Hydraulic Fracturing, An Overview

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Received August 08, 2018; Accepted November 20, 2018

Abstract: This article provides an overview of the state of the art in hydraulic fracturing, a controversial topic of the last decade. *To Frack or not to Frack, That is the Question* [1]; this question was posed at a meeting of the Western Regional Society of Petroleum Engineers. The fact is, we have witnessed an intense debate over hydraulic fracturing's economic benefits and its ill effects (perceived or real) during the past decade. Many, in particular those in the fossil energy industry, consider shale oil / gas, with the associated horizontal drilling and hydraulic fracturing, as one of the major developments in the oil and gas industry of the past two decades. Others, especially many environmentalists, consider fracking proponents as public enemy number one.

Different sections of this paper attempt to highlight different scientific facts about hydraulic fracturing, the common-sense environmental concerns, and the respective economic ramifications. After a brief overview of the principals of hydraulic fracturing in section 1, we discuss the importance of hydraulic fracturing in section 2. This is followed by fracture characterization (section 3) and geomechanics (section 4). These sections examine natural fractures in the subsurface and how one can characterize them, how hydraulic fracturing helps to expand the natural fractures and/or create new (stimulated) fractures, and the underlining rock mechanics properties and related stress regime. Section 5 addresses different environmental concerns about hydraulic fracturing. These include potential ground water contamination, amount of water used for hydraulic fracturing, the water disposal process, and methane emission concerns. Another environmental concern is induced seismicity or man-made earthquakes. Given the much publicized controversy on whether and to what extent hydraulic fracturing creates, section 6 is dedicated to covering this issue. Section 7 includes a case history from California, highlighting many of the topics discussed in other sections. The key message of this article is the best way to answer the question with which we began, namely to frack or not to frack, lies with science; the hope is, with sound scientific and engineering investigation, truth will prevail-- "**veritas omnia vincit**."

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DOI: 10.7569/JSEE.2018.629512

Keywords: *Hydraulic fracturing (HF), shale resources, energy resources, micro-seismic data, economic factors, environmental impact of HF, fracture characterization, geomechanics, induced seismicity, ground water contamination, stress field*

1 What is Hydraulic Fracturing?

Hydraulic fracturing (HF) is an oil and gas operation used to recover hydrocarbon resources that are trapped in low-permeability shale and other lithologies. Over geologic time periods, these resources were formed by the maturation of kerogen, the organic precursor of petroleum. However, unlike conventional oil and gas where hydrocarbons migrate into the reservoir from a separate source, the hydrocarbon source and reservoir rock share low permeability, forming unconventional systems. While there are significant volumes of hydrocarbon trapped in unconventional reservoirs, their extremely low natural permeability impedes commercial production using conventional techniques. HF is a process that involves the injection of large volumes of water (several million gallons), sand, and small volumes of chemical additives to increase oil or natural gas flow from low permeability formations. The large pressure associated with the injection of "fracturing fluid" creates new fractures and extends existing fractures that enhance hydrocarbon flow, while sand mixed with injected fluid holds the new and existing fractures open. Some of the injected fluid flows back to the wellbore and is pumped to the surface or injected back to the reservoir. Figure 1 is an example of a typical HF configuration.

HF is usually performed on horizontal or directional wells, oftentimes with the well track being perpendicular to the direction of maximum horizontal in-situ stress. A schematic display of the horizontal well and the enlarged shale fractures are shown in the bottom left part of Figure 1.

Although hydraulic fracturing has been used since the 1950s, over the last decade it has been the subject of intense public debate. Some of the concern has been over its potential impacts on drinking water, the potential for emission of gas, and the associated induced seismicity or man-made earthquakes. For more on various aspects of hydraulic fracturing debate and its benefits and drawbacks see *Hydraulic Fracturing 101* [2], the California Council on Science and Technology's (CCST) report on well stimulation [3], and hydraulic fracturing in Colorado [4].

2 Why Hydraulic Fracturing is Important

Hydraulic fracturing and horizontal drilling have played a key role in making shale a significant part of the fossil energy resources globally, especially in the United States (U.S.). According to the U.S. Energy Information Administration (EIA, 2016)[2], 95 percent of new U.S. wells drilled in 2016 were hydraulically fractured. This accounts for two-thirds of total U.S. natural gas production and about

DOI: 10.7569/JSEE.2018.629512

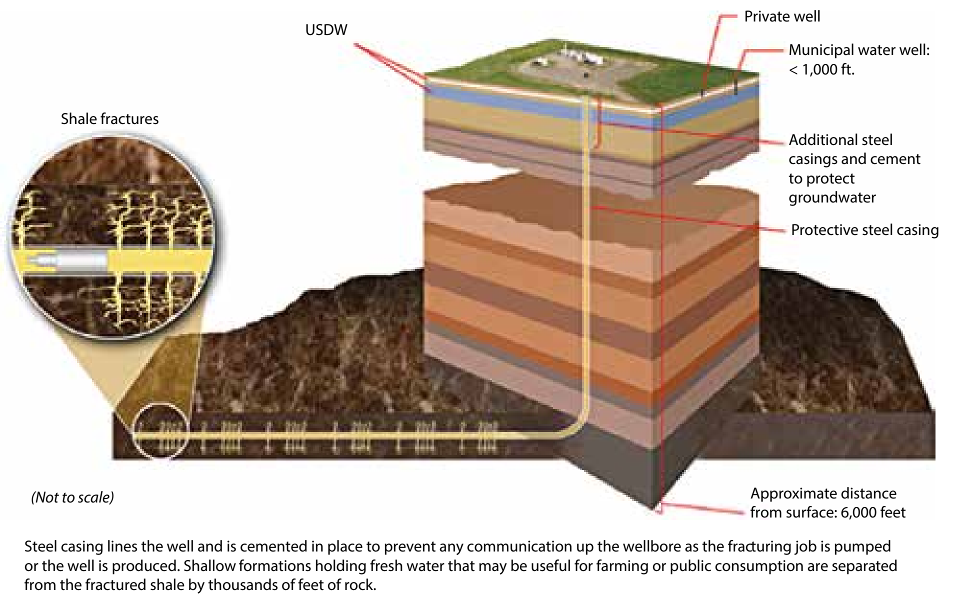

Figure 1 An Example of a Typical Hydraulic Fracturing Configuration [53].

half of U.S. crude oil production. While shale oil and gas has contributed substantially to U.S. reserves and greatly impacted U.S. oil production (increasing by about 3.2 million barrels/day), it is sobering to note that its contribution to global reserves is rather modest. U.S. reserves of shale oil amount to 25 billion barrels, an amount comparable to the annual global consumption of oil [5]. Thus, the availability of this resource does end the dominance of conventional oil as the primary source of global energy and limits the political and economic leverage major oil producers have enjoyed in the past.

It should be noted that since 2015, due to lower oil and gas prices, we have seen a noticeable decline in shale related activities, from exploration to drilling and production. According to the Baker Hughes rig count data, at peak in March 2015, there were 1900 active oil rigs operating in various U.S. basins [6]. Following the price collapse, the rig count dropped to about 400 in June 2016 and then began climbing again in response to higher oil prices. As of early 2018, the number of oil rigs stood at about 1000. The relative speed with which these operations can be turned on and off have a profound influence on the ability of oil producers to raise oil prices by limiting their own production.

The increased production of shale oil in the U.S. has made it easier for the world oil market to withstand several incidents when production and export from certain countries was halted from war or other political upheavals [7].

DOI: 10.7569/JSEE.2018.629512

Producing shale oil can cost upwards of $60/barrel. Prior to 2006, oil pricing hovered around $40/barrel, making hydraulic fracturing cost prohibitive. Subsequently, largely in response to increasing global demand, the oil price rose to above $100/barrel (with some spikes as high as $140/barrel). At these higher prices, shale oil production by hydraulic fracture was profitable and it spurred drilling activities in many U.S. basins. Profitability can vary significantly from one play to the next though. Figure 2 shows an earlier peak for shale production for different US plays that arrived in 2015, after which it dipped through 2017, with the rate of decline being an indication of the price sensitivities in different plays. Since 2017, production increased in all plays.

Modern HF combined with horizontal drilling allows multiple wells to be drilled from one surface location, reducing the size of the drilling area above ground by as much as 90 percent [8]. Fracking is the key to unlocking vast U.S. shale resources and freeing up oil and natural gas that previously was inaccessible, while protecting groundwater supplies and the environment. America's shale energy revolution began with extensive U.S. government agencies and contractors (e.g. Department of Energy, DOE; Gas Technology Institute, GTI). This was further accelerated by privately financed efforts (e.g. oil and gas operators and service companies). In both cases the primary driver was new technology.

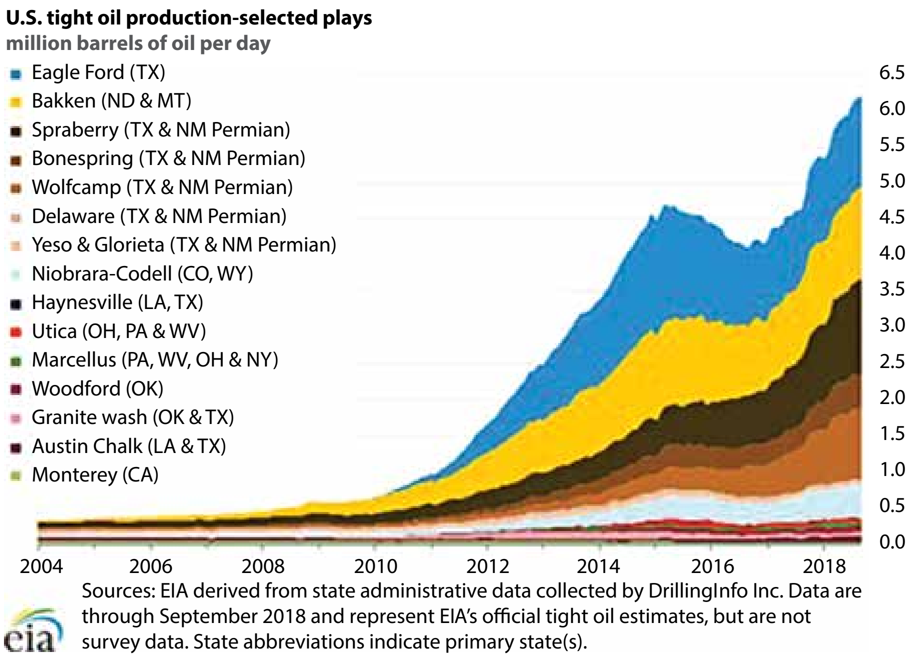

Figure 2 The Explosion of Shale Production Since 2010 [54].

DOI: 10.7569/JSEE.2018.629512

The notion of fracturing rocks to improve permeability is an old one. Based on an idea proposed by Floyd Farris of Stanolind Oil and Gas Corporation (later Amoco and then BP), attempts at producing oil in tight formations were made by using mixtures of naphthenic acid and palm oil (napalm). The process, "Hydrafrac," was patented in 1949 and licensed to Haliburton.

The Devonian shale basins of the Western Appalachian, Michigan, and Illinois Basins were known to contain vast quantities of gas, but the low permeability of the rock limited production from this resource. The declining US reserves of natural gas prompted the Department of Energy (DOE) and the Gas Research Institute (GRI) to sponsor research and development efforts for technologies for assessing and producing gas from this resource. These efforts led to techniques such as the slick-water fracture, horizontal drilling, and microseismic technology for characterizing and exploiting these resources. This included several DOE supported demonstration projects in Ohio, Texas, and New Mexico to validate these technologies [9].

The development of commercial fracking is largely due to the efforts of Mitchell Energy, who drew on the government-funded work and, despite numerous setbacks, persisted for decades in improving the technologies and driving down their costs. Of course, the rise in the cost of crude oil in 2008 helped in the process. Once hydraulic fracking became economically feasible, it was widely deployed by many companies and experiential learning drove down costs. The unleashing of natural gas from shale resulted in a sharp decline of its cost from about $15/Mbtu in 2008 to around $3/Mbtu in 2014. About a third of the natural gas is used for producing hydrogen, which in turn is used industrially to refine fuels or produce fertilizers. The large availability of natural gas at relatively low cost has allowed U.S. refineries to increase their output and increase the export of finished products.

While those against hydraulic fracturing may argue otherwise, the industry proponents maintain shale gas has also had a positive environmental impact. Since natural gas is not easily exported, its increased availability in the US has resulted in a decline in its price and made it the fuel of choice for electric power production. Many power producers switched from burning coal to burning natural gas. In 2005, electricity generation from coal and gas in the U.S. was 2,000 and 760 TWh and by 2017, the two sources were each generating about 1,200 TWh, while the total electricity generation has held steady at 4,000 TWh. Thus, over 700 TWh of coal generation has switched to gas with the attendant environmental benefit of reduced CO_2 emissions.

The positive economic impact of shale related natural gas and oil resources is undeniable. By helping to lower power and materials costs, as well as stimulating economic activity and positive impact on the labor market for a variety of businesses like service and supply companies, HF has supported growth across an economy that otherwise has struggled in recent years. According to an IMF Report, the shale gas revolution has had a macroeconomic impact between 0.3% and 1% of US GDP [10]. Many performance factors are used to assess the effectiveness and

DOI: 10.7569/JSEE.2018.629512

safety of HF. Among them are better understanding of fracture azimuth/geometry/length/distribution, Stimulated Reservoir Volume, and potential hazards (induced seismicity and hydraulic fracturing fluid leakage). We will revisit the environmental implications of hydraulic fracturing in a different section.

To summarize, one of the key factors impacting shale production is the economics and oil and gas prices, as discussed earlier. However, there are other factors that have impacted the economics of shale resources, such as the evolution of technologies, including subsurface characterization and advances in hydraulic fracturing, including the ability to monitor the creation of new fractures and the associated microseismic events. The next two sections provide some insight on the science behind hydraulic fracturing and how the advances in related science and technology can further improve the economics of production from shale and other tight formations.

3 Fracture Characterization

Microseismic mapping associated with hydraulic fracture stimulations is used to extract fracture geometry information, such as heights and lengths. Since a large amount of shear stress near the fracture tip is created, it allows one to accurately determine the length and the height of the fracture [11]. The assessment of fracture complexity using microseismicity has yielded good results, since the microseismicity reflects the general area of stimulation treatment. It is almost impossible to determine the interaction between created fractures with different levels of complexity. Furthermore, the technology to differentiate between stimulated, unchanged, or damaged fracture systems is still evolving. Microseismic imaging is an important technology for tracking fracture creation and reactivation of pre-existing fractures occurring during various industrial operations, particularly hydraulic fracture treatments of unconventional reservoirs. Often, microseismic locations are used to interpret the fracture geometry, although additional insights into the fracture deformations can also be extracted through source characterization. The resulting source deformation investigations provide additional information about the fracturing and are sometimes interpreted as representing the entire spectra of deformations. Furthermore, new nontraditional passive seismic imaging techniques, such as coherency-based stacking methods or emission tomography [12, 13], provide the potential for identification of low SNR emissions such as smaller microseismic events or low frequency creep failure [14].

In certain cases, the observed microseismicity is found to correspond to shear deformation, although hydraulic fracturing is generally considered a tensile fracturing process. The timeframe of observed microseismic shear deformations are also tied to the relatively high frequency content of the seismic recording equipment and much more rapid than the relative slow and hence aseismic tensile fracture dilation occurring throughout the injection period. Fracture movements can also potentially occur at some distance away from the hydraulic fracture (sometimes

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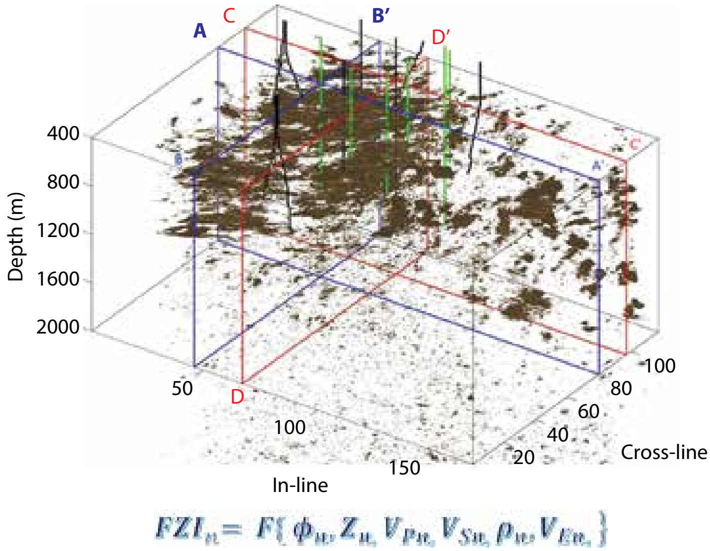

Figure 3 Fracture Mapping using MEQ, Seismic, & Petrophysical Data using ANN-based Hybrid FZI Attribute Mapping, from Maity and Aminzadeh (2015).

referred to as 'dry' microseismicity) and are associated with pressure and/or pressure changes resulting from the fracturing. Although the fracture geometry can often be inferred directly from the microseismicity, attempts to understand the fracture deformation from the microseismic deformation can be a challenge. Maity and Aminzadeh [15] report on the use of Microseismic, 3D seismic, and well log data combinations to characterize subsurface fractures by developing a neural network based on "Fracture Zone Identifier" or FZI attributes. Using repeated microseismic measurement data and possibly 4D seismic, the FZI attribute can also be used to quantify changes in the size and nature of the fractures and their growth. Figure 3 shows a three-dimensional display of subsurface characterization of the natural fracture zones. Obviously, after hydraulic fracturing, these fracture zones would be altered and the newly created or expanded fractures can be characterized using similar techniques.

Other techniques, such as the use of statistical distributions in seismicity, can also shed valuable insights into the fracturing process and its relation to the structural features within the reservoir [16]. Such methods examine seismicity as a function of the in-situ stress state within the reservoir.

4 Geomechanics of Hydraulic Fracturing

Geomechanical evaluation and modeling in the oil and gas industry is used to predict reservoir parameters, such as bottom hole pressure, in-situ rock stresses,

DOI: 10.7569/JSEE.2018.629512

modulus of elasticity, leak-off coefficient, formation porosity, and permeability. It is no coincidence that with increased demand for hydraulic fracturing, geomechanical simulations have gained popularity as well. For example, such evaluations allow determining the reservoir response to fracturing fluid injections. Starting with a discrete fracture network (DFN), one can model both the aseismic and microseismic modes of deformation. This helps interpret the resulting injection pressures, rates, and volumes, in conjunction with seismicity data, improving the interpretation stimulated fracture network.

Pre-existing fractures and the in-situ stress state have a significant bearing on hydraulic fracturing operations. In particular, hydraulic fracture propagation and hydraulic vs. natural fracture interactions can be correlated with the observed microseismicity distribution. Recent studies have shown a strong correlation between microseismicity distribution and in-situ reservoir properties such as faults and rock brittleness [17,18]. Recent studies involving ground truth measurements from the Hydraulic Fracturing Test Site in the Permian Basin [19] has shown that hydraulic fracture growth and complexity can be significant and the propped rock is relatively small in comparison with the overall stimulated rock [20]. New mathematical techniques are being developed to model for such significant fracture propagation complexities.

Geomechanical models are usually very sensitive to input parameters, including stress anisotropy, completion effectiveness to fracture initiation, and DFN characteristics. Correlating the microseismic data with the corresponding geomechanical deformation would increase confidence in the geomechanical simulation and provide an important framework to interpret the microseismicity as the geomechanical response of a reservoir. A linear elastic fracture mechanics (LEFM) model can describe stress distribution around a single hydraulic fracture. The full stress field solution is valid everywhere in the domain and is a function of stress boundary conditions and fracture geometry.

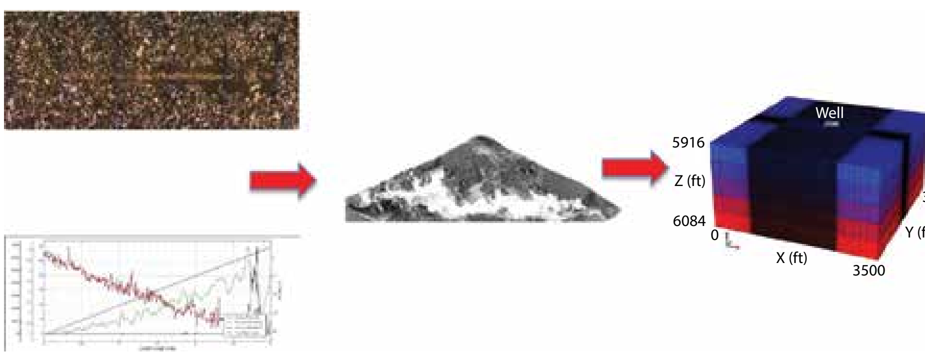

Figure 4 *The Process of Generating a* 3D Mesh of the Domain for Two-Way Coupled Flow-Geomechanics (Ante et al 2018).

DOI: 10.7569/JSEE.2018.629512

Predicting and controlling the initiation and cessation of a hydraulic fracture remains a challenge due to compositional and poromechanical heterogeneity, which causes stress concentration, and due to inelasticity at the grain scale. The presence of organic matter also affects the rock-mechanical properties and directionality in fracture initiation and propagation processes. Overall, understanding the fracturing behavior of a rock at the microscale plays a critical role in predicting the performance of hydraulic fracturing. Fracture initiation and propagation behaviors and estimation of fracture toughness and directionality could be accomplished through use of micro-scale geomechanical scratch tests [21]. The fracture toughness and directionality values of tight sandstone and shale samples are compared to understand the effect of lithology on fracture initiation and propagation processes, respectively. This is followed by initializing the model in a principal state of stress with the maximum principal compression of 9000 psi in the x-direction. The principal stresses in the y and z direction are 6000 psi. There is a zero-displacement boundary condition on all the boundaries. Figure 4 shows the discretized grid used for the simulation, with the injection well placed in center and perforated in layer 3, which is the middle layer in this five-layered model.

We discussed microseismic monitoring in the fracture characterization section, providing data on the effectiveness of stimulation operations. During fracture stimulation operations, a change of the in-situ stresses and rock volume generates microseismicity. Mapping the spatial and temporal pattern of these microseismic events is used for tracking the progress of hydraulic fracture propagation. Microseismic monitoring can also serve as a complementary indicator of changes in fluid pathways and mechanical changes in the treatment well. The deformation of the fracture wall opening relates to the fluid path way through P-waves. In addition, at the fracture tips, the shear stress regime may create S-waves which represent the extent of the fracture wall.

The primary data used for the evaluation of microseismic events is waveform measurements obtained from the surface, downhole receivers, or both. A "hybrid" microseismic survey design, comprised of both surface and borehole geophones, allows for optimum coverage for effective characterization of the subsurface [22]. These data provide information related to strain and stress changes in the reservoir, as well as the nature of the physical processes such as induced fracturing of the rock or slippage on preexisting fractures. Waveform measurements can also indicate undesired fracture growth or fault activation.

A processed microseismic waveform recording describes the magnitude and direction of rock movements. Vector and spectral fidelity define the accuracy of the measuring content, leading to the construction and calibration of a model of seismic P-wave and S-wave. The accuracy of microseismic interpretation depends on estimated event hypocenters, the accuracy of the velocity model, and the monitoring geometry. Thus, a low signal-to-noise ratio is one of the greatest challenges for the processing of microseismic data. Indirectly, field and surface deployment

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challenges can be significant and generally act as the primary constraint in survey geometries and resulting detectability.

One of the most important concepts in analyzing microseismic data is the seismic moment or the energy and magnitude which is used to characterize the size of microseismic events and incremental fracture surface areas and lengths. This will lead to the construction of the effective stimulated volume (ESV), which provides information on the complexity of the hydraulic fracture network. Consequently, the seismic moment or cumulative moment can provide insights into fracture behavior during stimulations. An energy-based approach is used to calibrate the fracture model with microseismic data. This approach presents an energy-based numerical algorithm which stimulates a vertical hydraulic fracture by parameter selections of elastic, stress, and material properties defined in a layered 3D geologic medium [23].

To provide the information about the mechanism of failure at fracture sites, the moment tensor inversion (MTI) concept can be used. MTI describes the orientation, magnitude, and slip of individual microseismic events. The decomposition of each moment tensor into different components provides us with an estimation of the different failure modes: shear slip, tensile opening, expansion, and their corresponding ratios. It also gives other processes the orientation of local fracture planes and the direction of shear slip. The MTI concept allows the construction of discrete fracture networks (DFN) representing the distribution, orientation shape, connectedness, and fluid properties of hydraulically induced fractures [24]. In addition, they can also detect complex fracturing behavior such as fault activation or fracture propagation alongside bedding plans [25].

Given an estimate of the fracture network in the subsurface, our models will ascertain whether a particular Subsurface Fluid Injection and Production (SFIP) strategy will cause a failure at a particular site. A more accurate statement would refer to the probability of failure occurring at a given site reflecting on the observation that this inference is predicated on a particular (simplified) model and a finite set of data, introducing uncertainty in the calibration and ensuing prediction. Hazard maps are themselves a function of the selected model and data and their sensitivity, with respect to additional data and/or model refinement, can be used to design data acquisition efforts and model refinement through multi-scale modeling. Accordingly, a hierarchical probabilistic model should be considered with parameters that reflect subscale effects and whose sampling distributions can be accurately estimated from data. Sensitivity of the hazard maps with respect to these parameters will then reflect the value of additional measurements and additional model complexity.

5 Environmental Aspects of Hydraulic Fracturing

Hydraulic Fracturing (HF) has been the subject of intense debate for its potential environmental risk factors. This has prompted much scrutiny of HF by regulators

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and the general public. Many in the environmental community believe biodiversity may suffer as a result of land development and water supply damage. Methane leakage may be much higher than previously reported by the EPA [26] and this has severe implications for the climate. Fracking could exacerbate the issue, which outweighs the potential CO_2 pollution reduction by using clean gas in place of oil/coal. Also, magnitude 2+ earthquakes have increased in frequency in Texas and Oklahoma as well as the more common induced seismicity below magnitude 2, although much of the seismicity is attributed to the waste water injection, not to HF directly. While it is difficult to predict, the ill effects of HF could be mitigated by research and policy in changes.

The four main areas of concern are considered to be: a) ground water contamination, b) too much water used in the process and its disposal process, c) methane emission, and d) induced seismicity. The first three issues will be addressed in this section, while the induced seismicity related concerns will be the subject of section 6.

a. Ground-Water Contamination. The CCST conducted an in-depth study of the issue and released a three-volume CCST Independent Report in 2016 titled: Advanced Well Stimulation Technologies in California. While there are several key findings, the general conclusions are that here are no publicly reported instances of potable water contamination from subsurface releases in California Well stimulation technologies that are currently practiced in California and this technology does not result in a significant increase in seismic hazard. Overall, in California, for the industry practice of today the direct environmental impacts of well stimulation practice appear to be relatively limited. It should be emphasized that these conclusions may not be easy to generalize elsewhere for various reasons including: differences in geology and reservoir parameters, differences in the volume of hydraulic fracturing jobs in California compared to many other states with more extensive shale production, and stricter California State regulations than Federal and many other states' regulations.

Some of these studies have been used by the American Petroleum Institute and other oil and gas industry advocates to point out that no additional regulations on hydraulic fracturing are required and many of the existing ones should be scaled back. For example, API argues in its ongoing workshop series, "Commitment to Excellence in Hydraulic Fracturing", that hydraulic fracturing is one of the tools that the oil and natural gas industry uses to reinforce with regulators, remind lawmakers, and educate the public on the industry's commitment to and leadership on safety, health, and environmental protection. Its website continuously revises the standards related to HF. They can be seen on the Hydraulic Fracturing section of API's website.

Others may argue that many compounds used for hydraulic fracturing may be harmful, especially if enough care is not given to avoid entry of the fracking fluid to the water column. The compounds used in hydraulic fracturing operation include: acids, Sodium Chloride, Polyacrylamide, Ethylene Glycol, Borate Salts, Sodium/Potassium Carbonate, Glutaraldehyde, Guar Gum, Citric Acid, and Isopropanol.

DOI: 10.7569/JSEE.2018.629512

Each of these compounds are used for specific purposes, such as helping dissolve minerals and initiate fissures in the rock before fracturing, delaying breakdown of the gel polymer chains, minimizing the friction between fluid and pipe, preventing scale deposits in the pipe, maintaining fluid viscosity with temperature increase, ensuring effectiveness of other components, eliminating bacteria in the water, thickening the water for sand suspension, preventing precipitation of metal oxides, and increasing the viscosity of the fracture fluid.

After the wells on a pad are drilled, cased, and cemented, the horizontal part of the production pipe is perforated with small holes in the casing to expose the wellbore to the shale. Then, fracking fluid is pumped into the well under high pressure to create micro-fractures in the shale and free the natural gas or oil. The sand in fracking fluid keeps the fractures open after the pressure is released and the chemicals are chief agents to reduce friction and prevent corrosion.

Federal and state regulatory agencies normally provide guidelines for energy development in the United States, including hydraulic fracturing. Regulations related to shale resources include the Clean Water Act, Clean Air Act, Safe Drinking Water Act, National Environmental Policy Act, Resource Conservation and Recovery Act, Emergency Planning, and the Community Right to Know Act. Some of these regulations have recently been under re-assessment and possibly revisions since mid-2017.

Debate continues on whether, and to what extent, hydraulic fracturing could be found responsible for ground water contamination. It is understood that a healthy debate should be based on science and the best practices in engineering, as well extensive modeling and simulation, combined with field monitoring. Some examples of such R&D efforts are found in Jabbari et al. [27] and Jabbari et al. [28]. Figure 5 shows an example of such work.

Recent studies at the Hydraulic Fracturing Test Site in the Midland Basin highlights the minimal environmental impact of large pad scale fracturing operations on ground water and air quality [29]. During this test, which involved fracturing of eleven new horizontal wells and two re-fractured wells, there was no migration of hydrocarbon or fracturing fluid into the nearby Edward-Trinity Plateau aquifer.

b) Amount of Water Used. A recent report by Ceres highlighted the concern that water used for fracking may be depleting water resources, particularly in arid regions, and, thus, exacerbating the water shortage [30]. Fracking of wells typically requires the use of several million gallons of water. However, the amount of water *per se* is not very large when compared with other uses of water. In the ten years from 2005 and 2014, fracking operations in Texas—the state with most frack wells—used 250 billion gallons of water or, on average, about 25 billion gallons a year [31]. However, overall annual water usage in Texas is 22 million acre-feet, or roughly 7,200 billion gallons of water. In other words, the water used for fracking in Texas represents less than 0.5% of water used each year. Viewed from this perspective, water use for fracking does not appear to cause shortages. Often though, the challenge with water use arises from the fact that it must be

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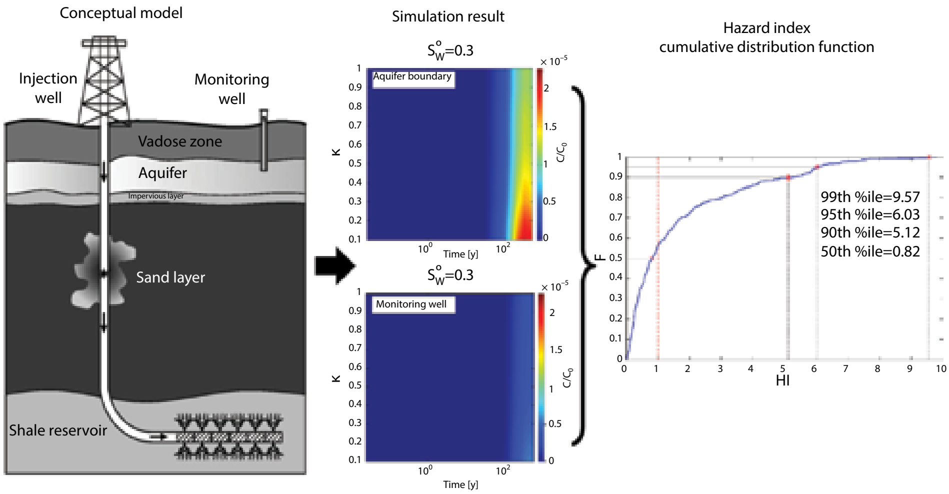

Figure 5 Numerical Modeling to Quantify Risk Factors for Water Contamination Associated with Hydraulic Fracturing, Jabbari et al (2016).

sourced locally—trucking in millions of gallons of water is expensive. Thus, if local groundwater supplies are limited, fracking operations could aggravate the water shortage. Other efforts to minimize the negative impact of hydraulic fracturing due to the excessive amount of water usage, especially in the areas with severe water shortage problems, includes recycling the waste water and hydraulic fracturing fluid [32].

c) Methane Emissions. Similar concerns have been raised on the potential emissions of CO_2 from power generation and methane emission from hydraulic fracturing. Others argue that such emissions are at their lowest point in nearly 30 years, in large part due to the widespread use of natural gas. Furthermore, it is argued that methane emissions from the oil and natural gas industry make up just four percent of total U.S. greenhouse gas emissions. Nevertheless, the debate can be settled by installing monitoring stations in major hydraulic fracturing operations to provide an accurate assessment of the potential risk and develop operational procedures to minimize and mitigate such risk. For additional details on the methane emission and other air pollution impacts of hydraulic fracturing, see the work by different U.S. national laboratories and others at Hydralicfracturing.com, 2018 [33].

6 Induced Seismicity

The potential for earthquake-like activity induced due to production of oil and natural gas has become a topic of recent interest, owing to environmental concerns. National seismic hazard maps in the United States are given by Peterson et al. [34]. It has been suggested that subsurface injection and production activities

DOI: 10.7569/JSEE.2018.629512

might factor into the risk of induced seismicity. The extensive use of hydraulic fracturing to stimulate production from shale plays has led many to speculate that the rise in hydraulic stimulation operations may have sparked a concurrent increase in seismicity. As the majority of mapped faults in California are considered by the US Seismic Hazard Map to be of higher risk, understanding the potential seismic sensitivity of the region to hydraulic stimulation takes on greater importance.

The material below is extracted from Frequently Asked Questions (FAQ) related to Induced Seismicity that has been released for public knowledge. It was also provided to the California Council on Science and Technology (CCST) that sought literature and data for reviews of well stimulation technologies in California and ISC submitted its recent study on "Hydraulic Fracturing and Induced Seismicity in California-A case study".

a. *What is induced seismicity?*
   Induced seismicity is seismic activity that occurs as a result of human activity (anthropogenic). Seismic activity refers to the frequency, type, and size of earthquakes. The vast majority of earthquakes are natural, caused by stresses that cause fracturing of the rock in the earth's crust. Examples of processes that might cause induced seismicity include subsurface wastewater injection, geothermal energy generation, and surface-water reservoir impoundment. Most seismic events related to induced seismicity cannot be felt by humans because they have very low magnitudes (less than 2 on the Richter scale) that can only detected by specialized instruments.
b. *What causes induced seismicity?*
   The main cause of induced seismicity is increased fluid pressure in rock pores that reduces natural friction and allows slippage of rocks along a fault. Researchers investigating causes of induced seismicity have documented that fluid pressures have a role in seismicity. As explained by the DOE, "pore pressures act against the weight of rock and forces holding the rock together; if the pore pressures are low, then only the imbalance of natural in situ earth stresses will cause an occasional earthquake. If, however, pore pressures increase, then it would take less of an imbalance to cause an earthquake." A recent study using data from hundreds of hydraulically fractured wells in sedimentary basins in Canada has shown a strong spatial correlation between induced earthquakes and high pore-pressure gradients [35].

   Cases have recently been observed in Oklahoma and Ohio, where seismic activity has been associated with the disposal of large volumes of wastewater into deep geologic formations. Such injection can disrupt the balance of stress within the rock, especially when not paired with corresponding fluid withdrawal. Other potential sources of induced seismicity include underground mining and chemical interaction of fluids with rock materials.

DOI: 10.7569/JSEE.2018.629512

c. *Can hydraulic fracturing cause "induced seismicity"?*

Hydraulic fracturing is a well stimulation practice that uses the injection of fluid to open flow channels in tight formations to produce the hydrocarbons locked within them. The practice has been in use for over sixty years.

A report published in 2013 by the National Academies of Science, NAS [36], concluded that hydraulic fracturing does not pose a high risk for inducing seismic events that could be felt by humans. The U.S. Geological Survey (USGS) also found that hydraulic fracturing is not a substantial cause of induced seismicity, and that "only very rarely" is hydraulic fracturing the cause of any earthquakes that can be felt by humans. The "micro-earthquakes" that hydraulic fracturing creates are too small to be felt or cause structural damage. Hydraulic fracturing has been associated with only minor seismic events at two U.S. locations, neither in California. Evidence of fault activation from hydraulic fracturing has been observed in the past [37], but these rarely cause earthquakes of significant magnitude to impact humans or structures. The largest known earthquake sequence was observed in Western Canada, where a fault system connected with the basement rock and took fluid during injection associated with hydraulic fracturing operations [38].

Accordingly, the DOE has also concluded that hydraulic fracturing is "rarely, if ever, a hazard when used to enhance permeability in oil and gas or other types of fluid-extraction activities." Furthermore, the USGS finds that "although the disposal process has the potential to trigger earthquakes…very few of the more than 30,000 wells designed for this purpose appear to cause earthquakes."

d. *How can one determine whether a seismic event is natural or induced?*

Ellsworth [39] addresses several issues in connection with natural versus induced seismicity. Davis and Frohlich [40] set forth a simple set of yes or no questions that could be used as a simple diagnostic tool in determining whether a seismic event was likely induced. The questions were as follows:

i. Are these events the first known earthquakes of this character in the region?
ii. Is there a clear correlation between injection and seismicity?
iii. Are the epicenters near wells (within five kilometers)?
iv. Do some earthquakes occur at or near injection depths?
v. If not, are there known geologic structures that may channel flow to sites of earthquakes?
vi. Are changes in fluid pressure at well bottoms sufficient to encourage seismicity?
vii. Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?

From these, an event may be scored with more "yes" answers indicating an increased likelihood of an event having been induced.

DOI: 10.7569/JSEE.2018.629512

e. *Has hydraulic fracturing caused earthquakes in California?*

A recent study by the USC Induced Seismicity Consortium (ISC) found no significant correlation between hydraulic fracturing and induced seismic activity in California. This study evaluated 30 years of seismic data in areas of oil production where hydraulic fracturing has been used in California and found little or no correlation between oil field activities in general and seismic activity.

The ISC study compared seismic activity from 1980 to 2013 with oil field activity, including hydraulic fracturing, at locations throughout California. Oil field activities and well locations were obtained from the California Division of Oil, Gas, and Geothermal Resources (DOGGR) and FracFocus [41]. Seismic activity data was compiled from the Northern and Southern California Earthquake Centers and included epicenter locations of seismic activity and the magnitudes and depths of seismic events. Database maps were prepared to display oil and gas well locations, well type (e.g. oil or gas producer, water flood injector, steam flood injector, water disposal), type of activity (drilling, producing, injecting, completing, stimulating, or abandoning), and the depth of the activity. For more details, see Section 8 where a couple of case histories are highlighted.

Composite maps were prepared, comparing locations of seismic events and known geologic faults with oil and gas well locations and oil field activities. Statistical analyses were conducted to determine whether there was any correlation between seismic events and oil field activities. Little or no correlation was found. For example, in northern California, a total of 303,609 seismic events were recorded from 1980-2013. The main area of northern California where oil and gas activities occurred is the Sacramento area, far from known fault zones, where oil is produced from shallow depths (less than 6 kilometers). Of the total 303,609 seismic events in northern California, only 210 events were in the Sacramento area and only 3 seismic events had magnitudes greater than 3; none were greater than 4.

f. *Does induced seismicity from wastewater injection by the oil industry differ from California in other states?*

The practice of deep wastewater injection is commonly used in states throughout the U.S. and is strictly regulated by state and federal laws. California has strict regulations governing subsurface wastewater injection. Injection wells used by the oil industry in California are different from the injection disposal wells linked to earthquakes in other states like Ohio, Oklahoma, Texas, and Arkansas. In California oil fields, wastewater is reinjected back into the formation after the oil is removed. In California, the water is injected into porous sandstone reservoirs from which water and oil was originally removed. In other areas of the U.S., wastewater is often injected into rocks with little porosity and storage capacity. Pore pressures in the rock increases dramatically as the limited available pore

DOI: 10.7569/JSEE.2018.629512

space is filled and additional injected water causes the rock to break, causing an induced seismic event. As a result, a University of California Santa Barbara geophysicist, Craig Nicholson, concluded that "very little of the state's [California] earthquake activity can be tied in any way to reinjection…there's not a connection like there is in the central and eastern United States."

g. *How do we know if an earthquake was caused by induced seismicity?*

Seismologists conduct extensive analyses of earthquake data and potential anthropogenic factors to determine whether an earthquake is natural, triggered, or induced. More information is needed to improve researchers' understanding of the "triggering" mechanisms of injection and production-related induced seismicity as well as any irregularities that naturally occurring earthquakes may have.

Recent studies by USC and the California Institute of Technology indicate that there is not a significant correlation between earthquakes and oil and gas field operations. A major reason for this is that natural earthquake epicenters are typically at depths below five kilometers, while oil field operations are conducted at depths shallower than two kilometers, typically less than one kilometer.

h. *Are there any documented cases of injuries or property damage caused by induced seismicity?*

There have been no documented cases in California where injuries or property damage have been caused by induced seismicity. However, property damage has been documented from shaking thought to be a result of wastewater injection into rock formations adjacent to known faults.

According to the National Research Council's Committee on the Induced Seismicity Potential in Energy Technologies Report [36], virtually all induced seismicity attributed to energy development has been small in magnitude and unable to be felt. The same committee also concluded that hydraulic fracturing does not pose a high risk to triggering noticeable seismic activity. Advanced hydraulic fracturing and horizontal drilling are the technology engines driving America's ongoing energy renaissance – surging oil and natural gas production that ranks first in the world. This oil and natural gas production, enabled by hydraulic fracturing, strengthens U.S. energy security, boosts the economy, and lowers consumer energy costs. In addition, the increased use of cleaner-burning natural gas is the main reason U.S. greenhouse gas emissions from electricity generation are at their lowest level in nearly 30 years. For decades, hydraulic fracturing has been used safely thanks to proven engineering and effective industry risk management practices and standards, as well as federal and state regulations.

Induced seismicity is a complex issue and the knowledge base surrounding it is rapidly changing. A one-size-fits-all approach isn't practical because of the significant differences in local geology and surface

DOI: 10.7569/JSEE.2018.629512

conditions, including population, building conditions, infrastructure, critical facilities, and seismic monitoring capabilities. As such, state regulators are best positioned to address potential issues linked to oil and gas injection wells in their state.

States are developing diverse strategies for avoiding, mitigating, and responding to potential risks as they locate, permit, and monitor Class II disposal wells. Many state regulators work with experts from government agencies, universities, private consultants, and industry experts on these issues. Effective planning involves identifying where there's risk of harm from a seismic event because people and property are located nearby. Again, state regulators are best able to make these assessments and plan adaptive responses in the event of a quake, such as adding seismic monitoring, adjusting injection rates and pressures, suspending injection well operations, or halting injection altogether and shutting in a well.

Both hydraulic fracturing and the underground disposal of produced waters from oil and natural gas operations are proven to be safe and environmentally reliable. Industry, academia, and government entities are clearly committed to pursuing further research to better understand the complex science and physical mechanisms associated with induced quaking events.

7 Case Study: Fracturing Induced Seismicity in California

This section includes highlights from a case study focused on establishing a correlation between hydraulic fracturing operations in California oilfields and seismic activity. Regions with a significant level of hydraulic stimulation operations were considered and hydraulic fracturing activity was compared to records of seismic activity for the same period of investigation. A qualitative methodology is used to differentiate potentially induced events from natural seismic events. The materials presented here are adapted from Aminzadeh and Aminzadeh et al. [42].

The potential for earthquake-like activity induced due to the production of oil and natural gas has become a topic of recent interest, owing to environmental concerns. It has been suggested that subsurface injection and production activities might factor into the risk of induced seismicity. The extensive use of hydraulic fracturing to stimulate production from shale plays has led many to speculate that the increase in incidences of hydraulic stimulation operations may have sparked a concurrent spike in seismicity (Ellsworth 2013). As the majority of mapped faults in California fall in higher risk areas of the US Seismic Hazard Map (Patterson et al, 2014) and Induced Seismicity Map (ISM), [43] derived from the publicly available data in California [44], understanding the potential seismic sensitivity of the region to hydraulic stimulation takes on greater importance.

The prolific nature of seismic activity in California, owing to an extensive network of faulting, hinders the task of differentiating potential induced seismic

DOI: 10.7569/JSEE.2018.629512

events from natural events. The task of locating potential induced events benefits from extensive data, however these data are not organized in a fashion conducive manner.

The case history we are highlighting here is from the San Joaquin Valley, California. The seismic catalogue used in this study was provided by the Southern California Seismic Network (SCSN). The catalog gives the location, date, depth, magnitude, and parameter uncertainties for over 470,000 events since 1932. The magnitude used in this study was local magnitude (M_L), with a magnitude of completeness (M_C) demonstrated by Hutton and Jones [45] to have significantly improved with installation of more seismic stations. In Aminzadeh [1], there is a review of the induced seismicity study conducted in San Joaquin Valley, California. A detailed statistical assessment of the induced seismicity potential within this region can be found in Goebel et al., 2015. Figure 6 is an example showing the distribution of different types of seismicity in the San Joaquin Valley. A first spatio-temporal test was conducted using records of hydraulic fracture operations conducted in the Bakersfield area from 2000 to 2013. The maximum true vertical depth for the fractured well dataset is just over 12,900 feet (3.9 km) and, thus, hypocenters for potential induced seismic events are expected to fall within a reasonable vicinity of the True Vertical Depth (TVD). Based on a simulation of pressure transfer using COMSOL and taking into account error in depth calculation of hypocenter, we considered events less than 10 km depth for our induced seismicity study. This is a more lenient depth constrain compared to many previous studies of induced seismicity, for which the limit was chosen around a five-kilometer depth. The left side of Figure 6 displays locations of hydraulic fracturing operations and earthquake epicenters from 2000 to 2013. The right map in Figure 6 displays hydraulic fracturing operations and only those earthquakes with a hypocentral depth less than ten kilometers. Following the filter treatment, no correlation remains.

The number of hydraulic fracturing and other SFIP operations were examined from 2000 to 2013. Hydraulic fracturing operations took place in five oilfields in the region, however, no spatial-temporal relationship was found between seismic events and fracturing activities. Some seismic events have been observed in some places between fracturing and induced seismicity, but it would be unrealistic to assume such correlations as a universal phenomenon.

Our case history also attempts to distinguish between induced and tectonic seismicity. The b-value analysis may provide insight into better ways to distinguish induced and tectonic seismicity. Goebel et al [46] identified several target areas where the petroleum industry activity is collocated with seismic activity and relatively low b-values. B-values are generally low close to the San Andreas Fault, possibly suggesting higher stress regimes compared to the more distant regions from active faults. The spatial b-value maps are a promising first step in delineating seismicity in low stress regimes from seismicity in higher stress regimes, which consequently have higher fault activation potential.

DOI: 10.7569/JSEE.2018.629512

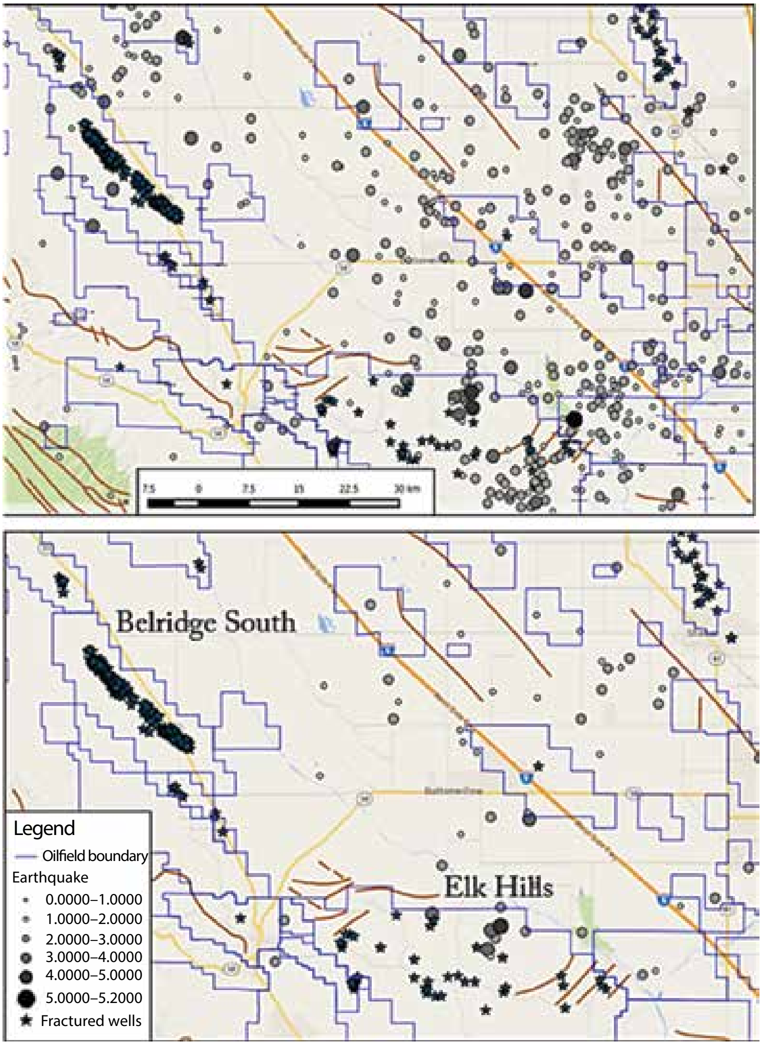

Figure 6 All Seismic Events in Study Area, San Joaquin Valley, California (left), Filtering of Seismic Events Based on an Event Depth Less than 10 km in San Joaquin Valley (right), Jabbari et al. [25]

Figure 7 (left) shows spatial variations in b-values in the study region in San Joaquin Valley. The faulting (tectonics) related to b-values generally seem lower (normally below 1, highlighted in blue colors). This can be compared against the higher b-values (in red colors), mostly in areas with a number of active oil and gas fields. Figure 7 (right) shows a few large oil fields with a color-coded number of hydraulic fracturing jobs.

DOI: 10.7569/JSEE.2018.629512

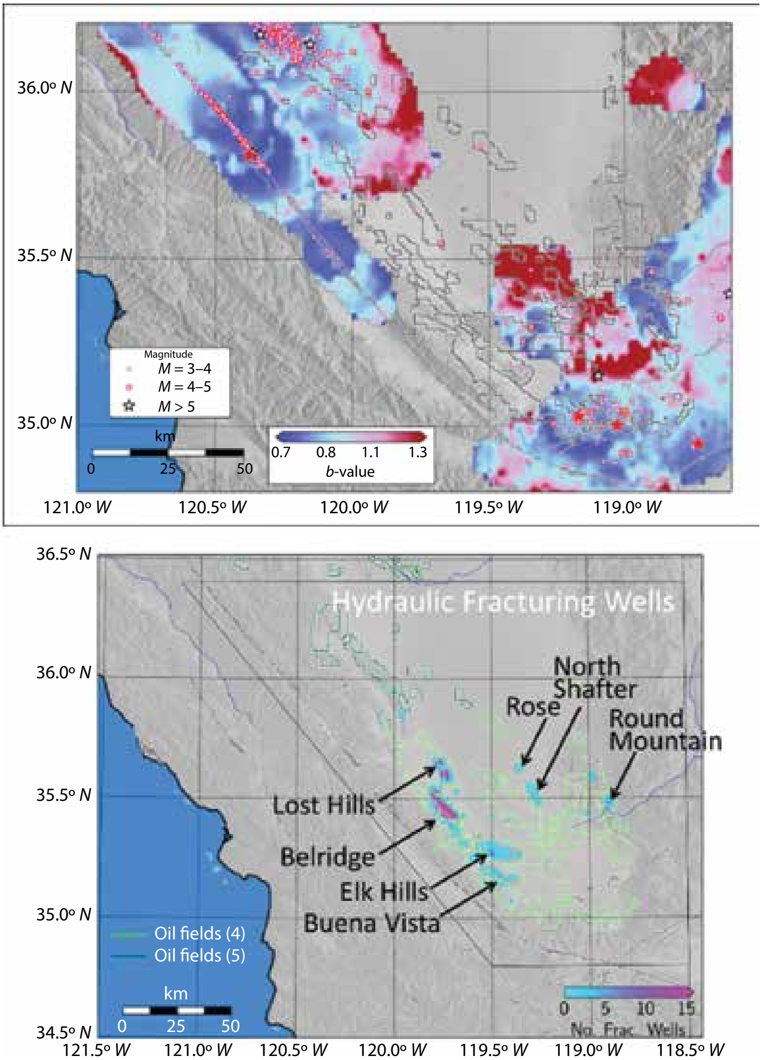

Figure 7 Spatial Variations in B-Values in the Study Region. (Left), Color Coded Number of Hydraulic Fracturing in a Few Sizable Oil and Gas Fields in San Joaquin Valley, (Right), [29]

The probability of activating faults due to anthropogenic influences is likely highest in regions where active faults, fluid injection wells, and low b-values have been encountered. This is the case within the southern part of the study region. In the proximity of active faults, both different types of seismicity may occur and more detailed studies are required to differentiate induced from natural (tectonic)

DOI: 10.7569/JSEE.2018.629512

seismicity. Areas of relatively high b-values are likely connected to smaller ambient stresses and seismic events are less likely to grow to large sizes.

The debate on the benefits and potential risks of hydraulic fracturing and other oil and gas operations will continue. Independent of one's stance on this debate, the need for additional research and more accurate assessment of the associated risk factors, along with the development of both monitoring programs and modeling approaches for alleviating the concerns is apparent. Ultimately, such work will lead to the mitigation of risks associated with the development of sound policies and strategies based upon strong science and engineering fundamentals while giving full consideration to environmental safety and economic factors.

See additional references on: What can microseismic tell us about hydraulic fracturing [47], Geomechanical approach for microseismic fracture mapping [48], Finite element method based modeling of hydraulic fracturing [49], Flowback of Fracturing Fluids with upgraded visualization of hydraulic Fracturing and its Implication of on Overall Well Performance [50], Simulation of Hydraulic Fracturing-Induced Permeability Stimulation using Coupled Flow and Continuum Damage Mechanics [51], and Oil, the Next Revolution [52].

Acknowledgement

The author acknowledges the financial support of the USC Induced Seismicity Consortium (isc.usc.edu) members, valuable input from Ripudaman Malhotra, the co-author of *A Cubic Mile of Oil*, and Kelly Rose of NETL.

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