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Potential Injection-Induced Seismicity Associated with Oil & Gas Development:

A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation

Second Edition

StatesFirst

An Initiative of the IOGCC & GWPC

Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation

This report is developed by the StatesFirst Induced Seismicity by Injection Work Group (ISWG) members (the State agencies) with input and support from the ISWG technical advisors (subject matter experts from academia, industry, federal agencies, and environmental organizations) to help better inform all stakeholders and the public on technical and regulatory considerations associated with evaluation and response, seismic monitoring systems, information sharing, and the use of ground motion metrics. It also is intended to summarize the range of approaches that have been used or are currently being used by states to manage and mitigate the risks associated with seismicity that may be induced by injection. StatesFirst is an initiative of the Interstate Oil and Gas Compact Commission and the Ground Water Protection Council.

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Preface

Although induced seismicity related to underground injection activities was first observed in the 1960s at the Rocky Mountain Arsenal near Denver, the dramatic increase in earthquake activity in the midcontinent since 2009 has focused attention on the potential hazard posed by earthquakes induced by injection. The science required to understand the process and predict its impacts is still undergoing significant change. This document is designed to provide state regulatory agencies with an overview of current technical and scientific information, along with considerations associated with evaluating seismic events, managing the risks of induced seismicity, and developing response strategies. It is not intended to offer specific regulatory recommendations to agencies but is intended to serve as a resource. Also, unlike prior studies by the National Research Council, U.S. Environmental Protection Agency, Stanford University, and others, this document is not intended to provide a broad literature review.

This report was developed by StatesFirst, an initiative of the Interstate Oil and Gas Compact Commission (IOGCC) and the Ground Water Protection Council (GWPC). The effort was led by the Induced Seismicity by Injection Work Group (ISWG), composed of representatives of state oil and gas regulatory agencies and geological surveys with support from subject matter experts from academia, industry, federal agencies, and environmental organizations.

The focus of this document is induced seismicity associated with underground disposal of oilfield-produced fluids in Class II wells. Appendix B provides background on Class II wells. Although far less likely to occur, the potential for felt induced seismicity related to hydraulic fracturing is discussed briefly in Chapter 1 and more extensively in Appendix I.

Management and mitigation of the risks associated with induced seismicity are best considered at the state level, with specific considerations at local or regional levels. A one-size-fits-all approach is infeasible, due to significant variability in local geology and surface conditions, including such factors as population, building conditions, infrastructure, critical facilities, and seismic monitoring capabilities. Appendix C includes summaries of approaches that various states have taken to address risk management and mitigation.

Although important, the issues of insurance and liability are not addressed in this report because each state has unique laws that render general consideration of these topics impractical.

This report uses the term “earthquake” to refer to a seismic event other than a microseismic event and “induced seismicity” to refer to earthquakes triggered by human activity. The term “potentially induced seismicity” is used to refer to specific seismic events that may be related to human activity, but where such activity has not been established definitively as a contributing factor.

Throughout this document moment magnitude (**M)** is used to denote the size of an earthquake unless otherwise noted. For a more complete description of moment magnitude and its relevance to the size of earthquakes, see Earthquake Magnitude in Appendix A.

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Executive Summary

Introduction

The fact that some human activities can cause seismicity has been known for decades. The vast majority of earthquakes are tectonic (due to natural causes), but under some circumstances human activities can trigger seismicity. Induced seismic activity has been documented since at least the 1920s and attributed to a broad range of human activities, including underground injection, oil and gas extraction, impoundment of large reservoirs behind dams, geothermal projects, mining extraction, construction, and underground nuclear tests.

This document discusses the potential for seismicity induced by the underground injection of fluids related to the development of oil and natural gas resources and identifies some strategies for evaluating and addressing such events. The ISWG recognizes that the science surrounding induced seismicity is undergoing significant changes and that any published report will need to be updated routinely to provide readers with the most up-to-date information available. To this end, the IOGCC and the GWPC commit to developing a process for updating this information in a manner consistent with the mission of the StatesFirst Initiative. In this second edition we have included an expanded discussion about hydraulic fracturing and updates to case studies. Additionally, the latest available information concerning induced seismicity has been included.

The principal focus of the document is seismicity potentially induced by injection of fluids in Class II disposal wells. Although public concern has focused on hydraulic fracturing as a major source of induced seismicity, scientific evidence suggests that hydraulic fracturing has a far lower potential to induce "felt" earthquakes than underground disposal.

The document focuses on the following topics:

- Understanding induced seismicity
- Assessing potentially injection-induced seismicity
- Risk management and mitigation strategies
- Considerations for external communication and engagement

Understanding Induced Seismicity

The majority of disposal wells in the United States do not pose a hazard for induced seismicity, but under some geologic and reservoir conditions a limited number of injection wells have been determined to be responsible for induced earthquakes with felt levels of ground shaking. To evaluate the need for mitigation and management of the risk of induced seismic events, it is important to understand the science. Understanding induced seismicity requires knowledge about the relationship between injection activities and the activation or reactivation of faults, including the effects of pore pressure increases from injection and the spatial and temporal relationships between injection and optimally-oriented, critically stressed faults. Because the same basic physics govern tectonic and induced earthquakes, it is possible to apply much of established earthquake science to understanding induced seismicity.

Recently, the frequency of earthquakes has increased in the mid-continental United States. Some of this activity may be linked to underground injection. Some events are occurring in areas that previously have not experienced noticeable seismic activity, creating an increased level of public concern. Some of this increase may be attributed to the greater ability to detect seismic events smaller than moment magnitude (**M)** 3.0 as well as increased monitoring of seismic activity.

Induced seismicity generally is confined to the shallow part of the earth's crust, often in the vicinity of the formation where the injection is occurring. For example, while natural earthquakes in the central and eastern United States can occur at maximum depths of 25 to 30 km, the majority of potentially induced earthquakes in Oklahoma are occurring in the top 6 km of the earth's crust. However, the largest injection-induced earthquakes and those events that may have the potential to be felt and potentially damaging have occurred in the Precambrian basement and not in the overlying sedimentary rock.

The main physical mechanism responsible for triggering injection-induced seismicity is the increased pore pressure on critically stressed fault surfaces, which effectively unclamps the fault and allows slip initiation. These faults generally are located in the Precambrian basement.

Earthquake hazards can include ground shaking, liquefaction, surface fault displacement, landslides, tsunamis, and uplift/ subsidence for large events (**M** > 6.0). Because induced seismic events, in general, are smaller than **M** 5.0 and short in duration, the primary hazard is ground shaking.

Ground-motion models can be used to predict the ground shaking at a given site to determine if it creates anxiety, hazards, or neither. Ground-motions models for injection-induced earthquakes are currently being developed with the recent availability of data particularly from induced earthquakes in Oklahoma, Kansas and Texas.

Assessing Potentially Injection-Induced Seismicity

At present, it is very difficult to clearly and uniquely differentiate between induced and tectonic earthquakes using long-established seismological methods. An assessment of potential induced seismicity may include the integration of multiple technical disciplines and skill sets, with collaboration among seismologists, reservoir engineers, geotechnical engineers, geologists, hydrogeologists, and geophysicists. Stakeholder collaboration is often essential to develop and characterize the broad data sets needed.

Historical seismicity data are needed to establish the background rate of naturally occurring events in a particular area over many decades or centuries, which, in turn, may indicate whether recent increases in seismicity are likely to be due to natural causes or are anomalous and perhaps induced by human activity. Increased monitoring and detection also influence the background seismicity rate. Many more seismic monitoring instruments are employed today than in the years prior to 2010.

Evaluating causation can be a complicated and time-intensive process that entails accurately locating the seismic event(s); locating critically stressed faults that can be reactivated; identifying the detailed temporal and spatial evolution of seismic events where fault slip first occurs and of any associated aftershocks; characterizing the subsurface stress near and on the fault; and developing a physical geomechanics/ reservoir engineering model that would evaluate whether an induced change (subsurface pore pressure change) could move the fault.

As stated by Davis and Frohlich (1993) in an initial screening in evaluating causation, seismologists typically explore potential spatial and temporal correlations relative to injection operations. They proposed a screening method using seven questions that address not only spatial and temporal correlations, but also injection-related subsurface pore pressure changes in proximity of the fault:

1. Are the events the first known earthquakes of this character in the region?
2. Is there a clear (temporal) correlation between injection and seismicity?
3. Are epicenters near wells (within 5 km)?
4. Do some earthquakes occur at or near injection depths?
5. If not, are there known geologic features that may channel flow to the sites of earthquakes?
6. Are changes in well pressures at well bottoms sufficient to encourage seismicity?
7. Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?

If all seven screening questions were answered no, the observed earthquakes were not induced by injection; conversely, if all seven questions were answered yes, then it is reasonable to conclude that the earthquakes may have been induced by injection. Both yes and no answers result in an ambiguous interpretation. In these circumstances, more detailed analyses could be conducted to better assess factors that may be contributing to causation.

Additional causation studies might include:

- Deploying temporary seismic monitoring networks
- Reviewing available seismological archives and records
- Identifying the range of potential anthropogenic sources that may be leading to subsurface stress perturbations
- Reviewing all available pressure data for injection wells in proximity to the seismic events
- Fully considering and characterizing other relevant data, such as subsurface fault mapping, including 2D and 3D seismic imaging data and fault interpretations; available geologic, seismologic, and depositional history; and available geologic and reservoir property data.

Risk Management and Mitigation Strategies

If a state regulatory agency makes a determination of injection-induced seismicity, the state regulator may employ strategies for mitigating and managing risk. Given the broad geologic differences across the United States, a one-size-fits-all regulatory approach for managing and mitigating risks of induced seismicity would not be appropriate. Consequently, states have developed diverse strategies for avoiding, mitigating, and responding to potential risks of induced seismicity in the siting, permitting, and seismic monitoring of Class II disposal wells.

Because of the site-specific considerations and technical complexity of tailoring a risk management and mitigation strategy, many state regulators choose to work with experts from government agencies, the regulated community, universities, and private consultants on this subject.

Understanding the distinction between risks and hazards is fundamental to effective planning and response to induced seismicity. The presence of a hazard does not constitute a risk in and of itself. For a risk to exist there must be exposure to the hazard and a mechanism for harm from the exposure. For example, earthquake hazard exists anywhere there is a fault capable of producing an earthquake. However, the risk of damage from an earthquake is low if that fault is far from people and property.

With respect to hazard and risk relative to injection-induced seismicity, two questions must be addressed:

- How likely is an injection operation to pose an induced-seismicity *hazard*?
- What is the *risk*—the probability of harm to people or property—if seismicity is induced?

Science-based approaches for assessing and managing seismicity risk associated with injection operations weigh both hazard and risk for a specific site and may consider:

- **Site characteristics**, taking into account the geological setting and formation characteristics, including tectonic, faulting, and soil conditions along with historical baseline seismicity levels (from USGS, state geological surveys, universities, and industrial array data);
- **Built environment**, including local construction standards as well as the location of public and private structures, infrastructures such as reservoirs and dams, and historical construction or significant architectural elements;
- **Operational scope**, including existing or proposed injection fluid volumes;
- **Estimations of maximum magnitudes** of potential induced seismic events; and
- **Estimations of potential ground motions** from potential induced seismic events.

Because the risk from induced seismicity depends on the characteristics of the locations and operations where injection is occurring, many states utilize site-specific, flexible, and adaptive response actions when an incident of seismicity occurs that may be linked to injection. States may determine that different types of response strategies are “fit for purpose,” depending on whether an event of potentially induced seismicity resulted in damage or felt levels of ground motion or was detected using seismic monitoring, with no damage or felt levels of ground motion.

Based on the assessment of risk from an event of potentially induced seismicity, a state regulatory agency may determine whether operations may be altered or resume at the well. When mitigation actions are determined to be appropriate, options might include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce ground motion and risk, permit modification, partial plug back of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.

State oil and gas regulatory agencies consider a variety of factors in determining if, when, and where seismic monitoring related to underground injection is appropriate. Screening protocols can help determine if seismic monitoring is warranted. If so, the state may include in a plan the method of seismic monitoring, equipment, reporting of data, thresholds for reporting changes in seismicity, steps to mitigate and/or manage risk by modifying operations, and thresholds for suspension of injection activity.

Although state regulatory agencies typically do not have the resources or expertise to undertake detailed seismic monitoring or investigations, they often will partner with other organizations such as the U.S. Geological Survey (USGS), state geological surveys, research institutions, universities, or third-party contractors to assist states in designing and installing both permanent and temporary seismic monitoring networks and in analyzing seismic monitoring data.

Considerations for External Communication and Engagement

Because of the increasing occurrence and detection of seismic events potentially linked to underground injection, public entities involved in responding should be prepared to provide the public with information and respond to inquiries.

It is important to develop a communication and response strategy as early as possible and before it is necessary to respond to an incident. The messages should be direct and clear.

Strategy development may be based on:

- Planning before the event
- Implementing a response
- Evaluating after the response

While common approaches can be considered, each state has a unique regulatory and legal structure that must be taken into account in any communication plan and response strategy.

Prior to any event the state agency should consider developing a strategy that focuses on:

- **Public surveys**: The goal is to understand the concerns of the public so that the educational and communications components of the strategy can address the issues that are important to the public.
- **Education**: The goal is to present information in a manner that can be understood by the audience. The process originates with the presenter and flows to the audience, using feedback to determine if the message was received and understood.
- **Communication**: An effective communication process begins with listening to the perceptions, concerns, ideas, and issues of the audience of the communication. If the intended receiver does not, for whatever reason, regard the response or message as germane to his or her personal concerns, effective and productive communication may not take place.

If it does not already have one, the agency could develop a strategy that includes methods of communicating with stakeholders, other agencies, the public, and legislators and within the agency itself before, during, and after the event.

Once an event has occurred at a threshold level, the agency would implement its communication and response plans. Identifying early on which state employees will publicly represent the state allows the state to appropriately respond to public inquiries with a consistent message and the most current information and updates. This protocol will indicate who is responsible to address questions based on the entity asking and questions being asked. Even if no physical damage has occurred, responding to a seismic event can be very similar to an emergency response.

The agency should be prepared to issue statements and respond to questions and concerns. The agency could consider holding stakeholder meetings, as appropriate. As they should with all issues, the agency representatives should speak clearly and plainly and choose language carefully. Certain words may cause unnecessary concerns or mischaracterize the situation or, stating conjecture or hypotheses without substantiating the facts can mislead the public. For example, it is important to convey that even if an agency such as the U.S. Geological Survey issues a report that an event occurred, this does not mean that it can accurately be linked to a source. Information needs to be verified by the appropriate state agency prior to making any conclusive statements. When reporting epicenter locations, one consideration is to include explicit listing of the location uncertainty, so that the public is clear about where the source of the event may possibly be.

After or between events the agency should consider following up with internal and external stakeholders about what was done well and what needs to be improved.

With any follow-up communication, the agency should not make promises or definitive statements concerning avoidance of future events. The key goal is to show the agency's involvement and ongoing commitment to addressing an evolving concern. Also, it may be important to designate someone who can respond to ongoing inquiries about the status and conclusions of state efforts and investigations.

Finally, it is important to view the before, during, and after sequence not as linear steps but rather as part of an iterative process of continually modifying and improving communication plans and strategies.

Key Message

Induced seismicity is a complex issue for which the base of knowledge changes rapidly. State regulatory agencies that deal with potential injection-induced seismicity should be prepared to use tools, knowledge, and expertise, many of which are offered in this document, to prepare for and respond to any occurrences.

Chapter 1: Understanding Induced Seismicity

Chapter Highlights

This chapter discusses the following:

- Key concepts of earthquake science, such as magnitude, ground motion and hazard
- The magnitude and depth of induced seismic events relative to natural earthquakes, including the relevance of shallow versus deep earthquakes and the ranges of magnitude for natural and induced events
- The hazards and risks related to induced seismicity and the difference between hazard and risk as they pertain to the potential effects of induced seismicity
- Ground-motion prediction models currently being used and the need to develop models specific to injection-induced earthquakes
- The ways in which fluid injection might cause seismic events, including the concept that the main physical mechanism responsible for triggering injection-induced seismicity is increased pore pressure on critically stressed faults, which decreases the effective normal stress, effectively unclamping the fault and allowing slip initiation (Hubbert and Rubbey 1959; Ellsworth 2013)
- The research on induced seismicity, including the recent evaluation of possible temporal and spatial correlations of disposal operations over broader geographic regions in Oklahoma to earthquakes in those specific geographic areas (Walsh and Zoback 2016)
- Future research needs, including approaches for better identification of the presence of critically stressed faults in proximity to injection sites and whether injection-induced earthquakes are different from natural earthquakes.

Introduction—Key Concepts and Earthquake Basics

While Appendix A contains a more detailed guide to earthquake science and Appendix J a glossary, the following key concepts, observations, and terms are useful in understanding this primer.

1. Earthquake basics:
    - Magnitude quantifies the size of the seismic event, while ground motion is a result (hazard) of the event;
    - Ground-motion resulting from the earthquake rupture process depends on magnitude, , distance, depth of event, properties of the intervening earth, and local geologic conditions;
    - Ground motion is the more significant measure of an earthquake—how seismicity affects people;
    - Magnitude scales are logarithmic—earthquake amplitude increases exponentially with scale;
    - Rates of seismic events for a given magnitude are logarithmic—the number of individual events increases exponentially with decreasing magnitude (the so-called Gutenberg-Richter relationship);
    - When a segment of fault slips, the slip and release of built-up strain energy can occur over an extended time period (e.g., weeks and months); there may be many smaller “foreshocks” and “aftershocks” associated with the ”mainshock”; while hundreds (or even thousands) of

separate seismic events may be recorded during this process, these events are generally associated with a single fault or fault patch undergoing movement. The size of the fault patch affected will impact the amount of seismic energy released which will determine the magnitude of any seismic events.

- Epicenter is the location of an earthquake at the earth's surface;
- Hypocenter is the location of the earthquake at depth or where the rupture begins;
- Earthquakes greater than **M** 2.5 are in the felt range; and
- Detection and location are not the same. An earthquake can be detected by a single seismic station but you need a minimum of three stations, located around the earthquake, to approximate the location horizontally and vertically. The denser the network is in terms of seismic stations, the better the earthquake can be located.

2. Where seismic stations are not present or are inadequately spaced, it often impairs the ability to detect or analyze events properly.
   - Earthquakes can occur almost everywhere;
   - Seismic station coverage across the United States since the 1970s is believed to be adequate to detect all earthquakes of **M** 3.0 and above, although locations and depths may be highly uncertain; and
   - Installing more seismic stations may result in detection of more earthquakes.
3. It often takes in-depth analysis of data, some of which may not exist, to attempt to differentiate between natural and induced earthquakes.
4. Most cases of induced seismicity have occurred on previously unknown faults:
   - The large majority of faults which produce smaller induced earthquakes are below the resolution of commonly used seismic imaging tools.
   - With respect to vertical or near vertical faults, detection is problematic with current imaging tools

The vast majority of earthquakes are tectonic (due to natural causes), but under some circumstances, seismicity can be triggered by human activities. Induced seismic activity has been documented since at least the 1920s and attributed to a broad range of human activities, including underground injection, oil and gas extraction, the impoundment of large reservoirs behind dams, geothermal projects, mining extraction, construction, and underground nuclear tests.

Oil and gas activities that involve injection of fluids from the subsurface can create induced seismic events that can be measured and felt. In many cases, felt injection-induced seismicity has been the result of direct injection into basement rocks or injection into overlying formations with permeable avenues of communication with basement rocks.

In one of the first comprehensive looks at induced seismicity, researchers at the U.S. Geological Survey (USGS) (Nicholson and Wesson 1990) described potential earthquake hazards associated with injection. Their report discussed known cases of injection-induced seismicity and explored probable physical mechanisms and conditions under which the triggering is most likely to occur based on the state of stress, injection pressure, and the physical and hydrological properties of the rocks into which the fluid is being injected. The report described that, under certain circumstances, the increased pore pressure resulting from fluid injection, whether for waste disposal, secondary recovery, geothermal energy, or solution mining, can trigger earthquakes. The report established criteria to assist in regulating well operations to minimize the seismic hazard associated with fluid injection.

Recently, the frequency of earthquakes has increased, particularly in the Mid-continent. Some of these events are occurring in areas that previously have not experienced felt earthquakes, creating an increased level of public concern. Figure 1.1 shows the earthquake distribution for events **M** ≥ 3.5 in the United States from 1974 through 2003. Figure 1.2 shows the annual number of recorded events of **M** ≥ 3 in the central United States from 1973 through 2016 (USGS, US Earthquakes 2015). The increase in seismicity, particularly in the Mid-continent beginning around 2008, shares a temporal and spatial correlation with increased oil and gas activity, and studies have indicated a connection with Class II disposal wells. However, detection of some of these events may be the result of increased seismic monitoring.

Because the same basic physics govern tectonic (natural) and induced earthquakes, it is possible to apply much of established earthquake science to understanding induced seismicity. Background on relevant earthquake science is provided in Appendix A.

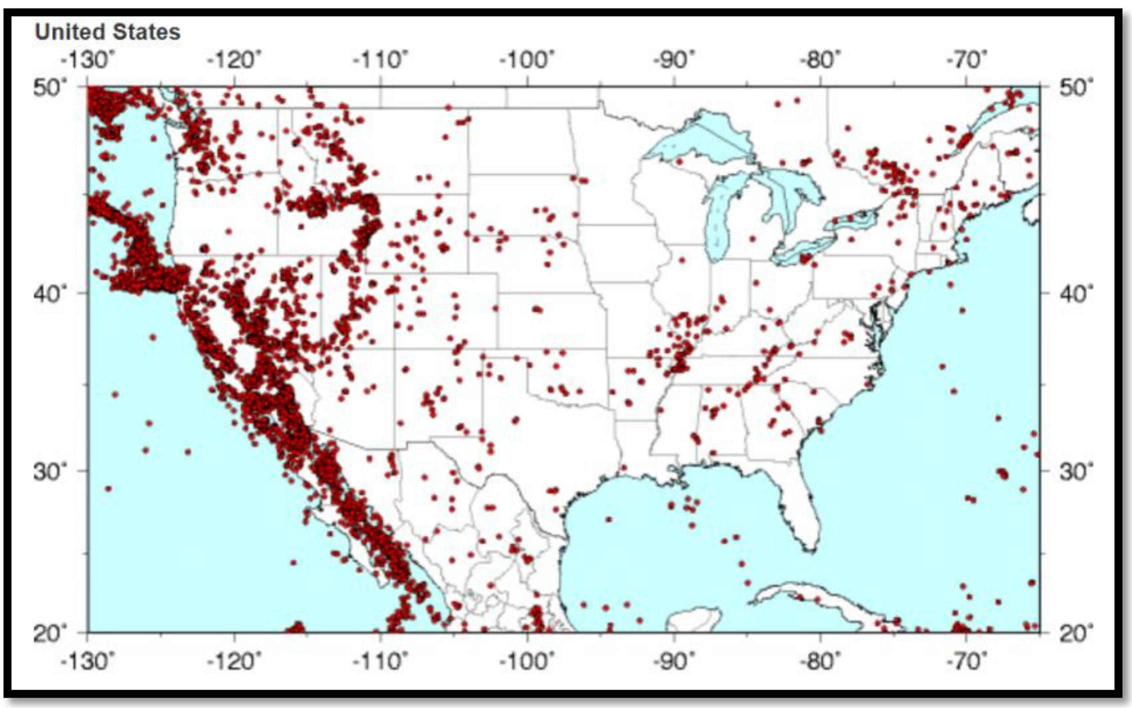


*Figure 1.1. U.S. earthquakes **M** 3.5 and greater, 1974−2003, available at http://earthquake.usgs.gov/earthquakes/states/top_states_maps.php. Source: USGS 2015.*

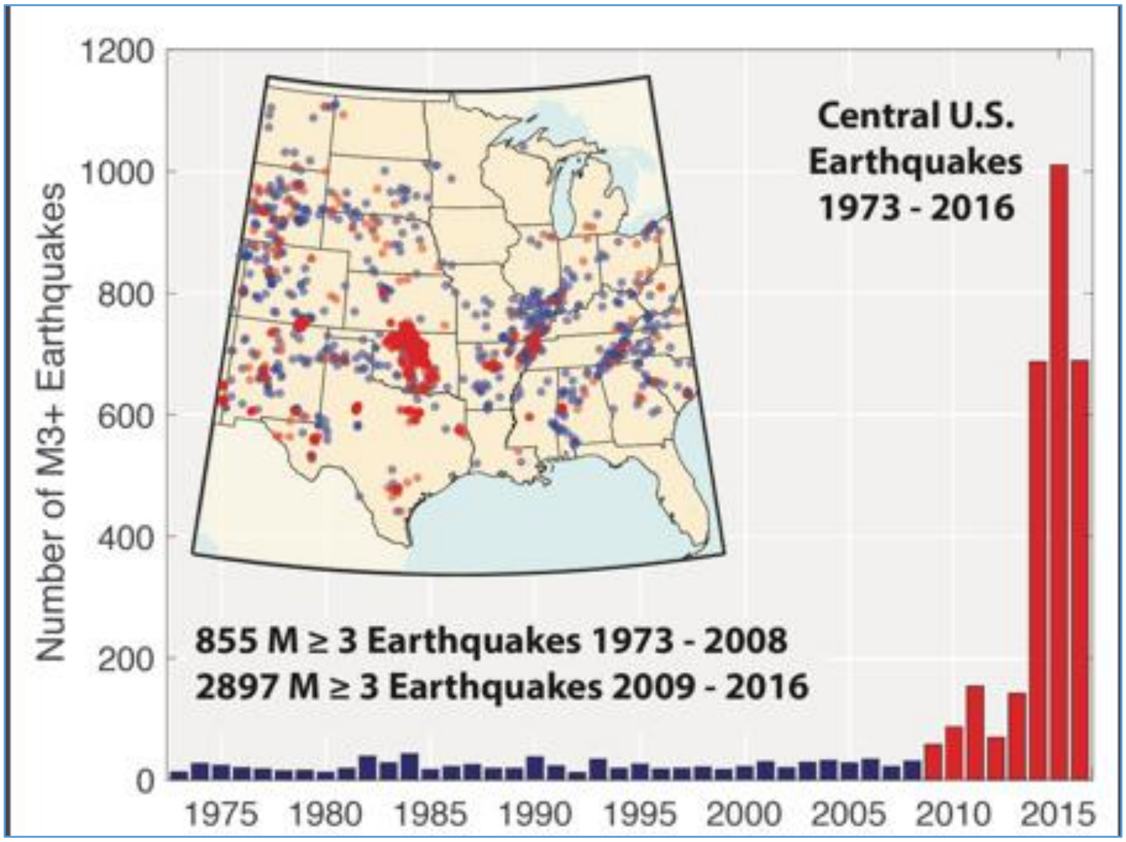


*Figure 1.2. The number of earthquakes **M** 3.0 and greater in the central United States, 1973−2016 available at http://earthquake.usgs.gov/earthquakes/states/top_states_maps.php. Source: USGS 2016*

Magnitude and Depth of Induced Earthquakes

As illustrated in Figure 1.3, induced earthquakes, because of their typically smaller size, possess substantially less energy than major tectonic earthquakes. Although the amount of energy released can be smaller than with natural earthquakes, induced earthquakes can still be damaging or create anxiety.

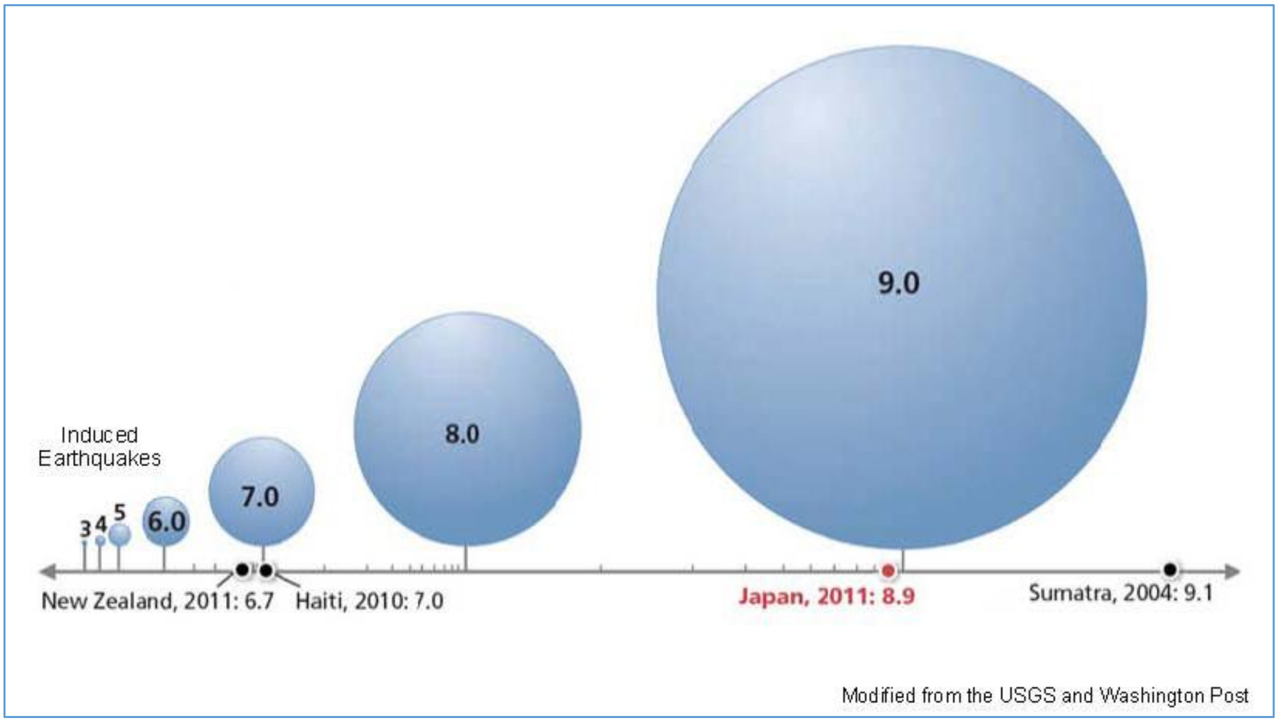


Figure 1.3. Schematic illustration of the energy release associated with earthquakes of various magnitudes. Image courtesy of ISWG.

The **M** 5.8 Pawnee, Oklahoma seismic event is the largest potentially injection-triggered event to occur in the United States. This event occurred in Osage County where underground injection is under the purview of the USEPA and not the Oklahoma Corporation Commission that controls such activity in the rest of the state. The depth of this event was reported as 5.4 kilometers putting it well into Precambrian basement rock. A case history synopsis for this and related events can be found in Appendix C of this document.

In general, natural earthquakes occur deeper in the earth's crust while induced earthquakes generally occur at shallower depths. The larger potentially injection-induced earthquakes have almost always occurred in Precambrian rock, where the rock is sufficiently strong to store larger amounts of tectonic strain energy. For example, the 2011 Youngstown, Ohio, earthquakes (maximum event **M** 3.9) occurred at depths of 3.5 to 4.0 km in the Precambrian basement (Kim 2013). Also, while natural earthquakes in the central and eastern United States can occur at maximum depths of 25 to 30 km, the majority of potentially induced earthquakes in Oklahoma are occurring in the top 6 km, well into the shallow crystalline basement (McNamara et al. 2015). This shallow depth often explains why induced earthquakes as small as **M** 2.0 can be felt. In general, natural earthquakes occurring in the central and eastern United States are not felt at that small of a magnitude unless they are very shallow.

Hazards and Risks of Induced Seismicity

Earthquake hazards can include ground shaking, liquefaction, surface fault displacement, landslides, tsunamis, and uplift/subsidence for very large events (**M** > 6.0). Because induced seismic events, in general, are smaller than **M** 5.0 with short durations, the primary concern is ground shaking.

Ground shaking can result in structural and nonstructural damage to buildings and other structures and can result in human anxiety.

- **Damage to structures**: It is commonly accepted that structural damage to modern engineered structures happens only in earthquakes larger than **M** 5.0. Very few cases are known in which injection-induced earthquakes have caused significant structural damage because they generally are smaller than **M** 5.0. However, older structures or those not designed to meet current earthquake resistance standards could be susceptible to structural damage in earthquakes of this magnitude or lower. In rare cases, nonstructural damage has been reported in earthquakes as small as **M** 3.0.

  In the United States significant damage to structures has been documented in several induced earthquakes including:

  - the Pawnee, Oklahoma **M** 5.8 earthquake which damaged brickwork and cracked sheetrock at a number of structures;
  - the 2011 **M** 5.7 Prague, Oklahoma, earthquake, which damaged some local homes, broke windows, cracked masonry, and collapsed a turret at St. Gregory's University (Earthquake Engineering Research Institute 2011);
  - the 2011 **M** 5.3 Trinidad, Colorado, earthquake, which caused structural damage to unreinforced masonry as well as nonstructural damage, including cracked masonry, fallen chimneys, broken windows, and fallen objects;
  - the 2016 **M** 5.0 Cushing, Oklahoma event which resulted in cracks to buildings and fallen bricks and facades on City Hall and the Lions Club; and
  - the 2012 **M** 4.8 Timpson, Texas, earthquake, which caused fallen chimneys and damage to masonry walls. (Morgan and Morgan 2011; Frohlich et al. 2014)
- **Human anxiety:** Anxiety refers to the human concern created by low-level ground shaking. Because injection-induced seismicity is generally of a small magnitude and short duration, human anxiety is often the primary impact associated with most felt events.

Ground-Motion Models for Induced Seismicity

Ground-motion models are used to predict the ground shaking at a given site to determine if it poses a hazard. Ground motion recordings of earthquakes from seismic stations in Oklahoma, Kansas and Texas are now becoming available and several efforts are underway to develop ground motion models.

The ground-motion models that are currently being used for injection-induced seismicity are extrapolated from data for tectonic related earthquakes, which introduces a number of uncertainties. For example, it is not known whether ground motions from injection- induced earthquakes differ statistically from those from natural earthquakes, whether they change (scale) with magnitude and distance in the same way, and, if so, whether this scaling is a function of tectonic regime as with natural earthquakes.

Examples of Current Models

Figure 1.4 shows several ground-motion models that have been used for injection-induced seismic events, including the Pacific Earthquake Engineering Research (PEER) Center's Next Generation of Attenuation (NGA)-West2 models and a model by Atkinson (2015). Both models are derived from data on natural earthquakes and are appropriate for tectonically active regions like the western United States. The NGA-West2 models are applicable down to **M** 3.0 to 3.5, while the Atkinson model is applicable for **M** 3.0 to 6.0 at distances less than 40 km.

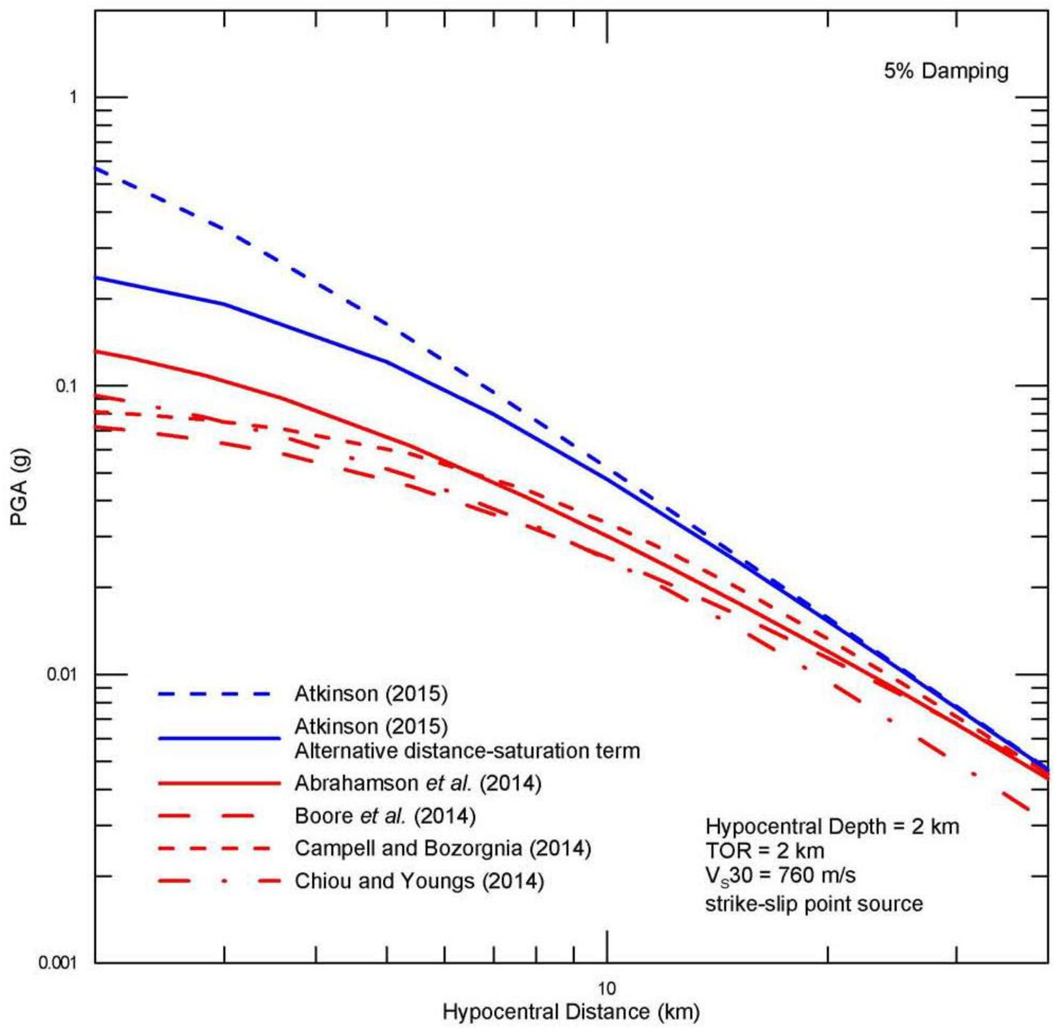


Figure 1.4. Comparison of NGA-West2 and Atkinson (2015) ground-motion models for **M** *4.5 on soft rock (V_S30 760 m/sec). Peak ground acceleration (PGA) in terms of factors of gravitational acceleration (g's) is predicted as a function of distance from the earthquake hypocenter. Source: Wong et al., 2017.*

Most recently, several new ground-motion prediction models for tectonic earthquakes in central and eastern United States have been developed as part of the NGA-East project (PEER 2015).

One such model for natural earthquakes in the central United States by Darragh et al. (2015) does not include injection-induced earthquakes because they may have much smaller stress drops. Other studies by researchers including the USGS (e.g., Hough 2014) also indicate that the stress drops of induced seismic events appear to be lower. The smaller stress drops for the latter will give smaller ground motions. This issue is a topic of active research.

Efforts are under way to develop new empirical ground-motion models for potential injection-induced seismicity based on the data being recorded in areas such as Oklahoma, Kansas and Texas (Wong et al. 2017). Figure 1.5 shows peak ground-acceleration values from several potentially injection-induced earthquakes in Oklahoma and Kansas compared to the model of Atkinson (2015). The data show the typical variability associated with the median ground-motion model and illustrate the uncertainty in ground-motion models.

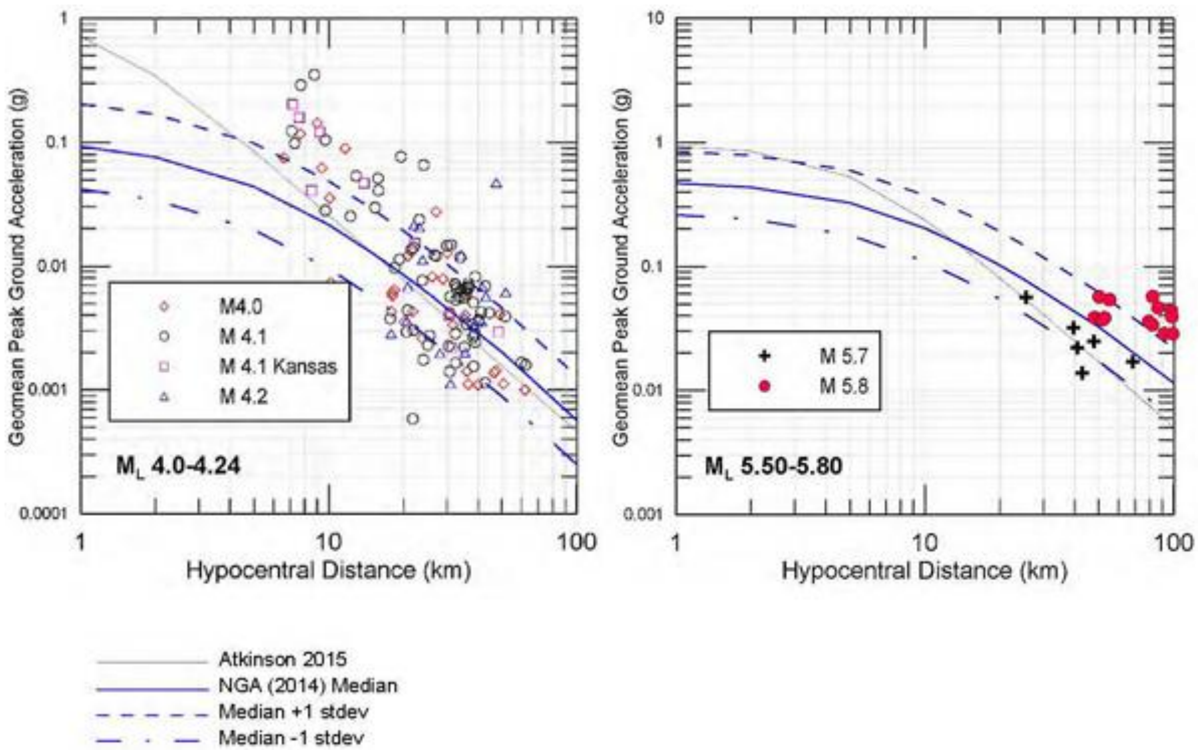


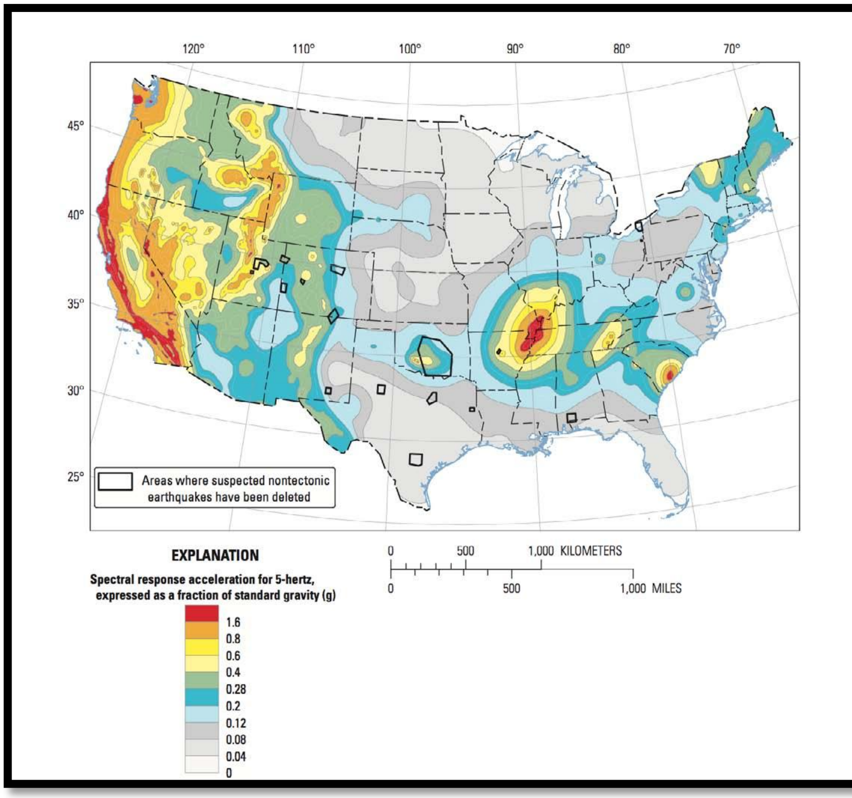
Figure 1.5. Comparison of Oklahoma and Kansas potentially injection-induced earthquake peak ground acceleration values and the Atkinson (2015) ground-motion model for two magnitude bins. Source: Wong et al. 2017.

USGS Hazard Maps

The USGS has characterized ground shaking in the United States through the development of the National Seismic Hazard Maps (NSHM), which are based on long-term seismicity records and geologic activity rates. These maps form the basis of the U.S. building codes, earthquake insurance ratings, and risk assessments.

In both 2015 and 2016, the USGS developed one-year seismic hazard forecasts for the central and eastern U.S. that includes the hazard from both induced and natural earthquakes (Petersen et al., 2016, 2017). The hazards maps drawn from these efforts assume that the non-stationary process of induced seismicity is stationary at least for a one-year period. The maps are based on inputs that include alternative earthquake catalog durations, maximum magnitudes, and ground motion models. The intent of the alternative models is to capture the uncertainties in the model parameters and the range of models in the scientific community.

In the 2017 forecast, the same methodology and logic trees were used as for the 2016 forecast with an updated earthquake catalog being incorporated into the model. The seismic hazard forecast for 2017 was lower than for 2016 as seismicity rates were lower in 2016 than in 2015. The shape of the hazard areas also shifted somewhat due to the inclusion of the 2016 earthquake data. (Petersen et al 2017).



F*igure 1.6. An example of the 2014 seismic hazard map (excluding potential induced seismicity) from the recent USGS report. Areas of potential induced seismicity are shown as black polygons on the map. Source: Petersen et al. 2015.*

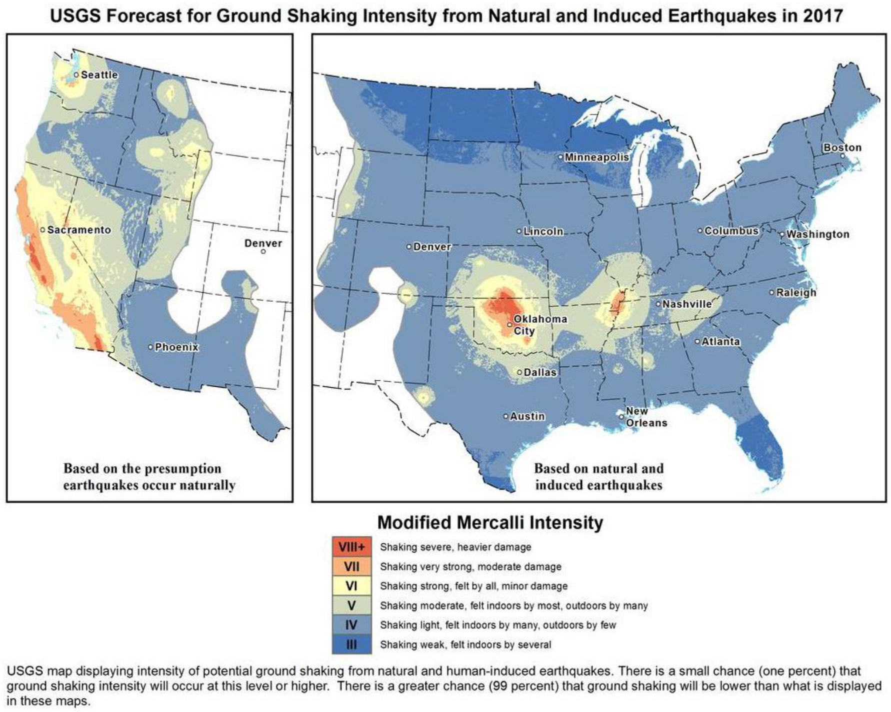


Figure 1.7. Short-term Induced Seismicity Models – 2017 One-Year Model, Source: USGS Earthquake Hazards Program - https://www.usgs.gov/news/new-usgs-maps-identify-potential-ground-shaking-hazards-2017

The USGS concludes that induced earthquakes are difficult to include in probabilistic seismic hazard analysis because the hazard is 1) highly variable spatially and temporally, 2) dependent on human economic or societal decisions about when to initiate or terminate wastewater disposal and how much fluid (volume) would be injected or extracted, 3) conditional on understanding differences between source and ground-shaking characteristics of induced and natural earthquakes, and 4) dependent on the length and depth extent of the causative faults, which generally are unknown. Many decisions are critical to the analysis, including modeling decisions about earthquake catalogs, rates, locations, maximum magnitudes, and ground motions.

The final USGS model will be released after further consideration of the reliability and scientific acceptability of each alternative input model.

Estimated Number of Induced Seismicity Locations

The report by the National Research Council (NRC), "Induced Seismicity Potential in Energy Technologies," published in 2013 and providing information only through 2011, is a detailed summary of induced seismicity of all types, principally in the United States (2013). At the time the first edition of this document was published, the NRC had identified 156 global locations where induced seismicity was suspected to be caused by energy technologies (during the last ~80+ years). Geothermal projects and reservoir impoundment projects (e.g., dam construction and hydroelectric power generation) accounted for a significant portion of these cases (69 locations). In the United States, the report notes 60 energy-development sites where seismic events were caused by or likely related to energy-development activities. The report identifies sites in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas. Since 2011, a significant number of new cases of potentially induced seismicity have been identified. The NRC report is briefly summarized in Appendix E and the full report is available at http://www.nap.edu/catalog.php?record_id=13355.

Since 2011, there has been a significant increase in the number of additional potential induced seismic events reported and studied in the published literature. Broadly in Oklahoma, it is believed a significant portion of the seismicity increase is associated with wide-spread disposal of waste-water in the Arbuckle formation. It should be noted that the seismicity in Oklahoma tracked by the Oklahoma Geological Survey showed a downward trend during 2016. Similarly in Texas, researchers are studying the potential for induced seismicity associated with disposal of saltwater into the Ellenberger formation. There have been several cases of moderate seismicity attributed to hydraulic fracturing operations in Oklahoma, Ohio, Pennsylvania, and western Canada.

How Fluid Injection May Induce Seismic Events

Class II fluid disposal typically involves injection into permeable formations. The majority of disposal wells in the United States do not pose a hazard for induced seismicity, but under some geologic and reservoir conditions a limited number of injection wells have been determined to be responsible for induced earthquakes with felt levels of ground shaking.

An earthquake occurring on a critically stressed fault after injection of fluids is considered a triggered earthquake because a relatively small amount of stress perturbation or pore pressure change caused the release of stress. The stress accumulates in the earth's crust through natural tectonic processes and can be stored for millennia before being released in an earthquake or earthquake sequence (Zoback and Gorelick 2012).

The main physical mechanism responsible for triggering injection-induced seismicity is increased pore pressure on the fault surface, which decreases the effective normal stress, effectively unclamping the fault and allowing slip initiation (Hubbert and Rubbey 1959; Ellsworth 2013). The slip is triggered when the stress acting along the fault exceeds the frictional resistance to sliding. The common concept that injected fluids cause earthquakes by lubricating underground faults is not entirely accurate because fluids do not decrease the coefficient of friction. Rather, injected fluids (or extracted fluids) cause earthquakes by changing the stress conditions on and within faults, bringing these stresses into a condition in which driving stresses equal or exceed resistive stresses, thereby promoting slip on the fault.

Factors that may increase the probability of triggering an event include the magnitude and the spatial extent of stress perturbation or pore pressure change, which is tied directly to the balance of the fluid being injected and withdrawn, the presence of critically stressed faults well oriented for failure (faults of concern), the *in-situ* stress condition, and the hydraulic connection between the injection zone and the critically stressed fault (Townend and Zoback 2000). See Chapter 2 for a detailed discussion of factors indicating whether an earthquake is induced.

For the most part, injection-induced seismic events, particularly those larger than **M** 1.0, are relieving tectonic stress stored along preexisting faults, but their occurrence has been accelerated by a triggering mechanism such as pore pressure increase due to injection. In other words, natural earthquakes may have occurred eventually in an area of induced earthquakes, although not necessarily in the exact same manner or time frame. This latter point is somewhat controversial, and it is not possible to assess how much longer it would have taken for the tectonic stresses to be relieved naturally in the absence of a triggering mechanism because fault reactivation strongly depends on *in-situ* stress conditions and how close to failure the causative faults were initially.

Research is under way to explore the physical links between the recently observed increase in mid-continent seismicity and oil and gas activities. Of particular note is the recent evaluation of possible temporal and spatial correlations of disposal operations over broad geographic regions in Oklahoma to earthquakes in those specific geographic areas (Walsh and Zoback 2015). Walsh and Zoback propose a conceptual model for the increased seismicity in Oklahoma based on their analysis of disposal well data and injection volumes and the correlations to observed patterns of seismicity. With the observation that many of the earthquakes in Oklahoma occur in the basement underlying the Arbuckle Formation, Walsh and Zoback hypothesize that the Arbuckle Formation (the disposal zone) may be in hydraulic communication with the underlying crystalline basement over broad areas. They add that significant growth in disposal of produced water increases pore pressure in the Arbuckle Group that then spreads out away from the injection wells with time, eventually triggering slip on critically stressed faults in the basement

Researchers continue to advance development of integrated technologies and approaches to evaluate the potential for fluid injection to induce fault slip. One such example is the now publicly-available "Fault Slip Potential" software tool; Rall Walsh of Stanford University recently developed this integrated reservoir-geomechanics software modeling tool to estimate the chance of a fault slipping in these circumstances, given stress, pore pressure, and injection conditions (see Appendix F).

Additional research (Langenbruch and Zoback, 2016) is focused on developing predictive models to better forecast potential seismicity based on statistical model of injection-related seismicity in Oklahoma that links changes of saltwater injection rates to seismicity rates. The Langenbruch and Zoback model is based on an approach developed to evaluate fluid injection–induced earthquakes at geothermal and hydrocarbon reservoirs that are usually associated with a single injection well and adapting this model to hundreds of large-volume injection wells and thousands of injection-related earthquakes in Oklahoma. The model is first calibrated the model with the observed earthquakes and reported injection volumes in the areas covered by the directives and then goes on to predict how induced seismicity in Oklahoma will respond to the mandated injection rate reduction. These forecasts associated with the innovative models suggest seismicity should be reduced with the volume reductions that have been implemented in Oklahoma.

Potential for Seismicity Related to Hydraulic Fracturing

Incidents of felt-level seismicity associated with hydraulic fracturing occur far less frequently than those associated with Class II disposal wells and typically have smaller magnitudes than injection-induced seismicity. Within the U.S., the largest published earthquake known to have been triggered by hydraulic fracturing is an event in Mahoning County, Ohio of about **M** 3.0 (Skoumal, et al.,, 2015). This event did generate a number of felt reports. The largest recorded seismic events to date, that researchers have associated with hydraulic fracturing operations, have been magnitude **M** 4+ events that occurred in the Alberta and British Columbia regions of Canada (Atkinson, 2016).

Since the energy release associated with an earthquake is dependent on the size of the fault segment that slips, and the amount of slip fault slip, the fact that larger events have occurred in Canada than in the US suggest the geologic conditions are significantly different; and ongoing research is focused on developing better understanding of the triggering release mechanisms associated with hydraulic fracturing potentially inducing surface felt seismic events.

As described in detail in Appendix I, the process of hydraulic fracturing is significantly different from the process of injecting fluid into a permeable and porous disposal zone. The volume of fluid injected over the short term is typically higher than with a disposal well; however, the hydraulic fracturing process lasts only a short time compared to a long-term disposal well. In hydraulic fracturing, the fluid is pumped into the well at high rates and pressures, causing the target formation to fracture. Hydraulic fracturing will produce very small earthquakes (microseismic events). Disposal wells are typically designed and operated to prevent such fracturing.

Unlike disposal, hydraulic fracturing is a transient process in which the wellbore typically is subdivided into stages, isolating subsequent intervals so that extended fault contact is not likely. Fracturing of a stage lasts from one to several hours, depending on volumes and rates. The well, which may be produced soon after the fracturing operation, becomes a pressure sink, drawing fluids into it and decreasing pore pressure in the vicinity of the well. Appendix I contains technical information regarding induced seismicity potential relative to hydraulic fracturing.

Several states including Ohio, Oklahoma and Pennsylvania have or are adopting procedures and action points for companies conducting hydraulic fracturing in order to limit the magnitude of any seismicity that may be associated with such operations. Research into the causes of such events is continuing. (See Appendix G)

Future Research

Induced seismicity has a long history with increased focus during the past five years, as evidenced by the recent scientific meetings and conferences on the subject. Although the basic mechanism of injection-induced earthquakes is well understood, each case is a product of the local geology, including faulting, *in-situ* stress conditions, hydrologic regime, and the characteristics of the causative injection. Some of the questions of interest to researchers include:

- What new methods and techniques can be used to better identify the presence of critically stressed faults in proximity to injection sites?
- Are stress drops of injection-induced earthquakes smaller than those of natural earthquakes?
- Are ground motions of induced earthquakes different from those caused by natural earthquakes?
- Can the maximum induced earthquake be estimated?
- If intensity is a measure that the induced-seismicity community wants to continue to use, how is it related to other ground-motion parameters? Is the relationship site-specific?

- Can advanced seismic waveform processing techniques be developed to offer higher sensitivity in detection and location of seismic events to better illuminate faults as they move?

Chapter 2: Assessing Potentially Injection-Induced Seismicity

Chapter Highlights

This chapter discusses the following:

- Assessing seismicity
    - Historic records – recorded by seismographs (instrumental), reported by humans and observed impacts on the built and natural environment, and geologic evidence (non-instrumental)
    - Contemporary and current and ongoing seismicity – recorded by seismographic networks, both regional and local, including seismic monitoring by States with regional and temporary local arrays
- Assessing conditions in the disposal zone and below
    - Fluid data – disposal volumes, rates, and pressures, by location and region
    - Geologic and hydrologic data – reservoir properties (e.g., porosity and permeability, thickness, brittleness and fractures, proximity to basement and known faults), pressure, in-situ stress, and deep faults in the region and their potential for reactivation
- Causation studies, including:
    - Conditions necessary for induced seismicity from fluid disposal
    - Uncertainty in the data
    - Screening tools
    - Developing geomechanics/reservoir models to predict stress and pressure changes and their ability to reactivate faults and cause earthquakes

Introduction

Assessing seismicity for whether it is related to injection involves three activities:

1. Assessing historical and contemporary seismicity
2. Assessing conditions in the injection zones
3. Assessing possible causes

This chapter will discuss these areas; the data required and its inherent uncertainty, and the subsequent analysis to help determine causation.

Historical Seismicity: Historical seismicity data are needed to establish the background rate of naturally occurring events in a particular area. This baseline enables detection of changes in the seismicity rate, which, in turn, may indicate whether recent increases in seismicity are likely to be due to natural causes or human activity. A survey of past events includes data from non-instrumental and instrumental records.

- **Non-instrumental records:** These can include academic reports, historical summaries of public reports, newspaper archives, and other historical accounts of earthquakes as well as paleoseismological observations (looking at the stratigraphic record of ancient earthquakes). These records are less complete and more qualitative than instrumental records. A primary reference is "Seismicity of the United States 1568−1989 (revised)" by Stover and Coffman (1993). This report documents felt and important instrumentally recorded earthquakes in each state. Paleoseismological observations sometimes offer direct evidence of past earthquakes, as in the case of the large surface deformation visible for the Meers Fault in Oklahoma (Crone and Luza 1990). More often, however, the evidence is indirect, particularly for past activity in the central and eastern United States. For example, evidence for possible past earthquake activity in the New Madrid Seismic Zone (Tuttle et al. 2005) consists of observations of liquefied loose sands.
- **Instrumental records:** These are obtained from national, regional, and local seismic networks. The USGS maintains a searchable database of earthquakes dating back to 1973, available at http://earthquake.usgs.gov/earthquakes/search/. A more complete catalog for the United States covering 1568 through 2012 was used to develop the 2014 National Seismic Hazard Map (Petersen et al. 2014) and can be downloaded at https://github.com/usgs/nshmp-haz-catalogs. In some cases, state governments maintain seismic networks that are not part of the USGS Advanced National Seismic System (ANSS). Some state seismicity catalogs are available online. For example, the Arkansas Geological Survey website (AGS 2014) provides information on station locations and events detected. Ohio, Oklahoma, and Texas have deployed portable seismic networks for proactive seismic monitoring in order to study potential induced seismicity. Similarly, some academic institutions operate seismic networks, either for permanent seismic monitoring or short-term projects, and may maintain archives of events of magnitudes lower than those detected by larger regional networks.

Instrumental records can offer much more information than non-instrumental records, but they are potentially limited by their incomplete and short duration coverage (Schorlemmer and Woessner 2008) as well as limited location accuracy, particularly for event depth (Husen and Hardebeck 2010). However, the earthquake catalog used to develop the 2014 National Seismic Hazard Maps (Petersen et al. 2015) is substantially complete for earthquakes with **M** ≥ 3.5 in the central and eastern United States (Ellsworth 2013).

The historical seismicity record is incomplete for small magnitude events (**M** < 3.5) in most regions of the United States because most of the sensitive seismographic networks needed to monitor such events have been deployed during only the last few decades. Utilizing historical seismicity records requires taking into account uncertainty in earthquake locations and depths.

Contemporary Seismicity:

Increases in seismicity, or seismic areas of interest, are evaluated with data from seismic networks. These can be regional or local, depending on the accuracy needed; whether mere detection is the objective or pinpointing the location of the events.

Regional seismic networks can detect earthquakes below the felt threshold (< **M** 2.5). Many networks can detect and locate earthquakes down to **M** 1. However, there is some uncertainty in the location of these earthquakes due to the wide spacing of seismic stations in these regional networks as well as uncertainties associated with velocity models used to locate earthquakes. Local seismic networks can provide better epicentral location as well as depths because of the density and proximity of the seismic stations.

A widely-spaced network of seismometers operated by the USGS and other organizations covers the United States. Earthquake locations initially reported by the national USGS network can have substantial uncertainty. The epicentral location uncertainty is ~5−10 km and depth uncertainty is ~10 km across most parts of the United States. This location uncertainty is due to the small number of seismic stations used, the wide separation of stations (often more than 100 miles), and the use of general models that do not reflect local variability in seismic velocities or geologic conditions. Depths are particularly problematic; for some events, the USGS usually fixes a default value and reports the depth at 5 km.

Seismic Monitoring/Strong Earthquake Shaking					
Metric	**Units**	**Hi-Risk Urban Areas**	**Mod-High Hazard Areas**	**National**	**Global**
Magnitude Completeness Level	M	2	2.5	3	4.5
Epicenter Uncertainty	km	2	5	10	20
Depth Uncertainty	km	4	10	10	20

Table 2.1. Performance targets for the ANSS for different areas. Adapted from Advanced National Seismic Systems Performance Standards Version 2.8.

In some states, regional networks are operated by universities such as the New Madrid network operated by Memphis University.

A more densely spaced but temporary network of seismometers was operated by an academic consortium, IRIS (the Incorporated Research Institutions for Seismology), that swept across the country in the past decade, with stations in place for several years before leapfrogging forward. This was part of a coordinated research program known as the EarthScope USArray. For example, from 2009 to 2011 the program deployed stations at 70 km spacing across Texas. This presented an opportunity to record much smaller earthquakes than usual and to locate them more accurately (Frohlich et al. 2015). The US Array data are available to all the states and may be a resource for early screening of seismic activity.

Seismic Monitoring by States

Because of the limitations inherent in the USGS National network (see Table 2.1) some states have augmented their seismic monitoring capabilities. Local seismic monitoring of seismic activity near a disposal well may assist a state in managing risks through appropriate operational controls, while seismic monitoring at the state level may improve detection of earthquakes and assist in examining causes and informing regulatory action. Because catalogs of events in state and local networks use different thresholds and processing methods than the USGS, data need to be reconciled for purposes of analysis and outreach. Data sharing, archiving, and dissemination are possible through a national repository managed by IRIS (http://ds.iris.edu/ds/nodes/dmc/). If a state decides to augment available seismic data, it may deploy either a permanent or temporary network.

Permanent Networks: A permanent, statewide network can supplement national and other networks to improve the detection threshold of seismic events and to provide better baseline data. Historic seismic activity, oil and gas activity, and other criteria can help determine network requirements. A permanent network operates on a continuous basis with automated analysis and near real-time notification. The network can be designed to target a detection level to record small seismic events and provide a good estimate of the location. Ideally, the network would be designed for the best detection capability around active oil and gas areas. Four states (Ohio, Oklahoma, Kansas, and Texas) already have deployed state seismic networks. Requiring operators to help fund the state seismic network could be added to well permitting fees in identified areas of potential induced-seismicity risk, such as those outlined in Petersen et al. (2015), or where injection is close to critical facilities, such as schools, hospitals, power plants, or airports.

Temporary Networks: A state agency may use temporary networks to allow rapid response to an earthquake or a local increase in seismicity or to proactively monitor areas of interest. These dense networks typically record aftershocks of an initial event or sometimes a larger main event (such as in Youngstown, Ohio, on New Year's Eve 2011). They can help determine more accurate earthquake locations and depths, highlight active geologic faults, and help determine potential causes. Temporary networks also can be deployed to areas of interest and where baseline data is desired before disposal. For example, the U.S. Bureau of Reclamation began recording background activity six years before saltwater injection began at Paradox Valley, Colorado.

Generally, a temporary network consists of three or more seismic stations. The temporary network can remain in place as long as needed because induced seismicity can continue to occur a year or more after injection ceases.

Because the number of seismic events increases exponentially with decreasing magnitude, target detection levels can be sufficiently low to allow detection of a sufficient number of events to illuminate active geologic features. However, post-processing of the data often may show such features. For example, if an **M** 3.0 has been detected by the National network, there may be 10 or more **M** 2.0 and 100 or more **M** 1.0 events associated with this sequence. In this case, a local network designed to detect and locate **M** 1.0s with confidence (the magnitude of completeness [M_c]) is likely to see enough seismic activity to assist with the interpretation.

Strong motion sensors (e.g., accelerometers) should be included in the network to measure actual surface ground motion (acceleration or velocity and frequency) resulting from the seismic events to assess effects on people and infrastructure in higher risk areas (see Appendix D).

Several states have deployed seismic networks. For example, Ohio receives real time data from 39 seismic stations, and will be deploying 14 additional stations. In Texas, TexNet installed 22 permanent and 3 auxiliary stations that, when integrated with the existing 18 stations, will compose the backbone seismic network of 43 stations. Texas will also make 36 portable stations available for temporary deployment, enough to cover three or more local areas of seismic interest. The Oklahoma Geologic Survey (OGS) has proposed a 3- year phased approach to upgrade the current seismic network consisting of 20 permanent seismometers. The proposal includes the installation of 72 permanent seismograph stations replacing the USGS and OGS temporary stations. The cost to install the new stations is estimated to be $3.5 million and will cost $400,000 to operate for 5 years. It should be noted that should the OGS be able to receive an operating budget in line with the Fiscal Year 2016 budget, the $400,000 operating costs would be absorbed in the annual operating budget.

State regulatory agencies may need outside assistance and expertise to undertake detailed seismic monitoring or investigations. Entities such as USGS, state geological surveys, research institutions, universities, or private consultants can assist states in designing and installing seismic networks and in analyzing seismic data. For example, USGS currently has ongoing relationships with Kansas and Oklahoma and has collaborated actively on the deployment, operation, and maintenance of temporary seismic stations. USGS has also worked with university partners on temporary deployments in Texas and Ohio.

The USGS is willing to work with new or expanding state networks to provide advice on how to optimize their design to improve location accuracy and best integrate with the capabilities of other ANSS seismic-monitoring networks. Networks may request to join ANSS as self-supporting participants, provided they meet ANSS policies, standards, and procedures (listed at http://earthquake.usgs.gov/seismic monitoring/anss/documents.php).

Disposal Zone Conditions:

The other aspect of induced seismicity is the waste disposal that may be causing it. This requires the gathering of injection data such as volumes, rates, and pressures, as well as details about the zone of injection, such as geological and hydrological properties, and the proximity to basement, and to faults and the geological properties between these features and the zone of injection. These data can be mapped or put into models that can estimate the effects of the disposal and their ability to reactivate faults.

Key data to understand subsurface conditions include:

- Fluid data:
    - Volumes, rates, pressures (downhole – average and maximum)
    - Physical properties: fluid density and temperature, compressibility
    - Fluid chemistry

    - In-situ fluid properties: physical and chemical, phases present (gas or liquid)

- Geological data:
    - Reservoir thickness and areal extent
    - Reservoir porosity, permeability
    - Mechanical properties – elasticity, ductility
    - Stratigraphy – especially presence of confining layers above and below
    - Presence and orientation of faults and fractures
    - In-situ stresses, vertically and horizontally, due to rock mass and fluids

Many of these data are available from state agencies (fluid data) and operator records on file with the state (basic geologic data e.g., from well logs), or known to state geologic survey organizations. Some data are questionable and may be difficult to use. For instance, the pressure data most commonly recorded is surface pressure, and often that may be just an instantaneous measurement. Surface data is rarely a good measure of downhole reservoir pressure as it is affected by tubing friction, wellbore conditions and near-wellbore damage. Downhole pressure gauges are not commonly employed but give more accurate representations, and some states are increasingly encouraging their use. Stress data can be inferred qualitatively from some well logs, but only in direction and relative magnitude and not quantitatively (except for overburden stress which can be calculated from rock density logs).

With the increased attention to induced seismicity, more and better data will be acquired with subsequent improvement in models that could help regulators predict seismicity, or attribute causation, and inform its mitigation, as discussed below.

Evaluating Causation

While most injection sites do not trigger earthquakes, induced seismicity can occur under certain conditions. The EPA report (USEPA 2015) "Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches", identifies three components as necessary for felt injection-induced seismicity:

- Sufficient pore pressure buildup from disposal activities
- Faults of concern
- A pathway allowing the increased pressure to communicate with the fault

When these conditions are present, an induced earthquake may occur on the fault when the balance between the stresses on the fault and the frictional strength of the fault is disrupted. The fault will remain locked as long as the shear stress is less than the clamping forces as modified by fluid pressure. A rise in pore pressure of as little as a few psi or a shear stress increase of the same amount can be sufficient to initiate an earthquake on a critically stressed fault.

Assessing causation requires combining seismicity information and disposal conditions as above. At present, it still remains difficult to clearly and uniquely differentiate between induced and tectonic earthquakes using seismological methods. Integration of multiple technical disciplines and skill sets often is required to perform a causation assessment with collaboration among seismologists, reservoir engineers, geomechanical engineers, geologists, and geophysicists. Stakeholder collaboration also is often critical to obtain the broad data sets necessary.

The current primary evaluation is spatial and temporal correlation; proximity and timing. Did events occur near a Class II disposal site concurrent with or soon after injection? However, this alone is insufficient to prove causation because spatial and temporal correlation does not address other factors, such as geomechanical processes associated with induced seismicity.

Evaluating causation can be a significant and time-intensive process, entailing locating the seismic event(s) accurately, locating critically stressed faults that may have been reactivated, identifying the detailed temporal and spatial evolution of seismic events where fault slip first occurs and of any associated aftershocks, characterizing the subsurface stress near and on the fault, and developing a physical geomechanics/reservoir model that would evaluate whether an induced subsurface pore pressure change could initiate an earthquake. Other anthropogenic causes need to be considered also. Along with injection wells and production wells, other sources may include geothermal operations, reservoir impoundment, lake-level fluctuations, and possibly other activities.

Uncertainty: The process described in this chapter involves significant challenges and uncertainty. For example:

- **Locating the seismic event(s)**: Evaluating the possibility of induced seismicity requires a reasonably precise and accurate location of earthquake hypocenters. Often, in those states without statewide or regional networks, the first examination of the seismic data is the earthquake locations reported by the USGS. In general, the epicentral location uncertainty is ~5 to 10 km and hypocenter location uncertainty is ~10 km across the majority of the United States (Table 2.1) for events less than **M** 3.0. Deployment of local seismic stations concurrent with an ongoing earthquake sequence provides a mechanism for reducing these location uncertainties.

- **Characterizing changes in subsurface stress**: A definitive assessment is difficult due to a lack of detailed knowledge of the subsurface stress conditions in proximity to the seismic activity. To evaluate whether fault reactivation is due to pore pressure increases from fluid injection versus dynamic tectonic forces requires reasonable knowledge of and estimates for fault friction, strength, and tectonic stress changes. In general, this information is not readily available. States are beginning to require more frequent and more accurate determination of bottom-hole pressures, which will help significantly with this challenge. Research continues to find ways to determine the relationship between stress and fault reactivation.

- **Developing a physical geomechanics/reservoir engineering model**: While reservoir pressure modeling and geomechanics analysis may be useful for evaluating relative order-of-magnitude impacts of injection, the analysis generally will not provide definitive conclusions regarding causation but will assist risk mitigation. In particular, information needed to model fluid pressure diffusion in the crystalline basement (where most earthquakes occur) is largely unknown. Geologic, seismologic, geophysical, and geomechanical judgment often must be applied to the assessment, considering all the available information and analysis.

Screening

Davis and Frohlich proposed an initial screening method using seven questions that address not only spatial and temporal correlations, but injection-related subsurface pore pressure changes in proximity to the fault (Davis and Frohlich 1993). Although these screening tests have come under criticism, they are:

1. Are the events the first known earthquakes of this character in the region?
2. Is there a clear (temporal) correlation between injection and seismicity?
3. Are epicenters near wells (within 5 km)?
4. Do some earthquakes occur at or near injection depths?
5. If not, are there known geologic features that may channel flow to the sites of earthquakes?
6. Are changes in well pressures at well bottoms sufficient to encourage seismicity?
7. Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?

These questions address the primary consideration in assessing causation, which is whether the injection has resulted in a sufficient pore pressure or stress perturbation in proximity to the critically stressed fault(s). It is not sufficient to look solely at temporal and spatial correlations of seismicity or at changes in well pressures at the disposal level without also considering the potential pore pressure perturbations at the fault (hypocenter). If all seven screening questions were to be answered no, the observed earthquakes were not induced by injection; conversely, if all seven questions were to be answered yes, then it is reasonable to conclude that the earthquakes may have been induced by injection.

A mixture of both yes and no answers results in an ambiguous interpretation. In these circumstances, more detailed analysis could be conducted to better assess factors that may be contributing to causation. This analysis generally would involve developing a better understanding of the geologic features and subsurface stresses in proximity to the fault, and further addressing question 7, “Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?” using reservoir engineering modeling tools that appropriately reflect important input data and recognize the uncertainty that may be present in the available data.

Modeling

After acquiring the available data, seismic and reservoir, it may be possible to develop computer models that attempt to predict the subsurface response to fluid disposal. These models typically start with a geologic characterization of the subsurface; what the reservoir conditions are like and how they vary laterally and vertically, what faults and fractures may be present and how are they aligned and how deep do they go, and what stresses and pressures are like in the subsurface. This would then be used by a reservoir model to determine how the addition of fluids would affect the subsurface; how pressure and stress would migrate and to what extent would they increase over time. And finally these could inform a geomechanical model which would assess the effects of an increase in pressure; how the would rock accommodate the new fluids and whether resulting stress be felt by nearby faults and would it be sufficient to reactivate them and cause an earthquake.

In some cases, additional modeling can then be used to help predict earthquake propagation and magnitude and the possible ground motion at the surface. Hazard maps and models would use these and then States could then prepare risk scenarios and appropriate regulatory responses, ahead of potential events rather than reactively.

Modeling generally would be done to appropriately reflect sensitivity studies associated with the range of data uncertainties, and may require the acquisition of additional data (like bottomhole pressure and flow tests) to better constrain the models. Indeed, one of the main advantages in creating all these models is to make clear the deficiencies in the available data. The sensitivity studies help highlight which data are the most critical for predictive capability, and thereby how much to trust the models. Appendix F provides a discussion of available reservoir and geomechanics modeling approaches and their applications and limitations.

Chapter 3: Risk Management and Mitigation Strategies

Chapter Highlights

This chapter discusses the following:

- The difference between a hazard and a risk
- The strategies for managing and mitigating the risk of induced seismicity
- The two basic questions risk assessment from induced seismicity addresses:
  - How likely is an injection operation to pose an induced-seismicity hazard?
  - What is the risk—the probability of harm to people or property—if seismicity is induced?
- Science-based approaches to assessing and managing induced seismic risk from injection including:
  - Characterizing the site
  - Estimating maximum magnitudes
  - Predicting hazards from ground motion
- Mitigation and response strategies:
  - Siting and permitting of new wells
  - Responding to an event

Introduction

This chapter presents risk management and mitigation strategies for potential induced seismicity from Class II disposal wells. It does not address potential induced seismicity from hydraulic fracturing, which is addressed in Appendix I. Risk management and mitigation strategies addressed herein rely on information discussed in Chapter 2.

States have developed diverse strategies for avoiding, mitigating, and responding to risks of induced seismicity in the siting, permitting, and seismic monitoring of Class II injection wells. Appendix C profiles examples of these strategies. In addition, stakeholders—including regulatory agencies, private companies, academicians, and public interest groups—have proposed an assortment of tools and guidelines that can support states in this effort. Several examples are summarized in Appendix G, "Tools for Risk Management and Mitigation."

Given the broad geologic differences across the United States, a one-size-fits-all regulatory approach would not be appropriate for managing and mitigating risks of induced seismicity. Conditions may vary across states or within a given state at a more localized level for a given area of interest. Cross-disciplinary expertise, as illustrated by Figure 3.1, may be needed to establish a framework for science-based risk management and mitigation. Because of the site-specific considerations and technical complexity of tailoring a risk management and mitigation strategy, many state regulators choose to work with expert consultants on this subject.

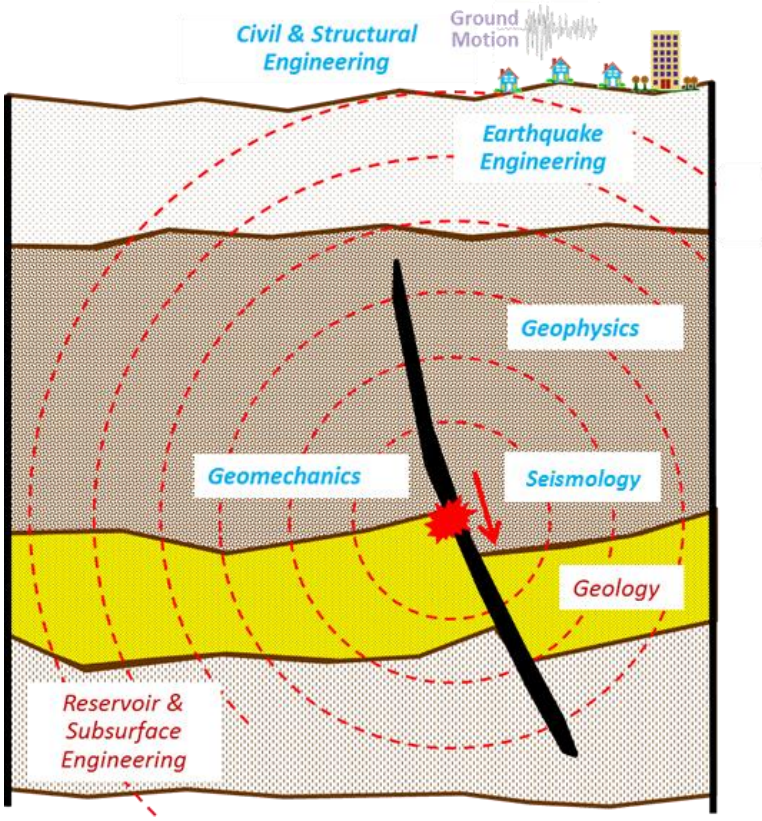


Figure 3.1. Schematic of types of expertise used to examine risk of induced seismicity (after AXPC SME 2012).

Chapter 4 addresses data collection and analysis, which are fundamental elements in any risk management strategy.

Risks and Hazards

Understanding the distinction between risks and hazards is fundamental to effective planning and response to induced seismicity.

- A **hazard** is any source of potential damage, harm, or adverse impact on something or someone.
- A **risk** is the chance or probability that a person or property will be harmed if exposed to a hazard.

The presence of a hazard does not constitute a risk in and of itself. For a risk to exist there must be exposure to the hazard and a mechanism for harm from the exposure. A high-risk activity is one that can frequently result in significant safety, health, environmental, or security consequences, while a very low-risk activity may result in minor consequences on a very infrequent basis, or even negligible consequences on a frequent basis.

Using these definitions, risk assessment regarding injection-induced seismicity addresses two distinct questions:

- **How likely is an injection operation to pose an induced-seismicity hazard?** Preconditions for a hazard include a fault of concern, sufficient pore pressure build-up in the area of the fault related to injection, and a pathway for communicating the pressure.
- **What is the risk—the probability of harm to people or property—if seismicity is induced?** Considerations include the potential magnitude of the earthquake, its associated ground motion, and the proximity of people and structures that might be affected.

To date, the likelihood of induced seismicity associated with a particular injection site has been very low, as has the risk of harm to people or property. While some incidents are believed to have caused injuries requiring medical attention and a limited amount of structural or nonstructural damage to buildings, the most significant common consequence has been anxiety. Industries such as mining, construction, seismic exploration, and geothermal follow statutes or guidelines with regard to ground motion and its effects. However, whether a given population considers detectable low levels of ground motion acceptable or unacceptable (and, therefore, perceived as harmful) is highly subjective and varies from site to site and region to region.

Science-Based Risk Management

Science-based approaches to assessing and managing seismicity risk associated with injection operations weigh both hazard and risk for a specific site. Considerations may include:

- **Site characteristics**, taking into account the geological setting and formation characteristics, including tectonic, faulting, and soil conditions, along with historical baseline seismicity levels (from USGS, state geologic surveys, and private array data);
- **Built environment**, including local construction standards as well as the location of public and private structures, infrastructures such as reservoirs and dams, and historical construction or significant architectural elements;
- **Operational scope**, including existing or proposed injection fluid volumes;
- **Estimations of maximum magnitudes** of potential events; and
- **Estimations of ground motions** related to events, which would vary by the magnitude of the earthquake, the distance from the earthquake to a site, the depth of the hypocenter, and geologic site conditions.

Any available data on past operating experience and potential occurrence of seismicity may be considered as well, along with an assessment of public sensitivity to seismicity in the area.

<u>Site characterization</u>**:** In assessing the risk associated with an injection site, identifying faults of concern is of primary importance, along with characterizing any pathways for communicating pressures to the fault. Such pathways can occur in areas of complex structural history when strata beneath the injection zone may be fractured naturally. Also, faulting in basement rock can extend into overlying sedimentary strata, providing direct communication between the disposal zone and the basement rock.

A main consideration is whether the pore pressure increase from injection can reach the crystalline basement.[1] Avoiding or minimizing the potential for injection into the basement can reduce the likelihood of induced seismicity associated with larger, critically stressed faults that may be present and unmapped in the basement structure. Therefore, the vertical distance between an injection formation and basement rock as well as the characteristics of strata below the injection zone are key factors in any risk assessment.

<u>Estimating maximum magnitudes</u>**:** It is currently not possible to reliably predict the maximum magnitude of injection-induced earthquakes that could occur in an area (see Appendix A). Because the size of the rupture area dictates the magnitude of an earthquake, the maximum-sized earthquake on that fault can be estimated if the dimensions of the fault are known. However, a given fault can produce earthquakes of different magnitudes depending on what portion of the fault is ruptured.

Empirical relationships between rupture length and rupture area have been developed (e.g., Wells and Coppersmith 1994) for tectonic earthquakes larger than **M** 5.0. These relationships are used in seismic-hazard evaluations when the dimensions of active faults are available, primarily from geologic studies, to estimate the maximum earthquake. However, in most locations of induced seismicity, particularly in the central and eastern United States, few active faults have been identified. Geophysical techniques can be used to image faults at depth, but this requires extensive 2D or 3D investigations. These techniques reveal some but not all faults. In particular, existing geophysical techniques are poor at imaging strike-slip faults and faults within crystalline basement, which also are the faults with the highest likelihood of producing an earthquake that could cause damage. Because most induced seismic events are smaller than **M** 5.0, the rupture areas are small. Typically, small faults in basement rock cannot be imaged by traditional oil and gas geophysical techniques.

<u>Predicting hazards from ground motion</u>**:** Several ground-motion models can serve as a starting point for estimating the ground motion from injection-induced seismic events and determining whether the ground motion would be likely to pose a hazard, result in anxiety, or neither (see Chapter 1). Assessing the potential ground-shaking hazard from injection-induced earthquakes typically requires the services of engineering seismologists and geotechnical and structural earthquake engineers.

Mitigation and Response Strategies

States consider a variety of strategies to mitigate risks of induced seismicity associated with a new or existing well, particularly when:

- Significant seismicity (above historical baseline levels) has occurred and a scientific assessment indicates that the seismicity is associated with fluid injection operations; or
- Technical assessment indicates the local area may possess significant risk associated with potential induced seismicity.

[1] As described in the case studies contained in the National Research Council (NRC) report and USEPA report.

Risks associated with potential induced seismicity typically are determined based on a site-by-site evaluation and often can be mitigated by injection-site characterization/selection, injection well design and construction features, and control over well operational factors.

Screening protocols can help determine what mitigation and response strategies may be appropriate under different circumstances. Some states use an “if this, then that” screening process, which may be summarized as a decision tree, risk management matrix, or traffic light system (see Appendix G). Traffic light systems describe the risk thresholds for taking varying levels of mitigation and response actions. Thresholds can be defined based on magnitude or level of ground motion detected and the risk management goals of the agency and may vary based on local conditions. Thresholds may be determined by considering questions such as:

- Did an event of specified magnitude occur within a specified distance of an injection well?
- Did the event occur within a particular area of interest, defined by historic seismicity?
- Did the event exceed a specified ground motion or magnitude?
- Did an evaluation define a reason for concern (e.g., well location within a specified distance of a critically stressed fault; spatial and temporal evaluation of well providing a potential link to seismicity; operational changes in injection pressure, injection volume, or reservoir pressure; or nearby population and infrastructure at risk given a specific level of ground motion)?

Siting and permitting of new wells: For proposed new wells, permitting protocols may include a review of key factors that can affect induced seismicity. Currently these include faulting in and/or seismic history of the area of a proposed disposal well, proximity to basement rock and pathways for pressure transmission into basement rock, reservoir conditions, and the proposed injection volume and rate. In areas where potentially induced seismicity is a concern, the state regulator may include, as part of each project’s operation permit, a mechanism for the well operator to be able to control, reduce, or eliminate the potential for felt seismic events. When an evaluation and response strategy is to be adopted to control operations that may cause unacceptable levels of induced seismicity, disclosure and discussion of the adopted system prior to the start of operations may be considered, so that these safeguards are clearly known and understood by all concerned.

Permitting regulations in some states require identification of known earthquake sources. Colorado, for example, requires the Colorado Geological Survey (CGS) to conduct a review of seismicity at proposed injection sites that includes use of CGS geologic maps, the USGS earthquake database, and area-specific knowledge to provide insight into the seismic potential at the location (COGCC 2011). If seismicity is identified in the vicinity of the proposed injection well site, the Colorado Oil and Gas Conservation Commission (COGCC) requires the operator to define the seismic potential and the proximity to faults using the geological and geophysical data prior to approval (COGCC 2011). The Railroad Commission of Texas requires reporting of all historic earthquakes that occurred within a 100-square-mile area, considering a 9.08-km radius, from a proposed injection well location using data from the USGS (RCT 2014). When establishing the historic seismicity in a local area, it is important to recognize the location error associated with reported events (~5−10 km).

Risk mitigation options in siting and permitting new Class II disposal wells may include:

- Obtaining local stakeholder input concerning risks (see Chapter 4)
- Selecting a different location for new wells
- Avoiding injection into the crystalline basement
- Locating faults in the vicinity of the proposed project area based on seismic survey data or surface expressions and placing the well outside the at-risk area where injected fluid may not significantly and adversely perturb the pore pressure/stress state
- Avoiding direct injection of fluids into known faults of concern.

Permits for new or existing Class II disposal wells might include some conditions, such as:

- Temporary seismic monitoring at specific sites
- Seismic monitoring during drilling for the presence of any previously unidentified faults
- A procedure to modify operations (e.g., step increases in flow during start up or reducing flow) if a specified ground-motion/magnitude event occurs within a specified distance from the well
- A procedure to suspend operations if seismicity levels increase above threshold values for minimizing public disturbance and damage
- A metric to determine if operations could be restarted and the procedure for establishing injection at safe levels.

Temporary seismic monitoring may be considered at the sites of proposed new disposal wells in local areas where induced seismicity is of significant risk. A seismic monitoring requirement with specific magnitude thresholds and location accuracy may be incorporated into the permit. Goals of seismic monitoring may include the ability to:

- Identify any seismic activity that may be attributable to injection at a site
- Indicate when any induced seismicity at a site has the potential to damage structures, be felt by the public, and/or cause serious disturbance to the public
- Use data to create appropriate site-specific actions to mitigate the risk of potential induced seismicity (see Appendix C).

A seismic monitoring plan might include the method of seismic monitoring, type of instrumentation required, reporting of data analysis, and an archive of the data in a public seismic database, thresholds for reporting changes in seismicity, steps to mitigate and/or manage risk by modifying operations, and thresholds for suspension of injection activity. For example, Ohio recently developed a new seismic evaluation program. The Ohio Department of Natural Resources selected disposal wells for seismic monitoring based on the geology and proximity of the injection zone to the Precambrian basement rocks, where most of the seismicity in Ohio occurs. Seismic monitoring occurs prior to injection and continues after it has begun. If no significant induced seismicity is detected, the seismic instrumentation may be moved to another location with the written approval of the division chief. This program is implemented on a case-by-case basis.

In some cases, states have decided to install their own permanent or temporary seismic networks, as discussed in Chapter 2.

Planning for and responding to an event of potentially induced seismicity: Because the risk from induced seismicity depends on the characteristics of the injection locations and operations, many states utilize site-specific, flexible, and adaptive response actions when an incident of seismicity occurs that may be linked to injection. States may determine that different types of response strategies are "fit for purpose," depending on whether an event of potentially induced seismicity resulted in damage or felt levels of ground motion or was detected using seismic monitoring, with no damage or felt levels of ground motion.

Generally, an initial step in developing a response strategy is to collect background and baseline information about the event. In some cases, a state also determines that seismic evaluation of an event of potentially induced seismicity is warranted. Input from many technical disciplines may be involved in such evaluations, addressing geology, hydrology, geophysics/geomechanics, seismology, reservoir engineering, civil engineering, oil and gas injection well operations, and permit conditions. Data that can be used to inform a seismic evaluation and reservoir/geomechanics modeling include:

- **Seismicity data** includes historic and current event recordings from USGS, State Geological Surveys, universities and private networks; epicenter locations and magnitudes to conduct spatial evaluations; and ground motion data.
- **Injection well data** includes:
    - Well location to conduct spatial evaluations
    - Daily injection volume to conduct temporal evaluations
    - Cumulative volume over time to conduct reservoir evaluations
    - Reservoir evaluations (e.g., Hall and Silin Plot[s])
    - Daily maximum injection pressure to calculate bottomhole/reservoir pressure;
    - Injectate specific gravity to calculate bottomhole/reservoir pressure
    - Bottomhole pressure (calculated or data from a downhole sensor)
    - Wellbore diagram showing construction of the well, injection depth (top and bottom of open-bore hole of location of perforations), and the formation(s) into which injection is taking place, and separation from basement
    - Log obtained when drilling the well that defines the locations of the formations penetrated
    - Mud log, gamma ray log
    - Log defining *in-situ* stress orientation
    - Resistivity imaging log
    - Dipole sonic log
    - Pressure transient tests
    - Step-rate test
    - Falloff test
- **Geologic data** includes general stratigraphy of typical formations in the area showing their stratigraphy to basement, maximum principal stress information, hydrogeologic data (for hydrogeologic flow and pore pressure modeling, location of faults (best defined by 3D seismic, if available)

- **Local factors** include population, infrastructure, public and private structures, reservoirs and dams

Appendix H contains details on data collection and interpretation.

Based on the risk assessment of the potentially induced seismic activity, a state may determine that operations can resume at the well. When mitigation actions are determined to be appropriate, options might include supplemental seismic monitoring, altering operational parameters (such as rates and pressures) to reduce ground motion and risk, permit modification, partial plugback of the well, controlled restart (if feasible), suspending or revoking injection authorization, or stopping injection and shutting in a well.

Chapter 4: Considerations for External Communication and Engagement

Chapter Highlights

This chapter discusses the following:

- The communication planning process, including preliminary scans, stakeholder involvement, tying communication strategies to risk, conducting mock exercises and other training
- Communication plan elements, such as scenario analysis, external and internal audience analysis, definition of key messages and communication strategies, communication team roles and responsibilities, materials and resources, and potential answers to frequently asked questions
- Guidelines for responding to an event include providing professional, clear, concise, and authoritative responses, listening, documenting, avoiding absolutes, and sharing only approved information
- Incorporating lessons learned, which includes understanding how communication takes place, documenting how decisions were made, avoiding definitive statement or promises, and improving a communications plan
- A case example from the Ohio Department of Natural Resources
- A case example from the Oklahoma Secretary of Energy and Environment

Introduction

Clear and direct communication with the public is an important responsibility of states that are managing the risks of induced seismicity. Many state oil and gas regulatory agencies choose to take a proactive approach by working with state public affairs officers on communication plans that address a range of possible scenarios. Some also adopt outreach strategies that include proactive public education and media engagement to share current information on relevant science and technology and on risk management methodologies used by the state. This chapter provides general guidelines for developing and continuously improving communication plans as well as for responding to induced seismic activity.

There are several key aspects of communication relative to earthquakes:

- Earthquakes can come with no warning and in areas that have not had previous activity
- Shocks may grow with time and activity may go on for days
- Initial official reports of locations and magnitudes can be inaccurate
- The USGS “Did You Feel It?” system and shake maps are good early indicators of intensity and location
- In most of the United States there is no public training as to what to expect from or do during an earthquake
- Public anxiety levels can be high and significant to deal with regardless of damage levels
- Determining causes of earthquakes may be difficult and jumping to conclusions should be avoided

Communication Planning Process

Any situation involving seismicity is likely to be fluid and evolving. Communication planning in advance of any seismic event equips state regulatory and public affairs officers to respond effectively when a dynamic situation arises by designating key communication roles and responsibilities, revisiting the plan when personnel change, evaluating and anticipating likely questions and concerns, drafting key messages and activities based on scenarios, and maintaining a library of up-to-date materials and resources that incorporate current research and knowledge.

While communication planning needs to reflect the specific regulatory and legal structure of each state as well as unique geologies and other local conditions, states may find it valuable to learn from and adopt common planning approaches. For example, in defining the process for communication planning, agencies may elect to:

- **Do a preliminary scan**. The scan can include gathering relevant communication case studies, information resources, and communication planning approaches from other states or agencies; reviewing current communication plans for the state as a whole and specific to the agency; and creating an inventory of communication media and outreach methods (social, print, electronic, community, etc.) available to the agency.
- **Involve stakeholders with multiple areas of expertise**. In crafting the plan, agencies have an opportunity to learn from industry, the research community, and emergency management officials regarding such topics as geology, seismicity, and event response strategies.
- **Tie communication strategies to risk management thresholds**. Agencies may use the thresholds in their risk management plans as communication planning scenarios, defining the strategies along with roles and responsibilities specific to each scenario.
- **Conduct mock event exercises and other training**. Once the communication plan is drafted, an agency may test its communication strategies with a mock event, and evaluate and improve the plan as appropriate. Training should include a drill for designated state employees who will publicly represent the state and clear instructions for communications.
- **Develop, revisit, and revise the communication plans on a regular cycle (e.g., annually)**. Updating and evaluating plans regularly enables agencies to respond to changing situations and knowledge and to ensure that key roles, responsibilities, messaging, and strategies are fully identified and understood.

The planning process may also define the actions to be taken after an event to evaluate the effectiveness of the plan and make improvements to messaging and strategies. Guidelines on plan evaluation are described in the section, "Incorporating Lessons Learned."

Communication Plan Elements

Even if no physical damage has occurred, responding to a seismic event can be similar to any emergency response. In communication planning, therefore, it is appropriate to consider a crisis communication model with clear roles, responsibilities, and procedures. Typically, elements of such a communication plan include:

- **Scenario analysis**. Scenarios may be related to thresholds established in the risk management plan. If these thresholds have not been defined, the planning team can review various scenarios that would merit different levels of communication responses.
- **External audience analysis**. This analysis considers the viewpoints, concerns, perceptions, misperceptions, and commonly asked questions for various external audiences. The agency can outline the likely expectations of different stakeholders (e.g., homeowners, public safety and political officials, businesses, media) and indicate which stakeholders receive notification and at what frequency. Proactive audience research, including public meetings and seismic monitoring media, can provide valuable insights on the unique concerns and needs of each audience. Media contacts for editors and reporters who are likely to be interested in the topic along with links to past coverage generally are maintained in a database by the public affairs office.
- **Internal audience analysis**. This analysis identifies leadership within the primary response agency, in other state agencies and offices, and in the legislature, who need current information and talking points. Generally, internal audiences include responsible parties in the public affairs office. Internal and interagency audiences may be identified using the RACI (Responsible, Accountable, Consulted, and Informed) model to ensure that all internal parties are appropriately informed and engaged in each scenario (http://www.cio.com/article/2395825/project-management/how-to-design-a-successful-raci-project-plan.html).
- **Definition of key messages and communication strategies**. Keeping in mind both the external and internal audiences, the planning team will define key messages and strategies to be used under different scenarios. Strategies typically will address liaisons to major internal audiences and stakeholders; outreach to media (including traditional and digital media) through press conferences, press releases, and other activities; use of online and social media assets owned by the agency or the state; use of a telephone notification system or other method for handling citizen calls; and engagement of appropriate third-party subject-matter experts. Messaging will anticipate the varying interests of each audience. Citizens may be most interested in how to respond to an event and where to receive additional information or updates. Media may be more interested in specifics around the event, the potential causes, and companies that might be involved in the event. Finally, elected officials will likely be requesting information to respond to constituents' questions to determine whether there is adequate regulatory authority to address the issue or avoid future issues.
- **Definition of communication team roles and responsibilities**. Typical roles may include a response manager with overall responsibility for managing the entire response as well as the communication team; an internal liaison to keep agency leaders and public affairs officials up to the minute on events; a designated and trained external (media) spokesperson, who often will be a public affairs officer; and an issue manager, who will support the spokesperson with any needed research and drafting, document events as they unfold, and maintain a history over time. The plan will define roles and responsibilities for each person and define the methods to be used to coordinate the team. In addition, other employees should be able to refer the public to the appropriate agency staff for additional information.
- **Definition of materials and resources**. The team will evaluate available communication and outreach materials and resources (e.g., media backgrounders, public education materials, and

briefings for state and local government leaders), identify gaps to be filled, assign responsibilities for developing new materials, and define the process for keeping the library of materials and resources up to date (typically assigned to the issue manager). Materials and resources should include information about the purpose, roles, and authorities of the various agencies concerning seismicity, the purpose of wastewater injection wells, the process of wastewater injection, hydraulic fracturing, and other oil and gas processes; the rules and regulations regarding injection wells, hydraulic fracturing, and other oil and gas processes; and the general causes of induced seismicity. The effort to develop and maintain current information may involve other government entities, industry, public interest groups, and the research community.

- **Drafting responses to frequently asked questions**. A valuable planning exercise is anticipating and drafting responses to likely frequently asked questions (FAQs). For example, FAQs might clarify the differences between hydraulic fracturing and underground disposal and explain the current consensus view on the relatively low hazards of induced seismicity related to hydraulic fracturing in comparison to disposal. Another FAQ response might address the difference between produced water and flowback water.
- **Outreach and education**. The agency also may plan its proactive outreach and education strategies as part of the planning process. Strategies may include public events and meetings, use of digital and social media, and other methods of educating and interacting with key audiences. Primary goals might include dissemination of information on what the state is doing to evaluate, avoid, mitigate, and manage the risk of potentially induced seismicity.

Guidelines for Responding to an Event

If a seismic event occurs at or above a threshold level, the agency would implement its communication plan. The following are guidelines for the designated spokesperson and others on the team who are drafting press releases and briefing materials:

- **Be professional and objective**. Speak clearly and plainly and be careful not to mischaracterize, minimize, or dramatize the situation. Reflect the agency's respect for public concerns about potentially induced seismicity and its commitment to answering questions and concerns.
- **Listen carefully**. Ensure that stakeholders have opportunities to voice their specific concerns, carefully define the issues as the agency understands them, seek feedback to assure that understanding was correct, and tailor response messages accordingly. Use stakeholder issues as the guide for agency messaging.
- **Avoid speculation**. Avoid speaking in speculative terms regarding public safety and seismicity. Make it clear that there are uncertainties, the situation could change, and the agency is keeping abreast of the situation. Demonstrate that the agency is open to new information and be candid about what is and is not known at any one time (e.g., "to the best of our knowledge and based on the information that we have today…"). This response may not satisfy all stakeholders, but it is consistent and appropriate considering the evolving nature of the knowledge base concerning potentially induced seismicity.
- **Review all information before release**. Be clear on what the agency considers fact, what it is evaluating or investigating, and what it does not know at the time of the questions. Avoid

conjectures and hypotheses without substantiation of the facts. For example, even if a reliable agency such as the USGS issues a report that an event occurred, it does not mean that it can be accurately linked to a source. Such information needs to be verified by the appropriate state agency prior to making any conclusive statements.

- **Monitor communications**. Keep track of media, social media, and stakeholder communications. Monitor what the research community is saying about the event, what various media outlets are saying, and what other agencies are doing in response to the event. Track which entities are asking specific questions (media, citizens, political officials).
- **Document**. Designate a historian to document how decisions are being made and for what reasons throughout the event.

Incorporating Lessons Learned

All communication is personal and individual, regardless of medium or the size of the audience. If the intended receiver does not, for whatever reason, regard a response or message as germane to his or her personal concerns, the communication may not be effective and productive.

It is critical that the agency evaluate its response and communication plans in this light after an event and appropriately modify and improve the plans based on what has been learned.

The agency should document how decisions were made and for what reasons during the event and then follow up with internal and external audiences about what was done well and what needs to be improved. A set of follow-up questions can be developed for each audience to gauge how well communications addressed their needs and expectations, what they learned during the process, and what they wish they knew before, during, and after the event.

With any follow-up communication, the agency should not make promises or definitive statements concerning avoidance of future events. The goal is to show the ongoing commitment of the agency to an evolving concern. Also, it may be important to designate someone at the state who can respond to ongoing inquiries about the status and conclusions of state efforts and investigations.

In the evaluation process, the agency should identify key stakeholders involved in the event that can help educate and communicate with other communities.

Based on its follow-up, the agency can improve its communication plan by considering:

- What communication strategies were effective or ineffective, and why?
- What forms of mediated communication were effective or ineffective, and why?
- What message was misunderstood, and why?
- Have stakeholder concerns changed, and if so, how?
- What worked or did not work regarding intra-agency communication and cooperation?
- What other assets can be used to improve the communication plan?

Case Example: Ohio Department of Natural Resources

On March 10, 2014, the USGS identified four seismic events ranging from **M** 2.2 to **M** 3.0 with a number of felt reports in Poland Township, Ohio. The readings involved a hydraulic fracturing operation. The Ohio Department of Natural Resources (ODNR), Division of Oil and Gas Resource Management, dispatched an oil and natural gas inspector to the site and requested the company halt operations while ODNR conducted an investigation. After reviewing all the data, the investigation concluded that there was a probable connection between the hydraulic fracturing and the seismic activity caused by a previously unknown fault.

Because this incident was only the fourth time hydraulic fracturing had been linked to seismic activity (and the second time in the United States), the agency knew it would draw media attention. The ODNR staff worked to develop a plan, determined the appropriate message, established talking points for the team, and determined how information would be disseminated to the stakeholders. They established the appropriate spokesperson and identified available resources.

The regulatory agency focused its message on more stringent permit conditions and actions by the regulators to address and monitor seismicity across the state. The ODNR drafted a release and worked with both local and national media to share the message. The agency proactively identified third-party validators to quote in the release and serve as an outside source for media, which was helpful in solidifying the credibility of their response and findings.

“ODNR’s directives are a sensible response to a serious issue that regulators across the country are closely examining,” said Gerry Baker, Associate Executive Director of the Interstate Oil and Gas Compact Commission. “IOGCC is pleased to work with Ohio and other states to share scientific data to better understand the nature of these occurrences.”

The Office of Communications was designated to handle media calls and monitor media coverage. The director and legislative staff called legislators when the announcement was imminent to ensure they were kept in the loop. The oil and natural gas subject matter experts taped a 30-second sound bite on a cell phone explaining the details of the announcement. The agency was then able to offer those sound bites to television stations across the state and country. They developed a fact sheet with frequently asked questions, which could be forwarded to stakeholders and media and put on their website.

Seismic monitoring stories in mainstream and social media allowed the agency to determine the effectiveness of their message and make corrections or clarifications as necessary. Overall, the messaging rollout was successful as ODNR was able to provide key points to a number of media outlets and avoid much of the misunderstanding that often takes hold following a seismic event.

Case Example: Oklahoma Secretary of Energy and Environment

By 2015 Oklahoma’s response to the issue of induced seismicity included not only the Oklahoma Corporation Commission and the Oklahoma Geological Survey, but several other agencies as well. At the same time, public concern and questions over the increased earthquake rate continued to grow, not only regarding the oil and gas production connection, but also as related to insurance and concerns over possible damage to the state’s infrastructure. What was needed was a one-stop approach to disseminating information about the state’s response.

The Oklahoma Secretary of Energy and Environment's Office created http://www.Earthquakes.ok.gov, a website that offers information on the state's response to induced seismicity, research, and other vital information. Participating agencies provide the Office with data and other information for the site, which is updated regularly. Among the features of the site is an interactive map that enables residents to look at seismicity rates and disposal well locations for their area.

The site has proven to be a valuable asset for providing comprehensive information to the public in a transparent manner and helping to dispel the misperception by some that the state government was ignoring the seismicity issue.

In 2014, Oklahoma Governor Mary Fallin formed the Coordinating Council on Seismic Activity and charged it with organizing state resources and related activities related to Oklahoma's recent increase in seismic activity. The council meets regularly to share data, studies, developments and proposed actions related to Oklahoma's earthquakes.

Appendix A: Relevant Earthquake Science

This appendix provides background on how earthquakes are generated and seismic waves propagated, the hazards they pose, and techniques used to estimate their magnitude, frequency, location, and intensity as well as associated ground motions, and risk.

Faults and Earthquake Generation

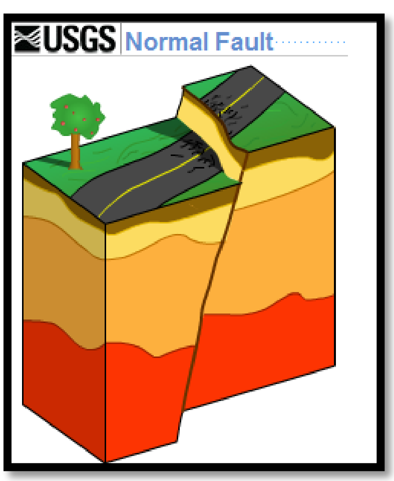
A fault is a fracture or zone of fractures between two blocks of rock (USGS Faults 2012) where the blocks move relative to each other. This movement may occur rapidly, in the form of an earthquake, or slowly, in the form of the phenomenon called fault creep. Faults may range in length from a few millimeters to a few thousand kilometers. Most active faults produce repeated displacements over geologic time.

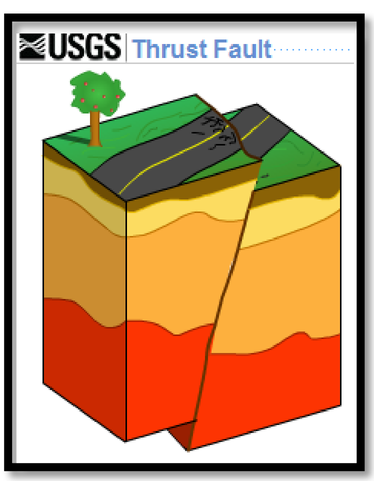
The fault plane can be horizontal or vertical or an angle in between. Geologists classify faults in three general categories, as shown in Figure A.1, using the angle of the fault plane with respect to the surface (known as the dip) and the direction of slip along the fault:

- **Normal fault**: A dip-slip fault in which the hanging wall (block above the fault) has moved downward relative to the foot wall (lower block). This type of faulting occurs in response to extension and is commonly observed in the western U.S. Basin and Range Province and along oceanic ridge systems.

- **Reverse fault**: A dip-slip fault in which the hanging wall moves up and over the foot wall. This type of faulting is common in areas of tectonic compression, such as western Oregon and Washington, Southern California and regions of the central and eastern United States. When the dip angle is shallow, a reverse fault is often described as a thrust fault.

- **Strike-slip fault**: A fault in which the two blocks slide horizontally past each other. The San Andreas Fault in California is an example of a right-lateral strike-slip fault. In a right-lateral strike-slip fault, the displacement of the far block is to the right when viewed from either side. In a left-lateral strike-slip fault, the displacement of the far block is to the left when viewed from either side.





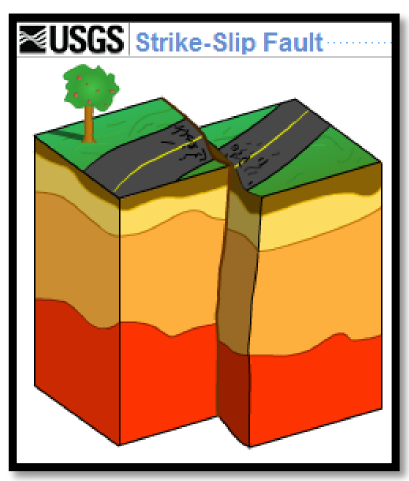


Figure A.1. Examples of a normal fault, thrust fault, and strike-slip fault. Images courtesy of USGS.

Faults that show both dip-slip and strike-slip motion are known as oblique-slip faults.

As illustrated in Figure A.2, the location inside the earth where the earthquake starts (rupture is initiated) is called the hypocenter, and the location directly above it on the surface of the earth is called the epicenter.

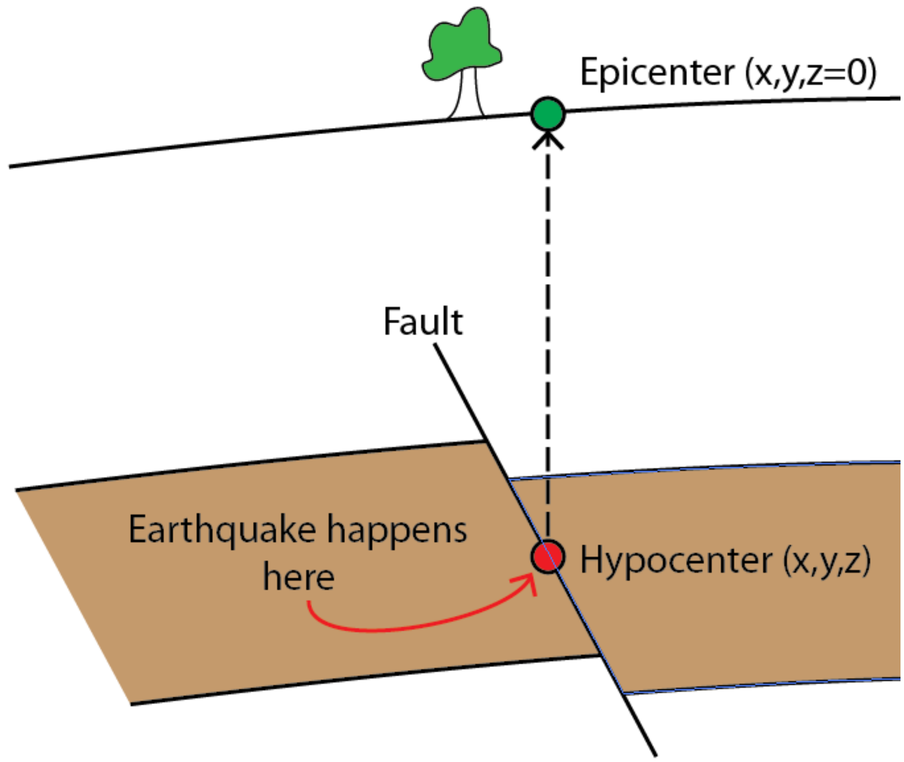


Figure A.2. Schematic illustrating the concept of epicenter and hypocenter locations of an earthquake. Source: ISWG.

As the fault slips, strain energy is expended by the crushing of rock within the fault zone, production of heat, and a release of a small percentage of energy as seismic waves. The relief of stress in one part of a fault may increase the stress in other sections, effectively transferring strain energy to those sections. Such stress transfers influence subsequent earthquakes (aftershocks).

An earthquake can present several types of hazards. Direct earthquake hazards include ground shaking, surface fault displacement, tsunamis, and uplift/subsidence for very large events (**M** > 7.0). Ground shaking, in turn, can introduce secondary hazards, such as liquefaction and slope failure (for example, landsliding). Impacts can include structural and nonstructural damage and human anxiety.

The modern concept of earthquake mechanisms began in the 1880s, when American geologist G.K. Gilbert theorized that earthquakes were the result of displacement along geological faults (Gilbert 1890). In 1910 geophysicist H.F. Reid suggested that earthquakes were the result of a phenomenon called elastic rebound based on observations of the 1906 **M** 7.9 San Francisco earthquake (Reid 1910). This theory states that an earthquake is generated by a rupture or sudden displacement along a fault strained beyond its elastic strength. In the process of strain accumulation, the opposing sides of the fault are stressed until a sudden displacement occurs, releasing the stored elastic energy (accumulated strain), and then opposing sides rebound to a less strained state with some permanent displacement. Each cycle of strain accumulation along a fault results in an earthquake. Elastic rebound has become the accepted model for the generation of most earthquakes, although some types of volcanic and deep earthquakes may have different mechanisms.

Scientists have tried many ways of predicting earthquakes, but to date such efforts have not been successful. For any particular fault, scientists may be able to identify the possibility of another earthquake in the future and its size, but they are not able to identify when it will happen.

Faults of Concern

The earth's crust is widely fractured and faulted. While the majority of faults will not produce a significant earthquake, scientists attempt to identify "faults of concern" (USEPA, 2015) that are optimally oriented for movement and are critically stressed and of sufficient size that a fault slip has the potential to cause a significant earthquake. Multiple technical disciplines are required to form an understanding of such a fault, which may refer to a single fault or a zone of multiple faults and fractures. Faults of concern generally are not well identified or mapped.

The orientation of the fault and the local subsurface stress distribution may have significant impact on whether a fault may slip, as shown in Figure A.10. The NRC report, *Induced Seismicity Potential in Energy Technologies* (2012), contains a detailed discussion of the subsurface conditions that may contribute to fault reactivation.

There are cases in which a fault is able to host earthquakes even if it is not well oriented for failure (for example, the San Andreas in California (Hickman and Zoback 2004; Townend and Zoback 2000). When weakening mechanisms become important at seismic-slip velocities, areas of a fault can slip even if it is not close to failure initially. For an earthquake to occur, however, a localized area must be close enough to failure that the stress perturbation due to injection can initiate it.

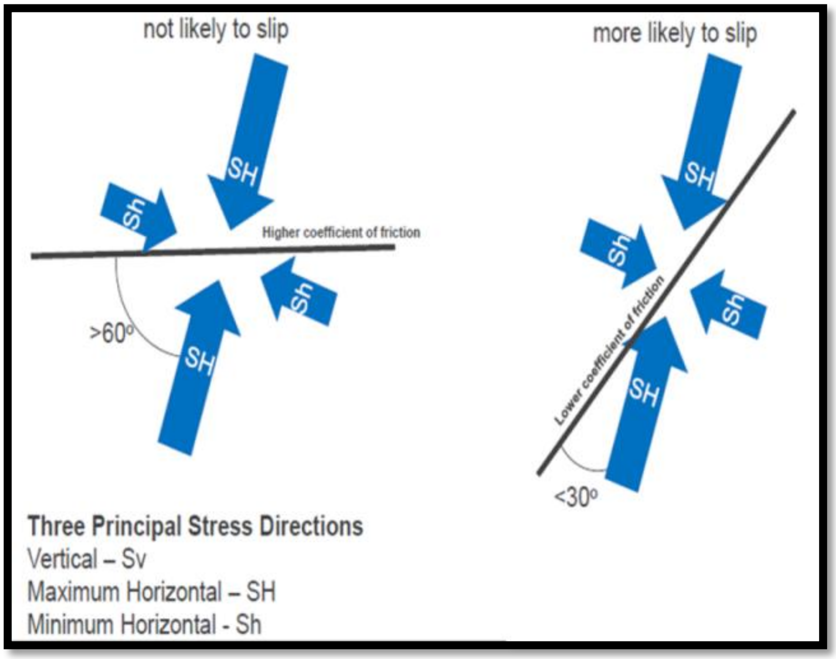


Figure A.10. Schematic showing conditions in which a fault may be more or less likely to slip. Source: ISWG.

Faults may be more prone to slip under certain stress conditions and geologic circumstances. In a given stress field, the ratio of shear stress to resisting strength on a fault depends on the fault orientation. Resisting strength depends on the stress acting perpendicular to the fault (i.e., the degree of clamping of the fault). While the two faults illustrated here have approximately the same shear stress, the fault on the right is more likely to slip; the fault on the left is less likely to slip because the larger stress, SH, is more perpendicular to the fault.

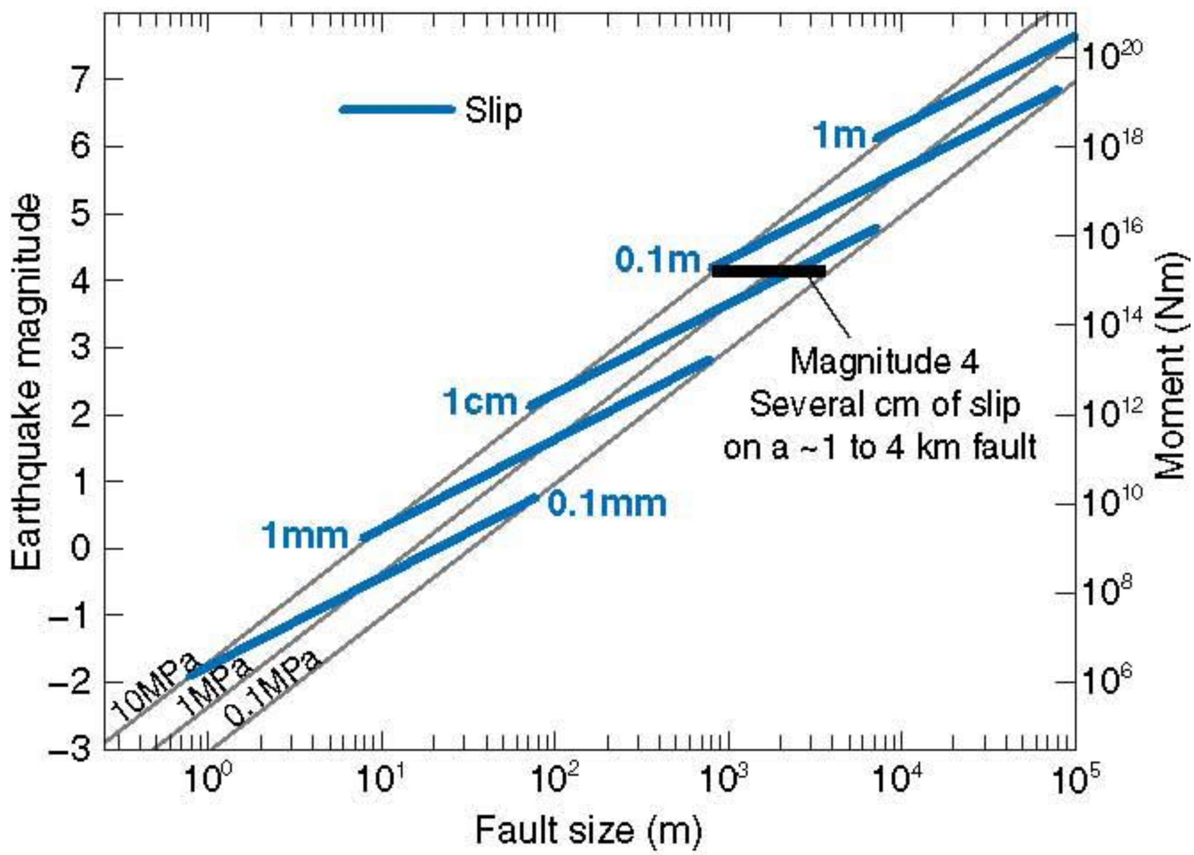


Figure A.11 Illustration of the relationships of fault size, fault slip, and stress drop relative to earthquake magnitude. Fault patch size is defined as the equivalent dimension of length in meters, representing the diameter of a circular fault patch that has slipped in the model. The dotted lines show two stress drop levels of 0.1MPa and 10 MPa. For example, an earthquake of ***M*** *5 will have a fault patch size of several thousand meters and will slip several centimeters. Figure courtesy of Mark Zoback, Stanford University*

Earthquake Magnitude

The magnitude of an earthquake is related to the area of the fault that ruptures and the amount of displacement along the fault. The larger the product of the rupture area and the displacement, the larger the earthquake and the more seismic energy released. Several measurement techniques and scales are commonly used to characterize the magnitude of earthquakes (Table A.1). All these techniques characterize the magnitude based on logarithmic scaling relationships.

Scale	Abbreviation	Description
Richter local	M_L	The original magnitude scale based on the amplitude of the seismic waves as recorded on a Wood-Anderson seismograph or instrument with the same response at local distances.
Moment	**M** or M_W	Measured from recordings and related to the earthquake seismic moment. Seismic moment is equal to the area of the fault surface that slips, the amount of slip, and the shear modulus of the material.
Surface wave	M_S	Measured from recordings of 20 sec period surface waves.
Body wave	m_b	A common scale used in the central and eastern United States based on the recorded amplitude of body waves.
Duration or coda	M_D or M_C	A scale used for microearthquake events (**M** < 3) based on the duration of the event.
Regional magnitude	m_{bLg}	A regional scale based on the amplitude of Lg surface waves.

Table A.1. Common scales used to characterize magnitude of earthquakes. Source: ISWG.

Earthquake size can range from magnitudes less than zero, resulting from fault slippage of a millimeter or less, to the largest events, **M** greater than 9.0, with fault displacements of many meters. The largest known earthquake was the 1960 **M** 9.5 Chile earthquake. Negative magnitudes are the result of more sophisticated measuring techniques because Richter set the magnitude scale with a “0” set at the smallest measurable event using 1930s technology.

Charles Richter developed the local magnitude (M_L) scale for southern California earthquakes in the early 1930s, allowing for the first time precise quantification of the size of an earthquake based on instrumental recordings. Because M_L values were simple to calculate, the scale rapidly became a worldwide standard. Since then, several other magnitude scales—such as moment magnitude (**M**), surface wave magnitude (M_S), and body wave magnitude (m_b)—have come into use. Events recorded regionally often are characterized by the size of the largest arrival, the Lg surface wave and are designated as m_{bLg}. Although the M_L scale is still commonly used, seismologists prefer the moment magnitude scale because it is based on seismic moment, which is the best measure of earthquake size. The seismic moment is the product of the area of the fault that ruptures, the average displacement on the fault, and the shear modulus, a parameter related to the rigidity of the rocks in the fault zone.

The USGS estimates that globally there are more than one million naturally occurring (tectonic) earthquakes per year of **M** 2.0 or greater (USGS 2015). Earthquakes of about **M** 3.0 or less are called microearthquakes as they commonly are not felt by people and generally are recorded only on local seismographs.

Sometimes an earthquake has foreshocks, smaller earthquakes that occur before the mainshock, generally along the same causative fault. Scientists cannot tell that an earthquake is a foreshock until the larger earthquake happens. The mainshock is commonly followed by aftershocks, which are smaller earthquakes in the same vicinity. Depending on the size of the mainshock, aftershocks can continue for weeks, months, years, and even decades (USGS Aftershocks 2012).

Earthquakes in a region generally follow the Gutenberg-Richter relationship (Richter and Gutenberg 1954), which describes the logarithmic increase in earthquake frequency as magnitudes decrease. The b-value quantifies the relative distribution of small and large earthquakes, and is observed to be around 1 globally, meaning that for an **M** 5.0 earthquake, there will be approximately 10 **M** 4.0 earthquakes and for each **M** 4.0 earthquake, there will be 10 **M** 3.0 earthquakes and so on. (A b-value of 1.5 means there would be about 30 **M** 4.0 events for each **M** 5.0 event, 1,000 **M** 3.0 events, and so on.) This relative distribution of small and large earthquakes is shown on a global scale in Table A.2.

Global Earthquake Frequency (from USGS Estimates)	
Magnitude	**Annual Average**
8 and higher	1 [a]
7 – 7.9	15 [a]
6 – 6.9	134 [b]
5 – 5.9	1319 [b]
4 – 4.9	13,000 (estimated)
3 – 3.9	130,000 (estimated)
2 – 2.9	1,300,000 (estimated)
a. Based on observations from 1900 b. Based on observations from 1990	

Table A.2. Annual global earthquake frequency; estimates from USGS available at http://earthquake.usgs.gov/earthquakes/eqarchives/year/eqstats.php.

Estimating Maximum Magnitude for Induced Earthquakes

No reliable technique currently exists for estimating the potential maximum induced seismic event in an area. Attempts can be made to inventory and characterize active and potentially active faults in an area and assess their potential maximum earthquakes based on their dimensions. Wells and Coppersmith (1994) developed empirical relationships between moment magnitude and fault dimensions for tectonic earthquakes (**M** > 5). However, not all faults may be sources of induced seismicity. Only faults that are favorably oriented in the tectonic stress field (given pore pressure changes from injection) and critically stressed are likely to be potential sites for induced seismic events. Factors such as the historical record of seismicity in an area also may be considered. It is believed that the maximum magnitude of an induced seismic event cannot exceed the size of the maximum tectonic earthquake in the area; however, the maximum tectonic earthquake in the central and eastern United States is an issue of considerable uncertainty (Petersen et al. 2008).

Estimating Earthquake Location

To estimate the location of an earthquake, seismologists analyze the seismic waves it generates. Seismic waves can be classified into three basic types: compressional or primary (P) waves, shear or secondary (S) waves, and surface waves (Figure A.3).

- **P-waves and S-waves** are called body waves because they can travel through the interior of the earth. The P-wave, which has the highest velocity and arrives first, causes particles in the earth to move back and forth in the direction the wave is travelling. S-waves generate transverse particle motion perpendicular to the direction the wave is travelling and generally move at half to two-thirds the speed of the P-wave. Because S-waves generate horizontal ground motions at the ground surface and carry much more energy than P-waves, they are of greater concern for hazard.
- **Surface waves**, which are generated by shallow earthquakes, travel along the earth's surface. There are two types of surface waves: Love and Rayleigh waves. Love waves, like S-waves, travel with transverse motions while Rayleigh waves result in both transverse and longitudinal motions. Surface waves can be damaging to long-period structures particularly when generated in sedimentary basins.

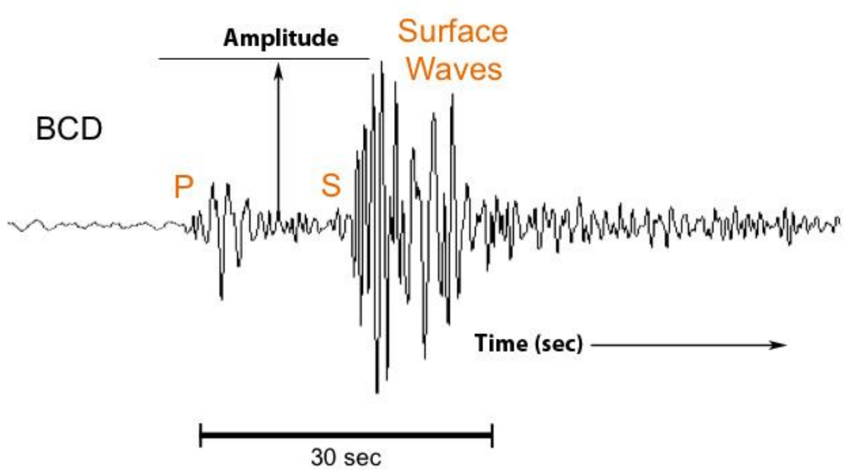


Figure A.3. Seismogram showing P-, S-, and surface waves (modified from http://akafka.files.wordpress.com/2012/10/maine_seismogram_bcd.png).

Using the time difference between when the P-waves and S-waves arrive, seismologists can estimate the distance of the earthquake from a seismic station. Figure A.4 shows a schematic of how the difference in P- to S-wave travel times is picked on a seismogram.

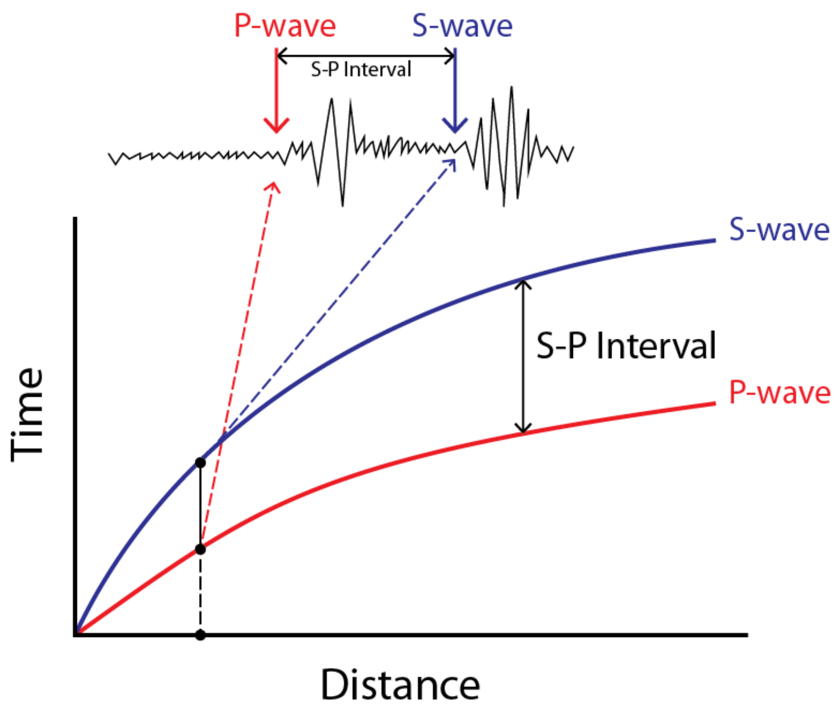


Figure A.4. Schematic illustrating the S-P travel time determination used in locating earthquakes. Source: ISWG.

Locating earthquakes accurately is a complex problem and requires an accurate velocity model of the earth, as the velocity model determines the travel times of the P- and S-waves. Earthquake location is an inverse problem, whereby the hypocenter and origin time of the earthquake are determined from the arrival times of waves at multiple stations. The earthquake hypocenter is then solved for by finding the point in the earth and origin time that most closely matches the observed P- and S-wave arrival times.

Characterizing Ground Motions

The hazard associated with an earthquake is related primarily to the levels of ground shaking. Ground-shaking levels are strongly influenced by earthquake magnitude, fault dimensions, orientation and type of fault, fault depths, and stress drop. The larger the earthquake, the larger is the rupture area, resulting in longer-duration ground motions. Smaller earthquakes (**M** < 5) usually can be regarded as point sources of energy released when computing the hazard. If the earthquake is larger, then the finite dimensions of the rupture area can impact the level of ground shaking particularly at close-in distances (< 10 km). Stress drop, which is the difference in stress on a fault before and immediately after an earthquake occurs, controls the ground motions at high and moderate frequencies.

Distance has a very significant impact on ground shaking: the greater the distance from the earthquake location, the lower the ground motions. In addition, the properties of the earth along the path the seismic waves travel have an impact because the earth dampens (attenuates) the energy of the waves. Finally, geologic conditions at a site can influence ground motions. Observations of earthquake damage stretching back centuries indicate that ground shaking on soil generally may be greater than on rock because soil can amplify ground motions. If the soil is deep enough, however, it can both amplify and de-amplify depending on the frequencies of the seismic waves. Deep soils tend to dampen ground motions at moderate to high frequencies (> 1 Hz) and amplify at low frequencies (< 1 Hz).

The preferred approach to characterizing ground motions is to use quantitative measures, such as acceleration, velocity, or displacement. Prior to modern seismic instrumentation, ground motions were only estimated qualitatively using intensity i.e., Modified Mercalli Scale (see following discussion). Common ground motion measures (Table A.3) are peak ground acceleration (PGA) and peak ground velocity (PGV). PGA is the most commonly used measure in seismology and earthquake engineering, while PGV is used for structural and nonstructural building damage criteria and for human annoyance.

Measure	**Typical Units**
Peak ground acceleration (PGA)	cm/sec^2, m/sec^2 or g's, where 1 g = 980 cm/sec^2
Peak ground velocity (PGV) or peak particle velocity (PPV)	cm/sec, m/sec, in/sec
Peak ground displacement (PGD)	cm, m, inches

Table A.3. Ground motion parameters and their commonly used units. Source: ISWG.

Instrumental recordings or time histories of ground shaking commonly are measured in terms of acceleration or velocity. A seismograph that measures ground acceleration is called a strong motion instrument or accelerograph. Figure A.5 shows acceleration record of an induced earthquake in Timpson, Texas, from three seismic stations.

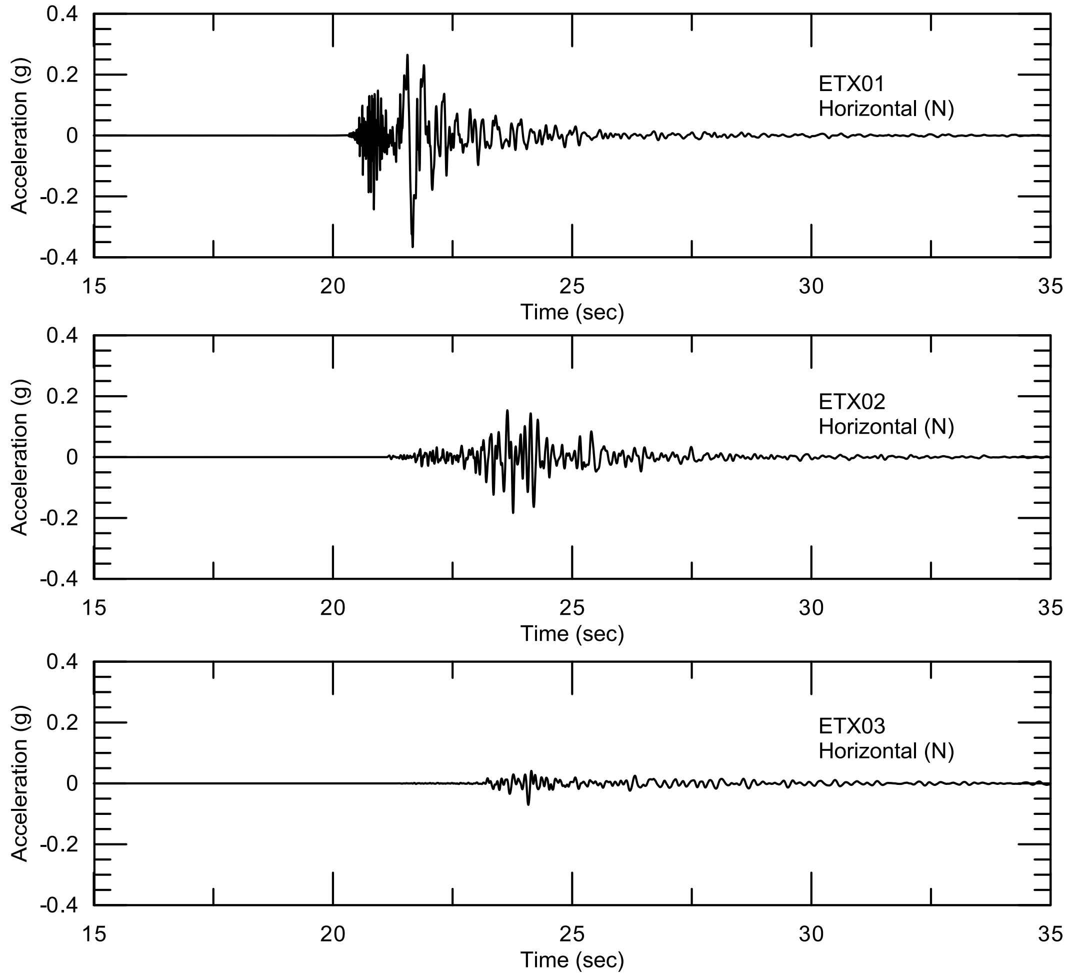


Figure A.5. Acceleration time histories of the 2013 ***M*** *4.1 Timpson, Texas, potentially injection-induced earthquake. Source: ISWG.*

Predicting Ground Motions

Estimating the severity and characteristics of earthquake ground motions has been one of the biggest challenges in earthquake engineering and engineering seismology. A fundamental tool used in seismic hazard analysis and other applications is the ground-motion model. There are numerous models for tectonically active regions, such as the western United States, and for the more tectonically stable central and eastern United States. These models rely on empirical motion data obtained from instrumental records of earthquakes or numerical modeling in the absence of adequate strong-motion data. Because there have been no large earthquakes (**M** > 7) in the central and eastern United States in modern times, numerical modeling has been used for ground-motion prediction in these regions.

A ground-motion model relates a ground-motion parameter, such as peak ground acceleration or peak ground velocity, to magnitude, distance, and site condition and, in some cases, other source and path parameters. Empirical models are developed by performing a statistical regression on a ground-motion parameter from the recorded data to find the best-fitting model. Current ground-motion models generally do not extend to magnitudes smaller than **M** 3.0. A considerable effort is underway to develop models for induced earthquakes in the central and eastern U.S.

Inputs into a ground-motion model include magnitude, distance, and site condition. The current ground-motion models use moment magnitude. For small earthquakes generally less than **M** 4, hypocentral distance is an adequate distance metric. For larger events, a distance metric that accounts for the finite dimensions of the fault rupture area is desirable. For most models, rupture distance (the shortest distance to the fault plane) is used.

Site condition inputs also are required to accurately predict ground shaking, particularly at a soil site. The time averaged shear-wave velocity (V_S) to a depth of at least 30 meters needs to be characterized. This parameter is used in the U.S. building code (International Building Code) to classify site conditions. If the geology beneath a site is complex, a site-specific site-response analysis may be necessary, particularly if the site is or will be occupied by an important or critical facility. In those cases, a shear-wave velocity profile down to rock or very firm soil is used to quantify the site and building foundation responses. This profile can be obtained through geophysical surveys, such as downhole and crosshole surveys, surface wave techniques, and microtremor surveys (for example, Stokoe and Wong 2011). For some areas of the United States, the National Earthquake Hazard Reduction Program has developed maps that classify sites by six categories (called NEHRP site classes): hard rock, rock, very dense soil and soft rock, stiff soil, soft soil, and soft liquefiable soil. These maps are based on shear-wave velocity data and, in some cases, the surficial geology.

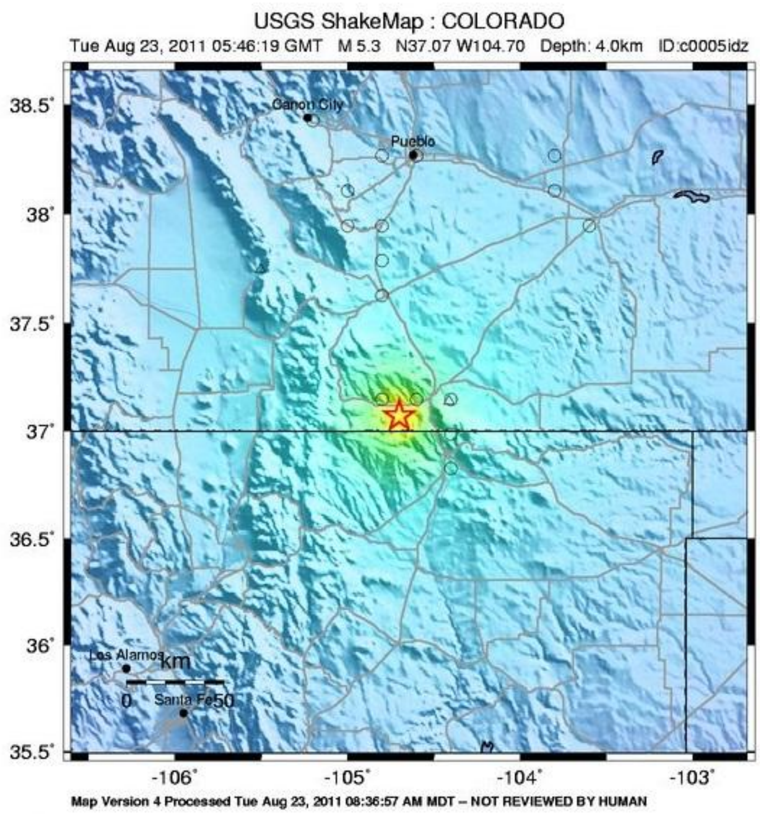
Earthquake Intensity

Intensity is a qualitative measure of the strength of shaking at a specific place and is characterized in terms of impact of this shaking on individuals as well as on objects and structures. It is not a measure of the size of the earthquake. The intensity scale most widely used today is the Modified Mercalli (MM) scale (Table A.4). Intensity is a useful measure for communication with the public and for providing a general sense of the ground shaking and impact.

MMI	Description	PGA (g)	PGV (cm/sec)	Observations (Richter 1958)
I	Not felt	< 0.00007	< 0.003	Not felt except by a few under especially favorable circumstances.
II to III	Weak	0.0008	0.04	Felt by only a few people, often indoors. Hanging objects swing. May not be recognized as an earthquake.
IV	Light	0.01	0.5	Hanging objects swing. Vibration like passing of heavy trucks; or sensation of a jolt like a heavy ball striking the walls. Standing motor cars rock. Windows, dishes, doors rattle. Glasses clink. Crockery clashes. In the upper range of IV, wooden walls and frames creak.
V	Moderate	0.05	3.0	Felt outdoors; direction estimated. Sleepers awakened, liquids disturbed, some spilled. Small unstable objects displaced or upset. Doors swing, close, open. Shutters, pictures move. Pendulum clocks stop, start, change rate.
VI	Strong	0.09	6.5	Felt by all. Many frightened and run outdoors. Persons walk unsteadily. Windows, dishes, glassware broken. Knickknacks, books, etc., off shelves. Pictures off walls. Furniture moved or overturned. Weak plaster and masonry cracked. Small bells ring (church, school). Trees, bushes shaken.
VII	Very strong	0.15	14	Difficult to stand. Noticed by drivers of motor cars. Hanging objects quiver. Furniture broken. Damage to masonry D, including cracks. Weak chimneys broken at roofline. Fall of plaster, loose bricks, stones, tiles, cornices, un-braced parapets, and architectural ornaments. Some cracks in masonry. Waves on ponds; water turbid with mud. Small slides and caving in along sand or gravel banks. Large bells ring. Concrete irrigation ditches damaged.
VIII	Severe	0.27	30	Steering of motor cars affected. Damage to masonry; partial collapse. Some damage to masonry B; none to masonry A. Fall of stucco and some masonry walls. Twisting, fall of chimneys, factory stacks, monuments, towers, elevated tanks. Frame houses moved on foundations if not bolted down; loose panel walls thrown out. Decayed piling broken off. Branches broken from trees. Changes in flow or temperature of springs and wells. Cracks in wet ground and on steep slopes.
Masonry A		Good workmanship, mortar, and design; reinforced, especially laterally, and bound together by using steel, concrete, etc.; designed to resist lateral forces.		
Masonry B		Good workmanship and mortar; reinforced, but not designed to resist lateral forces.		
Masonry C		Ordinary workmanship and mortar; no extreme weaknesses like failing to tie in at corners, but neither reinforced nor designed to resist horizontal forces.		
Masonry D		Weak materials, such as adobe; poor mortar; low standards of workmanship; weak horizontally.		
Note: MMI, description, PGA, and PGV from ShakeMap.				

Table A.4. Modified Mercalli intensity, peak ground acceleration, and peak ground velocity for the central United States. The MM scale has 12 levels but only 8 are shown. Source: ISWG.

Displaying the distributions of earthquake shaking: Maps of the location and strength of earthquake shaking provide valuable information to emergency managers, first responders, media, and the public by identifying the areas likely to be or that have been affected by an earthquake. Such maps routinely produced by the USGS and other ANSS networks are known as ShakeMaps and display the intensity of shaking as MM intensity, peak ground acceleration, and peak ground velocity (Wald et al. 1999) (Figure A.6). These maps may include measurements from seismometers, accelerometers, and reported intensities, although they most commonly are based on the earthquake epicenter and magnitude. For a particular earthquake, contours encompassing areas of similar intensity can be drawn. These isoseismal maps show that, generally, the larger the earthquake, the larger the felt area, and intensities decrease away from the epicenter. A ShakeMap is produced in near-real time minutes after most earthquakes of **M** 3.5 and larger in the United States.



PERCEIVED SHAKING	Not felt	Weak	Light	Moderate	Strong	Very strong	Severe	Violent	Extreme
POTENTIAL DAMAGE	none	none	none	Very light	Light	Moderate	Moderate/Heavy	Heavy	Very Heavy
PEAK ACC.(%g)	<.17	.17-1.4	1.4-3.9	3.9-9.2	9.2-18	18-34	34-65	65-124	>124
PEAK VEL.(cm/s)	<0.1	0.1-1.1	1.1-3.4	3.4-8.1	8.1-16	16-31	31-60	60-116	>116
INSTRUMENTAL INTENSITY	I	II-III	IV	V	VI	VII	VIII	IX	X+

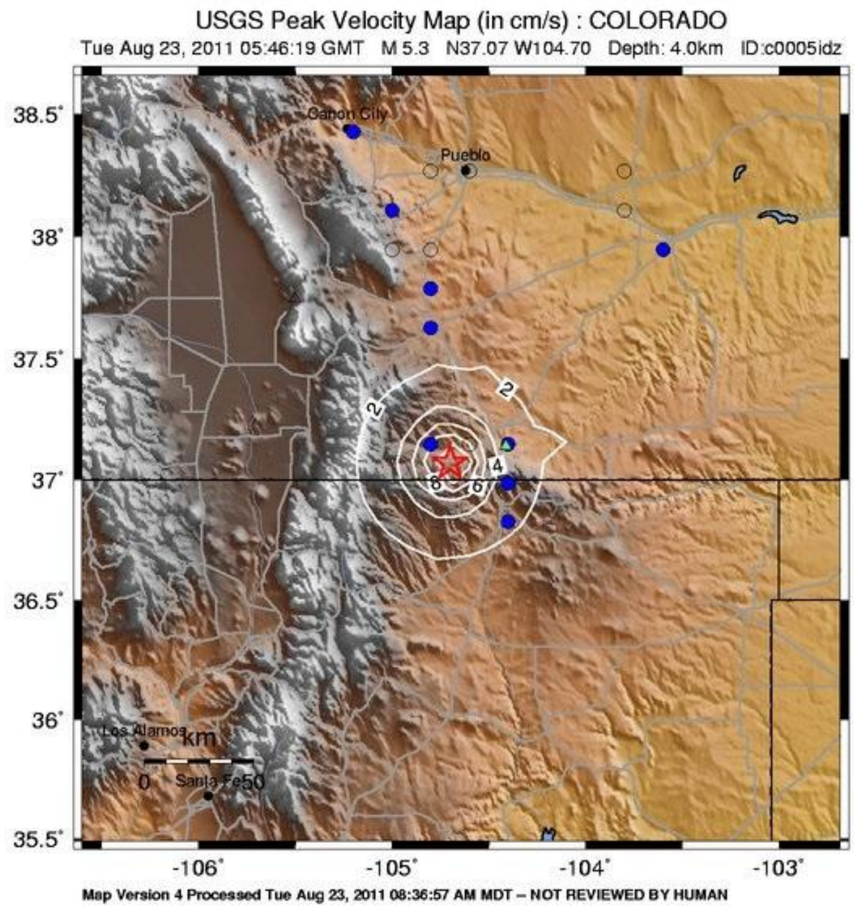


Figure A.6. Instrumental MM intensity (previous page), PGA (above), and PGV (bottom right) ShakeMaps of the 2011 **M** *5.3 Trinidad, Colorado, earthquake from the USGS. Source: ISWG.*

Correlating intensity with peak ground velocity and peak acceleration: A number of authors have developed relationships between Modified Mercalli intensity and peak ground velocity and peak ground acceleration for tectonic earthquakes (Wald et al. 1999; Kaka and Atkinson 2004; Atkinson and Kaka 2007). The original relationship derived by Wald et al. (1999) was developed from eight California tectonic earthquakes of **M** 5.8 and greater. Because these earthquakes are much larger and occur much deeper than typical injection-induced seismic events, there is considerable uncertainty regarding the use of this relationship for smaller magnitude induced earthquakes, particularly outside California. Because of this, assigning a peak ground acceleration or peak ground velocity to Modified Mercalli intensity (or vice versa) may not be reliable. Kaka and Atkinson (2004) and Atkinson and Kaka (2007) computed similar relationships for peak ground velocity in central and eastern North America and concluded that relationships between Modified Mercalli intensity and ground motion are significantly different in central and eastern North America than in California, and that the California relationships under-predict intensities in central and eastern North America. All three models are shown in Figure A.7.

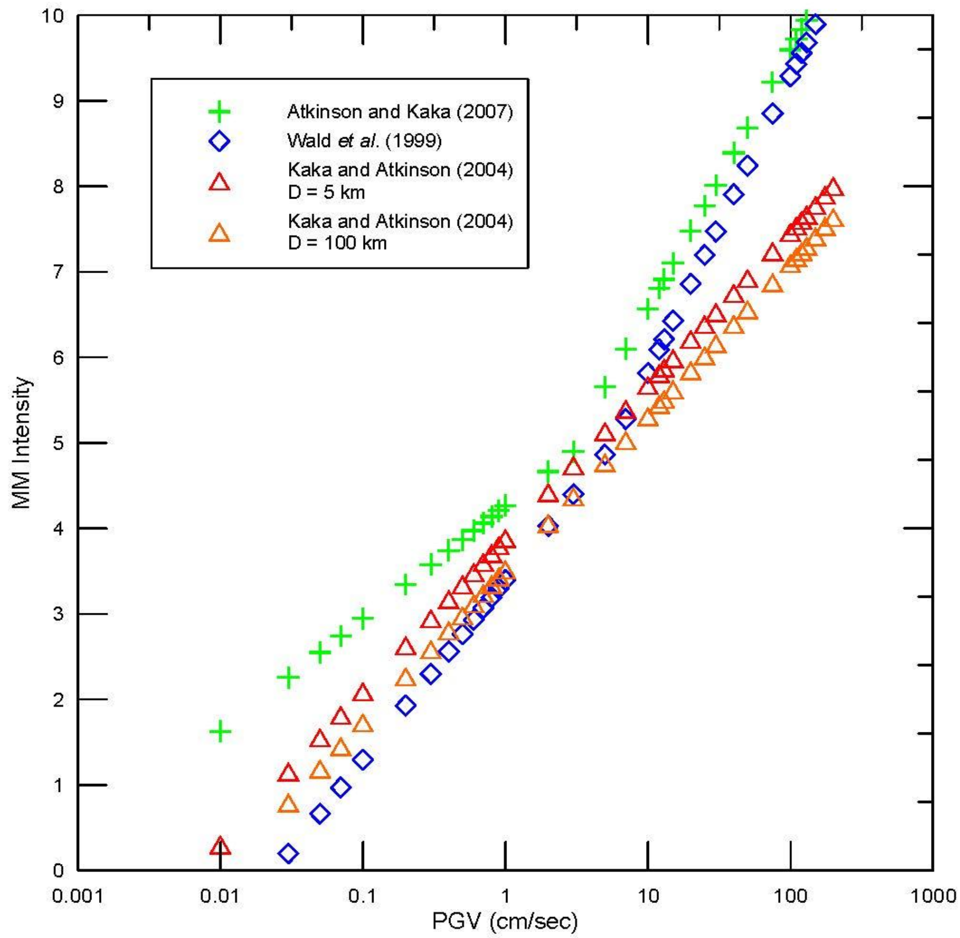


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Figure A.7. Comparison of models of MM intensities versus PGV. Source: Wong et al. 2017.

Impacts of Ground Motions on Structures

Ground motion can cause structural and nonstructural damage to buildings as well as to civil structures, such as dams, bridges, highways, railroads, tunnels, pipelines, tanks, and runways. It is commonly accepted that structural damage to modern engineered structures generally happens only in earthquakes larger than **M** 5.0. For example, for the National Seismic Hazard Maps, which are the basis for the building code in the United States (International Building Code), the USGS uses a minimum magnitude of **M** 5.0 in the western U.S. and **M** 4.75 in the central and eastern U.S. in their hazard calculations (Petersen et al. 2014). Poorly designed or constructed buildings, such as unreinforced masonry (URM), for example, brick and adobe (Table A4), and buildings built before modern building codes can be subject to nonstructural damage at magnitudes as low as **M** 4.0 and, in some rare cases, as low as **M** 3.0. Structural damage has been observed in very poorly designed and constructed buildings and in a few rare cases, in events smaller than **M** 5.0.

Structural damage can occur after several cycles of ground shaking, when resulting seismic loading induces strains resulting in failure of structural (load-carrying) components. Brittle structures, such as unreinforced masonry buildings, are particularly vulnerable. Maximum damage occurs when the predominant frequency of the larger amplitude seismic waves coincides with the natural frequency of a structure (called resonance). Most ground-shaking damage from earthquakes is attributed to S-waves, because of their generation of horizontal ground movement as they approach the earth's surface. Surface waves generally have larger amplitudes than body waves, but they have much longer wavelengths and frequencies much lower than 0.2 Hz. They generally will impact engineered structures only at large distances when the body waves have become less prominent. As a rule, surface waves do not become prominent until distances are reached that are two times the thickness of the earth's crust (Kramer 1996).

Building damage due to ground shaking can be classified into three categories (Dowding 1996):

- **Threshold cracking** encompasses cosmetic damage due to cracking of stucco, plaster, or gypsum boards where cracks are closed.
- **Minor damage** is superficial damage that does not cause a weakening of the structure and includes broken windows, loosened or fallen plaster, and hairline cracks in masonry.
- **Major damage** includes any weakening of the structures as indicated by large cracks, shifting of the foundation or bearing walls, or major settlement resulting in distortion or weakening of the superstructure.

In an early study Dowding (1985) indicated that threshold cracking occurred in older structures at peak particle velocities (or peak ground velocity) of about 8 cm/sec, minor damage at 11 cm/sec, and major damage at 20 cm/sec. The peak particle velocity level of damage is strongly correlated with the age and condition of the structure and the quality of construction. For example, unreinforced masonry structures are more prone to damage than modern reinforced masonry. Historical structures could be damaged at lower peak particle velocities than stated above.

Currently it is believed to be difficult to establish general thresholds of damaging ground motions because of the many factors that can impact damage. From a structural engineering perspective, the damage a building sustains in an earthquake is very specific to that building, its building type, age, quality of design and construction, and the characteristics of the ground shaking.

While damage to the structural system is the most important measure of building damage because it could result in casualties and catastrophic loss of function (due to unsafe conditions), damage to nonstructural systems and contents tends to dominate economic loss (FEMA 2010).

Human Anxiety Created by Ground Motions

Human anxiety can occur from low-level ground shaking that does not necessarily cause physical damage to the built or natural environment (Majer et al. 2014). Although the ground motions can be of low amplitude, if repeated often enough they could impact the health and mental well-being of people.

Although difficult to quantify, there is substantial literature on the human response to ground vibration from the mining and construction industry. For example, ISO (International Organization for Standardization) 2631 (ISO 1997, 2003) is a standard for assessing human response to ground acceleration for people standing, sitting, or lying. Bommer et al. (2006) show a useful figure illustrating the levels of human sensitivity to blast vibrations, reference levels for vibration perception and response from traffic, and vibration thresholds for pile-driving (Figure A.8).

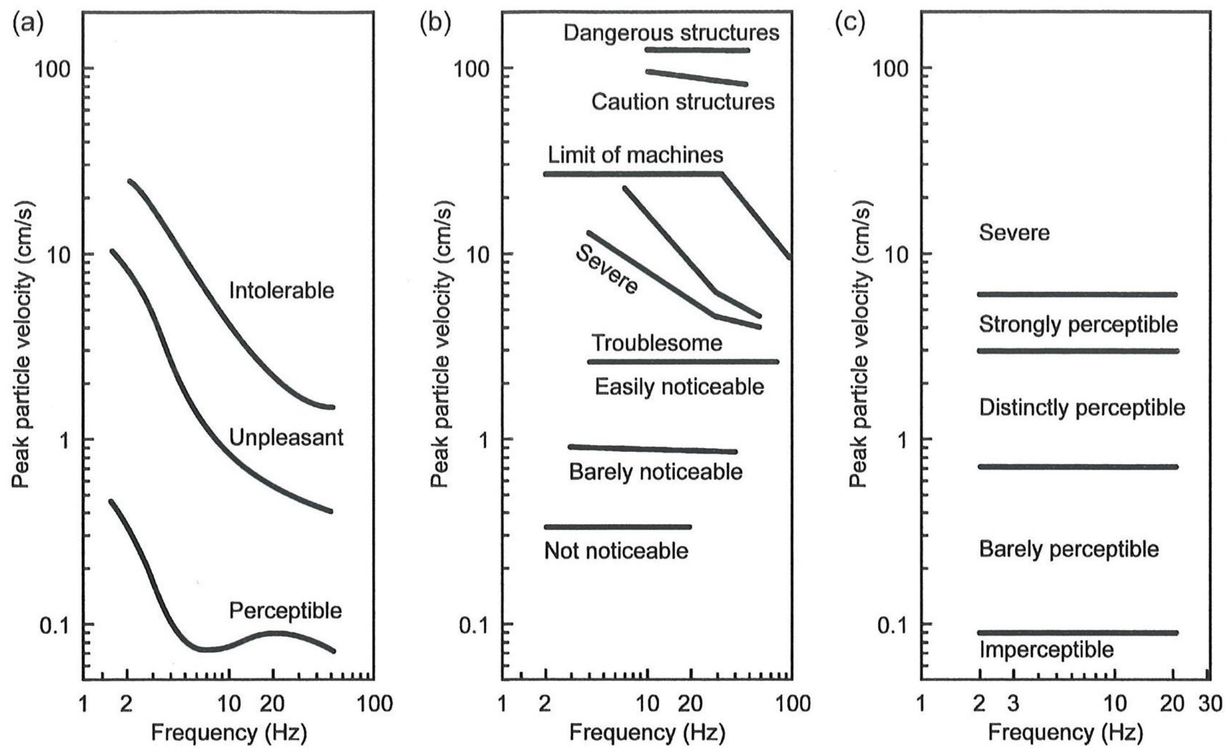


Figure A.8. Levels of human sensitivity to different sources of vibration, from (a) blasting, (b) traffic, and (c) pile-driving. Source: Bommer et al. 2006.

Figure A.9 is taken from Majer et al. (2014) and shows an example of a vulnerability function that describes the six possible states of human sensitivity: 1) comfortable, 2) a little uncomfortable, 3) fairly uncomfortable, 4) uncomfortable, 5) very uncomfortable, and 6) extremely uncomfortable. The curve gives the probability that a person would find a given level of ground shaking unacceptable. With this vulnerability function and knowledge of the impacted population (density and location), it would be possible to estimate the average number of people who would be inconvenienced and who would find the ground motion unacceptable (Majer et al. 2014).

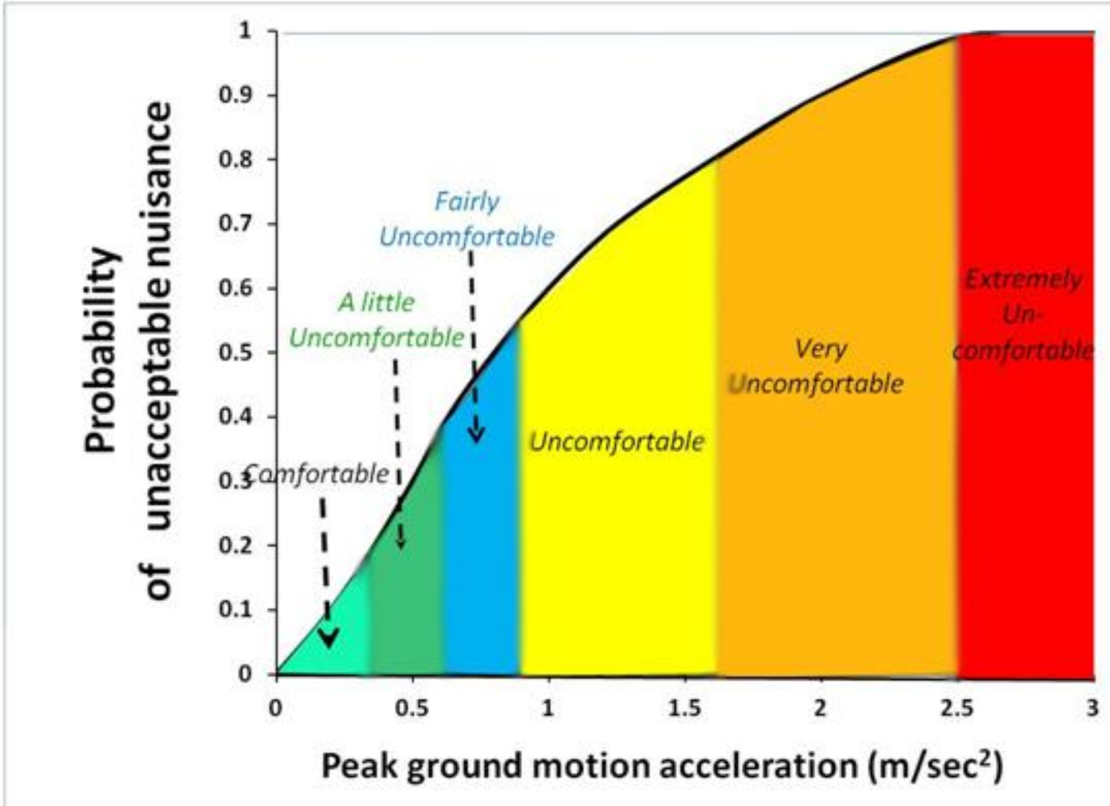


Figure A.9. Probability of unacceptable nuisance (after Majer et al. 2014).Seismic scaling relations. Figure courtesy of Mark Zoback, Stanford University.

Appendix B: Class II Injection Wells

Introduction

This appendix provides background on the Underground Injection Control (UIC) program, the types of Class II injection wells, and the construction criteria for and regulatory management of Class II disposal wells.

The U.S. Environmental Protection Agency (USEPA) UIC program considers six well types based on similarity in the fluids injected, activities, construction, injection depth, design, and operating techniques. Wells with common design and operating techniques are required to meet appropriate performance criteria. Extensive information on wells regulated under the UIC program is available at: http://water.epa.gov/type/groundwater/uic/wells.cfm. Table B.1 summarizes the typical uses for each class of well.

Underground Injection Well Classification Chart			
Well Class	Purpose	Active Wells*	Annual Injection Volume*
I	Injection of hazardous, non-hazardous and municipal wastes below the lowermost USDW	822	
II	Injection of fluids associated with the production of oil and natural gas resources for the puposes of disposal or enhanced oil and gas recovery	184,360	
III	Injection of fluids for the extraction of minerals	22,688	
IV	Injection of hazardous or radioactive wastes into or above a USDW	20	
V	Injection into wells not included in the other well classes but generally used to inject non-hazardous waste	476,898	N/A
VI	Injection of supercritical carbon dioxide for storage	7	N/A

* Source USEPA https://www.epa.gov/sites/production/files/2016-10/documents/underground_injection_control_inventory_fy_2015_0.pdf

Table B.1. Summary of UIC wells and estimated inventory. Source: USEPA 2016.
https://www.epa.gov/sites/production/files/2016-10/documents/underground_injection_control_inventory_fy_2015_0.pdf

Types of Class II Wells

Enhanced recovery wells inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and, in some limited applications, natural gas. The injected fluid thins or displaces small amounts of extractable oil and gas, which is then available for recovery. Enhanced recovery wells are the most numerous type of Class II wells, representing as much as 80 percent of the approximately 168,000 Class II wells.

Disposal wells inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. As oil and natural gas are brought to the surface, they generally are mixed with salt water. On a national average, approximately 10 barrels of brine are produced with every barrel of crude oil (GWPC 2013). The brine is segregated from the oil and then injected into the same underground formation or a similar formation. Disposal wells represent about 20 percent of Class II wells and have been used in oil-field-related activities since the 1930s. Today, there are approximately 30,000 active Class ll disposal wells used to dispose of oil and gas related waste (USEPA 2015).

Hydrocarbon storage wells inject liquid hydrocarbons in underground formations (such as salt caverns) where they are stored, generally as part of the U.S. Strategic Petroleum Reserve. More than 100 liquid hydrocarbon storage wells are in operation in the United States.

Construction of Class II Disposal Wells

As shown in the Figure B.1 below, Class II disposal wells are designed and constructed to adequately confine injected fluids to the authorized injection zone and prevent the migration of fluids into underground sources of drinking water (USDW). Injection wells are drilled and constructed with steel pipe (casing) cemented in place. Surface casing is typically cemented from below the protected groundwater up to the surface to prevent fluid movement. Cement also is placed behind the long casing string at critical sections to confine injected fluids to the authorized zone of injection.

A typical Class II disposal well also has injection tubing through which the fluids are pumped from the surface down and into the receiving geologic formations. A packer is commonly used to isolate the disposal zone from the space between the tubing and injection casing above the packer, called the annulus (see Figure B.1).

Regulation of Class II Disposal Wells

The UIC program under the Safe Drinking Water Act authorizes regulation of Class II disposal wells. Class II wells are regulated by either a state agency that has been granted regulatory authority over the program (primacy states) or by the USEPA. Primacy states have adopted regulations and regulatory programs that have been approved by USEPA as protective of underground sources of drinking water for Class II disposal well operations. These regulations address injection pressures, well testing, and in some states pressure monitoring and reporting. Class II well operators in direct implementation states must meet regulatory requirements implemented and enforced directly by USEPA.

Regulators are responsible for reviewing Class II disposal well permit applications, issuing permits, and overseeing existing Class II disposal wells. The regulatory process requires a technical review to assure adequate protection of drinking water and an administrative review to define operational guidelines. The subsurface conditions at a proposed site are evaluated to make sure the formations will keep the fluids out of USDWs. Through the permitting process, site-specific requirements are imposed to address any unusual circumstances. The regulations or the permits include limitations on factors such as the pumping pressure and the maximum disposal volumes/rates.

Regulators evaluate well construction to make sure all components have mechanical integrity. After Class II disposal wells are placed into service, periodic well testing and monitoring assures groundwater protection. Injection pressures and volumes are monitored as potential indicators of well performance. Effective monitoring is critically important for identifying well construction and performance problems.

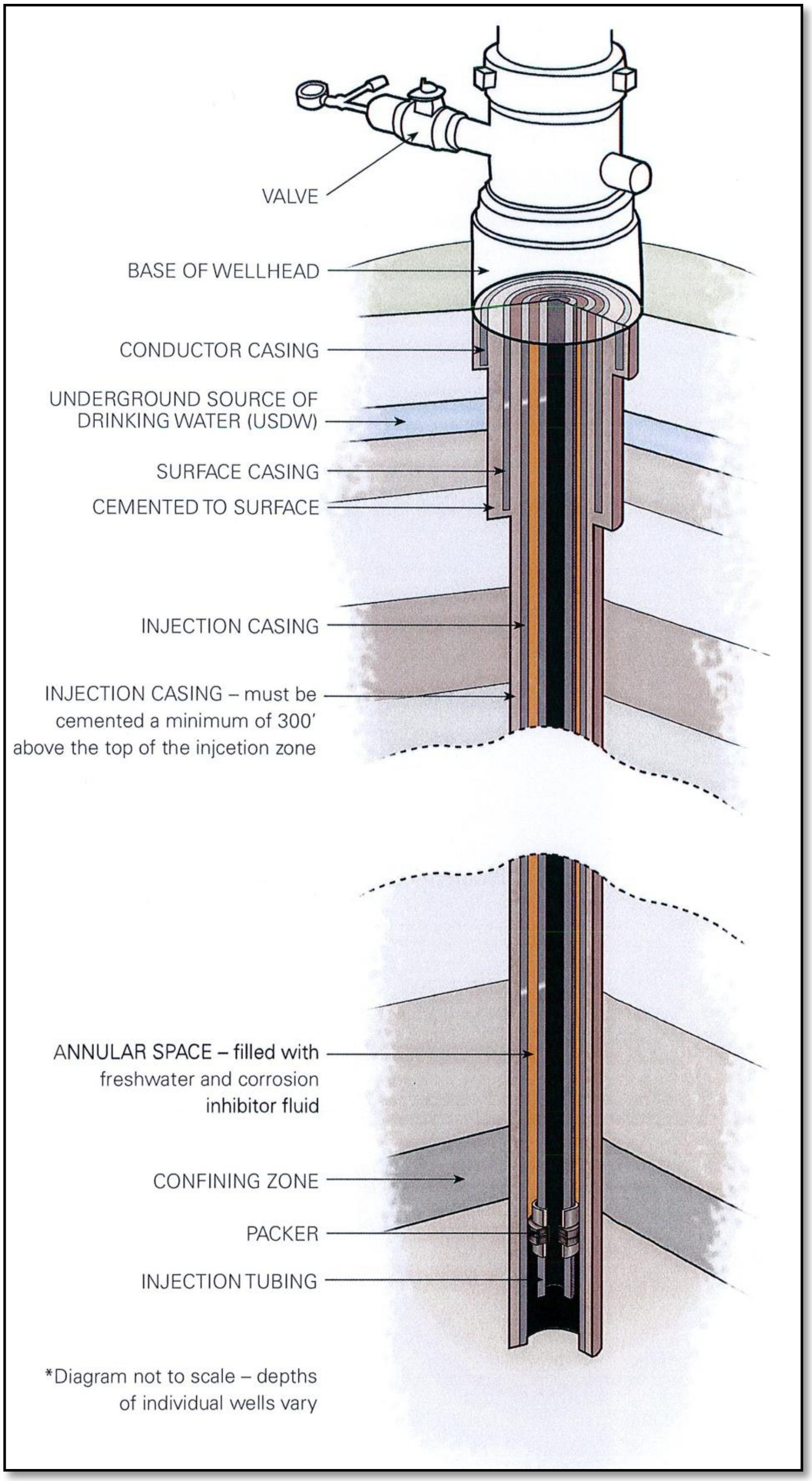


Figure B.1. Typical design of a Class II disposal well. Figure courtesy of ODNR.

Appendix C: Induced Seismicity Case Studies

Introduction

This appendix includes examples of how states have responded to instances of suspected induced seismicity through the use of local seismic networks. Each case presents a different situation, response, and observations that can be helpful for regulators, as well as technical details of seismology used.

Contents and highlights:

- Love County, Oklahoma: Benefits of USGS "Did you feel it?" reports, local network, disposal and event correlation, and industry action
- Youngstown, Ohio: Early deployment of a local network, accurate locations, regulatory action
- Geysers, California: Permanent network around known induced seismicity, community outreach
- Decatur CCS, Illinois: Compares two local arrays, surface and borehole, and differences in interpretations
- Greeley, Colorado: Local network, regulatory action; mitigation that may have resolved seismicity
- Pawnee, Oklahoma:
- Harrison County, Ohio: Hydraulic fracturing caused felt seismicity

Oklahoma Case Study — Love Disposal, Carter Co.

This case study follows incidence of earthquakes after initiation of disposal nearby. It illustrates the merits of the felt reports submitted to the USGS "Did you feel it?" system as a valuable tool in locating epicenters, in this instance more accurately than regional seismometer networks. Also, it is an example of voluntary action by an operator to mitigate the problem.

Background and Objectives. On September 17, 2013, earthquakes were detected in southern Oklahoma near Marietta. Residents reported felt earthquakes on the USGS "Did You Feel It" (DYFI) websites, many of which were not detected by the sparse OGS regional network. On September 23, two earthquakes of **M** 3.2 and **M** 3.4 occurred, which caused damage to chimneys, brick, and windows to homes near the epicenter. The damage associated with these small magnitude events suggested a shallow focal depth. Interestingly, the reports of damage were at least five miles north of the OGS epicenters and near a new commercial UIC well, Love County Disposal #1 (LCD-1), which had initiated water disposal into the Arbuckle September 3, two weeks prior to the felt event. It was clear that the nearest seismometers, located 40–100 miles north of the seismicity, would not be adequate for determining earthquake locations with the accuracy needed for correlating any causal relationship. A temporary network was deployed and better locations were achieved, closely matching the 'bull's-eye' of the DYFI reports.

Geology and Disposal. LCD-1 is a vertical well located in the Marietta Basin of southern Oklahoma, near a southwest plunging thrust fault that separates the Marietta and Ardmore Basins, just south of the Criner Uplift. Dips may be significant in this area. It was drilled to a depth of 6,342 feet, in the Arbuckle formation, several hundred feet above the basement, and completed over an interval of 4,366–6,273 feet.

LCD-1 began operations September 3. Disposal volumes rapidly increased to 5,000–7,000 bbl/day over two weeks (Figure C.1). Three days after the first detected earthquakes, volumes reached a peak of over 9,000 bbl/day. When the **M** 3.4 event occurred on September 23, the well operator voluntarily reduced volumes dramatically until the well was shut in three days later.

As injection volumes fell, the frequency and magnitude of earthquake events dropped rapidly. The local network operated during the last two days of injection. Earthquake locations clearly delineate a NESW zone of seismicity corresponding to the area of greatest MMI intensity. This orientation is consistent with the general stress field and active fault orientations observed in Oklahoma.

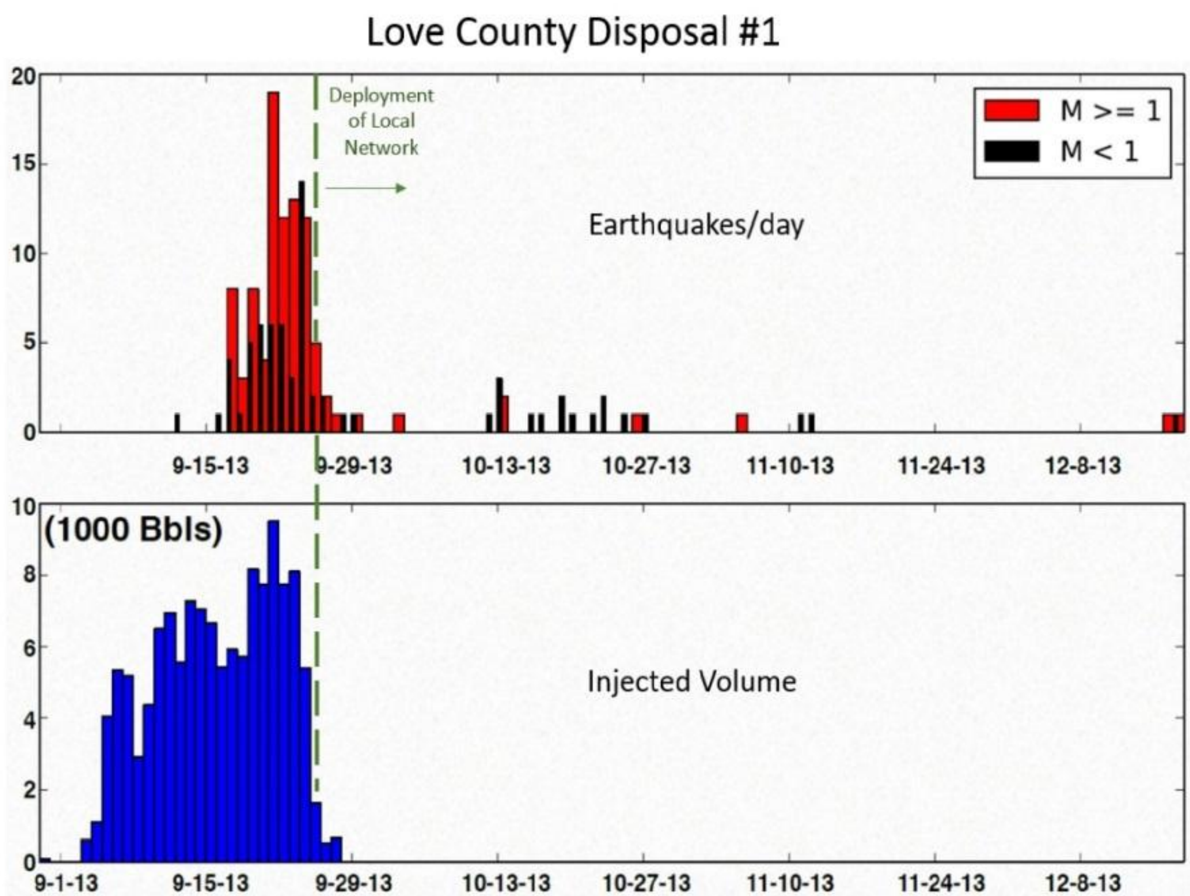


Figure C.1. Seismicity (top) recorded near and disposal histograms for the LDC-1. Source: Oklahoma Geological Survey.

Seismic Methodology. Prior to the earthquake swarm, the regional network consisted of seismometers 40–100 miles away, all located to the north of the seismicity. Event locations were calculated by OGS using the SEISAN software. Uncertainty in locations was not only due to the sparse network described above but also to the use of a simple 1D velocity model to represent the complex geology of the Arbuckle Mountains, Ouachita Thrust Belt, and Washita Valley Fault system. The apparent shallow depths of the earthquakes could also cause inaccuracies due to waveform distortion and the complex shallow velocity structure. The magnitude of completeness (M_c—the lowest magnitude confidently located) was estimated to be no better than 2.5.

To constrain the epicenter of the largest event (**M** 3.4) residents were interviewed and damage observed to determine the Modified Mercalli Intensity (MMI). Figure C.2 is the MMI intensity map, which clearly shows that maximum MMI intensity (VII) was significantly north of the original epicenters. Moreover, strong intensities and damage levels suggest shallower focal depths than the estimated 6 km depth. Some improvement to locations was achieved using the more advanced HYPODD software but significant scatter remained. Dozens of smaller earthquakes were found in the regional network data using cross correlation template matching techniques that improved the Mc closer to 1.0.

By September 25, a temporary local network of six continuous recording stations was deployed in the area closest to the strongest reported ground motion. These stations, spaced 3–5 miles apart, were powered by solar panel and battery. Real-time data was transmitted to the OGS system from one station, while the others saved data on flash storage systems for manual download. The waveforms were processed manually by OGS analysts using SEISAN software. The addition of the local network lowered the magnitude of completeness to nearly 0.5.

Results. Locations of the events seen by the regional network and the local network are indicated in Figure C.2, along with the Modified Mercalli Intensity map after the **M** 3.4 event. Local network locations are tightly grouped and also are near the center of shaking and the disposal well.

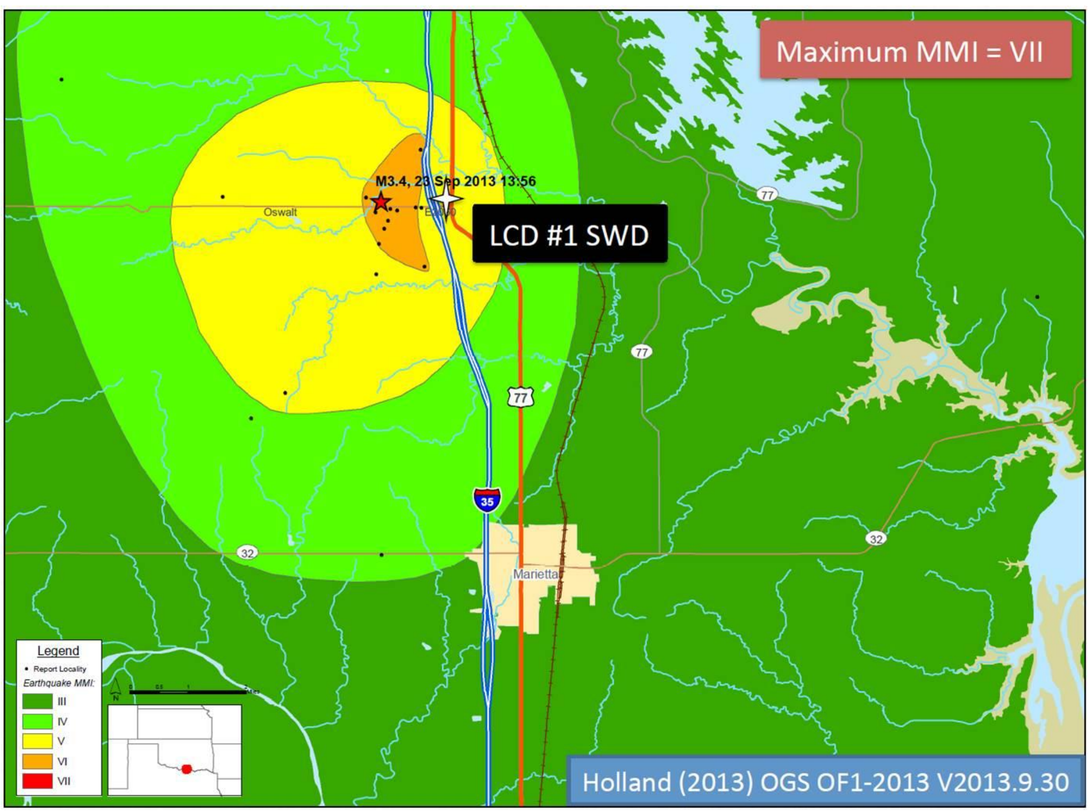


*Figure C.2. Modified Mercalli Index map of seismicity around the **M** 3.4 event near Marietta, OK.*

Discussion. The Oklahoma Corporation Commission (OCC) has given the LCD operator approval to resume injection up to a maximum of 3,000 bbl/day and a pressure limit of 375 psi. To date the operator has chosen to leave the well shut in.

Conclusions. The successful deployment of the local seismometer network was necessary to understand the potential contribution of the LCD well to the activation of nearby faults. The regional network locations had too much uncertainty to assess about cause and effect. Early DYFI reports accurately located the center of activity and were valuable in siting the temporary array.

Although the Love County swarm has similar characteristics to past swarms in the area, the temporal correlation of earthquakes relative to LCD injection presents a reasonable case for induced seismicity. Spatially, events located using the regional networks were within five miles of the LCD well. However, the distance between the LCD well and the greatest impact caused by the two largest earthquakes was approximately one mile. This damage proximity, coupled with event locations recorded on the temporary network, make a very strong case for induced seismicity

Ohio Case Study — Youngstown

This case study is an example of the integration of a state network with temporary networks and collaboration with academia. Early detection by the state network enabled deployment of a temporary array in time to detect the largest earthquakes, and thus to accurately determine their source locations, especially depth. This information helped the state take mitigating action and design further seismic monitoring, and to determine the presence and geometry of a previously unknown fault susceptible to reactivation.

Background and Objectives. Until recently, noticeable seismic activity in and around the Youngstown area had been relatively undocumented. Prior to the establishment of the Ohio Department of Natural Resources' (ODNR) Ohio Seismic Network (OhioSeis) in 1999, seismic monitoring in Ohio was sporadic. The OhioSeis network consists of 29 one-component systems located across the state but concentrated in areas of known natural seismicity. Before the establishment of OhioSeis, the Ohio Division of Geological Survey (ODGS) was unable to accurately detect any seismic events below approximately **M** 3.0. The nearest OhioSeis station is located at Youngstown State University.

Geology and Disposal. The bedrock units underlying the Youngstown area are dipping gently to the southeast at about 50 feet per mile into the Appalachian Basin. The closest known mapped fault system is the Smith Township Fault, a NWSE-oriented fault, located in southwestern Mahoning County.

A number of geologists have identified the Mahoning River Valley as a geologic lineament that may be related to faulting in the area, but no evidence of the fault that resulted in the Youngstown earthquakes had been delineated at the time of the drilling and completion of the Northstar #1 well (NS1). A 2D seismic reflection line reviewed after the NS1 was drilled identified a possible previously unknown fault zone in the Precambrian basement rock near the NS1.

The NS1 is located in an industrial district of northwestern Youngstown, Ohio. The well was drilled and completed as a stratigraphic test well in April 2010 to a depth of 9,192 feet, bottoming in the Precambrian basement rock. Following the evaluation of open-hole geophysical well logs, production casing was set and cemented in at a depth of 8,215 feet. The well was then completed as an open-hole injection well from the Knox Dolomite at 8,215 feet to the Precambrian at 9,192 feet. In July of 2010, a permit was issued to convert the NS1 to a Class II saltwater injection well. Injection operations commenced in late December of 2010.

Seismic events were detected in the Youngstown area in March 2011. On December 1, 2011, at the request of the ODGS, Lamont Cooperative Seismographic Network (associated with Columbia University's Lamont Doherty Earth Observatory) deployed four, three-component portable seismic units around Youngstown to monitor seismicity at close distances. These portable units can accurately determine hypocenters of small seismic events. The Lamont seismic monitoring network, along with the existing ODNR OhioSeis network, located seismic events related to the NS1.

Seismic Methodology. Since 2012, ODNR Division of Oil and Gas Resources Management (DOGRM) and oil and gas operators have deployed seven three-component portable seismic units in and around two additional permitted injection wells within approximately 12 miles of NS1. ODNR-DOGRM deployed three sets of digitizers and three-component sensors near the Northstar #4 injection well (NS4). The sensors are high frequency sensors with a range of 0.1 to 1000 Hz, with a natural frequency of 2 Hz. The ODNR-DOGRM stations are installed approximately three feet below the ground surface to reduce background noise.

One SWD well operator installed four portable seismic stations between July 2 and 4, 2013, in an urban setting east of Youngstown in Campbell, Ohio. Each of these seismic monitoring stations has a high frequency, 2 Hz, three-component sensor. Sensors were deployed at a depth of 60 feet below surface at each site in 4-inch diameter PVC-cased holes. A high resolution data logger was installed to convert the analog data from the sensor to digital data. Channels were sampled at 200 Hz and backed up on a local compact flash drive. Communication was accomplished using cellular data modems. Power was provided by an 85-watt solar panel and two 100 amp-hour batteries, with charging controlled by a solar charge controller with a low voltage disconnect.

Data from the stations were run through manual trigging algorithms each night to detect seismic events. Triggered seismic events were broken down into three main types: earthquake, explosion, and noise. After triggering events were manually reviewed, earthquake and explosions were picked and noise deleted from the records. The data from stations were forwarded in real-time to ODNR-DOGRM. The data from the three ODNR-DOGRM stations were also displayed in real-time to a contracted data server.

Results. From March of 2011 to July of 2013, the area around Youngstown experienced numerous seismic events, ranging from **M** 2.1 to **M** 3.9, located along a previously unknown fault. Twelve of the events were detected on OhioSeis, but could not be accurately located due to the sparse coverage of the seismic stations. With the addition of Lamont's four portable seismic units, three events in late December 2011 and early January 2012 were more accurately located. The Lamont stations were installed within 2 to 6.5 km of the seismic source area. Seismicity appeared to migrate gradually from the eastern end of the fault area close to the NS1 towards the west, away from the disposal well. Seismic events were located in the Precambrian basement from depths ranging from 3.5 to 4 km below the surface and 4 km from the injection zone. Seismic activity was believed to be stimulated by increased pore pressure along a previously unknown fault, which is striking 265° ENE-WSW and dipping steeply to the north. Multiple seismic events were relocated by Lamont to within 1 km of the disposal zone. Six events were felt locally. Figure C.3 shows the location of the NS1 and locations of some of the seismic events.

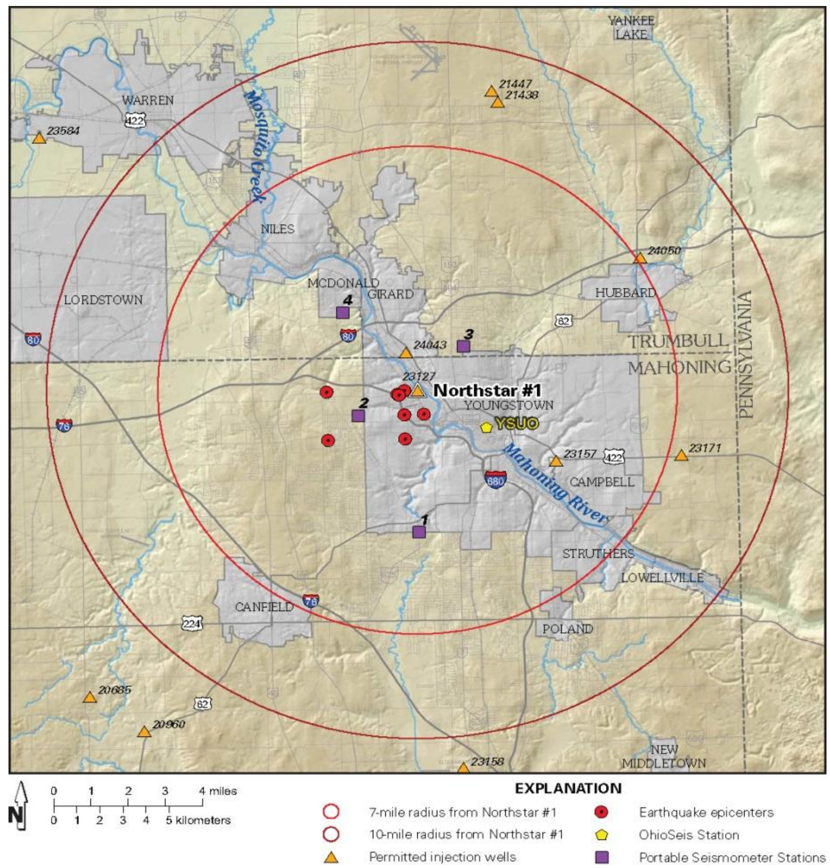


Figure C.3. Map of the Youngstown, Ohio, area showing the locations of permitted injection wells, seismic events, and seismometers. Source: Preliminary Report on the Northstar 1 Class II Injection Well, ODNR, March 2012.

The fault-plane solution (focal mechanism), calculated by Dr. Won-Young Kim at Lamont-Doherty Earth Observatory for the December 2011 event, indicates that the sense of movement of the fault was strike-slip (horizontal). The analyzed seismic data illustrates nodal planes striking at 265° and 171° from north. These calculations agree well with those done independently by Dr. Robert Herrmann at St. Louis University based on data from regional seismic stations. Seismic events relative to basement and the NS1 are shown in Figure C.4.

Shortly after the seismic monitoring network was installed, an **M** 1.3 earthquake was detected near NS1 on July 5, 2013. Figure C.4 shows the location of the July event as detected by the operator's seismic monitoring network, in map view (upper left) and cross-section views.

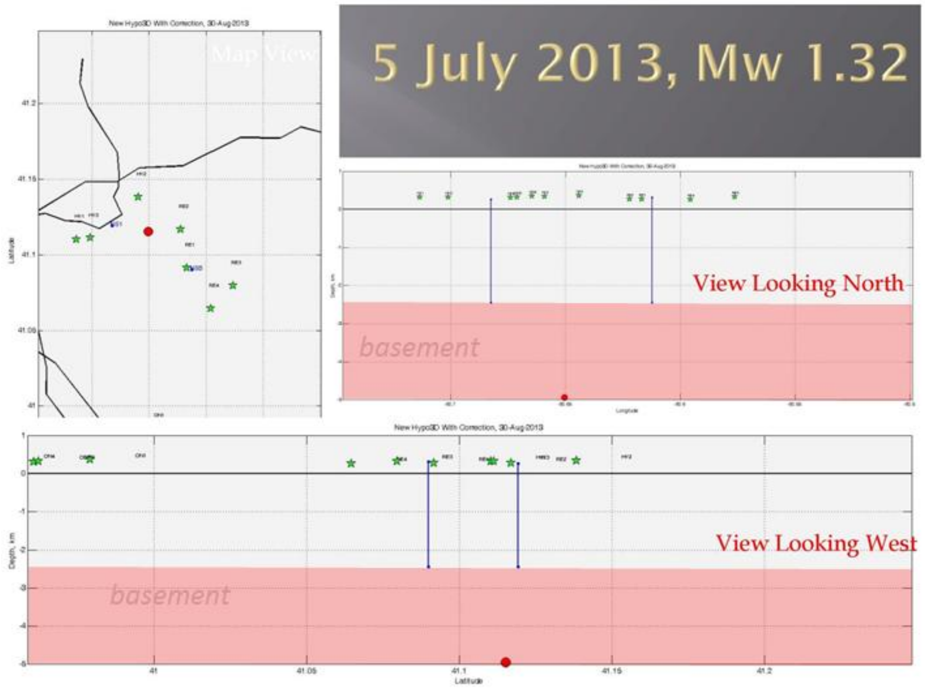


Figure C.4. The seismic monitoring network detection of a July 2013 seismic event near the NS1 well.

California Case Study — The Geysers Geothermal Field

This case study focuses on seismicity known to be induced by operations, and how a permanent seismic monitoring network enables the operations to continue while allowing mitigation and outreach to the local community. The study is derived from the geothermal industry, whose long history of managing induced seismicity offers useful lessons for UIC regulators.

Background and Objectives. Induced seismicity has been observed at The Geysers geothermal field since the mid-1960s, with the largest event an **M** 4.6 in the mid-1980s (Majer et al. 2007), although **M** 4 events have more recently begun occurring several times a year (see Figure C.5). The events occur in the main injection zone, with depths between 1 and 6 km.

The area is lightly populated, with several communities of a few thousand people within a few miles radius of the field and some inhabitants within less than a mile. The seismicity has grown as the amount of water injection has grown. Residents experience yearly events at rates of two to three **M** 4s, 30 to 40 **M** 3s, and 300 to 400 **M** 2s. Depending on the location, a few residents claim to feel event magnitudes as small as **M** 1.5, but this would be highly unusual. Some local opposition of the geothermal development exists due to induced seismicity. Some minor damage has occurred from the earthquakes, as well as public annoyances, but no lawsuits have been filed.

The Geysers Geothermal Field is the largest geothermal field (990 Mw) in the world. It was started in the early 1960s by Magma Power Inc., followed by Unocal Geothermal, and is currently operated by Calpine Inc., Northern California Power Authority (NCPA), and few smaller operators. It produces steam from a deep (up to 10,000 feet) under pressurized steam reservoir at 240–260°C. Extensive water injection has increased the amount of produced steam. The water is derived from power plant cooling tower condensate, waste water from nearby cities, and some local collected rainwater runoff.

Seismic monitoring at The Geysers was initiated in the late 1960s, a few years before injection began. Objectives are to detect low magnitudes (>~**M** 0.0) and locate events with an accuracy of +/- 400 m, sufficient to interpret geologic structure and water distribution (in time and space) as well as to help inform and guide injection practices for optimizing heat extraction. Analysis of seismic activity has aided mitigation activities designed to reduce the impact of induced seismicity on the community.

Geology, Disposal, and Velocity Model. The local geological structure has been interpreted from numerous drilling data, well logs, cuttings data and extensive geologic modeling performed by Unocal and Calpine. The system is bounded by two faults, the Mercuryville Fault to the southwest and the Collayami Fault to the northeast (EPRI 2014). The field itself has extensive small faults, dominated by the Big Sulfur Creek fault in the middle of the field. Depending on location within The Geysers steam field, wells may penetrate varying sequences of greenstone, serpentinite, chert (mélange), or greywacke at depths before entering the productive reservoir. Fractured greywacke sandstone is the characteristic rock in the producing reservoir throughout the geothermal field. The seismic activity stops at 4 km depth, corresponding to the start of the high temperature zone (> 400°C).

Monthly injection data consisting of pressure recordings and volumes are gathered by the operator and sent to the state of California Department of Oil, Gas and Geothermal (DOGGR). Most of these data can be accessed by the public.

Figure C.5 summarizes the rates of seismic events detected versus the injection and production history of the wells. Injection volumes average about 25 million gallons per day (mgd) (~600,000 Bbls/day)—more during the rainy season, less in the dry season. Before 1960, little or no seismicity was detected in the area of the current geothermal field. Earthquake activity increased soon after injection started in the late 1960s in an effort to decrease the rate of pressure decline of the reservoir and maintain the steam output. Currently the operators move the injection points to optimize steam withdrawal as well as minimize the effect of induced seismicity on the nearby population.

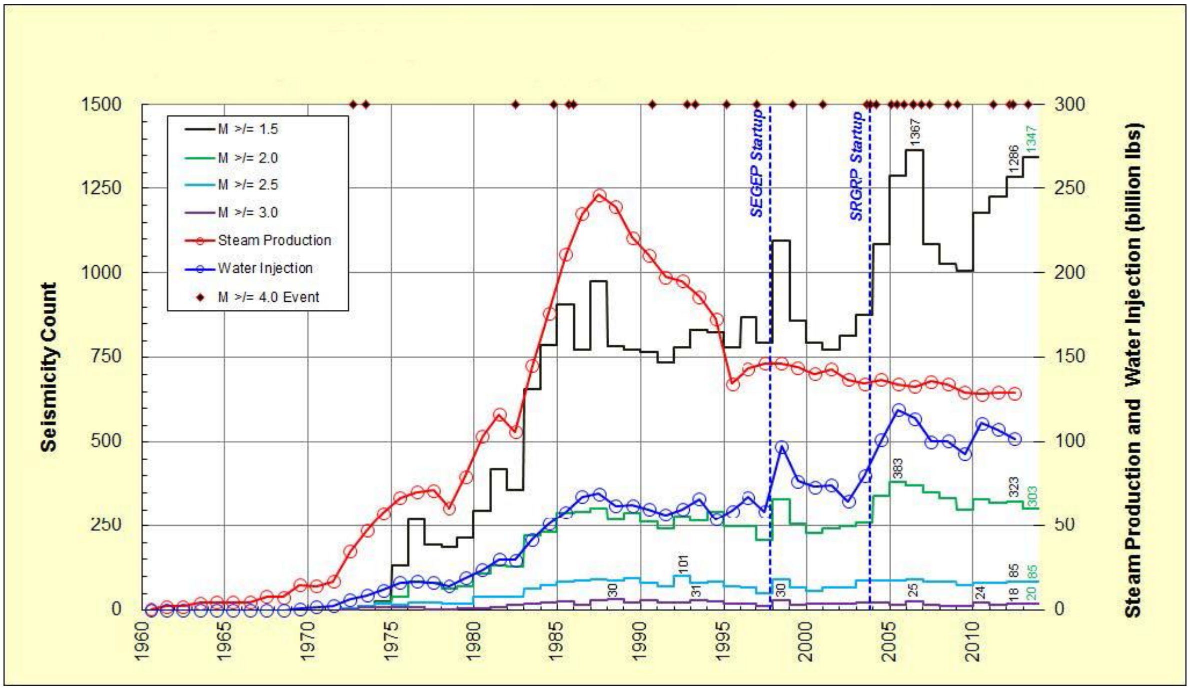


Figure C.5. History of seismicity at The Geysers for events of different sizes versus steam production and water injection volumes. Vertical dotted lines show the start of significant water injections (7 mgd in 1997 and 11 mgd in 2004) Source: from Craig Hartline, Calpine Inc.

The velocity structure of the field used to estimate event locations was derived from numerous inversion studies and tomographic velocity studies. However, the high temperature wells limit velocity logs. Velocity models were developed with incoming seismic event data and refined as more events accumulated.

Seismic Methodology. Lawrence Berkeley National Laboratory (LBNL), funded by the DOE Geothermal Technology Office, installed, operates, and maintains The Geysers seismic array with support from Calpine. Currently, the MEQ array includes 32 surface stations (also five shallow borehole stations from 100 to 500 feet deep) with data telemetered in real time to a central site that detects events and reports them to LBNL for real-time location and magnitude determination. The data are then publicly displayed in plane and 3D views on the internet. Two strong-motion accelerometers are also in the area to detect ground motion. Figure C.6 shows the stations (blue radio symbols) and injection wells (arrows).

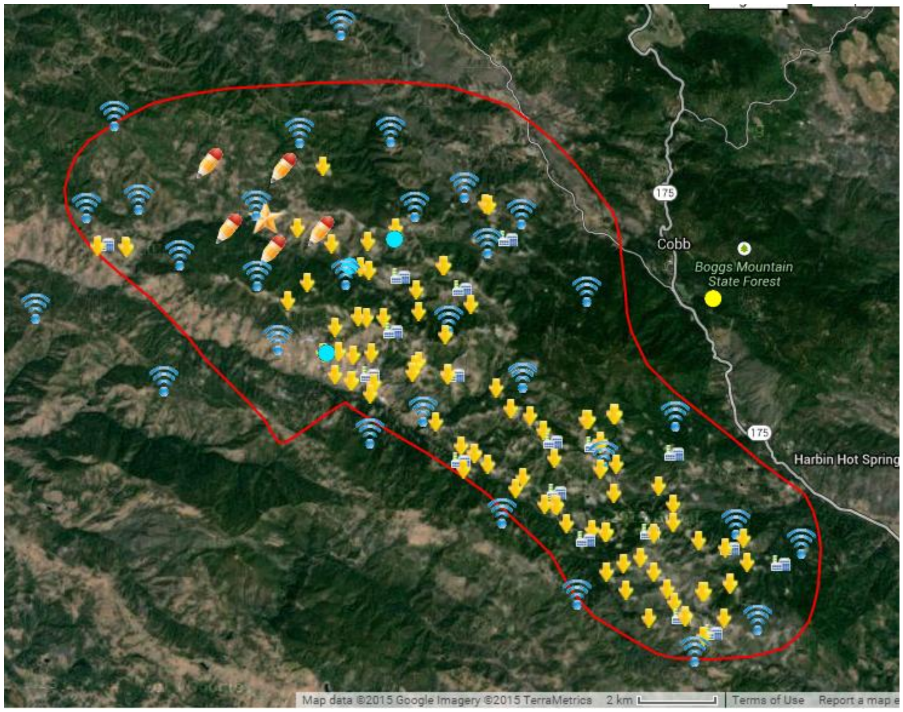


Figure C.6. Stations (blue radio symbols) and injection wells (yellow arrows) at The Geysers. The red line demarcates the production zone.

Each station has a three-component 4.5 Hz geophone, a digitizer (24-bit, 500 samples/sec) and two-way spread spectrum radios. Spacing of the stations averages 1 to 2 km.

Processing is mainly automated for waveform picking, phase windowing, spectral analysis, location, and magnitude determination. The volume of data (40,000 to 50,000 events per year) prohibits manual picking, except for largest events (**M** ≥ 3.5 events) and for selected injection experiments (often includes moment tensor analysis). Ultimately, the waveforms and processing results are sent to the Northern California Earthquake Data Center (NCEDC) operated by the USGS and the Berkeley Seismographic station and are available to the public. Real time data are available at http://esd.lbl.gov/research/projects/induced_seismicity/egs/geysers.html.

Results. Seismic events occur throughout the entire production zone. In the early days of production before significant injection began, local monitoring did detect some seismicity. More events were detected soon after injection started, near the injection points in the subsurface. Clusters of seismicity were located and their growth and migration was measured around the well and away (down as well as around) from it. As the field and injection points grew, the seismicity grew (Figure C.7). Magnitudes down to **M** 0.0 have been detected and located to an accuracy of +/- 500 m. Since 2000, over 500,000 events have been detected and located in The Geysers steam field.

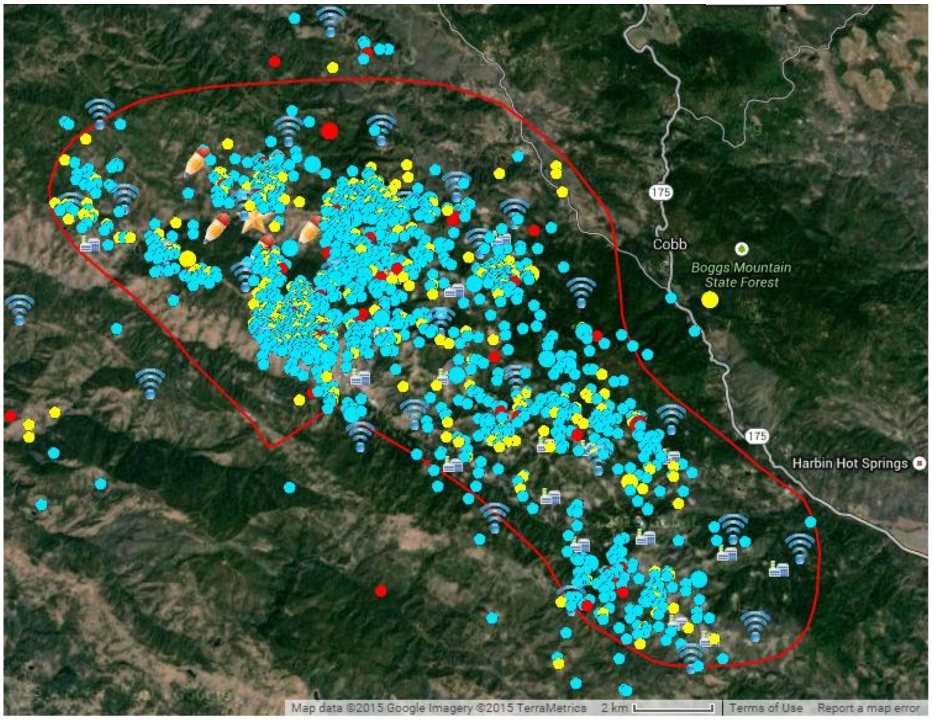


Figure C.7. A typical month of events (4,000 ***M*** *> 0) at The Geysers steam field.*

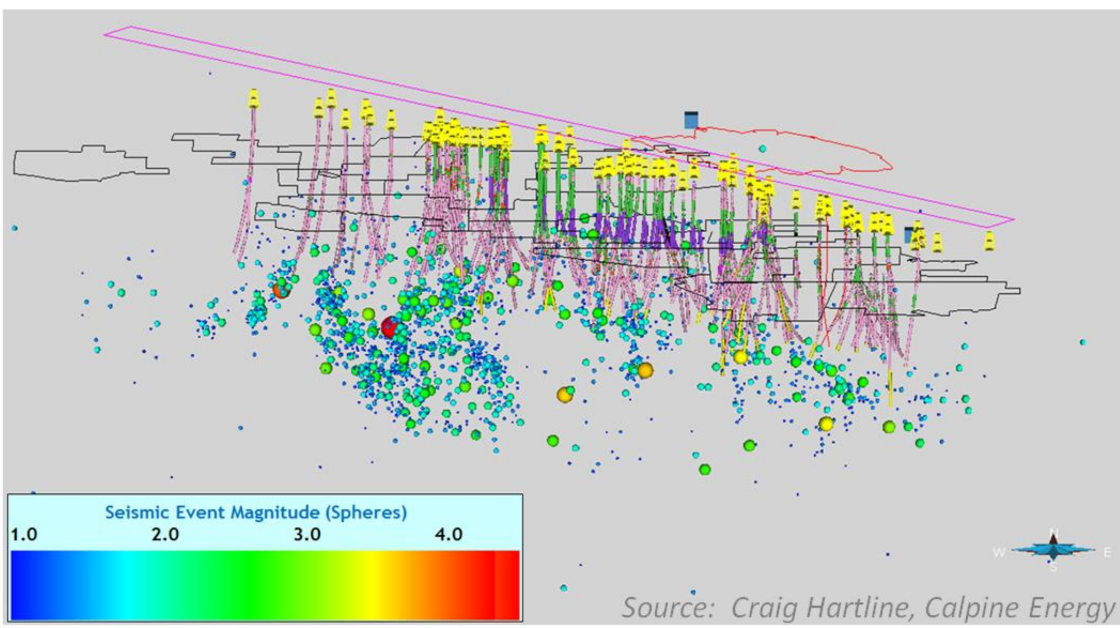


Figure C.8. Oblique cross-section view of The Geysers steam field with well trajectories and seismic events, sized and colored by magnitude. Source: Calpine Energy.

Discussion. The Geysers seismic network has become a critical resource to the operators in order to optimize and understand the steam reservoir production, as well as for mitigating the impact of induced seismicity on nearby communities. Over the years, the operators, through proactive communication and joint meetings, have formed an alliance with the community that is beneficial to all stakeholders.

Ideally, one could accomplish the same data quality and quantity with half the stations, by replacing the surface stations with 2 Hz shallow (300 feet) borehole stations. This would increase sensitivity and bandwidth. Mitigation efforts and data handling and processing have evolved over the course of the project, with all seismometers now being three-component broadband sensors.

All seismicity and injection data (seismicity in real time) are available to the public at the site mentioned above. Bi-annual meetings with all the stakeholders are open to the public and press. A hotline is also available to the public to voice any issues with the operators.

Many lessons can be learned from The Geysers experience. The information gained from studying induced seismicity is a valuable tool. This case illustrates that the more information one has on the causes of the seismicity, the better one can utilize that information as a tool to help mitigate the risk. Another lesson learned is that honest outreach and communication to the public regarding both known and unknown data and interpretations is critical to not only gain confidence from and acceptance by the public, but also for accurate risk assessment by the operator.

Illinois Case Study — Decatur Carbon Capture and Storage Project

This case study compares two separate local networks looking at the same earthquakes, and illustrates some pitfalls and significant differences in locations and interpretations arising from different sensor geometries and velocity models. This study underscores the need for caution when relying on seismic data.

Background and Objectives. The Illinois Basin-Decatur Project (IBDP) is located in Decatur, Illinois, at an Archer Daniels Midland (ADM) facility. Carbon dioxide produced from agricultural products and biofuel production is stored deep underground though UIC Class VI disposal wells. This case study documents two parallel seismic monitoring efforts—one operated by ADM, with deep vertical arrays of geophones in boreholes near the injection point—and another operated by the USGS, a surface array nearby using surface and shallow borehole sensors. This study allows a comparison between a typical hydraulic fracturing seismic monitoring (borehole) system and a surface seismic monitoring system such as would be used to monitor a Class II disposal well, in an area without site specific data to produce a detailed velocity model. The dataset comparison showed large differences in horizontal and vertical hypocenter locations. Surface sensor event locations were judged inferior due to the limited site information available, difficulties in analyzing waveforms produced by small microseismic events many kilometers away, and erroneous data created by noise typical of industrial areas.

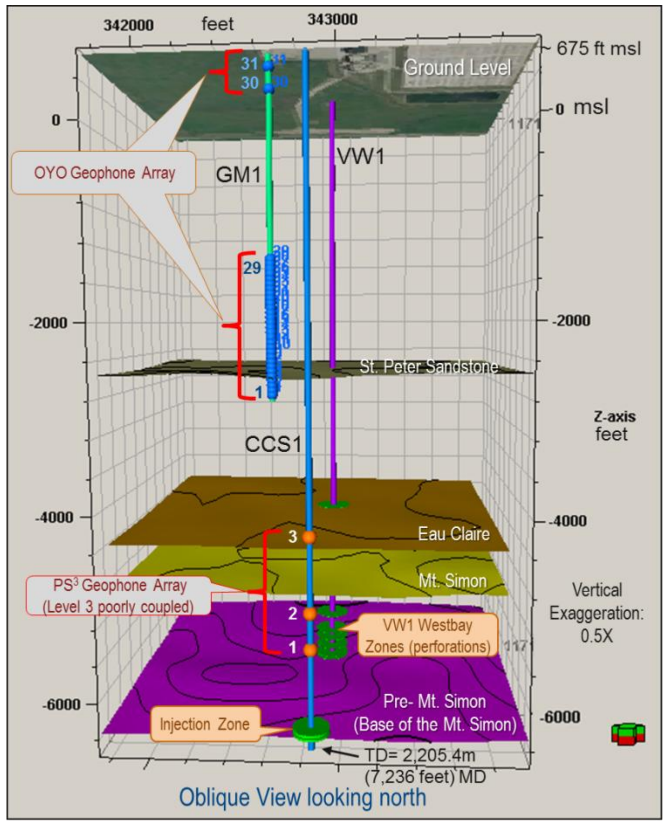
Geology, Disposal, and Velocity Model. The CO_2 reservoir is thick, high porosity sandstone with injection occurring at a depth of 2.1 km (7,025-7,050 feet). Below this unit is less porous sandstone 30 m thick, which rests on the Precambrian crystalline basement. The site has been characterized with surface seismic profiles and multiple deep boreholes with extensive geophysical testing. These data were used to develop detailed geologic and velocity models for the site.

Detailed geology and properties are provided by multiple boreholes penetrating the crystalline basement that have been geophysically logged, including sonic logs. The site has had 2D seismic lines and multiple 3D seismic surveys performed to characterize it. Near the surface is 115 feet of glacially derived material with varying sonic velocities.

Velocity data was derived from sonic logs in wells onsite and from seismic surveys to produce a velocity model. This model was checked with detected seismic events from drilling a nearby borehole and perforation shots in that hole.

Seismic Methodology

Figure C.9. Map of well locations (below) and diagram (right) for vertical arrays showing configuration of borehole and monitoring equipment for the IBDP site in relation to stratigraphy: the WellWatcher PS3 geophone array in the CCS1 well; the OYO, three-component, 31-level array in the GM1 well; and the Westbay system in the VW1 well for sampling and pressures readings at 11 levels. Source: from Will et al. 2014.



Vertical arrays: In 2010, two deep vertical arrays of geophones were installed 18 months prior to injection, which allowed for calibration as a nearby borehole was drilled and perforation shots were made. These vertical arrays consist of a four-component system within the injection borehole and a three-component system in another seismic monitoring well 200 feet away, with geophones closer to the surface providing some offset. Seismic monitoring started in 2010 and continues today in the post injection phase. The purpose of these instruments was to accurately locate events in the proximity of the disposal well and to determine if seismicity was related to the very low injection pressure used to inject fluids into the high permeability formation.

The injection well (CCS1) has a system consisting of 15 Hz geophones in a tetrahedral configuration, with four-component geophones at depths of 4,925 feet, 5,743 feet, and 6,137 feet. Because injection is also occurring in this borehole, geophones have picked up erroneous events associated with vibration within the tubing. The seismometer data is fed into recording system and put through a manual process to remove all the erroneous events. The second vertical array's geophones are much shallower, with 31 three-component 10 Hz geophones in an orthogonal configuration. The majority of these are between the depths of 2,046 and 3,445 feet, but two are at shallower depths of 136 feet and 357 feet, respectively. Calculated positions of several events were used to first orient these geophones relative to true north and then shots were used to more accurately orient the systems. All events were then realigned to true azimuths (NSEW).

Figure C.10. Map of USGS surface seismograph stations. CCS1 is the injection borehole; the three "borehole" installations shown are 500 feet deep. Source: Hickman et al. 2014.

Surface array: Nearly two years into the injection process, the USGS network started seismic monitoring with nine surface and three shallow 500-foot deep borehole installations. Later a fourth shallow borehole system was installed.

The surface installation consists of nine stations equipped with both a three-component broadband seismometer and a three-component force-balance accelerometer. The three borehole stations have the same accelerometer at the surface but have three-component, high-sensitivity geophones in the boreholes. The aperture of this network is about three miles centered on the injection well (Kaven et al. 2014).

The surface seismic monitoring used a 1D velocity model developed from the borehole information supplied for the site permit and also P-wave logs from one of the 500-foot deep boreholes. For event location, a constant ratio of P/S-wave velocities of 1.83 was used. The surface instrument analysis used Hypoinverse and Double Difference methods.

Results. Over the past five years and during the three years of injection, the IBDP network has recorded an average of four locatable events per day during injection. The network detects locatable events in the magnitude range from a little below **M** 2.0 to a few events a little above **M** 1.0. Ninety-four percent of the magnitudes fall below **M** 0.0. Most have occurred in clusters along what are presumed to be preexisting undetected planes of weakness that are oriented in the SWNE direction. Not all clusters followed an orderly progression in time with distance from the injection well as injection progressed. Some clusters—oriented closer to the critical stress conditions associated with the high horizontal *in-situ* stress—reacted sooner. The surface array located the events in the lower sandstones and into the upper part of the crystalline basement.

A comparison of the locatable events from the surface to subsurface arrays shows only about a six percent match in events over a four-month period. Comparison of locations nine months after surface installation showed a mismatch between the two systems, with the surface-defined event locations as great as 2 miles horizontally farther away and 1.3 miles deeper for small magnitude events near **M** 0.1. Events near **M** 1.0 had mismatches of about 0.7 miles in both horizontal and vertical directions. Analysis of data from the surface instruments placed events on a mile-long NWSE linear feature, while the subsurface array plotted events in a tight cluster slightly beyond this feature. However, improvement of a velocity model for the surface instrument analysis has events approaching the subsurface array locations, with the linear trend collapsing to a cluster.

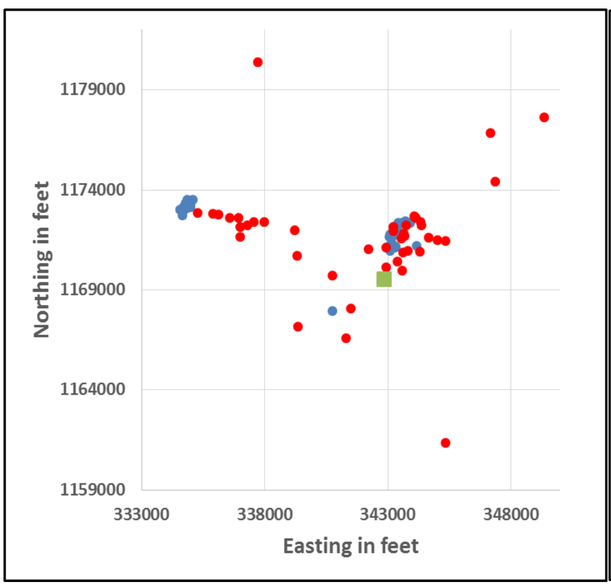


Figure C.11a. Comparison of the same four months of events located by the subsurface array (blue) to the surface array (red). Green is injection well and grid spacing is 5,000 feet.

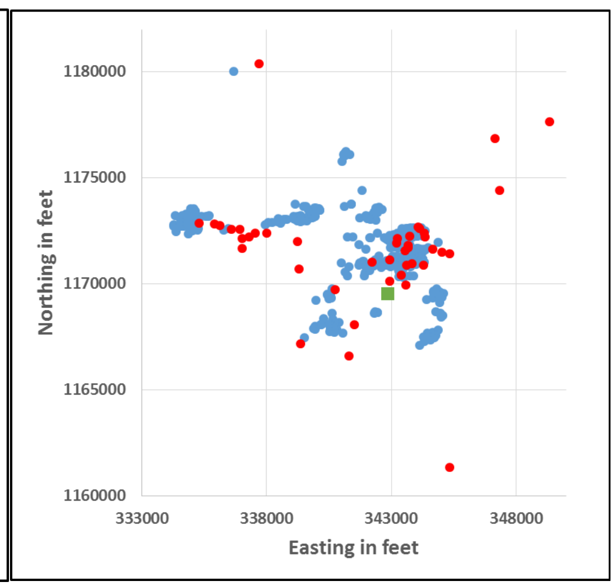


Figure C.11b. Same time period as C14.a, but showing all 567 subsurface array located events (blue) to the 41 surface array located events (red). Green is injection well and grid spacing is 5,000 feet.

Discussion. After further refinements and analysis, the linear feature seen in early interpretations from surface instruments show that the linear feature is not present. Early interpretations could have been that a one-mile long fault existed in this area.

This case study shows what large variations in locations can occur between surface and borehole data using reasonable velocity models. Areas with thick surface deposits that are extremely variable are a contributing factor for surface installations. Moreover, working with waveforms collected by surface seismic stations in a noisy industrial area, with low magnitude events occurring at 1.3 miles away or more, is challenging.

From a regulatory perspective, it is clear that caution is required before making decisions based on locations of microseismic events of roughly **M** ≤ 0.5, given their distance from the injection well and alignment, and the availability of information to develop a velocity model to accurately locate events.

Colorado Case Study — Greeley

This case study is an example, like the Ohio one, of a regional network detecting events, and a temporary local network locating more events with better accuracy. It illustrates the use of advanced seismological methods to improve locations of prior events, and the use of a 'Traffic Light' system to help regulators with mitigation action. Finally, it is an example of where plugging back a disposal well seems to have been beneficial and allowed disposal to resume safely.

Background and Objectives. On 31 May 2014 at 9:35 PM, an **M** 3.2 event was recorded by the USGS with an epicenter located 6 miles northeast of Greeley, Colorado in the proximity of the Class II underground injection control (UIC) well NGL C4A (Figure C.12). The C4A injection well is located in the SWSE quarter-quarter of Section 26, Township 6 North, Range 65 West, in Weld County, Colorado. Though there is little historical earthquake activity in the region, there are well documented induced events related to the Rocky Mountain Arsenal injection well that occurred near Denver in the 1960s.

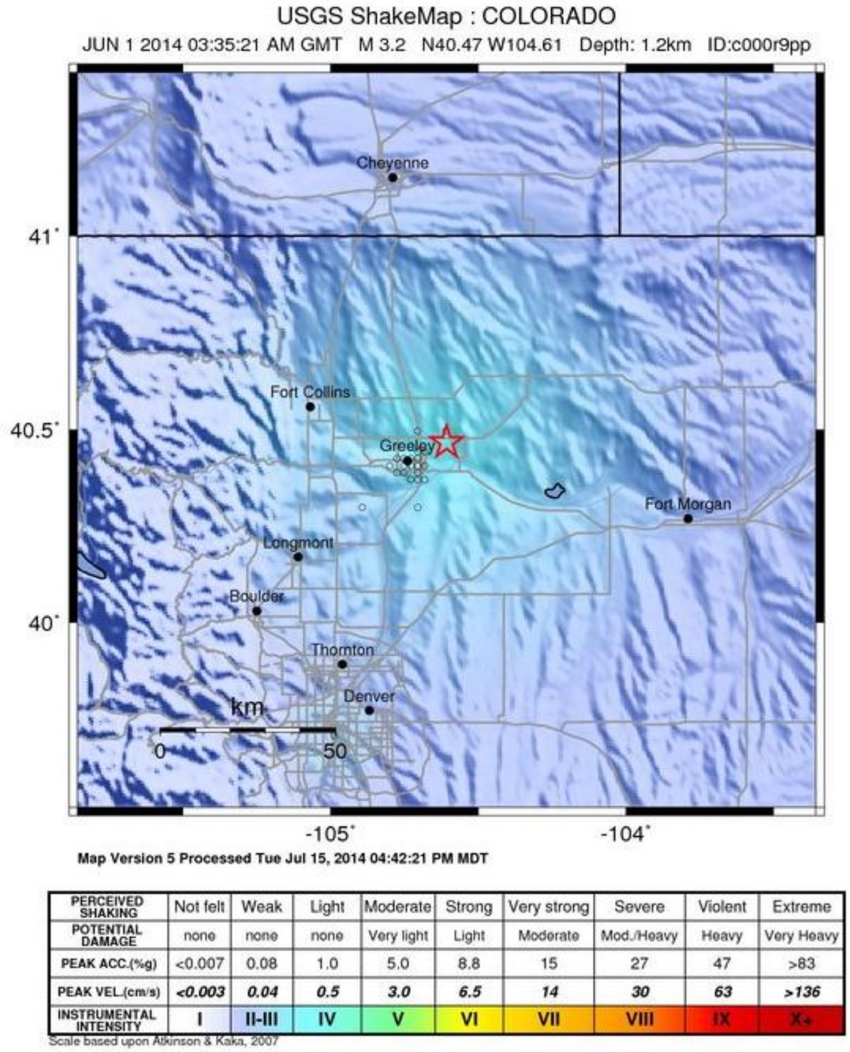


*Figure C.12. Shake map of the **M**3.2 earthquake near Greeley, CO, May 31, 2014. Source: National Earthquake Information Center, USGS.*

The region has a limited record of seismicity and is susceptible to a modest PGA of ~0.1 g for a fifty-year interval per the USGS National Earthquake Hazard Map. There is active oil and gas production and there are several Class II disposal wells in the region. And notably, this area is within the populated Denver–Ft. Collins metro corridor.

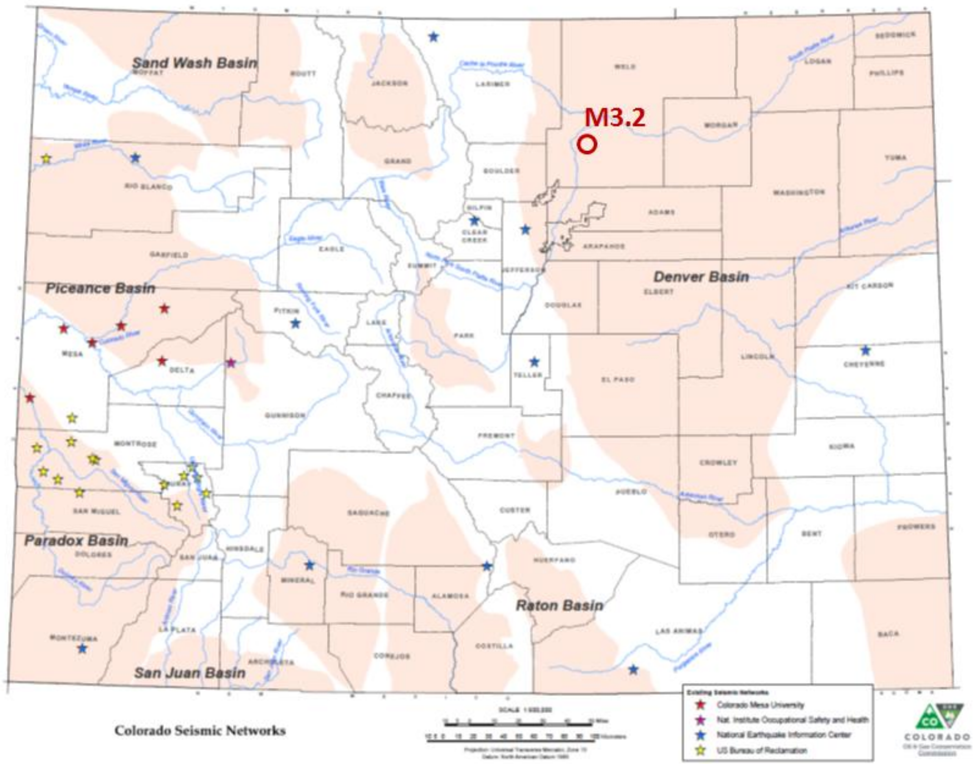


*Figure C.13. Seismic stations in Colorado and the location of the **M** 3.2 earthquake of 31 May 2014. Source: Colorado Oil and Gas Conservation Commission.*

Colorado has an existing regional seismic network containing 11 stationary seismometers placed across the state (Figure C.13). The closest instrument at the time of the initial May 2014 event was the USGS ISCO station, located in Golden, Colorado, approximately 70 miles from the recorded epicenter. The initial event was detected by the regional network and reported by USGS. Subsequent seismic monitoring following the Greeley event was initiated by a geophysical research team at the University of Colorado, which deployed a set of portable short period seismometers in early June of 2014 (Sheehan et al. 2014).

Geology and Disposal. The geologic setting is in the Denver-Julesburg Basin near the Greeley Arch, which separates the Denver Basin from the Cheyenne Basin. The disposal zone was in the Permian Lyons through Pennsylvanian Fountain Formations. The Fountain Formation sits on top of crystalline basement at a vertical depth of approximately 11,000 feet; zones of injection were initially less than 500 feet above the basement.

The published seismic data shows that the region has a variety of faulting styles from the deep reverse (wrench) faults, normal faulting, growth and listric faults. Generally, the faulting is a complex network of antithetic-synthetic faults originating from the basement. The faulting styles can be seen throughout the Upper Cretaceous section and into crystalline basement.

The C4A well was drilled to a depth of 10,818 feet. Disposal is through a slotted pipe liner with external casing packers, initially from a depth of 9,056 feet to total depth. Disposal data is gathered by the operator (NGL) and submitted to the Colorado Oil and Gas Conservation Commission as monthly injection volumes and maximum injection pressure. Injection began in April 2013 with higher rates of injection (>10,000 bpd) beginning in August 2013.

The USGS first reported seismic events on 31 May 2014 with a second **M** 2.6 event on 23 June 2014, thirteen months after initial disposal. University of Colorado deployed portable seismometers in early June 2014. The C4A well was shut in for evaluation on 23 June 2014. The C4A well data, drilling logs, and well files were reviewed. The review of drilling logs indicated several lost circulation zones in the lower several hundred feet of the well. The operator conducted a spinner survey to characterize flow in the well with most of the well's flow in the bottom few hundred feet. As a result, the operator plugged back the well approximately 458 feet to 10,360 feet. The spinner survey was re-run. The results were an even injection profile throughout the well. Re-injection began at 5,000 bpd on 19 July 2014, with the injection increasing to 7,500 bpd in August 2014 and again in October 2014 to 9,500 bpd. These increased injection volumes were allowed with review of the seismic monitoring data, with little seismicity detected since resumption of disposal.

Seismic Methodology. In addition to the regional seismometers already in place, a local seismic monitoring network was deployed at the location of the May event epicenter. The local seismic monitoring network consisted of portable short period seismometers and data recorders, which were on loan to the University of Colorado from the PASSCAL–IRIS Consortium.

By using a matched filter study, the University of Colorado retrospectively searched for waveforms at the ISCO station matching the **M** 3.2 event; that analysis suggests events associated with injection activity may have begun in November 2013.

Results. Event clusters located by the post-earthquake local network were observed to surround the NGL C4A injection well (Figure C.14) (Yeck et al. 2014).

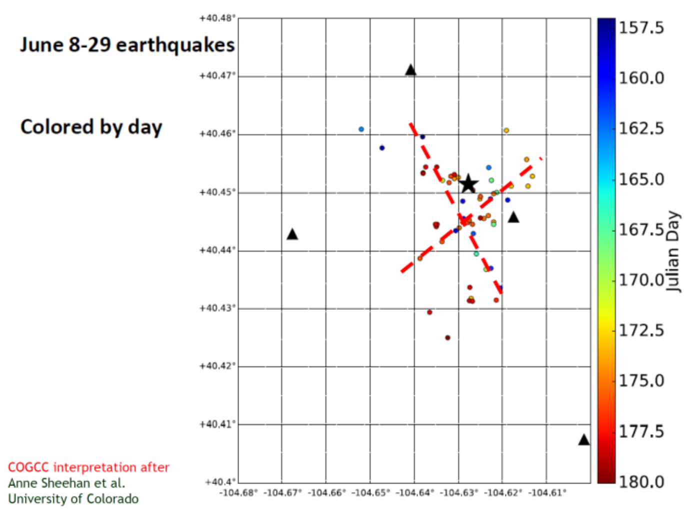


Figure C.14. Map view of temporary seismometer array (black triangles), the C4A SWD well, and events. Source: Colorado Oil and Gas Conservation Commission interpretation, after Anne Sheehan et al. 2014.

Discussion. The use of existing permanent and portable seismometers deployed around the C4A injection well provided the basis of seismic monitoring. The risk management plan AXPC/Industry induced seismicity Traffic Light scheme (NRC 2012) was implemented to monitor seismic activity. A base level of activity for magnitude and location was defined as a green light level. In this case, **M** 2.5 and a USGS epicenter location within 2.5 miles of the injection wells were defined as a green light limit.

Regional seismic networks allow for detection of **M** > 2.0 events, but have limited capabilities in accurately locating these events. Further, a regional network is unlikely to detect the numerous smaller events that may be associated with injection activities. In this case, having access to a local seismic monitoring network operated by University of Colorado researchers allowed for more proactive seismic monitoring subsequent to the initial event. Managed injection was then possible as higher spatial and temporal resolution data became available.

It is suggested that a review of drilling logs for lost circulation zones, particularly in the lower portion of a well, can help identify flow migration outside the injection zone, which could migrate to crystalline basement. Furthermore, it is important to know the appropriate distance between the injection zone and crystalline basement because this interface may have bearing on earthquake susceptibility (Zhang et al. 2013). A regional seismometer network combined with a portable network allows the seismic monitoring of seismicity and risk management of induced seismic events.

Texas Case Study – Development of TexNet

Beginning in 2008, the rate of seismicity significantly increased across the southern mid-continent of the United States, including parts of Texas. There has been an increase in the rate of recorded seismicity in Texas over the last several years. Between 1975 and 2008 there were, on average, one to two earthquakes per year of magnitude greater than M3.0. Between 2008 and 2016, the rate increased to about 12 to 15 earthquakes per year on average (The Academy of Medicine, Engineering and Science of Texas 2017).

The previously existing (pre-2016) network of 18 operating seismic monitoring stations, irregularly distributed across Texas, was insufficient to detect, locate, and properly characterize seismicity at a level of accuracy necessary to understand either what caused events or if any actions could be taken to reduce the recurrence of such events.

The Texas State Legislature appropriated funds for fiscal years 2016-2017 (House Bill 2 (HB 2) of the 84th Texas Legislature for the purchase and deployment of seismic equipment, maintenance of seismic networks, research and modeling of reservoir behavior for systems of wells in the vicinity of faults, and establishment of a technical advisory committee. This initiative is known as TexNet, which is operated by the Bureau of Economic Geology (BEG) which serves as the state geological survey.

TexNet is a network of stand-alone broadband seismometers that are being installed in suitable locations throughout Texas in two configurations, permanent and portable. TexNet installed 22 permanent and 3 auxiliary stations that, when integrated with the existing 18 stations, will compose the backbone seismic network of 43 stations, enabling BEG to monitor and catalog seismicity across Texas, at magnitudes to **M** 2.0, and lower in some local areas where seismometers are more closely spaced.

In addition to this backbone network, 36 portable seismic monitoring stations also have been acquired. Deployment of these portable stations will allow for detailed site-specific assessments of areas of active seismicity. These stations were designed to use broadband seismometers and accelerometers, which allow for the detailed characterization of ground motion when earthquakes are relatively close. As of late 2017 ten of these portable stations were deployed in the Dallas–Fort Worth metropolitan area and others in west Texas and south Texas. (See Figure C. 15).

HB 2 also required that BEG enter into collaborative research relationships with other universities in Texas, including the Texas A&M Engineering Experiment Station, for the purpose of modeling of reservoir behavior described by that subsection and other data analysis.

The Legislature established a technical advisory committee (TAC), composed of nine members appointed by the governor, at least two of whom represent higher education institutions and have seismic or reservoir modeling experience, at least two of whom are experts from the oil and gas industry, and at least one of whom is a Railroad Commission of Texas seismologist. The TAC advises on the use of appropriated funds and on preparation of progress reports.

Data from the TexNet seismic stations streams in real time to the TexNet Data Hub, installed at the BEG, for analysis and subsequent distribution to IRIS and the U.S. National Earthquake Information Center (NEIC), operated by the United States Geological Survey (USGS). Earthquake data and analyses will be available to the public through IRIS and a TexNet website.

Effective September 1, 2017, the Texas State Legislature enacted House Bill 2819, which added the language that was in HB 2 from the 84th Session to the Education Code and provided further definition of TAC makeup and responsibilities surrounding advising on the technical elements; reviewing and approving funding allocations; and reporting of data and progress.

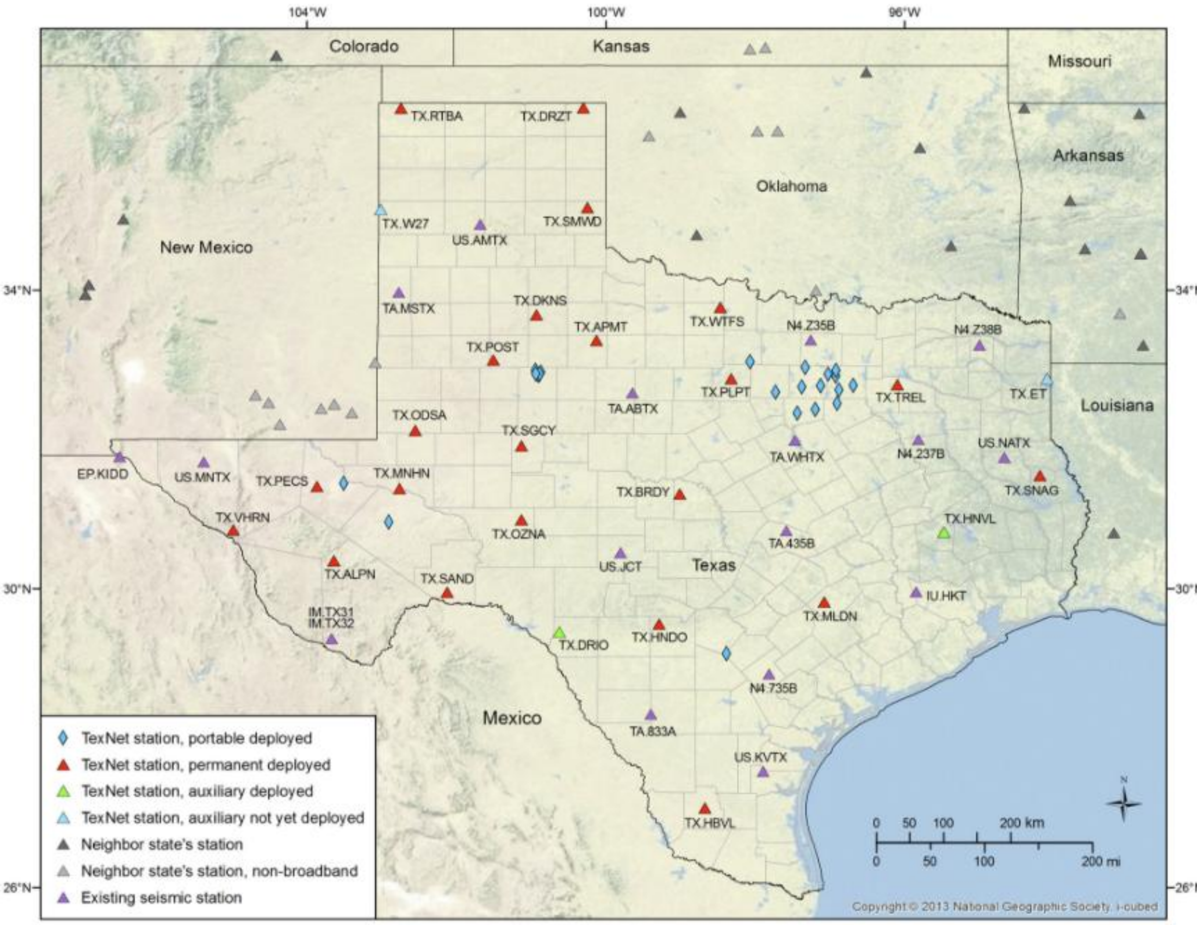


Figure C.15 Map of TexNet seismic network, as deployed in 2016-2017 and as of October 2017.

Oklahoma Case Study – Pawnee, OK

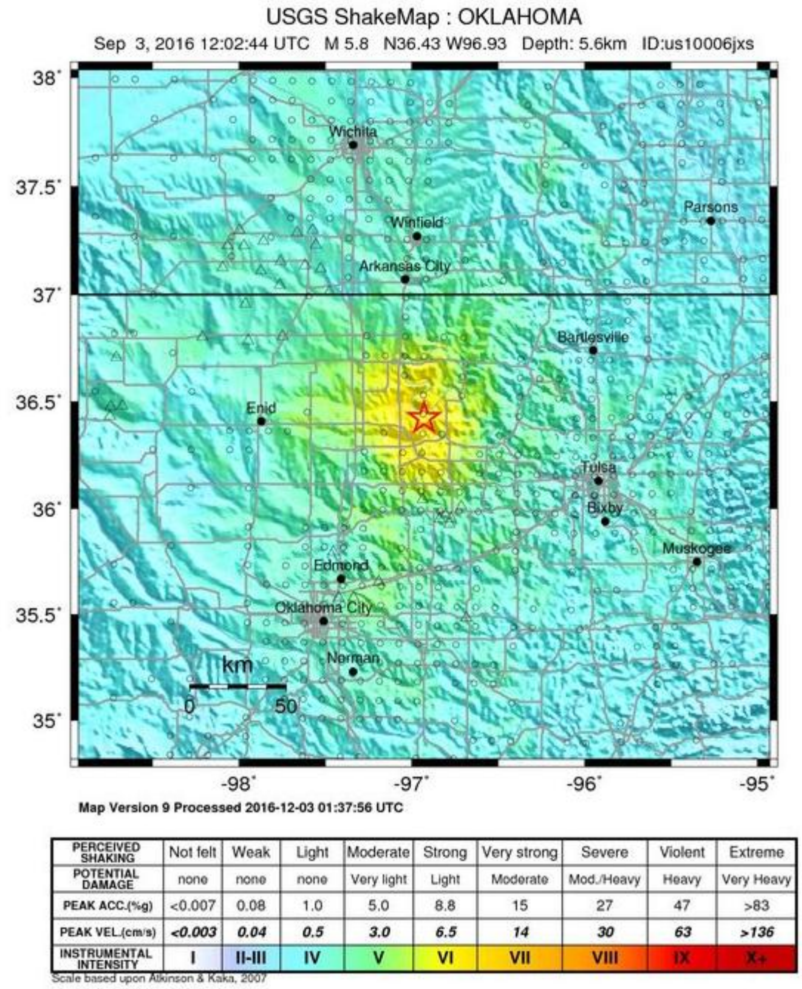
This case study focuses on the largest recorded magnitude earthquake to occur in Oklahoma in recent times. The expansion and improvement in the Oklahoma Geological Survey seismic network provided for quick resolution of the epicentral area that allowed the Oklahoma Corporation Commission and the USEPA to jointly take direction action and target selected underground injection wells for shut in and volume reduction.

Background and Objectives. On September 3, 2011, a **M**5.8 earthquake was generated near Pawnee, Oklahoma and was reported as felt over a wide area of the central US. This was followed by a series of aftershocks ranging from **M**2.6 to **M**3.6 within four hours of the mainshock. The estimated hypocentral depth of this event placed it in Pre-Cambrian basement rock. Another series of events ranging from **M**2.8 to **M**4.5 were recorded in the same vicinity on November 2, 2016. Signs of ground settlement and soil liquefaction from the **M**5.8 event were noted in a report by a Geotechnical Extreme Events Reconnaissance team (Clayton 2016). This team was dispatched by the Geotechnical Extreme Events Reconnaissance (GEER) Association which coordinates such visits under the sponsorship of the National Science Foundation. This team also noted that there was primarily non-structural damage to buildings in the area and that common observations included: façade failure, partial or full chimney collapse, and cracking of plaster and/or drywall. There were also reports of dishware falling off shelves and hanging picture frames falling to the floor. A follow up report put together by another GEER team focused on the geotechnical aspects of this major event. The extensive state-wide seismic monitoring network that had been installed by the Oklahoma Geological Survey assisted greatly in providing good location of the epicenter of this event.

Geology and Disposal. Saltwater disposal wells in the Pawnee area are primarily located in the Ordovician-age Arbuckle Formation which often lies on top of basement rock. Good information on the character of the Arbuckle is described in (Shelton 1985) and the following descriptions are primarily derived from such. The Arbuckle varies in thickness throughout its extent and is composed of carbonate mudstone, laminated dolomite, dolomitic limestone and interclast calcarenite with some sandstone beds. It is known to be vuggy in many areas. In some parts of northeast and north central Oklahoma it is underlain by the Cambrian-age Regan sandstone. The distribution and thickness of the Regan sandstone is uneven across this area due to irregular paleo-topographic relief on the surface of the basement. The Arbuckle is known to be underpressured in much of the area but the reasons for such have not been definitively shown. Much of the produced water that is disposed in the Pawnee area is generated by dewatering of the Paleozoic Mississippi Limestone although some of the injected water comes from older producing wells also. Saltwater disposal wells within Osage County where the epicentral area was located are regulated under the auspices of the USEPA as this is the location of the Osage Nation Reservation. Saltwater disposal wells in the adjacent counties are regulated by the Oklahoma Corporation Commission (OCC).

Seismic Methodology. The Oklahoma Geological Survey seismic monitoring network has grown substantially since 2009. Funding for additional seismic monitoring stations was provided by the Oklahoma Secretary of Energy and Environment and from a grant from the Research Partnership to Secure Energy for America (RPSEA). The USGS also funded a temporary localized dense array project in central Oklahoma. The OGS has used the SEISAN earthquake package since 2010 and this is to calculate moment magnitude (M_w) and to determine focal mechanisms. A regional velocity model is used to help determine the locations of earthquakes.

Results



PERCEIVED SHAKING	Not felt	Weak	Light	Moderate	Strong	Very strong	Severe	Violent	Extreme
POTENTIAL DAMAGE	none	none	none	Very light	Light	Moderate	Mod./Heavy	Heavy	Very Heavy
PEAK ACC.(%g)	<0.007	0.08	1.0	5.0	8.8	15	27	47	>83
PEAK VEL.(cm/s)	<0.003	0.04	0.5	3.0	6.5	14	30	63	>136
INSTRUMENTAL INTENSITY	I	II-III	IV	V	VI	VII	VIII	IX	X+

Figure C.16 USGS shake map of the Pawnee **M**5.8 earthquake with values for peak ground acceleration and peak ground velocity. The shake map displays the area and severity of shaking generated by the event. Instrumental intensity values are calculated from the integration of the square values of spectral acceleration ordinates.

Discussion. Immediately following the **M**5.8 event, the OCC ordered the shutdown of 37 saltwater disposal wells under its jurisdiction in areas adjacent to Osage County. On September 12, 2016, the OCC issued a directive modifying operations at 48 Arbuckle disposal wells with 32 wells being shut in and 16 additional wells being directed to reduce volumes. In addition, the USEPA who has jurisdiction for saltwater disposal wells in Osage County ordered five additional wells to shut down operations and 14 other such wells to reduce injection volumes as part of a coordinated response with the OCC. Following an **M**4.5 event on November 2, 2016, on November 3, the OCC ordered 4 additional disposal wells to be shut in, 10 Arbuckle disposal wells had their allowable injection volumes reduced by 25 percent in volume and 8 such disposal wells were limited in volumes to their last 30-day average. (Skinner 2016)

Ohio Case Study — Harrison County Ohio

This case study is an example of the use of data from the state seismic network and additional broadband EarthScope Transportable Array stations to analyze the seismicity of a hydraulic fracture induced sequence. This information helped the state to take mitigating actions with the operators involved, to determine the extent of a previously unknown basement fault.

Background and Objectives. Until 2013 there was no history of hydraulic fracture (HF) induced seismicity in the northeastern United States. This all changed in October of 2013 when a hydraulic fracture operation in Harrison County, Ohio was linked to inducing a series of small earthquakes (**M** 2.2 and below) on an unmapped basement fault (Friberg et al., 2014). This was followed in subsequent years (2014, 2015, and 2016) by activation of the same fault system by hydraulic fracture completions on wells to the east of the first occurrence, with some events reaching magnitudes as large as **M** 2.9 (Friberg et al, 2015, 2016). The research objectives were to obtain a better understanding of the mechanism connecting hydraulic fracture and activation of the faults as well as to determine the length of the basement fault itself.

Geology and Hydraulic Fracturing. Most of the shale gas exploration projects of the northeastern US of the past few years have been done in the Marcellus shale in Ohio and Pennsylvania. No seismicity has ever been associated with well completions in this geological formation. More recently, however, another deeper formation, known as the Utica shale, has become the target for shale gas operations in southeastern Ohio. Multiple instances of induced earthquakes have been reported in this formation (Friberg et al, 2014; Skoumal et al, 2015; Skoumal et al, 2016).

Horizontal drilling and hydraulic fracturing completions are the primary technologies used to extract fluids trapped in the shale formations. As summarized in Appendix I below, hydraulic fracturing uses high pressure water and sand injected into wells to cause small fractures (which often manifest as microearthquakes -3 < **M**< -1) in the formation to release the methane gas. In some rare instances, the stress perturbations or pressurized fluids from hydraulic fracturing operations communicate with basement tectonic faults that are critically stressed and optimally oriented, and cause them to rupture as larger earthquakes. Since the Utica formation is in closer proximity to basement (< 1500 ft) completion operations in it have more potential to activate basement faults.

Seismic Methodology. The EarthScope Transportable Array (TA) was deployed through Ohio starting in 2012 until 2015 and provided a number of high quality observatory grade seismic stations, which were used (Friberg et al. 2014) to observe a hydraulic fracture induced seismic sequence in Harrison County in 2013. Since November of 2013, ODNR Division of Oil and Gas Resources Management (DOGRM) and oil and gas operators deployed several stations as part of their OhioSeis monitoring program. These stations were deployed in the vicinity of the first earthquake sequence in Harrison County to get a better handle on the locations of earthquakes in this region of Ohio.

A cross-correlation template-matching algorithm (Friberg et al, 2014) was used to detect smaller earthquakes by finding similarities between the seismograms from larger earthquakes (templates) observed on the nearest EarthScope station against the continuous seismic records. This technique allows a researcher to detect events that are often two to three magnitude units lower than the original template events. In some instances in Harrison County events, there were cases with over 3000 smaller events coincident with completion operations on a well that led to larger events. In most cases, there was a precursory increase of activity as a larger earthquake was triggered on a tectonic fault.

Whenever there were earthquakes with clear seismic phases observed at 4 or more stations, they were manually analyzed to determine a more precise earthquake location and magnitude. A 1-D velocity model was used to locate the earthquakes within the network of seismic stations and achieved absolute location errors of less than 500m for some locations (Friberg et al., 2014). To further constrain the relative locations between earthquakes, an earthquake location algorithm that exploits the small time differences of seismic phases on adjacent earthquakes, known as a double-difference earthquake location (Waldhauser et al, 2001) was used. The double-difference earthquake location tightened up the clusters of earthquakes into linear features trending east west.

Results. Using data from the TA and OhioSeis network from 2013 to 2016 several earthquakes attributed in time to hydraulic fracturing of various wells in Harrison County, Ohio were observed (Friberg et al., 2014). Figure C.17 shows 274 positive magnitude earthquakes (**M** 0.1 to **M** 2.9) that had clear phase arrivals at four or more stations during this time span. The Figure shows the events outlining an east-west fault system that aligns with a preferred plane of a focal mechanism computed for the 2013 sequence. The depths of the majority of the earthquakes were all in or near to the crystalline basement with just a few extending into the overlying Paleozoic sediments. In each case, the earthquakes were coincident with HF completion operations on wells above of adjacent and the activity subsided within a few weeks after the operations ended.

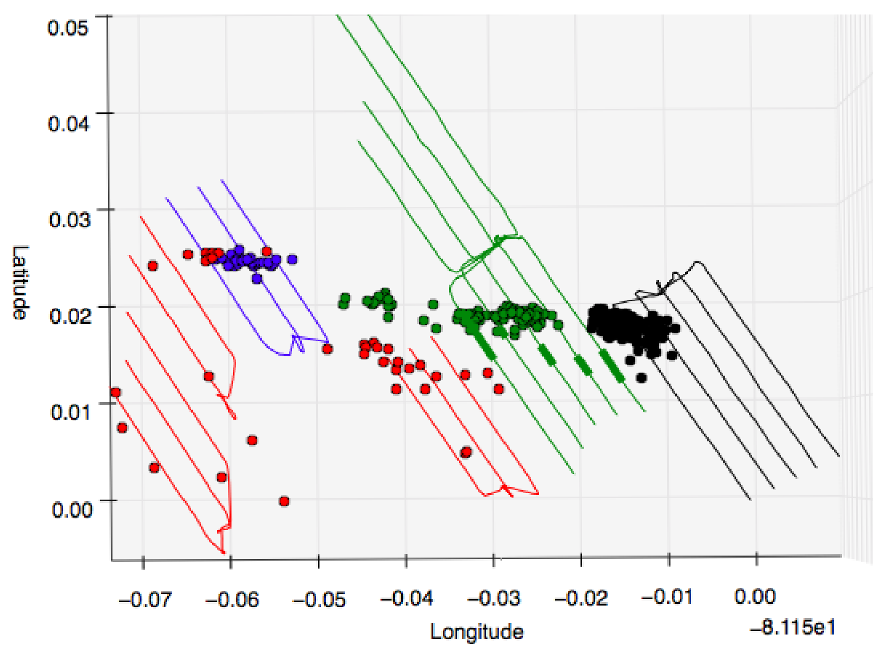


Figure C.17 Simple map view of earthquakes (circles) located from 2013 to 2016 along with wells (lines) being stimulated at the time (blue = 2013, red = 2014, green =2015, and black = 2016). The horizontal width of the image is 6km across.

In each earthquake sequence, we ran the cross correlation algorithm to detect smaller events. An example of the detections associated with HF operations on a specific well in September of 2015 is shown in Figure C.18. In each observed case smaller events were found and activity of some stages was higher than others, indicating preferential communication of those stages with the underlying fault. It is important to note that the well shown in the figure was performing zipper fracking on the first series of stages and that activity of smaller events increased prior to the largest earthquake observed, an **M** 2.9. After the largest event, the operator switched to stack fracking at request of the regulator and the subsequent stages had smaller magnitude events. Despite this prevalence of induced earthquakes in Harrison County, only a dozen hydraulic fracture operations out of some nearly 2000 wells in the Utica formation have induced seismicity to date.

While none of the earthquakes incurred any damage, and only a few were felt at the surface, the basement fault's extent was illuminated and found to be nearly 4km in length. Thus, the earthquakes highlighted and mapped a previously unknown fault in the basement rocks.

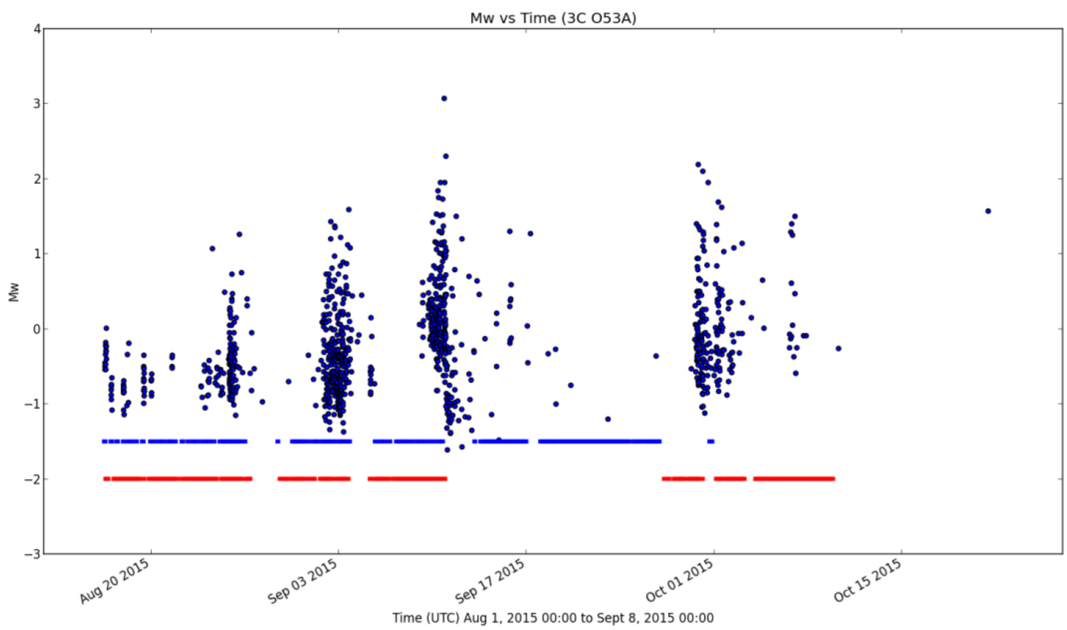


Figure C.18 Cross correlation detections of 519 events using a template-matching algorithm for events in 2015 (Friberg et al., 2014). Of these events, only 83 events were locatable and are shown in the map figure X1. The blue and red lines show the times of hydraulic fracture stages on the wells above the events. Note that the

Appendix D: Design and Installation of Seismic Monitoring Networks

Introduction

A seismic monitoring network consists of field equipment—sensors, data loggers, data communications, power sources, and enclosures—and off-site computers to store data for processing and archiving. Numerous consultants and vendors can assist states with the specialized work of designing and installing seismic monitoring networks. This appendix provides a primer for interested regulators.

Equipment and Operation

Sensors are deployed in an array of seismic monitoring stations within the network. Seismic sensors come in three basic types: 1) broadband sensors, 2) short-period or high frequency geophones, and 3) strong motion sensors or accelerometers (see discussion below). Modern sensors measure motion in the vertical direction and two orthogonal horizontal directions.

Data loggers are on-site units linked to the seismometer or other sensor, which record and process data for transmission. For data quality, seismologists recommend at least 24-bit resolution and a capability of recording waveform data at a sampling rate of 100–1000 Hz. Data loggers usually communicate in real time with a central computer for data processing and state-of-health seismic monitoring, and store data onboard in case communications are disrupted.

Data communications can be provided through cellular modems in most regions of the United States, enabling flexibility and low cost in the network design. Where this method is not possible, options such as spread-spectrum Ethernet or low-power VSAT satellite transceivers enable station placement anywhere within North America.

Power may be provided by available AC sources or distributed options such as solar or wind. Care should be taken to ensure that wind turbines and pole-mounted solar panels do not cause vibration that the seismic sensor may pick up.

Enclosures protect surface equipment against weather elements and vandalism. One popular solution is the use of steel job-site tool chests with double locks, which can be secured to the ground if possible. In some cases, a security fence around the site may be required. It is advisable to inform local police of the location and purpose of the equipment.

Data storage and processing: Seismic data recorded by a network may be transmitted electronically (via radio or cell phone, for instance) to a central site in real-time for event detection, processing, and cataloging. Preliminary results for location and magnitude can be made available via automated systems within a few minutes of an event occurring. If immediate results are not needed, or transmission impossible or too costly, data is stored in the data loggers onsite and can be manually retrieved periodically. Data should be in a format that is readily integrated with other systems, like the ANSS. The IRIS organization can archive data for use in the public domain. All continuous data should be archived and backed up daily. Meta-data, which includes details of the site, instrumentation, and the installation, should also be retained for each station for reprocessing as needed.

Network Installation: For simple background seismic monitoring networks, sensors can be deployed in “post-holes” with depths of 1 to 3 m below surface to avoid surface noise. In general, deeper deployments yield better results as they are both away from surface noise and can be better coupled with bedrock motion. These can be in purpose-drilled or existing wellbores. Depths for borehole type of deployments can be anywhere from 100 m to over 1 km in depth and require more rugged cabling and instrumentation. Where posthole or borehole sensors cannot be deployed, a surface deployment can be used but will often be accompanied by more noise and poorer coupling, which makes it harder to detect and locate smaller seismic events. Regardless of the type of emplacement, the sensor should be placed as far away from sources of cultural or electrical noise (e.g., roads, pump jacks, windmills, or other equipment) as possible.

Operations and Maintenance: Seismic monitoring stations do fail from time to time, so redundancy and regular state-of-health checks are suggested. Most seismic data loggers record state-of-health parameters and transmit these data to the acquisition computer in near real-time, enabling network operators to remotely monitor network performance and schedule operations and maintenance (O&M) trips to solve problems that could affect data quality and reliability. Basic O&M—including cleaning of solar panels, checking electrical connections, and upgrading firmware—should be performed on a station regularly, e.g., every quarter. Occasionally data transmission interruptions may require site visits to recover data from local storage in the data logger. A typical O&M site visit takes about 20 or 30 minutes.

Network Design

Number of sensors: Seismic sensor data is used to estimate distance to the event, based on seismic “P” and “S” wave arrival times. Placing multiple sensors in place allows for triangulation, which results in a location (see Appendix A). Accuracy in determining earthquake location improves with the number and location of sensors. A minimum of three stations is recommended, with a minimum of four to estimate earthquake depth location. It is not uncommon to deploy a dozen or more stations around areas of interest.

Distance: For smaller seismic events (~**M** 0.5–**M** 3.5) such as those normally associated with induced seismicity, stations need to be close to the event in order to record them. As a rule of thumb, the stations are set a separation distance of up to one to two times the depth at which the earthquake hypocenter might be expected to occur.

Types of sensors: Sensors always measure motion in three orthogonal directions but vary chiefly in their design frequency range. The optimum frequency band will depend on the event magnitude, distance of the sensor from the event and the attenuation of the signal as it passes through the earth, and other geologic conditions.

- *Broadband:* Regional and national networks usually employ broadband sensors as they cover a wider frequency range and are often deployed at greater distances, and can measure longer period signals. They are significantly more expensive and fragile than high-frequency geophones.
- *High-frequency*: Short-period, three-component geophone sensors can be used for local networks such as for cases of potentially induced seismicity as the seismic events tend to be small magnitude, close, and contain predominantly high frequency energy.

- *Strong motion sensors*: Strong-motion sensors (accelerometers) can complement the high-frequency sensors as they are useful for characterizing the level of longer period ground motion or shaking caused by earthquakes, of particular concern to people, buildings, and infrastructure.

Noise directly affects the ability to analyze seismic waveforms. Stations are better if located away from noise sources, e.g., roads, pumps, electrical lines, trees, water lines, and gas lines. Deploying sensors in boreholes, even shallow ones if coupled with bedrock, can dramatically reduce noise and provide clear earthquake signals, often to lower magnitudes. Networks should be designed to maximize the “signal to noise” ratio (the measure that seismologists use for the proportion of the data related to the earthquake versus background noise).

Velocity model: As mentioned earlier, distance is the primary measure from seismic data, and calculating distance relies on how fast the seismic waves travel through the earth. Having an accurate velocity model is the primary determinant of location accuracy; minor variations in velocity can cause large errors in location. Sonic logs from local oil and gas wells can provide starting data for both “P” and “S” wave velocities, but are naturally limited to the depth of the wells. Surface “check shot” and seismic refraction surveys can supplement these data. The USGS Advanced National Seismic System (ANSS) and National Earthquake Information Center (NEIC) can assist in network design and data integration as well as regional processing parameters when states lack their own velocity information.

Performance modeling is recommended as part of network design. Seismologists use these to predict the response of their instruments for earthquake magnitudes and locations (especially depth). The models take into account the number of stations, the placement of those stations, and minimum magnitude detection threshold desired, as well as the regional variations in the velocity model, attenuation properties, and site noise.

Appendix E: National Academies Studies and Report:

National Research Council Report on Induced Seismicity Potential in Energy Technologies (2013)

Findings of the National Research Council (NRC) report were based on a review of literature available through 2011. The summary below represents a snapshot at that point in time, and ongoing learning and study may possibly lead to adjustments and revisions of some of the conclusions presented by the NRC. Major findings and conclusions of the NRC study of induced seismicity associated with energy technologies:

- The basic mechanisms that can induce seismic events related to energy-related injection and extraction activities are not mysterious and are presently well understood.
- Only a very small fraction of injection and extraction activities among the hundreds of thousands of energy development wells in the United States have induced seismicity at levels that are noticeable to the public.
- Models to predict the size and location of earthquakes in response to net fluid injection or withdrawal require calibration from field data. The success of these models is compromised in large part due to the lack of basic data on the interactions among rock, faults, and fluid as a complex system; these data are difficult and expensive to obtain.
- Increases of pore pressure above ambient value due to injection of fluids and decreases in pore pressure below ambient value due to extraction of fluids have the potential to produce seismic events. For such activities to cause these events, several conditions have to exist simultaneously:
    - Significant change in net pore pressure in a reservoir;
    - A preexisting near-critical state of stress along a fracture or fault that is determined by crustal stresses and the fracture or fault orientation to the stress field; and
    - Fault rock properties supportive of a brittle failure.
- Independent capability exists for geomechanical modeling of pore pressure, temperature, and rock stress changes induced by injection and extraction and for modeling of earthquake sequences given knowledge of stress changes, pore pressure changes, and fault characteristics.
- The range of scales over which significant responses arise in the Earth with respect to induced seismic events is very wide and challenges the ability of models to simulate and eventually predict observations from the field.

With respect to findings and conclusions associated with potentially induced seismicity relative to specific energy technologies, the NRC report concluded:

- Injection pressures and net fluid volumes in energy technologies, such as geothermal energy and oil and gas production, are generally controlled to avoid increasing pore pressure in the reservoir above the initial reservoir pore pressure. These technologies thus appear less problematic in terms of inducing felt seismic events than technologies that result in a significant increase or decrease in net fluid volume.
- The induced seismic responses to injection or extraction differ in cause and magnitude among each of the three different forms of geothermal resources. Decrease of the temperature of the

subsurface rocks caused by injection of cold water in a geothermal field has the potential to produce seismic events.

- The potential for felt induced seismicity due to secondary recovery and enhanced oil recovery is low.
- The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events.
- The United States currently has approximately 30,000 Class II wastewater disposal wells among a total of 151,000 Class II injection wells (which includes injection wells for both secondary recovery and enhanced oil recovery). Very few felt seismic events have been reported as either caused by or temporally associated with wastewater disposal wells; these events have produced felt earthquakes generally less than **M** 4.0. Reducing injection volumes, rates, and pressures has been successful in decreasing rates of seismicity associated with wastewater injection.
- The proposed injection volumes of liquid carbon dioxide (CO_2) in large-scale sequestration projects are much larger than those associated with other energy technologies. There is no experience with fluid injection at these large scales and little data on seismicity associated with CO_2 pilot projects. If the reservoirs behave in a similar manner to oil and gas fields, these large net volumes may have the potential to impact the pore pressure over vast areas. Relative to other energy technologies, such large spatial areas may have potential to increase both the number and the magnitude of seismic events.

National Academies Unconventional Hydrocarbon Roundtable (December 2016)

In December 2016, the National Academies Unconventional Hydrocarbon Roundtable held a workshop focused in part on induced seismicity and recent learnings and observations. The panel examined the issue from the perspective that earthquakes caused by fluid injection are dependent upon geological conditions in the subsurface and their connection to volumes of fluid injected and pore pressure changes in the presence of existing faults. Earthquakes have been attributed to wastewater injection for disposal from conventional and unconventional wells (e.g. Oklahoma, Kansas); fluid injection specifically related to hydraulic fracturing (e.g., Canada); and some combination (e.g., Arkansas, Ohio). Key issues in understanding the conditions that may cause induced seismic events that may be felt at the surface include obtaining information about the behavior of rocks and fluids in the subsurface in specific areas, making observations, monitoring, and modeling fluid volumes and pressure changes, and finding ways for various stakeholders (industry, regulators, researchers, the public) to communicate and manage risk. The webcast and proceedings of the workshop are available at http://nas-sites.org/uhroundtable/past-events/onshore-workshop.

Appendix F: Methods for Estimating Reservoir Pressure Changes Associated with Injection

Introduction

A significant challenge associated with understanding whether injection may have triggered fault movement in a specific case is a substantial lack of detailed knowledge of the subsurface stress conditions in proximity to the fault that has slipped. To be able to evaluate whether the failure criteria was primarily met due to pressure increases from fluid injection versus changes to the stress field due to naturally occurring forces requires detailed knowledge of tectonic forces, fault friction, subsurface stress fields, and reservoir properties and structure. In general, this information is not accurately known or well characterized.

However, reservoir pressure modeling and geomechanics analysis can be very useful for evaluating relative order of magnitude impacts of injection and providing the supporting information and evidence to apply engineering and geotechnical judgment to a specific situation, considering all available information.

As described in many textbooks and articles on reservoir simulation, the tools of reservoir simulation range from the intuition and judgment of the engineer to complex mathematical models requiring use of advanced computing platforms. As highlighted by Coats (1987), generally the question is not whether to simulate but, rather, which tools or methods are most appropriate to use for the intended application, identifying the key assumptions that must be made in formulating the input data and calculation methods, and characterizing and appropriately accounting for the full range of uncertainty in the input data.

Over the last several decades, many techniques have been developed and applied for evaluating subsurface pore pressure changes from injection. These techniques include analytical reservoir engineering calculations, three-dimensional computational reservoir models, and integrated three-dimensional reservoir-geomechanics computational models. An appropriate analytical or computational method should be selected based on the specific study needs, the technical questions to be considered, the complexity of the reservoir system and fault system under study, and consideration of available input data, data quality, and data uncertainty.

When generally considering evaluation of pore pressure changes in reservoirs associated with saltwater disposal, in most instances the reservoirs targeted for injection will not be homogenous and reservoir properties can vary spatially in all three dimensions (a non-isotropic system). Further the reservoir and geologic structure may not be very well characterized, and the reservoir and geologic model input data may be poorly constrained. Therefore, when considering the accuracy and limitations associated with pressure field calculations, it is important to consider the potential limitations of various modeling approaches and appropriately account for uncertainty in the analysis and when reporting the results (Coats 1969).

In choosing application of a specific calculation approach, the sophistication and complexity of the model may generally be chosen dependent on the level and quality of the data. There can be a natural evolution on the application of reservoir modeling. For example, the first pass modeling effort may be relatively simple and may offer certain insights. Depending on the study requirements and the availability of the data, the analysis may evolve into applying increasingly sophisticated approaches in the model to explore broader sensitivities and expand the parametric studies to further understand the range of possible modeling outcomes. Often advancing to the next level of modeling may require further acquisition and refined definition of geologic and reservoir properties.

This appendix is intended to provide a general overview of available methods and approaches for performing reservoir pressure calculations and the brief overview of general considerations associated with the various approaches. This appendix is not intended to provide a detailed listing of specific computational methods or models, nor is it intended to provide a comprehensive literature review of modeling approaches applied to study of injection related induced seismicity. Specifically, this appendix provides an overview of:

- Key technical items to consider in advance of model development when pursuing or performing pressure field calculations;
- General types of calculations and modeling approaches that are well known to reservoir engineering and geomechanical engineering experts;
- Key items that would generally be prudent to consider when selecting a specific modeling approach; and
- Key elements that stakeholders may generally desire to understand when modeling results are presented or reported.

Key Items to Consider When Embarking on Pressure Modeling/Reservoir Simulation

The reliability, accuracy, and inherent usefulness of any calculation or reservoir simulation of subsurface pressure are substantially dependent on a range of considerations and factors, including:

- Developing a clear understanding of the public, scientific, or business need, and selecting the calculation approach relative to the specific needs.
- Understanding the uncertainty in how the faults have been identified and characterized, especially considering the locations (as inferred from hypocentral locations and focal mechanisms where available) of any actual fault segments that have been reactivated or from interpretation of seismic survey data.
- Identifying and appropriately characterizing the available input data, including characterizing the uncertainty in input data.
- Identifying “missing” or “unknown” input data, and the assumptions and judgment that may be applied in model development accounting for the unknowns.
- Understanding the accuracy and uncertainty of modeling/calculating four-dimensional (time/space) evaluation of the reservoir pressure behavior compared to seismicity data (including the temporal behavior and spatial locations of injection pressure changes relative to seismic event locations) in heterogeneous reservoirs.
- Evaluating the geologic and reservoir complexity, fault structure, stratigraphic layers, etc.
- Understanding whether a gas-phase may be present in the injection zone, and evaluating how to address presence of multiple fluid phases if gas is present in the injection reservoir.

- Establishing the appropriate initial conditions for the simulations or calculations, or if initial conditions are not well described, understanding how to address uncertainty in the initial conditions.
- Establishing the appropriate boundary conditions (e.g., flow or no-flow) for the simulations or calculations, or if boundary conditions are not well described, understanding how to address uncertainty in the boundary conditions.
- Accounting for, as appropriate, the potential presence of other "sources and sinks" (i.e., production and injection wells) in the area of study that can affect the pressure calculations.
- Appropriately calibrating and validating the model with available data and information and considering what may or may not be possible to perform through model history matching to verify integrity of model approach relative to the intended application.
- Implementing and performing parametric sensitivity studies based on the available data and accounting for uncertainty in input data and various model assumptions (and alternative model assumptions).

Types of Models and Calculation Methods

In general, there are three types of approaches that could be considered when evaluating injection related pressure changes: analytical solutions of the pressure diffusion equation; (single-phase or multi-phase) reservoir models, and coupled reservoir-geomechanics models.

In general, the required subsurface data to perform pressure calculations are typically estimated from available well logs, core data and well tests. Often, it is recognized that the available data may be limited, or not well characterized, in many instances; or there may be a high degree of reservoir heterogeneity, such that estimated input data values must also include the potential variability and uncertainty present in the reservoir characterization.

Calculated model results will also depend on model assumptions surrounding model size, flow or no-flow boundary conditions, description of faults (serving as permeable pathways or no-flow boundaries), vertical and lateral permeability estimates, use of single-phase flow or multi-phase flow, assumptions surrounding compressibility, etc. Since model input data is generally not well known, modeling typically involves sensitivity studies, using reasonable ranges for the required model input data.

Analytical Calculation Methods

As described in Appendix D of the recent USEPA Report (USEPA 2015), in some circumstances petroleum engineering analytical calculations can be performed and may provide insight relative to the three key components that must all be present for induced seismicity to occur. Different well and reservoir aspects can be evaluated depending on the possible analytical methods used. These types of petroleum engineering methods typically focus on the potential for reservoir pressure buildup and the reservoir flow pathways around a well and at a distance, and characterize reservoir behavior during the well's operation. The petroleum engineering analytical calculations will generally incorporate information typically collected from the well permit application and data on injection volumes and pressures reported for compliance purposes during operation of the well. These analytical calculations are generally based on single-phase fluid systems and assume generally homogenous reservoir conditions (e.g., single values of permeability, porosity, compressibility, fluid viscosity, etc.).

Well operational data can be analyzed using the steady state radial flow equation, while pressure transient tests are analyzed using solutions to the transient radial diffusivity equation. For best applicability, surface pressures should be converted to bottomhole conditions to account for friction pressure loss and the hydrostatic pressure from the fluid column must be added to the surface pressure as part of the bottomhole pressure calculation. The reporting frequency for injection rates can also impact the quality of the analysis.

Reservoir Computational Models

As described by Coats, in a broad sense, reservoir simulation has been practiced since the beginning of petroleum engineering in the 1930s. Before 1960, engineering calculations consisted largely of analytical methods, material balances, and one-dimensional calculations. Reservoir simulation (or reservoir computational models) became common in the early 1960s, as computing software and hardware enabled the solution of large sets of finite-difference equations describing 2D and 3D transient, multiphase flow in heterogeneous porous media. As such, reservoir simulation methods and approaches are generally well known and well established for the study of simple to very complex reservoir situations.

In applying reservoir simulation methods, there are a range of technical factors and considerations to address as part of the overall model development. These factors and considerations are well known to reservoir engineering experts, and for general reference, a detailed description of fundamental practices and principles associated with reservoir simulation can be found in the Society of Petroleum Engineers Monograph on reservoir simulation (Dalton 1990). As discussed in detail in this monograph, in considering applications of reservoir simulation, there are several key steps associated with developing and running the model, including a) designing the model; b) identifying the reservoir-rock and fluid property data; c) selecting the numerical method, d) establishing suitable grid and time step sizes, e) establishing appropriate initial conditions and boundary conditions; and f) validating simulator with appropriate testing, history matching, and comparison to available well or field data.

Coupled Reservoir-Geomechanics Models

Over the last decade, many researchers have focused on developing models and simulation capabilities that couple reservoir fluid flow dynamics with the reservoir geomechanics behavior. Coupled simulators are also now being used to investigate and study injection related seismicity. Coupled mechanisms play a significant role in understanding the potential for fault reactivation from pore-pressure changes due to fluid injection. From a fundamental physics perspective, the potential for fault reactivation is described by a coupled set of reservoir flow and geomechanics equations. Application of these types of coupled reservoir-geomechanics models typically requires extensive cross-disciplinary expertise and experience, a broad range of reservoir characterization data, and advanced computing resources.

An example of a simple coupled Reservoir-Geomechanics model is the Fault Slip Potential (FSP) tool developed jointly by Stanford University and ExxonMobil. This program uses fault location and orientation, injection well locations, rates, and reservoir characteristics, regional stress direction and magnitude, and natural pore pressure. It produces a probabilistic view of fault slip potential in these injection situations, which users can use as a screening tool in advance of siting disposal wells or before more advanced analysis if warranted. Figure F.1 shows an example view in the tool.

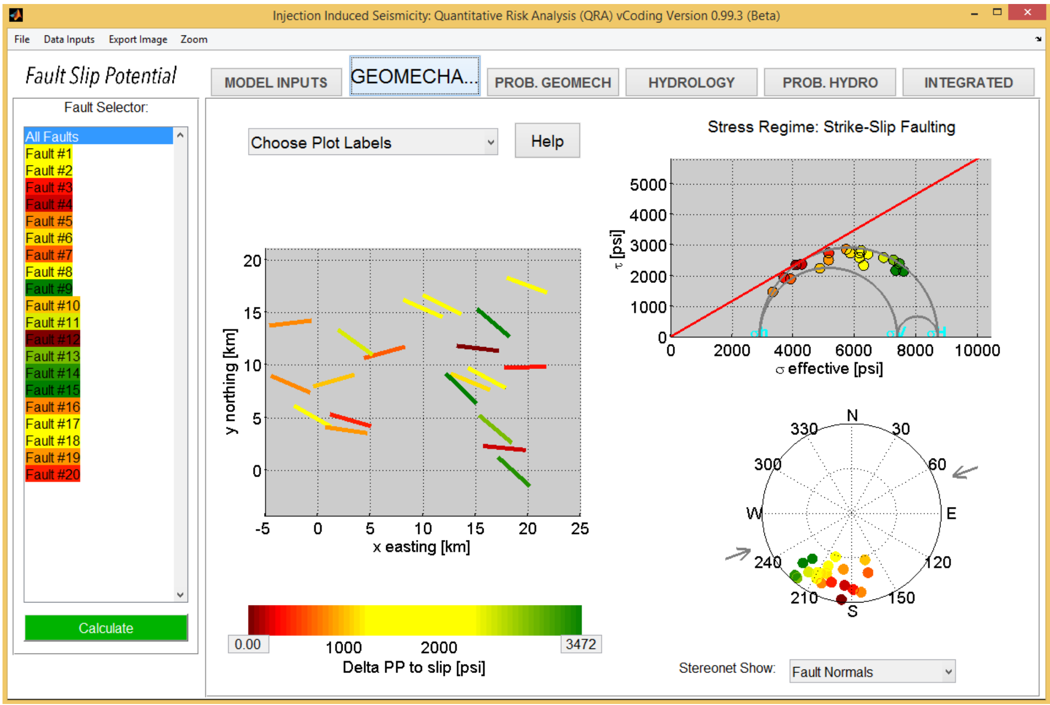


Figure F.1 A view of the Geomechanics tab within the Fault Slip Potential model, showing a map of faults colored by their likelihood of reactivation in a given injection scenario as input in separate tabs, with injection wells located within the faulted area. This evaluation tool can be accessed free, at https://scits.stanford.edu/software

Source: F.R. Walsh, used with permission

Key Considerations for Selecting a Model

In choosing application of a specific calculation approach, the sophistication and complexity of the model may generally be chosen dependent on the level and quality of the data. In some areas, there may be substantial subsurface characterization data that is available (such as in the case of The Geysers geothermal project). In other cases, there may be very limited subsurface and reservoir characterization data. The level of confidence in any calculation or simulation result is strongly dependent on the quality and accuracy of the available subsurface/reservoir characterization input data. Given this background, selecting a specific calculation or modeling approach or combination of approaches for a given application is then generally influenced by multiple considerations, including:

- The specific public, business, or scientific question or research to be addressed;
- The desired level of accuracy and "uncertainty" reduction to meet the public, business, or scientific question or research to be addressed;
- The desired level of accuracy and confidence necessary for making regulatory, business, or risk management decisions;

- The desired level of accuracy and confidence necessary to suitably test a hypothesis as plausible or implausible (or likely or unlikely);
- The available level of expertise, education, skills, and preferences of the individual modeler;
- The level of detail, availability, and complexity of the subsurface data and well operational data in proximity of the area of study;
- The number of injection wells in the area of study (and considering presence of other operations in area of study);
- The level of knowledge regarding fault locations, and potential fault slip locations, relative to the injection interval; and
- The available computational resources and software; considering available computing platforms (memory, CPU speed, etc.) and software (public open-source, commercial, O&G proprietary codes).

Key Considerations for Reporting Model Results

Many stakeholders may not be intimately familiar with reservoir engineering calculation methods and therefore may not be generally aware that the reservoir modeling calculations do not provide a “single” unique answer. Therefore, to aid stakeholder understanding of model results, it would generally be informative to describe the model approach, data assumptions, model assumptions, results, and result uncertainty considering the intended application of the results. Generally, various stakeholders would expect discussion of the following elements when presenting modeling work and any conclusions based on model results:

- Description of the modeling approach and simplifying assumptions;
- Description of input data available and used, and the uncertainties associated with the data;
- Description of input data that is not available, and how estimates were made in the absence of data;
- Description and characterization of the uncertainties in modeling results based on uncertainties in input data;
- Description and characterization of the range of sensitivity studies performed; and
- Description and characterization of the possible impacts that modeling assumptions have, or may have, on the presented results and conclusions.

Key Messages

Subsurface pressure calculations and reservoir modeling can provide very useful insights to inform the engineering and geotechnical assessments associated with risk assessment and causal assessments of potential injection-induced seismicity. It is important that the calculation and model approaches account for the data uncertainty considering the specific application and area of study.

The level of uncertainty in input data and the complexity of the specific situation will affect the scope of the modeling, the assumptions made in the model development, and the level of uncertainty in calculated results. For complex reservoirs, or situations where limited subsurface data may exist, modeling results may possess substantial uncertainty.

Calculation of reservoir pressure and stress changes due to subsurface fluid injection can be performed using engineering methods ranging from analytical solutions to coupled reservoir-geomechanics computational models. Selection of a specific calculation method(s) should consider:

- Which methods are most appropriate to use for the intended application and research, business, or regulatory purposes, considering the available data and resources;
- Identification of the level of accuracy desired for the intended application;
- Identification of the key assumptions used in formulating the input data and calculation methods; and
- Characterization of and accounting for the uncertainty in the input data.

It is important for stakeholders to understand that modeling results are generally “non-unique” and will have a spectrum of possible solutions dependent on the uncertainty and variability of the model input data and assumptions associated with the model formulation.

In general, stakeholders and the technical community will desire that results are reported with description of key model assumptions and the potential impacts the assumptions and data uncertainties may have on model results and conclusions.

Advanced reservoir modeling tools and expertise may need to be accessed for specific studies in complex situations, where there may be a high degree of reservoir heterogeneity, the presence of multiple wells, and/or complex geologic or reservoir structure.

In general, collaboration across multiple stakeholder groups may be necessary to identify, develop, and characterize the input data necessary to perform pressure calculations and reservoir modeling in actual applications.

Appendix G: Tools for Risk Management and Mitigation

Briefly profiled below are tools resulting from three recent efforts by diverse stakeholders to provide risk management and mitigation guidelines.

Stanford Center for Induced and Triggered Seismicity (SCITS)

Walters, Zoback, Baker, and Beroza (SCITS) recently compiled a report with a comprehensive review of the processes responsible for triggered earthquakes, in addition to broad scientific principles for site characterization and risk assessment (Walters et al. 2015). Published by SCITS, the report is publicly available at: https://scits.stanford.edu/researchguidelines.

Factors considered in the risk assessment protocol include the proximity (and vulnerability) of possibly affected population centers, structures, and facilities. The recommendations provided are intended to be goal-based, rather than prescriptive, and adaptable to local circumstances. A conceptual hazard and risk assessment workflow is presented as part of this work, and is shown in Figure G.1 below.

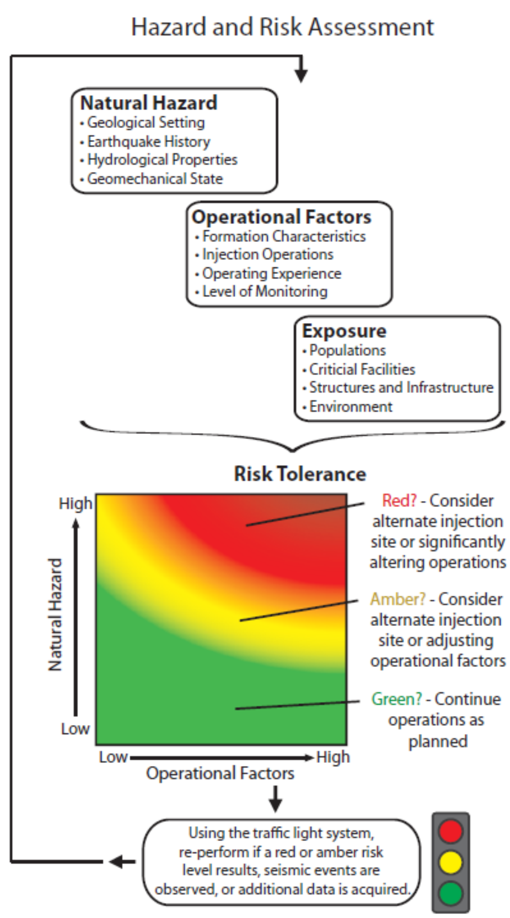


Figure G.1. Hazard and risk assessment workflow. In concept, the hazard, operational factors, exposure, and tolerance for risk are evaluated prior to injection operations. Source: Walters, Zoback, Baker, and Beroza (SCITS).

Factors related to risk and exposure that can be considered when developing an evaluation and response strategy are shown in Tables G.1 and G.2 below.

Saltwater Disposal Operational Factors	Formation Characteristics	Injection Operations	Operating Experience
Significant	Injection horizon likely in communication with basement, underpressured injection interval	High cumulative injection volumes and rates	Limited injection experience in region, past earthquakes clearly or ambiguously correlated with operations
Moderate	Injection horizon potentially in communication with basement, slightly underpressured injection interval	Moderate cumulative injection volumes and rates	Moderate injection experience in region with no surface felt ground shaking
Minor	Injection horizon not in communication with basement	Low cumulative injection volumes and rates	Extensive injection experience in region with no surface felt ground shaking

Table G.1. After R.J. Walters et al.: Factors related to saltwater disposal operations that contribute to the level of risk at an injection site. Source: SCITS 2015.

Exposure	Critical Facilities	Structures and Infrastructure	Environment	Populations
High	Facilities in the immediate vicinity with the potential to suffer damage	Few designed to withstand earthquakes based on current engineering practices	Many historical sites, protected species, and/or protected wildlands	High population density and/or total population
Moderate	Facilities in the nearby area	Many designed to withstand earthquakes based on current engineering practices	Few historical sites, protected species, and/or protected wildlands	Moderate population density and/or total population
Low	No facilities in the area	Most designed to withstand earthquakes based on current engineering practices	No historical sites, protected species, and/or protected wildlands	Low population density and/or total population

Table G.2. Technical factors that contribute to the level of exposure at an injection site. Source: SCITS 2015.

This framework incorporates established best practices drawn from regulations for Class II injection wells for the states of Arkansas, California, Colorado, Illinois, Ohio, Oklahoma, and Texas; and from recommendations by the American Exploration and Production Council's seismicity subject matter expert group, the British Columbia Oil and Gas Commission, the Canadian Association of Petroleum Producers, scientists at ExxonMobil, the International Association of Oil and Gas Producers, the National Research Council, the United Kingdom, the U.S. Environmental Protection Agency, several publications focusing on triggered earthquakes, and the U.S. Department of Energy protocol developed for seismicity associated with enhanced geothermal systems.

Stanford researchers continue to advance development of integrated technologies and approaches to evaluate the potential for fluid injection to induce fault slip. Recently, the Stanford Center for Induced and Triggered Seismicity Stanford University ("SCITS") has made publicly available the "Fault Slip Potential" software modeling tool for probabilistically screening faults near injection wells. This modeling tool can be used to estimate the chance of a fault slipping when given stress, pore pressure, injection conditions, and fault geometry and geomechanical characteristics. This software is available as free download at https://scits.stanford.edu/software.

SCITS intends to update this report as new information and models become available.

American Exploration and Production Council (AXPC)

AXPC, a national trade association representing independent oil and gas operators, developed an approach combining an "If This … Then That" methodology into a flow chart, along with three tool boxes to be used in evaluating the potential for induced seismicity. The flow chart (Figure G.2) and tool boxes (Tables G.3., G.4, and G.5) are presented below.

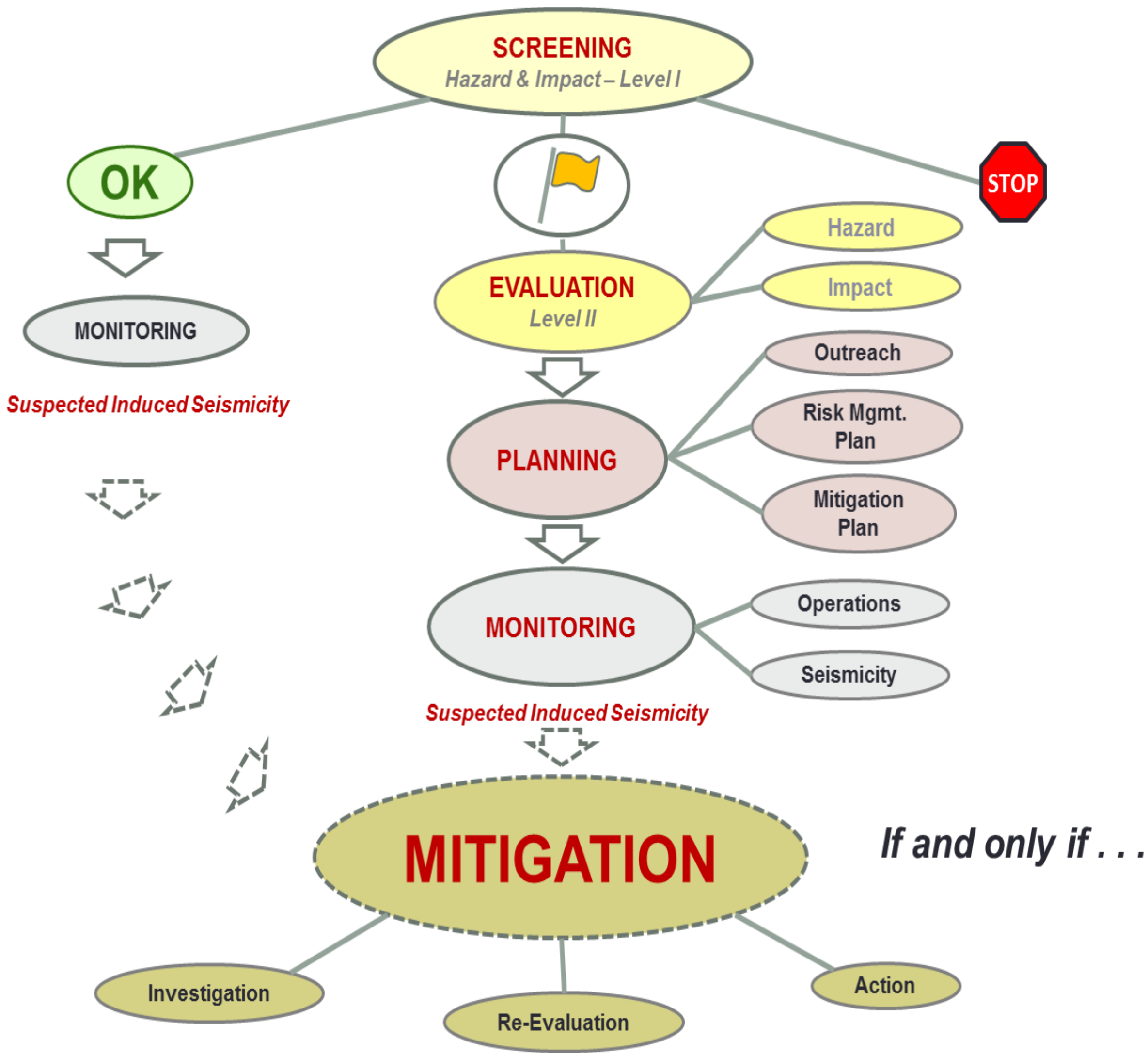


Figure G.2. "If This … Then That" flowchart. Source: AXPC SME 2013/2014.

Item	Data, Resources, and Tools
Key geologic horizons and features	Data from existing wells, reflection/refraction seismic data, and gravity/magnetic data Fault presence assessment from mapped horizons
Regional stress assessment	World stress map, literature, physical measurement, stress estimates from seismic and/or nearby well logs Model effect on the reservoir and surrounding rocks from stress changes associated with fluid injection
Surface features	State, USGS, and academic geological maps and published reports
Ground conditions	Consolidation, saturation, composition, and proximity to basement from State and USGS documents
Ground response	Expected peak velocities, acceleration, and spectral frequency. Refer to local civil engineering codes. Models from USGS, DOE, state agencies, and academia
Local seismic events	Academic (e.g., IRIS), State, and industry surveys. If not available, then regional or local dedicated network of seismometers and ground motion sensors. Establish magnitude, frequency of occurrence, and ground motion relationships
Reservoir characterization	Rock type, facies, age, matrix composition, porosity types, depth, thickness, and petrophysical properties. Lateral extent and continuity, proximity to outcrop, proximity to basement, lateral barriers and conduits, compartments, bounding layers and intervening formations to basement, sealing rocks in system
Reservoir properties	Hydrologic properties: permeability, porosity, transmissivity, natural fracture porosity, and storativity Mechanical properties: fracture gradient, closure pressure (ISIP), Young's Modulus, Poisson's Ratio, cohesion, coefficient of friction, pore pressure, lithostatic pressure, hydrostatic pressure, horizontal stress magnitudes and azimuth
Disposal conditions	Initial saturation, salinity, pore pressure, and static fluid level Fluid injection rates, pressures, cumulative volumes injected

Table G.3. Tool Box for the Evaluation of Potential Hazard (Seismic Activity). Source: AXPC SME 2013/2014.

Item	**Data, Resources, and Tools**
Population	Survey nearby population centers Assess the regional population density Comfort or familiarity with seismic events—assess potential nuisance thresholds
Structures and infrastructure	Summary of buildings, roads, pipelines, electric grid Critical infrastructure, e.g., hospitals, schools, historical sites Construction practices, materials Local codes, seismic event ready? Density of structures in the area
Dams, lakes, reservoirs	Presence of dams, reservoirs Ages, type of impoundment (e.g., earthen vs. concrete construction) History of fill/drawdown Substrate—material and known faults
Environmental	General description of local ecology Special environmental hazards
Intangible	Goodwill, trust, reputation
Risk	Probabilistic models with both chance of occurrence and estimated ranges of potential outcomes for damage assessments, e.g., from HAZUS (USGS)

Table G.4. Tool Box for the Evaluation of Potential Risk (Impact). Source: AXPC SME 2013/2014.

Item		**Data, Resources, and Tools**
Operations	Fluid parameters	Seismic monitoring and recording of injection rates, and pressure Injection volumes measured and recorded Injectate properties noted: e.g., salinity, chemistry
	Reservoir	Fluid levels, shut-in pressure, pore pressure, changes in conditions Pressure transient behavior, e.g., falloff, step rate tests Well performance and reservoir flow behavior (Hall plots, Silin plot) storage/transmissivity
Seismicity	Regional	Establish baseline conditions from USGS and other regional sources Maintain catalog of events from USGS and other regional sources Identify excursions from historical trends (temporal and spatial) Note surface effects from seismic events recorded
	Local	Install local array sufficient to locate events in the subsurface near the injection zone Deploy sensors capable of measuring peak ground acceleration and velocity in the vicinity of the injection site Monitor seismic events within a specified distance of the well Evaluate whether any observed seismic events are potentially induced or naturally occurring Report potentially induced threshold events established in the Risk Management plan that initiate mitigation steps

Table G.5. Tool Box for Seismic Monitoring. Source: AXPC SME 2013/2014.

AXPC also developed an example of a Traffic Light System (Table G.6) that could be used in conjunction with the planning step of the flow chart.

Planning - Risk Management Plan: Traffic Lights

- **Green** Continue operations – no seismicity felt at surface (MMI I-III+)*
- **Amber** Modify operations – seismicity felt at surface (MMI III-IV+)*
- **Red** Suspend operations – seismicity felt at surface with distress and/or damage (MMI V+)*

Perceived Shaking	Not Felt	Weak	Light	Moderate	Strong	Very Strong	Severe	Violent	Extreme
Potential Damage	none	none	none	Very Light	Light	Moderate	Moderate Heavy	Heavy	Very Heavy
Traffic Lights *									
Peak Acceleration (%g)	<0.17	0.17 to 1.4	1.4 to 3.9	3.9 to 9.2	9.2 to 18	18 to 34	34 to 65	65 to 124	>124
Peak Velocity (cm/s)	<0.1	0.1 to 1.1	1.1 to 3.4	3.4 to 8.1	8.1 to 16	13 to 31	31 to 60	60 to 116	>116
Magnitude	1 – 2.9	3 – 3.9	4 – 4.4	4.5 – 4.9	5 – 5.4	5.5 – 5.9	6 – 6.4	6.5 – 6.9	7.0+
Modified Mercalli	I	II to III	IV	V	VI	VII	VIII	IX	X+

* *Example only: Establish based upon local conditions, demographics and codes*

Table G.6. Example Traffic Light System. Source: AXPC SME 2013/2014.

U.S. Environmental Protection Agency

Another resource for information on induced seismicity is the recent USEPA report, "Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches," which provides insight on tools to help UIC regulators address injection-induced seismicity and describes the current understanding of potentially induced seismicity within the existing regulatory framework for Class II disposal (USEPA 2015). The report is available to the public at http://www.epa.gov/r5water/uic/ntwg/pdfs/induced-seismicity-201502.pdf.

In addition, in 2014, the EPA Underground Injection Control National Technical Workgroup published an example of a decision tree (Figure G.3) utilizing the "If This ... Then That" approach.

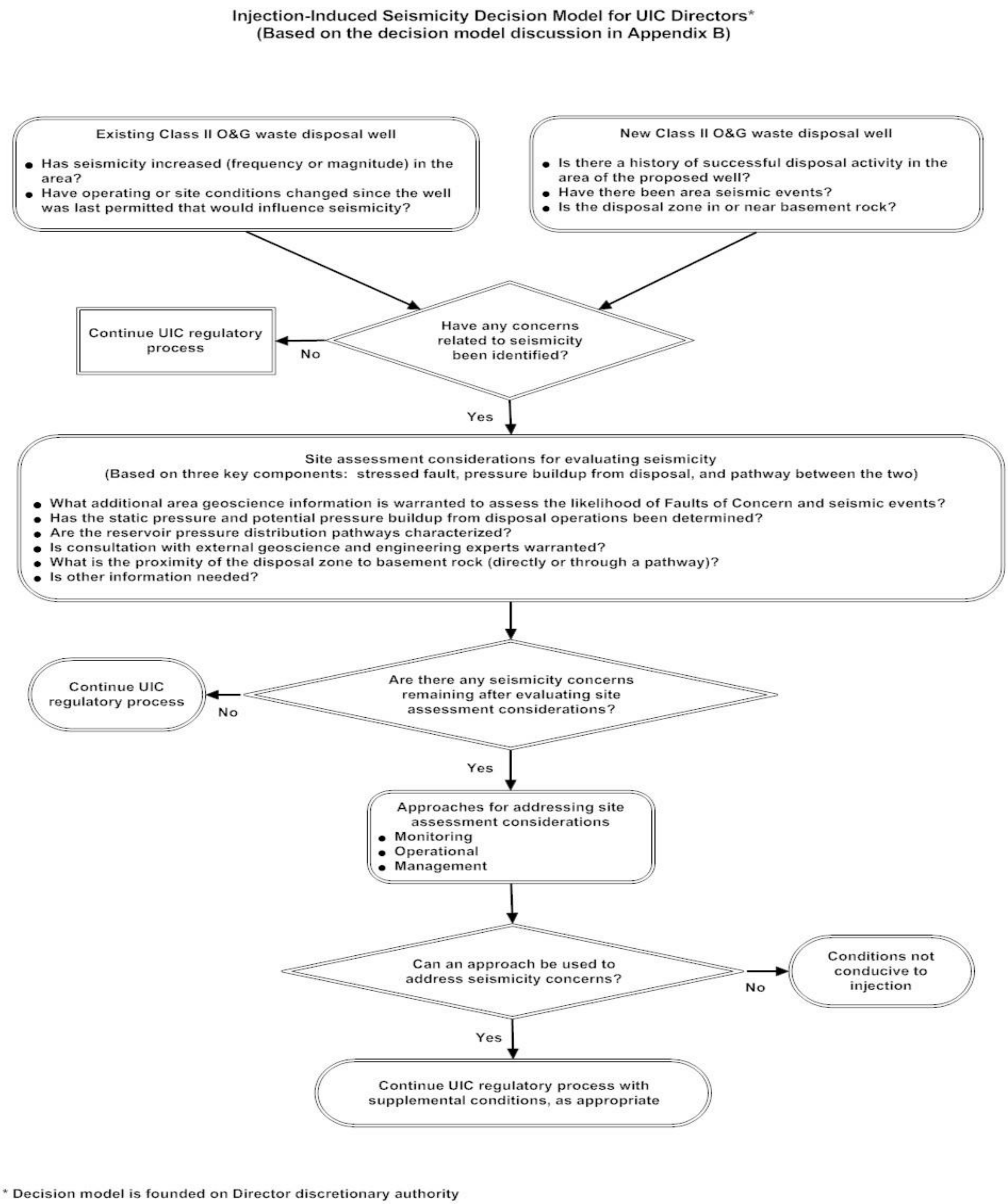


Figure G.3. Example decision tree. Source: USEPA UIC National Technical Workgroup 2014.

Appendix H: Data Collection and Interpretation

Introduction

Various categories of data are needed to determine whether the conditions are present for injection-induced seismicity: sufficient pore pressure buildup from disposal activities, a fault of concern, and a pathway for the increased pressure to communicate from the disposal well to the fault of concern. Such determinations are important for both risk management purposes and evaluation of causation.

Assembling and interpreting these data can be challenging, particularly because they may be distributed across many entities. Available data are limited in many categories, including:

- **Subsurface stresses**. Plate tectonics influence nearly all geologic processes (Kious 1996). Yet knowledge of subsurface stress conditions and the crystalline basement is limited for most of the United States. While subsurface stress measurements may be obtained via well logs and injection tests, the data may be obtained only for limited geographic locations and reservoir depths and may not be publicly available. Additionally, subsurface stress conditions are continuously changing due to natural phenomena and may vary both geographically and with depth (Zoback 2002). Substantially improving the mapping of subsurface stress fields across the will require ongoing collaboration between researchers and oil and gas operators, with recognition that mechanisms need to be put in place for appropriate handling of confidential business data and information.
- **Injection well data**. The frequency of reporting and accessibility of injection well data may be variable between states.
- **Fault locations**. Access to seismic imaging and fault maps needed to identify faults and their locations and orientations may be limited, and detailed basement fault maps generally do not exist across broad regions of the United States. Subsurface imaging and characterization of the deep basement geology is not routinely done, because this is not a prospective target for oil and gas resources, and seismic imaging can be problematic given basement depths and overlying formations.

Considering these challenges, collaboration across industry, researchers, and regulators is often critical in assembling and skillfully interpreting the necessary data. Recognizing data limits and constraints on information access is critical when evaluating a specific disposal well operation or suspected case of induced seismicity.

This appendix considers “raw data” collection as well as “interpretive data” based on the raw data. As an example, 3D seismic imaging waveforms are “raw data”, but expert interpretation is required to develop the “interpretive data” of identified faults and associated fault maps. Categories addressed are well data (raw), geologic and reservoir data (raw), fault maps (interpretive), basement maps (interpretive), subsurface stress maps (interpretive), and reservoir properties (interpretive). The appendix ends with data sharing considerations.

Well Data

Generally available Class II well data. The most common data available for Class II disposal wells are injection rates and volumes and injection tubing pressures. Such data are routinely reported as part of both EPA direct implementation and state UIC Class II program requirements. Bottomhole pressures (BHPs), which are more suitable for evaluating reservoir conditions, are not as readily available. BHPs either may be calculated based on surface pressure measurements and fluid engineering correlations, or directly measured with downhole pressure gauges. The frequency for reporting injection volumes and pressures varies among regulatory agencies and depends on site circumstances. Although less common, pressure transient test data are occasionally available.

Commonly Available UIC Data	Pressure Test Measurements (Less Commonly Available)
Injection rates or volumes Surface tubing pressures Well construction details (tubing/casing dimensions and depth, cementing information, completion type and injection interval) Reservoir information (gross and net injection zone thickness, porosity, name and description of disposal zone and overlying confining zones, bottomhole temperature, initial static BHP) Reservoir and injection fluids (specific gravity, fluid constituent analysis)	Falloff/injectivity test for reservoir characterization and well completion condition assessment Step rate test to determine formation fracture gradient Static pressures to measure initial pressure and static reservoir pressure change during well operations

Table H.1. Commonly available UIC data and pressure test measurements. Source: ISWG.

The frequency of recording and reporting of surface pressure, injection rate, and volume data can vary depending on the regulatory agency requirements. UIC programs may require reporting of injection pressure a number of ways, such as a maximum value and a monthly average or as monthly minimum and maximum values. Recently, improvements in data availability have progressed under state initiatives, such as the Oklahoma Corporation Commission rule authorizing requests for up to daily Arbuckle formation disposal well pressure and volumes.

Well pressure measurements and formation pressure buildup: The formation pressure generally increases with injection of fluids in the disposal zone. The magnitude of pressure buildup depends on the reservoir properties and characteristics and the injection volumes and rates, among other things. The pressure buildup is transmitted as a pressure front through fluids in the receiving formation radiating out from the injection well. Estimating the dynamic evolution of the pressure field due to disposal of fluids requires application of subsurface engineering and reservoir engineering analysis techniques (Lee 1996).

Depending on the reservoir and geologic data available, different modeling and calculation methods may be considered depending on the level of accuracy desired, and understanding the data uncertainties that may be present. These analyses consider estimates of reservoir rock and fluid properties, and predict pressure field changes with time, considering injection rates and pressures. Detailed estimates of reservoir properties are required to perform this type of analysis. For the analysis to provide reasonable accuracy requires reasonable estimates for model input data; in many instances, there may be significant uncertainty in reservoir properties.

Analysis of disposal well operating data and information from well testing, such as pressure transient tests, can provide details about the disposal zone reservoir pathway and the condition of the well.

Operating injection rates and pressures are typically collected as part of the permitting compliance activity and consequently are more readily available than pressure transient tests. Completion conditions reflect conditions at or near the wellbore in proximity to the injection interval, while reservoir characteristics describe the disposal zone away from the well. Reservoir characterization assesses the injection formation flow patterns, the formation's capacity to transfer pressure responses dependent on the completion characteristics of a disposal well.

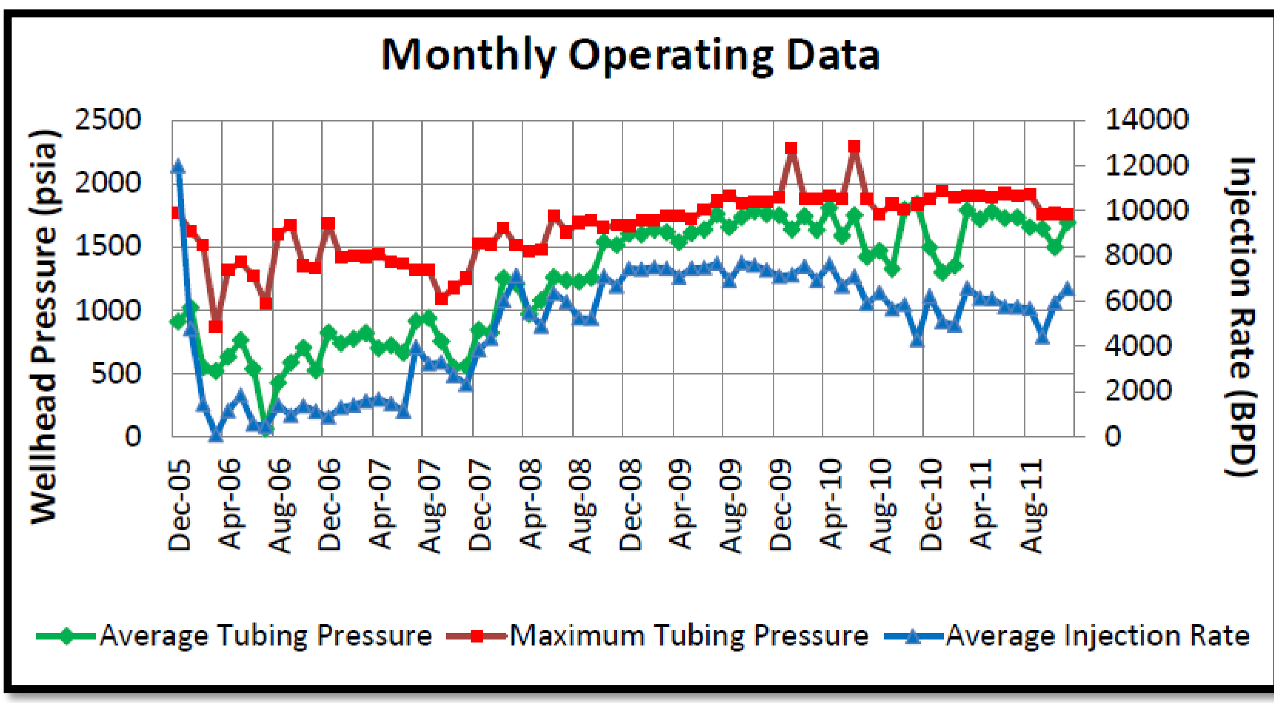


Figure H.1. Typical plot of monthly operating data from a Class II disposal well. Source: USEPA 2015.

Identifying reservoir behavior through appropriate analyses and evaluation of the results in the context of the available geoscience data (e.g., presence of faults, etc.) may inform the possible relationships between injection well operations and suspected induced seismic activity.

BHP measurements generally may not be measured with downhole gauges in disposal wells. If BHPs are required, reasonable estimates can be made from the surface pressure and injection rate information.

Estimations require engineering calculations to account for friction pressure loss based on the tubing geometry and injection rates; the hydrostatic pressure from the fluid column must be added to the surface pressure as part of the calculation. In addition, the pressure losses associated with perforation friction and completion geometry effects should also be considered when considering injection well pressure boundary conditions if reservoir models are used to evaluate reservoir pressure changes associated with fluid injection. Using estimates of BHPs, reservoir modeling can be performed to evaluate temporal and spatial evolution of the pressure field throughout the subsurface formations.

Geologic and Reservoir Data

Geologic and reservoir data consist of seismic surveys, well logs, and core data. Limitations of each data type are summarized in Table H.2.

Seismic surveys: Seismic surveys provide information on subsurface stratigraphy and structure as well as rock and fluid properties. Seismic data can provide broader understanding of the 2D or 3D subsurface structure as opposed to more localized data that may be available from well logs and core samples. In a seismic survey, seismic waves from a source (dynamite, air gun, or a vibrator truck) move downward into the subsurface. When acoustic waves hit an interface between two layers with different acoustic impedance, some wave energy reflects back to the surface (Figure H.2). How much energy is reflected depends on the change in acoustic impedance. Recording devices (geophones) at the surface or in a well record ground motion versus time. The basic data collected is amplitude of ground motion, polarity of ground motion, time, and spatial location of the geophone. This information must then be processed to produce a seismic section or 3D volume for interpretation. Seismic processing technology is often proprietary. It involves many steps and procedures that may focus on improving signal to noise, enhancing resolution, velocity analysis and migration (adjusting dipping reflectors into their correct orientation). For an interpreter, two key factors are whether the survey is in time or has been converted into depth and whether the survey has vertical exaggeration. Both factors impact whether the seismic image shows strata/structure in their true orientation.

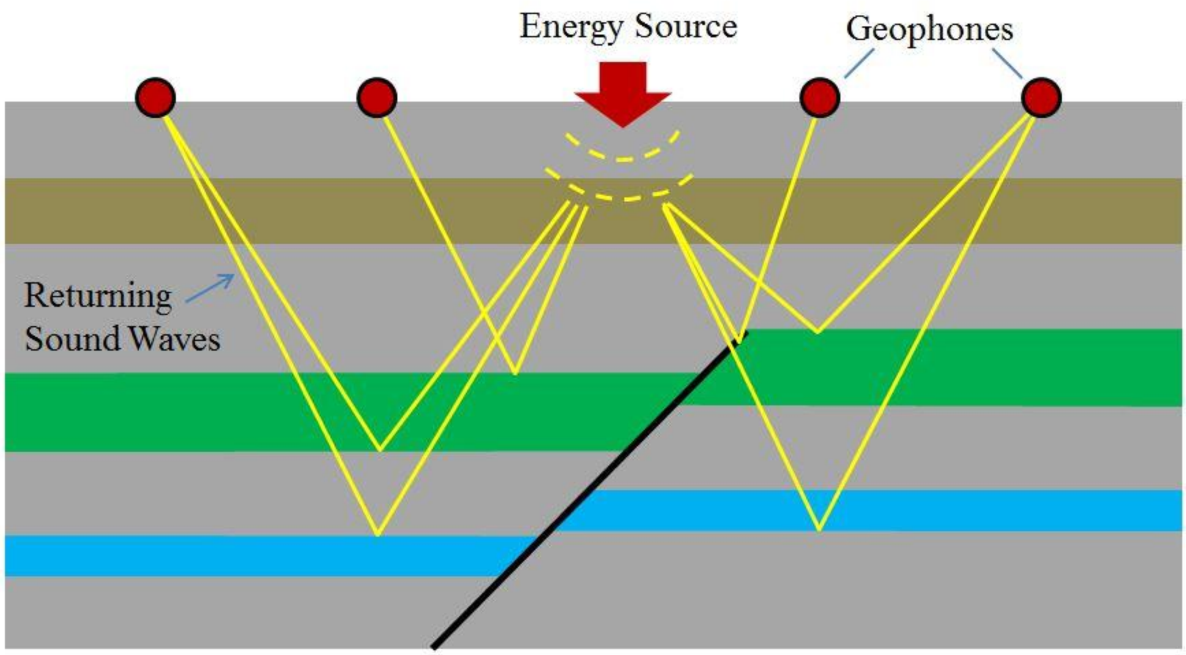


Figure H.2. Schematic representation of typical method used for performing a seismic survey. Source: ISWG.

Seismic interpretation can involve "picking" horizons and faults either with or without the aid of computer algorithms. Faults are usually interpreted by looking for bends, changes in dip, or truncation of reflectors. The visibility of faults on seismic surveys depends on their angle and how much they offset reflectors. Low angle normal faults and thrust faults with significant offset should be easy to interpret. However, high angle strike-slip faults with small offsets would be very difficult to see in seismic data (Figure H.3).

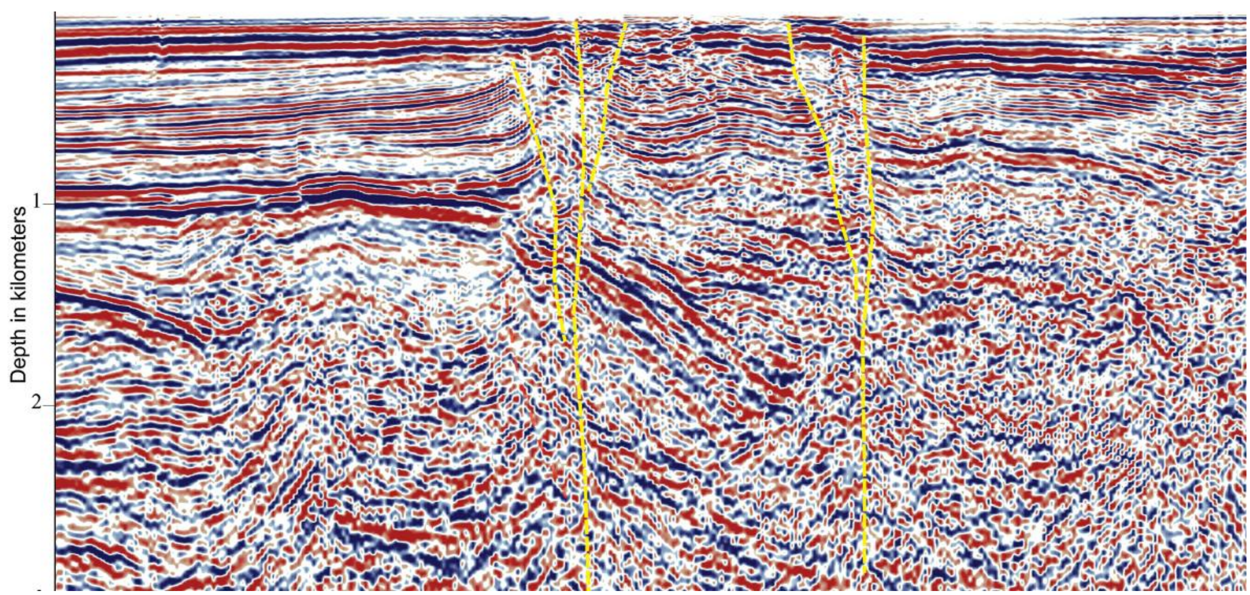


Figure H.3. Example seismic survey analysis illustrating interpretation of fault locations (yellow lines). Image courtesy of USGS. Source: USGS California Seafloor Mapping Program Data Collection 2014.

2D surveys are generally older and of lower quality. One advantage they may have is that many are regional lines that extend for tens of kilometers. With the advent of modern computers, 3D and even 4D seismic survey technologies and advanced processing capabilities have been developed. 4D seismic surveys involve repeating 3D seismic surveys a year or two apart. As the 3D and 4D surveys may target prospective acreage in exploration activities, they generally cover a relatively small area and often are proprietary.

Some acoustic wave energy may also refract at an interface and return to the surface. Refraction surveys were common in the first half of the 20th century but are relatively uncommon now. They have been used to detect crust/mantle boundary, depth to basement, and the top of the water table.

Vertical seismic profile (VSP) data are also sometimes available. In a VSP survey, the geophones are arranged vertically in a borehole rather than at the surface. VSP data are commonly used for velocity analysis. They may also be used to image vertical surfaces (salt dome-sediment interface). A "walk around" VSP moves the seismic source azimuthally around the borehole. Shear wave splitting in a "walk around" VSP can determine the orientation of subsurface fractures.

Well logs: Well logs record physical properties of the subsurface versus measured depth in a borehole (Figure H.4). Conventional wireline logging lowers instruments into a well on a wireline cable. Logging while drilling (LWD) or measurement while drilling (MWD) incorporates instruments into the drill string. Common logging tools are briefly discussed below. Many publications describe in detail various well log analysis techniques (Asquith 2004).

- **Gamma ray log**: measures the natural radioactivity of a formation in API units. This tool is useful for distinguishing lithology and changes in formation type with reservoir depth. Sandstones and carbonates typically are low in radioactive elements whereas shales and granitic basement usually contain higher amounts of radioactive elements.
- **Spontaneous potential log**: measures the natural voltage or potential difference between the surface and the borehole in mV. This tool is used to distinguish sandstone from shale, and estimate clay content and formation water salinity. In general, shale has a low and consistent SP response, and permeable beds (sands) shift to the right if the clay content is low and/or the pore water salinity is high.
- **Resistivity log**: measures the ability of a formation to impede (resist) the flow of electrical current in ohm-m. Resistivity depends on resistance, which is a material property and flow path. Resistivity varies with lithology and pore fluid content. Clay rich formations have lower resistivity than quartz/calcite/feldspar rich formations if the pore fluid content is the same. Hydrocarbons are poor conductors of electricity and water is a good conductor so resistivity logs are also used to detect hydrocarbon bearing versus water filled (wet) sands (Figure H.4). Resistivity logs are plotted on a logarithmic scale because values vary by several orders of magnitude. If porosity is known from another log, then resistivity logs are used to determine water saturation (percentage of pore space filled with water as opposed to oil or gas).
- **Sonic log**: measures how long it takes acoustic waves to travel a fixed distance through a formation. Transit time varies with lithology and texture but primarily depends on porosity. Dipole sonic logs measure transit time using azimuthally oriented acoustic waves. Shear wave anisotropy from a

dipole sonic log can be used to estimate the direction of maximum horizontal stress (Zoback et al. 2003); hence this log is particularly useful for determining stress field orientation. Sonic logs can also be used in converting seismic data from time to depth if other information (check shot or VSP) is not available.

- **Density log**: measures the bulk (grains plus pore fluids) density in g/m^3 of a formation by bombarding the formation with radiation from a known source and counting the resulting gamma radiation. Low gamma radiation implies a dense formation. Porosity as a fraction can be determined from bulk density. Estimating porosity is important for evaluating reservoir pressure response to injection.
- **Neutron porosity log**: measures the amount of hydrogen atoms in a formation, which is primarily contained in either water and/or hydrocarbons in the pore space. High concentration of hydrogen in clay minerals also may impact results. Estimated porosity is given as a fraction. Density porosity and neutron porosity are often plotted together. In many instances, they give consistent estimates of porosity. However, in gas filled sands the density porosity and neutron porosity estimates are significantly different resulting in a crossover of the curves; this log is then particularly useful for evaluating presence of gas in the reservoir.
- **Image log**: measures resistivity or acoustic impedance across the borehole wall with an azimuthal array of electrodes or a rotating transducer, respectively. These logs are used to identify rock fractures and their orientation as well as the dip direction of strata.
- **NMR log**: measures the nuclear magnetic resonance response of a formation to directly estimate its porosity and permeability. This log can be helpful to assess reservoir properties and variations of reservoir properties across the interval that was logged.

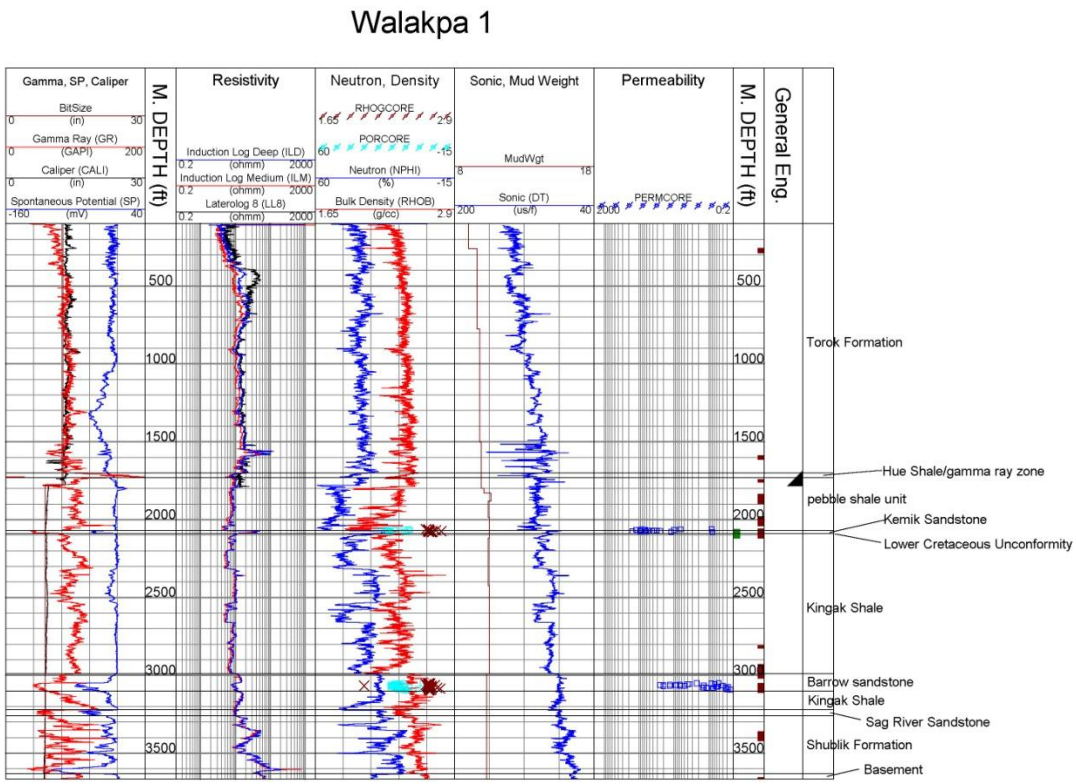


Figure H.4. Example of typical well log display. Source: USGS.
http://certmapper.cr.usgs.gov/data/PubArchives/OF00-200/WELLS/WALAKPA1/LAS/WA1LOG.JPG

Core data: Physical and chemical properties of subsurface rocks are measured from samples retrieved from the wellbore. As these are direct laboratory measurements on subsurface rocks, core data are the most accurate and detailed measurements. Core sampling is less common than seismic or well log data. Core analysis and/or storage are typically done by a service company.

A conventional core is a 4–5-inch diameter solid cylinder of rock extracted with a special drilling bit typically in 30-foot intervals (Figure H.5). Sidewall core is a 1-inch diameter and 1–2-inch long sample taken from the side of a wellbore using either an explosive charge to fire a core barrel into the formation or a rotary core bit. Drill cuttings are small bits of rock material brought to the surface by drilling fluid. Core data are often used to calibrate log data (e.g., water saturation or acoustic velocities). Information derived from core analysis is briefly described below.

- **Biostratigraphy and petrography**: core samples can be used for thin sections, XRD, and SEM analysis, which may provide information on paleontology, palynology, mineralogy, grain size, and porosity. This information can be used to determine the age, depositional environment, and diagenetic history of the formation. Conventional and sidewall core can be CT scanned for detailed textural/structural analysis.
- **Fluids and fluid flow (petrophysics)**: conventional and sidewall core samples can be used to estimate matrix permeability, relative permeability (water, oil, and gas), fracture permeability,

capillary pressure (force necessary for one fluid or gas to displace another in the pore space due to interfacial tension), water saturation, and wettability (preference of solid grains to contact one liquid or gas over another in the pore space). Water saturation, pore water salinity, and oil gravity also can be measured from core samples. Understanding the reservoir properties is important for reservoir modeling and subsurface pressure field calculations.

- **Geomechanical**: uniaxial and triaxial compression tests, thick wall cylinder tests and other analysis on conventional and sidewall core samples are used in conjunction with CT scans and visual inspection to determine geomechanical properties of the formation rock. Understanding the rock mechanical properties is important for geomechanical studies of fault reactivation.

Figure H.5. Image of core from Sag River Sandstone. Source: USGS.
https://www.google.com/search?q=usgs+sandstone+core+image&biw=1219&bih=836&source=lnms&tbm=isch&sa=X&ved=0CAYQ_AUoAWoVChMIybHdgoroxwIVAiWICh2qdAjI#imgrc=4iuaZVXbqASEkM%3A

Category	Limitations/Uncertainty
Seismic surveys	Seismic interpretations are not unique. Different interpretations can be influenced by interpreter experience and bias. This is illustrated by a study in which several hundred geologists were asked to interpret a 2D seismic section (Bond 2007). Eight distinct interpretations were possible, but only a handful of interpreters correctly interpreted. Errors can be introduced by large vertical scale exaggeration and depth conversion problems. Resolution of seismic data depends on the frequency and velocity of the acoustic waves. Resolution is typically ~100 feet so small beds or faults are not resolvable. Resolution depends on the type of seismic survey and numerous seismic data acquisition input parameters. While seismic data can be used to infer a lot about the subsurface, it does not directly measure either lithology or fluid content. This information must be supplemented with well log or core data.
Well logs	If the borehole is not vertical, then measured depth is greater than the true vertical depth (TVD). Drilling muds invade the formation immediately around the borehole, changing its properties. Some log analysis requires bottomhole temperature. Well logs only measure physical properties within a short radial distance of the borehole, typically centimeters to meters depending on the tool. Some log analysis requires bottomhole temperature corrections and understanding the resistivity of the drilling mud filtrate. As the tool averages properties over a portion of the borehole, thin units may have a muted impact (e.g., a thin, water-wet sand will have a smaller reduction in resistivity than a thick water-wet sand). Some logs (e.g., resistivity) have high frequency noise.
Core data	Drilling muds invade the formation, changing its properties. Changes in temperature and pressure from *in-situ* conditions (e.g., depressurization expansion) and/or the retrieval process may damage the core sample and change its properties. Core samples can dry out during storage, which can change their physical properties. Core samples only measure physical/fluid properties within a small volume, which may not be representative of the larger reservoir (e.g., core may not sample fractures or deformation bands, which largely control fluid transport on a reservoir scale).

Table H.2. Limitations of raw geologic and reservoir data. Source: ISWG.

Fault Maps (Interpretive Data)

Most faults pose no or very little seismic risk. Faults of concern depend on the stress field and fault orientation relationship will determine which faults are active and could potentially move. Fault maps have been traditionally used by the USGS to produce seismic hazard maps of the United States. These are coupled with regional stress maps to identify potentially active faults; faults that are aligned perpendicular to the maximum stress component in the subsurface are unlikely to be active and will have little importance in determining earthquake hazard a site (Walters et al. 2015). Site specific characterization of injection sites using fault maps is suggested in many current guidelines and publications (Walters et al. 2015b).

Major faults in the crust of the United States have been mapped using traditional geologic methods over the past hundred years, but these methods by no means capture all potential faults of concern. Many faults remain unidentified or mapped. In the absence of identified or mapped faults, the regulatory agency may use additional tools to make decisions relative to injection operations. As larger magnitude earthquakes require larger fault slip, identification of the largest fault locations and siting injection wells away from these locations can reduce the likelihood of large induced seismic events. Determining "how far away is far enough" may require reservoir characterization and reservoir modeling work to identify the distance over which pore pressures may be increased from the injection.

There is long-term need for improved identification and mapping of potentially active faults systems to better manage potential risks of induced seismicity (NRC 2012). Industry, academia, and government researchers are now working collaboratively to characterize and map faults and subsurface stress fields. One such project is currently being carried out in Oklahoma by the Stanford Center for Induced and Triggered Seismicity (SCITS) in cooperation with the Oklahoma Geologic Survey and the Oklahoma Corporation Commission (Walsh 2015).

Data collection: One way to map active faults is to use precisely relocated seismic data, or seismic data from higher accuracy deployable seismic monitoring arrays. Beyond seismicity measurements, examination of lineaments (linear features on the surface) obtained from satellite imaging enable geologists to identify regional faults over large swaths of land (Jacobi 2002). These can be ground-truthed by examining outcrops of formations that are intersected by the lineaments and by identifying fracture intensification domains that often surround faults.

In the central United States, where the majority of induced seismicity is occurring, it appears that many earthquakes are associated with buried and deep fault systems. Generally, the only way these deep buried faults may be identified is through seismic imaging. Traditional approaches like geologic mapping and even aerial photography and satellite imagery are unlikely to be helpful when faults are buried and do not have surface expression.

A recent example of improving regional fault maps by combining high-resolution proprietary data with traditional maps is being performed by the Oklahoma Geological Survey (Holland 2015), which is collaborating with industry in a way that preserves the proprietary nature of the data. Figure H.6 shows the Oklahoma Geological Survey's preliminary fault map as compiled from oil and gas industry data and published literature. This preliminary version identifies surface and subsurface faults on one map. The fault database continues to grow as more faults from published literature are being identified and added to the database nearly every day. A preliminary compilation of the fault database was made available as an OGS Open File Report OF3-2015 titled, "Preliminary Fault Map of Oklahoma," with digital files and references available on the Oklahoma Geological Survey website. Combining operator data and public data enables development of more robust products to aid in identification of the potential locations of faults of concern in proximity to potential injection sites.

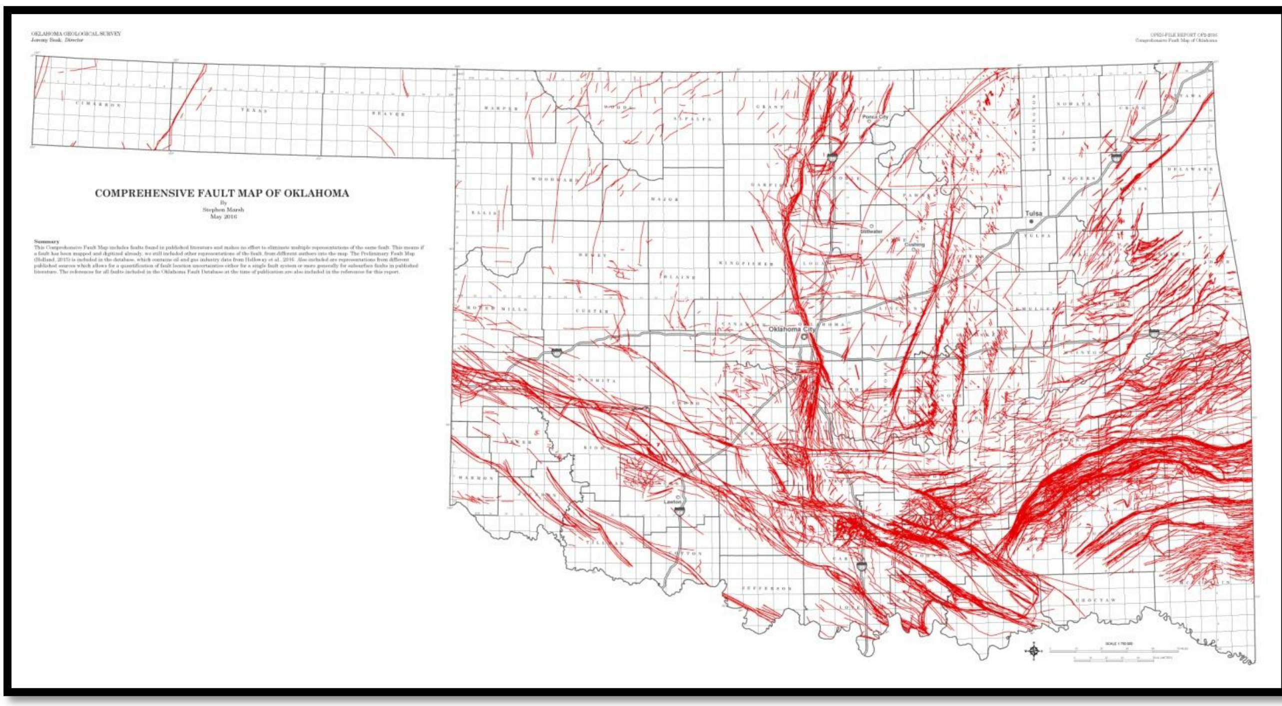


Figure H.6 Oklahoma fault map (preliminary). Source: Oklahoma Geological Survey Open File Report OF2-2016.

The USGS maintains a fault and fold database for some faults active in the Quaternary period, but it does not include all the faults that could be reactivated. Figure H.7 shows the USGS Quaternary period fault map (USGS 2015), which clearly does not identify many known faults across the broad mid-continent of the United States. Additional data on faults may be available through state, industry, and academic institution sources.

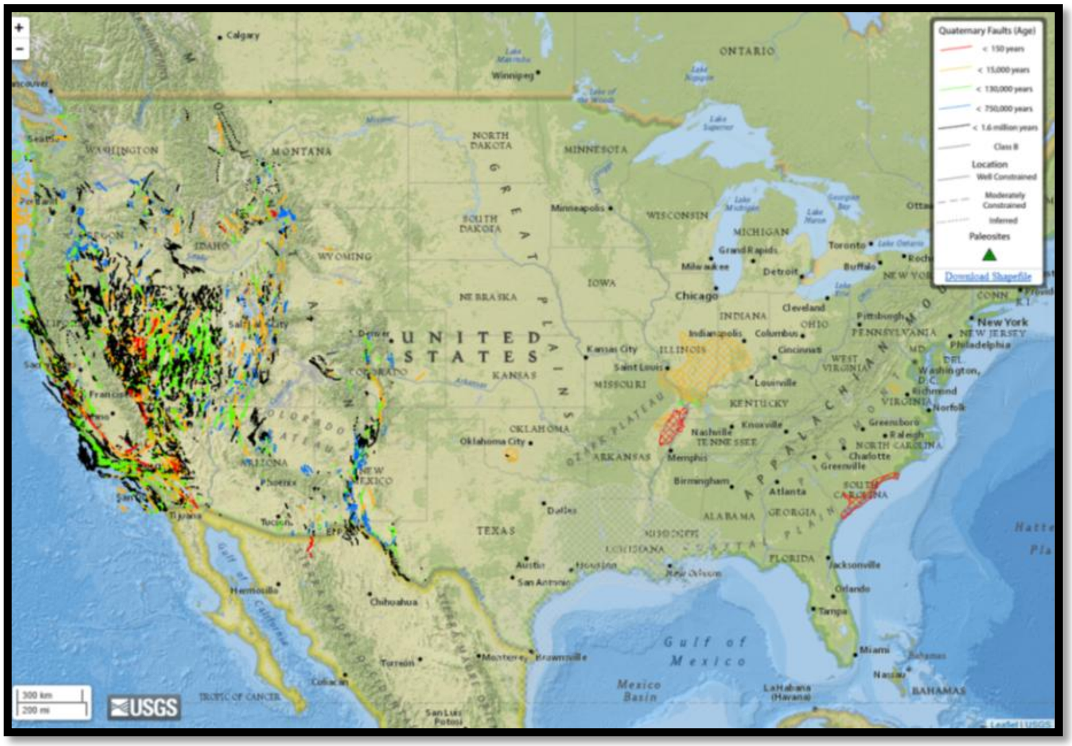


Figure H.7. USGS Quaternary Fault and Fold Map. Source: USGS 2015.

Limitations of fault maps and other interpretive data are summarized in Table H.2.

Basement Fault Maps (Interpretive Data)

Knowledge of basement faults can provide important information regarding the potential for induced seismic activity. These deeper faults are in the less ductile crystalline rocks below shallow sedimentary rock and are less likely to plastically deform when critically stressed. Basement fault maps have not typically been used to characterize specific sites for oil or gas production; however, the influence basement faults exert on overlying formations may be useful for the characterization of field sites.

Data collection: The depth of basement faults complicates their detection and mapping. While many of the same techniques used to map crustal faults can be used for basement rocks, fewer wells penetrate the basement rock, making ground-truthing of suspected fault locations via core logs difficult. Lineaments can still be used to identify fault locations, but the hundreds of meters to several kilometers of rock above these faults may obscure some surface features. Fewer outcrops of continental basement formations exist as well. Mapping of the estimated basement depths for the broad United States has been developed by some researchers (Mooney 2010); and several state geologic agencies maintain their own basement depth and fault maps based on more detailed state and local data. As an example, (Figure H.8), the Ohio Department of Natural Resources Geological Survey has published maps portraying deep faults and other structures identified by a variety of geologic studies (ODNR 2015). Some faults are well known, whereas others are speculative. Very few are visible at the surface.

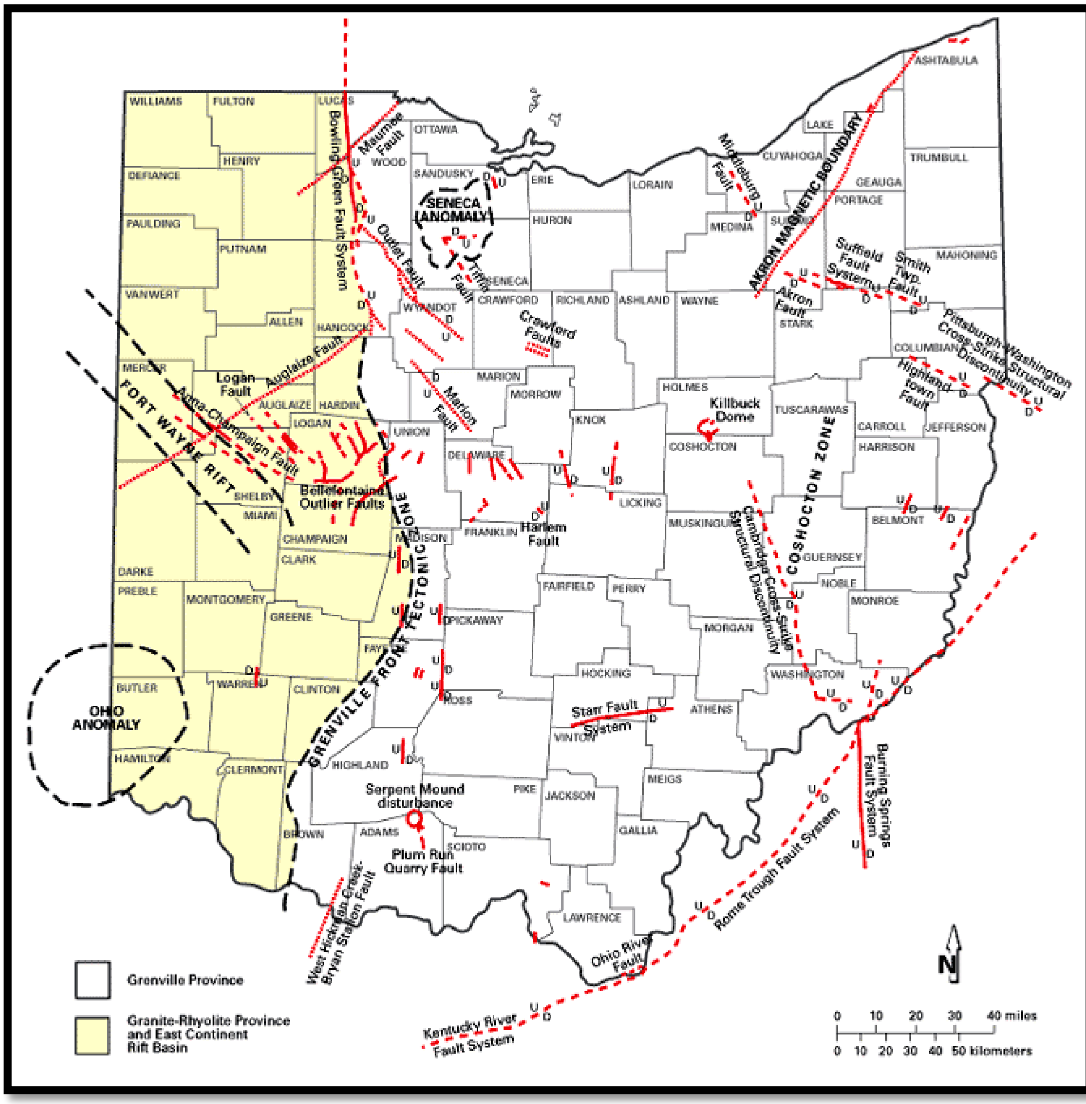


Figure H.8. Ohio map of deep faults and basement faults. Source: Ohio Geological Survey 2015.

While seismic surveys can be used to identify basement faults, they are typically sparse in areal extent and proprietary in nature. In addition to seismic measurements, magnetic and gravity anomaly measurements can assist in locating basement structure. Gravity anomaly measurements provide insight into crustal thickness and changes in values can indicate an offset due to a deep fault. Magnetic anomaly measurements can indicate changes in the subsurface chemistry or magnetism influenced by changes in basement depth. Faults interpreted from gravity and magnetic anomaly surveys are low resolution and placement is inferred from modeling.

Limitations on basement fault mapping are summarized in Table H.2.

Subsurface Stress Maps (Interpretive Data)

Determination of the *in-situ* state of stresses in the subsurface is both complex and often expensive and possesses a large degree of uncertainty due to the sparseness of data. While the oil and gas industry occasionally collects borehole and well log data that can be used to estimate subsurface stresses, this information is not readily or broadly available as part of injection well planning or permitting.

Generally public information on the *in-situ* stress in the earth is too fragmentary to allow confident estimates of the actual stresses acting on a fault. In most cases, the only reliable information available is the magnitude of the vertical stress, as it can simply be estimated from the average density of the overlying rock and the depth. Estimating the general fault types and configurations as well as the broad orientation of the maximum and minimum horizontal stresses at a scale of tens or hundreds of kilometers is also sometimes possible, based on a variety of stress indicators. One such example is shown in Figure H.9 (NRC 2013), which presents one dataset associated with mapping of maximum horizontal stress data in North America.

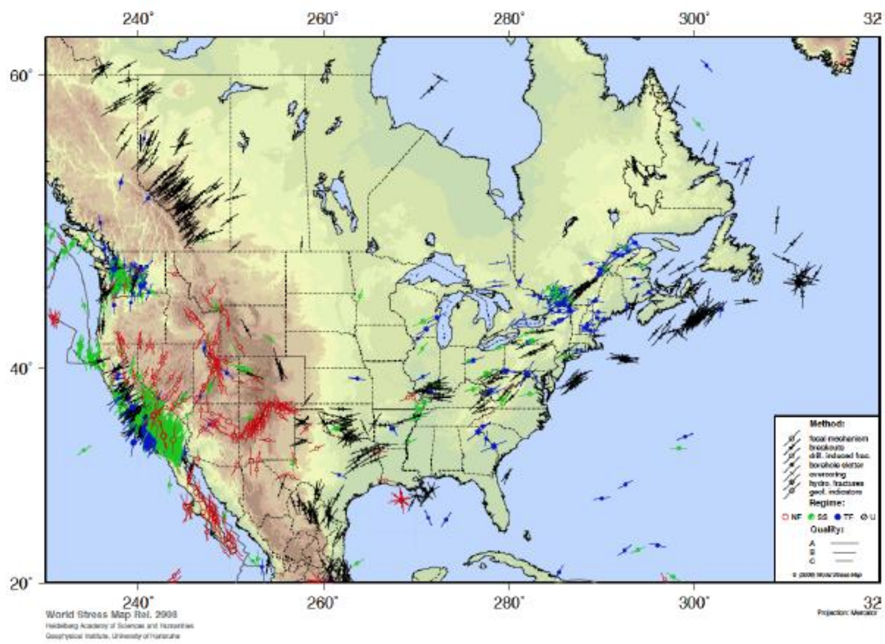


Figure 4. North America stress map. The stress map displays the orientations of the maximum horizontal compressive stress (σ_H). The length of the stress symbols represents the data quality, with A being the best quality. Quality A data are assumed to record the orientation of σ_H to within 10°-15°, quality B data to within 15°-20°, and quality C data to within 25°. As can be seen from this global dataset, stress measurements are absent in many parts of North America and the offshore. Because stress measurements are important in the consideration of induced seismicity, their measurement, particularly in areas where data are sparse, could usefully contribute to understanding the potential for induced seismicity related to energy development. The tectonic regimes are: NF for normal faulting, SS for strike-slip faulting, TF for thrust faulting, and U for an unknown regime. Topographic relief is indicated by green (lower elevations) to brown (higher elevations) shading. Data used to plot this map were accessed from www.world-stress-map.org/ (see Heidbach et al., 2008).

Figure H.9. Figure from NRC Report providing North America stress map. Data may be downloaded from www.world-stress-map.org site. Source: Heidbach et al. 2008.

Although the conditions for initiating slip on a preexisting fault are well understood, it is difficult to make reliable estimates of the various quantities in the Coulomb criterion. Lacking these estimates, predicting how close or how far the fault system is from instability and slip is essentially impossible, even if the orientation of the fault is known. The implication is that the magnitude of the increase in pore pressure that will cause a known fault to slip generally cannot be calculated. Therefore, generally, it is not possible to uniquely predict the conditions (changes in pressure/stress) that would actually lead to fault slip. Further, when anomalous seismicity occurs, the lack of accurate subsurface stress information also substantially complicates understanding of whether naturally-occurring stress changes or pore pressure changes associated with fluid injection may be primarily responsible for the observed fault slip.

Nonetheless, understanding how different factors contribute to slip initiation is valuable because it provides insight about whether fluid injection or withdrawal may be a stabilizing or a destabilizing factor for a fault (in other words, whether fluid injection or withdrawal causes the difference between the driving shear stress and the shear strength to increase or decrease). Any perturbation in the stress or pore pressure associated with an increase of the shear stress magnitude and/or a decrease of the normal stress and/or an increase of the pore pressure could be destabilizing; such a perturbation brings the system closer to critical conditions for failure.

Researchers are currently undertaking efforts to improve the quality of stress maps. An example of a regional stress map is shown in Figure H.10 (Alt 2015) utilizing geophysical image logs made available by oil and gas companies. Over 80 high-quality indicators of the direction of maximum horizontal stress (blue lines) have been added to the ~10 previously available high quality data points in the state. Such an approach can help assess the potential existence of faults that may be more prone to reactivation if they are preferentially oriented relative to the current-day stress state (at fault depth location).

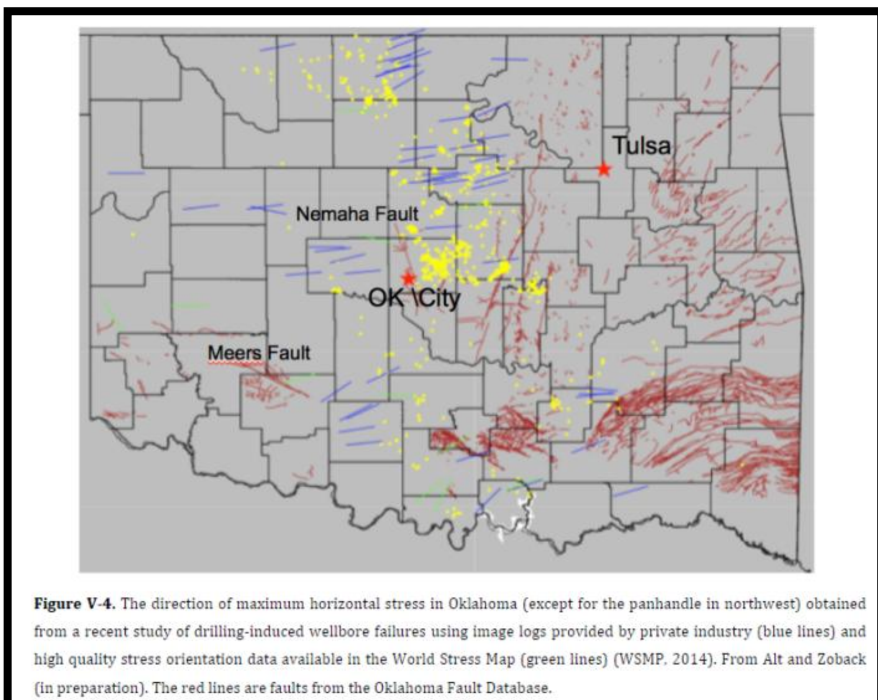


Figure H.10. Figure illustrating combined stress map and fault map with higher resolution data in Oklahoma. Source: Alt 2015.

Developing stress maps such as this requires reliable estimates of 3D stress components from well logs and reservoir property measurements. The equations and methods for measuring and calculating subsurface stresses and pore pressures are available in the reservoir and geomechanics literature (Zoback et al. 2003).

Reservoir Properties (Interpretive Data)

As discussed in "Well Data" above, the most commonly available information for injection wells is well head pressure and injection volume versus time. In addition, bottomhole pressure can be measured directly or estimated. Other tests sometimes conducted in wells to determine reservoir properties include:

- **Leakoff test (LOT)** measures the fracture pressure of a formation. The well is shut in and fluid is pumped into the well bore until fluid enters the formation or leaks off.
- **Pressure fall off (PFO)** monitors pressure change with time after the well is shut in. After sufficient time, the pressure levels off and indicates a measure of the average reservoir pressure. How long it takes for the well to approach this leveling (or asymptotic) value measures the permeability of the surrounding formation as well as the "skin effect." If successive PFO tests take appreciably longer to reach the asymptotic value, this may indicate buildup of skin or material plugging up the borehole. Pressure Buildup (PBU) is a similar test for a producing well.
- **Repeat formation tester (RFT)** can be repeatedly set and retracted into the formation at different depths. Pressure and temperature are measured with a gauge. The tool can also take two fluid samples.
- **Modular formation dynamics Tester (MDT)** is similar to an RFT but has newer quartz gauges to measure pressure and temperature and can take more fluid samples.
- **Diagnostic Fracture Injection Test (DFIT)**: a small volume of water is pumped into the formation until it fractures. The valve is then closed and pressure in the well is allowed to fall off over one to two days. A quartz transducer measures the pressure transient. This test is also known as a Data Frac, Mini-Frac, or Mini Fall-off (MFO).
- **Interference test** is a multiple well test. A pressure transient is introduced in one well while the pressure is measured in an adjacent shut-in well. This test determines whether there is communication between the two wells. It also can be used to determine permeability and hydraulic diffusivity.
- **Production data:** in producing fields, oil rate, gas rate, gas oil ratio, and water rate are also measured often on a daily basis.

Limitations of reservoir properties data are summarized in Table H.3.

Category	Limitations/Uncertainty
Fault maps	Faults may be too small to identify with traditional fault mapping techniques. Surface features used to map faults may be obscured by vegetation, slump, or fissile lithologic units. High resolution data are often propriety. Identification of faults by itself is not enough to know if the seismic hazard due to injection nearby to this fault is increased; stress state of the fault is required in order to understand if the fault is active.
Basement fault maps	Fewer deep wells and basement outcrops mean there are fewer opportunities to validate the locations of suspected basement faults. Because of the depth and lack of reflectivity in the basement, seismic surveys and traditional detection techniques are less likely to capture faults in the basement. Variances in reflectivity and formation acoustic differences can also impact the results. Basement stress regime may not be as well understood from limited data. The basement geology in general is poorly understood due to its older age. This is due to the limited data increased depth, and because it has a longer, more extensive and complex geological history than horizons within the sedimentary section.
Reservoir properties	Pressure readings are subject to temperature drift. Older RFT tests may not have penetrated into the formation. Pressures measured by RFTs and MDTs may not be very representative if insufficient sampling time is used, and/or measurements made in lower permeability formations. Leakoff tests have to start below fracture pressure and have sufficient test points. This may not be possible with shallow wells and available equipment. Pressure falloff tests must have sufficient points recorded, as well as a steady injection rate prior to the test. Most regulations prohibit fracturing an injection well to avoid loss of injection confinement to the intended disposal zone. Highly deviated and lateral wells will not show the same character as wells that are essentially vertical.

Table H.3. Limitations of interpretive data. Source: ISWG.

Data and Information Sharing Considerations

Injection well operating data (injection rates and volumes, well design, etc.) are not typically considered confidential business information. They are reported as required by the UIC program regulations and are publicly available. Data tabulation, reporting frequency, data-base formats, and record-keeping methods may differ by each state with delegated UIC primacy. Currently, many regulations require annual submission of injection pressures, volumes, and rates as measured throughout the year. More frequent reporting of injection pressures, volumes, and rates could be considered to provide more timely data access and enable improved analysis of potential spatial and temporal correlations between particular injection wells and observed seismicity. Additionally, use of a common data format and database that is accessible to the public would improve transparency and enable interested stakeholders to be informed of injection practices in their specific areas of interest.

In contrast, subsurface and reservoir data associated with hydrocarbon-bearing reservoir intervals are broadly considered as confidential business information due to their importance in making commercial business decisions regarding field and reservoir development. Detailed well logs and reservoir property measurements typically are associated with production activities. Substantially less detail is available for injection wells; for example, stress measurements, advanced well logs, and seismic surveys are generally not performed for injection wells.

Development of improved stress maps and fault maps generally must rely on confidential business information supplied by industry. Agencies can put in place appropriate mechanisms that would allow industry to preserve confidential business information while providing sufficient data to assess subsurface stress fields and the potential presence of faults of concern. Such mechanisms could involve confidentiality agreements and/or specific relevant data provided based on geographic basis, without reference to operator or well name. Sharing of “raw” data and “interpretive” data may drive the agreement structure or data sharing approach. One recent example of broad stakeholder collaboration is the development of enhanced stress and faults maps in Oklahoma via the collaborative efforts of the Oklahoma Geological Survey, Oklahoma Corporation Commission, Stanford University, and various industry companies. Confidentiality provisions and data-handling agreements enable operators to provide well logs, stress data, and fault interpretations without public release of confidential business information.

Key Messages

Given the geologic diversity across the United States, differences associated with the location and volumes of subsurface injection of saltwater, diversity and scope of operations, and allocation of state resources, there clearly is not a “one-size-fits-all” best practice for data and information collection, reporting, and sharing. Rather, best practices at the state and local levels may be developed based on the local geology, environment, and risk levels, considering state and local stakeholder discussions and engagement.

Development of improved stress and fault maps requires collaboration across multiple stakeholder groups. For specific local situations, data requested from industry should be handled in a manner that reflects consideration of confidential/proprietary business information and other potential contractual obligations that may be in place. Also, because, interpretive data may be subject to revision and updates as new information becomes available, consideration should be given to the potential uncertainty and associated with these data when they are applied in specific regulations or permit conditions. Regulators may wish to consider how to mediate and broker information and data collection and sharing, so that the most effective and appropriate datasets are considered and appropriate expertise is brought together to conduct studies and investigations.

Finally, industry stakeholders may want to evaluate the data collection and archival capability of regulatory agencies that hold injection well data, along with the companies that supply this data, and to identify opportunities to improve data collection and reporting capabilities with advanced computing systems, enabling more timely access to relevant injection well data.

Appendix I: Considerations for Hydraulic Fracturing

Considerations Specific to Hydraulic Fracturing

Induced seismicity associated with hydraulic fracturing is rare. However, in limited cases, hydraulic fracturing has been associated with induced seismicity felt levels of ground shaking. Based on limited occurrences, there also appear to be similarities between disposal and hydraulic fracturing induced seismicity. In a small percentage of hydraulic fracturing operations, fracturing has reactivated faults. The seismicity of concern may only occur on critically stressed faults; most other preexisting faults may not be activated.

General risk management and mitigation approaches relevant to potential injection-induced seismicity also can be applied to hydraulic fracturing. However, induced seismicity of any significant risk associated with hydraulic fracturing is extremely rare, is quickly mitigated, and when detected at the surface is at the lowest levels of surface impact. Therefore, evaluation and response systems should be tailored differently for hydraulic fracturing than for disposal.

When considering systems such as the "Traffic Light" for hydraulic fracturing applications, "green-to-yellow" and/or "yellow-to-red" thresholds should be established based on the local conditions and geology, and considering specific levels of ground shaking that are of local public concern. Depending on the specific local area, thresholds could consider, or be set consistent with, established acceptable limits from other industrial activities, such as mining, blasting, and geothermal operations (Siskind 1983).

Understanding the Hydraulic Fracturing Process

Recovering hydrocarbons from shale (and other tight-rock formations) using horizontal drilling and hydraulic fracturing typically takes four to eight weeks for a single well – from preparing the site for drilling and completion of the well to production itself – after which the well may produce for 20 to 40 years. The hydraulic fracturing operation, which is a part of well completion, has a relatively short duration, typically a few days per well (King G. E., 2014).

If multiple wells are drilled from a single pad location, the duration of the drilling, completion and fracturing operations will increase correspondingly in time (e.g., a four well pad or eight well pad may take several months to complete the operations).

As illustrated in Figure I.1, a well can be a mile or more deep and thousands of feet below fresh groundwater zones before gradually turning from a vertical to a horizontal orientation. The horizontal portion of the well may extend more than 10,000 feet in length. A single well site (or pad) can accommodate a number of wells. Steel pipe known as surface casing is cemented into place at the uppermost portion of a well to protect fresh water aquifers.

As the well is drilled deeper, additional casing is installed and cemented in place to isolate geological formations between the surface and the reservoir prior to commencing hydraulic fracturing operations. Protective measures, such as containment equipment and spill response procedures are used and optimized to the local circumstances; these may include the use of liners under well pads, rubber composite mats under rigs, secondary containment measures for storage tanks, and barriers to control any potential surface runoff from the site (King G. E., 2012).

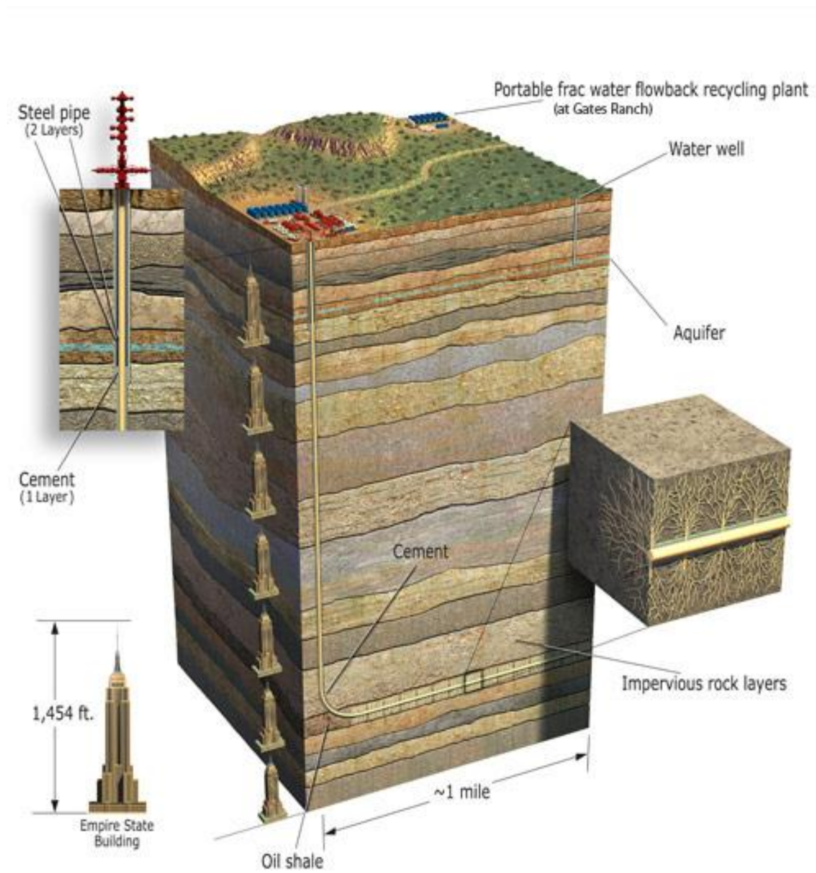


Figure I.1. Illustration of hydraulic fractured horizontal well. Original source unknown: Re-printed from (Groundwater Protection Council, 2010) URL http://fracfocus.org/hydraulic-fracturing-how-it-works/hydraulic-fracturing-process.

After the well(s) on a pad is drilled, cased and cemented, it is necessary to connect the hydrocarbons in the reservoir formation to the wellbore so that it can flow to the surface. This is accomplished via multi-zone hydraulic fracturing operations, which can be done in several ways (Soliman, 2012) (Nygaard, 2013). Currently, the "*Perf-and-Plug*" method is the most widely used method for multi-zone fracturing of horizontal wells.

In the Perf-and-Plug method, a mechanical device is placed downhole to perforate the horizontal part of the production pipe to make small holes in the casing, exposing the wellbore to the shale. Then a mixture consisting primarily of water, sand and a small percentage of chemicals is pumped into the well under high pressure to create fractures in the shale, enhancing the flow of oil and natural gas.

As illustrated schematically in Figure I.2, sand keeps the fractures open after the pressure is released. These fractures may be a few millimeters wide and extend horizontally several hundred feet to provide extended connection and flow-pathways in the oil or natural gas reservoir. The chemicals in the mixture are primarily used to reduce friction, prevent corrosion, and inhibit bacterial growth.

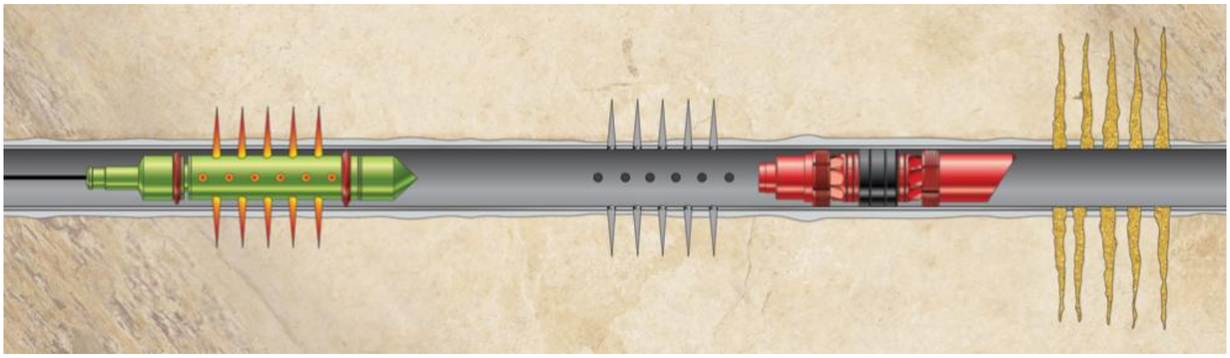


Figure I.2. Illustration of multi-zone hydraulic fracturing using the "Plug and Perf" technique (not to scale). Image source Re-printed from (Drilling Contractor, 2012) URL: http://www.drillingcontractor.org/self-removing-efdas-level-stimulation-access-14457 Image Source: Halliburton, Inc.

Understanding Hydraulic Fracturing on Multi-Well Pads.

Significant environmental benefits are realized by drilling multiple horizontal wells from a single surface location. This can result in as much as 90 percent reduction in overall surface disturbance compared to drilling each well from its own surface location.

Figure I.3 illustrates the concept of using a single surface pad location to drill multiple horizontal wells. Multi-well pads improve safety performance and reduce hydraulic fracturing time, surface disturbance, and environmental impacts (Tolman, 2009). By consolidating the wells and production to one pad site, companies can reduce the number of access roads and pipelines needed to service wells and can reduce truck traffic through the use of centralized water and sand delivery.

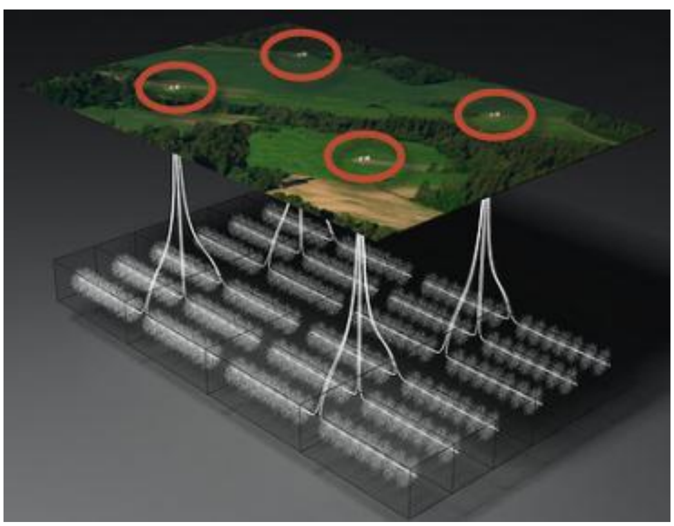


Figure I.3. In this graphic, six horizontal wells are drilled from each surface location highlighted by the red circles. Image source: US Energy Information Association (https://www.eia.gov/todayinenergy/detail.php?id=7910).

Understanding Alternating Well Hydraulic Fracturing ("zipper method")

The term "zipper" is used to describe a completion methodology to more efficiently and effectively perform multi-zone fracturing when two or more wells are drilled from a single surface pad. The zipper method involves hydraulically fracturing a stage (i.e., a specific depth interval) in one well, while preparing the next stage in an adjacent well for hydraulic fracturing by running wireline and perforation operations. The next well is sequentially stimulated after completing the fracture treatment in the first well (Jacobs, 2014). Thus, the method can be called "zipper fracturing" or more accurately "alternating well hydraulic fracturing." The most common well design utilizing this method are cased and cemented horizontal wellbores that are fractured using the "*Plug and Perf*" method (Jacobs, 2014). This allows completion operations to continue with minimal interruption and operational downtime.

Figure I.4 schematically illustrates this method for various well configurations and fracturing sequences. Figure I.4 (A) shows a traditional ("non-zipper") sequential well fracturing operation, where the fracturing operations are completed in their entirety one well at a time. Figure I.4 (B) illustrates the "zipper" method where the hydraulic fracture stages are alternated between adjacent wells. This alternating well hydraulic fracturing procedure earned its name from the zipper-like configuration of the fracture stages created between the two horizontal wellbores drilled parallel to each other.

Many different wellbore trajectories, other than directly offsetting parallel wellbores during the simultaneous operations, can be associated with zipper-fracturing. As examples, Figure I.4(C) illustrates a two-well pad with parallel wellbores with fractures placed offset from each other across the wells; and Figure I.4 (D) illustrates an eight-well pad with parallel wellbores with fractures placed immediately adjacent across the wells. Spacing between wells is established considering state oil and natural gas regulations and specific local reservoir properties (e.g., permeability) that affect reservoir drainage and hydrocarbon recovery.

Optimization of well spacing, hydraulic fracture stage spacing, and the volume of water and sand used in fracturing operations is generally established through reservoir modeling studies, production test results, and well performance. In general, zipper fracturing only differs from sequential fracturing in the order of the fracturing stages in the wells.

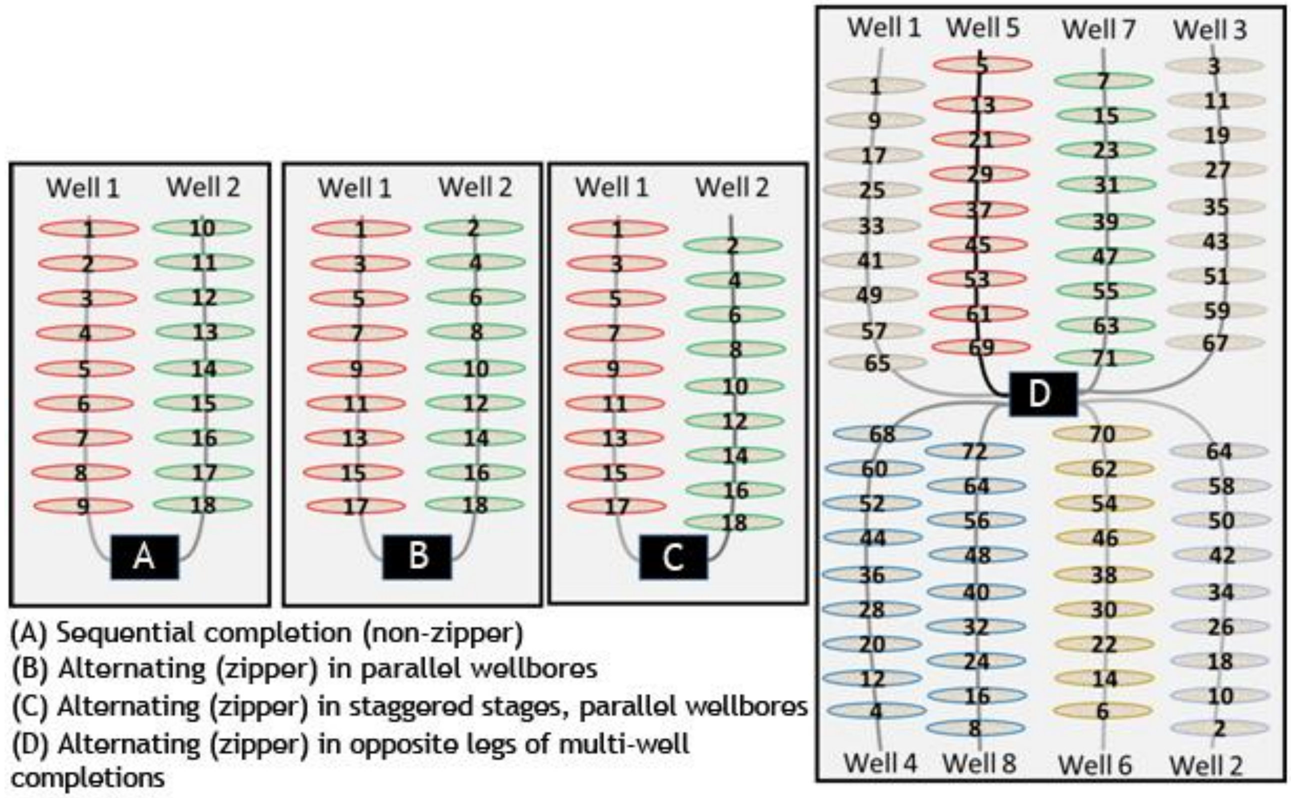


Figure I.4. Examples of different horizontal well and multi-zone hydraulic fracture sequencing for simultaneous operations and application of concepts associated with "zipper-frac" operational methods. The fracture sequencing is labeled numerically in each illustration. (Image after Patel, 2016)

In addition to providing significant operational and financial efficiencies, simultaneous completion operations and the application of zipper fracturing methodologies, may improve stimulation effectiveness and increase oil and natural gas recovery from the reservoir (Sierra, 2014) (Patel, 2016) (Nagel, 2011) (Pirayehgar, 2016).

Understanding Microseismic Events Always Occur with Hydraulic Fracturing

Micro-seismic events are very weak seismic responses from the subsurface formation. Micro-seismic events are always expected to occur during hydraulic fracturing. They are not felt by people and do not cause damage at the surface. Micro-seismic activity provides information on the fracture behavior and its growth over time.

Microseismic monitoring, which is a fracture diagnostic tool used to determine geometric characteristics of hydraulic fracturing treatments for optimization and control, can also be used for assessing seismicity. Thousands of microearthquakes may be detected during a single stage of a hydraulic fracturing operation. It is important to understand that microearthquakes are routine and normal occurrences during hydraulic fracturing, and are associated with the fracture propagation and the normal subsurface rock fracturing process. These microearthquakes cause absolutely no identified hazard in normal operations. The risk associated with hydraulic fracturing is primarily associated with the very rare possibility that the subsurface pressure/stress potentially induced by the hydraulic fracture injection actually propagates the hydraulic fractures and directly communicates with a pre-existing critically stressed fault of concern.

A database of microseismic monitoring results was interrogated for the largest microseism detected in each stage of all monitored wells in six unconventional reservoirs, and a histogram of that data is shown in Figure I.5 (Warpinski 2013). The microearthquakes are likely due to slippage along faults, natural fractures, and bedding planes, with the largest probably being fault interactions. For the several thousand fracture stages that were monitored in this study, none of the microearthquakes exceeded M 1.0. The most frequently occurring microseisms are typically around M -1.0 to -1.5.

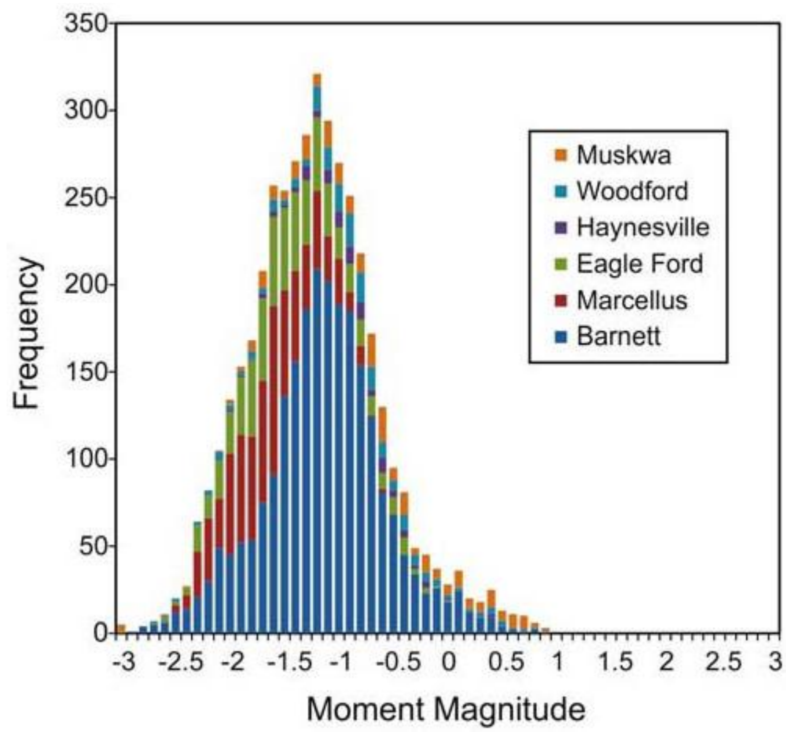


Figure I.5. Histogram of maximum magnitude microearthquake detected in six major unconventional reservoirs. Source: Warpinski 2013.

These results show that the typical magnitudes (**M**) of hydraulic fracturing micro-seismic events cannot be felt at the surface without the use of sensitive instruments that measure small subsurface vibrations (e.g., geophones and seismometers). Earthquakes greater than **M** 2.5, in general, may be felt by humans. Earthquake magnitude scales, such as the Richter scale are logarithmic. Therefore, when comparing the smallest felt earthquakes (of approximately **M**2.5) to hydraulic fracturing micro-seismic events (mean = **M**-1), there is generally 10,000 times lower movement than a typical **M**-1.5, hence the reason why these micro-seismic events cannot be felt at the earth's surface.

Understanding the Differences between Hydraulic Fracturing and Salt-Water Disposal

With respect to induced seismicity, hydraulic fracturing is different from salt-water disposal in many important ways. These include:

- Hydraulic fracturing operations are intended to fracture the rock while injection operations are rarely intended to fracture the rock.
- The pumping operation only lasts for a short period of time; each fracture stage ranges from one hour to several hours depending on volumes and rates; the entire well stimulation typically lasts several days, but depends on the well completion type.
- The amount of fluid pumped in a fracture treatment is orders of magnitude less than in a disposal operation over time. Similarly, the total energy put into the system is relatively small when compared to disposal operations.
- The fluids in a fracture treatment are largely stored in the fractures; and some volume of the fracturing fluids is normally recovered soon after the treatment while the remaining fluid is imbibed in the reservoir. When considering a specific hydrocarbon reservoir where fracturing is performed, fracturing is very different from injecting into a permeable disposal zone where the fluid is stored in the porous and permeable formation.
- In addition, the well will typically be produced relatively soon after the fracturing operations are completed. With flowback, the initially increased pressure associated with the hydraulic fracturing operation is relieved by the subsequent flowback. Then with longer-term production, the reservoir pressure is further reduced below original reservoir pressure due to depletion effects. Therefore, unlike disposal well operations, hydraulic fracturing operations followed by production operations generally results in lowering of reservoir pore pressure in proximity to the well.

Understanding Hydraulic Fracturing Data Availability

Detailed information on injection pressure, rate, and fluid and sand volumes are available for every hydraulic fracturing treatment. Detailed information is recorded, including surface pressure, flow rate, sand concentration, additive rates, and other parameters. In addition, because geologic controls are often highly resolved in hydraulic fracturing operations, operators will typically have detailed geologic information on the stratigraphy. Formation dip and faults with large vertical displacements can be correlated, which can be integrated with seismicity.

Though not routinely done, operators may monitor microseisms during hydraulic fracturing to diagnose geometric characteristics of the fracturing treatments for optimization and control. This microseismic data also can be used for assessing potentially induced seismicity by evaluating such factors as fracture height growth. Extensive publications in oil and gas technical journals discuss hydraulic fracture growth upward and downward, which may be useful to review when considering the potential for induced seismicity in hydraulic fracturing areas. For example, one database on fracture height growth (Fisher 2012) shows that height growth in the Marcellus shale is primarily upward and is not likely to contact basement features. In another example, although there are numerous cases of downward growth in the Barnett shale, it is far from the basement and the hydraulic fractures propagating downward terminate in the thick Ellenberger formation. Finally, because the fractures created by hydraulic fracturing in the Eagle Ford Shale have very little height growth in any direction, they too are unlikely to induce significant seismicity.

Understanding Risk Management Approaches

State regulatory agencies are developing diverse strategies for avoiding, mitigating and responding to seismicity. Many regulators work on these issues with the input of experts from government agencies, universities, private consultants, and industry.

Understanding the distinction between risks and hazards is fundamental to effective planning and response to seismicity. A hazard is any source of potential damage, harm, or adverse impact on something or someone; while a risk is the chance or probability that a person or property will be harmed if exposed to a hazard. The presence of a hazard does not constitute a risk in and of itself. For a risk to exist there must be exposure to the hazard and a mechanism for harm from the exposure

Traffic Light Systems

State regulatory agency risk management approaches have generally been developed based on public considerations and the perception of local risk exposures. These approaches have been framed around two key risk management concepts involving the use of "Traffic Light Systems" and/or "Areas of Interest".

Traffic Light Systems typically specify seismic event magnitude thresholds that if exceeded, mandate an action, such as communication with the regulator, or a change to the scope of operations. For example, when a "yellow light" magnitude threshold for a seismic event is exceeded, the scope of operations may be modified. When a "red light" magnitude threshold for a seismic event is exceeded, the operation is suspended and further investigation is performed.

Thresholds may vary based on local conditions and the risk management goals of a given agency. The thresholds are based on standardized earthquake magnitude measurements derived from ground motions recorded by a seismic monitoring network. When considering selection of traffic light thresholds, the equipment, procedures, and resource requirements for implementation of a specific system can vary substantially depending on desired thresholds for taking action. Background "noise" levels must also be considered, as other nearby industrial operations (such as mining blasts, for example), or natural tectonic chatter may also be detected.

Traffic light thresholds may also consider background thresholds associated with hydraulic fracturing and recognize that micro-seismic events are anticipated and may routinely observe recorded events of approximately **M**1 (see Figure I.5 above)

The magnitude distribution of "normally" occurring micro-seismicity associated with hydraulic fracturing should be carefully considered when establishing the background (or baseline) "noise" level and when considering the establishment of "Traffic Light System" thresholds. The uncertainties in magnitude calculation should be considered and evaluated when developing thresholds for certain actions, for example when developing Traffic Light System thresholds. Considerable research is underway within the seismological sciences to better understand the potential errors and uncertainties associated with calculation of earthquake magnitudes for small seismic events. A variety of approaches are used for calculating Moment Magnitude (Mw) and Local or Richter Magnitude (ML) (Spence, 1989); and this can lead to variability between estimates calculated using these different approaches (Mereu, 2017) (Ross, 2016). The potential differences between Moment Magnitude and Richter (Local) Magnitude calculations can be significant for seismic events less than approximately **M**3 (Ross, 2016). Research has also shown there can be uncertainties in different methodologies for calculation of a specific magnitude dependent on factors such as spectral content and distance from the source (Kane, 2011).

Areas of Interest

Another common approach used by regulators is to define an "Area of Interest". If operations are conducted within the specific Area of Interest, constraints on scope of operations are pre-defined or implementation of seismic monitoring may be required or enhanced. Areas of interest may be defined based on historical seismic activity and location of operations relative to known fault systems and/or known proximity to the deeper basement rock.

The larger seismic events in Alberta have been associated by some researchers with basement-controlled fault structures and their proximity to fossil reefs (Schultz, 2016). The seismic events in the Horn River and Montney plays in British Columbia have also been linked to faults that were interpreted to extended into the basement (BC Oil and Gas Commission, 2012) (Atkinson, 2016).

In Ohio, investigations of seismic events in proximity to hydraulic fracturing operations in Harrison County (M3.1 event) and Poland Township (M3.0 event) have also suggest that hydraulic fracturing operations may have triggered movement of faults that extend into the basement structure (Dade, 2017) (Skoumal, 2015).

More recently, Oklahoma Geologic Survey analysis of seismicity data and hydraulic fracturing operations in the South Central Oklahoma Oil Province ("SCOOP") and the Sooner Trend Anadarko Basin Canadian and Kingfisher counties ("STACK") has prompted the Oklahoma Corporation Commission to implement an area of interest and traffic light system to mitigate risk of hydraulic fracturing operations triggering surface-felt seismicity in the SCOOP and STACK plays (Oklahoma Corporation Commission, 2016).

In Pennsylvania, a sequence of seismic events (**M**1.8 – **M**2.3) that occurred in April, 2016, was associated with nearby hydraulic fracturing operations. These events were not felt at the surface, but were detected by the Pennsylvania seismic network (Pennsylvania Department of Environmental Protection, 2017). Based on this information, the Pennsylvania Department of Environmental Protection highlighted that hydraulic fracturing in the Utica shale was performed in proximity to crystalline basement rock.

Ongoing research continues to evaluate when proximity to basement may be a relevant factor to consider for risk assessment and management approaches associated with hydraulic fracturing.

Risk Mitigation Systems Tailored to Local Conditions

Risk management systems should be designed and implemented to be responsive and mitigate potential risks independent of specific completion methodologies that are being employed.

Whether a Traffic-Light System and/or Area of Interest are implemented as the risk mitigation approach, the approach should to be implemented considering the risk exposures for the local community. It is desirable for the system to enable flexibility in the forward risk mitigation elements such that protocols and procedures may be specifically tailored and adaptable for each unique situation.

If seismic events are observed during simultaneous operations and application of zipper fracturing methods or concepts during fracturing of multiple wells on a single pad, a substantial range of potential mitigation steps exist and could be considered. The mitigation strategies depend on the configuration of the wellbores; and evaluation of available subsurface information and seismicity trends.

If a felt seismic event occurs near ongoing fracturing operations, various mitigation approaches could be considered that utilize the breadth of operational flexibility afforded by the presence of the multiple wells on the single pad. If these very rare events are encountered, careful evaluation and site-specific research is key to effectively inform the response strategy and align potential operational adjustments to mitigate potential future events in the local area.

Because of the proprietary nature of certain information related to hydraulic fracturing, regulators may need to work closely with the operators.

Unlike data related to disposal well operations, much of the data obtained during hydraulic fracturing operations is likely to be considered confidential because of what it reveals about well completion approaches. Because rules about data reporting of well completion and hydraulic fracturing operations differ by state, wide variations can be expected in the types of information that can be gleaned from public sources or that would routinely be available for correlation with any seismicity. One public source of information is FracFocus (http://www.fracfocus.org/), the nationwide system for disclosing the additives and chemicals used in the hydraulic fracturing process, which also records water volumes.

Specific Examples of Regulatory Risk management Approaches

States and provinces have adopted a variety of strategies for risk management and response related to potential fracturing-induced seismicity. For example:

- Oklahoma's oil and gas industry is poised to launch new, major operations in the coming year in Oklahoma's latest oil and natural gas plays, the South Central Oklahoma Oil Province (SCOOP) and the Sooner Trend Anadarko Basin Canadian and Kingfisher counties (STACK). These areas are expected to account for the vast majority of new oil and gas activity in Oklahoma. In a proactive approach, the Oklahoma Corporation Commission's Oil and Gas Conservation Division (OGCD) and the Oklahoma Geological Survey (OGS), along with interested operators, have developed seismicity guidelines focused on operators in the SCOOP and STACK. Within an "area of interest" associated with the SCOOP and STACK plays, the OGCD will take the actions listed below following anomalous seismic activity within 1.25 miles of hydraulic fracturing operations:
    - If magnitude, as determined by the OGS, is greater than or equal to 2.5M: OGCD contacts designated representative for the operator with active completion operations within a 2 km radius of located seismic events. Implementation of the operator's internal mitigation practices commences. Operation continues.
    - If magnitude is greater than or equal to 3.0M: Operator initiates a pause of operations for no less than 6 hours. Technical conference/call held between the OGCD staff and operator

about operator mitigation practices. Upon agreement between operator and OGCD regarding mitigation practices and reduced seismic activity, operator permitted to resume with revised completion procedure.
  - If magnitude is greater than or equal to **M**3.5: Operator suspends operations. In-person technical conference held with OGCD staff and operator to examine whether operation can resume with changes.

- Currently, within certain areas of interest, Ohio has implemented permit conditions requiring seismicity monitoring for fracturing operations conducted within three miles of a known fault or within three miles of the epicenter of a recorded seismic event recorded since 1990 with **M**2.0 or greater. If an event is detected by any seismic network, Ohio has developed the following response procedures. An event less than **M**1.5 requires no action. An event between **M**1.5 but less than **M**2.0 requires notification (either by the division to the operator or the operator to the division). This threshold allows for initial discussion between the parties to possibly limit escalation of magnitude. An event between **M**2.0 but less than **M**2.5 will result in a temporary pause of frac work on the well(s) of concern. During the pause, the operator should consider and may propose modifications to the completion design such as skipping stages, reducing job volumes and pressures and/or changing from zipper fracing to stack fracing. The division may authorize resumption of frac activity after discussions with the operator and if the proposed modifications are reasonable and appropriate. An event greater than **M**2.5 will cause a temporary stop on the well(s) in question. The stop will not be lifted by the division until a complete assessment of the event including cause, location and remediation has been fully vetted by the division and the operator. At this point, several operators have opted to discontinue frac operations altogether and instead move to place the stages completed to that point into production. The temporary stop only affects the well(s) being completed at the time of the event. Completion activity is allowed to shift to other well(s) on the pad not associated with the event. An earthquake of **M**1.0 during hydraulic fracturing operations would trigger a temporary red-light suspension of operations until the cause is investigated.
- California's well stimulation regulations are designed to ensure that well stimulation via hydraulic fracturing does not generate seismicity that causes public concern or damage to structures, and to provide assurance that fractures created during hydraulic fracturing do not encounter and activate a fault. Monitoring of the California Integrated Seismic Network is required during and after hydraulic fracturing. If an earthquake of **M**2.7 or greater occurs within a specified area around the well, further hydraulic fracturing in the area is suspended until the Division, in consultation with the California Geologic Survey, determines that there is no indication of a heightened risk of seismic activity from hydraulic fracturing.
- In Pennsylvania, the Department of Environmental Protection has implemented an approach following several low magnitude earthquakes that occurred in Lawrence County just west of New Castle on April 25, 2016. Epicenter locations for the earthquakes vary slightly based on the degree of data refinement, but in general are confined to Mahoning, North Beaver and Union Townships in Pennsylvania. Due to this relationship, DEP has put in place permit conditions for operators to monitor and respond to seismic activity associated with Utica Shale Formation gas wells within North Beaver, Mahoning and Union Townships in Pennsylvania. Among various requirements,

these permit conditions require the operator to notify the DEP of an “Event” above a 1.0ML and within a 6-mile radius of a wellbore path; and further requires the operator notify the DEP of an “Event” equal to or above a 2.0ML and within a 3-mile radius of a wellbore path as well as suspend fracturing operations.

- **Energy regulators in Alberta, Canada have established seismicity monitoring requirements for all fracturing operations in the Duvernay zone in one localized area where potentially induced seismicity events were recorded coincident with fracturing. A traffic light system is implemented that provides a “yellow light” condition established for M2.0 events—requiring reporting—and a “red light” condition established for M4.0 events. The Alberta rules requires sufficient seismometers to detect any potentially induced seismicity within 5 km of the wells being fractured. The operator is responsible for fielding an array, analyzing the seismicity data, and reporting any seismicity above M2.0. Energy regulators in British Columbia, Canada have established a traffic light system associate with hydraulic fracturing (and injection or disposal operations) on a well, whereby the well permit holder must immediately report to the British Columbia Oil and Gas Commission any seismic event within a 3 km radius of the drilling pad that is recorded by the well permit holder or reported to the well permit holder by any source available, if the seismic event has a magnitude of M4.0 or greater, or a ground motion is felt on the surface by any individual within the 3 km radius.**

Mitigation Options

One approach to mitigate the risks of felt seismicity is to monitor pressures during hydraulic fracturing. Another approach is to use advanced modeling to evaluate possible seismicity (Wiemer et al. 2015). When induced seismicity is associated with hydraulic fracturing, shutting down the pumping may result in a steady decrease in the number and size of seismic events. This behavior has been observed in microseismicity using downhole geophone arrays and also in the few cases where potentially induced seismicity has been observed at the surface. In an extreme case, immediate flowback would rapidly decrease the downhole pressure and alleviate the potentially induced seismicity source mechanism. Exact potentialities for flowback would depend on both the type of completion and timing of the seismicity relative to staging (e.g., a plug set over a previous stage would not allow for flowback of that previous stage until the plug was drilled out). Depending on local circumstances, well design, and specific geology and reservoir conditions, mitigation options might include: a) pumping of successive stages at reduced volumes; b) skipping a next stage; c) delay of further pumping until seismicity subsides; and d) potentially redesigning the perforation clusters to allow pumping at lower rates and volumes, e) avoiding identified faults of concern during hydraulic fracturing operations.

The Oklahoma Geologic Survey reported on a sequence of small earthquakes in Garvin County (Holland 2011) in one of the early reports on the possibility of hydraulic fracturing inducing earthquakes. The Oklahoma Geologic Survey reported that a sequence of approximately 50 earthquakes, ranging from **M**1.0 to **M**2.8, could be extracted from the monitoring data, and that the majority of earthquakes occurred within about 24 hours of the first earthquake. Based on temporal and spatial correlation, the researchers suggested there was possibility the earthquakes may have been associated with hydraulic fracturing operations in the area.

There also have been a few cases (mostly in Canada) where seismicity appears to have been induced by hydraulic fracturing with felt levels ground shaking. In some recent reports (AER 2015), seismicity has exceeded **M**4.

Some researchers have recently attributed hydraulic fracturing operations as possibly inducing seismic events in the Utica shale, where hydraulic fracturing operations may be performed in closer proximity to the basement than typical Marcellus shale operations (Skoumal 2015). During one hydraulic fracturing operation, a sequence of 77 events on one fault (ranging from **M**1 to **M**3) was detected using cross-correlation with regional EarthScope seismometers. These events grew in size and frequency between 4 and 12 March 2014 and then halted after the Ohio Department of Natural Resources issued a shutdown. The seismicity occurred during six stimulation stages along two horizontal well legs that were located ~0.8 km away (Figure I.6). Nearly 100 stimulation stages in the same or nearby wells at greater distances did not produce detected (**M** > 1) seismicity. The seismicity appears to have outlined a ~600-meter linear feature at the top of the Precambrian basement along an azimuth ~30° from the regional maximum stress. The left-lateral strike-slip focal mechanism for the largest earthquake was consistent with the seismicity distribution and suggests a possible mechanism of hydraulic fracturing for induced slip along a preexisting fault/fracture zone optimally oriented in the regional stress field. The focal mechanism, orientation, and depth of the seismicity were similar to earthquakes previously potentially induced by wastewater disposal in Ohio.

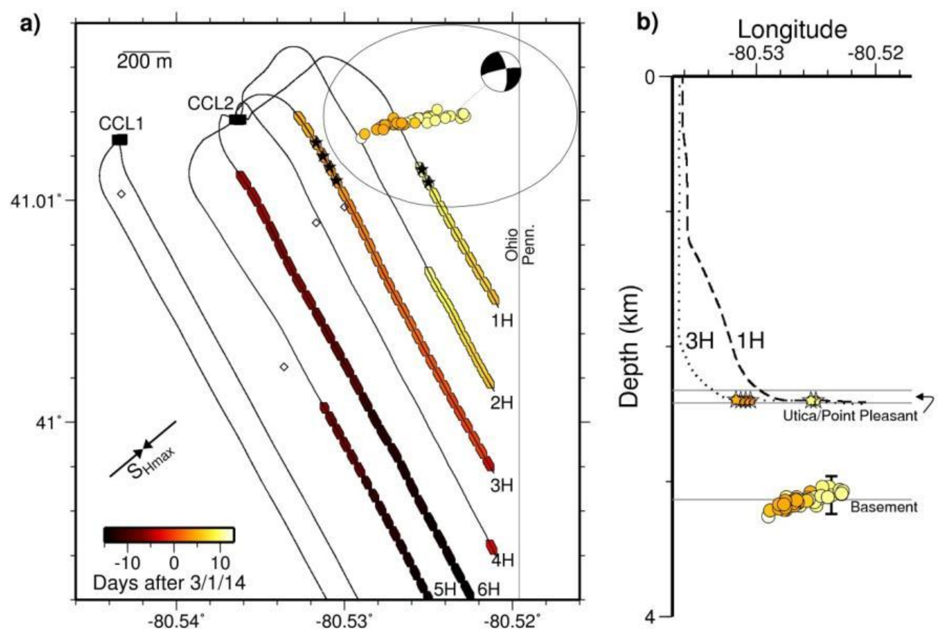


Figure I.6. Potentially induced seismicity during hydraulic fracturing near Poland, Ohio. Image a)

Figure I-6 is a map of well paths (curved lines), with hydraulic fracturing stages shaded according to time. Stars indicate only the closest stages produced seismicity (circles, shaded by time). Focal mechanism is from the **M**3.0 earthquake, with a left-lateral fault plane that matches the linear seismicity, ~30° from the maximum horizontal stress (SHmax). Image b) is an east-west cross-section with no exaggeration showing well paths (dashed and dotted) and stages (stars) that produced seismicity (circles). Source: Skoumal, Brudzinski, and Currie 2015.

The proposed criterion associated with proximity to basement suggests that currently available microseismic data on fracture height growth can be used to help assess the potential for induced seismicity in hydraulic fracturing operations. For example, a database on fracture height growth (Fisher 2012) shows that height growth in the Marcellus shale is primarily upward and is not likely to contact basement features. On the other hand, there are numerous cases of downward growth in the Barnett Shale, but the Barnett Shale is far from the basement and the hydraulic fractures that propagate downward terminate in the thick Ellenberger formation. Fractures in the Eagle Ford Shale have very little height growth in any direction and are also not likely to induce significant seismicity during hydraulic fracturing operations.

The surface pressure, flow rate, sand concentration, additive rates, and other parameters are measured and recorded for every hydraulic fracturing treatment. Thus, there will normally be very detailed information available about the actual operations that might have induced seismicity in a given well. This information can be correlated with seismicity and geologic features that may or may not have been detected from seismic surveys, well control, or the drilling of the horizontal wells.

Geologic controls are often much more resolved in fracturing operations because of the importance of optimizing fracture behavior, landing zone of the horizontal wells, type of completion, number of stages, and various other factors. In addition, operators will typically have well established well-control information on the layering, formation dip, faults with large vertical displacements, and other factors.

This is often true even if no seismic data is available. However, seismic data would generally provide more comprehensive earth-model data.

Surface measureable or felt seismicity is far more likely if the fracture injection interconnects with faults in the basement rocks; thus, only the reservoirs in close proximity to basement rocks are likely to be problematic.

Ground Motion

As with any seismic event, the amount and characteristics of the ground motion generated by the seismicity is the key factor in determining structural damage (Siskind 1983). There is very little ground motion data from the few incidences of seismicity associated with hydraulic fracturing. There is no documented damage and only a few cases of being felt. In the UK Bowland shale incident (de Pater 2011), at least one person apparently felt an **M**2.3 earthquake. In the Poland, Ohio, incident, some people felt the **M**3.0 earthquake and one of the smaller magnitude earthquakes. In the Horn River basin (BCOGC 2012) and the Montney trend incidents in Canada (AER 2015), numerous people onsite felt a number of earthquakes that were greater than **M**4.

The best assumption, at this time, is that the ground motion associated with hydraulic fracturing may probably be very similar to that associated with the same size disposal-related seismic event. Some recent studies (Atkinson 2015) and (Hough 2014) suggest that both disposal well and fracturing may have lower shaking intensities than natural earthquakes

Monitoring

Typical sources of seismic monitoring information related to hydraulic fracturing induced seismicity include:

- Downhole microseismic
- Surface microseismic
- Surface earthquake monitoring

Each of these provides different capabilities for monitoring seismicity associated with hydraulic fracturing: 1) seismic monitoring that is able to record extremely small microseisms that occur during a hydraulic fracture job, which are typically **M**< 0 and **M**2) seismic monitoring for the potential for felt induced seismicity (**M** > 2). Although microseismic monitoring (**M** < 0) is a useful engineering tool for understanding hydraulic fracture geometry, it is performed on a minor portion of hydraulic fracturing procedures.

Downhole microseismic monitoring is used to analyze well stimulations. This technology has been available since about 2000. It is employed to provide diagnostic information for optimizing completions and fracturing treatments, and may be used to better understand potential nearby faulting and hydraulic fracturing. Downhole microseismic data are usually acquired with a 1000- to 2000-foot long array of receivers placed in a nearby offset well at a depth relatively close to the depth of the fracturing treatments.

Microseismic data during hydraulic fracturing are also collected with large microseismic surface arrays consisting of hundreds or thousands of geophone or accelerometer stations. Some surface monitoring is done with low frequency geophones or accelerometers and can provide accurate magnitude information about the larger earthquakes recorded during a hydraulic fracturing. Surface earthquake monitoring capable of recording **M** > 1–2 earthquakes using permanent or transportable arrays have been used in several instances to provide information about possible hydraulic fracturing induced seismicity. Some researchers have leveraged the EarthScope transportable array, in combination with temporary arrays, to evaluate seismicity potentially associated with hydraulic fracturing (Friberg 2014).

In Alberta, Canada, the energy regulator issued an order requiring monitoring of seismicity for all fracturing operations in the Duvernay zone in one localized area where a number of potentially induced seismicity events were recorded coincident with fracturing treatments. The order required sufficient seismometers to detect an **M**2.0 event that occurs within 5 km of the wells being fractured. The operator is responsible for fielding an array and analyzing the seismicity data; any seismicity above **M**2.0 must be reported.

In certain situations, when mathematically precise seismic event locations greater than **M**2.0 may be required during hydraulic fracturing operations, at least four three-component portable seismic monitors should be considered, as three monitors would be required for effective triangulation and with one monitor within close proximity of the wellhead for more precise depth estimates of event location. The seismometers should be selected to achieve targeted performance specifications considering sensitivity, resolution, and accuracy and need to be designed to fit the local conditions.

It may also be appropriate to consider placement of additional seismometer(s) if measurement redundancy is desired. The seismometers should be deployed in an appropriate low-noise environment (relative to local ambient conditions and measurement requirements), to the extent possible distributed equidistant from the center of the well(s) to be hydraulically fractured, and located to adequately sample variations in surface geology. The seismometers should be deployed at least a few days before fracturing operations begin to establish ambient noise levels and to determine if any pre-fracturing seismicity is occurring, and should remain in place at least a few days after completion of fracturing operations.

Data and Information Sharing

The primary difference between data and information sharing considering hydraulic fracturing operations compared to disposal well operations is the level of detail obtained during hydraulic fracturing operations and the potential for much of that fracturing data to be considered confidential because of what it reveals about the well completion methods, procedures, and approaches. Different states, provinces, and countries have different rules about data reporting of well completion and hydraulic fracturing operations. As a result, there is likely to be wide variations in the type of information that can be gleaned from public sources or be routinely available for correlation with any seismicity.

FracFocus (http://www.fracfocus.org/) is the nationwide system for disclosing the additives and chemicals used in the hydraulic fracturing process. Water volumes are also recorded in FracFocus.

Evaluation and Response

In the event of possible induced seismicity associated with hydraulic fracturing operations, the process of shutting down the pumping may result in a steady decrease in seismicity, both event number and size. This behavior has been observed in microseismicity using downhole geophone arrays and also in the few cases where induced seismicity has been observed at the surface. In an extreme case, immediate flowback would rapidly decrease the downhole pressure and alleviate the induced seismicity source mechanism, but exact potentialities for flowback would depend on both the type of completion and timing of the seismicity relative to staging (e.g., a plug that was set over a previous stage would not allow for flowback of that previous stage until the plug was drilled out). Depending on local circumstances, well design, and specific geology and reservoir conditions, various mitigation options could include, but not necessarily be limited to: a) pumping of successive stages at reduced volumes; b) skipping a next stage; c) delay of further pumping until seismicity subsides; and d) potentially redesigning the perforation clusters to allow pumping at lower rates and volumes.

As the observation of many hydraulic fracturing operations has shown, induced seismicity potentially related to hydraulic fracturing is extremely rare. When it does occur, it is often quickly mitigated, and in the United States has had little direct impact. Therefore, the evaluation and response systems such as the "Traffic Light" for hydraulic fracturing should be tailored differently than those for disposal. The fracturing of a stage is a very transient process, and the subdivision of the wellbore into stages isolates subsequent intervals so that extended fault contact is not likely.

There are multiple locations for which the regulatory agency has established special conditions for seismic monitoring during hydraulic fracturing. For example, within certain areas, Ohio has implemented permit conditions requiring seismic monitoring for fracturing operations conducted within three miles of a known fault or within three miles of the epicenter of a recorded seismic event **M**2.0 or greater. These conditions require the operator to deploy a seismic network approved by the division prior to initiating completion activity. The network can be removed some time after the well(s) are in production and upon written permission from the division chief. However, in most cases, seismic monitoring conditions were not applied to the drilling permit because the well is not located within the three mile area of concern. In these cases when seismicity is detected and located by the State network in close proximity to a well pad where frac work has begun, the response thresholds at **M**1.5, **M**2.0 and **M**2.5 are applied and operator of the pad becomes involved in response discussions. NOTE: A case study of hydraulic fracturing induced seismicity is included in Appendix C.

California's well stimulation regulations, per SB 4, were finalized in December 2014. Rules include the addition of Section 1785.1, related to seismicity monitoring, to address concerns that well stimulation via hydraulic fracturing would not generate seismicity that causes public concern or damage to structures, and to provide assurance that fractures created during hydraulic fracturing do not encounter and activate a fault. The California approach requires monitoring of the California Integrated Seismic Network during and after hydraulic fracturing. If an earthquake **M**2.7 or greater occurs within a specified area around the well, then further hydraulic fracturing in the area is suspended until the Division, in consultation with the California Geologic Survey, determines that there is no indication of a heightened risk of seismic activity from hydraulic fracturing.

Similar to the detailed discussions and considerations contained in Chapter 3, when considering evaluation and response systems for hydraulic fracturing applications, thresholds should be established based on the local conditions and geology, and considering specific levels of ground shaking that are of local public concern. Depending on the specific local area, thresholds could consider, or be set consistent with, established acceptable limits from other industrial activities, e.g., mining, blasting, geothermal, etc. (Siskind 1983).

Understanding Surface Felt Events Are Extremely Rare

A limited number of seismic events with sufficient size to be felt at the surface have been associated with hydraulic fracturing operations (Rubinstein, 2015). The largest recorded seismic events to date, that researchers have associated with hydraulic fracturing operations, have been magnitude M4+ events that occurred in the Alberta and British Columbia regions of Canada (Atkinson, 2016).

In a review of localized seismicity occurring between 1985 through 2015 in Western Canada, researchers (Atkinson, 2016) examined over 12,000 wells. Based on time and space correlations of fracturing operations with M ≥3 seismic events, the historic events data suggest that hydraulic fracturing may be associated with seismic events in approximately 0.2% to 0.4% of the wells (e.g., 30 to 50 of 12,289 wells).

In a review of localized seismicity in Ohio (Skoumal, 2015) (Brudzinski, 2017), research focused on approximately 1,500 hydraulically fractured wells. Based on time and space correlations of fracturing operations considering M2 or greater seismic events, seismic data analysis "template-matching" techniques indicated that seismic events were associated with less than 0.4% of the wells (i.e. six of over 1,500 wells).

When considering most horizontal wells in Ohio may have 45 stages or more, the percentage of hydraulic fracturing associated events is very low indeed. Additional review by the ODNR Division of Oil and Gas

Resources Management estimates that there have been over 75,600 fracturing stages associated with over 1,680 wells with twenty-nine **M**2 or greater seismic events which serves to firmly establish the rarity of such events (Simmers, 2017) corresponding to ~0.04% of the frac stages.

The field observations are consistent with extensive studies performed by researchers at Lawrence Berkeley National Laboratory as part of the USEPA study of the potential impacts of hydraulic fracturing on drinking water sources (Rutqvist, 2013) (Rutqvist, 2015).

This research showed that when faults are present, the magnitude of seismic events may be somewhat larger than those typically associated with micro-seismic events originating from hydraulic fracturing because of the larger surface area that is available for slippage. The researchers highlight that their results are *"in agreement with earlier studies and field observations showing that it is very unlikely that activation of a fault by shale-gas hydraulic fracturing at great depth (thousands of meters) could cause felt seismicity"* (Rutqvist, 2015).

While none of the earthquakes incurred any damage, and only a few were felt at the surface, the basement fault's extent was illuminated and found to be nearly 4km in length. Thus, the earthquakes highlighted and mapped a previously unknown fault in the basement rocks.

Key Messages

Application of multi-well pad development techniques, coupled with technological advances such as simultaneous operations and zipper fracturing have been effective in reducing local impacts. The use of multi-well pads has provided a significant environmental benefit by greatly reducing the overall surface area impacted by well operations as opposed to drilling each well from a single pad.

Approaches to assess and manage seismicity risk from hydraulic fracturing operations should take into account the local conditions, operational scope, geological setting, and historical baseline seismicity levels and reflect reasonable and prudent consideration of local engineering and building standards. Reasonable and practical evaluation and response systems are best developed considering the actual level of risk associated with local conditions. Given the broad geologic differences and diversity that exist across the United States, it would not be appropriate to adopt a "one-size-fits-all" regulatory approach for managing the risk. Local conditions must be considered (with the recognition that this could vary between states and within a given state at a more localized level for a given area of interest).

Appendix J: Glossary of Terms

Amplitude	Measure of a parameter associated with a seismic wave or vibration (e.g., displacement, velocity); commonly refers to the maximum value of ground shaking or vibration. Can represent ground velocity or acceleration.
Average annual value	Amount of damage per causative event multiplied by the annual probability of occurrence of such events, summed over all possible earthquakes and all possible consequences of each earthquake.
Basement crystalline (basement)	The igneous and metamorphic rocks that underlie the main sedimentary rock sequence of a region and form the crust of the continents.
Class II Disposal Well	See Underground Injection Well.
Deterministic seismic hazard analysis	Estimation of the hazard from a selected scenario earthquake or seismic event.
Earthquake	Rapid slip or displacement on a geologic fault resulting in the release of seismic energy. Some earthquakes can be "induced" as a result of a man-made activity, e.g., by fluid injection.
Enhanced geothermal systems	Activities undertaken to increase the permeability in a targeted subsurface volume, via injection and withdrawal of fluids into and from the rock formations, intended to result in an increased ability to extract energy from a subsurface heat source.
Epicenter	The point on the earth's surface vertically above the hypocenter (or focus) point in the crust where a seismic rupture begins. Epicenter coordinates in most earthquake catalogs are given in the WGS84 reference frame. The position uncertainty of the hypocenter location varies from about 100 m horizontally and 300 m vertically for the best located events, those in the middle of densely spaced seismograph networks, to tens of kilometers for events in large parts of the United States. (EPA)
Fault	A fracture or fracture zone along which there has been displacement of the sides relative to one another parallel to the fracture plane or planes.
Fault mechanism	Description of the rupture process of an earthquake, i.e., style of faulting, and the rupture fault plane on which it occurs.

Fault of concern	A fault optimally oriented for movement and located in a critically stressed region. The fault is also of sufficient size, and possesses sufficient accumulated stress/strain, such that fault slip and movement has the potential to cause a significant earthquake. Fault may refer to a single fault or a zone of multiple faults and fractures.
Focal mechanism	Graphic representation of the faulting mechanism of an earthquake, commonly described as slip on a plane specified by the strike, dip and slip angle (rake).
Ground-motion prediction model	Mathematical formula that relates the magnitude of the earthquake, distance from the fault, and local site conditions to the amplitude of a specified ground-motion parameter, e.g., peak ground acceleration (PGA).
Hydraulic fracturing	The process of fracturing rock with hydraulic pressure in order to increase permeability. High volume hydraulic fracturing refers to the larger amounts of fluids used to hydraulically fracture tight formations (usually shale) that are developed by horizontal drilling.
Hypocenter	The point within the earth of rupture initiation of an earthquake.
Human response curves	Graphic representation of a human's sensitivity and response to vibration as a function of frequency.
Induced seismic event	Seismic event, e.g., an earthquake caused by human activities such as fluid injection, reservoir impoundment, mining, and other activities. The term "induced" has been used to include "triggered seismic events" and so sometimes the terms are used interchangeably. See "triggered seismic events" below and in this report.
Long string	String of casing that is typically used as a production or injection casing.
Moment magnitude	Preferred method to calculate the magnitude of an earthquake or seismic event based on its seismic moment. Seismologists regard moment magnitude as a more accurate estimate of the size of an earthquake than earlier scales such as Richter local magnitude. Moment magnitude and Richter local magnitude are roughly equivalent for magnitudes less than 7.0.
Normal force	The force that is oriented normal (perpendicular) to a given fault, fracture plane, or slip surface.

Normal stress	The component of stress oriented normal (perpendicular) to a given fault, fracture plane, or slip surface.
Paleoseismicity	Earthquakes recorded geologically, most of them unknown from human descriptions or seismograms. Geologic records of past earthquakes can include faulted layers of sediment and rock, injections of liquefied sand, landslides, abruptly raised or lowered shorelines, and tsunami deposits.
Peak ground acceleration	Maximum amplitude of the absolute value of the acceleration of the ground.
Peak ground displacement	Maximum amplitude of the absolute value of the displacement of the ground.
Peak ground velocity	Maximum amplitude of the absolute value of the velocity of the ground.
Peak particle velocity	Maximum amplitude of the absolute value of the velocity of an object or surface.
Probabilistic seismic hazard analysis	Quantitative evaluation of the likelihood (probability) of the ground motions that are expected to occur or be exceeded given a specified annual frequency or return period.
Precambrian basement	The igneous and metamorphic rocks that exist below the oldest sedimentary rock cover.
Probability of exceedance	Likelihood that the value of a specified parameter is equaled or exceeded.
Quad	Unit of energy equal to 10^{15} BTU, l.055 x 10^{18} Joule, and 293.07 Terawatt-hours.
Rock permeability	Ability of a rock to transmit fluids (oil, water, gas, etc.).
Seismic hazard	The potential for the effects of an earthquake to result in loss or damage, such as ground shaking, liquefaction, and landslides.
Seismic hazard curve	A graphical representation of a probabilistic seismic hazard analysis. The probabilistic hazard is expressed as the relationship between some ground-motion parameter, e.g., PGA and annual exceedance probability (frequency or return period).
Seismic moment	A quantitative measure of the size of an earthquake defined as the product of the area of the fault rupture, the average fault slip, and

	the shear modulus of the rock surrounding the fault.
Seismic risk	Probability of loss or damage due to exposure to a seismic hazard.
Shear force	The force that acts tangential to a given fault, fracture plane. or slip surface.
Shear stress	The component of stress that acts tangential to a given fault, fracture plane, or slip surface.
Shear-wave velocity profile	Relationship between the shear-wave velocity of the earth and depth. Shear-wave velocities of the near-surface (top hundreds of meters) of the ground control the amplification of incoming seismic waves, resulting in frequency-dependent increases or decreases in the amplitudes of ground shaking.
Spectral frequency	Frequencies that constitute the ground-motion record. They are the frequencies for which it is necessary to know the energy they carry to be able to reconstitute the full record in the time domain.
Strain	The amount of any change in dimension or shape of a body when subjected to deformation under an applied stress.
Strain energy	The energy stored in a body due to deformation.
Stress	The force per unit area acting on a surface within a body.
Surface casing	The casing string used to protect groundwater resources. This casing string is typically placed below protected aquifers, which vary from state to state, but may include potable water, usable water, USDWs, or other defined zones.
Tectonic	Pertaining to either the force or the resulting structural features from those forces acting within the earth; refers to crustal rock-deformation processes that affect relatively large areas.
Tectonic stresses	Stresses in the earth due to geologic processes such as movement of the tectonic plates.
Temperature gradient	Physical quantity that describes (in this context) the change in temperature with depth in the earth. The temperature gradient is a dimensional quantity expressed in units of degrees (on a particular temperature scale) per unit length (e.g., degree centigrade/km).
Thermal contraction	Contracting response of hot materials when interacting with cool

	fluids.
Tomography	Imaging by sections or sectioning, through the use of any kind of penetrating wave. A device used in tomography is called a tomograph, while the image produced is a tomogram.
Triggered seismic event	Seismic event that is the result of failure along a preexisting zone of weakness, e.g., a fault that is already critically stressed and is pushed to failure by a stress perturbation from natural or manmade activities.
Underground Injection Well	An injection well is a device that places fluid deep underground into porous rock formations, such as sandstone or limestone, or into or below the shallow soil layer. These fluids may be water, wastewater, brine (salt water), or water mixed with chemicals. Underground Injection Control (UIC) well classes: Class I – Inject hazardous wastes, industrial nonhazardous liquids, or municipal wastewater beneath the lowermost USDW. Class II – Inject brines and other fluids associated with oil and gas production, and hydrocarbons for storage. Most of the injected fluid is for disposal of salt water (brine), which is brought to the surface in the process of producing (extracting) oil and gas. In addition, brine and other fluids are injected to enhance (improve) recovery of oil and gas. Class VI – Inject Carbon Dioxide (CO_2) for long term storage, also known as Geologic Sequestration of CO_2. For definitions of other UIC well classes, please refer to the USEPA UIC web site: http://water.epa.gov/type/groundwater/uic/wells.cfm
Underground Source of Drinking Water (USDW)	An underground source of drinking water is an aquifer or a part of an aquifer[1] that is currently used as a drinking water source for human consumption or may be needed as a drinking water source in the future. Specifically, a USDW is an aquifer or part of an aquifer that is not an exempted aquifer[1] and: • Supplies any public water system[2], or • Contains a sufficient quantity of ground water to supply a public water system, and either currently supplies drinking water for human consumption or contains fewer than

	10,000 mg/l total dissolved solids (TDS). [1] For definition of "aquifer" or "exempt aquifer," refer to the USEPA UIC Glossary web site: http://water.epa.gov/type/groundwater/uic/glossary.cfm [2] For definition of "public water system," refer to the USEPA Drinking Water web site: http://water.epa.gov/infrastructure/drinkingwater/pws/index.cfm
Vibration	Dynamic motion of an object, characterized by direction and amplitude.
Vibration exposure	Person's exposure to vibrations, in this case ground-motion vibration.
Vulnerability function	Function that characterizes potential damages in terms of a relation that gives the level of consequence (damage, nuisance, economic losses) as a function of the level of the ground motion at a particular location.

Appendix K: Glossary of Acronyms

AGS	**Arkansas Geological Survey**
ANSS	Advanced National Seismic System
CGS	Colorado Geological Survey
COGCC	Colorado Oil and Gas Conservation Commission
DOE	U.S. Department of Energy
EGS	Enhanced Geothermal Systems
FEMA	Federal Emergency Management Agency
GWPC	Ground Water Protection Council
IOGCC	Interstate Oil and Gas Compact Commission
IRIS	Incorporated Research Institutions for Seismology
ISO	International Organization for Standardization
ISWG	Induced Seismicity Work Group
M or M_w	Moment magnitude
MMI	Modified Mercalli Index
NEIC	National Earthquake Information Center
NRC	National Research Council
NTW	National Technical Workgroup
ODNR	Ohio Department of Natural Resources
P	Primary
PEER	Pacific Engineering Earthquake Research
PGA	Peak Ground Acceleration
PGD	Peak Ground Displacement
PGV	Peak Ground Velocity
PPV	Peak Particle Velocity

S	Secondary
SCITS	Stanford Consortium for Induced and Triggered Seismicity
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey

Appendix L: List of References

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