Geothermal Hydraulic Stimulation: Overview of Methods and Best Practices

Ian Warren

National Renewable Energy Laboratory

Keywords

Geothermal, hydraulic stimulation, induced seismicity

ABSTRACT

This paper outlines important information related to the hydraulic stimulation of geothermal wells and considerations for regulators responsible for evaluating applications to conduct these operations. Hydraulic stimulation applied to geothermal wells is an evolving technology that is different from the hydraulic fracturing process widely used to complete unconventional oil and gas wells. Important differences relate to operating pressures, variations in rock and fracture processes, and characteristics and disposal of hydraulic fracture fluids. Hydraulic stimulation is not widely used in the geothermal industry; however, future development of enhanced geothermal systems (EGS) will require hydraulic stimulation in order to enhance and create fracture permeability to allow wells to deliver sufficient heat and fluid to power plants. Gigawatts of EGS potential have been identified (U.S. Department of Energy 2019), so it is expected that the use of hydraulic stimulation of geothermal wells will be more common in the future.

At present, there are no formal regulations guiding drilling programs or sundry notices that propose hydraulic stimulation of geothermal wells. On federal lands, important constraints and oversight are embedded in the process for obtaining Geothermal Drilling Permits outlined in the Code of Federal Regulations (43 CFR § 3262.11); in Geothermal Resource Order 2 (GRO 2) guidance for assessment and mitigation of impacts of geothermal operations as well as construction and testing of geothermal wells; and in a Bureau of Land Management (BLM) Induced Seismicity Instruction Memorandum (BLM 2018). Additionally, local knowledge from

BLM field offices and expertise of BLM engineers, or that of state regulators for operations on private and state lands, will be applied to fully assess operator applications to conduct geothermal hydraulic stimulation activities.

Significant research effort has been directed toward EGS, so geothermal hydraulic stimulation techniques, impacts, and results are evolving and becoming better understood, including adaptation of decades of oil and gas industry experience with hydraulic fracturing of unconventional reservoirs. Recent EGS activities in the United States provide details about hydraulic stimulation with respect to oversight, stimulation design, execution, and results. Based on experience to date, the important issues to address when hydraulically stimulating a geothermal well include the following:

1. Wellbore construction and integrity must be appropriate to protect groundwater and manage stimulation pressures.

2. Understanding of lithology, faults, fractures, and subsurface stress state is necessary to design stimulation plans and predict results.

3. Seismic monitoring allows for observation and mitigation of induced seismicity.

1. Introduction

Geothermal power utilizes the heat of the interior of the Earth to generate electricity. This is achieved through a system of wells that bore into permeable rock formations hundreds to thousands of feet below the Earth's surface to access liquid or steam reservoirs. The geothermal fluid is brought to the surface via production wells and transported to power plants via surface pipe networks, where it flashes to steam to drive turbines (steam plant) or transfers its heat to a working fluid that is vaporized to drive turbines (binary power plant). The turbines drive generators that produce electricity. After passing through turbines, steam condenses into a liquid, or, in the case of a binary system, the brine is cooled from the heat exchange process with the working fluid. For both plant types, the cooled geothermal fluid is returned to the subsurface via injection wells at a much lower temperature than it was extracted. Circulation of the injected fluid through the reservoir extracts heat from the rocks before the fluid eventually arrives back at production wells to cycle through the process again.

Hydraulic stimulation is a technique used to stimulate and reopen preexisting fractures or to create new fractures, increasing permeability that allows larger volumes of fluid to be extracted for power production. The technique is particularly important for development of enhanced geothermal systems (EGS), which require creation of an interconnected subsurface fracture network in order to have sufficient permeability for economic power production. This paper details the components of hydraulic stimulation and the important considerations for evaluating proposed hydraulic stimulation operations with respect to risk management and impact mitigation, with particular focus on geothermal systems that require enhancement or creation of fracture permeability. The focus is on federal lands from a regulatory and guidance perspective, so additional or varying state and local guidance is not considered.

2. Overview of Hydraulic Stimulation Techniques

Multiple types of stimulation can be applied to geothermal wells, including chemical, thermal, and hydraulic. All include the injection of fluids into geothermal wells, and multiple types of stimulation can be combined within a single well stimulation plan. Stimulation operations occur after the well has been completed, and typically after well testing indicates the well is less productive than expected (especially if production is low enough that the well is not viable for electricity production). Productivity and commerciality determinations can be unique to individual geothermal fields.

Chemical stimulation is a routine process and typically involves injection of dilute acid solutions with the goal of dissolving secondary minerals filling fractures, thereby increasing fracture porosity and permeability. It can also be used to address mineral impediments to permeability in the rock matrix. Typically, chemical stimulation addresses well productivity issues at the wellbore-rock interface, between one and tens of meters away from the wellbore, and is particularly useful for removing alkaline drilling muds from the wellbore or for increasing permeability in carbonate rock formations. Chemical stimulation can be used on its own or to precede a hydraulic stimulation process. This paper is not concerned with chemical stimulation. Hydraulic stimulation is distinct from chemical stimulation because it relies on fluid volume and pressure to stimulate.

Thermal stimulation involves injection of cold (typically ambient temperature) water into hot rock at depth. The rock volume contracts as it is cooled by the injectate so that fracture apertures grow larger, thereby increasing permeability by up to two orders of magnitude (Grant et al. 2013). Volume changes associated with thermal stimulation also affect the local stress field, potentially increasing the likelihood of slip on a wider range of natural fracture orientations (Jansen and Miller 2017). Depending on rates and volumes of injection, thermal stimulation can potentially reach hundreds of meters from the wellbore.

Hydraulic stimulation involves application of pressure and fluid volume to open preexisting fractures and/or create new fractures to increase permeability. Geothermal hydraulic stimulation typically uses larger fluid volumes at lower pressures than oil and gas hydraulic fracturing. Unlike hydraulic fracturing, stimulation typically does not exceed the fracture pressure of the formation. Proppants—materials used to keep fractures open—may also be added to the stimulation fluid so that fractures remain open after stimulation. Effects can reach hundreds to thousands of meters from the wellbore, depending on rates and volumes of injection. Injected fluids are typically below the temperature of the subsurface, so most stimulation operations include a component of thermal stimulation.

3. Geothermal Wells

3.1 Geothermal Drilling Permits

Geothermal resource development is subject to many federal, state, and local laws and regulations depending on the location of the resource. On federal lands that are leased by the entity planning to drill a geothermal well, a Geothermal Drilling Permit (GDP) is required before drilling a well. To comply with National Environmental Policy Act (NEPA) requirements, GDPs require prior completion of an Environmental Assessment, Environmental Impact Statement, a Determination of NEPA Adequacy, or a categorical exclusion. These analyses assess the surface effects of geothermal drilling operations. Effects can be ecological, aesthetic, historical, cultural, economic, social, or health-related, and can be direct, indirect, or cumulative. In addition, some states require an approved GDP from an appropriate state agency prior to initiating any surface-disturbing activities or drilling operations. Significant understanding of the impacts of drilling operations must be obtained prior to the drilling of a well, and many of the same impacts are considered with respect to permitting of hydraulic stimulation operations. A GDP may include stimulation activities, or stimulation operations may be proposed via sundry notice and reviewed separately. This paper does not provide full details of the NEPA and GDP processes; rather, the reader should understand that significant review of impacts will have taken place before hydraulic stimulation is considered.

3.2 Summary of Guidelines for Geothermal Well Drilling: Geothermal Resource Orders, Onshore Orders, and Code of Federal Regulations Subpart 3260

A complete GDP includes both a drilling program and an operations plan (Table 1). A drilling program (43 CFR 3261.13) describes all the operational aspects of drilling, completing, and testing a well. An operations plan (43 CFR 3261.12) describes how geothermal leases will be drilled and tested for geothermal resources and specifically defines the area that must be reviewed for potential impacts. An operator has two options for obtaining approval to drill a geothermal well: (1) the filing of a sundry notice (BLM Form 3260–3) that includes an operations plan with approved GDPs or (2) the filing of a GDP that includes both an operations plan and a drilling program. An approval of the sundry notice allows the operator to begin building drill pads and access roads; however, drilling operations may not commence until a drilling program attached to the GDP has been approved.

The drilling program outlines the specifics of drilling, completion, and testing of a single well or group of similar wells. In assessing the drilling program, specific requirements and guidelines are given in Geothermal Resource Order Number 2 (GRO 2; see Table 2). Requirements set forth in GRO 2 are designed to ensure that geothermal wells are correctly constructed and tested. Pressure testing of cemented casing strings in particular demonstrates that wells, at the time of passing these tests, have casing that isolates geothermal fluids from fresh groundwater aquifers.

GRO 2 defines guidelines for the cementing of casing strings. From shallowest to deepest, the different types of casing strings are conductor casing, surface casing, intermediate casing, and production casing. Geothermal wells will, at a minimum, have conductor and surface casing strings. Additional casings may be required based on well control equipment, local geologic and hydrologic conditions, and target depths. In general, fewer casing strings are better for geothermal wells, if appropriate and safe, as each successive string is smaller in diameter. With geothermal wells, maximum flow rates typically are desired, and smaller diameter casings increase friction losses and can reduce productivity.

Onshore Oil and Gas Order Number 2 addresses drilling operations and includes information helpful for reviewing GDP applications that can be used as a reference. Local knowledge and experience of BLM field office scientists as well as support from state office engineers can be incorporated through Conditions of Approval.

Table 1. Summary Contents of BLM Geothermal Operations and Drilling Programs

Operation Plans (43 CFR § 3261.12)
(1) Well pad layout and design
(2) A description of existing and planned access roads
(3) A description of any ancillary facilities
(4) The source of drill pad and road building material
(5) The water source
(6) A statement describing surface ownership
(7) A description of procedures to protect the environment and other resources
(8) Plans for surface reclamation
(9) Any other information that BLM may require
Drilling Programs (43 CFR § 3261.13)
(a) A drilling program describes all the operational aspects of your proposal to drill, complete, and test a well.
(b) Send to BLM:
(1) A detailed description of the equipment, materials, and procedures you will use
(2) The proposed/anticipated depth of the well
(3) If you plan to directionally drill your well:
(i) The proposed bottom hole location and distances from the nearest section or tract lines
(ii) The kick-off point
(iii) The direction of deviation
(iv) The angle of build-up and maximum angle
(v) Plan and cross section maps indicating the surface and bottom hole locations
(4) The casing and cementing program
(5) The circulation media (mud, air, foam, etc.)
(6) A description of the logs that you will run
(7) A description and diagram of the blowout prevention equipment you will use during each phase of drilling
(8) The expected depth and thickness of fresh water zones
(9) Anticipated lost circulation zones
(10) Anticipated reservoir temperature and pressure
(11) Anticipated temperature gradient in the area
(12) A plat certified by a licensed surveyor showing the surveyed surface location and distances from the nearest section or tract lines
(13) Procedures and durations of well testing
(14) Any other information we [BLM] may require

Table 2. Casing, Cementing, and Testing Guidelines from GRO 2

Casing	Minimum Depth	Maximum Depth	Cementing	Pressure Tests***	Comments
Conductor	50'	200'	To surface	No pressure testing	
Surface	200'	1,300'	To surface	If set 500' or greater, test to 1,000 psi or 0.2 psi/ft, whichever is greater, prior to drilling out; if <500', test to 500 psi****	Set at depth equivalent to 10% of the proposed total depth of the well or next casing string; segregates geothermal fluids from groundwater
Intermediate	Surface or 100' above base of surface casing	**	To surface or 100' of overlap with surface casing		Designed to segregate geothermal fluids from shallower fluids
Production*	Surface or 100' above base of intermediate casing	**			

* Geothermal production casing is commonly uncemented slotted +/- blank liner

** No maximum depth given

*** Pressure not to exceed working pressure of casing or well control equipment, whichever is lesser; additional pressure tests may be conducted while drilling to meet well control equipment requirements

**** Pressure can decline by no more than 10% during a 30-minute test; repairs required to mitigate failed tests

4. Geothermal Hydraulic Stimulation

4.1 Overview

Hydraulic stimulation involves injection of fluids at various pressures, flow rates, and cumulative volumes. For geothermal applications, the fluid is dominantly water, though nontoxic additives may be added to modify the fluid viscosity (e.g., gel that is also used during drilling). Depending on depth of stimulation, in situ stresses, and pressure imposed, injection of fluid into a geothermal reservoir aims to reactivate, propagate, and enhance the permeability of preexisting fractures and/or create new fractures. Preexisting and new fractures represent different failure processes in terms of fracture initiation and propagation. When hydraulically stimulating a geothermal well, preexisting fractures can be reactivated via shear failure, and new fractures can form via tensile failure. Shearing rather than tensile fracturing is an effective process to develop a fracture network suitable for geothermal heat extraction because it takes advantage of naturally preexisting fractures.

Natural fractures, especially those favorably aligned with respect to the principal stress orientations so that they are near failure, require minimal pressure increase to undergo shear failure (i.e., slip) compared to the higher pressures required to create new fractures via tensile fracturing as is more typical in oil and gas operations. Shear failure causes slip along preexisting fractures, and misfit of asperities along the walls of the fracture can prevent closure of the fractures after injection is stopped and fluid pressure decreases. In the case of primarily tensile failure that creates new fractures, the sustainability of generated fractures depends on maintenance of fracture apertures after fluid pressure is released.

Though there is limited experience with proppants in geothermal wells, proppants are widely used and their deployment is well understood for stimulation of oil and gas wells. Proppants are used to maintain fracture apertures after hydraulic stimulation operations are complete with transport and placement of proppants supporting the long-term opening of the fracture. However, with respect to composition and deployment strategies, use of proppants is largely still at the research stage for geothermal wells.

Overview of typical, but not exclusive, steps that comprise a hydraulic stimulation operation are summarized in Table 3 (modified from Idaho National Laboratory 2006).

Table 3. Potential Process Steps Associated with Hydraulic Stimulation

Process Step	Description
Well completed with appropriate and tested casing	The well to be stimulated will be constructed so that casing properties, cement, and casing shoe depths are adequate for planned stimulation pressures. Cement and casing will have been tested during drill operations to ensure isolation of reservoir fluids from groundwater; confirmation of casing integrity can be done with additional pressure tests and/or cement bond logs, especially if the well has been inactive.
Establish subsurface rock characteristics	Rock physical properties, lithology, fractures, and permeable zones (geothermal fluid entries) must be identified for the zone(s) to be stimulated, and data from the well to be stimulated will be most relevant. In situ stresses can be constrained with formation integrity tests, leak-off tests, sonic logs, interpretation of borehole breakouts and drilling-induced fractures, and/or regional scale stress data. At a minimum, estimates about rock strength, local fracture gradient, and stress can be constrained by local and regional earthquakes, Global Positioning System data, geoscience data sets, and compiled rock properties by the U.S. Geological Survey, state surveys, and others.
Identify water source	A water source will have already been identified for drilling operations, and the same can be used for hydraulic stimulation. Possible sources include local groundwater, local surface waters, or water transported from a more distant source. If the project is near an existing geothermal operation, cooling (blow down) water or geothermal reservoir fluids may be utilized.
Establish microseismic sensor array	An operator’s best management practices may involve microseismic monitoring during stimulation activities. The local geology and the target well will guide best positions for the sensors of the seismic array; permanent arrays may need additional stations if not optimally situated to image hydraulic stimulation microseismicity. Ideally, the array should be designed and installed at the surface and in boreholes to enhance location of microseismic events before, during, and after stimulation.

Process Step	Description
Install pumps, pipes, and valves	Pumps, pipes, and valves need to be installed that can accommodate the planned stimulation volumes and pressures. Single pumps may be adequate, or a series of pumps may be required to achieve required flow rates and pressures. Pits from drilling operations may be augmented with tanks to allow sufficient storage of stimulation fluid. Valves allowing isolation of the well should be installed. At a minimum, pressure should be monitored at the wellhead and at the pump(s). Measurement of flow rate can be recorded with flow meters, or recorded based upon pump parameters (e.g., volume per stroke). All components of the fluid pumping system should be tested for leaks prior to stimulation operations.
Conduct stepped flow rate injections	Hydraulic stimulation is typically done by increasing the injection rate in steps and maintaining each step until the pressure stabilizes. The stimulation plan will define stages of pressure and volume for each zone to be stimulated; steps should begin at lower pressures and proceed to higher pressures. Some steps may be designed to deliver tracer and/or proppants. The targeted maximum pressure can be designed to cause shear failure of preexisting fractures or to induce the formation of new fractures; however, the pressure should not exceed the fracture gradient at casing shoes exposed to the stimulation pressure.
Maintain high flow rate until seismicity migration target is reached	The stimulation plan may not limit volumes injected but instead could have a goal of continued injection until an EGS reservoir volume is generated, as defined by induced microseismic events. For open-ended stimulation plans, water resources to support the stimulation must be confirmed to be adequate or limits on their use defined prior to stimulation operations.
Perform shut-in test and carry out dynamic surveys	Shut-in/fall-off tests should be performed to assess the size and permeability of the created or expanded reservoir. Shut-in tests can be performed between stimulation stages to assess stimulation effects and at the end of stimulation operations. During stabilized injection (rate and pressure), pressure-temperature-spinner (PTS) logs can be run to define performance of stimulated zones and stimulation progress. Final PTS logging should be completed near the end of stimulation operations.
Allow reservoir pressure to stabilize and perform new injection tests	After stimulation operations, the reservoir pressure will stabilize, after which injection tests at stepped rates are conducted to assess permeability enhancement and reservoir size. Pressure and volume limits defined in the stimulation plan still apply, though post-stimulation tests are typically conducted at lower pressures nearer to expected operational conditions.
Flow test production wells	Hydraulic stimulation operations are generally the same for injection or production wells. If stimulation is completed on a production well, post-stimulation flow testing can be conducted to assess permeability enhancement with flowing PTS surveys and build-up tests after flow testing. Flow test plans are typically part of drilling programs and may have already been completed prior to stimulation. Flow of production wells, especially EGS wells, may require pumping. Data collected during stimulation operations will inform the need and sizing for any pumps required to flow the well. If pumped, dynamic surveys may not be possible, and surveys from the stimulation operations will have to inform flowing zones and their characteristics. Post-flow, static temperature surveys potentially provide information about flowing zones in pumped wells.

Process Step	Description
Conduct circulation and tracer tests	In EGS environments, where both production and injection wells have been stimulated, circulation tests assess the connectivity between the injection and production wells generated with hydraulic stimulation. Tracer dosing of the injection well and sampling at the production well allows evaluation of the reservoir flow-through volume, residence time, fracture permeability, and short-circuit paths. Similar tracer tests can be conducted on any stimulated well with injection of tracer at one or more injection wells and sampling at the stimulated well. However, for non-EGS stimulations, documenting a well's improved performance may be all that is necessary to conclude the stimulation operations.

4.2 Geothermal Hydraulic Stimulation Process

Hydraulic stimulation entails pumping fluid at prescribed rates, pressures, and cumulative volumes. As mentioned previously, the fluid is predominantly water, even where additives are used to modify the physical properties of the fluid (e.g., addition of gel to increase viscosity in order to better transport proppants) or to modify fluid chemistry to affect how the fluid reacts with hot rock at depth. Aside from the addition of proppants, stimulation fluids are not likely to use additives not already used for drilling fluids. Hydraulic stimulation of geothermal wells is an evolving science, however, and different techniques could be developed that include new additives.

Idaho National Laboratory (2006) identified a series of potential process steps associated with hydraulic stimulation; these are summarized in Table 3. Hydraulic stimulation operations in an EGS development may involve different steps than stimulation of a well in a typical hydrothermal environment. This is because the general goals of stimulation are different: EGS stimulations are designed to create a new, fractured reservoir, whereas hydrothermal stimulations are primarily designed to improve well performance. There is an overlap between these end members, and field- and well-specific considerations will dictate the details and process steps of any particular stimulation plan.

Components and techniques used by the oil and gas industry can be applied to or adapted for hydraulic stimulation of geothermal wells. Characterization of the subsurface prior to hydraulic stimulation can be accomplished with geological observations; leak off and formation integrity tests while drilling; caliper, sonic, spontaneous potential, resistivity, gamma, neutron, and image logs of wells; and well flow or injection tests. In situ stress can be evaluated with geomechanical techniques that range from regional, local, and well scale in order to design hydraulic stimulation programs and predict outcomes.

Management of post-stimulation fluids for geothermal wells is distinctly different as compared to hydrocarbon wells. Geothermal wells are typically flow tested with reservoir fluids discharged to pits—either reserve pits constructed for drilling or larger pits designed for longer-term flow tests—and hydraulic stimulation fluid, along with reservoir fluid, is produced when the well is flow tested after hydraulic stimulation. Post-stimulation flow test fluids do not require special treatment because the additives are those used for drilling, benign compounds used for tracer testing, and/or nonreactive proppants designed to stay in the stimulated rock formation. In contrast, hydrocarbon stimulations produce flowback fluids that include scale inhibitors, friction reducers, and metals and semimetals leached from reservoirs. These fluids are cleaned, sometimes recycled, and ultimately transported to and injected into disposal wells. Disposal of hydrocarbon stimulation flowback fluids, along with coproduced fluids, are responsible for much of the seismicity associated with unconventional hydrocarbons development, and this type of activity and associated induced seismic hazard is not part of geothermal hydraulic stimulation operations.

A crucial component of designing a hydraulic stimulation is understanding the natural faults and fractures that intersect the borehole and the in situ stress state. Geomechanics is the geologic specialty that deals with understanding how rocks, stresses, pressures, and temperatures interact. Understanding the geomechanics of the formations to be hydraulically stimulated is crucial to designing a hydraulic stimulation program. The more detailed and constrained the geomechanics, the more likely the hydraulic stimulation will be successful and produce expected results. However, especially during exploration and early development stages, many geothermal projects may have little or no geomechanical data.

4.3 Zonal Isolation

Precisely targeting hydraulic stimulation requires zonal isolation that directs fluid and pressure to specific intervals of the well. In some instances, currently available mechanical packers for zonal isolation can be deployed while harsher geothermal environments are test beds for new tool development, especially development of tool components that can perform in high-temperature and corrosive environments. Mechanical packers use components that can be deployed from the surface to seal the well at a specific depth and may be permanent, but typically are made of drillable materials and are designed to be temporary. A single packer isolates the wellbore above from the wellbore below, while packers deployed in pairs can isolate a specific depth interval.

Polymer diverters have been developed for geothermal wells (e.g., Altarock's thermally degradable zonal isolation materials), and they can be tuned to isolate zones based on specific temperatures before they ultimately degrade at reservoir temperatures, effectively un-isolating the zone. They do not work in the same way mechanical packers do; rather, they plug zones of naturally occurring fractures so that stimulation fluid and pressure can be diverted to less permeable zones in order to induce opening of additional fractures, thereby increasing fracture permeability in the well. Polymer diverters have been partially successful in stimulation operations, most notably at the Newberry EGS project (Nordin et al. 2013).

4.4 Proppants

Proppants applied to geothermal stimulations are largely at the research stage, with focus on their performance in geothermal environments. Recent research has focused on quartz sand, bauxite, and ceramic proppants and surface coatings that can improve their performance in high-temperature and chemically reactive geothermal environments (Raysoni and Weaver 2013; Mattson et al. 2016). Hydraulic shear of preexisting fractures is thought to result in self-propping when adjacent fracture walls are offset during shear failure, so proppants may not be included in some geothermal hydraulic stimulation plans.

4.5 Tracers

Geothermal hydraulic stimulation plans may include tracer testing. Tracer testing is a long-used tool for characterizing geothermal reservoir flow paths and for management of geothermal reservoirs. Tracer testing is conducted by injecting substances that are thermally stable (i.e., conservative), have zero or very low background concentrations, are capable of being detected at low concentrations, and are environmentally benign. Tracers are injected into wells, and their concentrations are monitored at production wells. The mass of tracer that is measured at a production well over time can be used to characterize the flow paths between injection and production wells (Shook 2003; 2005). As part of hydraulic stimulation plans, or subsequent injection tests, tracers can be used to assess the connections between the hydraulically stimulated well and other wells in the field. Some common tracers used for geothermal testing are listed in Table 4.

Table 4. Summary of Typical Tracers Used to Evaluate Geothermal Resources (Adapted from Axelsson 2013)

Liquid-phase tracers:
Halides such as iodide and bromide
Radioactive tracers such as iodide-125 and iodide-131
Fluorescent dyes such as fluorescein and rhodamine
Aromatic acids such as benzoic acid
Naphthalene sulfonates
Steam-phase tracers:
Fluorinated hydrocarbons such as R-134a and R-23
Sulphur hexafluoride
Two-phase tracers:
Tritiated water
Alcohols such as methanol, ethanol, and n-propanol

Rather than being thermally stable, reactive tracers are affected by reservoir temperatures along flow paths between injection and production wells. They are designed to interact with the reservoir temperature and permeability so that temperature-time relationships between injection and production wells can be better characterized. Ongoing research and field trials aim to better constrain reactions and reaction times so that reactive tracers can provide more detailed information about reservoir temperature evolution (Tester et al. 1987; Plummer et al. 2011).

4.2 ***Future Importance of Hydraulic Stimulation***

The U.S. Department of Energy's *GeoVision* report (2019) describes the potential for expansion of geothermal energy usage in the United States. A large part of the potential growth is predicted to come from wide-scale deployment of EGS. Thus, we expect that orders-of-magnitude-more hydraulic stimulation operations will be proposed. Stimulation designs, techniques, fluids, and tools will evolve as more geothermal hydraulic stimulations are completed and knowledge gained.

5. Seismic Monitoring, Induced Seismicity, and Water Supply

Seismic monitoring for induced seismicity and water supply are two essential requirements for any hydraulic stimulation effort associated with geothermal energy development. Prior to hydraulic stimulation operations, induced seismicity and water use will be the most important impacts to reassess and add to the impact and resource studies completed for drill permitting. Seismic monitoring is required to establish a baseline for natural seismicity, inform the stimulation plan, and prevent induced seismicity from negatively impacting public, infrastructure, and other resources. Adequate water resources are necessary for conducting stimulation operations and to manage reservoirs over time, especially EGS reservoirs that may require water to initially charge them and to maintain pressure during their exploitation. New resource impact studies may be required, or those completed for drill permitting may allow for a Determination of NEPA Adequacy. A geothermal well at a remote field might not impact population centers and infrastructure, so robust monitoring of induced seismicity may not be required during hydraulic stimulation operations.

5.1 Monitoring Induced Seismicity

Hydraulic stimulation aims to improve and create fracture permeability of geothermal wells. In the case of EGS, the process is largely responsible for creation of the geothermal reservoir with opening of preexisting fractures and formation of new fractures. Best Practices for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems (Majer et al. 2012; 2016) provides guidelines for monitoring induced seismicity associated with hydraulic stimulation.

5.1.1 What Is Induced Seismicity?

Natural seismicity is common in active tectonic environments, along tectonic plate boundaries, and associated with volcanic activity. When a preexisting fracture slips or a new fracture is formed, energy is released. Induced seismicity refers to seismicity that is related to human interaction with the surface and subsurface that affects stress conditions in the subsurface (e.g., addition and subtraction of mass associated with dams, mining, construction, or fluid disposal). Injection of any fluids into the subsurface can raise pore pressures and this reduces the energy required to make a fault slip. During hydraulic stimulation of a geothermal well, only small slips and fracture-forming events are a result of the stimulation. These produce microearthquakes (MEQs), with magnitudes of less than 2 on the Richter scale, which are not felt but can be located using passive seismic monitoring with an installed seismic geophone array. Locations of MEQs in three-dimensional space help define where fractures are being stimulated and created. Where hydraulic stimulation operations are planned, care must be taken to document the occurrence of preexisting faults and fractures and constrain the subsurface stress environment.

5.1.2 Importance of Seismic Monitoring

The fluid pressures imposed during hydraulic stimulations can potentially cause larger faults to slip if those faults and subsurface stress conditions are not known. Subsurface fluid injection has been identified as the cause of seismic activity, including at geothermal sites (Majer et al. 2007). Hydraulic stimulation involves the injection of fluids, so we recommend that processes and protocols be in place to prevent large seismic events that could negatively impact population centers and infrastructure. Majer et al. (2016) detail the processes and protocols that should be in place prior to hydraulic stimulation so that unplanned, large events can be avoided and mitigated.

5.1.3 BLM Induced Seismicity Screening Document

In 2018, an Induced Seismicity Screening Worksheet and accompanying guidance document were implemented as BLM Instructional Memorandum (IM) 2018-107 (Beckers et al. 2018). The IM is designed to apply to GDPs, Utilization Plans, and sundry notice applications that propose hydraulic stimulation activities for new or existing wells. The Induced Seismicity Screening Worksheet is designed to determine whether the proposed project includes sufficient information for BLM to evaluate the potential for induced seismicity impacts or concerns, and to determine whether BLM personnel have an appropriate level of technical expertise to process the permit. It is not a formal analysis of seismic risk.

The worksheet has four possible outcomes:

1. Resolve issues with operator: Unsatisfactory communication or mitigation plan or unresolved past negligence or noncompliance issues should be resolved before screening can continue.

2. Low-level concern: Initial screening passed; proceed with next steps in processing the application.

3. Medium-level concern: The BLM field office can proceed with evaluation of the application after involving the State Office Geothermal Program Lead. They may recommend consulting with industry or academic seismic experts and potentially apply the Energy Department’s Induced Seismicity Protocol.

4. High-level concern: The BLM field office should not proceed further with processing the application without first contacting the State Office Geothermal Program Lead. The Geothermal Program Lead will perform in-depth review (likely in consultation with industry or academic seismic experts) and require the applicant to implement the full Induced Seismicity Protocol.

A summary of the worksheet process is shown in Figure 1. The Induced Seismicity Screening Worksheet is the BLM’s tool for addressing the preliminary screening evaluation of the best practice guidelines (Majer et al. 2016). The preliminary screening evaluation is equally applicable to non-EGS wells with similar proposed hydraulic stimulation activities.

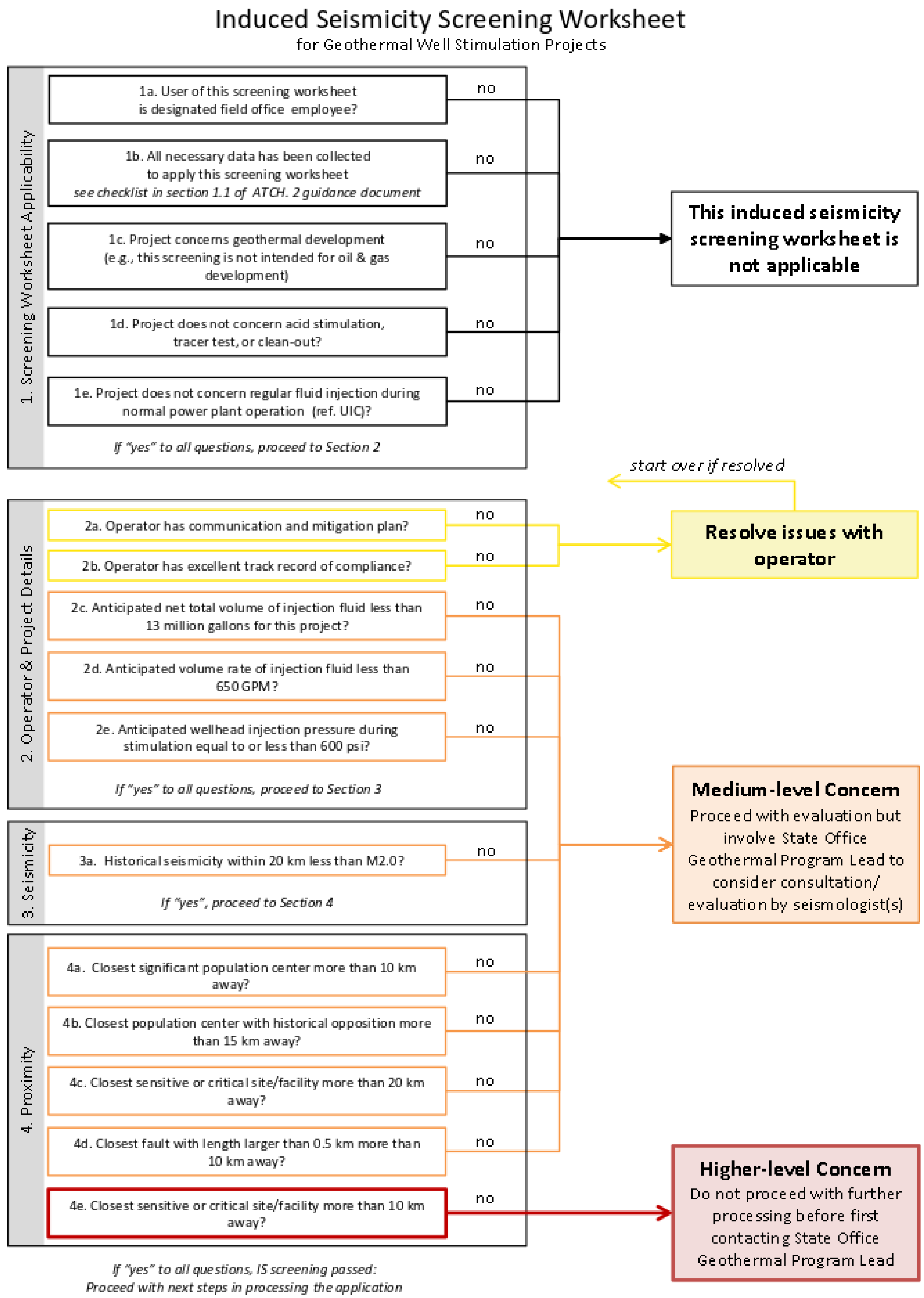

Figure 1. BLM Geothermal Program Induced Seismicity Screening Worksheet decision workflow

5.1.4 Best Practices for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems

Though focused on EGS projects, Majer et al. (2012; 2016) define seven basic steps for the induced seismicity protocol. One of the steps relates specifically to EGS design and operations, and it is excluded from the list below. Though the guidelines are designed for potentially large EGS projects, these steps provide a detailed account of considerations to potentially address any geothermal well hydraulic stimulation activities, particularly well stimulations conducted near population centers and infrastructure.

Step 1: Preliminary Screening Evaluation

BLM’s IM 2018-107 outlines how personnel can complete the preliminary screening evaluation. Majer et al. (2012; 2016) provide more detailed and complete guidelines designed for large EGS projects. This step is mainly risk analysis with focus on local, state, and federal government acceptance criteria, impact on local communities, natural seismicity and associated long-term risk, estimate of the magnitude of the worst-case induced earthquake and associated risk, project benefits, and full documentation of the risk analysis.

Step 2: Outreach and Communications

The recommended approach is to identify key stakeholders early in the process, establish an outreach team, provide complete and credible project information, and develop a community perspective to foster public trust.

Step 3: Criteria for Damage, Vibration, and Noise

Majer et al. (2012; 2016) provide detailed information about the interaction between the surface and subsurface built environment and earthquakes. American National Standards Institute and similar organizations have information that informs thresholds for vibration frequency, acceleration, and duration in order to assess the risk of damage to materials and structures. The transportation, construction, and mining industries have vibration and ground-borne noise impact criteria that can be readily applied to seismic hazard assessment.

Step 4: Collection of Seismicity Data

Historic baseline data should be collected so that a probabilistic seismic hazard analysis can be conducted, and this may require early installation of a local network to record a meaningful number of background seismic events if regional earthquake catalogues do not contain enough nearby events. The local network provides information about background seismicity and provides the ability to monitor hydraulic stimulation activities, with identified MEQs contributing to understanding the subsurface response to hydraulic stimulation (i.e., the volume of rock responsive to hydraulic stimulation). Majer et al. (2012; 2016) describe the basic requirements of seismic data collection: (1) location and time of events; (2) magnitude of events; (3) focal mechanisms of events; (4) rate of seismicity; and (5) real-time data available during hydraulic stimulation and EGS operations.

Step 5: Hazard Evaluation of Natural and Induced Seismic Events

The goal of this step is to estimate the ground shaking hazard from natural and induced seismicity. The hazards from natural seismicity are estimated through seismic hazard assessment methodologies that consider seismic sources, fault geometry, maximum magnitude, recurrence parameters, recurrence rates, earthquakes not associated with known faults, and local site conditions. In order to characterize the induced seismicity risk, knowledge of the local stress field is compared to the local geology in order to understand faults that may be at risk of failure if significant hydraulic stimulation pressure is applied. The seismic hazard assessments typically provide hazard curves that show the annual frequency of exceedance of a specified ground motion parameter.

Step 6: Risk-Based Mitigation Plan

Majer et al. (2016) define a formal methodology for defining and estimating risk based on the risk equation:

Equation 1: Risk = Hazard x Vulnerability x Cost of Consequences

Hazard is characterized as the probability of future ground shaking. *Vulnerability* is a probabilistic assessment of damage as a function of the amplitude of ground shaking. *Cost of consequences* is the cost to repair or replace physical damage. Nonphysical damage (e.g., nuisance) can be estimated, but is difficult to formally quantify. Physical damage to buildings and infrastructure is more readily estimable using insurance industry tools. Risk assessments should attempt to understand the impacts of a worst-case-scenario induced earthquake.

5.2 Water Resources

Significant water resources may be necessary for hydraulic stimulation. Well size, depth, and number of zones to be isolated influence water requirements, and duration of hydraulic stimulation can significantly impact total water requirements. Water resources will have been evaluated during the GDP process, and the construction of the well will have isolated any groundwater resources present. Drilling operations can require significant water to build drilling mud and make up downhole losses, and prior to hydraulic stimulation, wells may have undergone flow or injection tests, so these fluids may be available for stimulation operations. In operating geothermal fields, injection water may be diverted for longer-term stimulation.

A well-designed stimulation plan should reasonably constrain water requirements and identify suitable sources for water just as for the GDP. Conditions may change with time such that water resources associated with EGS operations may need to be regularly assessed.

6. Best Management Practices and Lessons Learned

Limited experience with hydraulic stimulation of geothermal wells means limited data to inform best management practices, with the experience largely confined to EGS research and development. The GDP process guides well drilling and construction so that a well is potentially ready for hydraulic stimulation operations when completed. Two particularly important impacts described previously are induced seismicity and water use; the former benefits from the BLM IM 2018-107 and Majer et al. (2012; 2016) best practice guidance for screening projects and identifying and managing induced seismicity risk.

6.1 Best Management Practices

Experience gained from well drilling and completion and from hydraulic stimulation projects for EGS have provided context for evaluating the planning and execution of hydraulic stimulation operations. A basic list of components that inform evolving best management practices is described in the following subsections.

6.1.1 Well Drilling and Completion

A geothermal well that is drilled on federal land and completed will have been given prior scrutiny covering NEPA impacts, an approved well design, an approved drill program, approval of test and construction procedures while drilling, and final well completion reporting. This information provides the context for evaluating any proposed hydraulic stimulation plan. Leak-off tests, formation integrity data, and borehole image and caliper logs can provide information about subsurface stress to inform hydraulic stimulation plans.

6.1.2 Seismic Monitoring

BLM IM 2018-107 describes how projects should be screened with respect to induced seismicity risk and requirements for seismic monitoring. Majer et al. (2012; 2016) describe best practices for addressing and managing induced seismicity.

6.1.3 Mechanical Integrity Testing

Mechanical integrity testing may be required for all wells, especially older wells, to confirm that there are no leaks from casing or casing components, and no indications of vertical fluid movement behind the casing. Mechanical integrity testing may be required by states. There are multiple pressure tests and downhole logs that can be conducted in order to meet mechanical integrity testing requirements. Prior guidance (e.g., Geothermal Technical Working Paper No. 2 [DOE 2016]) and some jurisdictions require that a cement bond log be run and analyzed to confirm there is no fluid movement behind casing; however, these can be difficult to interpret in practice.

6.1.4 Pressure and Flow Rate Monitoring

Records of pressure and flow rates may be required (e.g., a Condition of Approval) to monitor hydraulic stimulation progress and to maintain conditions proposed in the hydraulic stimulation plan. Unexpected changes can potentially force modification of hydraulic stimulation plans.

6.1.5 Fluids Handling and Storage

As previously described, components in addition to water will likely have been used in drilling operations, and management of the fluids will have been approved in the drilling program. Additives will be documented with Safety Data Sheets.

6.2 Lessons Learned from EGS Projects

6.2.1 Summary

McClure and Horne (2014) reviewed 10 EGS projects and found that hydraulic stimulation operations involved pressure-limiting behavior, flow from discrete zones, and bottomhole pressure greater than the minimum principal stress. They hypothesize that natural fractures opened under these conditions and new fractures formed off them as splays or as extensions at their tips. Their concept of mixed-mechanism stimulation explains the common observation of flow localization at natural fractures even when the minimum principal stress is exceeded during stimulation, a condition that allows formation of new fractures. This is an important finding, as the ratio of hydraulic shearing to hydraulic fracturing affects the type of fracture network that might form.

Recent, well-documented EGS experiments partly funded by the U.S. Department of Energy have been conducted in underperforming wells associated with geothermal operations in the western United States. One of these projects was at Desert Peak well 27-15 and provides a potential roadmap for conducting a robust hydraulic stimulation. Results at Desert Peak helped inform the hydraulic stimulation plan for Brady’s well 15-12 that is located on a BLM geothermal lease. BLM ultimately approved well 15-12’s hydraulic stimulation plan, which was initiated with a sundry notice that was processed by the BLM in 2012 and 2013.

6.2.2 Brady’s Hot Spring EGS Operations Summary

The BLM process for reviewing the stimulation plan proposed for well 15-12 is captured in the following documents: (1) Ormat’s DE-GO-18200 Well 15-12 Stimulation Plan; (2) Environmental Assessment DOI-BLM-NV-W010-2012-0057-EA DOE/EA-1944 Brady Hot Springs Well 15-12 Hydro-Stimulation; (3) Finding of No Significant Impact (FONSI) DOI-BLM-NV-W010-2012-0057-EA; and (4) Decision Record DOI-BLM-NV-W010-2012-0057-EA. Different guidelines and proposed rules promulgated from 2012 and 2013 mean that the same proposal may now be treated differently; however, the process for approval for well 15-12’s stimulation plan demonstrates how the process has been completed successfully in the past.

Ormat’s stimulation plan was developed from experience gained at Desert Peak well 27-15 (Akerley et al. 2020). Pre-stimulation injection testing as well as PTS and image logs identified the depth interval to be stimulated (4,450–4,600 ft) and established baseline injectivity (~0.05 gallons per minute per pound per square inch [gpm/psi]). The target interval was characterized by lithologic and wireline logs, and laboratory testing provided additional mineralogical and mechanical properties. Image logs allowed identification and characterization of fractures and stress indicators. Combined with injection test data and rock physical properties, a geomechanical model was developed that included directions and estimates of magnitude for S_{Hmax} and S_{hmin} so that thresholds of shear stimulation and hydraulic fracturing could be estimated. The updated geologic model identified permeability primarily associated with the complex, NNE-striking Brady’s Fault Zone.

The stimulation plan included details of the equipment configuration to be used, the parameters to be monitored during stimulation, and the fluid to be used for stimulation. All the steps for the hydraulic stimulation and data recording to be done during the test were described with four primary components to the stimulation plan: (1) pre-conditioning shear stimulation $<S_{hmin}$ (minimum horizontal stress); (2) multistage hydraulic fracturing $>S_{hmin}$; (3) post-stimulation injectivity testing; and (4) long-term injection testing. Monitoring included real-time MEQ recording using a passive seismic array consisting of five borehole stations and three surface stations centered on well 15-12.

Three intervals were chosen for stimulation: 4,255–4,414 feet, 4,414–4,750 feet, and 4,750–5,009 feet (total depth) with zonal isolation provided by a series of packer assemblies with sliding-sleeve completion sections that can be either opened or closed, controlling access to each interval to be stimulated (Akerley et al. 2020). The pre-conditioning stage was carried out in four steps over seven days: ramp up, stable injection, fall-off, and post-stimulation injection testing. Stimulation and testing targeted all zones together and were conducted at pressures below S_{hmin}, designed to induce slip on preexisting fractures. The injection test confirmed injectivity of 0.3 gpm/psi, a sixfold increase in injectivity compared to pre-stimulation. No MEQs were recorded.

Multistage stimulation was conducted over five days at pressures above S_{hmin} and with cooled injection fluid to facilitate thermal stimulation. Stimulation of the deepest zone (Zone 1: 4,750 to 5,009 feet) was conducted over two days. Injection began at 80 gpm and was increased in a series of 10- to 15-minute intervals until reaching a maximum rate of 630 gpm at the planned maximum wellhead pressure of ~1,400 psi. The average injectivity for Zone 1 was 0.45 gpm/psi. The second stimulation focused on the middle zone (Zone 2: 4,414 to 4,750 ft) and was conducted over two days. Pumping to stimulate the middle zone started at a rate of 250 gpm for approximately 25 minutes. Thereafter, the rate was increased in 1- to 3-minute steps of 84 gpm, up to a maximum rate of 1,092 gpm and wellhead pressure ~1,400 psi. After 12 hours of stable injection, the well was shut-in to record the pressure fall-off. The average injectivity was 0.53 gpm/psi. The third stimulation focused on the upper zone (Zone 3: 4,255 to 4,414 ft) and was conducted over two days. The injection rate to the shallow zone was ramped up to 294 gpm while maintaining the wellhead pressure below 1,400 psi. The injection rate was increased to 336 gpm and maintained for the next 7 hours with wellhead pressure gradually decreasing from 1,400 psi. The rate was increased to 378 gpm for the last 12 hours of the stimulation stage. The average injectivity was 0.24 gpm/psi. No MEQs were identified during the hydraulic fracturing phase of stimulation.

The post-stimulation injection test was conducted with maximum injection rate of 100 gpm and pressures below S_{hmin}. Average injectivity during this test was 1.17 gpm/psi. A long-term injection test at well 15-12 conducted over more than a year saw no change in injectivity; however, the test was at relatively low flow rate and wellhead pressure (100 gpm and 96 psi, respectively). Injectivity increased 30-fold at Brady's, indicating that the stimulation succeeded in enhancing permeability, but lack of tracer returns indicates that well 15-12 remains hydraulically isolated from the productive part of the field.

Akerley et al. (2020) note that at Brady's, well 15-12 is not connected to the main reservoir, so success required development of fracture permeability to connect to the main reservoir. Akerley et al. (2020) explain that higher stimulation pressures might have been possible at well 15-12; however, their knowledge of the geomechanical setting enabled them to determine this might have risked vertical growth of fractures rather than the horizontal propagation needed to connect to the main reservoir.

6.3 Guidance from the Oil and Gas Industry

Despite differing operating conditions and environments, experience from hydraulic stimulation in the oil and gas industry can help guide geothermal hydraulic stimulation technology and practice as it evolves. Significant best practice guidance has been developed in the oil and gas industry related to hydraulic stimulation.

Hydraulic fracturing best practices from the oil and gas industry are captured in the American Petroleum Institute's (API's) "Recommended Practice 100-1 Hydraulic Fracturing - Well Integrity and Fracture Containment" guidelines. Well integrity is defined as the design and installation of well equipment to a standard that protects and isolates useable quality groundwater, delivers and executes a hydraulic fracture treatment to the downhole target interval, and contains and isolates the produced fluids. Fracture containment is defined as the design and execution of hydraulic fracturing treatments to contain the resulting fracture within a prescribed geologic interval. Fracture containment combines those parameters that are existing, those that can be established at installation, and those that can be controlled during execution. Existing parameters relate to measurable formation characteristics with associated ranges of uncertainties; established parameters relate to well barriers and integrity as created during well construction; and controllable parameters relate to hydraulic stimulation design and execution.

The general guidance from this document is useful to consider for geothermal hydraulic stimulation as the technology evolves. Related best practice documents that cover the broader scope of hydraulic fracturing operations and that might be relevant to the continuing evolution of geothermal hydraulic stimulation include *ANSI/API Recommended Practice 100-2 Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing*, *ANSI/API 100-3 Community Engagement Guidelines*, *API Standard 65 Part 2 Isolating Potential Flow Zones During Well Construction*, and *API Recommended Practice 51R Environmental Protection for Onshore Oil and Gas Production Operations and Leases*.

Abundant additional materials are available from API relating to drilling, well construction, well completion, well testing, well stimulation, and more. However, not all oil and gas hydraulic fracturing processes and technologies are immediately transferable to today's geothermal wells. Significant differences between oil and gas hydraulic fracturing and geothermal hydraulic stimulation relate to geological environments and well configurations. Oil and gas wells are drilled in hydrocarbon-bearing sedimentary basins. Geothermal wells are typically drilled in non-sedimentary, harder, igneous rock environments. Oil and gas operators typically have much greater understanding of the subsurface, including knowledge about subsurface stress, than their geothermal operator counterparts. Hydraulic fracturing of oil and gas wells is typically done in stages along horizontal legs that are hundreds to thousands of meters long, whereas geothermal wells currently are vertical or have legs that are drilled directionally to angles from vertical greater than 45°.

Oil and gas hydraulic fracturing is designed to create new fractures and requires pressures capable of breaking rock formations, whereas geothermal hydraulic stimulation has historically focused on inducing slip along preexisting fractures with lower imposed pressures. As the technology evolves, geothermal hydraulic stimulation is likely to focus on higher-pressure stimulation that is specifically designed to form new fractures, though the formation of new fractures may be happening in some lower-pressure geothermal hydraulic stimulations (McClure and Horne 2014).

7 Conclusions

With more experience with geothermal hydraulic stimulation techniques, improved technologies, and favorable economics, these stimulation procedures may become more common and widely used for reservoir enhancement and management. It may be expected that many more proposals to conduct hydraulic stimulation operations will be reviewed by BLM and other regulators.

A good understanding of geomechanical settings, stimulation goals, and robust plans to monitor and mitigate induced seismicity risk are essential for an effective hydraulic stimulation plan. The stimulation plan and operations at Brady's Hot Springs provide a good example of what is required for completion of hydraulic stimulation operations, and how to successfully conduct stimulation operations.

Acknowledgement

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Interior Bureau of Land Management's Renewable Energy Coordination under contracts L16PG00068 and L20PG00048 with the National Renewable Energy Laboratory (NREL). The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

REFERENCES

Akerley, J.H., Robertson-Tait, A., Zemach, E., Spielman, P., and Drakos, P. 2020. "Near-Field EGS: A Review and Comparison of the EGS Demonstration Projects at Desert Peak and Bradys." Proceedings of the World Geothermal Congress 2020. Reykjavik, Iceland, April 26–May 2, 2020, 12 p.

Axelsson, G. 2013. "Tracer tests in geothermal resource management." *European Physical Journal Web of Conferences.* 50, 02001, 8 p.

BLM. 2018. *Use of Induced Seismicity Screening Worksheet in Evaluating Proposals for Geothermal Well Stimulation Projects or Enhanced/Engineered Geothermal System (EGS) Operations: BLM IM 2018-107*. 3 Attachments, accessed online at https://www.blm.gov/policy/im-2018-107.

Beckers, K.F., Young, K.R., Munger, D., Jensen, A. and the Induced Seismicity Expert Team. 2018. *Appendix B: BLM Induced Seismicity Screening Worksheet Guidance Document*: Attachment 3, BLM IM 2018-107, 17 p.

DOE. 2016. *Geothermal Technical Working Paper No. 2: Production Drilling and Well Completion*. DOE/EE-1396.2 June 2016. 90 p. https://www1.eere.energy.gov/geothermal/pdfs/twp2_production_drilling-public_comment_final_draft.pdf

Grant, Clearwater, J., Quinão, J., Bixley, P.F., and Le Brun, Morgane. 2013. "Thermal Stimulation of Geothermal Wells: A Review of Field Data." Proceedings, 38th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, February 11–13, SGP-TR-198, 7 p.

Idaho National Laboratory. 2006. *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century*. INL/EXT-06-11746, 372 p.

Jansen, G. and Miller, S.A. 2017. "On the Role of Thermal Stresses during Hydraulic Stimulation of Geothermal Reservoirs." *Geofluids*, v. 2017, Article ID 4653278, 15 p.

Majer, E, Baria, R., Stark, M., Oates, S., Bommer, J., Smith, B., and Asanuma, H. 2007. "Induced seismicity associated with Enhanced Geothermal Systems." *Geothermics*, v. 36, p. 185–222.

Majer, E., Nelson, J., Robertson-Tait, A., Savy, J., and Wong, I. 2012. *Protocol for addressing induced seismicity associated with enhanced geothermal systems.* U.S. Department of Energy/Energy Efficiency and Renewable Energy. DOE/EE-0662, 52 p.

Majer, E., Nelson, J., Robertson-Tait, A., Savy, J., and Wong, I. 2016. *Best Practices for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems (EGS*). Version April 8, 2016, Lawrence Berkeley National Laboratory, 115 p.

Mattson, E.D., Neupane, G., Plummer, M., Jones, C., and Moore, J. 2016. "Long-term sustainability of fracture conductivity in geothermal systems using proppants." Proceedings, 41st Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, February 22–24, SGP-TR-209, 6 p.

McClure, M.W. and Horne, R.N. 2014. "An investigation of stimulation mechanisms in Enhanced Geothermal Systems." *International Journal of Rock Mechanics & Mining Sciences*, v. 72, pp. 242–260.

Nordin, Y., Petty, S., Cladouhos, T., Sawyer, M., and DeRocher, T. 2013. "Multiple Zone Geothermal Stimulation Case Study: Fluid Diversion Using Thermo-Degradable Zonal Isolation Materials." *GRC Transactions*, vol. 37, pp. 51–55.

Plummer, M.A., Palmer, C.D., Mattson, E.D., and Hull, L.C. 2011. "A reactive tracer analysis method for monitoring thermal drawdown in geothermal reservoirs." Proceedings, 36th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, January 31–February 2, SGP-TR-191, 6 p.

Raysoni, N. and Weaver, J. 2013. "Long-Term Hydrothermal Proppant Performance." *SPE Production & Operation*s, v. 28, Issue 4, pp. 414–426.

Shook, G. M. 2003. "A Simple, Fast Method of Estimating Fractured Reservoir Geometry from Tracer Tests." *Geothermal Resources Council Transactions*, 27, pp. 407–411.

Shook, G. M. 2005. "A systematic method for tracer test analysis: an example using Beowawe tracer data." Proceedings, 15th Workshop on Geothermal Reservoir Engineering, Stanford, SGP-TR-176, 6 p.

Tester, J.W., B.A. Robinson, and J. Ferguson. 1987. "The theory and selection of chemically reactive tracers for reservoir thermal capacity production." Proceedings, 12th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, January 20-22, SGP-TR-109, pp. 219–227.

U.S. Department of Energy. 2019. *GeoVision: Harnessing the Heat Beneath Our Feet.* Office of Energy Efficiency and Renewable Energy. https://www.energy.gov/eere/geothermal/downloads/geovision-harnessing-heat-beneath-our-feet.