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

Overview of the Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation

Environmentally Friendly Drilling Systems (EFD) Program

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October 12, 2015

Table of Contents

Introduction

StatesFirst Induced Seismicity by Injection Work Group (ISWG) chartered in 2014 introduced a primer on September 28, 2015, titled "Potential Injection-Induced Seismicity Associated with Oil & Gas Development: A Primer on Technical and Regulatory Considerations Informing Risk Management and Mitigation". The 148 page primer provides a valuable overview of the current state of research and technical understanding of induced seismicity related to Class II disposal wells and provides guidance in mitigating seismic risks associated with waste water disposal wells.

StatesFirst is a collaborative partnership between the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas compact Commission (IOGCC). The primer contains the input of subject matter specialists from academia, industry, federal agencies, and environmental organizations. To download the Primer or to view an in-depth Webinar featuring commentary from key work group participants, visit www.statesfirstinitiative.org.

The four main chapters of the primer focus on the following topics:

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

The nine appendices discuss the relevant earthquake science, Class II injection wells, induced seismicity case studies, design and installation of seismic monitoring networks, NRC report on induced seismicity potential in energy technologies, methods for estimating reservoir pressures changes associated with injection, tools for risk management and mitigation, and data collection and interpretation. Although far less likely to occur, the potential for felt induced seismicity related to hydraulic fracturing is also briefly discussed in the appendices.

The primer uses the term "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.

The primer is solely informational. Although further data and study are needed and significant uncertainties exist, regulators and industry can use the tools, knowledge, and expertise in the primer and take steps to inform and protect the public. This report is aimed at providing an overview of the information discussed in the primer with the hope that it will help both public and the decision making process.

Chapter 1: Understanding Induced Seismicity

The majority of disposal wells in the United States do not pose a hazard for induced seismicity. Even though, 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 (Walsh and Zoback, 2015, McGarr, 2015, Ellsworth, 2013, and Frohlich, 2012). Therefore, to evaluate the need for mitigation and management of the risk of induced seismic events, it is important to understand the basic earthquake science. This chapter focuses on concepts and observations that are useful in understanding the primer. Appendix A includes more detailed information on understanding earthquakes.

Key Concepts of Earthquake Science

1. Earthquake basics:
    - Magnitude quantifies the size of the seismic event, while ground motion is an effect of the event;
    - Ground-motion effects depend on magnitude, distance, depth of event, properties of the intervening earth, and local geological conditions;
    - Magnitude scales are logarithmic – earthquake amplitude increases exponentially with scale; and
    - Epicenter is the location of the earthquake at the earth's surface, while hypocenter is the location where the rupture begins.

2. No seismic stations often equals no detected seismicity:
    - Seismic stations across U.S. are believed to be adequate to detect all earthquakes of **M** 3.0 and above, although locations and depths may be highly uncertain.

3. Most cases of induced seismicity have occurred on previously unknown faults:
    - Usually smaller magnitude events; and
    - Many faults do not reach the surface and can be below resolution of imaging tools.

Key observations

- Majority of earthquakes are tectonic but seismicity can be triggered by human activities.
- Induced seismicity is not limited to underground injection but also to oil and gas extraction, impoundment of reservoirs behind dams, geothermal projects, mining

extraction, construction, underground nuclear tests, and carbon capture and storage projects.

- Most cases of felt injection-induced activity have been attributed to
  - direct injection into basement rocks,
  - injection into overlying formations with permeable avenues of communication with basement rocks.
- The majority of faults are stable and will not produce a significant earthquake.
- Faults of concern are characterized by a fault optimally oriented for movement, at or near critical stress, sufficient size, and accumulated stress/strain such that fault slip has the potential to cause a significant earthquake.

Figure 1.1 shows recorded events of **M** ≥ 3 in the central United States from 1973 through 2015 (USGS, US Earthquakes 2015). Throughout this document **M** is used to denote the size of an earthquake. The increase in seismic activity shares a temporal and spatial correlation with increased oil and natural 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.

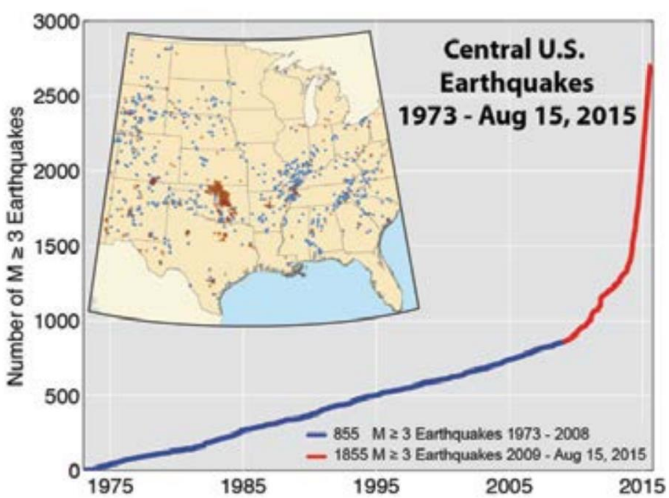

FIGURE 1.1. *Earthquakes* **M** *3.0 and greater in the central United States, 1973–2015, available at http://earthquake.usgs.gov/ earthquakes/states/top_states _maps.php.*

Source: USGS 2015.

Magnitude and Depth of Induced Earthquakes

Induced earthquakes are usually smaller in size with less energy than tectonic earthquakes (Figure 1.2). Largest potentially injection-induced earthquake almost always occur in Precambrian rock. Induced seismicity seems to be usually confined to shallow part of earth's crust in the vicinity of injection. 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, 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.

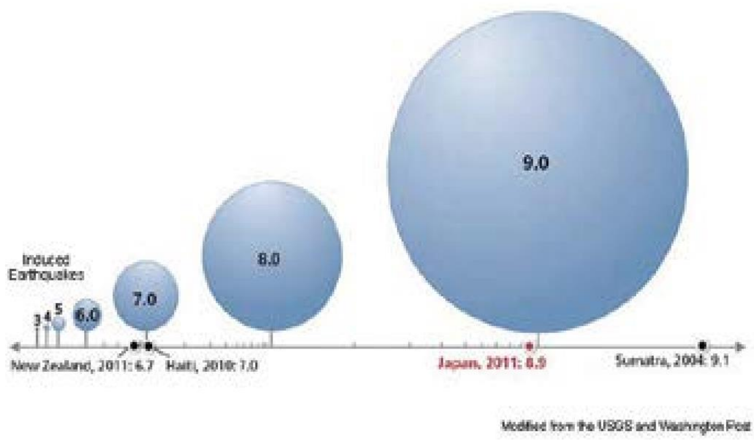

FIGURE 1.2. *Schematic illustration of the energy release associated with earthquakes of various magnitudes. Image courtesy of ISWG.*

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 rock.

Hazards and Risks of Induced Seismicity

As induced seismic events are smaller than **M** 5.0 with short durations, the primary hazard is ground shaking. Ground shaking can result in structural and nonstructural damage to buildings and other structures and can result in human anxiety.

Ground-motion models can be used to predict the ground shaking at a given site to determine if it creates anxiety, hazards, or neither. Currently, there is no U.S. empirical ground-motion model for injection-induced earthquakes, with the exception of models for The Geysers geothermal field in California, because data from injection-induced earthquakes are currently quite limited.

USGS Hazard Maps

Recently, the USGS released a preliminary report describing how to evaluate the sensitivity of the seismic hazards for considering potentially induced seismicity in future USGS hazard map development (Petersen et al. 2015). The report is available at [http://dx.doi.org/10.3133/ofr20151070.](http://dx.doi.org/10.3133/ofr20151070) As illustrated in Figure 1.3, the USGS preliminary report suggests that inclusion of potential induced seismicity has increased the seismic hazard in Oklahoma and in other regional areas in which it has occurred or is suspected to have occurred.

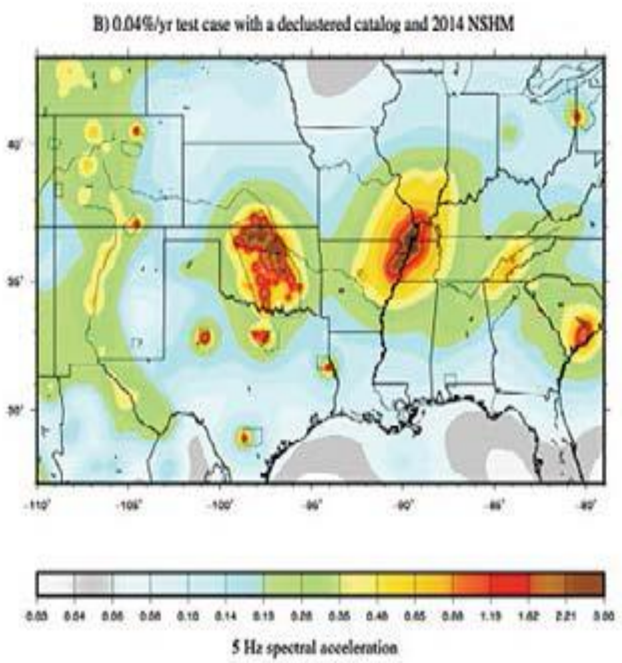

FIGURE 1.3. *An example model for seismic hazard analysis that includes possible/potential induced seismic events as interpreted by the USGS. Source: Petersen et al. 2015.*

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). The report indicates 60 energy-development sites where seismic events were caused by or likely related to energy-development activities in the United States. The sites are in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas. The full NRC report is available at http://www.nap.edu/catalog/13355/induced-seismicity-potential-in-energy-technologies.

Future Research

Some key questions and research needs:

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

Chapter 2: Assessing Potentially Injection-Induced Seismicity

Currently, it is very difficult to 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. This chapter focuses on evaluating general patterns of seismicity, detection and location, seismic monitoring by states, evaluating causation of specific seismic events, methods used in causation studies, and further analysis to evaluate causation.

Assessing induced seismicity

Necessary components for felt injection-induced seismicity:

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

State considerations for evaluating potential injection-induced seismicity:

- Evaluate general patterns of seismicity to reveal areas of concern,
- Perform an investigation to evaluate possible causal factors of specific events, and
- Recognizing a detailed seismological and subsurface characterization and modeling effort may be needed.

Characterizing the anomalous seismic activity:

- Spike in number and sizes of earthquakes,
- Occurrence of earthquakes in areas that historically have not experienced seismic activity.

Seismic monitoring by States

The USGS and other organizations operate a widely spaced network of seismometers in the United States. Therefore, earthquake locations initially reported by the national USGS network can have substantial uncertainty. The uncertainty in epicenter location is ~5−10 km and in depth is ~10 km across most parts of the United States. This location uncertainty is due to the small number of seismic stations used and the wide separation of stations. If a state decides to augment seismic monitoring with improved accuracy, it may deploy either a permanent or temporary network.

State considerations:

- Public safety
- Managing and mitigating risk
- Public and stakeholder response and education
- Permanent networks or temporary networks

Evaluating Causation of Specific Seismic Events

Evaluating causation can be a complicated and time-intensive process. This process involves significant challenges and uncertainty such as:

- Locating the seismic event(s)
- Locating critically stressed faults that can be reactivated
- Identifying temporal-spatial behavior and characterizing changes in subsurface stress where fault slip first occurs and of any associated aftershocks
- Characterizing the subsurface stress near and on the fault
- Developing a physical geomechanics/reservoir engineering model: model that would predict whether induced pressure change could initiate earthquake.

Methods Used in Causation Studies

In 1993 Davis and Frohlich proposed an initial screening method using seven questions that address not only spatial and temporal correlations, but also injection-related subsurface pore pressure changes in proximity to the fault.

Initial screening questions:

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?

Further Analysis to Evaluate Causation

If all of the above 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 analysis could be conducted to better assess factors that may be contributing to causation.

Additional causation studies might include:

- Deploying temporary seismic monitoring networks: Enables accurately locating of seismic events (epicenter and focal depth).
- Reviewing available seismological archives and records: An understanding of the historical seismicity record.
- Identifying the range of potential anthropogenic sources that may be leading to subsurface stress perturbations: Along with injection wells and production wells, other sources may include mining operations, geothermal operations, reservoir impoundment/dam construction, lake-level fluctuations, aquifer fluctuations, and other activities.
- Reviewing all available pressure data for injection wells in proximity to the seismic events: Data would include injection well pressure data with the initial and current reservoir pressure conditions as well as the historical injection well operational data (e.g., daily, weekly, or monthly injection rates, pressures).
- 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: This data would include geologic, seismologic, and depositional history; available geologic and reservoir property data; information related to subsurface mapping, including 2D and 3D seismic imaging data and fault interpretations; stress field orientation, and stress magnitude data derived from measurements made in wells and borehole-imaging well logs.

Chapter 3: 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. This chapter discusses risk management and mitigation strategies for potential induced seismicity from Class II disposal wells.

Risks and Hazards

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.

Hazard: any source of potential damage, harm or adverse impact on something or someone.

Risk: the chance or probability that a person or property will be harmed if exposed to a hazard.

Using these definitions, risk assessment regarding injection-induced seismicity addresses two basic 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

Science-Based Risk Management

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:

Characterizing the site**:** geological setting and formation characteristics, including tectonic, faulting, and soil conditions, historical baseline seismicity levels;

Built Environment: 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: existing or proposed injection fluid volumes;

Estimating maximum magnitudes: potential events;

Estimations of ground motion: vary by the magnitude of the earthquake, the distance from the earthquake to a site, the depth of the hypocenter, and geological site conditions.

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.

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. 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. Appendix G includes screening processes that is being used by some states.

Screening questions to determine the threshold:

- 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 of 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 providing a potential link to seismicity, Operational changes in injection pressure, injection volume, or reservoir pressure; Nearby infrastructure at risk given a specific level of ground motion)

Siting and Permitting of New Wells

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

- Obtaining local stakeholder input concerning risks
- 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.

Permitting conditions for new or existing Class II disposal wells:

- 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.

Responding to an Event

Data that can be used to inform a seismic evaluation and reservoir/geomechanics modeling include:

- Seismicity data: historic and current event recordings from USGS, State Geological Surveys, and private array data; epicenter locations and magnitudes to conduct spatial evaluations; and ground motion data.
- Injection well data:
    - 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
    - FMI log
    - Dipole sonic log
    - Pressure transient tests
    - Step-rate test
    - Falloff tests
- Geologic data: includes general stratigraphy of typical formations in the area showing their stratigraphy to basement maximum principal stress, hydrogeological data (for hydrogeological flow and pore pressure modeling, location of faults (best defined by 3D seismic, if available)
- Local factors: population, infrastructure, public and private structures, reservoirs and dams

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: Consideration for External Communication and Engagement

This chapter is focused on communication planning process, communication plan elements, and guidelines responding to an event. Because of the increasing occurrence and detection of seismic events potentially linked to underground injection, it is important to be prepared to provide the public with information and respond to inquiries. Strategy development may be based on planning before the event, implementing a response, and evaluating after the response.

Communication Planning Process:

- Preliminary scan to gather relevant information
- Involve stakeholders with multiple areas of expertise
- Tie communication strategies to risk management thresholds
- Conduct mock event exercises and training
- Develop, revisit, and revise the communication plans on a regular cycle

Communication Planning Elements

In communication planning, consider a crisis communication model with clear roles, responsibilities, and procedures.

Planning elements:

- Scenario analysis
- External and Internal audience analysis
- Definition of key messages and communication strategies
- Definition of communication team roles and responsibilities
- Definition of materials and resources
- Drafting responses to frequently asked questions

Key considerations:

- Clear and direct communication with public is an important responsibility of states
- Many states choose proactive approach
- Earthquakes arrive without warning and are unpredictable
- Most of US has no public training on what to expect from earthquakes
- Public anxiety levels can be high

- Determining cause is very difficult in most instances
- Studies take time

Guidelines for Responding to an Event

- Be professional and objective
- Document
- Avoid speculation
- Review all information before release
- Monitor communications

Incorporating Lessons Learned

It is important in evaluating the response and communication plans after an event and appropriately modify and improve the plans based on what has been learned.

Considerations for improvement:

- 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?

Appendix A: Relevant Earthquake Science

Faults and Earthquake Generation

A fault is a fracture or zone of fractures between two blocks of rock that allows the blocks to move relative to each other. This movement may occur rapidly, in the form of an earthquake, or slowly, in the form of fault creep. The fault plane can be horizontal or vertical or an angle in between. As shown in Figure A.1, depending on the angle of the fault plane with respect to the surface (dip) and the direction of slip along the fault, fault can be classified into three categories.

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).

Thrust fault: A dip-slip fault in which the hanging wall moves up and over the foot wall.

Strike-slip fault: A fault in which the two blocks slide horizontally past each other. The San Andreas Fault is an example of a right-lateral fault.

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

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 section of a fault may increase the stress in other sections, effectively transferring strain energy to those sections. Such stress transfers influence subsequent earthquakes or aftershocks.

Earthquake Magnitude

Several measurement techniques and scales are commonly used to characterize the magnitude of earthquakes as shown in Table A.1.

Scale	Abbreviation	Description
Richter local	ML	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 MW	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	MS	Measured from recordings of 20 sec period surface waves.
Body wave	Mb	A common scale used in the central and eastern U.S. based on the recorded amplitude of body waves.
Duration or coda	MD or MC	A scale used for micro earthquakes events ($M < 3$) based on the duration of the event.
Regional magnitude	MLg	A regional scale based on the amplitude of Lg surface waves.

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

Estimating Earthquake Location

By analyzing the seismic waves generated by an earthquake seismologists can estimate its location. Seismic waves can be classified into three basic types: compressional or primary (P) waves, shear or secondary (S) waves, and surface waves.

P-waves and S-waves: also 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. S-waves carry much more energy than P-waves and, consequently, are of greater concern for hazard.

Surface waves: 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.

Seismologists can estimate the distance of the earthquake from a seismic station by using the time difference between when the P-waves and S-waves arrive.

Faults of Concern

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.1. The NRC report, *Induced Seismicity Potential in Energy Technologies* (2012), contains a detailed discussion of the subsurface conditions that may contribute to fault reactivation. Faults of concern are characterized by a fault optimally oriented for movement, at or near critical stress, sufficient size and accumulated stress/strain such that fault slip has the potential to cause a significant earthquake.

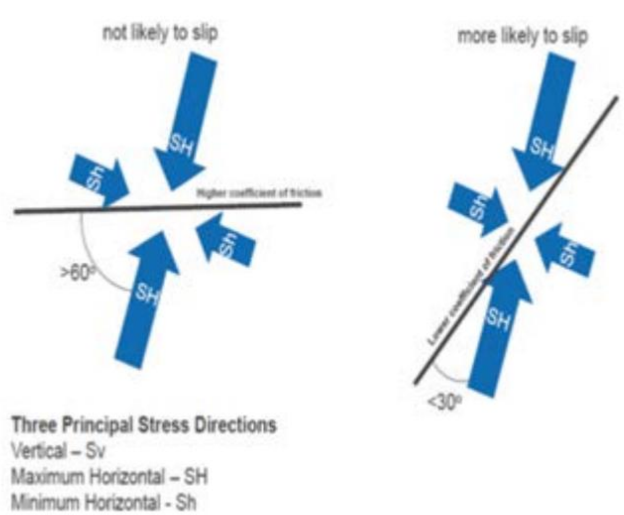

FIGURE A.2. *Schematic showing conditions in which a fault may be more or less likely to slip. Source: ISWG.*

Appendix B: Class II Injection Wells

The U.S. Environmental Protection Agency (USEPA) Underground Injection Control (UIC) program considers six well types based on similarity in the fluids injected, activities, construction, injection depth, design, and operating techniques. Table B.1 summarizes the typical uses for each class of well.

Underground Injection Control Well Classification Chart		
Well Class	Purpose	Active Wells*
I	Injection of hazardous, nonhazardous, and municipal wastes below the lowermost USDW	678
II	Injection of fluids associated with the production of oil and natural gas resources for the purpose of disposal or enhanced oil and gas recovery	168,000
III	Injection of fluids for the extraction of minerals	22,000
IV	Injection of hazardous or radioactive wastes into or above USDW	33 sites
V	Injection into wells not included in the other well classes but generally used to inject nonhazardous waste	469,000**
VI	Injection of supercritical carbon dioxide for storage	0***
* All numbers estimated from state agency surveys and USEPA publications ** USEPA estimate of Class V wells (Note: 2005 state survey indicated between 650,000 and 1.5 Mil) *** Existing commercial wells with permits issued under the Class VI program		

TABLE B.1. *Summary of UIC wells and estimated inventory. Source: GWPC 2013.*

Types of Class II Wells

Disposal wells: Inject brines and other fluids associated with the production of oil and natural gas or natural gas storage operations. 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 % of Class II wells. Today, there are approximately 30,000 active Class II disposal wells used to dispose of oil and gas related waste (USEPA 2015).

Enhanced oil recovery (EOR) wells: Inject brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover residual oil and, in some limited applications, natural gas. EOR wells represent as much as 80 percent of the approximately 168,000 Class II wells.

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.

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.

APPENDIX C: Induced Seismicity Case Studies

Appendix C of the primer includes examples of how states have responded to instances of suspected induced seismicity through the use of local seismic networks. Each case study presents a unique situation, response, and observations that can be helpful for regulators.

Case Studies:

- 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

Appendix D: Design and Installation of Seismic Monitoring Networks

If a state decides to augment seismic monitoring with improved accuracy, it may deploy either a permanent or temporary network. Numerous consultants and vendors can assist states with the specialized work of designing and installing seismic monitoring networks.

Equipment and Operation Considerations

Sensors**:** Deployed in an array of seismic monitoring stations within the network. There are three basic types: 1) broadband sensors, 2) short-period or high frequency geophones, and 3) strong motion sensors or accelerometers.

Data loggers: On-site units linked to the seismometer or other sensor, which record and process data for transmission. For data quality, at least 24 bit resolution and a capability of recording waveform data at a sampling rate of 100–1000 Hz are recommended.

Data communications: 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: Provided by available AC sources or distributed options such as solar or wind.

Enclosures: Protect surface equipment against weather elements and vandalism. One popular solution is the use of steel job-site tool chests with double locks.

Data storage and processing**:** Seismic data recorded by a network may be transmitted electronically to a central site in real-time for event detection, processing, and cataloging. 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. 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.

Network and Design Considerations

Number of sensors**:** Placing multiple sensors in place allows for triangulation, which results in a location. 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.

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. Broadband, high-frequency, and strong motion sensors are the types of sensors that can be used depending on the need.

APPENDIX E: NRC Report on Induced Seismicity Potential in Energy Technologies

Appendix E of the primer summarizes the major findings of the National Research Council (NRC) report that was based on a review of literature available through 2011. The full NRC report of induced seismicity associated with energy technologies is available at http://www.nap.edu/catalog/13355/induced-seismicity-potential-in-energy-technologies.

Appendix F: Methods of Estimation Reservoir Pressure Changes Associated with Injection

Reservoir pressure modeling and geomechanics analysis can be very useful for evaluating relative order of magnitude impacts of injection. This appendix is intended to provide a general overview of available methods and approaches for performing reservoir pressure calculations and a brief overview of general considerations associated with the various approaches.

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

- 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.
- Identifying and appropriately characterizing the available input data and identifying “missing” or “unknown” input data.
- Evaluating the geologic and reservoir complexity, fault structure, stratigraphic layers, etc.
- Establishing the appropriate initial conditions for the simulations or calculations.
- Establishing the appropriate 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.

Types of Models and Calculation Methods

Analytical Calculation Methods

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. 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.

Reservoir Computational Models

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).

Coupled Reservoir–Geomechanics Models

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.

Key Considerations for Selecting a Model

- 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
- 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

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.

- 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
- Description and characterization of the possible impacts that modeling assumptions have, or may have, on the presented results and conclusions.

Appendix G: Tools for Risk Management and Mitigation

Briefly stated below are three tools by diverse stakeholders to provide risk management and mitigations guidelines.

Stanford Center for Induced and Triggered Seismicity (SCITS)

Walters, Zoback, Baker, and Beroza (SCITS) have 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). This report is publicly available at: https://scits.stanford.edu/researchguidelines. A conceptual hazard and risk assessment workflow is presented as part of this work is shown in Figure G.1 below. SCITS has also developed an example of a Traffic Light System (Figure G.2 and Figure G.3). 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.

American Exploration and Production Council (AXPC)

AXPC has 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 and the tool boxes for the evaluation of seismic hazard are presented in the Appendix G of the primer.

U.S Environmental Protection Agency

A recent USEPA report, "Minimizing and Managing Potential Impacts of Injection-Induced Seismicity from Class II Disposal Wells: Practical Approaches," also 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.

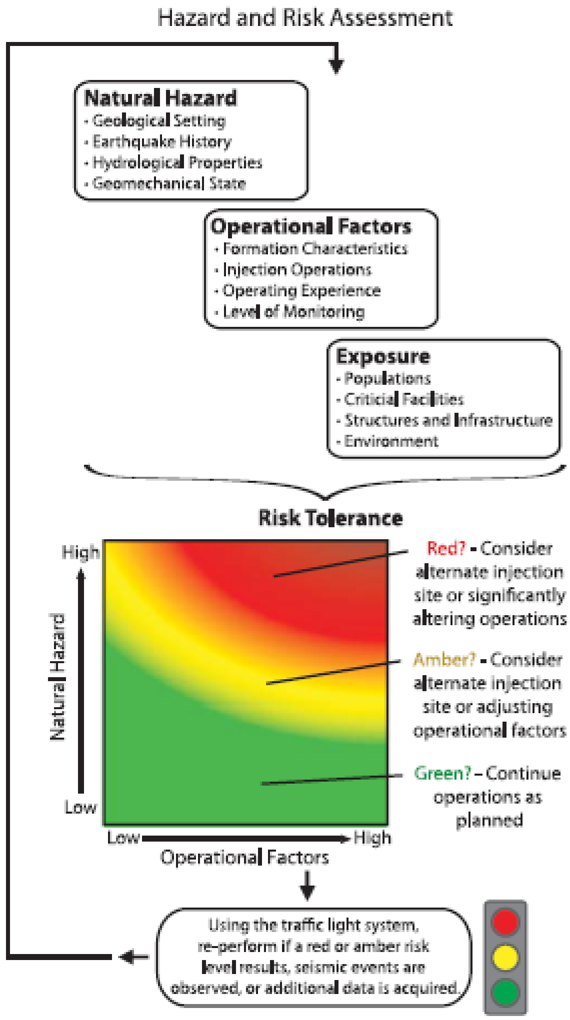

FIGURE G.1. Hazard and risk-assessment in concept, the hazard, operational factors, exposure, and tolerance for risk are evaluated prior to injection operations and reflected by shifting the green to red color spectrum in the risk tolerance matrix. After injection begins, the occurrence of earthquakes in the region and additional site-characterization data could require additional iterations of the workflow. Source: Walters, Zoback, Baker, and Beroza (SCITS).

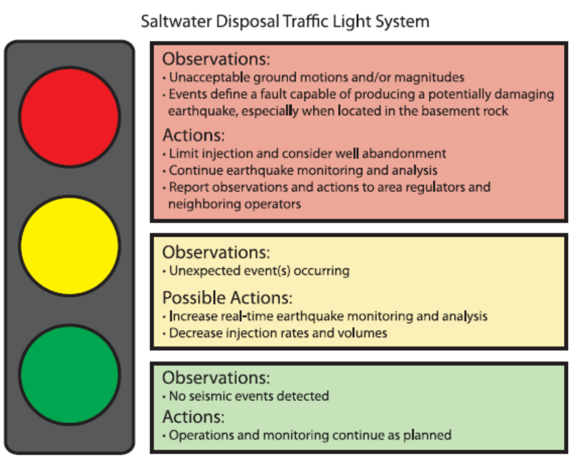

FIGURE G.2. Traffic-light system applicable to saltwater disposal. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic-light systems. Source: Walters, Zoback, Baker, and Beroza (SCITS).

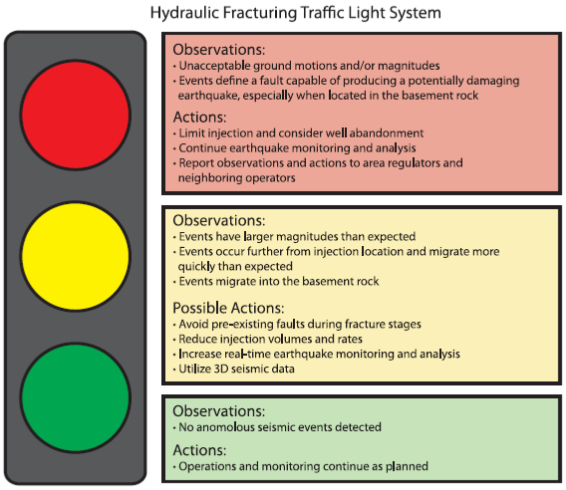

FIGURE G.3. Traffic-light system applicable to hydraulic fracturing. The green, amber, and red panels represent the levels of heightened awareness frequently represented in traffic-light systems. Source: Walters, Zoback, Baker, and Beroza (SCITS).

Appendix H: Data Collection and Interpretation

Various categories of data are needed to determine whether the conditions are present for injection-induced seismicity. The three main types of data are subsurface stresses, injection well data, and fault locations.

Generally Available Class II Well Data

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.*

Geologic and Reservoir Data

Geologic and reservoir data consist of data from seismic surveys, well logs, and core data. This section provides information on different types of well logs and core data types. Limitations of each data type is also tabulated in this section. Data collection methods for basement fault maps and subsurface stress maps are also discussed. Other tests conducted in wells to determine reservoir properties are also included.

Data and Information Sharing Considerations

Injection well operating data are not typically considered confidential business information. 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. Therefore, 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.

Appendix I: Considerations for Hydraulic Fracturing

Felt-level seismicity incidents associated with hydraulic fracturing occur far less frequently than those associated with Class II disposal wells. When it does occur, it typically has a low magnitude, often quickly mitigated, and in the Unites States has had very little impact. Process of hydraulic fracturing is significantly different than disposal well operations, resulting in lower risk.

Mitigation Options

In the event of possible induced seismicity associated with hydraulic fracturing operations, depending on local circumstances, well design, and specific geology and reservoir conditions, various mitigation options could include, but not necessarily limited to:

- Pumping of successive stages at reduced volumes,
- Skipping a next stage,
- Delay of further pumping until seismicity subsides, and
- Potentially redesigning the perforation clusters to allow pumping at lower rates and volumes.

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.

Examples of Regulatory Risk Management Approaches

- Alberta and British Columbia, Canada**:** Energy regulators are required to monitor in particular local areas that are exhibiting potentially fracturing-induced seismicity. A yellow light is triggered at **M** 2.0 events—requiring reporting—and a red light at **M** 4.0. The order 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 **M** 2.0.
- Ohio**:** Currently, certain areas of interest 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 of **M** 2.0 or greater. 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: Well stimulation regulations are designed to ensure that 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. Seismic monitoring 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 operation 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.

Understanding the Differences between Hydraulic Fracturing and Salt-Water Disposal

- Hydraulic fracturing operations are intended to fracture the rock while disposal operations are rarely intended to fracture the rock.
- Hydraulic fracturing 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 amount of fluid pumped in a fracture treatment is orders of magnitude less than in a disposal operation over time.
- 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 while disposal operations injecting into a permeable disposal zone where the fluid is stored in the porous and permeable formation.
- 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. 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.