.0194

Source: Matheson Mine Consultants 2012 a-c

4.5.5 Induced Seismicity and Additional Seismic Monitoring During Hydraulic Fracturing

Microseismicity was measured directly during and after the hydraulic fracturing. However, the public has expressed concern related to induced seismicity along the Newport-Inglewood Fault potentially resulting from hydraulic fracturing or water injection. This section addresses this topic using data from the Newport-Inglewood Fault across southern California, and measurements made at the field as part of the California Institute of Technology's monitoring program for the region.

The Newport-Inglewood Fault is discernible at the surface by the chain of low hills extending from Culver City (the Baldwin Hills) to Signal Hill. According to the Southern California Earthquake Center (Petersen and Wesnousky 1994), the fault is not marked by a sharp zone, but instead is marked by a broad zone of seismicity centered on the fault trace. Faults of the Newport-Inglewood zone of deformation are predominantly defined in the subsurface from oil-well data and groundwater data. Petersen and Wesnousky (1994) evaluated all seismic events greater than Magnitude 2 in the Newport-Inglewood Fault zone, and determined that most epicenters are located at depths between 3.5 miles and 12 miles below ground surface (Petersen and Wesnousky 1994, Hauksson 1987).

In comparison, the waterflood operation at the Inglewood Oil Field extends to depths of up to 3,000 feet (0.57 mile) and the deepest hydraulic fracturing occurs at less than 10,000 feet depth (1.9 miles). The very small, not discernible, microseismic effects of fracturing are located 1.6 miles above the zone where most epicenters are located, and the waterflood is 2.9 miles above this zone. Based on distHance alone, there would be little or no relationship between the location of Inglewood Oil Field activities and the much deeper epicenters of most earthquakes along the Newport-Inglewood fault zone.

In addition to the seismic monitoring conducted by Matheson Mining Consultants, Inc., seismic data collected by the permanently installed California Institute of Technology (Cal-Tech) accelerometer (seismometer) at the CI.BHP Baldwin Hills location (adjacent to the PXP field office at 5640 South Fairfax Avenue, approximately 6,300 feet southeast of VIC1-635 and 7,806 feet southeast of VIC1-330, and 9,620 feet from the TVIC wells) was reviewed for the time periods before and during the hydraulic fracturing and high-rate gravel pack operations. The data collected from the seismograph during the VIC1-635 operation showed two minor spikes during the time period reviewed (the largest of which measured 0.0012 inch per second). Analysis of the data by Dr. Hauksson, a Senior Research Associate in Geophysics with the Cal-Tech Seismological Laboratory indicates that no seismic events above background levels (0.0003 to 0.0006 inch per second) were recorded. These spikes tend to occur randomly every two or three hours and could be related to local traffic. According to Dr. Hauksson, these spikes are common in urban areas and not considered significant (Matheson Mining Consultants, Inc. 2012a). No data above background levels was recorded on the Cal-Tech seismograph during the VIC1-330 operation (Matheson Mining Consultants, Inc. 2012b). The data collected from the seismograph during the TVIC high-rate gravel pack operations showed some spikes during the time period reviewed but no significant signals above the background levels. As with the VIC1-635 operation, analysis of the data by Dr. Hauksson indicates that the noise recorded on the seismograph during the time period of the hydraulic fracturing operation, even the spikes, did not exceed background levels (Matheson Mining Consultants, Inc. 2012a).

The utilization of these data is relevant in addressing public concerns about the potential for ground movement triggered through induced seismicity as a result of hydraulic fracturing and high-rate gravel pack operations at the Inglewood Oil Field. Based on an analysis of the data, all tests indicate that the hydraulic fracturing analyzed in this study did not induce seismic activity. Any microseismicity as a result of the hydraulic fracturing was imperceptible at the surface. In addition, any effects of oil field operations are much shallower than the zones typically associated with earthquake epicenters along the Newport-Inglewood Fault zone. The Baldwin Hills CSD includes provisions that address the effects of earthquakes on the field. These include construction provisions, and provisions to cease operations after large earthquakes and conduct inspections. For example, the Magnitude 6.4 Coalinga earthquake of 1983, in the San Joaquin Valley of California, caused damage to some oilfield facilities. Most of the damage was to surface facilities, with very minor subsurface damage. Fourteen of 1,725 active wells had some damage (Hughes et al. 1990). This event led to enhanced safety measures. The Baldwin Hills CSD requires an accelerometer on the field for purposes of monitoring seismic activity and triggering inspections.

4.5.6 Potential for Induced Seismicity at Other Areas in the United States

National Issue

Several earthquakes in Mahoning County, Ohio (an area that is not historically seismically active) prompted Ohio's Department of Natural Resources to shut down five deep underground injection wells in January 2012, due to concerns that wastewater injected into the wells under pressure triggered the earthquakes. Similarly, a 5.6-Magnitude earthquake shook Oklahoma in November 2011, following a series of smaller quakes over the preceding months that may also have been attributed to wastewater injection.

All agencies that have reviewed the question have determined that hydraulic fracturing itself is not the cause and is likely not capable of producing an earthquake event of any notable size. Seismologists at the U.S. Geologic Survey have found that hydraulic fracturing "itself probably does not put enough energy into the ground to trigger an earthquake" (USGS 2012). Review of the source studies for the articles found that many point to energy-related activities other than hydraulic fracturing (e.g., injection for waste disposal) as the source of induced seismicity.

As recently as June 2012, the National Research Council, a division of the National Academies of Science, released a report titled *Induced Seismicity Potential in Energy Technologies.* The report found that only one felt event in England had been confirmed and attributed to hydraulic fracturing globally. This case, caused by Cuadrilla in England in 2011, recorded two earthquakes (one Magnitude 2.3 and one Magnitude 1.5) that Cuadrilla believes was due to hydraulic fracturing. These are below a level that would be felt. The cause was thought to be injection of large volumes of sand and proppant.

Of the 35,000 shale gas wells that had been hydraulically fractured, only one case was suspected, but not confirmed, to be attributed to hydraulic fracturing connected to shale gas development. Two other cases connected to conventional oil and gas development were associated with, but never confirmed to stem from, the application of hydraulic fracturing technologies. The report found that, "the very low number of felt events relative to the large number of hydraulically fractured wells for shale gas is likely due to the short duration of injection of fluids and the limited fluid volumes in a small spatial area" (NRC 2012).

Seismic activity as a result of energy-related activities is not a new phenomenon. According to the USDOE Lawrence Berkeley National Laboratory, energy-related activities have been linked to isolated events of induced seismicity since the 1930s, which marks the start of large-scale fluid extraction (USDOE 2012). USDOE has found that hydraulic fracturing is known to cause slight tremors when fluid is injected into the ground under high pressure, but these are on the order of Magnitude -3 and -4 and are practically imperceptible.

Most of the USDOE research conducted to date however has pointed to the injection of fluids into deep wells for waste disposal as a cause of induced seismicity, as well as the use of reservoirs for water supplies, carbon sequestration, and geothermal energy operation. Injection into deep wells could cause seismic events capable of being felt if fluids migrate into neighboring rock formations. The deep, old rocks that surround injection wells have many faults that have reached equilibrium over hundreds of millions of years, but migrating fluid due to wastewater injection could disrupt this equilibrium and trigger shaking (de Pater and Baisch 2011).

Similarly, USGS studies have indicated that hydraulic fracturing did not cause increased seismicity in the midcontinent United States. As part of an effort to understand the potential impacts from U.S. energy production, the USGS has been investigating the recent increase in the number of earthquakes in the midcontinent United States with a Magnitude of three or greater on the Richter scale. Scientists looked carefully at regions where energy production activities have changed during recent years. The results of the studies suggest that hydraulic fracturing has not caused the increased frequency of earthquakes; however, in some instances, the increase in seismicity was linked to deep underground injection wells. The USGS indicates that it is still unclear whether the increased seismic activity is related to changes in production methodology or the increased rate of oil and gas production. For example, the USGS has previously reported that oil and gas extraction can cause earthquakes when removal of large quantities of oil, gas, or water changes underground stresses. The studies also note that not all underground injection causes earthquakes and that there have not been conclusive examples that underground injection may trigger large, major earthquakes even if located near a fault (Hayes 2012).

The recent National Resource Council study of induced seismicity (NRC 2012) finds that many factors are important in the relationship between human activity and induced seismicity: the depth, rate, and net volume of injected or extracted fluids, bottom-hole pressure, permeability of the relevant geologic layers, locations and properties of faults, and crustal stress conditions. Moreover, in a recent survey of earthquake activity and injection wells in Texas, the results suggested that injection rates, pressures, geological substrate permeability as well as fault location and underlying fault stress could influence the probability of fluid injection creating earthquakes (Frohlich 2012). In the siting of many injection wells, these factors are not well known. At the Inglewood Oil Field however the geological conditions are well known and there is a long history of successful waterflood operations.

Ohio Case Study

Although Mahoning County, Ohio, is historically not a seismically active area, nine low-Magnitude earthquakes were observed beginning in early 2011. Initial media coverage following the earthquakes pointed to hydraulic fracturing as the cause (Fountain 2011, Palmer 2012). Seismologists later plotted the quakes however and determined that their epicenters corresponded to Northstar 1, a 9,000-foot deep Class II injection well used to dispose of brine and wastes from natural gas hydraulic fracturing operations. The state shut down four deep disposal wells in January 2011, after a Magnitude-4 earthquake occurred. The Ohio Department of Natural Resources concluded that the earthquakes were caused by deep underground injection at Northstar 1, not the hydraulic fracturing operations, for the following reasons: injection operations began at Northstar 1 shortly before the first seismic events were recorded in the area; seismic events were clustered around the wellbore (the focal depths of the events were 4,000 feet laterally and 2,500 vertically from the well bore terminus); and there is evidence of fractures and permeable zones in the surrounding formation. Further modeling and analysis of the Northstar 1 well and the surrounding geology are required to establish a better understanding of what happened. Additional studies are underway by ODNR and cooperating agencies (ODNR 2012).

Texas Case Study

In 2011 and 2012, a retrospective survey was conducted near the Dallas-Fort Worth area in Texas. The study's intent was to review the relationship between detectable earthquakes and the characteristics of nearby injection wells. The study reviewed earthquake activity between November 2009 and September 2011 over a 70-km area of the Barnett Shale using temporary seismographs installed under the National Science Foundation's funded EarthScope U.S. Array program. It identified that there were a sizable number (67) of earthquakes Magnitudes 1.5 and higher that could be identified under the U.S. Array program. Only one-eighth of these were reported by the National Earthquake Information Center, however.

The earthquakes identified seemed to have varying relationships with the surrounding injection wells. The rates of injection wells nearest the strongest cluster of earthquakes typically exceeded 150,000 barrels of water per month. However, 90 percent of wells that had injection rates exceeding 150,000 barrels of water per month did not have related earthquakes. The study suggested that earthquakes may more likely be triggered if the injection reaches a critical rate, but that the rate could depend on localized geologic conditions. The geological substrate permeability as well as fault location and underlying fault stress could influence the probability of fluid injection triggering earthquakes (Frohlich 2012).

Oklahoma Case Study

In January 2011, the Oklahoma Geologic Service was contacted with reports of multiple earthquakes observed in the Garvin County area within a 24-hour period. Following the reports, the Oklahoma Geologic Service confirmed that in fact, over 50 earthquakes ranging in Magnitude 1.0 to 2.8 were recorded in this area. A review of activity in the area also confirmed that a hydraulic fracturing event had taken place that day at the nearby Eola field. This area of south-central Oklahoma has historically been seismically active; therefore, a network of seismic stations was installed in 1977 which allowed for the accurate reporting and determination of epicenters for this series of quakes. The Eola field is located in an area where several fault blocks are located between major faults (the Eola, Reagan, and Mill Creek faults). The Oklahoma Geologic Survey conducted its own study to determine if the reported earthquakes were in fact induced by the hydraulic fracturing that had taken place on the field. The study involved a series of model simulations and statistical analyses using the data records by the seismic monitors as well as data collected from the field operator regarding the hydraulic fracturing event itself. The Oklahoma Geologic Service found that there was a clear correlation between the hydraulic fracturing event and the observed seismicity, and that all of the epicenters of the seismic events were within 5 km (3.1 miles) of the Eola field and that some of the earthquakes occurred at similar depths as the reservoirs which were fractured (approximately 630 meters or 2,066 feet). However, the service could not confirm that the fluid pressure at the hypocentral location of the earthquakes was enough to generate seismicity and given the extensive seismic history in the area, the Service could not determine if the hydraulic fracturing had actually induced the earthquakes. The study also noted that the earthquakes observed were extremely low Magnitude in nature and were felt by only one individual (Holland 2011).

Basel, Switzerland Case Study

One of the most publicized instances of induced seismicity that is cited by critiques of hydraulic fracturing occurred at a geothermal project in Basel, Switzerland. In 2006, during the course of the development of an enhanced geothermal reservoir at a depth of about 5 km (3.1 miles) underneath the city, a Magnitude 3.4 earthquake was triggered. The earthquake occurred after 11,500 cubic meters of liquid (3.03 million gallons) were injected into a 5-km (3.1 miles) deep injection well. A steady increase in seismicity was detected in response to a gradual increase in flow rate and wellhead pressure. Monitors recorded more than 10,000 seismic events during the injection phase. After water had been injected for about 16 hours, a Magnitude 2.6 event occurred within the reservoir, which exceeded the safety threshold for continued well stimulation. In response, injection was halted prematurely. Two additional seismic events of Magnitude-2.7 and 3.4 occurred several hours later. At that point, the well was opened and the water was allowed to flow back. The seismic activity declined quickly thereafter. The well was officially shut down in 2009 (Deichmann and Giardini 2009).

A study was commissioned by the Canton of Basel-Stadt and the Swiss federal government to assess the seismic risk resulting from continued development and operation of the geothermal system. The study addressed the effect of continued development and operation of the geothermal facility and its effect on induced seismicity, as well as the effects of operations on natural seismicity in the Basel Region; i.e., “triggered seismicity.” A 3-D geological model was used to map eight relevant faults in the vicinity of the Basel geothermal reservoir. The seismic activity (time intervals when large earthquakes could be expected) of each fault was estimated, and it was determined that the presence of the geothermal reservoir could have a direct impact on the recurrence time of these natural earthquakes by modifying subsurface stresses but that variation would be small. The study also found that there is a possibility that earthquakes exceeding the strength of previous seismic activity would occur during continued development and operation of the facility. Based on model simulations, the largest “triggered” seismic event was predicted to have a Magnitude 4.5 (Baisch et. al 2009).

Rocky Mountain Arsenal

One of the first records of induced seismicity linked to deep underground injection was at the Rocky Mountain Arsenal, where a deep injection well constructed in 1961 was used to dispose of wastes from the U.S. Army’s chemical weapon testing operations. The well was drilled to a depth of 12,045 feet. It was cased and sealed to 11,975 feet, and the remaining 70 feet were left as an open hole for fluid injection. 165 million gallons of Basin F liquid waste, consisting of salty water that includes some metals, chlorides, wastewater and toxic organics was injected into the well from 1962–1966. During that time period, there were several small earthquakes in the area, and in 1966 a correlation was noticed between the frequency of earthquakes and the volume of water being pumped. Pumping was halted in 1966 due to the possibility that the fluid injection was triggering the earthquakes in the area. Over the next two years earthquakes continued to occur as far as 6 km (3.7 miles) from the injection well as the pressure front caused by injection dissipated (Nicholson and Wesson 1990). The well remained unused for almost twenty years until the army permanently sealed it in 1985.

Relevance to Inglewood Oil Field

The studies of the potential link between hydraulic fracturing and earthquakes have all concluded that the hydraulic fracturing produces small, imperceptible microseismic events (like dropping a milk bottle on the floor according to Stanford geophysicist, Mark Zoback [COGA 2012]) as part of the process itself. These microseismic events were recorded by the microseismicity monitoring conducted during the VIC1-330 and VIC1-635 hydraulic fracturing operations completed as a part of this study, and most were restricted to the target oil producing zone. These microseismic events did not cause any recordable event at the surface, based on two types of vibration monitoring and the Cal-Tech accelerometer.

The Inglewood Oil Field does not inject wastewater in the manner where small (Magnitude 3 or 4) earthquakes have been detected in Ohio and elsewhere. In those cases, the wastewater is injected into a formation other than the gas-producing zone. At Inglewood, the waterflood operation injects treated produced water into the depressurized oil-bearing formation. The waterflood therefore does not increase the subsurface pressure. The waterflood has been conducted waterflood operations since 1954, and since 1971 at a rate to halt subsidence. No earthquakes on the Newport-Inglewood Fault zone, or any other fault zone, have been attributed to the waterflood operation. This history is validated by the National Research Council study which found, “the potential for felt induced seismicity due to secondary recovery and EOR is low” (NRC 2012). As part of the CSD conditions, ground motion, vibration, and seismicity are monitored to determine whether there is a connection. In the two years of monitoring so far, there has been no connection between oil field operations, including the waterflood, high-rate gravel pack, or high-volume hydraulic fracturing operations, and seismicity, vibration, or ground movement.

Petersen and Wesnousky (1994) evaluated all seismic events greater than Magnitude-2 on the Newport-Inglewood Fault zone, and determined that most epicenters are located at depths between 3.5 miles and 12 miles depth (Petersen and Wesnousky 1994, Hauksson 1987). In comparison, the waterflood operation at the Inglewood Oil Field extends to depths of up to 3,000 feet (0.57 mile) and the deepest hydraulic fracturing occurs at less than 10,000 feet depth (1.9 miles). Therefore, any effects of oil field operations are much shallower than the zones typically associated with earthquake epicenters along the Newport-Inglewood Fault zone.

4.6 Methane

4.6.1 Subsurface Occurrence of Methane

As described in Chapter 2, the Los Angeles Basin is the richest oil basin in the world based on the volume of hydrocarbons per volume of sedimentary fill (Biddle 1991). Most of the oil and gas lies trapped beneath both shales and faults, allowing it to accumulate at depth. However, some surface seeps do occur, as at the La Brea Tar Pits, and methane also migrates to the surface.

There are three types of gases that may exist within the geological and soil units underlying the active surface of the Inglewood Oil Field, including biogenic (swamp or sewer) gas, thermogenic (field) gas, and processed natural (or piped) gas.

Biogenic gas is primarily methane with carbon dioxide and sulfide gases that result from decomposition of organic material, such as from former marshy areas or from sewers. Although biogenic gas contains of mostly methane and carbon dioxide, these gases also consist of lesser amounts of ethane, propane, and butane, as well as trace amounts of hydrogen sulfide and ammonia. In the active surface field area, marshy areas were formerly present immediately north of the Baldwin Hills, in the former floodplain of Ballona Creek (Hsu et al. 1982). In addition, the large-diameter (approximately 15-foot) City of Los Angeles North Outfall Replacement Sewer underlies the active surface field boundary. Both of these features are potential sources of biogenic gas.

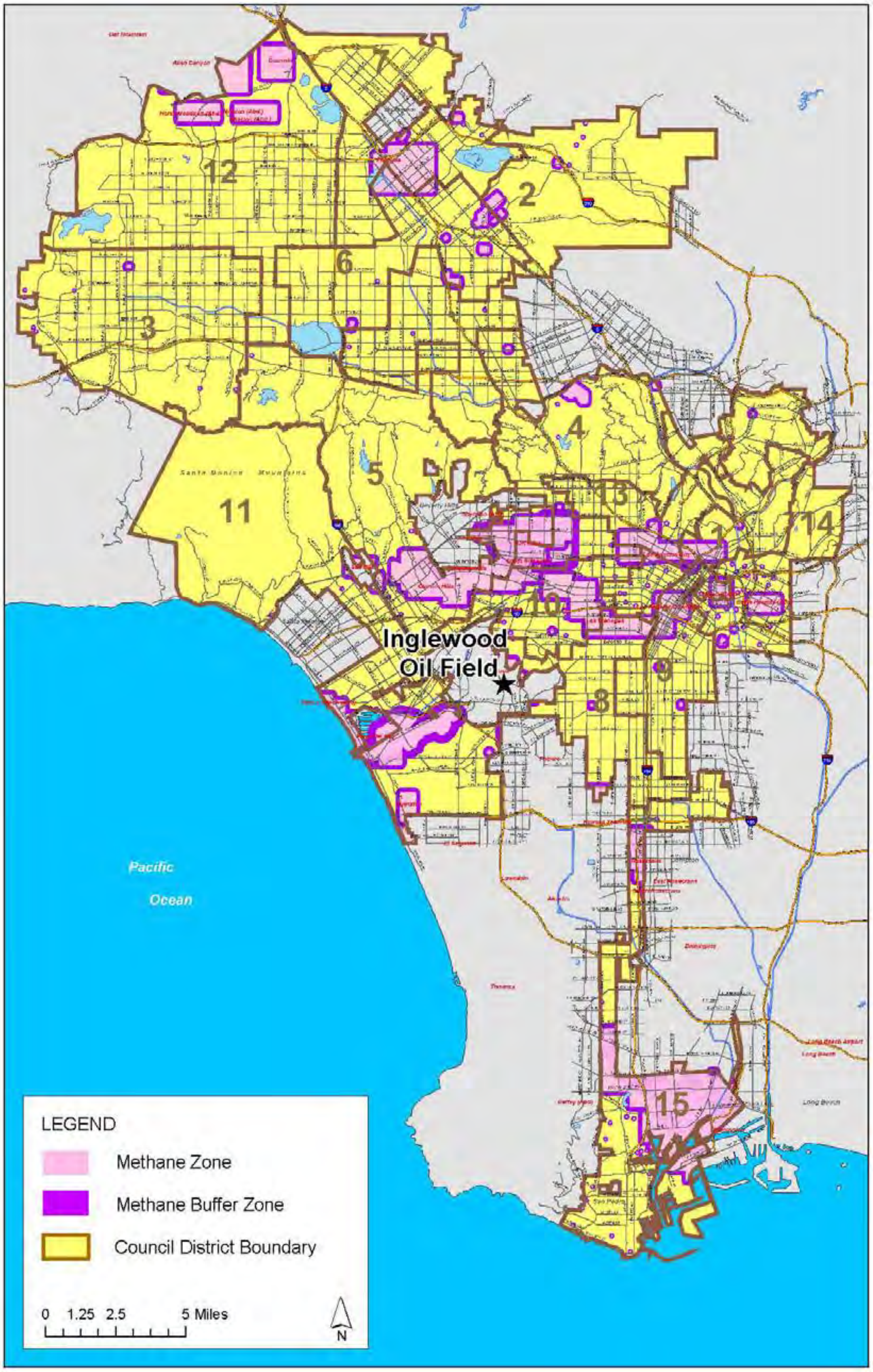
Thermogenic gas is generated at depth when increased temperatures and pressures alter organic material to form gases. Similar to biogenic gas, thermogenic gas contains a broad range of gas components including methane, ethane, propane, and butane, as well as trace amounts of toxic gases, including hydrogen sulfide. Activities at the Inglewood Oil Field produce oil and associated thermogenic gas.

Natural gas at the field is processed and sold to the BP Carson refinery, sold to Southern California Gas Company, or utilized for field use. Processed natural gas began as thermogenic gas derived from the oil and gas producing zones, and then had most non-methane components removed and reused.

These various types of gases exhibit distinct chemical characteristics, which permits "finger-printing" of gases, or differentiation between gas types (California Public Utilities Commission 2004).

4.6.2 Regulatory Framework for Methane

Due to the probability of methane gas releases from naturally occurring thermogenic and biogenic sources in this prolific oil and gas province, the City of Los Angeles has established a zoning ordinance identifying two zones, a Methane Zone and a Methane Buffer Zone (Figure 4-7). Special requirements for new construction, existing construction, and monitoring for methane have been established for these zones. The Baldwin Hills are not in the City of Los Angeles, and therefore are not classified on the methane map. However, the field is surrounded by such zones, and there is likelihood that methane conditions beneath the field are consistent with the relatively high background levels of methane in the Los Angeles Basin.



Source: City of Los Angeles 2004

Figure 4-7 Methane Zone Map

Following an explosion at the Ross Department Store in the Wilshire-Fairfax district of Los Angeles, and in an effort to avoid land use conflicts between oil field operations and urban environments, Senate Bill 1458 (Roberti) in 1986 directed the Department of Conservation and DOGGR to identify areas with the greatest potential for gas migration into structures, which could cause potential health and safety issues. A *Study of Abandoned Oil and Gas Wells and Methane and Other Hazardous Gas Accumulations* (Geoscience Analytical, Inc. 1986) identified eight high risk areas in the Southern California region that have the potential to cause a health and safety issue. These areas are categorized based on their locations within urban areas, having a history of seeps, and history of having plugged and abandoned wells within their boundaries. The Inglewood Oil Field was not identified as a high risk area in the study. The areas identified include: Salt Lake Oil Field (City of Los Angeles – Fairfax/Wilshire District); Newport Oil Field (City of Newport Beach); Santa Fe Springs Oil Field (City of Santa Fe Springs); the Rideout Heights area of the Whittier Oil Field (City of Whittier); Los Angeles City Oil Field (City of Los Angeles); Brea-Olinda Oil Field (City of Brea); Summerland Oil Field (City of Summerland); and Huntington Beach Oil Field (City of Huntington Beach) (Geoscience 1986).

Gas samples were collected at all high risk locations in the DOGGR study and analyzed to determine the hydrocarbon gas content and the origin of the soil gases. Of all the samples collected and indicating gas seepage, only two had the potential of originating from old oil and gas wells. In these two locations (Newport Beach and Huntington Beach) it was suspected that structures were built over old wells that were not plugged and abandoned to current standards. Although these old wells could have been the cause of the gas seepage, gas analysis indicated that the gas was biogenic in nature (i.e., not related to the oil and gas productive zone in the wells) and therefore the wells may have only been a conduit for the shallow biogenic gas (DOGGR, personal communication 2008 reported in CSD EIR).

Hamilton and Meehan (1992) also examined the causes of methane migration and the explosion in the Ross Store, as well as another natural gas vent in the Fairfax District near the La Brea Tar Pits. They reported that the methane was thermogenic in origin (that is, from the underlying oil-producing zone), but proposed that an additional scenario could account for the subsurface migration of methane: overpressuring of the oil-producing zone, leading to fracturing of the surrounding rocks and movement of methane along those newly-formed fractures. They recommended that DOGGR monitor injection operations to ensure that injection above the fracture pressure during produced water injection not exceed the formation fracture stress.

Chilingar and Endres (2005) have also evaluated methane migration in oil and gas producing areas, principally the many urban oil fields in Southern California. They conclude that “virtually all leaks can be traced to the poor well completion and/or abandonment procedures (i.e., poor cementing practices).” They advocate the evaluation of the integrity of old wells in the urban setting as a means to reduce this risk.

DOGGR reviews all applications for water injection wells under the authority of the UIC program. Injection wells for oil and gas development are Class 2 wells in this program, and DOGGR must evaluate the proposed injection pressures, the surrounding geology, and the well integrity of wells within one-quarter mile of any new proposed injection well. Because the field is contiguous and not interspersed with urban and residential development, the active Inglewood Oil Field is well positioned to address these issues in the Baldwin Hills. Because the field is active, it ensures that any unidentified issues will be addressed during field development, in comparison to orphan wells elsewhere in the state for which there is no identified owner.

4.6.3 Gas Monitoring Prior to Hydraulic Fracturing at the Inglewood Oil Field

Background soil gas methane concentrations throughout Southern California are typically 50 parts per million volume (ppmv) or less, although in Los Angeles certain areas are known to have higher background concentrations and have been identified on City Methane Zone Maps.

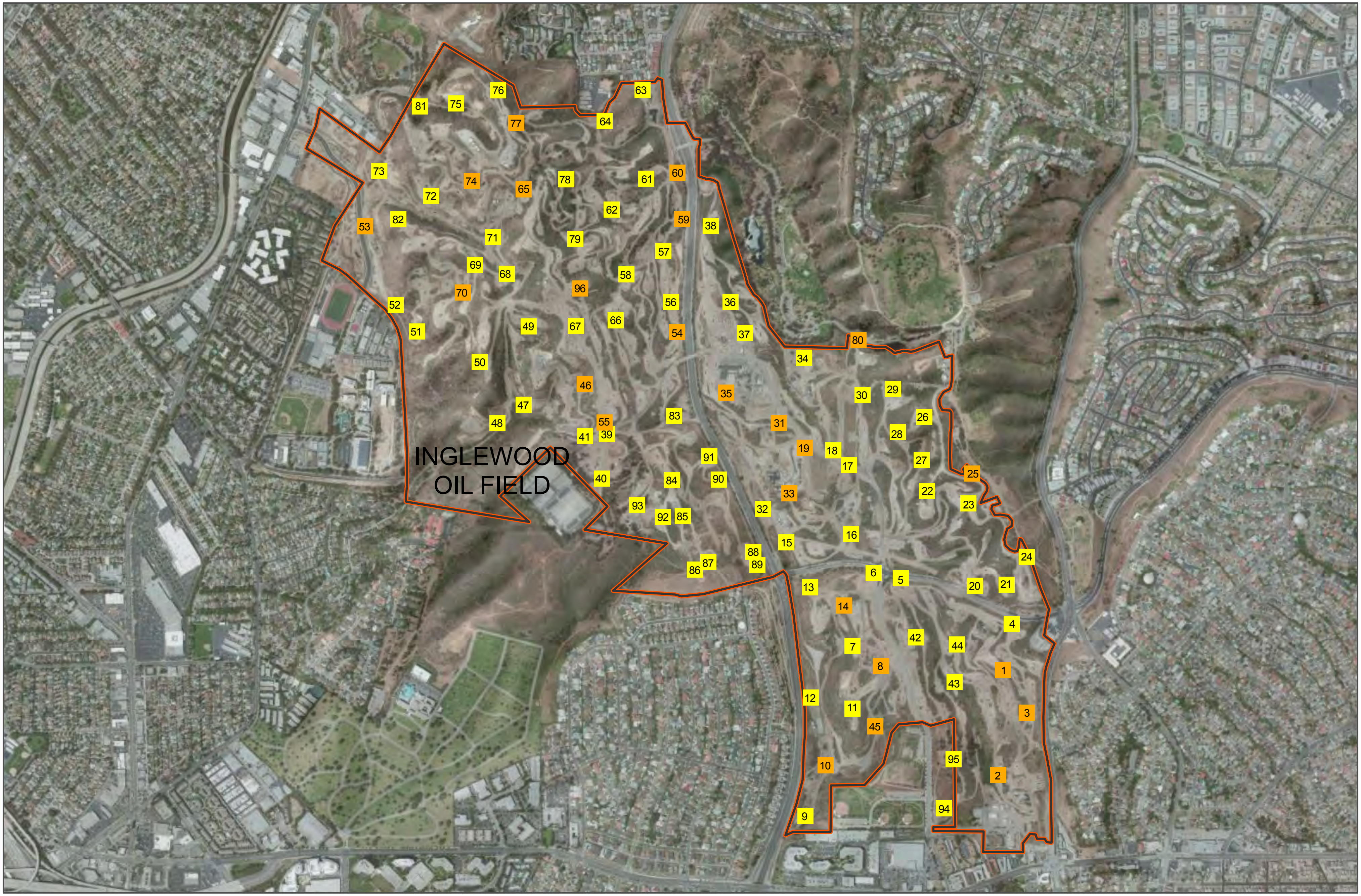
Since 2007, PXP has conducted annual soil gas surveys throughout the Inglewood Oil Field to test for methane concentrations and potential gas leaks from abandoned and idle wells. In 2007, GeoScience Analytical, Inc. sampled 94 locations, probing soil to a depth of four feet. The majority of these sampling locations were in the vicinity of idled or abandoned wells. Soil gases were extracted from each of the soil probes and transported to the laboratory for analyses of C_1 (methane) up to C_7 hydrocarbons, and hydrogen sulfide. The same 94 sample locations were tested in 2008 and 2009, with the addition of two other sites (GeoScience Analytical, Inc. 2009). Figure 4-8 depicts the sampling locations.

Methane concentrations detected in 2007 ranged from 1.0 ppmv to a high of 981,400 ppmv in the case of location #7, located near well LAI 1-130, which was an idled well. Given the high value for this location, additional soil gas vapor testing was done at 12 sites located around well LAI 1-130. The results of this additional sampling indicated that the source of the gas was most likely well LAI 1-130. The well was subsequently abandoned to the current DOGGR standards.

4.6.4 Gas Monitoring After High-Volume Hydraulic Fracturing

Soil gas testing was conducted again in 2011, following the high-volume hydraulic fracture operation of VIC1-330 in early September. During this sample event, 31 soil samples were taken and tested for C_1 to C_7 hydrocarbons and hydrogen sulfide. Of the samples tested, only two had readings greater than 500 ppmv (1,346 and 551 ppmv); both of which were well under the level for concern (12,500 ppmv) (GeoScience Analytical, Inc. 2011). GeoScience Analytical, Inc. concluded that the soil gases detected on the field were most likely the result of bacterial decomposition of crude oil in the near surface soils, i.e. biogenic (GeoScience Analytical, Inc. 2011). Isotopic analysis of three of the shallow soil gas samples was conducted to validate this finding. Carbon and hydrogen isotopic ratios were measured, and the results confirm a biogenic source for shallow soil gas (Figure 4-9).

There was no detected correlation between the hydraulic fracturing operation and the detected soil gas on the field.



Cardno ENTRIX

N

0 500 1,000 2,000 Feet

LEGEND

2012 Sample Locations

Location Not Sampled in 2012

(Exempt per CSD — 2 Years Below Background 50 PPM)

Inglewood Oil Field Boundary

PLAINS EXPLORATION & PRODUCTION COMPANY

Figure 4-8

Soil Gas Survey Sample Locations

07 | 05 | 12

4.6.5 Groundwater Monitoring for Methane after Hydraulic Fracturing

Methane in groundwater was tested during the quarterly sampling conducted on the Inglewood Oil Field (see Section 4.2). Groundwater was never measured for methane prior to high-volume hydraulic fracturing. Samples collected after high-volume hydraulic fracturing detected dissolved methane in all but one well (MW-7), at concentrations ranging from 0.01 to 9.7 mg/L. Wells MW-8, MW-11A, MW-11B, and MW-13 are located across the center of the field, and had concentrations ranging from 3.5 to 9.7 mg/L methane; all other concentrations were below 0.190 mg/L. Methane in water is not toxic and therefore, there is no drinking water standard (MCL) established. The City of Los Angeles methane zoning ordinance does not address methane in groundwater; the ordinance only addresses levels in soil gas and applies construction standards (Ordinance No. 175750). In water supplies, methane volatilizes from water, and at very high concentrations can displace oxygen. The U.S. Office of Surface Mining considers 28 mg/L in a water supply well as indicative that action be taken to reduce the concentration before use. Concentrations below 10 mg/L are considered safe, and between 10 and 28 mg/L the U.S. Office of Surface Mining suggests monitoring. The U.S. Bureau of Land Management also lists 10 mg/L as a safe concentration (U.S. Office of Surface Mining 2001). Therefore, all methane detections noted in groundwater samples within the oil field were within the level considered safe for any conditions. None of the water beneath the Baldwin Hills is used as a water supply, nor does it supply water at a yield suitable for a water supply.

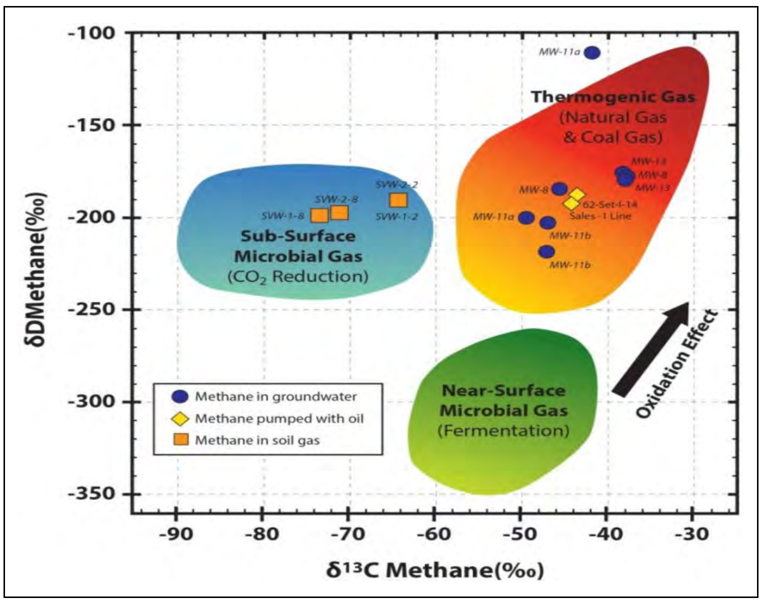


Figure 4-9 Methane Isotopic Results

Based on isotopic analysis of the dissolved methane in groundwater, it is thermogenic (from the oil-bearing formation) in origin, whereas detections in shallow soil gas are biogenic in origin (Figure 4-9). Therefore the methane in water and the methane in soil gas at the Inglewood Oil Field have different sources and are not in continuity. There are shallow occurrences of oil in the Investment Zone, within the Pico Formation, that are not commercially produced. Since these untapped zones are in closest proximity to the water-bearing zones, and the occurrence of methane is pervasive in the monitoring results, it does not appear to be related to oil and gas production activity. The occurrence is also not correlated to the locations of high-volume hydraulic fracturing. None of the levels detected are at concentrations that exceed levels considered safe, and none trigger further action under current regulations.

4.6.6 Methane Emissions and Climate Change

National Issue

Methane is the simplest hydrocarbon (alkane), consisting of one carbon and four hydrogen atoms. Methane is the main component of natural gas, typically over 90 percent by volume, and is one of the most abundant naturally-occurring organic compounds on earth. Pure methane is colorless, odorless, and nontoxic, but highly flammable, which makes it an attractive clean-burning fuel with a "carbon footprint" about 50 percent lower than coal when used to generate electricity. Since methane is 44 percent lighter than air, it dissipates upward when released. However, although nontoxic, methane is a simple asphyxiant and may displace oxygen in enclosed spaces and may also form explosive mixtures with air under certain conditions, thus presenting hazards. Methane is a greenhouse gas with an IPCC GWP coefficient of 21 relative to carbon dioxide. This means that methane has 21 times the averaged relative radiative forcing effect of CO_2 (USEPA 2011a, CCAR 2009).

A public concern related to hydraulic fracturing deals with methane gas that can escape into the atmosphere as a result of hydraulic fracturing operations and contribute to climate change. It is commonly recognized that methane gas can potentially escape as fugitive emissions during well completion. Large volumes of water are forced under pressure into the ground to fracture a rock formation and increase gas flow. A large portion of this water returns to the surface as flowback water within the first several days to weeks after injection. The flowback water is accompanied by quantities of methane that exceed the amount that can be dissolved within the flowback fluids. To assist in minimizing fugitive emissions at the Inglewood Oil Field, all flowback water accompanied by methane gas is piped to portable 500 bbl tanks connected to a South Coast Air Quality Management District (SCAQMD) permitted vapor control system. This is standard practice for oil operations throughout the Los Angeles Basin but differs from the air quality policies in shale gas producing states where in most cases, until recently, emissions from the flowback operations were largely unregulated. The rate of methane released with flowback fluid corresponds to the initial production rate and pressure of a well. Methane is also released during "drill-out," which is the stage of developing shale gases and oil in which the plugs that are set to separate fracturing stages are drilled out to release gas and/or oil for production. Fugitive methane emissions might result from equipment leaks and routine venting from pressure relief valves that are designed to purposefully vent gas (Howarth et al. 2011).

Untreated raw gas can contain some hydrogen sulfide (H_2S) which is highly odorous – the "rotten egg" smell – and the H_2S is toxic in high enough concentrations. Other natural sources of hydrogen sulfide include decaying organic matter under anaerobic (oxygen deprived) conditions. While hydrogen sulfide presents risks to oilfield workers, it is not considered a public safety risk due to safety zones between drilling activities and the general public which provide adequate distances for atmospheric dispersion in the event of leaks.

Relevance to Inglewood Oil Field

The Inglewood Oil Field operates in compliance with the requirements of the SCAQMD pursuant to Rules 463, 1148.1, 1173, and 1176 as applicable, which effectively control emissions of methane and other hydrocarbons into the atmosphere. In this regard emissions regulations relevant to the Inglewood Oil Field are significantly advanced compared to most shale gas producing states where, until recently, emissions from the flowback operations were predominantly unregulated. The Inglewood Oil Field is in the development stage rather than the exploration stage, so natural gas and produced water are contained in pipelines or enclosed tanks. Most concerns expressed regarding methane emissions to air and their effect on climate change are from natural gas fields in the exploration phase, where piping and gas treatment and sale facilities are not yet in place, as it is at Inglewood. As required by SCAQMD, there is an ongoing program of monitoring and repairing fugitive sources of hydrocarbon emissions. On a general comparative basis, air quality regulations in many oil and gas producing states are less comprehensive than the regulations adopted by the SCQAMD and apply to oil and gas activities at the Inglewood Oil Field.

The "carbon footprint" concern has been minimized at the Inglewood Oil Field as a result of its historic, stable long-term operation, and extensive local regulatory compliance framework for air quality including greenhouse gases. Unlike drilling operations in other less-regulated western states, current SCAQMD regulations prohibit uncontrolled venting of gas to the atmosphere which effectively mitigates the effects of hydraulic fracturing during well completion.

4.7 Other Emissions to Air

In compliance with SCAQMD Rules 463, 1148.1, 1173 and 1176 as applicable, hydrocarbon emissions at the Inglewood Oil Field are controlled and also monitored as described in an Air Monitoring Plan in accordance with Section E.2(d) of the Baldwin Hills CSD. This plan requires monitoring for hydrogen sulfide and total hydrocarbon vapors. It also requires that drilling or completion operations shut down if monitoring detects concentrations of hydrogen sulfide greater than 10 ppmv or hydrocarbon concentration of 1,000 ppmv or greater. Construction equipment and vehicles used for on-road and off-road purposes are also regulated by the CSD under Sections E.2(j) through E.2(n).

The following analyses focus on how the new USEPA hydraulic fracturing rules mesh with current SCAQMD rules, whether SCAQMD compliance comprises "de facto" USEPA compliance, or whether additional measures (activities, equipment) will be required to comply with USEPA notwithstanding SCAQMD. Applicable SCAQMD rules which prohibit uncontrolled emissions of VOC/GHG (e.g., raw untreated natural gas, tank headspace vapors, fugitive hydrocarbon leaks, etc.) are identified below:

- **Rule 463.** Organic Liquid Storage
- **Rule 1148.1.** Oil and Gas Production Wells
- **Rule 1173.** Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants
- **Rule 1176.** VOC Emissions from Wastewater Systems

40 CFR Part 63 – New Source Performance Standards (NSPS) for New Hydraulically Fractured Wells (drilled after August 23, 2011)

To ensure that smog-forming volatile organic compounds (VOCs) are controlled without slowing natural gas production, USEPA's final NSPS for VOCs establishes two phases for reducing VOCs during well completion. This approach will provide industry time to order and manufacture enough equipment to capture natural gas using a process called *green completions,* also known as "reduced emissions completions."

USEPA established the phased approach to address concerns raised in comments related to the availability of equipment and operators to conduct green completions in time to meet compliance dates in the proposed rule.

Phase 1

In the first phase (before January 1, 2015), industry must reduce VOC emissions either by flaring using a completion combustion device or by capturing the gas using green completions with a completion combustion device (unless combustion is a safety hazard or is prohibited by state or local regulations).

- A completion combustion device burns off the gas that would otherwise escape during the well-completion period (combustion generally would occur through pit flaring). Industry may use completion combustion devices to reduce VOC emissions until January 1, 2015, unless state or local requirements prohibit the practice or require more stringent controls (e.g., SCAQMD Rule 1148.1). USEPA encourages industry to begin using green completions during this time.

Phase 2

Beginning January 1, 2015, operators must capture the gas and make it available for use or sale, which they can do through the use of green completions.

- A completion device which captures the gas that would otherwise escape during the well-completion period will be required. Industry must use completion devices to reduce VOC emissions beginning January 1, 2015. Captured gas must be sent to economic use, either as fuel gas, sales gas, or reinjection.
- USEPA estimates that use of green completions for the three- to 10-day flowback period reduces VOC emissions from completions and recompletions of hydraulically fractured wells by 95 percent at each well (USEPA 2012d)
- Both combustion and green completions will reduce the VOCs that currently escape into the air during well completion. Capturing the gas through a green completion prevents a valuable resource from going to waste and does not generate NO_X, which is a byproduct of combustion.
- Methane, a potent greenhouse gas, and air toxics, which are linked to cancer and other serious health effects, also would be significantly reduced as a co-benefit of reducing VOCs.

Exceptions for New Wells

Green completions are not required for:

- New exploratory ("wildcat") wells or delineation wells (used to define the borders of a natural gas reservoir), because they are not near a pipeline to bring the gas to market.

- Hydraulically fractured low-pressure wells, where natural gas cannot be routed to the gathering line. Operators may use a simple formula based on well depth and well pressure to determine whether a well is a low-pressure well.

Owners/operators must reduce emissions from these wells using combustion during the well-completion process, unless combustion is a safety hazard or is prohibited by state or local regulations.

SCAQMD Rule 1148.1 – Oil and Gas Production Wells (relevant excerpts below, see entire rule for details)

"(a) The purpose of this rule is to reduce emissions of volatile organic compounds (VOCs) from the wellheads, the well cellars and the handling of produced gas at oil and gas production facilities.

(b) This rule applies to onshore oil producing wells, well cellars and produced gas handling activities at onshore facilities where petroleum and processed gas are produced, gathered, separated, processed and stored. Natural gas distribution, transmission and associated storage operations are not subject to the requirements of this rule.

(d)(6) Effective January 1, 2006, the operator of an oil and gas production facility shall not allow natural gas or produced gas to be vented into the atmosphere. The emissions of produced gas shall be collected and controlled using one of the following:

- *A system handling gas for fuel, sale, or underground injection; or*
- *A device, approved by the Executive Officer, with a VOC vapor removal efficiency demonstrated to be at least 95% by weight per test method of paragraph (g)(2) or by demonstrating an outlet VOC concentration of 50 ppm according to the test method in paragraph (g)(1). If the control device uses supplemental natural gas to control VOC, it shall be equipped with a device that automatically shuts off the flow of natural gas in the event of a flame-out or pilot failure.*

(d (7) Except as Rule 1173 applies to components of produced gas handling equipment located within 100 meters of a sensitive receptor, the operator shall repair any gaseous leaks of 250 ppm TOC or greater by the close of the business day following the leak discovery or take actions to prevent the release of TOC emissions to the atmosphere until repairs have been completed.

(d (8) Effective March 5, 2004, unless approved in writing by the Executive Officer, CARB, and USEPA as having no significant emissions impacts, no person shall:

- *Remove or otherwise render ineffective a well cellar at an oil and gas production well except for purposes of abandonment to be certified by the California Department of Conservation, Division of Oil, Gas and Geothermal Resources; or*
- *Drill a new oil and gas production well unless a well cellar is installed for containment of fluids."*

Analysis

Until December 31, 2014, compliance with SCAQMD Rule 1148.1 subparts (d)(6)(A) – capture, or (d)(6)(B) – incineration, constitutes compliance with Phase 1 of the new USEPA rule. Beginning January 1, 2015, only capture pursuant to subpart (d)(6)(A) can be used for so-called "green completions" under Phase 2; incineration pursuant to subpart (d)(6)(B) will no longer be allowed by USEPA. Thus, subpart (d)(6)(B) will be superseded by 40 CFR 63 on January 1, 2015. Since PXP presently complies with Rule 1148.1, PXP is also presently in basic compliance with 40 CFR 63.

Other Equipment - NSPS Requirements for New & Modified Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a condition such as liquid level, pressure, and temperature at wells and natural gas processing plants, among other locations in the oil and natural gas industry. These controllers often are powered by high-pressure natural gas and may release gas (including VOCs and methane) with every valve movement, or continuously in many cases as part of their normal operations.

The final rule affects high-bleed, gas-driven controllers (with a gas bleed rate greater than 6 standard cubic feet per hour) that are located between the wellhead and the point where gas enters the transmission pipeline.

- The rule sets limits for controllers based on location. For controllers used at the well site, the gas bleed limit is 6 cubic feet of gas per hour at an individual controller.
- The final rule phases in this requirement over one year, to give manufacturers of pneumatic controllers time to test and document that the gas bleed rate of their pneumatic controllers is below 6 cubic feet per hour.
- Low-bleed controllers used at well sites (with a gas bleed rate less than 6 standard cubic feet per hour) are not subject to this rule.

The final rule includes exceptions for applications requiring high-bleed controllers for certain purposes, including operational requirements and safety. The rule also includes requirements for initial performance testing, recordkeeping and annual reporting.

Analysis

Since PXP presently complies with SCAQMD Rule 1173 (*Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants; and Rule 466.1 – Valves and Flanges*) PXP is also presently in basic compliance with this section of 40 CFR 63, notwithstanding particulars and details. This topic will also require coverage in the MRRP discussed above.

Other Equipment - NSPS Requirements for Storage Vessels at the Well Site

Storage tanks at natural gas well sites are commonly used to store condensate, crude oil and produced water. These tanks may be subject to two standards: the NSPS for VOCs and the major source air toxics standards (NESHAP) for Oil and Natural Gas Production.

NSPS Requirements

New storage tanks with VOC emissions of 6 tons a year or more must reduce VOC emissions by at least 95 percent. USEPA expects this will generally be accomplished by routing emissions to a combustion device.

- To ensure enough combustion devices are available, the final rule provides a one-year phase-in for this requirement.
- After one year, owners/operators of new storage tanks at sites with wells in production must comply. Owners/operators at sites with no wells in production will have 30 days to determine the emissions from a tank; and another 30 days to install controls.

Air Toxics Requirements

In response to public comments, USEPA did not finalize proposed air toxics standards for storage vessels *without* the potential for flash emissions, which currently are not regulated under the NESHAP for Oil and Natural Gas Production. The agency determined that it needs additional data in order to establish emission standards for this type of storage vessel. The previous standards for storage tanks *with* the potential for flash emissions remain in place.

- The final rule amends the definition of "associated equipment, " meaning that emissions from all storage vessels now will be counted toward determining whether a facility is a major source under the NESHAP for Oil and Natural Gas Production.

Analysis

Since PXP presently complies with SCAQMD Rule 1176 (*VOC Emissions from Wastewater Systems*), Rule 463 (*Organic Liquid Storage*), and Rule 1178 (*Further Reductions of VOC Emissions From Storage Tanks at Petroleum Facilities*) PXP is also presently in basic compliance with this section of 40 CFR 63, notwithstanding particulars and details.

In particular, during the hydraulic fracturing process, any fluid flowback is captured in a closed system diverted to a portable 500 bbl. tank connected to a SCAQMD-permitted hydrocarbon vapor control system (activated carbon canisters). While PXP currently logs and reports the performance of this system to SCAQMD pursuant to the rule, this topic also requires coverage in the MRRP discussed above. Also, all aboveground stationary tanks are vapor tight and connected to existing vapor recovery systems as required by Rule.

Construction Emissions Estimation for Off-road Equipment and On-road Vehicles

Cardno ENTRIX has estimated mass emissions of criteria pollutants and greenhouse gases (GHG) for off-road equipment and on-road vehicles using emission factors published by the SCAQMD (SCAQMD 2008) and USEPA (USEPA 2011e, 2011f). The project schedule and equipment/vehicle list provided by PXP and Halliburton served as the basis for the analysis. The results of the analysis are presented in the emissions thresholds and summary Tables 4-2, 4-3, and 4-4 contained in this section (SCAQMD 2011). As shown in the tables, the estimated emissions are well below the daily limits set by the SCAQMD.

Table 4-2 Emissions Thresholds – South Coast AQMD

Criteria Pollutant	Temporary Construction lbs/day	Permanent Operation[1] lbs/day
Volatile Organic Compounds (VOC as CH_4)	75	55
Carbon Monoxide (CO)	550	550
Oxides of Nitrogen (NO_X as NO_2)	100	55
Sulfur Dioxide (SO_X as SO_2)	150	150
Respirable Particulates (PM_{10})	150	150
Fine Particulates ($PM_{2.5}$)	55	55

Source: SCAQMD 2011

[1] Does not apply to this project (not a permanent stationary source)

Table 4-3 Estimated Emissions of Criteria Pollutants

Criteria Pollutants	Maximum lbs/day	Threshold lbs/day	Total tons
Volatile Organic Compounds (VOC as CH_4)	2.0	75	0.007
Carbon Monoxide (CO)	13.8	550	0.048
Oxides of Nitrogen (NO_X as NO_2)	13.8	100	0.048
Sulfur Dioxide (SO_X as SO_2)	0.01	150	0.000
Combustion Particulates (C-PM_{10})	0.7	150	0.002
Combustion Particulates (C-$PM_{2.5}$)	0.6	55	0.002

Table 4-4 Estimated Emissions of Greenhouse Gases

Greenhouse Gases	Daily lbs/day	Total Project	
		Tons[1]	Tonnes[2]
Carbon Dioxide (GHG - CO_2)	1,320	4.62	4.19
Methane (GHG - CH_4)	0.03	0.0001	0.0001
Nitrous Oxide (GHG - N_2O)	0.08	0.0003	0.0002
Carbon Dioxide Equivalents (CO_2 eqv)	1,344	4.71	4.27

Sources: USEPA 2011e, 2011f, CCAR 2009

[1] short ton = 2,000 lbs

[2] metric tonne = 1,000 kg or 2,204.6 lbs

Methodology

For general engine exhaust emissions, the pre-processed SCAQMD factors are outputs from the California Air Resources Board (CARB) EMFAC and OFFROAD software applications and are the same conservative factors used in the official statewide URBEMIS and CalEEMod software applications for general land use planning in all 58 counties. For federal relevancy in all 50 states, the on-road and off-road factors are consistent with 40 CFR Parts 9, 69, 80, 86, 89, 94, 1039, 1048, 1051, 1065, and 1068 as applicable. For diesel off-road equipment with specified Tiers (1, 2, 3 or 4), engine exhaust emissions are based on applicable standards pursuant to 40 CFR 89.112, 13 CCR 2423, and 69 FR 38957-39273.

SCAQMD on-road and off-road factors were used for volatile organic compounds (VOC), carbon monoxide (CO), nitrogen oxides (NO_X), sulfur oxides (SO_X), respirable particulate matter (PM_{10}), carbon dioxide (CO_2), and methane (CH_4). USEPA factors were used for nitrous oxide (N2O), which are not included in the SCAQMD factors. For specified off-road Tiers, USEPA factors for VOC, CO, NO_X, SO_X, PM_{10}, CO_2, CH_4 and N_2O were used. For estimation purposes, fine particulate matter ($PM_{2.5}$) was quantified as 92 percent of PM_{10} for consistency with the EMFAC software (SCAQMD 2008). Where applicable, off-road and/or on-road fugitive dust emissions were estimated using USEPA algorithms contained in Chapters 11 and 13 of AP-42 (USEPA 2011a, 2011b).

Global Warming Potential (GWP) coefficients developed by the Intergovernmental Panel on Climate Change (IPCC) were used to quantify the globally averaged relative radiative forcing effects of a given GHG, using carbon dioxide as the reference gas. Accordingly, GWP coefficients of 1 for CO_2, 21 for CH_4, and 310 for N_2O were applied to aggregate GHGs as CO_2 equivalents (CO_2e) (USEPA 2011e, CCAR 2009).

4.8 Noise and Vibration

Noise attenuation and noise limits for activities occurring on the Inglewood Oil Field are addressed in Section E.5 of the CSD. This regulation sets hours for quiet drilling on the oil field (as outlined in the associated Quiet Mode Drilling Plan) and time limits for construction and deliveries to the oil field. Vibration levels are addressed in Section E.6 and must not exceed a velocity of 0.25 mm/second over a range of 1 to 100 hertz (Hz) in any developed area. The CSD requires that noise and vibration levels be monitored on the oil field to ensure that oil operations do not exceed the set thresholds. Table 4-5 lists noise levels for various types of sources for reference (70 dB, which is an annoyingly loud noise level to some individuals is used as an arbitrary base of comparison).

Table 4-5 Noise Sources and Their Effects

Noise Source	Decibel Level	Human Effects
Jet take-off (at 25 meters)	150	Eardrum rupture
Aircraft carrier deck	140	
Military jet aircraft take-off from aircraft carrier with afterburner at 50 feet (130 dB).	130	
Thunderclap, chain saw. Oxygen torch (121 dB).	120	Painful. 32 times as loud as 70 dB.
Steel mill, auto horn at 1 meter. Turbo-fan aircraft at takeoff power at 200 feet (118 dB). Riveting machine (110 dB); live rock music (108 - 114 dB).	110	Average human pain threshold. 16 times as loud as 70 dB.
Jet take-off (at 305 meters), use of outboard motor, power lawn mower, motorcycle, farm tractor, jackhammer, garbage truck. Boeing 707 or DC-8 aircraft at one nautical mile (6080 feet) before landing (106 dB); jet flyover at 1000 feet (103 dB); Bell J-2A helicopter at 100 feet (100 dB).	100	8 times as loud as 70 dB. Serious damage possible in 8-hr exposure
Boeing 737 or DC-9 aircraft at one nautical mile (6080 feet) before landing (97 dB); power mower (96 dB); motorcycle at 25 feet (90 dB). Newspaper press (97 dB).	90	4 times as loud as 70 dB. Likely damage 8-hr exposure
Garbage disposal, dishwasher, average factory, freight train (at 15 meters). Car wash at 20 feet (89 dB); propeller plane flyover at 1000 feet (88 dB); diesel truck 40 mph at 50 feet (84 dB); diesel train at 45 mph at 100 feet (83 dB). Food blender (88 dB); milling machine (85 dB); garbage disposal (80 dB).	80	2 times as loud as 70 dB. Possible damage in 8 hr exposure.
Passenger car at 65 mph at 25 feet (77 dB); freeway at 50 feet from pavement edge 10 a.m. (76 dB). Living room music (76 dB); radio or TV-audio, vacuum cleaner (70 dB).	70	Arbitrary base of comparison. Upper 70s are annoyingly loud to some people.
Conversation in restaurant, office, background music, Air conditioning unit at 100 feet	60	Half as loud as 70 dB. Fairly quiet
Quiet suburb, conversation at home. Large electrical transformers at 100 feet	50	One-fourth as loud as 70 dB.
Library, bird calls (44 dB); lowest limit of urban ambient sound	40	One-eighth as loud as 70 dB.
Quiet rural area	30	One-sixteenth as loud as 70 dB. Very Quiet
Whisper, rustling leaves	20	
Breathing	10	Barely audible

Sources: Federal Interagency Committee on Noise 1974; 1992 *Federal Agency Review of Selected Airport Noise Analysis Issues*, Federal Interagency Committee on Noise (August 1992).

To address concerns regarding perceptible vibration and noise during high-volume hydraulic fracturing operations, PXP commissioned Behrens and Associates, Inc., a firm specializing in noise and vibration studies, to measure produced vibration during the VIC1-330 and VIC1-635 high-volume hydraulic fractures and the TVIC-221 and TVIC-3254 high-rate gravel pack events. The ground-borne vibration survey for each event was completed while all equipment was operated under normal loads and conditions.

The high-volume hydraulic fracturing treatment on September 16, 2011, was completed on the VIC1-330 well, located in the northwestern portion of the field. Ground-borne vibration levels were measured in one direction (west) at 10-foot intervals from the high-volume hydraulic fracture operation (Figure 4-10A). Measured levels indicate that the maximum ground-borne vibration produced during the operation was 0.006 inch per second (0.1524 mm/second), as measured 40 feet from the operation. At 160 feet from the operation, measured vibration was 0.001 inch per second (0.0254 mm/second). As shown on the Figure 4-10 below, both of these levels are imperceptible to humans (Behrens and Associates, Inc. 2011). These measurements are also below the limit set by the CSD. No noise monitoring was conducted during the VIC1-330 treatment.

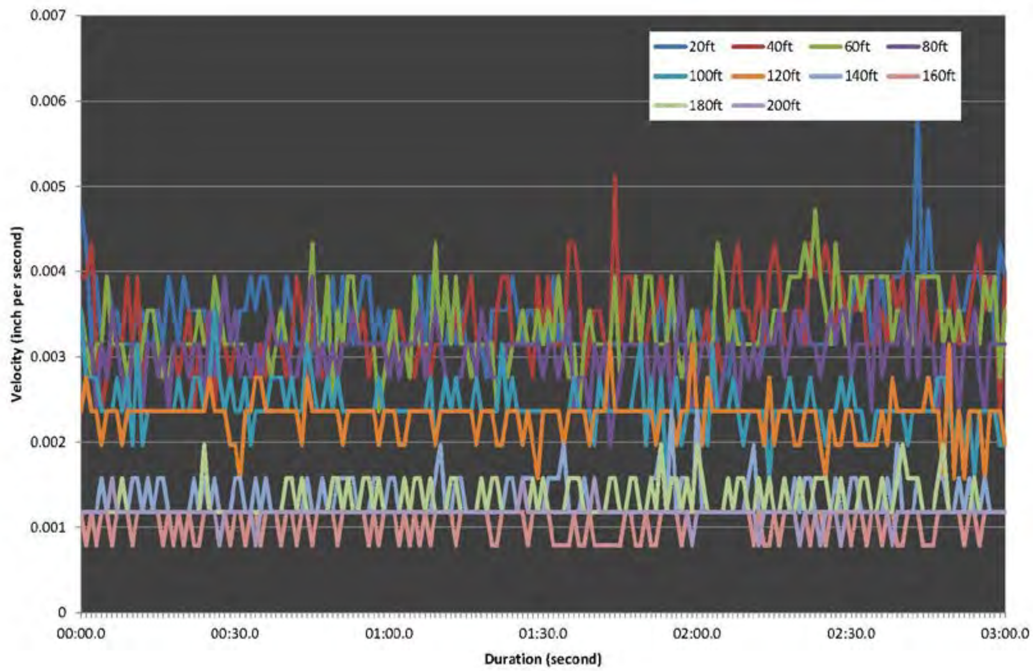


Figure 4-10A Ground Vibration Level Measurements from High-Volume Hydraulic Fracture at VIC1-330

The high-volume hydraulic fracture on January 6, 2012, was completed on the VIC1-635 well. Ground-borne vibration levels were measured to the south of the high-volume hydraulic fracture site at 50, 100, 150, and 200 feet from the well. Measured levels (Figure 4-10B) indicate that the maximum ground-borne vibration was 0.0012 inch per second (0.0305 mm/sec) as measured 50 feet from the operation. Similar to the measured level during the prior high-volume hydraulic fracture operation at VIC1-330, at 150 feet from the operation, measured vibration was 0.001 inch per second (0.0254 mm/second). These measured levels are imperceptible to humans.

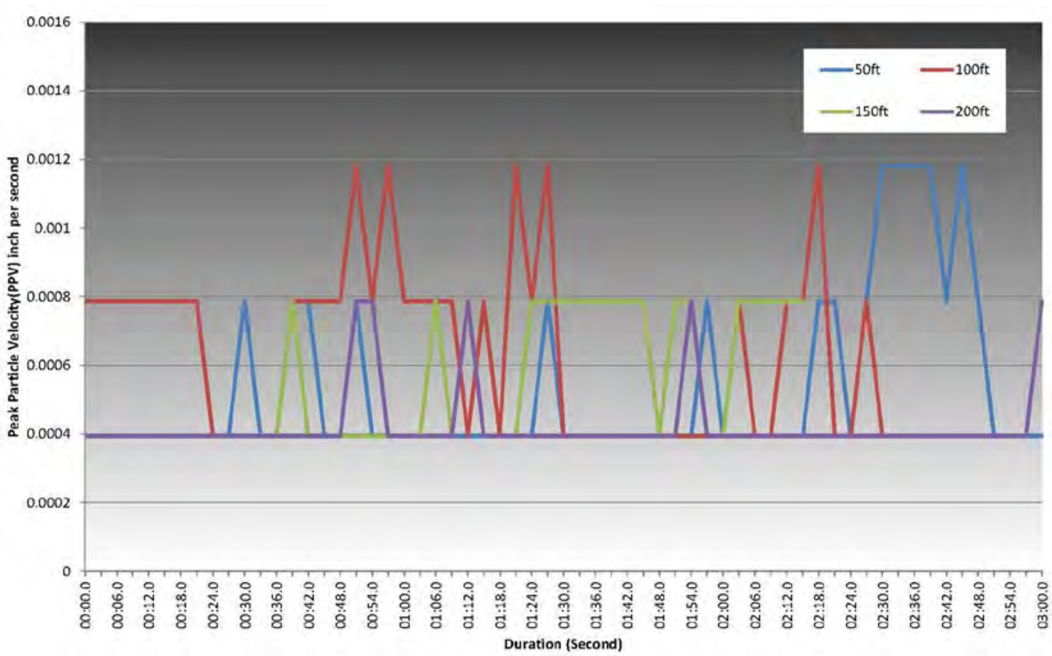


Figure 4-10B Ground Vibration Level Measurements from High-Volume Hydraulic Fracture at VIC1-635

In addition to ground-borne vibration measurements, Behrens and Associates, Inc. also took sound level measurements during the high-volume hydraulic fracturing operation at VIC1-635 using a calibrated sound level meter. The microphone was set at five feet above ground surface. The measured noise level at 100 and 200 feet from the operation was 68.9 and 68.4 decibels (dBA), respectively (Behrens and Associates, Inc. 2012a). These are within CSD limits.

The high-rate gravel pack treatments were completed on January 7 and 8, 2012, on the TVIC-221 and TVIC-3254 wells, which are located immediately adjacent to one another. The ground-borne vibration levels were measured during the high-rate gravel pack at TVIC-221 and TVIC-3254 at a distance of 50, 100, 200, and 300 feet to the east of the high-rate gravel pack operation site (Figure 4-10C).

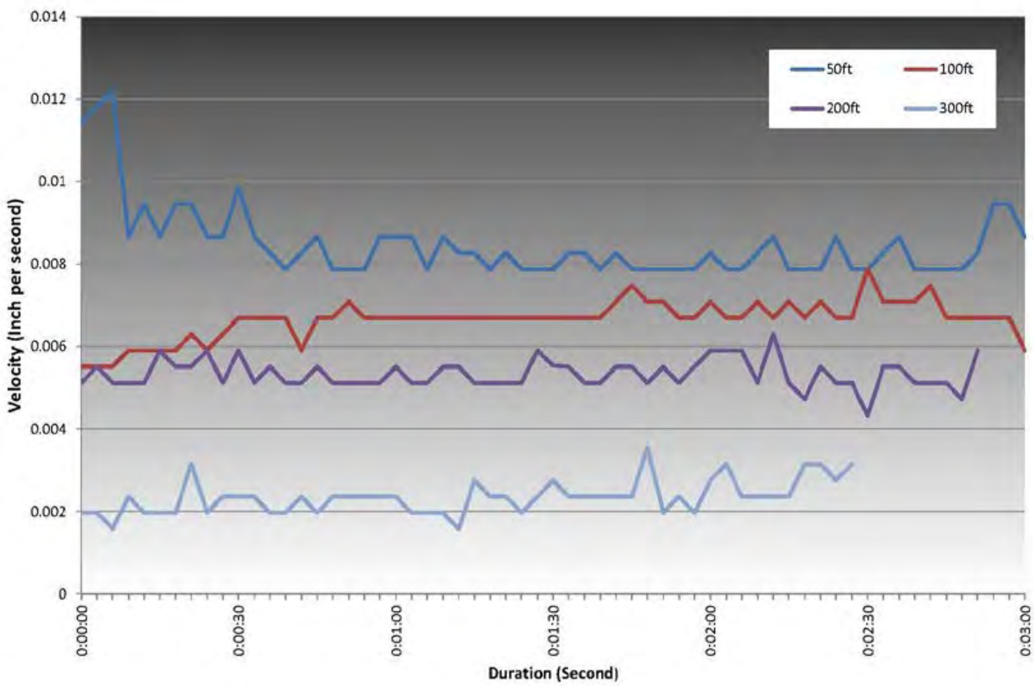


Figure 4-10C Ground Vibration Level Measurements from Gravel Pack Operations at TVIC-221 and TVIC-3254

Measured levels indicate that the maximum ground-borne vibration produced during the high-rate gravel pack operation was 0.012 inch per second (0.304 mm/second), as measured 50 feet from the operation. At 300 feet from the operation, measured vibration was less than 0.004 inch per second (0.102 mm/second). While 0.01 inch per second is the low threshold of vibration that may be perceptible to humans (see Figure 4-11), levels measured further from the site are imperceptible. Further, while the vibration level near the well is greater than the 0.25 mm/second CSD limit, the vibration is decreased to below the limit well away from any developed areas (Behrens and Associates 2012b).

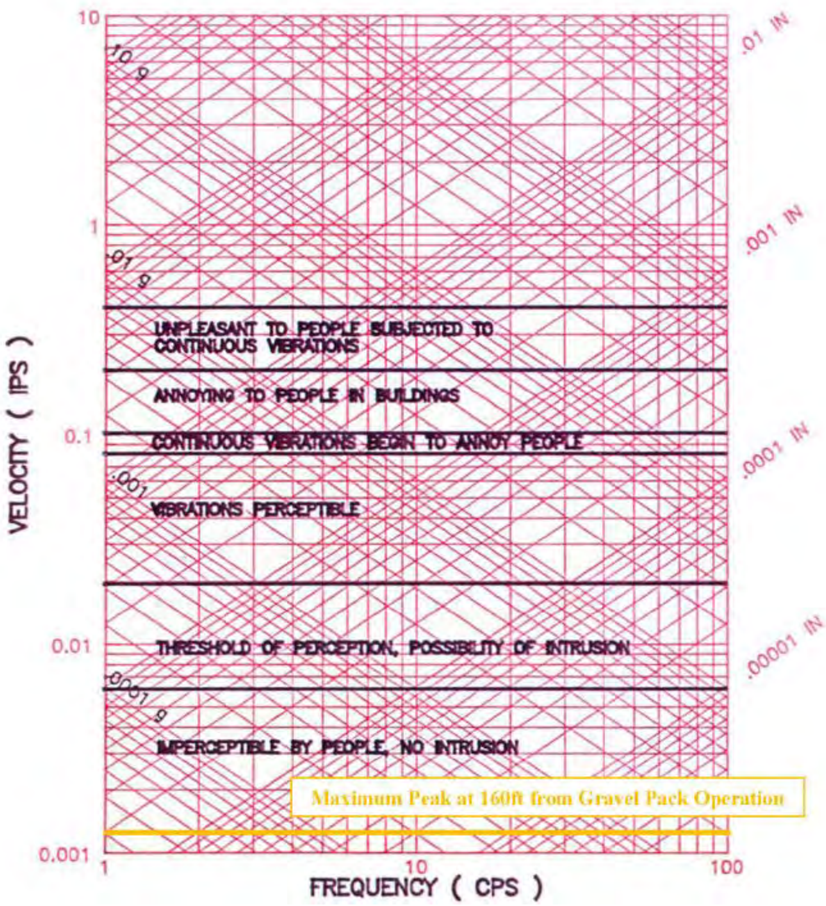


Figure 4-11 Vibration Sensitivity Chart

Sound level measurements were conducted at 100 feet and 200 feet from the TVIC-221 and TVIC-3254 high-rate gravel pack operations. The measured noise level at 100 feet was measured at 68.1 dBA and the noise level at 200 feet was 63.5 dBA (Behrens and Associates 2012b). These are within CSD limits.

4.9 Los Angeles County Department of Public Health Study

In response to health concerns expressed by residents in communities near the Inglewood Oil Field during the EIR process for the CSD, and at the request of the Second Supervisorial District, the Los Angeles County Department of Public Health (LAC DPH) conducted a community health assessment on the population living in communities surrounding the Inglewood Oil Field. The assessment was designed to determine if the health concerns reflect a higher than expected rate or an unusual pattern of disease in the concerned communities. The report was sent to three external peer reviewers who found it to be technically sound.

The conclusions of the health study indicate that there is not a detectable relationship between the activities at the Inglewood Oil Field and the health of the surrounding community. Five types of blood-related cancer (most common types of cancer associated with petroleum exposure) to determine if operations at the Inglewood Oil Field had any adverse impact on cancer rates in the surrounding community. The study found there was no conclusive evidence or link between Inglewood Oil Field activities and cancer rates in the community. The report acknowledges that the data cannot determine whether there is a small adverse health effect, nor can the data address the contribution of other, non-quantifiable health-related issues such as smoking, lack of exercise, and social determinants of health (LAC DPH 2011). As described in Chapter 7, conventional hydraulic fracturing and high-rate gravel pack operations have occurred at the field for several years along with other oil and gas development activity. Any prospective impact from these operations would have contributed to the assessment's baseline findings. The Health Study indicates that operations at the field have not had an adverse effect on the health of the local community.

The Health Assessment included five components, each of which is summarized below:

- An analysis of mortality (death) rates based on data reported on death certificates;
- An analysis of rates of low-birth-weight births based on data reported on birth certificates;
- An analysis of rates of birth defects based on data collected by the California Birth Defects Monitoring Program;
- An analysis of cancer rates based on data compiled by the University of Southern California (USC) Cancer Surveillance Program; and
- A community health survey of self-reported illness, including asthma and other health concerns.

The report of the Health Assessment (LAC DPH 2011) included conclusions for the first four components. The community health survey of self-reported illness was postponed to allow enough time to evaluate the effects of continuous drilling and released in April 2012.

4.9.1 Mortality

From 2000 to 2007, the mortality rate for all causes of death was 731.9 deaths per 100,000 persons in the Inglewood Oil Field communities and 751.7 deaths per 100,000 persons in Los Angeles County, after adjusting for age and the racial/ethnic distribution of the underlying populations. Although the mortality rate appears lower in the Inglewood Oil Field communities, there was no statistically significant difference in the mortality rates for all causes of death, after adjusting for age and race/ethnicity.

The differences in mortality rates for the leading causes of death and premature death do not appear to be related to the geographic location of the Inglewood Oil Field communities. Many of the differences observed within these communities are common in Los Angeles County and represent a significant public health challenge throughout the county. The disparities in mortality rates can best be addressed by targeting the underlying causes of these disparities.

4.9.2 Low Birth Weight

After adjusting for race/ethnicity, the rate of low-birth-weight births was 7.2 per 100 live births in the Inglewood Oil Field communities and 7.0 per 100 live births in Los Angeles County as a whole. There was no statistical difference in the rates of low-birth-weight births in the Inglewood Oil Field communities compared to Los Angeles County, after adjusting for race/ethnicity. There were differences in rates of low-birth-weight births among racial/ethnic groups with African

Americans having the highest rates of low-birth-weight births in the Inglewood Oil Field communities as well as in Los Angeles County. These disparities in low-birth-weight births represent another significant public health challenge throughout the county.

4.9.3 Birth Defects

For 28 of the 29 categories of birth defects, there was no statistically significant difference in the Inglewood Oil Field communities compared to Los Angeles County as a whole. Babies born in the Inglewood Oil Field communities between 1990 and 1997 were slightly more likely (1.2 times as likely) to be born with a limb defect compared to babies countywide. Limb defects are not known to be caused by exposure to petroleum products. Since multiple comparisons were made, the increase may be explained by statistical chance.

4.9.4 Cancer

The analysis found no evidence of elevated rates of acute myelogenous leukemia (AML), the type of cancer most definitively linked to petroleum products (benzene) or three of the other types of blood-related cancer for any of the race/ethnic groups examined. There was an excess risk of chronic myelogenous leukemia (CML) in non-Hispanic whites based on the occurrence of two cases above the expected number in 2000 through 2005. CML has not been consistently linked with exposure to petroleum products from oil fields or refineries. These two additional cases of CML may be explained by statistical chance, because the analysis examined multiple comparisons. Furthermore, in most of the studies examining this issue, occupational exposure to specific petroleum-based chemicals, such as benzene, was measured, rather than residential proximity to oil wells.

4.9.5 Community Survey

The community survey was developed to quantify self-reported illness and environmental concerns among residents living near the Inglewood Oil Field. The community was defined by a 1/5-mile buffer around the oil field and participants were randomly selected. Surveying was conducted by telephone in both English and Spanish. A total of 1,020 residents participated. The survey results were compared to a health survey conducted for all of Los Angeles County in 2007 to provide a comparison between those living in proximity to the Inglewood Oil Field and residents of the county as a whole. The results indicated that the prevalence of health conditions reported by respondents to the Inglewood Oil Field survey were similar to those in Los Angeles County, with the exception that more reported high blood pressure/hypertension in the area around the Inglewood Oil Field than in the Los Angeles County survey. The survey also found that the racial/ethnic disparities that exist in Los Angeles County were also reflected in the Inglewood Oil Field community (greater African Americans report hypertension and heart disease and the 46 percent of respondents in the Inglewood Oil Field community survey were African American compared to 9 percent in the Los Angeles County survey. Other issues addressed in the survey were smoking (13 percent of respondents reported smoking), eating fast food more than once per week (38 percent), and being obese or overweight (26 percent and 39 percent respectively).

With regard to the Inglewood Oil Field, participants were asked about the presence of offensive odors, illnesses caused by outdoor air pollution, and noise. Of the respondents, 86 percent did not notice any odors, and of those that did report odors, only 1.3 percent indicated concern that the odor was caused by the oil field. While 58 percent of respondents indicated concerns about air pollution, only 14.5 percent reported having an illness or symptom in the past year caused by pollution in the air outdoors. This percentage is slightly less than the percentage reported by Los Angeles County residents as a whole (17.5 percent). In regard to noise, participants were asked how much they were bothered by noise from six neighborhood sources: (1) cars and trucks, (2) airplanes, (3) garden equipment, (4) neighbors (including loud music, crying children, or barking dogs), (5) construction, and (6) oil field operations. Of the six sources, noise from the oil field was reported least frequently (LAC DPH 2012).

4.9.6 Health Assessment Limitations and Recommendations

The Health Assessment (LAC DPH 2011) noted limitations and a recommendation. The limitations were as follows:

- The analyses cannot confirm whether exposures to chemicals from oil drilling activities at the Inglewood Oil Field may be associated with a small increase in the risk of mortality, low-birth weight births, birth defects, or cancer among specific individuals living nearby, because epidemiological investigations of this type are more conclusive with larger sample sizes (more cases to analyze).
- The analyses do not take into account other important determinants of health such as behavioral risk factors (such as smoking and physical activity), social factors (such as community resilience, education, income, and access to health care) since these data were not available on the birth certificates, death records, or cancer registry records.
- The analysis cannot establish causal relationships between emissions from oil drilling activities and specific causes of death because of the lack of information on the individual levels of exposure to emissions that could establish dose-response curves and temporal relationships as well as the multitude of other risk factors that influence these disease outcomes. For example, a high-rate of mortality from asthma in the community adjacent to the Inglewood Oil Field would not prove that the oil field operations are causing asthma since there are many other potential causes, such as exposures to traffic-related air pollution, tobacco smoke, or adverse environmental conditions in the home. Alternatively, a normal or low rate of mortality from asthma would not prove that the Inglewood Oil Field is safe, again because of the many other factors that influence the rate. Thus, these results should be interpreted with caution.

All of the conclusions of the health study indicate that there is not a detectable relationship between the activities at the Inglewood Oil Field and the health of the surrounding community and that the occurrences of diseases of concern and mortality rates in the community are consistent with the rate of occurrences throughout the Los Angeles Basin. In other words, areas with no oil field operations were determined to have roughly the same mortality rate as the surveyed community around the Inglewood Oil Field. However, the report acknowledges that the data cannot determine whether there is a small effect, nor can the data address other health-related issues such as smoking, exercise, and social determinants of health. Because of these limitations, the Health Assessment recommends that local community health and safety would be more appropriately assessed by careful monitoring of the Inglewood Oil Field operations to ensure compliance with regulations and standards. In this regard, the CSD provides for Environmental Compliance Coordinator inspections and the annual Environmental Quality Assurance Program audit.

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Chapter 5

Regulatory Framework

5.1 Introduction: Local Source of Energy in the Context of Community Concerns

Since high-volume hydraulic fracturing was first used for shale gas development in the northeastern United States and tight sands development in the Intermountain West, there has been extensive coverage of controversies surrounding its use. Hydraulic fracturing has been called "the environmental issue of 2011" by Time magazine, was the subject of an HBO® movie ("Gasland"), and has been at the center of the debate regarding the pace at which the United States will move towards renewable sources of energy generation.

Although most of the news has been about the development of shale gas, tight sands and coalbed methane deposits, rather than the type of oil and natural gas development that occurs at the Inglewood Oil Field, community outreach conducted as part of this study (including one public meeting and open comment period) has indicated that many of the concerns surrounding shale gas development are shared by the local community. Questions and concerns submitted by the public to Los Angeles County for evaluation in this study were clearly influenced by media coverage of controversies in other parts of the country. As identified through the community outreach conducted by the County and other studies conducted on hydraulic fracturing operations in the U.S., the primary environmental and health issues of concern associated with hydraulic fracturing operations include:

- Potential for contamination of groundwater, including drinking water supplies;
- Potential for migration of gases and related explosion hazards;
- Environmental hazards associated with the chemical packages used during hydraulic fracturing operations;
- Potential for hydraulic fracturing operations to cause earthquakes;
- Issues related to well integrity; and,
- Air emissions and greenhouse gas emissions of hydraulic fracturing operations in comparison to regular oil field operations.

Many of these concerns are addressed by the existing regulatory framework. However, public concern has led to continuing efforts to expand the regulatory framework. This section summarizes the California regulatory framework as it pertains to oil and gas development, and hydraulic fracturing. The section then summarizes regulations and ongoing studies conducted by the Federal government, and many state governments. Finally, the regulatory framework specific to the Inglewood Oil Field, including the additional regulatory overlay of the CSD provisions, is considered in the context of state and federal regulations and guidelines.

5.2 Regulatory Framework and Government-Sponsored Reviews of Hydraulic Fracturing

The federal, state, and local laws, ordinances, regulations, and standards that govern oil field development throughout the United States mandate protection or mitigations against the potential environmental impacts of the entire development process. These protections include numerous provisions in the Clean Air Act, Clean Water Act, Safe Drinking Water Act, Endangered Species Act, and the Oil Pollution Act. Extensive California regulations and local provisions regulating nuisance also apply. The Inglewood Oil Field is unusual in that it has much greater regulation and oversight of its operations than most other onshore oil fields as a result of the Baldwin Hills CSD, which governs operations at the Inglewood Oil Field.

The widespread use of hydraulic fracturing since 1949 has been addressed through this extensive regulatory framework. Hydraulic fracturing is only one part of the entire oil and natural gas development process, and does not require, by itself, individual permits or approvals in California or most other oil and gas producing states. Instead, protections required for these resources during oil and gas development also apply to the use of hydraulic fracturing in general, as a completion technique.

Natural gas drilling activity brought hydraulic fracturing well completion techniques into public prominence. Shale gas production began and was first proven successful in the current oil and gas-producing states of Texas, Oklahoma, and the Intermountain region, and was viewed as a means to more securely achieve energy independence. USEPA reviews of high-volume hydraulic fracturing as used for coal-bed methane in 2004 found no justification for additional environmental controls (USEPA 2004). Significant national and public interest in the technique emerged however, when the shale gas production reached the Marcellus Shale in the northeast United States, especially Pennsylvania. The introduction and application of new technologies led to a dramatic and rapid increase in exploration activity. Communities largely unfamiliar with the oil and natural gas industry began seeing a large influx of drill rigs and production pumps, and construction of new well pads, access roads, and supporting infrastructure such as tanks and surface impoundments. This led to public concern that environmental issues were not being adequately addressed. That initial concern was primarily related to the policy of oilfield service companies to maintain confidentiality of the precise chemical names and concentrations used in hydraulic fracturing fluids. This information was considered a proprietary trade secret and oilfield service companies maintained that to reveal the information would put them at a competitive disadvantage. As a result, several states initiated independent reviews of the environmental impacts of hydraulic fracturing with an emphasis on water quality and chemical disclosure. The most comprehensive of these reviews was the Supplemental Generic Environmental Impact Statement (SGEIS) prepared by the State of New York in 2011, following release of a Generic Environmental Impact Statement which had not specifically regulated hydraulic fracturing operations as a specific action.

Growing public attention has also led the USEPA to allocate increased resources to studying the technique. In addition, the USEPA currently has two ongoing reviews, the first focused on the potential effects of hydraulic fracturing on drinking water supplies, and the second focused on the definition of “diesel fuel” as part of a review of the 2005 EPAct provisions. The 2005 EPAct recognizes hydraulic fracturing as a well completion process, and requires a UIC permit if the fluid used for hydraulic fracturing is diesel fuel. The USEPA is the federal agency tasked with implementing the underground injection control program; however, 42 states (including California) have primary enforcement and permitting responsibility under this program. In California, the Division of Oil, Gas, and Geothermal Resources (DOGGR) is the state agency that enforces the underground injection control program. The USEPA also recently released air quality rules relative to hydraulic fracturing.

Since the passage of the 2005 EPAct, many states have adopted regulations or passed legislation requiring operators to disclose the composition of the fluids used in the hydraulic fracturing process. In 2011, the U.S. Secretary of Energy convened a shale gas Production Subcommittee made up of university, agency, and NGO experts to address the expanded production of shale gas in a safe manner (www.shalegas.energy.gov). The committee concluded that shale gas can be developed in an environmentally responsible manner, and emphasized among other things the need for improved public information, improved coordination between shale gas developers and local, state, and federal government (including the STRONGER reviews described in this Section), as well as the kinds of protections that are in place at the Inglewood Oil Field through the CSD and other regulations and voluntary reporting.

The Inglewood Oil Field is not developing shale gas reserves, but primarily oil reserves with associated natural gas. As such, some specific regulations, studies, and concerns described in this section are not strictly applicable to the Inglewood Oil Field. However, they are described in this report because they give an important context to the questions and concerns that have been raised by the community.

This section addresses the current regulatory framework governing the use of hydraulic fracturing at the time of writing, and presents the results of various studies prepared by the federal government and by individual states.

5.3 California Regulations

5.3.1 DOGGR Regulations

DOGGR was formed in 1915 to regulate all oil and gas activities in the state of California with uniform laws and regulations. DOGGR supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells. By regulating these activities DOGGR aims to prevent damage to: (1) life, health, property, and natural resources; (2) underground and surface waters suitable for irrigation or domestic use; and (3) oil, gas, and geothermal reservoirs.

DOGGR responsibilities are detailed in Section 3000 of the California Public Resources Code and Title 14, Chapter 4 of the California Code of Regulations. These regulations address issues such as well spacing, blow-out prevention devices, casing requirements, plugging and abandonment of wells, maintenance of facilities and safety systems, inspection frequency and reporting requirements. DOGGR programs also include: well permitting and testing; safety inspections; oversight of production and injection projects; environmental lease inspections; idle-well testing; inspecting oilfield tanks, pipelines, and sumps; hazardous and orphan well plugging and abandonment contracts; and subsidence monitoring.

California oil and gas regulations were reviewed in 1992 by the IOGCC and USEPA, at which time DOGGR made numerous changes to its program based on recommendations provided as part of the review. For example, DOGGR initiated the Idle-Well Management Program, which aims to reduce the number of long-term idle wells by encouraging operators to reactivate or plug and abandon their idle wells. In addition, DOGGR strengthened its requirements regarding well bonds and pipelines located in environmentally sensitive areas. The State Review of Oil and Natural Gas Environmental Regulations (STRONGER), a non-profit, multi-stakeholder organization that helps oil and natural gas producing states evaluate their environmental regulations associated with the exploration, development and production of crude oil and natural gas was formed in 1999, and reviewed California's regulations again in 2002. The STRONGER Review took note of California's stringent regulations on exploration and production waste management requirements and Underground Injection Control (UIC) programs. The Review included DOGGR's public participation and outreach, interagency coordination, abandoned well program, and data management proficiency. During the 2002 review the Stronger Review team did not address, nor offer recommendations for, hydraulic fracturing operations or regulations (STRONGER 2002).

While DOGGR's regulations do not include provisions specific to hydraulic fracturing, its broad authority over oil and gas operations gas and regulations encompasses the regulation of hydraulic fracturing in order to protect life, health, property, and natural resources including water supply (under Section 3106 of the Public Resources Code).

5.3.2 Baldwin Hills Community Standards District

The Baldwin Hills CSD, on Page 9, describes hydraulic fracturing (fracing) by including it in the definition of reworking, as follows:

> *"'Reworking' shall mean recompletion of an existing well and includes operations such as liner replacements, perforating, or fracing. Reworking also includes redrilling a well that is not deepened or sidetracked beyond the existing well bore."*

The CSD does not contain specific provisions which apply only to hydraulic fracturing. Rather, the CSD addresses all environmental aspects of oil field operation, and these aspects also apply to the potential environmental effects associated with hydraulic fracturing. These include analysis and provisions that address air quality, water quality, traffic, noise, and impacts to other environmental resource categories. The Baldwin Hills CSD also addresses seismic risk, contingency measures in the event of earthquakes including a requirement for an on-site accelerometer to measure effects of seismic activity and trigger contingency actions. The CSD also analyzes cumulative impacts, and environmental justice. The Baldwin Hills CSD, and the associated EIR, are incorporated by reference in to this Hydraulic Fracturing Study. The Hydraulic Fracturing Study does not identify a new impact not analyzed in the EIR, nor does it identify impacts greater in significance than those analyzed in the EIR.

5.3.3 Proposed California Regulations

As stated above, DOGGR does not currently regulate hydraulic fracturing specifically; it does not monitor hydraulic fracturing, nor are there reporting or permitting requirements. During legislative budget hearings held in Sacramento in March 2011, representatives from the California State Department of Conservation (DOC) testified that the agency would promulgate its own rulemaking process related to hydraulic fracturing. DOGGR hosted seven workshops between May and July 2012, to gather information as part of the rulemaking process. Two workshops were conducted in the Los Angeles Basin, one in the City of Culver City on June 12, 2012, and one in Long Beach on June 13, 2013. DOGGR plans to circulate the draft regulations in Fall 2012.

In addition to DOGGR's plans for rulemaking, two bills related to establishing new regulations for the practice of hydraulic fracturing were introduced in the California Legislature during the 2011–2012 legislative session, Assembly Bill 591 and Senate Bill 1054. The Legislature adjourned for the year without passing either measure.

California Assembly Bill 591, introduced in February 2011, would have required operators conducting hydraulic fracturing to disclose the chemical constituents of the fracturing fluid to DOGGR and the public, as well as the following additional information to DOGGR:

- the source and amount of water used in the exploration or production of the well;
- data on the use, recovery and disposal of any radiological components or tracers injected into the well; and
- if hydraulic fracturing is used, disclosure of the chemical information data described above.

California Senate Bill 1054 (Pavley), introduced in February 2012, would have required well owners or operators to notify surface property owners before commencing drilling operations and hydraulic fracturing operations near or below their property. The bill would have also required that notification be given to DOGGR, the appropriate RWQCB, water supplier, and municipal government. The bill would have also extended DOGGR's permit review time from the current 10 days to 15 days and required DOGGR to submit an annual report to the Legislature that includes the number of wells with notices, and an evaluation of compliance for the notification requirements.

5.4 Federal Regulations and Studies

5.4.1 Federal Regulations

Underground Injection Control Program

At the federal level, hydraulic fracturing is addressed under the Safe Drinking Water Act (SDWA), which was enacted in 1974. The SDWA gives USEPA's Office of Water the primary authority to protect drinking water. Under the UIC Program of the SDWA, USEPA is required to protect drinking water from contamination caused by underground injection of fluids. The UIC Program established six classes of injection wells that have purposes ranging from injection of hazardous materials and sewage, mining fluids, radioactive wastes, oil and gas fluids, and carbon dioxide (CO2) sequestration. Class II wells are associated with oil and natural gas production and include injection of:

- Fluids brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production (e.g., produced water);
- Fluids used for enhanced oil or natural gas recovery; and,

- Liquid hydrocarbons being stored, usually as part of the U.S. Strategic Petroleum Reserve. (USEPA 2011b).

As part of the 2005 EPAct, the U.S. Congress included hydraulic fracturing under the authority of the UIC Program when diesel fuels are used in the fracturing process (Paragraph 1 of Section 1421(d)). The EPAct did not provide a definition of diesel fuel. As of this writing, USEPA is conducting a review to develop a definition of diesel fuel. Interpretations of "diesel fuel" vary from only the use of 100 percent diesel fuel to the use of any diesel in a chemical package. The review process began in spring 2011 and draft guidance was issued in May 2012.

The Inglewood Oil Field does not use diesel fuel, in any amount, for hydraulic fracturing, and available records indicate that it was never used.

Chemical Disclosure

In 2009, the Fracturing Responsibility and Awareness of Chemicals Act was introduced in Congress. The legislation is commonly referred to as the FRAC Act. The FRAC Act proposes regulating hydraulic fracturing by requiring public disclosure of the chemical constituents used in hydraulic fracturing fluids. The FRAC Act states that proprietary information must be released in the event of a medical emergency. Congress did not take any action of the FRAC Act in the 111th session of Congress, (2009 through 2011). The Act was re-introduced in the 112th Congress in March 2011 (Lustgarten 2009). Since the FRAC Act, there have also been other bills discussed or introduced in Congress.

PXP posts the chemicals used in hydraulic fracturing on the public website FracFocus.org, as described below. This disclosure is consistent with the current regulations in the various states with disclosure laws.

EPA Regulation for VOC Reduction

On April 17, 2012, the USEPA released new regulations for reducing air pollution from hydraulic fracturing under the National Emissions Standard for Hazardous Air Pollutants (NESHAPS) for oil and natural gas production. The focus is on reduction of volatile organic compounds (VOCs) that are smog precursor compounds. The new regulations will take effect in two phases:

- **Phase 1:** Before January 1, 2014, use a combustion device (flare) or gas capture to reduce VOC emissions.
- **Phase 2:** Before January 1, 2015, capture all natural gas for sale. Exceptions are provided for exploratory wells or delineated wells used to determine or define the area of a natural gas reservoir, because exploratory wells are not near a pipeline and unable to bring gas to market, and for low pressure wells that cannot supply a gathering line.

The Inglewood Oil Field already exceeds the requirements of this new regulation through compliance with SCAQMD provisions as discussed in greater detail in Chapter 4.

5.4.2 Federal Studies

USEPA's Review of the Impacts of Hydraulic Fracturing on Drinking Water - 2004

In 2004, the USEPA conducted a study that analyzed the potential for contamination of underground sources of drinking water (USDW) caused by hydraulic fracturing of coalbed methane (CBM) natural gas wells. Like shale gas, CBM is an unconventional source of natural gas. Natural gas extraction wells are drilled into coal seams, the coal seam is dewatered by pumping, and natural gas then can desorb from the coal and be brought to the surface in the well. While not all CBM wells are completed by hydraulic fracturing, a portion of the wells do require the utilization of the technique. CBM resources tend to be at shallower depths than shale gas, and accordingly have a greater potential for affecting groundwater supplies if wells are not installed and abandoned according to current standards. The USEPA conducted this study in response to public concern that completing CBM wells by hydraulic fracturing had impacted the quality of groundwater, as well as by congressional need for additional data in the development of the 2005 EPAct. The USEPA released the results of the study in a report titled *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reserves*.

The USEPA's 2004 study was two-fold. The first part was an extensive review of existing literature on the impacts of hydraulic fracturing on USDWs. The USEPA reviewed more than 200 peer reviewed publications and interviewed more than 50 employees in the natural gas industry, representatives of state and local agencies, and 40 concerned citizens and groups. The research focused on water quality incidents potentially associated with CBM hydraulic fracturing.

The second part of the study included a review of incidents of drinking water contamination thought to be associated with CBM hydraulic fracturing operations. The USEPA reviewed studies and investigations performed by state agencies in response to citizen complaints. Complaints investigated included: (a) drinking water with unpleasant taste and odor, (b) impacts to wildlife and vegetation, and (c) loss of water in wells and aquifers. After reviewing the data and incidents, the USEPA concluded that there were no conclusive links between water quality degradation in USDWs and hydraulic fracturing in nearby CBM wells, even though thousands of CBM wells annually were being hydraulically fractured.

The USEPA did determine that in some instances, the coal beds being produced were located within drinking water sources; that is, the coal beds were shallow enough to be within fresh water aquifers. In these cases, fluids and chemicals (including diesel fuels) used for hydraulic fracturing were introduced directly into drinking water sources, because the coal beds were located in drinking water sources. As a result of this finding, the USEPA entered into a Memorandum of Agreement in 2003 with three major service companies, which cumulatively perform 95 percent of the United States' hydraulic fracturing projects, to eliminate diesel fuel from the fracturing fluids that are injected directly into USDWs.

The 2004 USEPA study concluded that hydraulic fracturing fluids in CBM wells do not threaten USDWs. Based on this conclusion, the USEPA recommended against a Phase II study (USEPA 2004).

The Inglewood Oil Field does not use diesel for hydraulic fracturing or for high-rate gravel packs.

USEPA's Additional Review of Impacts of Hydraulic Fracturing – 2011

Continued technological advancements in the field of hydraulic fracturing and the application of the technology to tight sand and shale reservoirs has made the practice more prevalent since USEPA released its 2004 report. Public interest and concerns about the impact of hydraulic fracturing on human health and the environment have grown in direct proportion with increased media and internet attention to the practice. Concerns intensified when hydraulic fracturing was introduced in the Marcellus Shale in the northeastern states in approximately 2005. As a result of increased public interest, in fiscal year 2010 the U.S. Congress' Appropriation Conference Committee directed USEPA to conduct research to study the relationship between hydraulic fracturing and drinking water resources. The purpose of the study was to answer two overarching questions: (1) Can hydraulic fracturing impact drinking water resources, and, if so, (2) what conditions intensify these impacts?

In February 2011, the USEPA published a *Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*, with the objective of identifying the factors that have the potential to affect sources of drinking water. The study began with input from an External Science Advisory Board, which recommended that the study include:

- Use of lifecycle framework to identify important research questions;
- Direct initial research to sources and pathways of potential impacts of hydraulic fracturing on water resources, especially drinking water;
- Analysis of five to ten in-depth case studies at locations representing the full range of regional variability across the nation; and,
- Stakeholder engagement throughout the research process.

As the study focuses almost exclusively on water resources, USEPA examined how water was used during each stage of hydraulic fracturing operations and developed related fundamental research questions (Table 5-1).

To answer these questions, the USEPA study will use a combination of:

- retrospective case studies focusing on studying potential impacts where hydraulic fracturing has already occurred;
- prospective case studies focusing on sites where hydraulic fracturing will occur after research has begun so that site conditions can utilize monitoring before, during, and after hydraulic fracturing operations; and
- general scenario evaluations which will explore hypothetical situations related to hydraulic fracturing.

Table 5-1 Examination of Water Use During Hydraulic Fracturing

Water Use in Hydraulic Fracturing Stage	Research Questions
Water acquisition	How might large volume water withdrawals from ground and surface water resources impact drinking water resources?
Chemical mixing/site management	What are the possible impacts of releases of hydraulic fracturing fluids on drinking water resources?
Well construction and injection of fracturing fluids	What are the possible impacts from the injection and fracturing process on drinking water resources?
Flowback and produced water generation	What are the possible impacts of releases of flowback and produced water on drinking water resources?
Water treatment and waste disposal	What are the possible impacts of inadequate treatment or hydraulic fracturing wastewater on drinking water resources?

Source: USEPA 2011d

In each case, the research approach includes literature reviews, gathering and analyzing existing data, analytical methods, modeling/scenario evaluations, toxicity assessments, and stakeholder-suggested case studies. In addition, the USEPA will summarize the available data on chemical, physical, and toxicological properties of hydraulic fracturing fluid additives to better understand their effects and identify data gaps. The chemicals will also be compared to naturally occurring substances.

The USEPA's November 2011 Final Study Plan states that they have conducted an initial literature review, requested and received information from industry on chemicals and practices used in hydraulic fracturing, discussed initial plans for case studies with landowners and industry representatives, and conducted baseline sampling for retrospective case studies. An interim report is expected by the end of 2012 and is expected to contain a synthesis of results from the retroactive case studies and initial results from prospective case studies. A final report will be released in 2014, which will include results from the long-term prospective studies (USEPA 2011d).

The Inglewood Oil Field has very limited groundwater, no aquifers or water supplies, and is not located within or near an underground source of drinking water. The water supply for the nearby communities is derived primarily from the Colorado River and from Northern California with supplemental groundwater sources all located more than 1.5 miles from the oil field. As such, the results of the ongoing USEPA Study on the effects of hydraulic fracturing to drinking water supplies are not anticipated to produce results that are relevant to operations on the Inglewood Oil Field.

5.5 State Regulations and Studies

5.5.1 State-Specific Regulations

Hydraulic fracturing that includes diesel fuel is subject to the federal UIC program; this program is implemented by the California DOGGR, consistent with most states that have an oil and gas industry. The Inglewood Oil Field does not use diesel fuel for hydraulic fracturing.

Oil and gas producing states have regulated the practice by focusing on regulations specific to well bore integrity, well drilling and casing requirements, waste disposal, setback and operating requirements, and other conditions. The USDOE has stated that regulation at the state and local level allow laws to be tailored to the local environment, and state regulatory agencies tend to have the best information, knowledge and experience of the local conditions (USDOE et al. 2009).

State Chemical Disclosure Regulations

While regulations requiring the disclosure of the chemical constituents used in hydraulic fracturing fluids are under consideration at the federal level, several states have enacted regulations requiring chemical disclosure. Between 2010 and 2011, eight states passed chemical disclosure regulations. Wyoming was first to pass a regulation in September 2010, followed by Arkansas, Pennsylvania, Michigan, Texas, Montana, Colorado, Louisiana, and West Virginia. Ohio also amended existing laws in July 2012, to include disclosure of chemicals used in hydraulic fracturing. California, Illinois, and New Mexico have proposed rules, and several additional states appear to be considering rules.

Each state's regulations are generally consistent, although each differs slightly. For example, some regulations follow the federal proposal that companies can assert that information is proprietary. Other states require disclosure of propriety information to regulatory agencies but not the public. Table 5-2 summarizes the key provisions of the chemical disclosure regulations of the eight states that have enacted chemical disclosure laws.

Legislation was introduced in the 2011–2012 California legislative session that would have required operators conducting hydraulic fracturing to disclose the chemical constituents of the fracturing fluid to DOGGR and the public. In addition, a rulemaking process that will likely require disclosure of hydraulic fracturing chemicals is currently (as of the writing of this study) underway by DOGGR.

The Inglewood Oil Field voluntarily meets the requirements of most state chemical disclosure laws by posting the information on the publically-available website FracFocus.org, described below. As such, PXP would likely be in compliance with any reasonably contemplated chemical disclosure laws at either the State or Federal level.

Table 5-2 Summary of State Chemical Disclosure Regulations

State	Date Enacted	Enforced By	Reporting Required	Volume or Concentration Reporting Required	Proprietary Chemical Disclosure
Wyoming[a]	Sep-10	Wyoming Oil and Gas Conservation Commission	All chemicals used in hydraulic fracturing	Volume and concentration of the products are disclosed, but not of individual ingredients in chemical mixtures	Disclosed to regulators; undisclosed to the public.
Arkansas[a]	Jan-11	Arkansas Department of Environmental Quality	All chemicals used in hydraulic fracturing	None	Disclosure not required
Pennsylvania[a]	Feb-11	Bureau of Oil and Gas Management	All fracturing additives and chemicals All hazardous chemicals (as defined by OSHA) used on well-by-well basis	For hazardous chemicals only	Disclosure not required

Table 5-2 Summary of State Chemical Disclosure Regulations

State	Date Enacted	Enforced By	Reporting Required	Volume or Concentration Reporting Required	Proprietary Chemical Disclosure
Michigan[a]	Jun-11	Michigan Department of Environmental Quality	All hazardous chemicals (as defined by OSHA)	For hazardous chemicals only	Disclosure not required
Texas[a]	Dec-11	Texas Railroad Commission	All chemicals used in hydraulic fracturing.	For hazardous chemicals only	Disclosure not required
Montana[b]	Aug-11	Montana Board of Oil and Gas Conservation	All chemicals used on well-by-well basis	Concentrations of additives	Disclosure not required
Colorado[c]	Dec-11	Colorado Oil and Gas Conservation Commission	All chemicals used in hydraulic fracturing	Concentration of all chemicals	Requires disclosure of chemical family only
West Virginia[e]	Dec-11	West Virginia Department of Environmental Protection	All chemical used in hydraulic fracturing	None	Disclosure not required
Louisiana[d]	Oct-11	Louisiana Department of Natural Resources	All chemicals used in hydraulic fracturing	Concentration of all chemicals	Requires disclosure of chemical family only
Ohio[e]	Jul-12	Ohio Department of Natural Resources	All chemicals used in hydraulic fracturing	Volume and concentration of products	Disclosure not required

Sources: [a] Kusnetz 2011, [b] Falstad 2011, [c] Watson 2011, [d] Hall 2011, [e]NRDC 2012b

Self-Regulation by Industry

Disclosure of the chemical compounds used in hydraulic fracturing has been one of the primary issues that aroused public skepticism regarding the safety of hydraulic fracturing for development of shale gas in New York. As state and federal chemical disclosure laws were in development, the Groundwater Protection Council and Interstate Oil and Gas Compact Commission (IOGCC) in collaboration with the oil and natural gas industry, began examining methods to promote self-reporting and self-regulation to fill the gap and respond to public interest. This collaboration led to the development and launch of FracFocus (www.fracfocus.org) in 2011, a national hydraulic fracturing chemical registry.

FracFocus is managed by the Ground Water Protection Council and IOGCC. The mission of these organizations is conservation and environmental protection. The site was created to provide public access to reported chemicals used for hydraulic fracturing within an area of interest in a user-friendly interface. To help the public put the information into perspective, the site also provides objective information on hydraulic fracturing, the chemicals used, and the purposes they serve and the means by which groundwater is protected.

The high-volume hydraulic fracturing operations completed for this study were reported by PXP on FracFocus and are provided in Appendix B. PXP uses FracFocus on a company-wide basis for all shale oil and natural gas related hydraulic fracturing completions.

New York Supplemental Generic EIS

In 1992, New York State published a Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program. In general, a Generic EIS (GEIS) is similar to a Programmatic Environmental Impact Report prepared pursuant to the California Environmental

Quality Act (CEQA). The New York GEIS analyzes the environmental impacts of the development of oil, natural gas, and solution mining resources, and provides options for mitigation. In this way, common or generic impacts of these activities can be considered "pre-evaluated," and if implemented in conformance with the mitigation conditions no further review is needed. Where site-specific actions differ from those evaluated in the GEIS, or where alternate mitigation is proposed, supplemental environmental review is conducted on those site-specific features.

New York's GEIS did not evaluate the effects of high-volume hydraulic fracturing as currently applied in the Marcellus Shale. As a result, the New York Department of Environmental Quality prepared a Supplemental Generic EIS (SGEIS) to study new technology and techniques related to hydraulic fracturing and to identify potential adverse impacts associated with the new technologies. The Draft SGEIS was released in September 2009 and in response to public comment, a Revised Draft was released in September 2011. The public comment period for the revised draft ended in January 2012, no further iterations have been released.

The draft SGEIS and the GEIS noted potential impacts, including water withdrawals, stormwater runoff, leaks and spills, and waste disposal. However, no adverse impacts to water resources were determined with regard to disposal of waste fluids, except that the disposal of flowback water could cause adverse impacts if not treated before disposal.

The draft SGEIS also finds that there is no significant impact to water resources likely to occur as a result of underground vertical migration of fracturing fluids through the shale formations, primarily the Marcellus Shale. The shale formations are vertically separated from the potential freshwater aquifers by at least 1,000 feet of sandstones and shales with low permeability. Furthermore, a supporting study for the draft SGEIS determined that it is highly unlikely that groundwater contamination would occur by fluids escaping from wellbores. The study notes that regulatory officials from 15 states recently testified that groundwater contamination as a result of high-volume hydraulic fracturing has not occurred (NYSDEC 2011).

In 2009, the New York City Department of Environmental Protection (NYCDEP) expanded upon the draft SGEIS, assessing potential impacts specific to the New York City water supply resulting from natural gas development in the Catskill and Delaware watersheds. Although, the Marcellus Shale in these areas has high gas production potential, these two watersheds provide 90 percent of New York City's water supply. The assessment concluded that there were potential cumulative impacts from a conceivable large-scale high-volume fracturing program in the Catskill and Delaware watersheds, which could substantially increase the risk to the New York City water supply (NYCDEP 2009). The overall recommendation of the NYCDEP study is that hydraulic fracturing not proceed, although it provides recommended mitigation measures if hydraulic fracturing does occur. However, in comparison to current and future activities to the Inglewood Oil Field, the NYCDEP assessment assumes a high density fracturing effort, which is much less than what has been done so far, and is proposed to occur, at the Inglewood Oil Field.

There are several relevant comparisons to be made between the conditions evaluated in the SGEIS, the NYCDEP study, and the Inglewood Oil Field. First, New York City's water supply, as well as much of the state, is derived from surface waters in relatively pristine areas and transported in pipes to New York City, and as such the water supply does not require filtration. The Inglewood Oil Field, however, has no surface water supplies within 10 miles, no groundwater supplies within

1.5 miles and no water transportation infrastructure. Ballona Creek is north and west of the field, but is not used for water supply. As is discussed in detail in Chapter 4, beneath the field itself, there is very limited groundwater, no aquifers or water supplies. The water supply for the nearby communities is derived primarily from the Colorado River and from Northern California; with supplemental groundwater sources all located more than 1.5 miles from the oil field (West Basin Municipal Water District 2011, Culver City 2010, City of Inglewood 2010, Golden State Water Company 2011, California American Water 2011b, see Figure 4-3b). There are no sources of groundwater supplying the City of Culver City system (Culver City 2010). The distance from water supply systems minimizes any potential risk of water quality contamination from fracturing. Note that even with this consideration, the SGEIS protections are still met by the Inglewood Oil Field, despite the much lower potential for water quality impacts.

Second, the Inglewood Oil Field has recently been the subject of a site-specific EIR, prompted by the proposal of the CSD by the County. Table 5-3 below provides a summary of the findings of the SGEIS and a comparison of its' suggested mitigation measures with the Baldwin Hills CSD regulations. In part because the CSD is site-specific, there is a greater amount and type of protections required compared to the SGEIS.

Table 5-3 Summary of Findings of the SGEIS and Comparison with Baldwin Hills CSD

Resource	SGEIS Impact	SGEIS Mitigation	Consistency with Inglewood Oil Field CSD
Water Resources	Depletion of water supply in streams	Passby Flow Requirements	No nearby streams for water supply, Cal Water indicates there is sufficient water supply to meet field needs
	Damage to groundwater resources	Pump testing and site-specific evaluation	Site specific monitoring and reporting; no local groundwater use and limited isolated occurrence of groundwater
	Water Contamination from stormwater runoff	State Pollution Discharge Elimination System (SPDES) permit with all associated requirements	National Pollutant Discharge Elimination System (NPDES permits and compliance with a site specific Construction Stormwater Pollution Prevention Plan are required
	Water Contamination from spills or hydraulic fracturing fluids in wellbores	Onsite reserve pits, blow-out preventers, secondary containment (dikes, pads, liners, sumps)	Secondary containment units, Catch Basins, containment berms, SPCC, NPDES permit
	Aquifer/Groundwater Contamination from Hydraulic Fracturing		Site specific monitoring and reporting; no local groundwater use and limited isolated occurrence of groundwater
	Contamination of soil/water from improper disposal or transportation of waste solids and fluids		BMPs required as part of SWPPP. BMPs include: operating procedures, and practices to control site runoff, spills/leaks, waste disposal
	Contamination of NYC unfiltered water supply	No hydraulic fracturing within 4,000 feet of these watersheds	Nothing comparable in California to NY unfiltered supply. No fracturing in Inglewood occurs closer than 1.5 miles (7,920 feet) from any water resource.

Table 5-3 Summary of Findings of the SGEIS and Comparison with Baldwin Hills CSD

Resource	SGEIS Impact	SGEIS Mitigation	Consistency with Inglewood Oil Field CSD
Freshwater Wetlands	Contamination from accidental release	Site-specific SEQRA review and required permits. Mandatory setbacks.	A system of catch basins around the field addresses potential for accidental releases. Regulated by NPDES program.
Ecosystems and Wildlife	Habitat fragmentation	BMPs to reduce habitat impacts, surveys and restrictions during mating migratory/mating seasons	Site specific special status species habitat protection plan and reporting Site specific Stormwater Pollution Prevention Plan
	Harm to populations due to habitat loss	Well pad reclamation	Site specific special status species habitat protection plan and reporting
	Invasive species	BMPs to reduce invasive species	Site specific special status species habitat protection plan and reporting Monitoring; restoration focused on removal of invasive species
Air Quality	Degradation of air quality	Technology standards, restrictions on sulfur content and BTEX class compounds, and public reporting	Implementation of Air Monitoring Plan. H_2S provisions. Extensive regulatory framework monitored and enforced by SCAQMD that exceeds NY requirements
GHG emissions	Increased GHG emissions due to drilling and production	GHG impacts mitigation plan	Compliance with AB 32 California Climate Change Act, GHG inventories Site specific Air Monitoring Plan
Naturally Occurring Radioactive Material	Exposure of workers and the public to harmful levels of radiation	Monitoring and testing requirements	CSD does not address because Naturally Occurring Radioactive Material does not occur onsite.
Visual	Temporary visual impacts from new structures	Visual impacts mitigation plan and design siting requirements	Landscaping Plan, Visual Site plan (removal of abandoned/unused equipment, licorice paint used on equipment)Screening landscaping, painting
Noise	Temporary Impacts from drilling and fracturing operations and traffic	Noise impacts mitigation plan	CSD Section E.5: Noise Attenuation (noise limits, back-up alarm restrictions, limited delivery hours, construction time limits, construction equipment requirements): Quiet Mode Drilling Plan including sound walls for drilling within 300 feet of residences.
Transportation	Increased traffic, damaged roadways	Road use agreements, transportation plan, road condition assessment	There is no anticipated impact/increase to traffic associated with future oil development; addressed in CSD EIR Inglewood Oil Field is an already developed, active oil field, and drilling is at existing pads to the extent feasible. Different from New York case where much of the development footprint is new.

Source: NYSDEC 2011, County of Los Angeles 2008

STRONGER Reviews

In 2007 there were 33 states with either oil or natural gas production, 27 of which cumulatively produce more than 99.9 percent of the United States' oil and natural gas (GWPC 2009). The State Review of Oil and Natural Gas Environmental Regulations (STRONGER) was formed in 1999, and is a non-profit, multi-stakeholder organization that helps oil and natural gas producing states evaluate their environmental regulations associated with the exploration, development and production of crude oil and natural gas. Prior to 1999, reviews were jointly conducted by the IOGCC and USEPA. The USEPA, USDOE and the America Petroleum Institute, among others, have provided funding to support the STRONGER reviews of the State regulatory review processes. In 2009, a Hydraulic Fracturing Workgroup was formed within STRONGER to address regulatory issues specific to hydraulic fracturing as a well completion technology. STRONGER reviews in 2011 have tended to focus on oil and gas regulations as they apply to hydraulic fracturing operations. STRONGER developed guidelines for hydraulic fracturing in 2010, and reviews of this process in different states generally follow these guidelines. The guidelines are not detailed, but set forth general guidelines such as:

- Wells should be properly designed and constructed.
- Water, wastewater, and waste management should be planned and conducted carefully.
- Information on the chemicals used in hydraulic fracturing operations should be disclosed and reported.

Four states were reviewed in 2011: Oklahoma, Ohio, Louisiana, and Colorado. Pennsylvania was reviewed in 2010 and Arkansas was reviewed in 2012. There was a STRONGER review for California in 2002, but the review did not address hydraulic fracturing. The STRONGER state review process is a non-regulatory program and relies on states to volunteer for reviews. Summaries of the findings for California and the states reviewed from 2010 to 2012 follow below.

California

California regulations were initially reviewed by IOGCC and USEPA in 1992, at which time DOGGR made numerous beneficial changes to its program. For example, DOGGR initiated the Idle-Well Management Program, which aims to reduce the number of long-term idle wells by encouraging operators to reactivate or plug and abandon their idle wells. In addition, DOGGR has strengthened its requirements regarding well bonds and pipelines located in environmentally sensitive areas. STRONGER reviewed California's regulations in 2002. The STRONGER Review Team commended DOGGR's changes since the initial IOGCC/USEPA review and also took note of California's stringent regulations on exploration and production waste management requirements and UIC programs. The Review included DOGGR's public participation and outreach, interagency coordination, abandoned well program, and data management proficiency. During the 2002 review the Stronger Review team did not address, nor offer recommendations for, hydraulic fracturing operations or regulations (STRONGER 2002). This 2002 Review indicated that as of 2000, California had approximately 207 operating oil fields and produced 840,000 barrels per day, ranking fourth in the United States for oil production. Today, California produces approximately 550,200 barrels per day with 209 active oil fields (DOGGR 2011).

Oklahoma

The Oklahoma Corporation Commission and the Oil and Gas Conservation Division (OGCD) regulate oil and gas operations in the state. Hydraulic fracturing has been conducted in Oklahoma for over sixty years. More than 100,000 wells have been hydraulically fractured during this time and state regulatory agencies have never identified an instance where hydraulic fracturing has adversely affected groundwater resources. Specifically, the OGCD mapped the base of fresh water throughout the state and determined that the oil and gas producing zones were all much deeper than the base of fresh water in nearly all well locations. Consequently, the OGCD determined that the risk of drinking water contamination resulting from hydraulic fracturing operations is limited. Nonetheless, in 2010, the OGCD recently incorporated new regulatory measures, such as well completion reports, and stricter requirements for the storage and recycling of flowback water, to address this limited risk. The state also initiated a five-year plan to help manage hydraulic fracturing (STRONGER 2011a).

Pennsylvania

The STRONGER review for Pennsylvania was conducted in 2010. Hydraulic fracturing is regulated by the Department of Environmental Protection (DEP) and the Bureau of Oil and Gas Management (BOGM). Hydraulic fracturing has been used in Pennsylvania since the 1950s and nearly all of the wells drilled since the 1980s have been hydraulically fractured. According to the DEP there are no verified instances of groundwater contamination resulting from hydraulic fracturing. Pennsylvania has more comprehensive regulations than Oklahoma, likely due to the increased interest in development of the Marcellus Shale. (STRONGER 2010) For example, in 2008, BOGM began requiring plans to manage water withdrawal and protect water quality standards.

As a result of the development of the Marcellus Shale, there have been several surface and subsurface water control issues, such as water withdrawal and wastewater management. Plans must indicate how much water will be withdrawn and from where, so that the DEP can ensure that excessive water withdrawals will not impact water quantity. Produced water recycling is encouraged, and there are strong regulations for fracturing waste generation, transportation and disposal. The 2010 film “Gasland” highlighted drinking water concerns in the town of Dimock, Pennsylvania. This topic is addressed in Chapter 4, including the results of recent USEPA sampling of local supply wells in Dimock that did not detect contaminants of concern.

Ohio

Oil and natural gas operations are overseen by the Ohio Department of Natural Resources (ODNR) and the Divisions of Mineral Resource Management (DMRM). Hydraulic fracturing has been performed since the 1950s and most wells drilled today are hydraulically fractured. The STRONGER review did not identify any instances of groundwater contamination as a result of hydraulic fracturing. After an independent review of its oil and gas program, the DMRM updated its regulations pertaining to hydraulic fracturing in June 2010.

STRONGER’s 2011 review indicated that Ohio has strong reporting requirements and enforcement tools. They also praised Ohio for thoroughly reviewing potential pathways for groundwater contamination and increasing staffing levels in the DMRM. In addition, STRONGER commended Ohio for thoroughly reviewing and revising oil and gas regulations in

2010. STRONGER provided several recommendations on how to strengthen existing regulations including ensuring that sufficient information is available with regard to the chemical constituents of fracturing fluids and thoroughly evaluating the need for and availability of surface and groundwater for hydraulic fracturing operations in the context of competing water uses. The overall finding was that the regulations protect water resources. More than 800,000 wells have been fractured in Ohio without any verified instances of groundwater contamination (STRONGER 2011b).

Louisiana

Hydraulic fracturing has been occurring in Louisiana since the 1960s, and is regulated by the Louisiana Office of Conservation. Currently, the Haynesville Shale is the primary area of interest for hydraulic fracturing operations in the state of Louisiana. This formation must be fractured to be commercially productive. Work permits are required prior to well construction operations, including hydraulic fracturing. Production in the Haynesville Shale began in 1910 and there are 1,586 Class II injection wells in this area. There have been no cases of contamination of underground sources of drinking water in this area. There are also rules related to the exploration and production of gas in the Haynesville Shale, including setback, noise, vibration, odor, lighting, venting and flaring requirements. Regulations for pressure testing of casing and cementing, as well as requirements for fracturing fluid flowback storage and disposal, also exist (STRONGER 2011c).

Colorado

The Colorado Oil and Gas Conservation Commission regulates oil and gas operations, including hydraulic fracturing, which has been occurring in Colorado since 1947. Nearly all active wells in Colorado have been hydraulically fractured, and no instances of ground water contamination have been confirmed. In 2007, Colorado comprehensively updated its oil and gas regulations, resulting in several new requirements related to hydraulic fracturing including but not limited to: (a) chemical inventories at well sites are required, (b) wells must be cased with steel pipes and surrounded by cement to prevent fluid and gas leakage, (c) surface casing to a specified minimum depth is required for well control and to protect shallow aquifers, (d) setbacks, baseline water quality sampling and other improved environmental protections, (e) baseline water well sampling is required, and (f) operators developing coal bed methane (CBM) wells must inspect local plugged and abandoned wells within one-quarter mile, sample adjacent water supply wells, and meet other requirements to minimize gas or water leakage. These new regulatory provisions were all commended by STRONGER (STRONGER 2011d).

Arkansas

STRONGER issued its review of Arkansas' oil and gas regulatory program in 2012. The Arkansas Oil and Gas Commission regulates the industry, and the review concluded that the Arkansas program is well managed and generally meets the 2010 Hydraulic Fracturing Guidelines. Program strengths included an update of oil and gas rules in 2004, in response to the increased activity in the Fayetteville Shale. In particular, Arkansas was among the first states in the nation to establish a system for the public disclosure of chemicals used in hydraulic fracturing operations. The program also has an effective water well complaint protocol, and a web site with information on hydraulic fracturing, including the areas of the Fayetteville Shale with active hydraulic fracturing of wells.

The Fayetteville Shale currently has 4,000 active oil and gas wells, with plans for development of over 14,000 more natural gas wells. Both the Arkansas Oil and Gas Commission and the Arkansas Department of Environmental Quality have responded to complaints of water well contamination within the Fayetteville Shale development area. To date, neither agency has found any evidence of water contamination from hydraulic fracturing in any of the water wells tested. In addition, the United States Geological Survey office in Little Rock has recently completed a water well testing program in Van Buren County, one of the most heavily drilled counties where hydraulic fracturing operations have occurred. No evidence of contamination from hydraulic fracturing has been found in the water wells tested.

STRONGER recommended that Arkansas require agency notification prior to commencing hydraulic fracturing operations. They also recommended increased funding and staffing of the Arkansas Oil and Gas Commission to allow for inspections (STRONGER 2012).

Summary

The STRONGER reviews have focused on regulatory programs, but in each state they also evaluated records with respect to contamination of underground sources of drinking water by hydraulic fracturing activity, hence the relevance to this study. The states reviewed in 2011 and 2012 have thousands of wells that had been hydraulically fractured. No evidence for groundwater contamination was found in any of these cases. Reviews had been conducted by state agencies, federal agencies, and the U.S. Geological Survey.

Table 5-4 summarizes the findings of the STRONGER reviews as they relate to hydraulic fracturing. The first column includes strengths of the regulatory program, and the second column includes recommendations. In general the comments refer to the regulatory programs themselves.

Although the recommendations apply more to regulatory agencies than to specific oil fields, where the recommendations are specific to the process of hydraulic fracturing, the Inglewood Oil Field would either meet or exceed these recommendations. In part this is because the Inglewood Oil Field operates under enhanced environmental controls that require notification, setbacks, and other provisions as required by existing regulations, primarily the CSD. In addition, PXP is voluntarily following chemical disclosure policies that meet those recommended by STRONGER.

Table 5-4 Summary of State STRONGER Reviews of Hydraulic Fracturing

Existing Regulation Strengths as summarized by STRONGER	Recommendations from STRONGER
Oklahoma	
▪ Comprehensive regulatory standards for hydraulic fracturing have been developed which: (see following cells)	▪ Reporting requirements should include volumes of hydraulic fracturing fluids and proppants used, pressures recorded, and hydraulic fracture materials used
▪ Prohibits pollution of a fresh water from well completion activities	▪ Recycling of flowback water and use of alternate, lower quality water should be encouraged
▪ Provides minimum casing and cementing standards	▪ More stringent regulations with regard to notification to the Oklahoma Corporation Commission prior to fracturing operations should be required

Table 5-4 Summary of State STRONGER Reviews of Hydraulic Fracturing

Existing Regulation Strengths as summarized by STRONGER	Recommendations from STRONGER
▪ Provides strong regulations related to the construction and maintenance of flowback water storage tanks ▪ Requires sampling of hydraulic fracturing waste materials or flowback water to monitor chemicals of concern, primarily salts and TDS	▪ The state should procure additional funding to ensure a staffing needs are met based on expected needs in the future
Pennsylvania	
▪ Comprehensive water planning process to ensure that demands on water resources related to hydraulic fracturing are managed through a planning process	▪ Stronger casing and cementing requirements have been proposed but have not been adopted into law
▪ Regulations encourage baseline groundwater quality sampling plans	▪ Encourage more comprehensive baseline studies in situations where there are increased risk factors
▪ Potential risks must be identified in a preparedness plan, which requires operators to list chemical additives used and wastes generated	▪ Require operators to identify potential conduits for fluid migration
▪ Waste characterization is required, including generation, transportation and disposal tracking	▪ Require notification prior to hydraulic fracturing. Currently this information is only transmitted via well completion reports and DEP does not have the opportunity to inspect
▪ Strong waste storage tank/pit requirements	▪ Secondary containment requirements for tanks used in hydraulic fracturing regulations
Ohio	
▪ Comprehensive well completion reporting is required and must include type and volume of fluid used for stimulation, reservoir breakdown pressure, recovered fluid containment methods, etc.	▪ Chemical disclosure regulations should be more comprehensive than currently exist
▪ Casing and cementing plans are required during the permitting process	▪ The state should evaluate the impact of hydraulic fracturing on surface and groundwater availability
▪ Notification is required before hydraulic fracturing occurs ▪ Well permits require a comprehensive review of potential pathways for groundwater contamination ▪ Pit placement and construction guidelines are implemented through permit conditions ▪ Strong enforcement tools	▪ Stricter spill notification regulations
Louisiana	
▪ The use of alternative water sources and the recycling of waste fluids are encouraged and promoted by recent legal amendments	▪ The minimum depth of surface casing is based on the total depth of the well. To protect groundwater, the depth to the USDW and depths of productive zones should also be considered
▪ Permitting of commercial waste fluid treatment and reclamation for hydraulic fracturing water supply purposes has been streamlined to make the process easier	▪ There are no cementing requirements for well construction or for casing weights or grades. Standards should be developed to meet anticipated pressures
▪ Increase in water source and volume reporting requirements, coupled with recycling provisions has significantly decreased water demand	▪ Reporting should include materials used, volumes of fracturing fluids, proppants used, and fracture pressures
▪ Surface water has been sufficiently analyzed and there is adequate water available for anticipated hydraulic fracturing needs	▪ Spill Prevention and Control Plans are currently required, but additional contingency plans are recommended

Table 5-4 Summary of State STRONGER Reviews of Hydraulic Fracturing

Existing Regulation Strengths as summarized by STRONGER	Recommendations from STRONGER
Colorado	
▪ Operators are required to keep chemical inventories at all well sites, which must be provided to agencies and health care providers upon request	▪ To help protect water resources from contamination, standards should be developed for minimum and maximum surface casing depths. All past problems related to surface casing in a hydraulically fractured well should be considered when developing this standard.
▪ Bradenhead annulus pressure during hydraulic fracturing operations must be measured and reported in an effort to help protect groundwater	▪ Materials used, aggregate volumes of fracturing fluids, proppants used and fracture pressures should be recorded
▪ Identification of potential pathways for fluid migration is required in certain circumstance	▪ An evaluation of naturally occurring radioactive material in hydraulic fracturing wastes should be required ▪ The availability of water resources for fracturing operations should be evaluated, as water supply is a significant issue in this arid region. Plans should be implemented to maximize water reuse and recycling if it is determine that water supply is an issue ▪ Requires operators to study and address potential pathways for fluid migration in more detail ▪ Stricter regulations related to providing notification and receiving approval prior to hydraulic fracturing
Arkansas	
▪ Since 2006, AOGC reviewed and revised numerous rules concerning environmental and production related concerns associated with hydraulic fracturing	▪ Notification prior to hydraulic fracturing so field inspectors can better monitor operations and related activities
▪ Developed water well complaint protocol, guiding staff towards efficient review and response to water well complaints and identification of laboratory analysis parameters	▪ Funding to continue support of Arkansas Department of Environmental Quality and seek resources to better Department
▪ AOGC's user friendly website informs public of hydraulic fracturing operations and other pertinent information regarding hydraulic fracturing	▪ Funding to increase AOGC Staffing Levels to ensure Commission inspection goals are met

Source: STRONGER 2010, 2011a-d, 2012.

NRDC's Evaluation of Hydraulic Fracturing Wastewater and Disclosure Regulations

In May 2012, the Natural Resources Defense Council (NRDC) published a report analyzing regulations related to wastewater generated from hydraulic fracturing. The report focuses on wastewater disposal methods and regulations in Pennsylvania but notes that the issues raised are relevant everywhere hydraulic fracturing occurs.

The report states that the most common management options for shale gas wastewater are recycling for continued use during oil and gas operations, treatment and discharge to surface waters, storage in impoundments and tanks, and applying it to the land (e.g. dust suppression). NRDC highlights environmental concerns associated with each disposal method, such as accidental spills when wastewater is temporarily stored in tanks or ponds on-site, inadequate treatment at publicly owned treatment facilities, or chemicals washing off roadways as a result of the land application method. Subsequently, NRDC recommends the following policy changes to strengthen regulations: regulate discharges from treatment plants more strictly; regulate hydraulic fracturing wastewater as a hazardous waste, either under RCRA or state regulations; only allow injecting of wastewater with hazardous characteristics into Class I hazardous waste wells, and strictly regulate Class II disposal wells in the interim; and prohibit land application and temporary storage in impoundments and tanks.

At the Inglewood Oilfield, produced water is transported by pipeline to the field's water treatment plant where it is mixed with other produced water generated at the field, treated, and reinjected into the oil and gas producing formations. This is in accordance with CSD Condition E.2.(i), which requires that all produced water is contained within closed systems at all time. NRDC notes that on-site recycling can have significant cost and environmental benefits by reducing freshwater consumption as well as the amount of wastewater requiring disposal. NRDC also notes that disposal by underground injection requires less treatment than other methods and creates the least risk of contaminating the environment. NRDC notes that this method can create risks of earthquakes and can require transportation over long distances, though in the case of the Inglewood Oilfield it is transported within the field boundary via pipeline and the existence of the waterflood operation significantly reduces concerns of induced seismicity because it injects water in to the depressurized zones of oil extraction.

NRDC encourages on-site wastewater recycling, the method used at the Inglewood Oilfield for beneficial reuse of its treated produced water, and does not identify any related policy recommendations directly pertaining to wastewater reuse other than noting that the benefits of reuse can sometimes be offset by the energy use and generation of concentrated residuals (NRDC 2012a).

As noted above, the focus of the NRDC report is primarily hydraulic fracturing in the Marcellus Shale and Pennsylvania regulations. In response to the report, in July 2012, the Secretary of Pennsylvania Department of Environmental Protection (DEP) issued a letter stating that "the Report is incorrect and inapplicable to Pennsylvania in many respects." The letter asserts that the report incorrectly characterizes wastewater disposal methods currently used in Pennsylvania and the associated regulations. The letter also mentions that report underestimates the quantity of wastewater that is recycled and indicates that the NRDC is biased against the industry (Pennsylvania DEP 2012). In turn, the NRDC issued a response letter defending the report and continuing to urge Pennsylvania DEP to strengthen their regulations.

In addition to assessing wastewater regulations, in a separate article published in July 2012, NRDC conducted a comparison of disclosure regulations for hydraulic fracturing between states related to advance public notice requirements prior to hydraulic fracturing; disclosure of information concerning the geological and environmental context of the wells, comprehensive disclosure about the hydraulic fracturing "treatment" (i.e. pressures, volume and type of base fluids, depths, etc.); and disclosure about the volume of wastewater created as well as its storage, treatment and/or disposal. The article points to lack of public access to disclosed information even when disclosure regulations do exist, and poor compliance with and enforcement of regulation (NRDC 2012b).

5.6 Inglewood Oil Field in State and National Regulatory Perspective

The federal, state, and local laws, ordinances, regulations, and standards that govern oil field development throughout the United States require protections against the potential environmental impacts of the entire development process. These protections range from provisions in the Clean Air Act, Clean Water Act, Safe Drinking Water Act, Endangered Species Act, and through extensive California regulation addressing air quality, water resources, biological resources, and cultural resources, and at the local level. The Inglewood Oil Field is unusual in that it has much greater regulation and oversight of its operations than most other onshore oil fields as a result of the County of Los Angeles CSD.

The Baldwin Hills CSD, and the associated EIR, together address most of the issues that are part of a hydraulic fracturing operation, such as truck traffic, water use, community compatibility (noise, light and glare, etc.), air quality, and other environmental resource categories. In addition, the EIR evaluates cumulative impacts, and environmental justice. These two documents are incorporated by reference into this Hydraulic Fracturing Study, which evaluates the effects measured and monitored during the high-volume hydraulic hydraulic fracturing and high rate gravel packing operations conducted in 2011 and 2012, as well as past activities of this type. The Hydraulic Fracturing Study did not identify a new impact not analyzed in the EIR, nor did it identify impacts greater in significance than those analyzed in the EIR.

Exacting protective measures and close monitoring are required by the Baldwin Hills CSD and by county, regional and federal agencies. These field-specific reviews and public and agency interactions compel PXP to enforce real-time compliance with all environmental standards in the Inglewood Oil Field. The long history of oil production in the area provides operators with an excellent understanding of the local subsurface conditions and reduces standard risks and uncertainties that would be present in new operations.

Chapter 6

Qualifications of Preparers

Current Position
Vice President,
Senior Principal

Discipline Areas

- Geology
- Geochemistry
- Hydrogeology
- Remediation Technology
- Fate and Transport Analysis
- CEQA/NEPA Environmental Impact Analysis
- Sediment Transport Analysis
- Civil Engineering

Education

- Ph.D., Geology and Geochemistry, Massachusetts Institute of Technology, 1989
- B.S., Civil Engineering and Geology, Stanford University, Stanford, 1983

Professional Registrations

- California Registered Geologist No. 5927

Appointed Positions

- National Academy of Sciences appointed Scientific Advisory Board – Giant Sequoia National Monument
- Natural Resources Management Department, former Executive in Residence – California Polytechnic University, San Luis Obispo
- UNESCO World Heritage Site Designation Advisory Council
- Volcanologist, RED Nacional de Emergencia, Chile

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Daniel R. Tormey, Ph.D., P.G.

Hydrogeologist, Geochemist, & Civil Engineer

Dr. Tormey is an expert in water and energy. He works with the environmental aspects of all types of energy and energy development, as well as water supply, water quality, hydrology, sediment transport, and groundwater-surfacewater interaction. He has well-developed skills in framing and analyzing environmental issues, and in communicating complex ideas to a wide range of audiences. Noted for the creativity of his approaches, he has conducted numerous studies related to the development of unconventional sources of natural gas, including high-volume hydraulic fracturing of oil and gas shales, and coal bed methane development.

Dr. Tormey has managed projects on behalf of government regulatory agencies (US Bureau of Land Management, US Forest Service, Federal Energy Regulatory Commission, US Bureau of Reclamation, US Army Corps of Engineers, US Office of Surface Mining, California State Lands Commission, California Public Utilities Commission, RWQCB-SD, local agencies) and for project proponents (PG&E, SCE, oil and gas companies, water agencies, among others). He has testified in the Federal Court of Claims on water rights and water takings issues. Dr. Tormey has managed the preparation of 15 Proponents Environmental Assessments for submission to the California Public Utilities Commission for projects including transmission lines and pipelines, and power plants fired by natural gas, oil, diesel, coal, and nuclear.

Dr. Tormey has evaluated environmental aspects and risks of oil and gas development and transport on many oil and gas fields in California and elsewhere in America, and more than 15 fields worldwide. He has led studies of the environmental impacts of hydraulic fracturing, water injection, and other oil and gas practices. He has evaluated beneficial reuse of produced water for agriculture, industrial, and restoration of habitat. He has studied carbon capture and storage using depleted oilfields as the storage reservoir, as well as the use of CO_2 for enhanced oil recovery. He has prepared environmental reports for pipelines carrying oil, natural gas, hydrogen, refined products, and biosolids. He has managed or been technical lead on offshore oil and gas projects, including licensing of eight liquefied natural gas (LNG) import terminals, marine terminals, and platforms (operation, abandonment, and reuse). He has extensive experience in the preparation of environmental reviews supporting acquisition or divestiture of oil and gas producing facilities and related infrastructure.

He has worked on assessment, remediation, and restoration on many oilfields throughout the world, and is an expert on benchmarking and applying sound environmental solutions in that arena. He has pioneered bioremediation of oil-impacted soils, and has designed over 15 acres of such treatment cells. He has also considered the overall environmental setting (biological and cultural resources) of the oilfield in determining appropriate remediation responses.

Dr. Tormey has been technical lead for over two hundred projects requiring fate and transport analysis of chemicals in the environment, including modeling of chemicals in groundwater and surfacewater, study of linked groundwater-surfacewater systems, sediment transport analysis, quantification of adsorption/desorption kinetics, air dispersion modeling, among others. His work with contaminants also includes site assessment, forensic geochemistry, risk assessment, feasibility study, and site remediation. Dr. Tormey has served as a technical expert in fate and transport issues supporting either litigation and testimony in State Court, and agency testimony involving petroleum, solvents, metals, pesticides, and plastic components.

Dr. Tormey actively pursues volcanology research around the world, with a focus on interactions between geophysical variables that affect risk assessment, risk preparedness, and contingency planning.

Megan Schwartz
Senior Project Scientist

Current Position
Senior Project Scientist

Discipline Areas
> NEPA CEQA Planning
> Permitting
> Oil and Gas
> Renewable Energy
> Litigation Support
> Environmental Site Assessments

Education
> M.E.S.M. Environmental Science & Management, UC Santa Barbara, 2004
> B.A. Biological Anthropology, UC San Diego, 2002

Ms. Schwartz is a senior environmental planner and project manager with a Masters in Environmental Science and Management. She has addressed many controversial issues related to energy development in the southwestern United States and globally. Ms. Schwartz has addressed the potential impacts of proposed projects under both the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA). She also excels at regulatory compliance, including permitting and mitigation planning and implementation. She works with electrical local utilities and the oil and gas industry, as well as the regulatory agencies with jurisdiction over energy production.

Ms. Schwartz has worked on a variety of energy issues including hydroelectric power including dam removal on the Klamath River, oil and gas development around the world with a focus on water quality and community compatibility. She has also evaluated environmental effects of submarine cable installation, natural gas storage, transmission lines in the southwest and connecting to wind power in Mexico, and coal-fired power plants being either retired or repowered. Ms. Schwartz has been a technical lead on studies examining potential contamination of local groundwater supplies and beneficial reuse options of produced water from oil and gas fields. She has also evaluated the composition of additives used for hydraulic fracturing.

Molly Middaugh
Senior Staff Scientist

Current Position
Senior Staff Scientist

Discipline Areas
> Environmental Management, Permitting, and Compliance
> NEPA/CEQA
> Permitting
> Litigation Support
> Natural Resources Damages
> Environmental Communications
> Energy and Climate Change Policy

Education
> B.A. Environmental Analysis, Pomona College (Magna Cum Laude), 2010

Ms. Middaugh is a senior staff environmental scientist with a background in environmental science, economics, and policy. Her experience includes employment in the public, private and NGO sectors. Ms. Middaugh has worked on significant projects related to energy policy, with an emphasis on climate change, carbon offsets and international deforestation policy. She has a strong understanding of federal environmental regulations and policy that first developed when she worked for a member of the U.S. House of Representatives on Capitol Hill, as well as for the Energy and Climate Change program of the Center for Strategic and International Studies, also in Washington D.C.

Ms. Middaugh has evaluated the environmental impacts of energy and mining-related projects under the NEPA and CEQA process, as well as obtaining California and federal permits for these actions. She assists in analyzing and prioritizing environmental risks of oil and gas development. Ms. Middaugh also characterizes the chemical properties of and assesses beneficial reuses of produced water. She is currently engaged in the analysis of the chemical composition of fluids used as additives in hydraulic fracturing. She has also analyzed the environmental economic consequences in Natural Resource Damage claims.

Ms. Middaugh also works as part of the environmental communications team to translate technical scientific documents into more simple and understandable language.

Chapter 7
Supporting Material and References

7.1 Supporting Material

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Appendix A

Peer Reviewer Comment Letter

Summary of Peer Reviewer Comments for the Hydraulic Fracture Study: PXP Inglewood Oil Field

Prepared for

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Prepared by

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October 3, 2012

FINAL REPORT

Context

In May, 2012, the authors of this report were selected by the County of Los Angeles (the "County") and Plains Exploration & Production Company ("PXP") as peer reviewers for the *Hydraulic Fracturing Study: PXP Inglewood Oil Field* prepared by Cardno-ENTRIX (the "consultant"). This report and peer review resulted from the Baldwin Hills CSD litigation Settlement Agreement.

Based on the direction provided in Term 13 of the Settlement Agreement, the objective of the peer review is to review the work of the independent consultant and provide advice to the consultant and a final evaluation to the County and PXP in order to provide an accurate and verifiable study:

> *The peer reviewer will be provided with access to all the data and materials provided to the independent expert. The peer reviewer shall agree to keep all proprietary information confidential. If the peer reviewer determines that the study is materially inadequate, incomplete or inaccurate, it shall so advise PXP's consultant who will complete the study as reasonably recommended by the peer reviewer and provide the revised study to the peer reviewer within 90 days. Upon acceptance by the peer reviewer, the study and all supporting material, including comments by the peer reviewer, shall be forwarded to the County, DOGGR, the Regional Water Quality Control Board ("RWQCB"), CAP and Petitioners and be available to the public, with any proprietary information redacted.*

In June, 2012, we began the process of reviewing the data used to develop the study, evaluating reports drafts and conducting a two day visit the site to get a perspective on the site context. What follows is a summary of the iterative process of review, advice and evaluation that led to the completion of the final study. Upon completion of the review, we both feel, based on information provided us and our own experience, that the report is adequate, complete and accurate and reflected thoughtful consideration for our comments and suggestions.

Process

We received the report draft of the study on July 14th, 2012 in compliance with the Settlement Agreement. We were also provided access to all data, research and reports used to assemble this draft at this time. We completed an initial review of the draft and the background material and developed comment and advice. These comments were communicated over a period of weeks rather than as one single response as we worked independently and then in coordination with each other and the contractor. This process allowed a number of key points to be refined based on effective criticism. The consultant responded by providing a revised draft for our review and advice. From this draft, we provided further advice and comment. The final study therefore reflects this iterative peer review process rather than a single review and response that typify journal peer review. Ultimately, the final report is more responsive to our input than may have been otherwise.

Throughout this process, we strived to offer thoughtful and timely input into the evaluation and provide advice to the consultant on ways to improve the study and ultimately to consider whether the report was materially adequate, complete and accurate. In this memo, we tried to be cognizant of this charge and summarize the process, advice and evaluation.

Evaluation of the Draft Reports

Overall Impression: For the first draft of the report, both of us concluded that the report's organization was overly complex which might have made it difficult for a general audience to understand. We found ourselves losing some key concepts due to the flow. We suggested that certain chapters be combined and that the flow reflect a time relationship. This request led the consultant to produce a second draft reflecting the reorganization. The number of chapters went from 11 to 7 in total. With this consolidation and reorganization, the second draft was far more understandable for the non-technical reader.

The major consolidations involved creating a chapter called "Environmental Effects Monitored in Conjunction with Hydraulic Fracturing Tests" by combining two chapters that split the environmental effects into two parts. Also, the overall discussion of hydraulic fracturing was taken from two chapters to one covering "past, present and future." Finally, a single regulatory chapter captured both the regulatory framework of various jurisdictions and public concerns with operations that were originally two separate chapters. This new report structure carries to the final version.

The study benefits from the tremendous amount of available data. Given the field's long history of production, there is a significant amount of data available to assess the geological and operating conditions at the field. In addition to the historic data, the current operator conducted two fully-monitored hydraulic fracturing operations and two high-rate gravel packs. Other available data includes a number of reports on geological characterization, environmental evaluations, potential community impacts, and regulations. The draft report did a reasonable job presenting a summary of this vast database. We offered some suggestions of ways to streamline the material presented to enhance readability.

Completeness: Both the first and revised draft were quite comprehensive and for the most part complete. A few areas found to be lacking in the first draft included the following:

1. Given the relevance of fluid migration to this topic, we felt that the consultant needed to expand the discussion of hydraulic connectivity given in the first draft. In the revised draft, the discussion was combined into one clear section discussing this important topic.
2. The first draft was lacking a truly representative geological cross section of the field along with a geologic map. A sequence of cross sections providing a better visualization and a geologic map of the field appeared in the revised draft.
3. Being that our experience is primarily in the northeastern USA and Canada, we thought that a better discussion was needed on how this field compares to those outside of California where many of these issues have arisen.
4. Many figures lacked scales, adequate figure captions, and legends. In the revised draft, these items were improved. Annotation was added to the remaining figures for the final report.
5. We suggested a revised discussion of induced seismicity to include the relevance of the 1983 Coalinga earthquake to potential hydraulic fracturing in the, deeper thrust-faulted, pre-Pliocene units of the Inglewood field in light of similar geologic settings and regional stress regimes. This was included in section 4.5.5.

Also, there were a few key resources were not included in the draft that, if included, could help the reader understand the issues involved with hydraulic fracturing including Frolich 2012, Myers 2012, NRC earthquake study 2012, USGS 2012, and Warner 2012. Most of our suggested references were incorporated into the revised draft and many of these references were used to respond to our concerns above.

Adequacy: As mentioned, the draft report was extremely comprehensive. There were a few areas that we did not feel were completely adequate:

1. The diagrams showing the geologic structure at the field are difficult to understand and interpret. We requested that these should be redone or the text should be expanded to explain the visual. The final draft accomplishes this.
2. The oil fields of California and this field particularly are not similar to the fields of either Texas or the northeast. This distinction needed to be adequately explained to put the discussion of environmental issues in context. The revised draft did a much better job of this.
3. The regulatory section initially did not focus on the key elements of California in a way that made it clear to us how operations are regulated. The revised draft

combined sections and brought California front and center making this much easier to follow.

Accuracy: We did not find any major inaccuracies in either draft though there were some specific statements that were either inaccurate or contradictory and needed revision. Also, there were a few statements that lacked supporting evidence and could be questioned for accuracy. We requested that these statements be corrected or supporting evidence be provided. In response to our comments the author corrected statement in revised draft or provided a rationale for leaving the text as is that satisfied our inquiry.

Topic-Specific Report Comments

In addition to the numerous typographical edits and suggestions, there were some topic-specific comments that we spent considerable time reviewing. These topics include geology, induced fractures, seismicity, environmental issues, and regulation.

Geology: We had some issues with the readability of the diagrams for non-technical audiences. The first draft included one diagram which did not convey the complexity of the field as described by the work of Elliot and others (2009). The final version includes all three of their cross sections and the description. This helps to explain the geological conditions in the field much better and helps put the 3D visualizations in context. Blade-like features in the subsurface of several of the diagrams were unexplained and easily misinterpreted as fracture orientation. These features actually represent the distribution of proppant for the hydraulic fracturing stages. The final draft clarifies this with better legends.

Induced Hydraulic Fractures: We had some trouble understanding the discussion of the height and orientation of the induced hydraulic fractures from the two Nodular Shale tests. We suggested clarification of height of induced fractures to read height of zone of induced fractures. This change was made in the final draft.

Seismicity: In addition to the comment on page three, we requested some discussion of how the operator designs the surface infrastructure for hydraulic fracturing to mitigate the impact of a seismic event similar to what occurred at Coalinga. The final draft includes a description of the required standards for structures and other surface equipment.

Environmental Issues: The report covered the environmental issues typically identified with hydraulic fracturing but these issues were spread among a few chapters. We suggested that they be combined into one chapter.

One issue that we commented on was the potential for fluid migration. The first draft did approach this topic but we felt that a clearer description needed to be included regarding why the geology limited fluid movement. In the revised report, the information presented and the flow of the discussion better explains why the lack of hydraulic connectivity minimizes the potential for fluid migration off of the site.

Since air emissions releases are of concern, the air quality section needs to be as comprehensive as possible. The draft report covered this topic well in three different chapters. We suggested that this might be more effective if most of this information could be condensed into the environmental effects chapter. This was accomplished in the reorganization of the revised draft.

There are a number of issues with hydraulic fracturing that are actually common to any oilfield operation regardless of the completion method. This includes many of the community impacts such as traffic and noise. The Baldwin Hills CSD EIR covers many of these common issues. Though we did not suggest that this study repeat the contents of the EIR, we felt that some reference should refer the reader to the appropriate EIR documents.

Regulation: The first draft covered regulations but we felt that the section should be reorganized so California regulation was covered first and that comparisons with other jurisdictions be made to California. Upon revision, the new regulation section accomplishes this effectively. The comparison table with the New York SGEIS is particularly useful to identify specific issues such as spill containment that were identified as important issues in the New York process.

Concluding Comments and Final Report Evaluation

Through the iterative review process, our comments, questions and criticisms were integrated into study in ways that, we feel, improved the final product. As peer reviewers, it is not our charge to become coauthors but to offer suggestions for improvement based on our expertise. In the end, the work remains that of the authors.

As the endpoint of the peer review process, the County and PXP has asked us to make a determination as specified in the Settlement Agreement:

> "If the peer reviewer determines that the study is materially inadequate, incomplete or inaccurate, it shall so advise PXP's consultant"

On September 30, 2012 we received from the consultant the final report for review and acceptance. Upon review, we both feel, based on information provided us and our own experience, that the report is adequate, complete and accurate and reflected thoughtful consideration for our comments and suggestions. This document serves as our final advice to the consultant, the County and PXP.

The Reviewers:

John P. Martin, Ph.D.

John is the founder of JPMartin Energy Strategy LLC which provides strategic planning, resource evaluation, project management and government/public relations services to the energy industry, academic institutions and governments. Prior to forming JPMartin Energy Strategy LLC in 2011, John spent 17 years working on energy research and policy issues at the New York State Energy Research and Development Authority and developed a series of projects targeting oil and gas resources, renewable energy development and environmental mitigation. He currently serves on the USDOE's Unconventional Resources Technical Advisory Committee. While at NYSERDA, he co-directed the Governor's Carbon Capture and Sequestration (CCS) Working Group, an interagency committee organized in 2007 to address CCS issues and served as point person on a series of technical studies looking at all aspects of hydraulic fracturing and multiwell pad development. John regularly lectures and publishes on such diverse topics as the shale resources development, carbon capture and sequestration, compressed-air energy storage, renewable energy resource development, and research policy. Prior to joining NYSERDA, he worked in academia, consulting and regional planning. He holds a Ph.D. in Urban and Environmental Studies, an M.S. in Economics and a B.S. in Geology, all from Rensselaer Polytechnic Institute. He also holds an M.B.A. from Miami University and completed graduate work in mineral economics at West Virginia University.

Peter D. Muller, Ph.D., C.P.G.

Independent consulting geologist specializing in structural geology, geologic mapping, and geologic data analysis. Presently researching subsurface migration of fluids in the northern Appalachian Basin and the relationship to hydraulic fracturing. Senior Geologist with Alpha Geoscience (2010-2012) concentrating on shale gas development in NY and PA. Professor of geology at the State University of New York at Oneonta (1983-2009; Chair 1999-2003) teaching courses in structural geology, map and field geology, engineering geology, mineral resources, waste management, physical geology, and environmental science. Worked as a staff geologist for Dames and Moore Consultants (1973-1975) and the Maryland Geological Survey (1980-1982). Peter received his BS in geology from Bucknell University (1971) and PhD in geology from Binghamton University (1980). He has extensive geological field experience in a wide range of settings, both domestic and international, and has published peer-reviewed research (articles and maps) on the structure, petrology, and tectonics of the Maryland Piedmont, the Adirondack Mountains of New York, and the Ruby and Blacktail ranges of southwest Montana.

Appendix B

Chemical Additives Used and FracFocus Reports

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	9/15/2011
State:	California
County:	Los Angeles
API Number:	0403726720
Operator Name:	Plains Exploration & Production
Well Name and Number:	VIC 1-330
Longitude:	-118.379139976
Latitude:	34.006457093
Long/Lat Projection:	NAD83
Production Type:	Oil
True Vertical Depth (TVD):	8,030
Total Water Volume (gal)*:	168,210

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
7% KCL Water	Operator				100.00%	86.77644%	Density = 8.700
SAND - PREMIUM WHITE	Halliburton	Proppant	Crystalline Silica, Quartz	14808-60-7	100.00%	3.70605%	
PRC SAND	Halliburton	Proppant	Crystalline Silica, Quartz	14808-60-7	100.00%	8.59803%	
			Hexamethylenetetramine	1009-7-0	2.00%	0.17196%	
			Phenol / Formaldehyde Resin	900303-35-4	5.00%	0.42990%	
SSA-2	Halliburton	Sand	Crystalline Silica, Quartz	14808-60-7	100.00%	0.35578%	
FR-66	Halliburton	Friction Reducer	Hydrotreated Light Petroleum Distillate	64742-47-8	30.00%	0.01335%	
LOSURF-300M™	Halliburton	Surfactant	1,2,4 Trimethylbenzene	95-63-6	1.00%	0.00079%	
			Ethanol	64-17-5	60.00%	0.04763%	
			Heavy Aromatic Petroleum Naphtha	64742-94-5	30.00%	0.02382%	
			Naphthalene	91-20-3	1.00%	0.00079%	
			Poly(oxy-1,2-Ethanediyl), Alpha-(4-Nonylphenyl)-Omega-Hydroxy -,Branched	127087-87-0	10.00%	0.00794%	
CL-28M CROSSLINKER	Halliburton	Crosslinker	Crystalline Silica, Quartz	14808-60-7	5.00%	0.00249%	
			Borate Salts	Proprietary	60.00%	0.02989%	
MO-67	Halliburton	Buffer	Sodium Hydroxide	1310-73-2	30.00%	0.00283%	
BA-40L BUFFERING AGENT	Halliburton	Buffer	Potassium Carbonate	584-08-7	60.00%	0.03990%	
FE-1A ACIDIZING COMPOSITION	Halliburton	Misc Additive	Acetic Acid	64-19-7	60.00%	0.00255%	
			Acetic Anhydride	108-24-7	100.00%	0.00425%	
K-38	Halliburton	Crosslinker	Disodium Octaborate Tetrahydrate	12008-41-2	100.00%	0.02099%	
LGC-36 UC	Halliburton	Gelling Agent	Guar Gum	9000-30-0	60.00%	0.16582%	
			Naphtha, Hydrotreated Heavy	64742-48-9	60.00%	0.16582%	
BE-3S BACTERICIDE	Halliburton	Biocide	2,2 Dibromo-3-Nitrilopropionamide	10222-01-2	100.00%	0.00119%	
			2-Monobromo-3-Nitrilopropionamide	1113-55-9	5.00%	0.00006%	
OPTIFLO-III DELAYED RELEASE BREAKER	Halliburton	Breaker	Ammonium Persulfate	7727-54-0	100.00%	0.00889%	
			Crystalline Silica, Quartz	14808-60-7	30.00%	0.00267%	
SP BREAKER	Halliburton	Breaker	Sodium Persulfate	7775-27-1	100.00%	0.00237%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

All component information listed was obtained from the supplier's Material Safety Data Sheets (MSDS). As such, the Operator is not responsible for inaccurate and/or incomplete information. Any questions regarding the content of the MSDS should be directed to the supplier who provided it. The Occupational Safety and Health Administration's (OSHA) regulations govern the criteria for the disclosure of this information. Please note that Federal Law protects "proprietary", "trade secret", and "confidential business information" and the criteria for how this information is reported on an MSDS is subject to 29 CFR 1910.1200(i) and Appendix D.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	1/5/2012
State:	California
County:	Los Angeles
API Number:	0403726421
Operator Name:	Plains Exploration & Production
Well Name and Number:	VIC1 635
Longitude:	-118.3771225
Latitude:	34.00234951
Long/Lat Projection:	NAD83
Production Type:	Oil
True Vertical Depth (TVD):	8,430
Total Water Volume (gal)*:	125,248

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
7% KCL Water	Operator				100.00%	81.77644%	Density = 8.700
SAND - COMMON WHITE	Halliburton	Proppant	Crystalline silica, quartz	14808-60-7	100.00%	1.42615%	
SAND - PREMIUM WHITE	Halliburton	Proppant	Crystalline silica, quartz	14808-60-7	100.00%	4.30405%	
CRC SAND	Halliburton	Proppant	Crystalline silica, quartz	14808-60-7	100.00%	9.98805%	
			Hexamethylenetetramine	1009-7-0	2.00%	0.19976%	
			Phenol / formaldehyde resin	900303-35-4	5.00%	0.49940%	
LOSURF-300M™	Halliburton	Surfactant	1,2,4 Trimethylbenzene	95-63-6	1.00%	0.00079%	
			Ethanol	64-17-5	60.00%	0.04763%	
			Heavy aromatic petroleum naphtha	64742-94-5	30.00%	0.02382%	
			Naphthalene	91-20-3	1.00%	0.00079%	
			Poly(oxy-1,2-ethanediyl), alpha-(4-nonylphenyl)-omega-hydroxy-, branched	127087-87-0	10.00%	0.00794%	
K-38	Halliburton	Crosslinker	Disodium octaborate tetrahydrate	12008-41-2	100.00%	0.02099%	
FR-66	Halliburton	Friction Reducer	Hydrotreated light petroleum distillate	64742-47-8	30.00%	0.01335%	
SandWedge® NT	Halliburton	Conductivity Enhancer	Dipropylene glycol monomethyl ether	34590-94-8	60.00%	0.29738%	
			Heavy aromatic petroleum naphtha	64742-94-5	10.00%	0.04956%	
BA-40L BUFFERING AGENT	Halliburton	Buffer	Potassium carbonate	584-08-7	60.00%	0.03990%	
CL-28M CROSSLINKER	Halliburton	Crosslinker	Crystalline silica, quartz	14808-60-7	5.00%	0.00250%	
			Borate salts	Confidential Business Information	60.00%	0.02995%	
FE-1A ACIDIZING COMPOSITION	Halliburton	Misc Additive	Acetic acid	64-19-7	60.00%	0.01278%	
			Acetic anhydride	108-24-7	100.00%	0.02130%	

LGC-36 UC	Halliburton	Gelling Agent	Guar gum	9000-30-0	60.00%	0.16582%	
			Naphtha, hydrotreated heavy	64742-48-9	60.00%	0.16582%	
MO-67	Halliburton	Buffer	Sodium hydroxide	1310-73-2	30.00%	0.00283%	
BE-3S BACTERICIDE	Halliburton	Biocide	2,2 Dibromo-3-nitrilopropionamide	10222-01-2	100.00%	0.00285%	
			2-Monobromo-3-nitrilopropionamide	1113-55-9	5.00%	0.00014%	
K-38	Halliburton	Crosslinker	Disodium octaborate tetrahydrate	12008-41-2	100.00%	0.01902%	
SP BREAKER	Halliburton	Breaker	Sodium persulfate	7775-27-1	100.00%	0.01949%	

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** Information is based on the maximum potential for concentration and thus the total may be over 100%

Ingredient information for chemicals subject to 29 CFR 1910.1200(i) and Appendix D are obtained from suppliers Material Safety Data Sheets (MSDS)