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Fracture Caging to Limit Induced Seismicity

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Key Points

1. A production well cage can enable high-pressure fluid-injection simultaneously with closed-loop flow-containment in fractured rock.
2. Model, laboratory, and field evidence indicate that fracture caging can reduce induced seismic magnitudes despite natural complexity.
3. A cage of production wells improves subsurface flow control and adaptability to transient and dynamic fracture networks.

Abstract

Geothermal resources offer a stable low-carbon energy source. However, geothermal sites can collocate with the hypocenters of large-magnitude seismic events. Large seismic events pose a risk to public safety and are therefore a liability for efforts to develop geothermal resources. Here, we propose 'fracture caging' to limit induced seismic event magnitudes and present evidence from numerical model predictions, laboratory experiments, and field observations. Fracture caging involves drilling tactical production wells around a geothermal injection zone to contain fluids in fracture dominated flow systems. Prior to our work, the effect of small wells on the growth of large fractures and on flow through fractures was subject to debate. Our work shows that production wells can impede fracture growth and contain high-pressure fluids in fracture-dominated rocks. This containment offers a mechanism to limit induced seismicity.

Plain Language Summary

Below the ground's surface, fluid can lubricate rocks which enables them to more easily slip and generate earthquakes. This is a problem for developing geothermal energy resources that require long-term injection of water. If water could be injected without risk of earthquakes, geothermal energy production could be expanded to supply more than 60 GW of electricity in the United States alone. To confront the earthquake risk, we propose that tactical arrangements of production wells around geothermal injection wells can be used to prevent large seismic events. We refer to this arrangement as 'fracture caging' because it contains injected fluid in a limited volume of fractured rock in order to prevent uncontrolled stimulation of the larger fractures that generate earthquakes. Prior to this work, we incorrectly assumed that small wells (e.g., 0.3 m diameter) could not inhibit the growth of large fractures (e.g., greater than 100 m diameter). We also incorrectly assumed that these wells could not contain fluids in the dynamic and uncertain

fracture networks that are common in natural rocks. However, our models, experiments, and field data now show that fracture caging can work to contain injected fluids and thereby also limit induced seismicity, even in complex natural rock.

Key Words

Earthquake, Geothermal, Risk Mitigation, Energy, Traffic Light Protocol

1. Introduction

In 2017, a 5.4 magnitude injection collocated earthquake rocked Pohang, South Korea, damaging buildings and forcing many residents into emergency housing (Kim et al., 2018; Grigoli et al. 2018). Like most geothermal facilities, this site planned for a few injection and production wells to extract heat from the subsurface to generate electricity (Olasolo et al., 2016). This large seismic event occurred despite careful planning and use of 'cyclic soft stimulation' to mitigate induced seismicity risk (Hofmann et al., 2019). Unfortunately, this example is just one of many injection-associated seismic events with other notable examples including Basel, Landau, Oklahoma, and Soultz-sous-Forêts (Cuenot et al., 2008; Ellsworth, 2013; Keranen et al., 2013). For Pohang, the damage from the seismic events led to the shutdown of the geothermal plant which had been expected to produce as much as 6.2 MW_e of low-carbon base-load energy. Finding a direct solution to limit induced seismicity is crucial to the future of geothermal energy because earthquakes generated by humans are undesirable, to say the least (Giardini, 2009).

Based on a U.S. Department of Energy report (Hamm et al., 2019), an estimated 60 GW_e could be generated by 2050 from the underutilized geothermal resources in the United States alone. At the end of 2015, the total net capacity of geothermal energy production in the United States was only 2.7 GW_e (Geothermal Energy Association, 2016). Currently, the primary seismic risk mitigation strategy is to place geothermal facilities in remote areas, but this greatly limits resource options and increases parasitic energy losses due to long-distance transmission lines. A more ideal solution would be to directly limit induced seismic risk and allow geothermal facilities to be safely located closer to consumers.

Building on our recent work (Kneafsey et al., 2019; Frash et al., 2018; Frash et al., 2019; Frash, 2020), we now introduce 'fracture caging' (Figure 1) as a means to reduce induced seismicity at geothermal sites where flow is dominated by fractures. Fracture caging uses tactical patterns of

production wells drilled around injection wells to contain the injected fluids inside of a targeted reservoir. We will show that caging can contain injected fluids by closed-loop flow in otherwise leaky, open, and dynamic fracture systems. Instead of the pressure balancing that is sought by conventional reservoir multi-well solutions (Raleigh et al., 1976), fracture caging uses flow containment to limit the maximum magnitude of seismic events induced by fluid injection or extraction while also enabling safe long-term high-pressure fluid injection. This is a crucial distinction because conventional limits on pressure and flow rates can cripple the energy output potential of geothermal plants but caging imposes lesser restrictions.

2. Fracture Caging Mechanisms

The mechanisms for fracture caging build on four independent constituents: (1) fracture growth is hindered by production wells and leaky fracture networks, (2) fracture flow is contained using a cage of production wells around an injection well, (3) seismic fracture slip is triggered by pore fluid perturbations, and (4) the perturbed length of a fracture has links to maximum seismic event magnitude. Combined, these constituents invoke the ability to limit new fracture growth, contain high-pressure injected fluids within a targeted rock volume, minimize the perturbations in leaky systems that cause shear slip, and thereby limit the number and magnitude of seismic events. In effect, caging induces closed-loop flow inside leaky fracture-dominated flow-networks.

2.1. Fracture growth inhibition

Increasing fracture fluid pressure can induce fracture growth, whether by extension of existing fractures or by creation of new fractures (Valko and Economides, 1995; Rutledge and Phillips, 2003; McClure and Horne, 2014). New fracture growth offers a mechanism for seismicity as these fractures grow or when they shear slip (Zhao and Young, 2011). If a growing fracture requiring a high-pressure to propagate intercepts an existing high-permeability feature, such as a well or a large conductive fault, this intercepted feature will act as a pressure sink. However, it is not obvious whether the propagating fracture will be halted, inhibited, or unimpeded by a tiny well of 0.1 to 0.5 m diameter when fractures can exceed 100 m diameter. To investigate this interaction, we employed numerical modeling and laboratory experiments. Interestingly, the results from this work (Figure 2) indicate that production wells can have a profound inhibiting effect on pressure driven fracture propagation.

We modeled coupled fracture propagation and fluid flow through a rock and well system using GEOS (Fu et al., 2013; Settgast et al., 2017). For a base case, the rock was assumed to be isotropic, homogeneous, and impermeable granite and the fracture was assumed to be planar. Fracture toughness was included and the injection fluid was water. We evaluated three cases (Figure 2): (1) a single injection well, (2) an injection and production well pair, and (3) a cage of four production wells (producers) around one injection well (injector). Each case was subjected to the same boundary conditions and injection conditions. As expected, the single well model predicted unlimited fracture growth by injection. Partial fracture inhibition in the direction of the producer was predicted in the case of one production well. Fracture inhibition with as much as 94% containment of the injected fluid was predicted in the case of the four-producer cage.

Laboratory block hydraulic fracture experiments were completed to validate the model's prediction of fracture containment (Figure 2). Here, we show hydraulic fracture geometries created by fluid injection into a granite block (2c), injection and production through another granite block (2f), and within a cage of four production wells in acrylic (2i). The granite natural rock experiments included true-triaxial stress confinement (Frash et al., 2015). Injection of fluid into granite with no production well produced an uncontained fracture through 95% length and 100% height of the cubic block. Injection of a larger volume of fluid into the granite block with one production well produced a shorter fracture at 85% length and 50% height of the block. The hydraulic fracture in acrylic was inhibited and contained despite continued injection and nearly imperceptible growth after the fracture intercepted all four of the production wells. The result of containment by four production wells has also been achieved in cement and granite (Frash et al., 2018 and Hu and Ghassemi, 2018), verified by tracers or visual inspection of fractures.

Only our most relevant and readily comparable experiments are shown in Figure 2. Additional related experiments have included more heterogeneous materials, different injection parameters, and alternative stress conditions, as performed by others and ourselves (Frash, 2014; Frash et al., 2015; Frash et al., 2018, Hu and Ghassemi, 2018; Frash, 2020). These included shale rocks, cement systems, and other granites. All the multi-well experiments confirmed fracture growth inhibition when the hydraulic fracture intercepted production wells.

2.2. Fracture flow containment

Fluid flowing into fractures outside of a targeted injection zone can generate large magnitude induced seismicity (Guglielmi et al., 2015). Furthermore, it has been argued that most high-permeability in-situ fractures and faults are at or near a critical state of stress, where even small perturbations could induce seismic slip (Townsend and Zoback, 2000). However, even in critically stressed fractures, the perturbed portion of large fractures and faults has a controlling effect on induced seismic event magnitudes (Galis et al., 2017). Therefore, flow sinks (i.e., production wells) around the high-pressure fluid injection zone could prevent fluid flow outside of this zone that would otherwise lead to larger seismic events (Figs. 1 and 2).

Parallel-plate experiments were used to model flow containment in permeable open fractures. This represents any large leaky fracture, whether characterized as tensile, shear, or mixed. These used constant-rate injection and production that alternated between red and blue dyed water (Figure 2). The experiments simulated flow from an injection well (2b), an injection-production well pair (2e), and a caged injection well bounded by four equidistant production wells (2h). The injection only scenario was uncontained, the injector-producer pair was partially contained, and the five-well system was nearly completely contained. Tight color band spacing indicates near zero outward flow. This demonstrates that four-well fracture caging in open and permeable fracture systems can contain most injected fluid when the injection rate is equal to production. In the field, tracer surveys and microseismic monitoring can be used to confirm flow containment.

2.3. Fracture and slip criteria in a limited perturbed volume

Many criteria have been developed to model tensile and shear fracture growth, shear slip, and seismicity (Wenzel, 2017; Kang et al., 2019; Morris et al., 1996). For shear fractures, Mohr-Coulomb criteria will predict slip with increasing pore pressure. For tensile fractures, linear-elastic fracture mechanics will predict fracture growth above a critical injection pressure. Shear and tensile fractures interact to form complex networks and wing cracks that are more difficult to analyze. Advanced poromechanical and discrete fracture network models clarify that seismic slip can be induced by pressure increase (injection) or decrease (production), even when fractures do not hydraulically connect back to a well (Segall et al., 1994; Rubinstein and Mahani, 2015; Maxwell et al., 2015). Already, this brief and incomplete description of mechanisms paints a complex picture for predicting seismic fracture growth and slip. However, all these mechanisms

originate from a perturbed volume of rock. Fracture caging limits the volume of rock that is perturbed by fluid injection, whether directly or indirectly, and will thereby limit the volume of rock subjected to induced fracture growth and slip.

2.4. Seismic magnitude, perturbed fracture area, and well spacing

A subsurface rupture's length can be related to a maximum event magnitude using the empirical relationship between subsurface rupture length (L_{RLD}) and event magnitude (M_w) established by Wells and Coppersmith (1994), based on a comprehensive collection of field data:

$$M_w = 4.38 + 1.49 \cdot \log\left(L_{RLD}\right) \quad (1)$$

A similar link between seismic magnitude and slip length is established by the definition of seismic moment, M_o (Kanamori and Anderson, 1975). Galis et al. (2017) use numerical models to predict that the inset dimensions of fracture pressure perturbations within large fractures will limit maximum seismic magnitudes, even if the fracture is critically stressed. Thus, the perturbed area of a large fracture is linked to the maximum seismic event magnitude that we could expect from that portion of the fracture. This is the fourth constituent of fracture caging.

Established by the four constituent mechanisms above, the perturbed rock volume is defined and controlled by production well placement in a caged system. Thus, the area that is perturbed within large fractures that intersect this volume is also controlled. This volume is most readily defined by the spacing of the wells that form the cage. Therefore, we can postulate that well spacing will link to the maximum magnitude of induced seismic events in a fracture caged system. If true, well spacing substituted for rupture length in Eq. (1) provides a preliminary predictor for the maximum magnitude of seismic events induced in a caged system.

3. Field and Laboratory Fracture Caging

Seismic event cumulative count and maximum magnitude are correlated with cumulative injected fluid volumes (Figure 3). For example, the cumulative number of seismic events measured using a constant detection threshold during injection into the Duvernay shale play is nearly linearly correlated with cumulative injected volumes (Schultz et al., 2018). For another example, maximum event magnitude and cumulative injected volume at various injection sites are also correlated (McGarr, 2014; Galis et al., 2017). However, there are outliers from these trends. One concerning outlier is the large M_w 5.4 event at Pohang. This event is possibly

attributed to disturbing a critically stressed fault. In contrast, other outliers exhibited event counts and magnitudes having decaying correlation with injected fluid volume. Data was not adjusted for produced fluid because this adjustment would be victim to speculation. Low seismicity outliers show signs of fracture caging even though they were not optimized for this purpose because caging was not yet considered.

One of our granite block laboratory experiments used a 30 cm cubic specimen with one injection well and two production wells (Frash et al., 2015). During this experiment, acoustic emissions peaked early and then decayed despite continued injection to orders of magnitude larger volumes and at faster rates (Figure 3). Corresponding event magnitudes peaked at an injection volume that was less than 1% of the final total injected volume. The granite block's physical size, drained outer boundary, and close well spacing limited the maximum fracture size and limited the maximum possible acoustic emission event magnitude. In effect, this laboratory experiment serves as a near-perfect example of fracture caging reducing induced seismicity.

The EGS Collab project (Kneafsey et al., 2019) in Lead, South Dakota, started in 2017 and is ongoing. This project drilled eight 60 m long wells from a 1480 m depth tunnel in schist at the Sanford Underground Research Facility (Figure 4). Water injection created a complex fracture flow network with fracture locations identified by a suite of methods that included microseismic monitoring. Induced seismic events were most prevalent during early high-rate injections and were later observed to decrease despite continued long term injection (Figure 3). This project is an example of a fully caged system because: (1) the injected fluid recovery eventually exceeded 95% of the injection rate, (2) seismicity was low after the initial small volume injections, and (3) it was very difficult to inject fluid past the monitoring wells and into the production well.

The hot dry rock geothermal project at Hijiori, Japan, lasted from 1985 to 2002 and included four wells with the deepest drilled to a maximum of 2300 m depth in granodiorite (GERD, 1997). The rate of microseismic events was high during the first low-volume injections to stimulate the wells, but the events decreased when production wells were brought online. In fact, seismicity dropped so low during the 1991 circulation tests that the operators decided to do an "AE promotion test" (GERD, 1991) where injection rates were increased by a factor of three to successfully induce microseismicity and confirm that the sensor network was functioning. The trend of renewed induced seismicity and larger induced seismic events due to increased injection

rates was consistent through the project to 1995 (GERD, 1995). We lacked access to sufficient data after 1995 for its inclusion in our analysis. This project is a field example of fracture caging with partial containment because recovery of the injected fluid from production wells during circulation tests ranged from 30% to 77%, so some injected fluid was not contained within the targeted stimulated reservoir volume.

Production at 100% of the injection rate is not the only factor for reduced seismicity. For example, seismic events greater than M_w 2 were observed during circulation tests at the four-well, 3800 m deep, geothermal site at Soultz-sous-Forêts, France, where operations use 100% reinjection of produced fluids (Cuenot, 2011). In this case, seismic event locations indicate fault activations both away from and between the wells. Also, tracer tests indicated that around 65% of the produced fluid could be natural brine from the surrounding environment (Schill et al., 2017). This indicates that 65% of the high-pressure injected fluid could be leaking away to cause seismicity even though injection and production rates were equal. A complete fracture caged system would be indicated by closer to 100% recovery of injected fluid, perhaps using conservative tracers to confirm a closed-loop system.

4. Challenges from Natural Complexity

Fracture caging to successfully control fluid flow and reduce seismic risk is likely to be sensitive to rock heterogeneity, anisotropy, injection parameters such as fluid viscosity, and general site uncertainty. We investigate complex and dynamic flow through fracture caged systems using laboratory experiments, the highly characterized EGS Collab project, and insights gained from Soultz-sous-Forêts.

Modifying the setup from the plate flow experiments in Figure 2, we injected blue-dye into the plate flow model after placing a random distribution of 600 mesh glass beads and air bubbles (Figure 4a,b). Simultaneously, we produced fluid at the same rate from four production wells. In this heterogeneous situation, two production wells became clogged with beads and ceased flowing part way through the experiment. The wells that continued to flow were able to contain the flow in their respective directions despite the added complexity in this experiment. A model with GEOS predicted a similar result by adding stress heterogeneity to the fracture propagation and flow model. These results indicate that more wells are preferable to maximize the likelihood of successful fracture caging.

Evidence of transient and dynamically changing flow through a fracture cage was observed by the EGS Collab Project (Kneafsey et al., 2019). Multi-day constant injection-rate tests between October 2018 and April 2019 resulted in erratic flow rates from all the production wells, never reaching a steady state. Initially, water was dominantly produced from the open production well but this changed when a monitoring well (OT) began to produce the most fluid after its cement seal failed. Over time, all wells and the tunnel became production wells. Over 85% recovery of the injected fluid was achieved during the project. The combined well production provided the high recovery and the multiple wells improved adaptability to the dynamic system.

We have shown that fracture caging is subject to limitations, but it can still be successful in complex situations. Undesirable situations do exist, such as when fracture network flow bypasses production wells, as was apparent at Soultz-sous-Forêts. Stochastic evaluations that directly consider these scenarios would help optimize well placement to mitigate against complications. Confirmation of caging can be attained by miscroseismic and tracer surveys. Successful caging will depend on confirmation efforts and careful planning that considers complications and anticipates changes to the well system based on the results of the confirmation effort.

5. Conclusions

We offer that fracture caging can mitigate the induced seismicity hazards from high-pressure fluid injection or low-pressure fluid production by arrangements of wells that: (1) inhibit fracture growth, (2) contain pressure perturbations, (3) limit seismic slip lengths, and (4) limit maximum seismic magnitudes. This is akin to creating a closed-loop flow system inside of an open fracture network. Heterogeneity is a challenge for fracture caging that can be overcome by intelligent stochastic design. In addition to limiting seismicity, our models, experiments, and field data analysis indicate that fracture caging can improve fluid containment, increase resilience to dynamic conditions, and enable safe long-term high-pressure fluid injection. While the complete limitations are yet to be determined and more studies may be needed to improve confidence, fracture caging could be a path for increased geothermal energy production at a reduced risk of induced seismic events. It does not escape our notice that fracture caging could have implications beyond geothermal energy, such as for waste disposal wells.

Acknowledgements and Data Availability

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Author contributions: Laboratory experiments were conducted and analyzed by L.P.F., J.C.H., and N.J.W. Data from the EGS Collab site was collected by the EGS Collab team with the values in this manuscript extracted by L.P.F., G.N., and P.F. Numerical modelling with GEOS was performed by P.F. and J.M. Projects making this work possible were led by M.G., J.W.C., and T.K.

Competing interests: All authors declare no conflicts of interest.

Data and materials availability: Data for the Hijiori Hot Dry Rock project seismic events was provided by Yanagisawa, N. The EGS Collab project is ongoing with data available on the Geothermal Data Repository (GDR).

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Figures

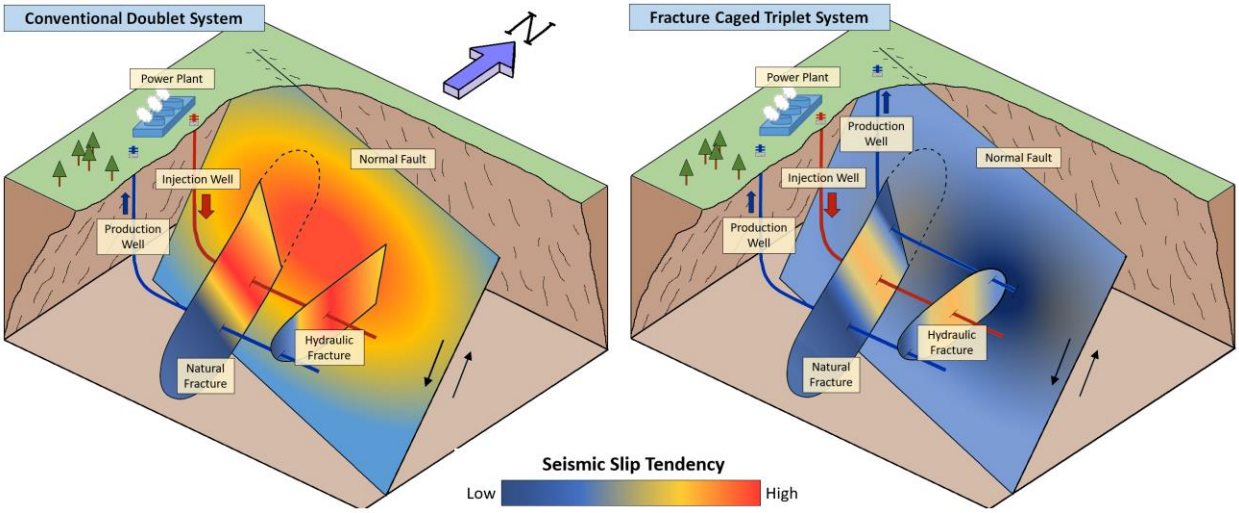

Figure 1. Fracture caging to limit seismic slip tendency from geothermal injection wells. The placement of injection and production wells can limit the disturbed volume of rock.

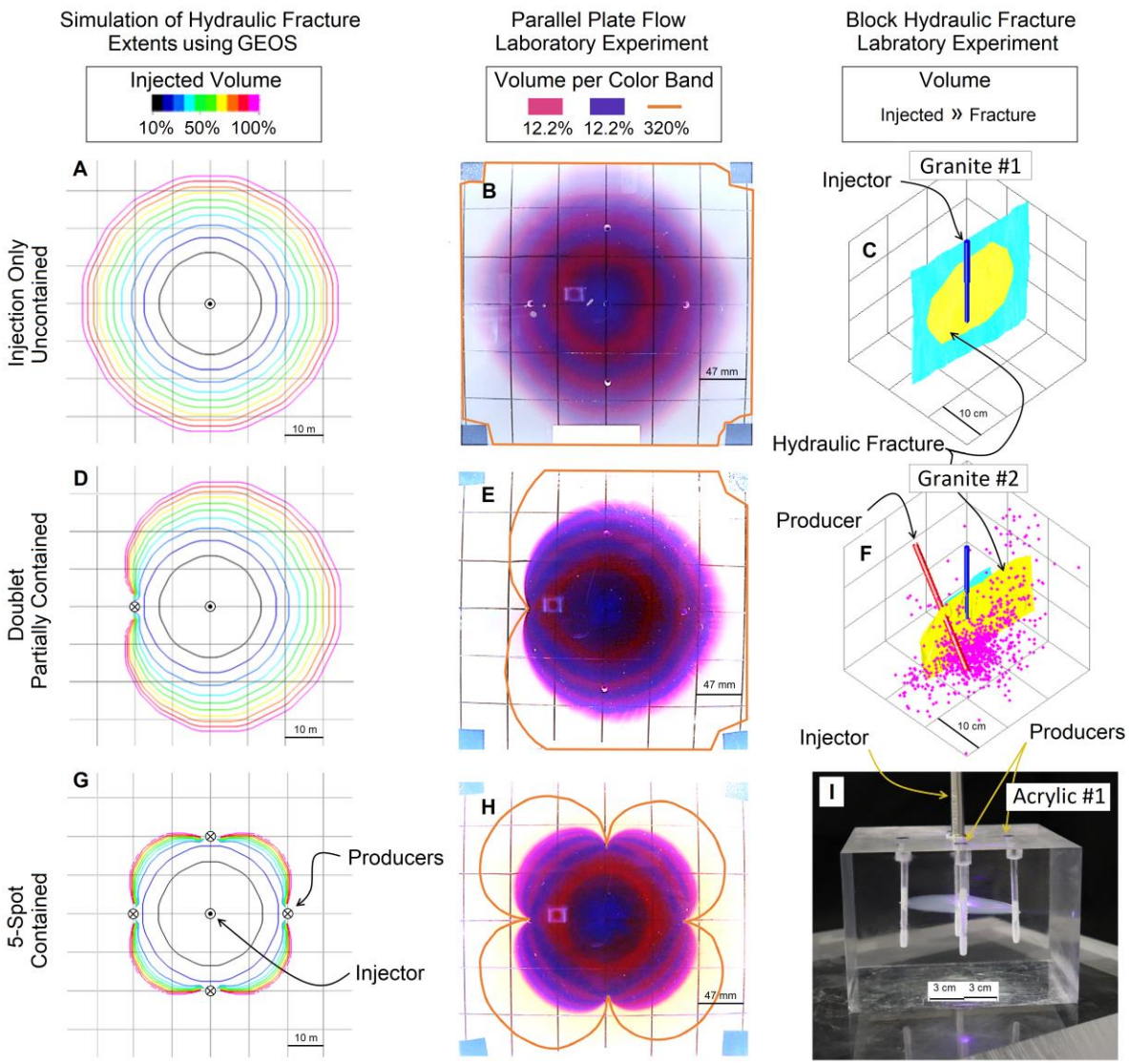

Figure 2. Model and experiments exhibiting fracture caging mechanisms. Fracture growth and fluid flow are uncontained during injection without production as evidenced by **(A)** hydraulic fracture model prediction, **(B)** parallel plate flow experiments, and **(C)** cut-sections after hydraulic fracturing in a granite block. Drilling one production well prior to injection can partially contain fracture growth and fluid flow during injection as shown by **(D)** model prediction for a doublet, **(E)** parallel plate flow experiments with a doublet, and **(F)** stimulation of a doublet in a granite block with acoustic emission hypocenters shown. A 5-spot fracture cage drilled prior to injection enables containment of fracture growth and fluid flow as found by **(G)** model prediction, **(H)** parallel plate flow experiments, and **(I)** hydraulic fracturing an acrylic block.

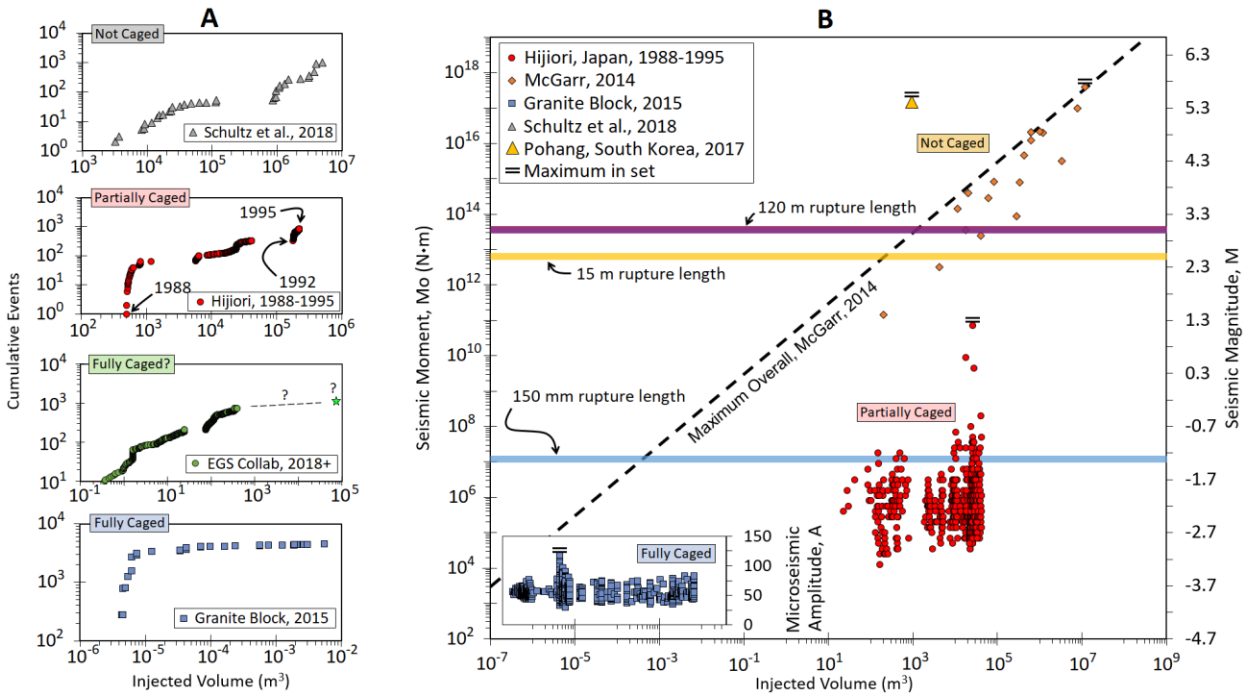

Figure 3. Induced seismicity behavior with and without fracture caging. **(A)** Cumulative seismic events plateau with increasing injected volume for fully caged fractures in a laboratory granite block (Frash et al., 2015) and at the EGS Collab experiment site (Kneafsey et al., 2019) but this effect is less pronounced in for the leaky partially caged fracture system at the Hijiori Hot Dry Rock Geothermal Power Project in Japan (GERD, 1997) and almost absent in the injection dominated Duvernay Shale Play in Canada (Schultz et al., 2018). **(B)** Seismic or acoustic event magnitudes peak at lower maximum magnitudes as a function of injected volume in the fully caged laboratory granite block and the partially caged Hijiori project than the peaks observed for injection dominated systems (McGarr, 2014). Predicted maximum seismic magnitudes (Eq. 1) for the block experiment, EGS Collab, and Hijiori are shown as a function of the well spacing at 150 mm, 15 m, and 150 m, respectively.

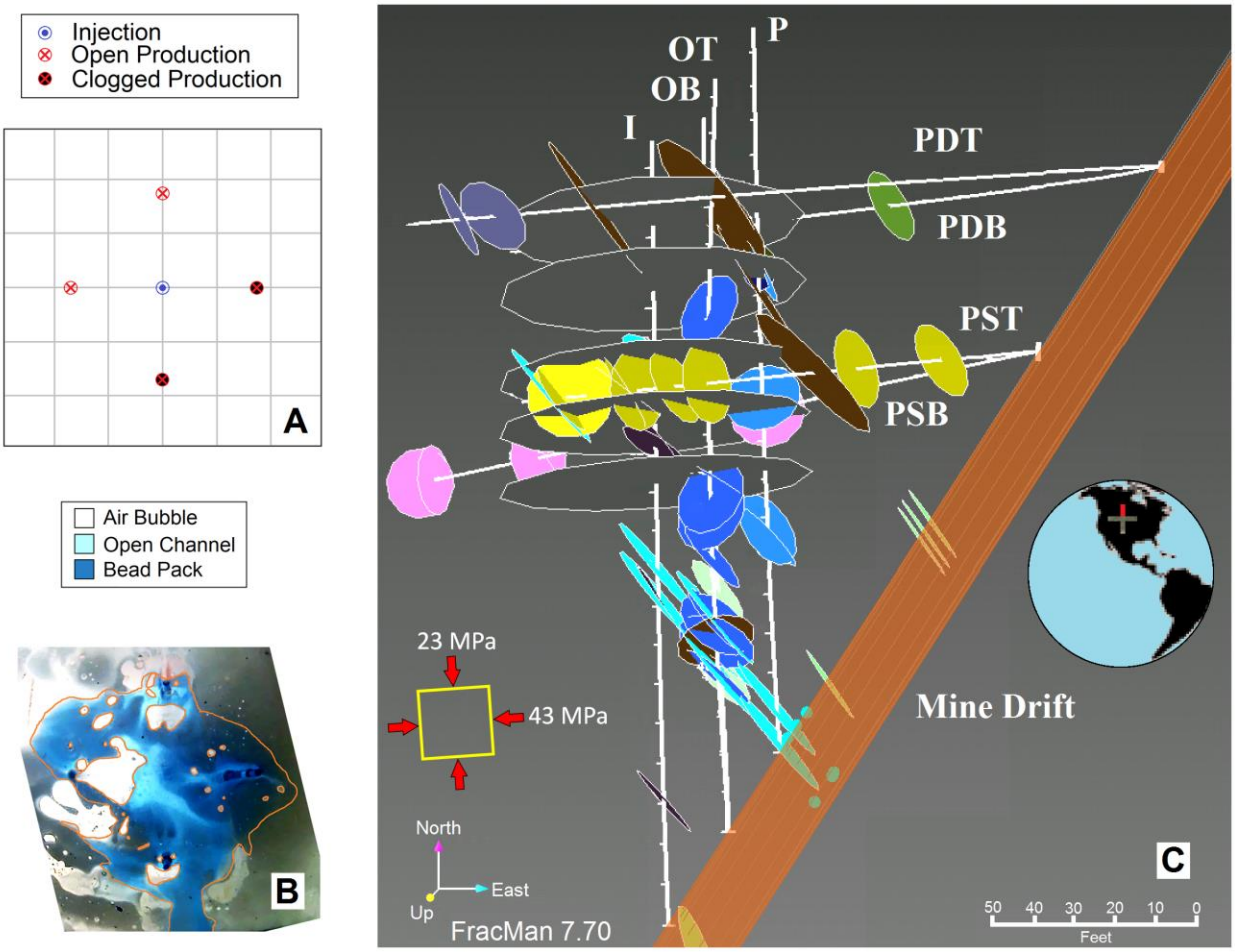

Figure 4. Complexity in fracture dominated flow systems. **(A)** Glass beads clogging some production wells and **(B)** resulting partially caged flow in a heterogeneous parallel plate flow test. **(C)** Surveyed layout of EGS Collab Experiment 1 with an injection hole (I), a production hole (P), six instrumented monitoring holes (OT, OB, PST, PSB, PDT, and PDB), and fractures that are interpreted to be significant for fluid flow (discs).