

# Effectiveness of Microseismic Monitoring for Optimizing Hydraulic Fracturing in California

by

Ann M. Alampi

Submitted to the Department of Earth, Atmospheric and Planetary Sciences

in Partial Fulfillment of the Requirements for the Degree of

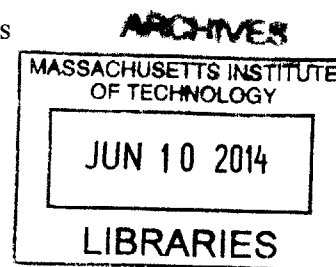
Bachelor of Science in Earth, Atmospheric and Planetary Sciences

at the Massachusetts Institute of Technology

May 11, 2014

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## **Abstract**

Hydraulic fracturing has fundamentally changed the oil and gas industry in the past 10 years. Bakersfield, California provides a unique case study because steam injection, a type of hydraulic fracturing, has been used there for more than 60 years. Seven companies, varying in size and strategy, use steam injection in California. Some of these companies use microseismic monitoring technologies to maximize production from hydrocarbon reservoirs. In this study, the effectiveness of microseismic monitoring to maximize production in California is explored. This is accomplished by comparing trends in oil and gas production volumes with each company's use of microseismic monitoring. This project found that operators that use microseismic most extensively have not achieved a competitive advantage over other operators. This means that substantial investments in monitoring research, installation and data interpretation have not paid off and may not be worthwhile. This result should help companies improve their current projects and shape future investment decisions.

Thesis supervisor: Michael Fehler

## **Acknowledgments**

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## I. Introduction

21<sup>st</sup> century development of unconventional hydrocarbon production techniques (hydraulic fracturing and directional (nonvertical) drilling) has driven an increase in oil and gas production in North America. United States oil production grew by 18% in 2013 and is at its highest level since 1988 (Energy Information Administration, 2014; Harvey & Loder, 2013). It is now expected that the United States will become the world's highest volume crude oil producer by 2015 (Gold, 2014). This is a significant change, considering that, since the 1950s, US oil production volumes declined until the beginning of the early 21<sup>st</sup> century (Energy Information Administration, 2014). In the 21<sup>st</sup> century, oil and gas companies<sup>1</sup> created an economical method to access increased volumes of hydrocarbons by drilling in directions that are not vertical (i.e. “directionally” or “horizontally,” see Figure 1). Using today's available technologies, from 2011 to 2013 alone, recoverable crude oil resources have increased by 35% in the US and 11% globally (Energy Information Administration, 2013). Between 2011 and 2013, recoverable natural gas resources have increased by 38% in the US and 47% globally (Energy Information Administration, 2013).

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<sup>1</sup> These companies are sometimes referred to as “firms,” “producers,” or “operators”

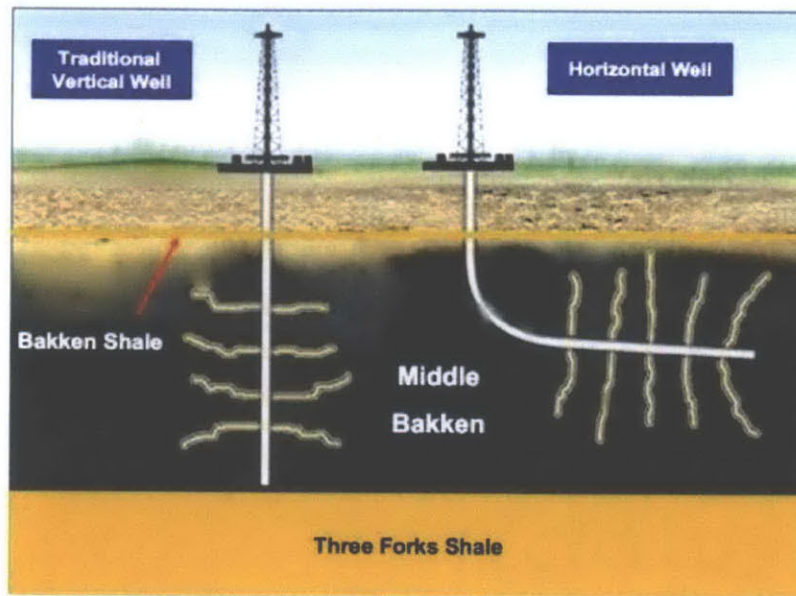


Figure 1: A conventional, vertical well compared to an unconventional, horizontal well. In the early 21<sup>st</sup> century, the technology to drill horizontally became economical and effective enough for widespread use in the United States. This has allowed access to (up to 47%) higher volumes of oil and natural gas (Energy Information Administration, 2013). An example of each type of well is shown in the figure above (the vertical well is on the left, horizontal on the right). (Image source: “Environmentally Friendly Drilling Systems.”)

Operators can then access the previously unattainable reservoirs by stimulating (“fracking”<sup>2</sup>) them. Fracking involves pumping pressurized water into a well, which opens fractures in rock, releasing oil and gas (see Figure 2). Mixtures of water, sand (“proppants,” see Figure 3) and, sometimes, chemical lubricants are injected to increase permeability, widen the fractures and reduce friction. Thus the fractures create pathways for oil and gas to migrate from the reservoir to the well.

<sup>2</sup> Synonyms for “fracking” include “hydrofracking,” and “hydraulic fracturing”

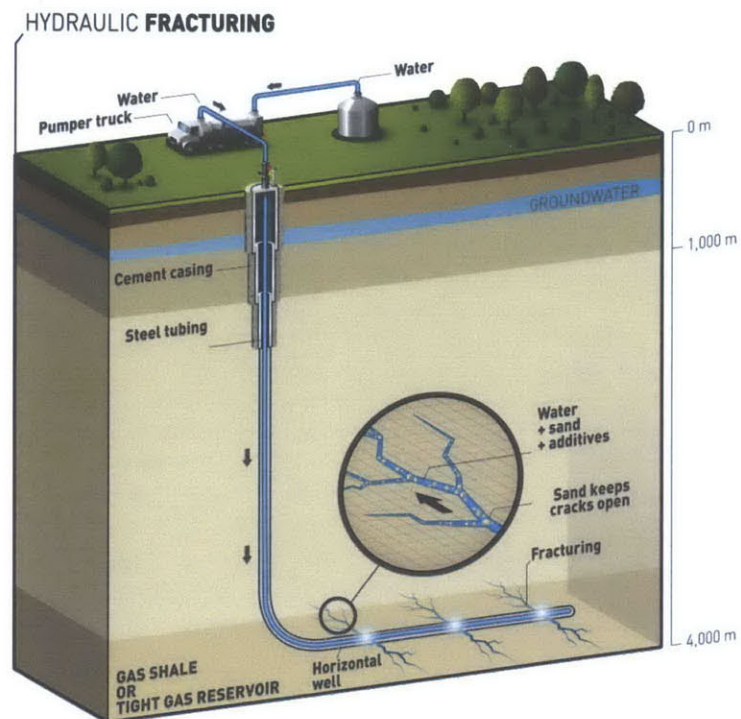


Figure 2: A fracked horizontal well with water pumped into it. Along the horizontal part of the well, there are holes in the steel tubing and cement casing that surround the well. A slurry of water, sand and additives exit the well into the surrounding rock, opening fractures in rock. (Image source <http://en.skifergas.dk/media/99887/Hydraulic%20Fracturation%20Schematic.jpg>)



Figure 3: A zoomed-in view of a microfracture in rock that is held open by grains of sand or of a small, manufactured solid. This solid is known as a “proppant.” (Image source: <http://www.wintershall.com/en/press-news/domestic-production.html>)

In the second half of the 20<sup>th</sup> century, a type of fracking that involves steam (instead of liquid water) was developed. This process is called steam injection and it involves three main stages (see Figure 4). The first stage is injection, when steam is pushed into the well and down into the reservoir. The second stage is soaking, which is a period of change to the rock and hydrocarbons due to increased temperature and pressure. During soaking, the steam pressurizes the surrounding rock (fracturing it) and heats both the rock and hydrocarbons. The increase in temperature decreases the density and viscosity of the hydrocarbons. In stage 3 (production), the less dense, less viscous hydrocarbons rise to the surface.

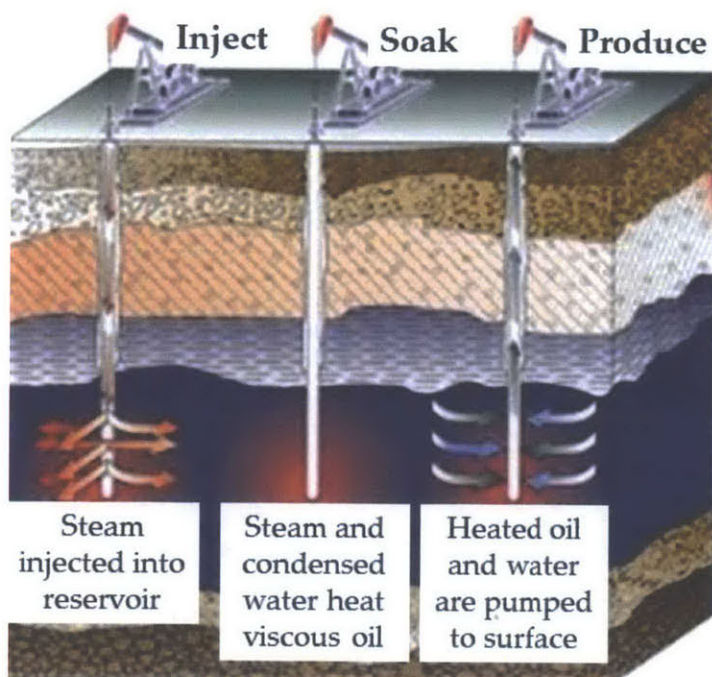


Figure 4: Illustration of the three stages of steam injection. In this type of fracking, steam is the fluid injected into the well. The heat of the steam makes the hydrocarbons less dense and less viscous. Then the heated oil and condensed water are pumped to the surface, producing oil from the well (Image source: <http://www.catspawdynamics.com/cyclic-steam-stimulation>)



Horizontal drilling and hydraulic fracturing (using liquid water) have been increasingly used in the early 21<sup>st</sup> century, growing especially quickly in North Dakota's Bakken formation (see Figure 5) and in many Texas formations (such as the Eagle Ford and the Barnett Shale). Taking the Bakken as an example, oil production increased from 100,000 barrels per day in 2008 to over 600,000 barrels per day in 2012. This is a huge change when compared to all of North Dakota's other reservoirs, which produced a fairly steady 100,000 barrels per day from 2005 through 2012 (see Figure 5).

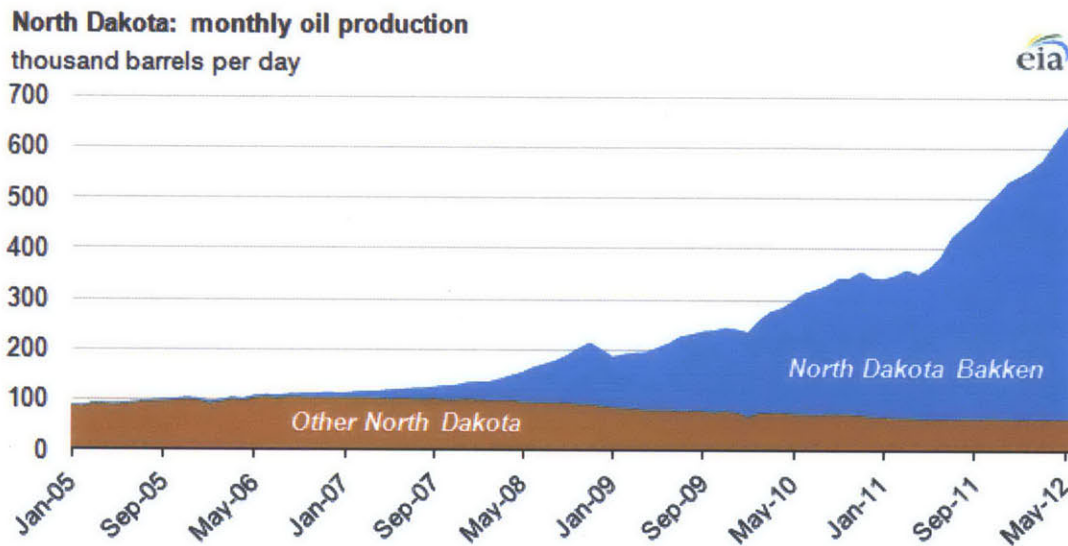


Figure 5: The incredibly fast growth in production due to fracking in the North Dakota Bakken oil reservoir. (Image Source: <http://www.eia.gov/todayinenergy/detail.cfm?id=7550&src=email>)

As oil and gas companies' production volumes increase, they seek advantages over their competitors that would make their production increase even more. They strive to understand how to optimize well production and become more efficient, either by reducing their costs or increasing their revenue (which is directly proportional to their production). A critical part of optimizing well production is the understanding of underground structures of reservoirs and the

channels through which the reserves flow. Knowing more about the flow of oil and gas through fracture networks would help them estimate expected production and make investment decisions. Modeling the hydraulic fracture network allows producers to anticipate production from individual wells and to be informed when they make high-stakes investment decisions.

Many companies use microseismic monitoring to make predictions about hydraulic fracture networks' effects on well performance. Microseismic monitoring uses geophones to gather data to help model the geometry of hydraulic fractures and the volume of stimulated rock (Maxwell, 2011). However, some factors that contribute to well productivity are still not fully understood and the interpretation of microseismic models can vary widely. This variation makes it difficult for the leadership of oil and gas companies to make investment decisions, so it is in their best interest to know whether (and to what extent) microseismic monitoring analysis benefits them.

This study explores the effectiveness of microseismic monitoring and other methods for maximizing production from unconventional resources in California. This project's goal is to compare trends in oil and gas productivity with the use of microseismic monitoring. Professional geophysicists with operators in California indicate that data from microseismic monitoring are difficult to interpret. Therefore, interpreting models built from microseismic monitoring may not be a reliable way to make investment decisions.

Hydrocarbon reservoirs in California diatomites present a complex challenge for decision-makers. Diatomite rock is mainly composed of the siliceous shells of single-cell plants called diatoms (Minner et al., 2002). Diatomite's microstructure is disordered and creates large variations in reservoir properties with depth (Barenblatt, Patzek, Prostokishin, & Silin, 2002;

Minner et al., 2002). Oil production from California's diatomite reservoirs began 40 years ago, with the advent of hydraulic fracturing (Barenblatt et al., 2002). Operators in the diatomites in the San Joaquin Valley near Bakersfield, California use steam injection to hydraulically fracture the formation (Barenblatt et al., 2002). A paper by researchers from Mobil explains that steam injection is appropriate for shallow reservoirs (as found in California diatomites) with high porosity (40 to 70%), low permeability (.1-1md), and high concentrations of heavy oil (Barenblatt et al., 2002; Murer et al., 2000). The properties of diatomite make hydrocarbon production and understanding of fracture systems very difficult (Barenblatt et al., 2002).

Since 2001, some operators have been drilling non-vertical holes and, most recently, have been drilling horizontally (as is done in Texas and North Dakota) (California Department of Conservation, 2014). The long history and ample public data relating to steam fracturing in California make it a meaningful case study. By comparing several companies operating in California's Lost Hills Diatomite, this research provides analysis of the strategies that are successfully and unsuccessfully used to optimize well production.

## II. Methods

In order to compare trends in oil and gas productivity with the use of microseismic monitoring, data about hydrocarbon production were needed. We chose to examine the Lost Hills Diatomite because California's public well and production data were easily accessible at no cost, and because of that area's established, widespread history of steam injection. These data were accessed online at the State of California's Division of Oil, Gas and Geothermal Resources (well data were found at <http://www.conservation.ca.gov/dog/maps/Pages/GISMapping2.aspx> and production volumes were found at <http://opi.consrv.ca.gov/opi/opi.dll>). All data were publicly available. Therefore, no proprietary data were used for this study. California divides its records by geographic districts, and hydraulic fracturing is mainly used in District 4 (Figures 6 and 7). Data were downloaded in Microsoft Excel format and processed using Excel.

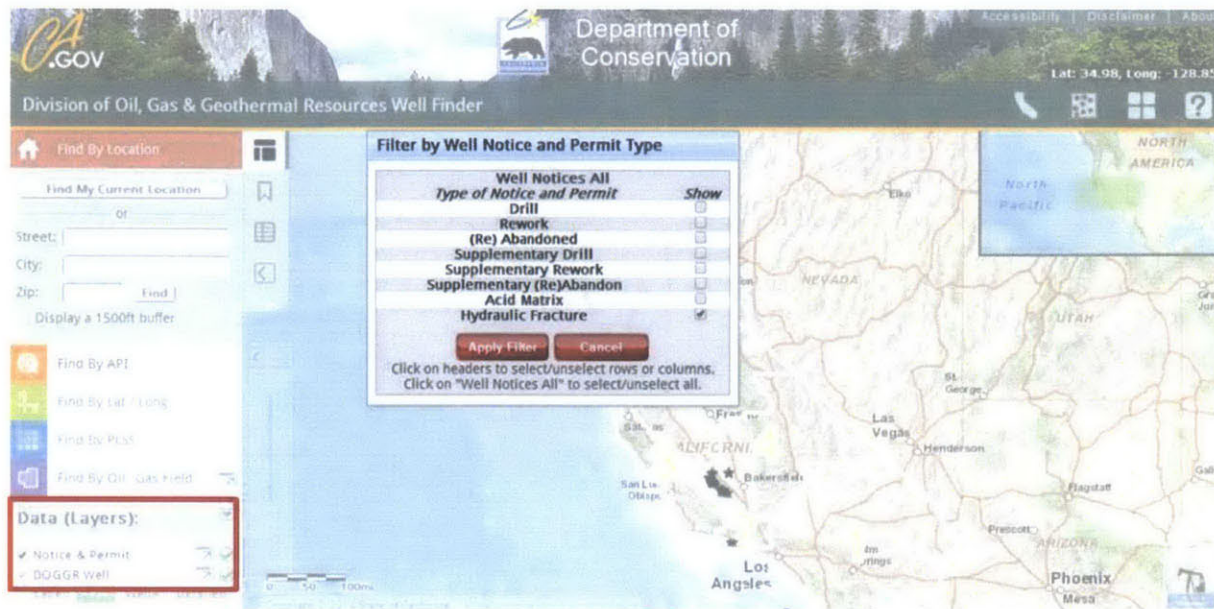


Figure 6: Selection process for viewing only the hydraulically fractured wells out of all California wells. Layers of data can be adjusted using the State of California's Division of Oil, Gas and Geothermal Resources web site (at <http://maps.conservation.ca.gov/doggr/index.html>). Navigating to the area in the bottom left, outlined in red, and clicking on the box with an arrow next to "Notice & Permit" brings up the "filter by well notice and permit type" option. Deselecting every "show" option except "Hydraulic Fracture" displays permits for Hydraulic Fracturing.

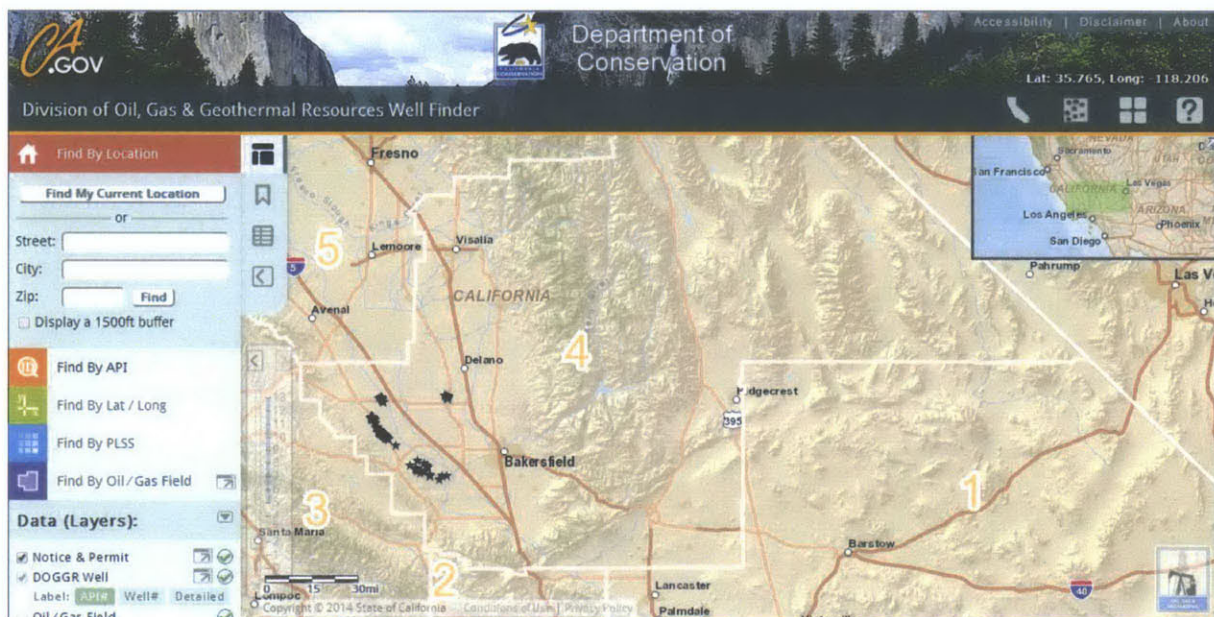


Figure 7: Shows a map of wells from the same web site as Figure 6. Making the selections described in the Figure 6 caption displays only those wells with Hydraulic Fracturing permits. These wells are clustered in the Bakersfield area, noted by the black stars. These are in California District 4, which is defined by the boundaries of Inyo, Kern and Tulare Counties. This image is zoomed to provide more detail about District 4.

Production volumes from individual wells were not available publicly at the time of this research. Therefore, as shown in Appendix A, we used the sum of each operator's oil and gas production volume in District 4 (California Department of Conservation, 2014). We also determined the percentage of each operator's total District 4 wells that were hydraulically fractured (by dividing each operator's hydraulically fractured well count by their total number of wells). In order to count the number of hydraulically fractured wells, we used the Excel Spreadsheet's column of the well data called "Hydraulically Fractured" (HF=="Y" for yes or "N" for No) and selected only the data entries where HF == Y (California Department of Conservation, 2014).

Selecting only the HF==Y entries revealed that there are seven companies that are fracking in California District 4. Therefore, those seven companies are the only companies relevant to our study. When analyzing trends over time, we chose the appropriate time period based on each oil and gas company's disclosures on the use of fracking and horizontal drilling technologies. To choose the appropriate time range for each operator, we again used the GIS Mapping Well Data to select for HF==Y. We then sorted the data chronologically (using the "Spud Date" column) and determined the first year in which each operator fracked and directionally/horizontally drilled five or more wells (see example in Figure 8). Table 1 contains the time range for each operator we studied.

1	OperatorName	Hydraulically Fractured	SPUDDate	DirectionalStatusCode
55	Aera Energy LLC	Y	9/23/2000	Directionally drilled
56	Aera Energy LLC	Y	11/18/2000	Directionally drilled
57	Macpherson Oil Company	Y	1/20/2001	Directionally drilled
58	Aera Energy LLC	Y	1/29/2001	Directionally drilled
59	Aera Energy LLC	Y	2/19/2001	Directionally drilled
60	Aera Energy LLC	Y	5/22/2001	Directionally drilled
61	Aera Energy LLC	Y	5/25/2001	Directionally drilled
62	Aera Energy LLC	Y	6/12/2001	Directionally drilled
63	Aera Energy LLC	Y	7/15/2001	Directionally drilled
64	Aera Energy LLC	Y	8/10/2001	Not Directionally drilled
65	Aera Energy LLC	Y	8/19/2001	Horizontally drilled
66	Aera Energy LLC	Y	8/24/2001	Directionally drilled
67	Aera Energy LLC	Y	12/20/2001	Not Directionally drilled
68	Vintage Production California LLC	Y	2/4/2002	Directionally drilled
69	Aera Energy LLC	Y	3/10/2002	Directionally drilled
70	Aera Energy LLC	Y	6/16/2002	Directionally drilled
71	Aera Energy LLC	Y	6/18/2002	Directionally drilled
72	Aera Energy LLC	Y	6/19/2002	Directionally drilled
73	Aera Energy LLC	Y	9/12/2002	Not Directionally drilled
74	Aera Energy LLC	Y	9/21/2002	Not Directionally drilled
75	Aera Energy LLC	Y	11/24/2002	Directionally drilled
76	Vintage Production California LLC	Y	1/7/2003	Not Directionally drilled
77	Vintage Production California LLC	Y	3/11/2003	Not Directionally drilled

Figure 8: Example of choice for each operator’s relevant time range. Aera Energy LLC’s Year that fracking began is considered to be 2001 because that was the first year in which they fracked more than five directionally/horizontally drilled wells (in District 4 of California). This is based on the column named “spud date,” which indicates the first date of drilling. The yellow highlights the eight wells that were directionally/horizontally drilled and fracked. In 2001, Macpherson Oil Company was the only other operator that fracked a well, but they only fracked one well, so their Year that fracking began was later than 2001.

**Table 1: Choice of time range for each operator**

Operator Name	Year that fracking began	Number of fracked, directionally/horizontally drilled wells in that year
Aera Energy LLC	2001	8
Vintage Production California LLC	2008	2 + 3 “unknown directional status”
ExxonMobil Corporation	2010	8 “unknown directional status”
Chevron U.S.A. Inc.	2011	6
Occidental of Elk Hills, Inc.	2011	13
Breitburn Operating L.P.	2013	1 + 4 “unknown directional status”
Macpherson Oil Company	Dates not listed	1 in 2013, 4 directionally drilled in unknown years

Year that fracking began is considered the first year in which an operator fracked and directionally/horizontally drilled at least five wells. The different operators disclose somewhat different information, so the “number of fracked...” column provides notes on the instances when directional status is unknown. Macpherson Oil Company does not provide dates for many of their fracked wells.

In order to compare the performance of the seven operators, we needed a way to compare their success (their growth in production volume) due to fracking. Each operator publicly provides a sum of volumes of oil and natural gas produced by all of their wells in District 4. The procedure for finding these data online is explained in Appendix A. In order to compare the performance of the operators, we assumed that their goal is to produce the most oil and gas possible. We then used Microsoft Excel to graph each operator's oil production volumes from 2000 until the year in which they began fracking. The only exceptions to this choice of time range were Aera (who began fracking in 2001, so we graphed their production starting in 1995) and Vintage (who was the next company to begin fracking, in 2008, so we also graphed their data from 1995 on). We then graphed their production volumes from their first year of fracking through the most recent data (usually from 2013 or early 2014) that were available. Using Microsoft Excel's "trend line" feature, we created a linear fit for the pre-fracking and post-fracking production data, and compared the slopes. This provided us with a metric to compare their production growth/decline rate before they began fracking and after they began fracking. The slope since each operator began fracking tells us the company's rate of production growth in recent years.

Comparing the pre-fracking and post-fracking slopes tells us how dramatically different the recent rate of production growth is from growth/decline in pre-fracking years. We were able to quantify the impact of fracking by calculating the change in slopes:

$$\text{Change in oil or gas slope} = \text{post-fracking slope} - \text{pre-fracking slope}$$



In order to compare trends in productivity with the use of microseismic monitoring<sup>3</sup>, information about the use of microseismic is needed. Detailed microseismic data are generally proprietary and there are no publications that specify its use in the Monterey Shale. Therefore, we use public information, especially Google Scholar results for papers about microseismic written by employees of the seven operators (see example in Figure 9). Google Scholar results were the most quantifiable means to compare the various operators (compared to reading each company's website, our conversations with researchers at these companies and the client lists of microseismic service companies). Therefore, our metric about microseismic modeling use is the number of Google Scholar search results for each company's name + microseismic. We also searched for each company's name + microseismic + California. In the case of Aera Energy, which is a joint venture between Shell and ExxonMobil, we added the number of search results for "Aera Energy" to the number of results for Shell and ExxonMobil.

Before we performed the Google Scholar searches, a geophysicist at Chevron<sup>4</sup> indicated to us that tiltmeters are a more common monitoring technology in California. Therefore, we also performed Google Scholar searches for each company's name + tiltmeter. The search results (shown in Figure 10) shaped our methods going forward: in-depth study of the use of tiltmeters would not add value to our study or change our conclusions.

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<sup>3</sup> "Microseismic monitoring" is often abbreviated to "microseismic" in the oil and gas industry

<sup>4</sup> Personal correspondence with Andrei Popa, Chevron, April 2014

Google Scholar

Search: "aera energy" microseismic california

10 results (0.63 sec)

Articles

Case law

My library

Any time

Since 2014

Since 2013

Since 2010

Custom range

Sort by: relevance

Sort by: date

include patents

include citations

Create alert

**Use of INSAR in surveillance and control of a field project**  
 TW Patzek, DB Silin · 2009 · eScholarship.org  
 ... information of surface displacement over a giant oil field in California, USA  
 Using ... **Aera Energy** has paid for and provided to Berkeley the equipment  
 and ... 9 citations · D. Patzek, TW Rector, JW and Veegar, HJ. **Microseismicity**  
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**The Belridge Giant Oil Field: 100 Years of History and a Look to a Bright Future**  
 ME Allan, JJ Laicata · Oral presentation given at the ... 2011 · www.searchanddiscovery.com  
 Allan, Malcolm E · 1 · Laicata, Joseph J · 1 (1) **Aera Energy** LLC, Bakersfield, CA, ... of the well that  
 discovered the Belridge giant oil field in the San Joaquin Valley of California ... drives in the oil  
 sands and in the diatomite shales, installation of a large **microseismic** array, distributed ...  
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**of the Distal Margin of a Fanshaped Turbidite Reservoir—The ARCO-DOE 91X-3  
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**Water Injection into a Low-Permeability Rock: 1 Hydrofracture Growth**  
 TW Patzek, DB Silin · Transport in Porous Media, 2001 · Springer  
 ... Rd, MS 90-1116, Berkeley, CA 94720, USA 2University of California, Berkeley, Materials ... three  
 remote listening wells with multiple cemented geophones to triangulate the **microseismic** events  
 during ... (1996) used the same geophone array to triangulate **microseismicity** during ...  
 Cited by 20 · Related articles · All 14 versions · Web of Science · Cite · Save

Lossy transmission line model of hydrofractured well dynamics

**"Aera Energy" Microseismic California**

**10 results**

[PDF] from springer.com  
 Full text · MIT Libraries

[PDF] from utexas.edu

Figure 9: An example search for an operator name + microseismic + California. We performed this search for each operator and recorded the number of search results. We also performed this search without the word "California," and by substituting "microseismic" with the name of another monitoring technology, "tiltmeters." (Image source: [http://scholar.google.com/scholar?hl=en&q=%22aera+energy%22+microseismic+california&btnG=&as\\_sdt=1%2C22&as\\_sdtp=](http://scholar.google.com/scholar?hl=en&q=%22aera+energy%22+microseismic+california&btnG=&as_sdt=1%2C22&as_sdtp=))

### III. Results

Google Scholar searches for each operator were performed and demonstrated that there is variety in their level of monitoring technology use (see Table 2, Figure 10 and Figure 11). The operator with the highest level of monitoring technology use is Aera Energy, followed by Chevron, ExxonMobil and Occidental. Google Scholar searches for each of those companies resulted in several hundred, even thousands of papers. In contrast, Breitburn, Vintage and Macpherson all returned three or fewer papers.

**Table 2: Comparison of operators based on their number of research papers related to monitoring technology**

Level of use of monitoring technology	Operator Name	Number of search results for “Operator name + Microseismic/Tiltmeter + California”
Highest	Aera (as Aera + ExxonMobil + Shell search results)	2658
High	Chevron	612
High	ExxonMobil	519
Middle	Occidental	389
Lowest	Breitburn	1
Lowest	Macpherson	0
Lowest	Vintage	0

The number of published papers is used as a proxy for the level of use of monitoring technology. Source: Google Scholar search of “*Name of Company* microseismic California” and “*Name of Company* tiltmeter California” e.g. “‘Aera energy’ microseismic California.”

### Google Scholar search results for “Operator Name” + “Technology Name”

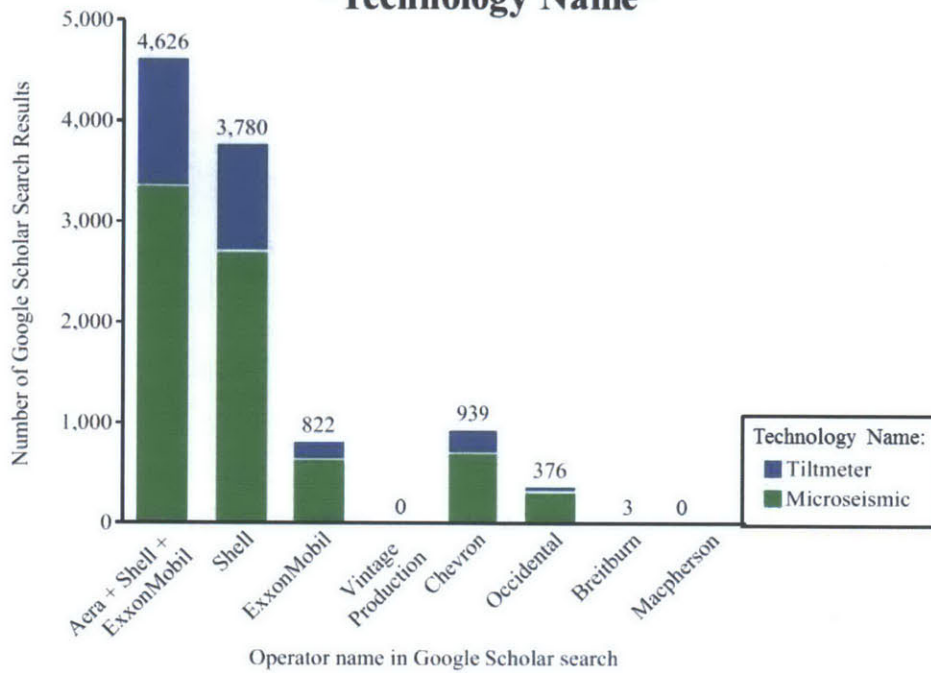


Figure 10: Number of Google Scholar search results for each operator and monitoring technology. Although Shell does not frac in California, the number of search results for Shell is important because Aera is a joint venture between Shell and ExxonMobil. Therefore, Aera is presumed to benefit from Shell’s knowledge and use of microseismic monitoring, and the number of Shell search results is included in the sum of Aera + Shell + ExxonMobil search results.

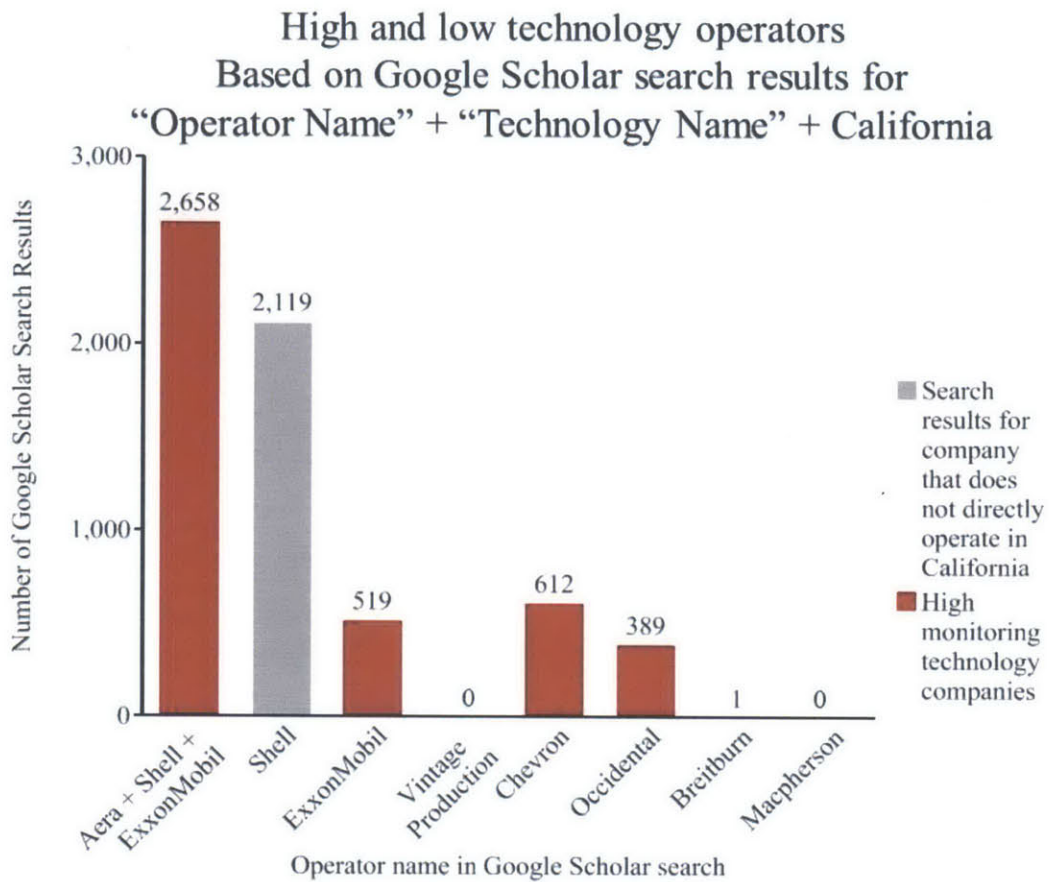
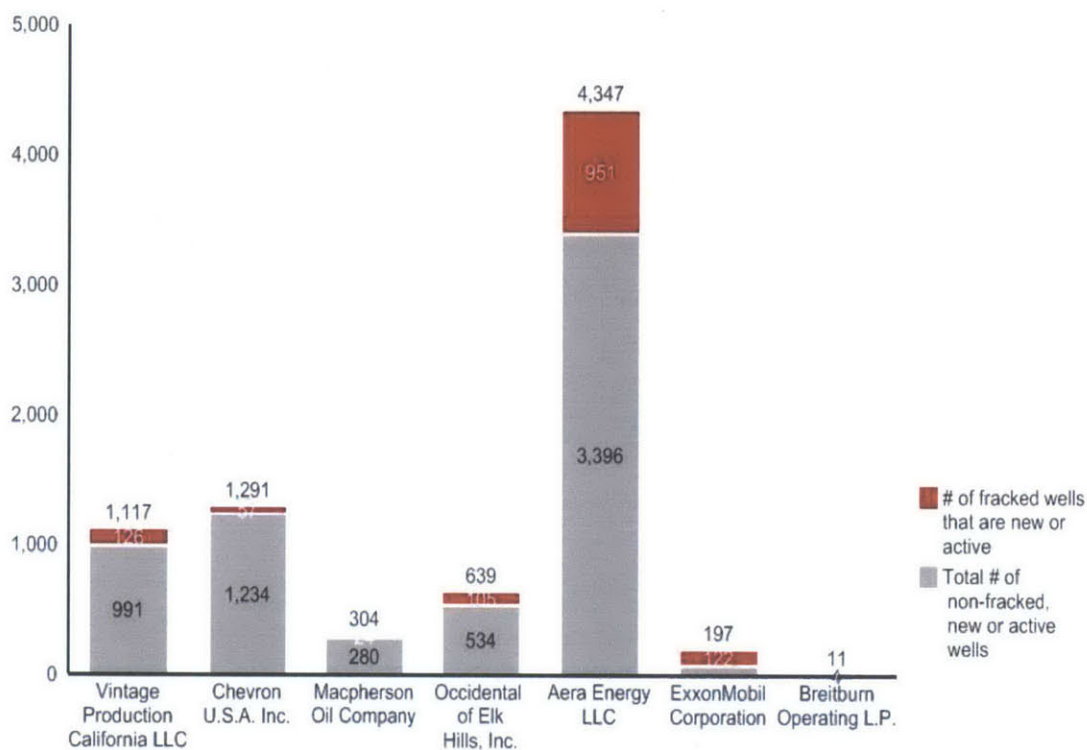


Figure 11: Number of Google Scholar search results for each operator, each monitoring technology and California. The red bars indicate which of the operators that frac in California use monitoring technologies the most. Shell is not included because they do not frac in California (the number of search results for Shell is important because Aera is a joint venture between Shell and ExxonMobil, benefiting from Shell’s knowledge and use of microseismic monitoring, so the number of Shell search results is included in the sum of Aera + Shell + ExxonMobil search results).

Number of wells with spud dates since first year of fracking



Percentage of fracked wells out of total new + active wells						
11%	4%	7%	16%	22%	62%	64%

Figure 12: Comparison of fracked and non-fracked wells that have been drilled since each company’s first year of fracking. Percentages listed below indicate the percentage of fracked wells out of the total wells for each bar in the histogram. Refer back to Table 1 for information on each operator’s Year that fracking began. Each bar shows a total number of wells that have been drilled in this time period (e.g. the count of Aera wells includes all currently active wells that have been drilled since 2001, whereas the count of Vintage Production wells only includes active wells drilled since 2008). Each bar is divided into fracked (red) and non-fracked (grey) wells.

In order to analyze the impact of microseismic monitoring on production success, we noted from Figures 11 and 12 that there is one main operator (Aera Energy) that has used a high level of microseismic monitoring (2658 Google Scholar results), has fracked many wells (951

wells since 2001) which is a substantial percentage (22%) of their wells in District 4 of California. In contrast, there is another operator (Vintage Production) that has used the lowest level of microseismic monitoring (0 Google Scholar results), fracked many wells (126 since 2008) representing a substantial percentage (11%) of their wells in District 4. Aera and Vintage were also the first two operators to both frac and directionally drill at least five wells, so they have the most established history of any of the operators in this part of California. Therefore, these two companies became our choice for further analysis and comparison.

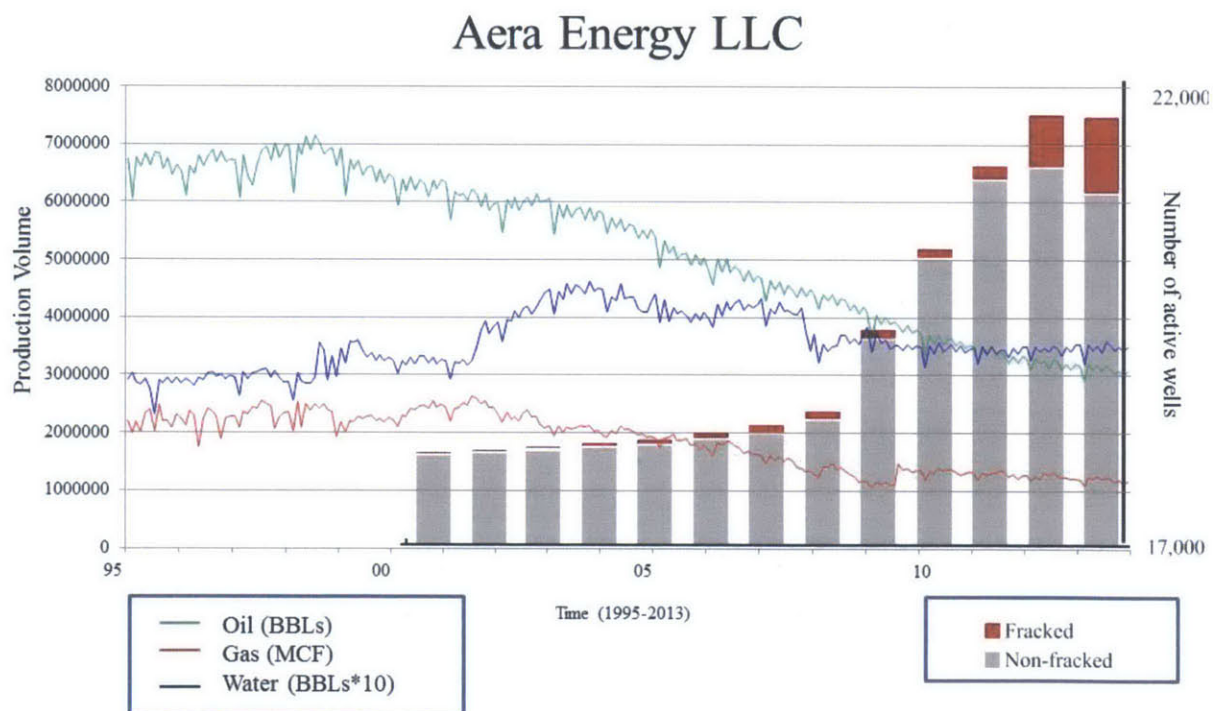


Figure 13: Oil, gas and water production volumes for Aera Energy since 1995, superimposed over a histogram of the number of active wells (fracked and non-fracked) each year since the year that fracking began. Aera Energy has increased the total number of active wells and the number of active fracked wells each year between 2001 and 2012. However, production volumes have decreased most years between 2001 and 2012. Aera changed the trend of its oil and gas production volumes from steeply negative to slightly less steeply negative (in the case of oil) and shallowly negative (in the case of gas).

Analysis of Aera's production volumes over time (Figure 13) shows that, despite a rapid increase in the total number of wells and the number of fracked wells, Aera's production has been declining for over a decade. This led us to ask whether Aera's production is declining any less rapidly now that it is pressured by its surrounding competitors' progress in learning to frac since 2008. Calculating the slopes of oil and gas production over time (Figure 14) reveals that Aera has been declining more slowly since 2008.

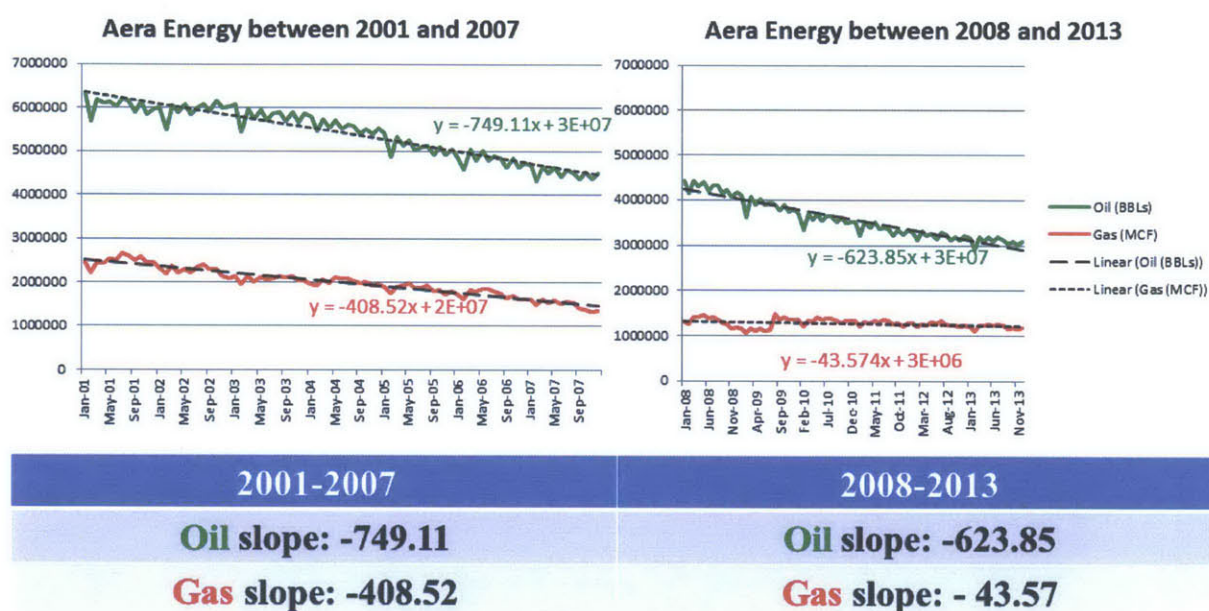


Figure 14: Pre- and post-entrance of fracking competitors comparison of trends in production volume for Aera Energy. As observed in Figure 13, the slope of oil and gas production changes in 2007, which is just before other companies (beginning with Vintage Production) began fracking in District 4 of California. This closer look at trends in production volume shows the linear fit to pre-2007 and post-2007 oil and gas production volumes.

In comparison, Vintage Production has turned its production volumes around. As shown in Figures 15 and 16, oil and gas production volumes were declining from year to year between 2001 and 2008. However, after Vintage began fracking in 2008, both oil and gas production rapidly increased.



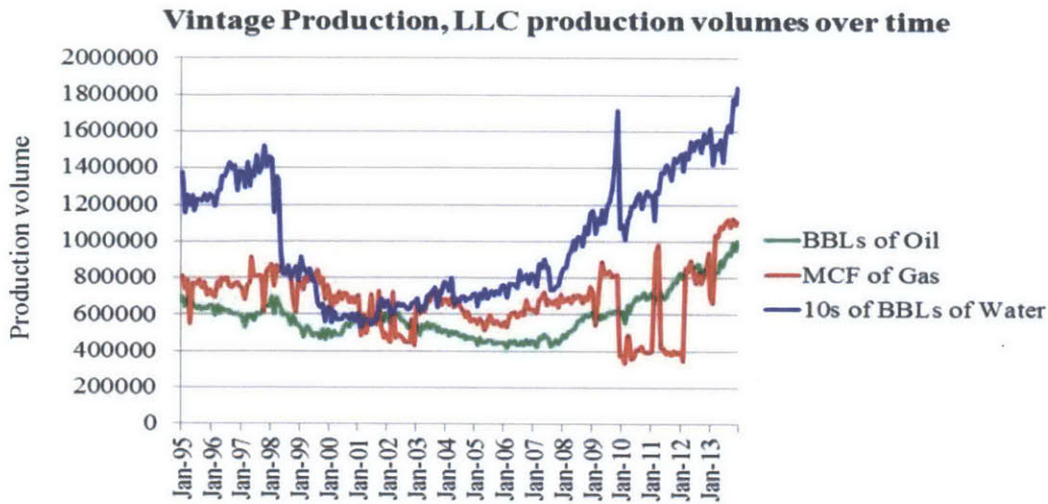


Figure 15: Oil, gas and water production volumes for Vintage Production since 1995. Vintage Production has changed the trend of its oil and gas production volumes from shallow (and, in the case of oil, negative) to steeply positive.

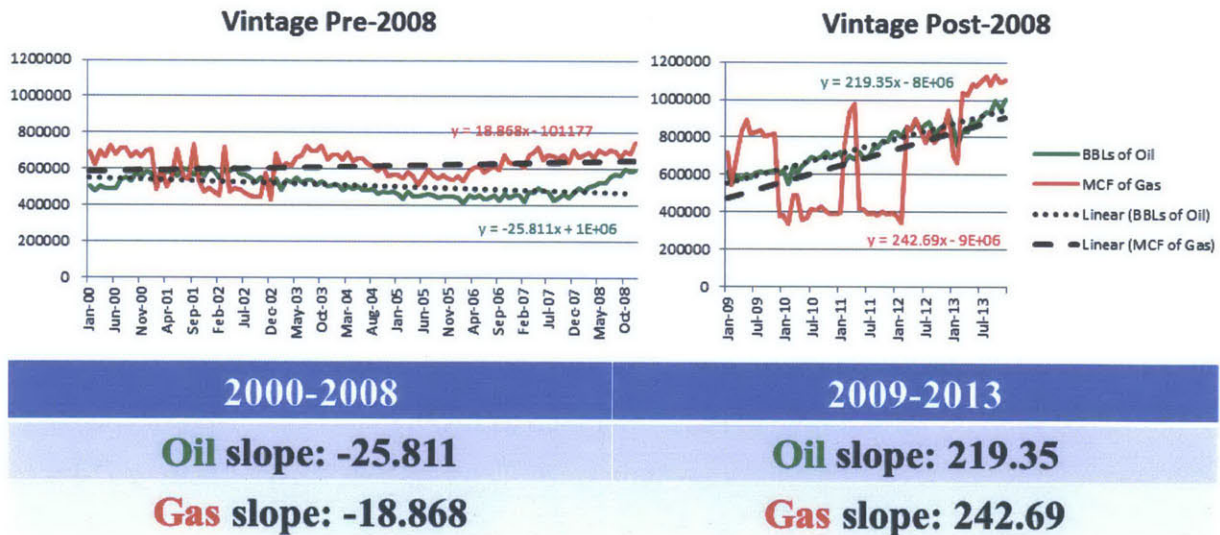


Figure 16: Pre- and post-fracking comparison of trends in production volume for Vintage Production. This closer look at trends in production volume shows the linear fit to pre-2008 and post-2008 oil and gas production volumes.

A side-by-side comparison of Aera and Vintage (Table 3) uses the change in oil and gas slopes to quantify the impact that fracking has had on each company's production growth.

Similarly, Figure 17 plots all seven operators' change in oil slope along the y-axis, comparing the magnitude of change in production growth (or decline) due to fracking with the extent of microseismic monitoring use and the percentage of total wells in District 4 that are fracked.

**Table 3: Change in oil and gas slope, pre- and post-fracking for Vintage Production compared to Aera Energy**

High-tech = Aera	Low-tech = Vintage
Slopes for oil	Slopes for oil
Pre-2007: -749.11	Pre-2008: -25.811
Post-2007: -623.85	Post-2008: 219.35
<b>&gt;&gt;Change in oil slope (trend) = 125.26</b>	<b>&gt;&gt;Change in oil slope (trend) = 245.161</b>
Slopes for gas	Slopes for gas
Pre-2007: -408.52	Pre-2008: 18.868
Post-2007: -43.57	Post-2008: 242.69
<b>&gt;&gt;Change in gas slope (trend) = 364.95</b>	<b>&gt;&gt;Change in gas slope = (trend) 223.822</b>

Change in oil slope before and after fracking  
(see Table 3 for example)

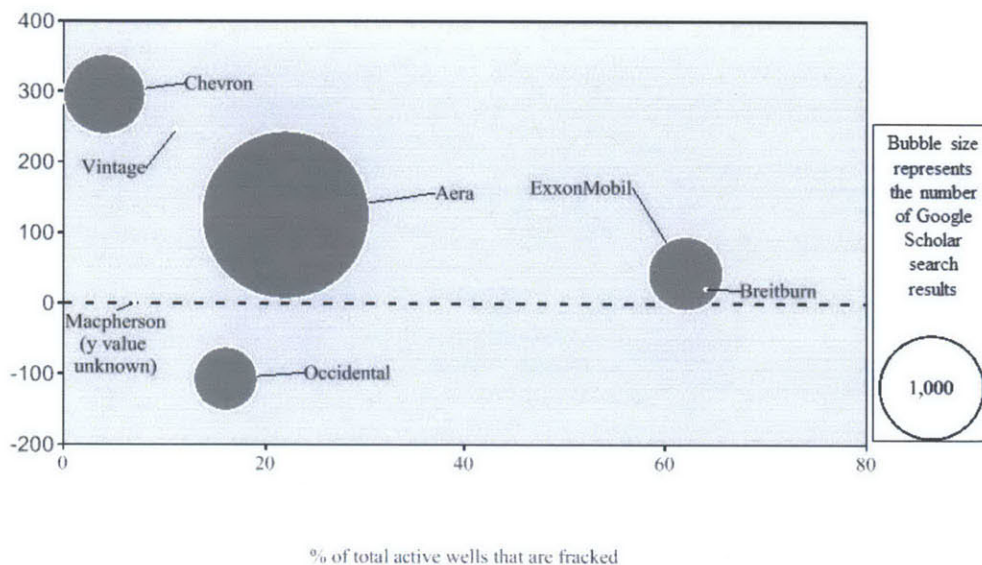


Figure 17: Comparison of all seven operators, with bubble sizes based on the number of Google Scholar search results (for “Operator name” + “technology name” + “California”), x-axis showing the percentage of active wells that are fracked, and y-axis showing the change between the rate of change of oil production over time before and after fracking (i.e. small bubbles represent low monitoring technology operators, low x values indicate that fracked wells represent a relatively small fraction of the operator’s total wells in District 4, and negative y values indicate that production volumes per year have decreased faster since fracking began). For an example of the calculation of y-values, see Table 3. Macpherson’s y-value is unknown because data were not publicly available.

In a similar format to Figure 17, Figure 18 compares all seven operators’ post-fracking oil slopes with the extent of microseismic monitoring use and the percentage of total wells in District 4 that are fracked. Where Figure 17 shows the impact that fracking had on the pre-fracking production growth/decline rate, Figure 18 shows the recent state of each company’s growth/decline in production.

Slope of oil production curve after fracking began

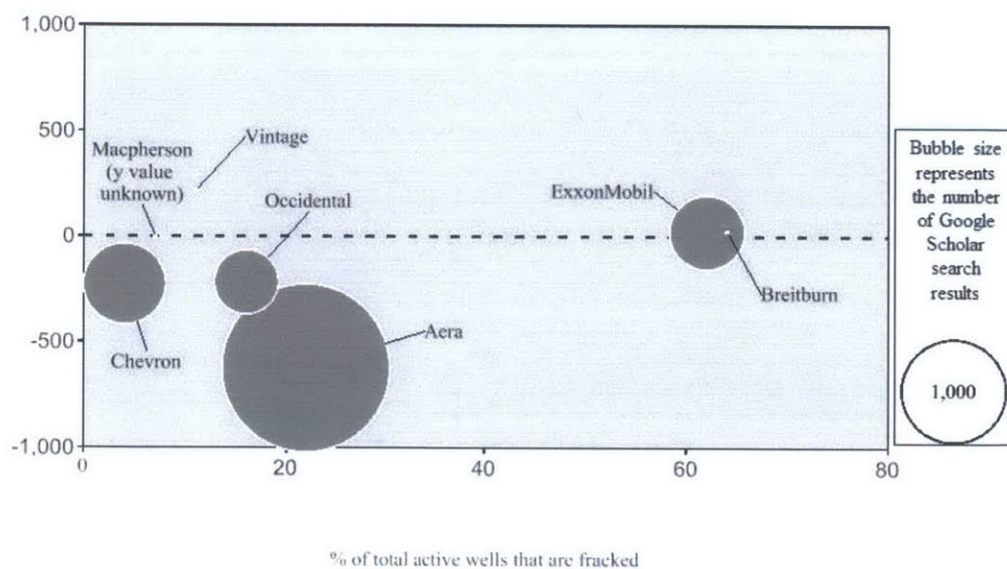


Figure 18: Comparison, similar to Figure 17, of all seven operators. Here, the y-axis represents the slope of the oil production curve for the years since fracking began for each individual operator (as opposed to Figure 17's y-axis of change between the pre-fracking slope and post-fracking slope). Macpherson's y value is still unknown because data were not publicly available.

## IV. Discussion

In Figures 17 and 18, we compare all seven operators on the dimensions of: number of Google Scholar search results for microseismic, percentage of fracked wells out of total wells in California District 4, and rate of change of production over time. Figure 17 shows that operators with high use of microseismic monitoring have not necessarily improved their production levels of oil more quickly than competitors with low use of microseismic monitoring (e.g. ExxonMobil and Breitburn both have comparable percentages of fracked wells out of total wells, have barely increased their rate of production over time, and have very different levels of microseismic use). Figure 18 shows that the companies with the highest use of microseismic monitoring have seen the slowest growth in oil production since they began fracking.

In addition to the broad analysis of all seven operators, we chose Aera and Vintage as case studies for in-depth research. Aera serves as the example of a “high tech” (i.e. high use of microseismic monitoring technology) company, whereas Vintage is an example of a “low tech” operator. The comparison of slopes (see Table 3) for Aera Energy and Vintage Production demonstrates that, in a much shorter time period of fracking, Vintage has improved its rate of change of production volume for oil by much more than Aera. From year to year, Aera’s oil and gas production still decline (as indicated by the negative slopes of both oil and gas post-2007). Aera’s gas production has improved more quickly than Vintage’s (since, as shown in Table 3,  $364.95 > 223.822$ ), but not enough that their gas production would increase from year to year (the post-2007 slope is negative). Vintage is increasing its oil and gas production each year (both post-2008 slopes are positive). This seems to indicate that the higher use of monitoring technology has not provided Aera with a significant competitive advantage.

That is not to say that monitoring may become more advantageous in the future. Aera has 7.5 times as many fracked wells as Vintage, so it is possible that they have only adopted new, efficient monitoring technologies on their newest wells. If Aera continues to improve, it may see further production improvements in upcoming years. However, Vintage has increased production volumes even faster than Aera, so Aera's improvement may even be slowed by their time and resources allocated to microseismic monitoring.

Almost all of the analysis of production volume over time was done by comparing pre- and post-fracking slopes. However, we decided to compare Aera Energy's pre-2007 and post-2007 slopes because, as seen in Figure 13, they did not frac a substantial number of wells or mitigate their decline in production over time until several years after they first began to frac in 2001. We believe that this is because they started to see other competitors drilling more and fracking more in District 4, so they likely made a strategic change around 2007.

We have based our study on the assumption that the major difference (that would be reflected in different production growth levels) between Aera and Vintage is their level of monitoring technology. Other factors may have impacted the differences in production growth rates to a lesser extent. We believe the assumption that monitoring technology is the major influence on production to be valid because it was confirmed during personal correspondence with geophysicists employed by at least three oil and gas companies<sup>5</sup>. However, as influential as microseismic monitoring is on production levels, the geophysicists indicated that there are still challenges in interpreting the data from monitoring and that monitoring is not always an efficient way to make future drilling decisions. Our analysis confirms that Aera may not benefit from its high use of microseismic monitoring.

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<sup>5</sup>These geophysicists wished to remain anonymous.

We also assumed that Aera benefits fully from the technological resources of its two joint owners: Shell and ExxonMobil. We believe that it is a valid assumption that Aera's geophysical research expertise/strategy is most accurately reflected by summing the Google Scholar search results for Aera itself with the results for both Shell and ExxonMobil (see Figures 10 and 11).

Our study would have been improved by access to data for production from fracked wells (rather than the existing data, which are for aggregate monthly production by all wells from each operator, as shown in Appendix A). The analysis shown in Figure 13 shows that an increasing proportion of Aera Energy's wells drilled each year were fracked. Therefore, we assumed that fracked wells were the major factor responsible for an increasing proportion of Aera Energy's oil and gas production.

## V. Conclusion

We asked whether operators' use of microseismic monitoring effectively creates a competitive advantage. Google Scholar search results for each company's microseismic research were used as our quantifiable proxy for the extent of microseismic use by each of the seven companies fracking in California. We also compared the number of wells that each company has fracked, and what percentage of their wells has been fracked to be mindful of the differences in the proportional significance of fracked wells to each company, as compared to non-fracked wells. Using the search results, production volumes and percentages of fracked wells, we saw that, overall, companies that use microseismic monitoring have not grown more quickly than companies that do not use microseismic. Aera Energy and Vintage Production were two companies that fracked most extensively and differed most dramatically in Google Scholar search results. Therefore, we studied Aera Energy as a "high use of monitoring technology" company and Vintage Production as a "low use of monitoring technology" company. We compared the trends in each case study's oil and gas production volumes. After these case studies, we still found that operators that use microseismic most extensively have not achieved a competitive advantage over other operators. This raises questions about whether the investment in microseismic monitoring is worthwhile. Companies should consider this result carefully when deciding on improvements to their current projects and their future investments.



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## Appendix A: Production volumes for each operator over time

Graphs made using <http://opi.consrv.ca.gov/opi/opi.dll>, by selecting District 4, then selecting each operator, clicking “Get Sums,” then “Production Graph.”

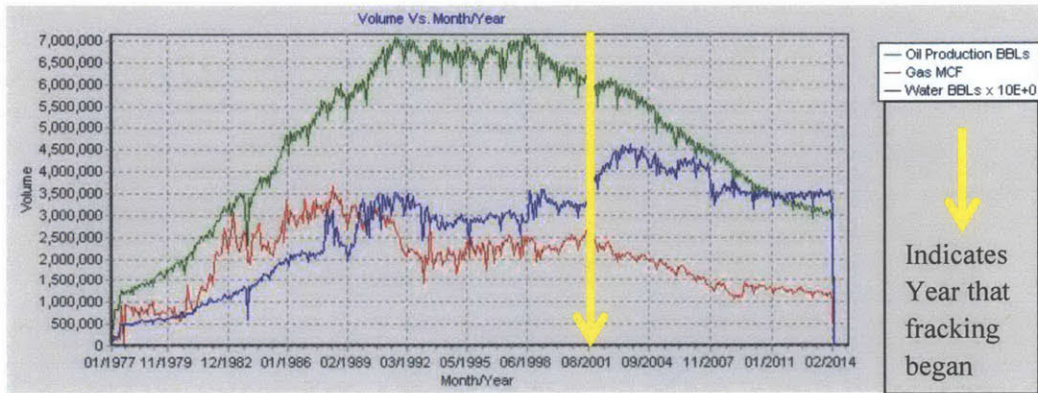


Figure B.1: Aera Energy's district 4 production over time

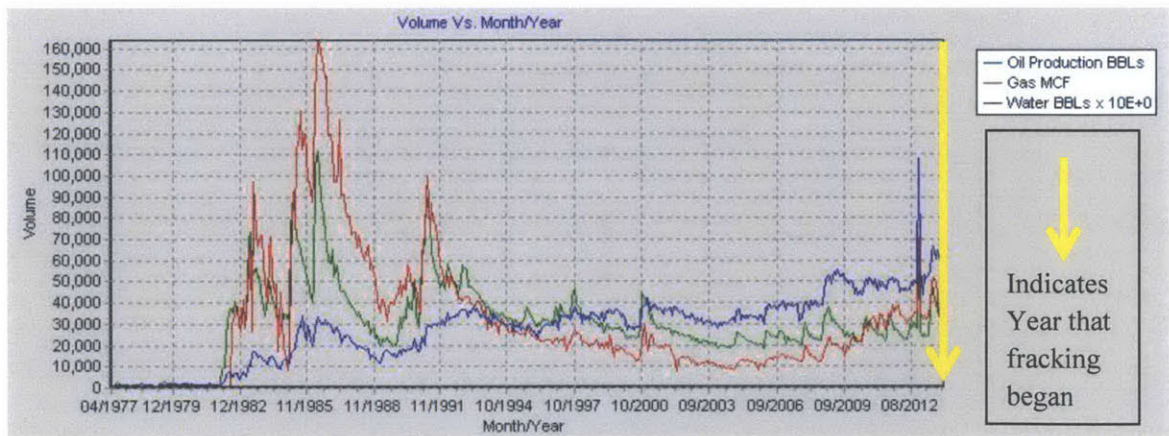


Figure B. 2: Breitburn Operating L.P.'s district 4 production over time

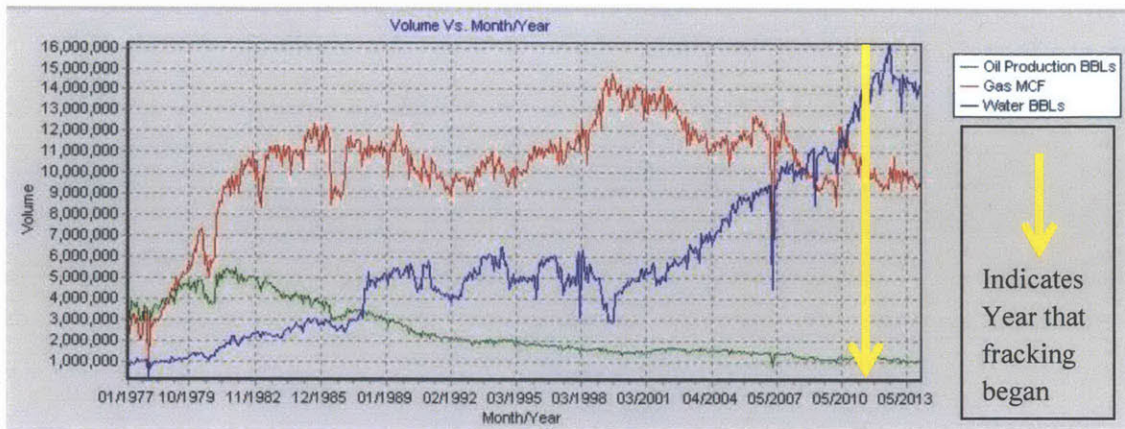


Figure B.3: Chevron district 4 production over time

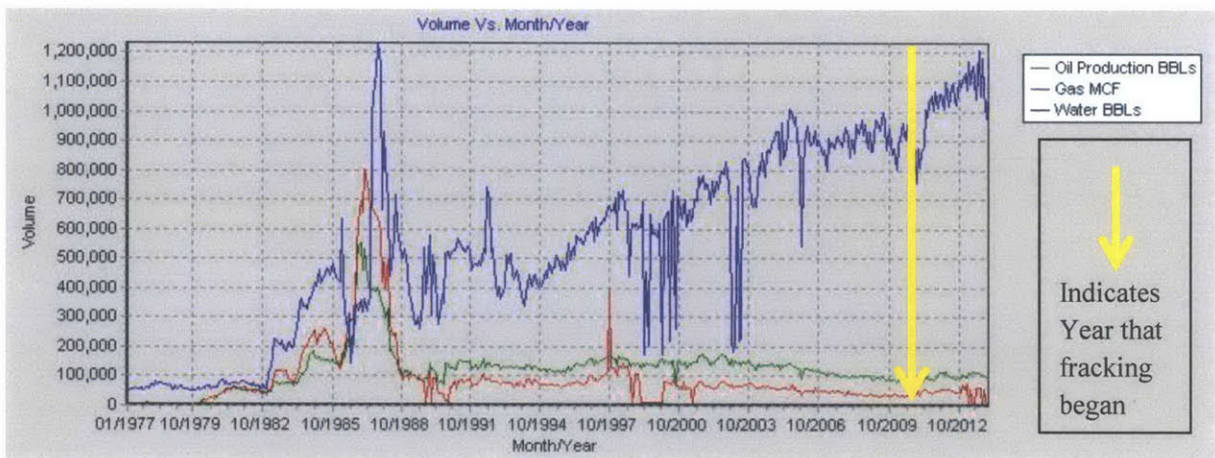


Figure B.4: ExxonMobil district 4 production over time

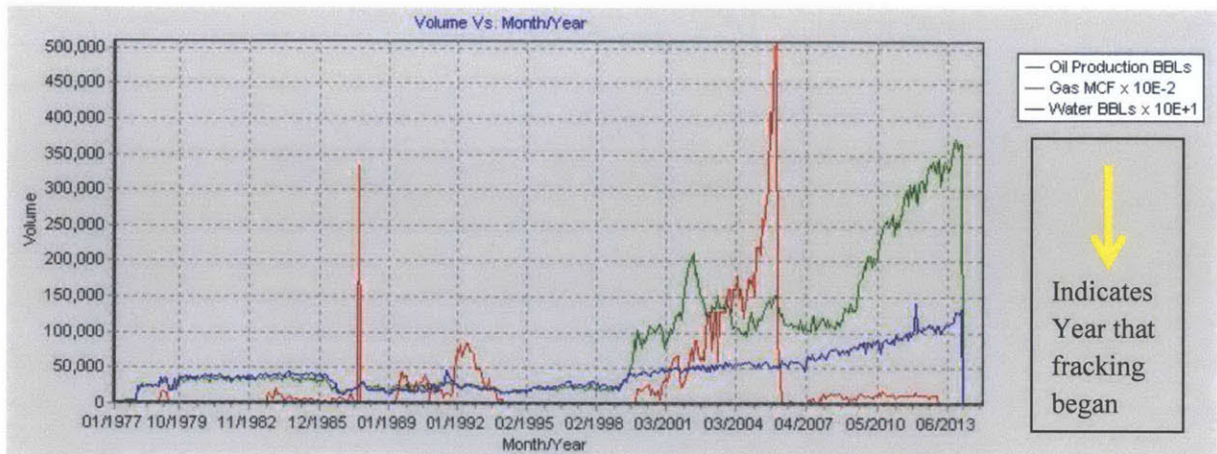


Figure B.5: Macpherson district 4 production over time

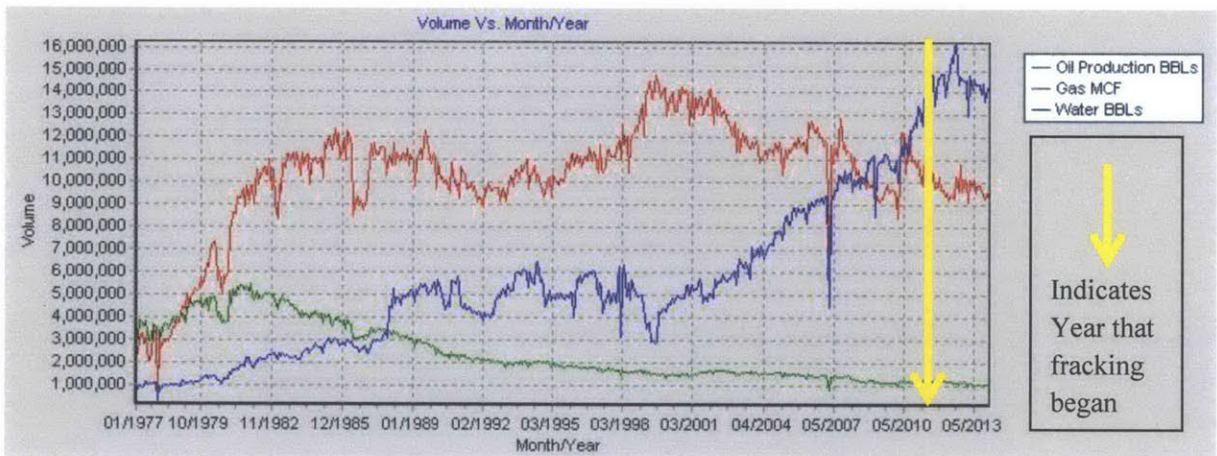


Figure B.6: Occidental district 4 production over time

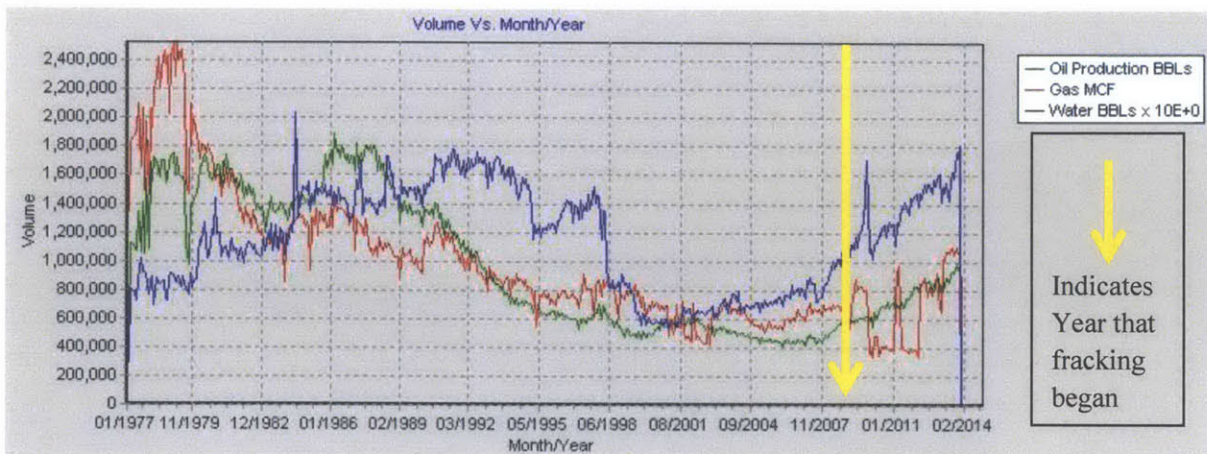


Figure B.7: Vintage district 4 production over time