Engineering Geology 175 (2014) 74–80

Contents lists available at ScienceDirect

Engineering Geology

journal homepage: www.elsevier.com/locate/enggeo

Correlations between formation properties and induced seismicity during high pressure injection into granitic rock

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ARTICLE INFO

Article history:
Received 17 August 2013
Received in revised form 3 February 2014
Accepted 24 March 2014
Available online 2 April 2014

Keywords:
Induced seismicity
Geothermal
Water injection
Fault development
Rate and state friction

ABSTRACT

We reviewed published results from six projects where hydraulic stimulation was performed in granitic rock. At each project, fractures in the formation were well-oriented to slip at the injection pressures used during stimulation. In all but one case, thousands of cubic meters of water were injected, and in every case, flow rates on the order of tens of liters per second were used. Despite these similarities, there was a large variation in the severity of induced seismicity that occurred in response to injection. At the three projects where induced seismicity was significant, observations at the wellbore showed evidence of well-developed brittle fault zones. At the three projects where induced seismicity was less significant, observations at the wellbore indicated only crack-like features and did not suggest significant fault development. These results suggest that assessments of the degree of fault development at the wellbore may be useful for predicting induced seismicity hazard. We cannot rule out that the differences were caused by variations in frictional properties that were unrelated to the degree of fault development (and it is possible that there is a relationship between these two parameters). The projects with more significant seismicity tended to be deeper, and if this is a meaningful correlation, it is unclear whether depth influenced seismic hazard through the degree of fault development, frictional properties, or some other variable. The results of this paper are not conclusive, but they suggest that there may be significant opportunity for future research on identifying geological conditions that increase induced seismicity hazard.

1. Introduction

Induced seismicity is an issue of growing importance for the exploitation of geothermal energy (Majer et al., 2007, 2011; Cladouhos et al., 2010; Evans et al., 2012), wastewater disposal (Frohlich et al., 2011; Kim, 2013; Zhang et al., 2013), CO_2 sequestration (Zoback and Gorelick, 2012), hydrocarbon production (Suckale, 2009), and other activities (McGarr et al., 2002; Hitzman, 2012). Appropriate management of induced seismicity requires estimation of induced seismic hazard.

Some methodologies for estimating induced seismic hazard are purely statistical (Bommer et al., 2006; Bachmann et al., 2011) or hybrid statistical/fluid flow models (Shapiro et al., 2007; Gischig and Wiemer, 2013). However, these methods are site-specific and must be conditioned by performing the activity for which seismic hazard needs to be assessed. Low natural seismicity does not necessarily indicate that induced seismic hazard will be low, though there is some correlation (Evans et al., 2012).

In addition to purely statistical methods, numerical simulation has been used for induced seismic hazard analysis. This may involve kinematic modeling of deformation to estimate induced stress on neighboring faults (Segall, 1989; Hunt and Morelli, 2006; Vörös and Baisch, 2009) or dynamic modeling that couples fluid flow, stresses induced by deformation, and friction evolution (Baisch et al., 2010; McClure and Horne, 2011). However, model results are dependent on assumptions and input parameters that may be challenging to estimate. For example, change in stress on a fault may be estimated, but it is unclear how this should be related quantitatively to increased hazard (due to uncertainties such as the fault stress state and frictional properties).

All approaches to induced seismicity hazard analysis, whether purely statistical, physically based, or a hybrid of both, could benefit from methodologies that relate geophysical and geological observations to hazard (e.g., Davis and Frohlich, 1993). McGarr (1976) predicted that induced seismic moment release should be proportional to the volume of fluid injected, and this has been borne out by subsequent experience (Rutledge et al., 2004; Bommer et al., 2006; Hunt and Morelli, 2006; Baisch and Vörös, 2009). However, the constant of proportionality between injection volume and moment release varies over orders of magnitude between different locations. For example, there are over 35,000 wells in the United States that have been hydraulically fractured in unconventional shale resources, and there are only a handful of

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http://dx.doi.org/10.1016/j.enggeo.2014.03.015

confirmed instances of an induced event felt at the surface (page 76 of Hitzman, 2012). Induced seismicity does appear to be associated with oil and gas activities in many cases, but this is apparently due to long term fluid injection (Frohlich et al., 2011) or extraction (van Eijs et al., 2006). On the other hand, hydraulic stimulation for exploitation of geothermal resources in crystalline rock has routinely induced seismic events felt at the surface (Majer et al., 2007, 2011; Cladouhos et al., 2010; Evans et al., 2012). Even among geothermal hydraulic fracturing projects, a huge diversity in induced seismicity hazard has been observed (Table 1; Kaieda et al., 2010). More work is needed to explain how geological conditions cause these large variations in induced seismicity.

It is universally accepted that hydraulic fracturing in an oil and gas settings causes the initiation and propagation of new fractures (Economides and Nolte, 2000). However, during injection, fluid could leakoff into existing faults and cause slip (and potentially seismicity). In EGS, it is typically believed that injection predominantly causes induced slip on preexisting fractures (Cladouhos et al., 2011), though some authors have argued that there is probably more new fracture propagation than is commonly believed (McClure, 2012; Jung, 2013; McClure and Horne, submitted for publication).

For significant induced seismicity to occur: (1) faults must be oriented properly with respect to the prevailing stress field so that they slip in response to imposed changes in stress and/or fluid pressure, (2) faults must have appropriate frictional properties so that slip occurs rapidly enough to generate seismicity, and (3) faults must be large enough to host significant events.

The first requirement, appropriately oriented faults, can be understood in the context of Coulomb theory (Chapter 2 of Hitzman, 2012). It has been argued that, in general, the crust is in a state of failure equilibrium (Townend and Zoback, 2000), suggesting that nearly everywhere in the subsurface, faults are present that will slip in response to an increase in fluid pressure.

The second requirement, rapid slip, can be explained in the context of results from laboratory friction experiments. Experiments have shown that the tendency for faults to slip seismically (rapidly) or aseismically (gradually) depends on the frictional properties of the minerals contacting in the fracture walls. Rock type, temperature, and other factors affect the tendency for fractures to slip seismically or aseismically (Dieterich, 2007).

There is a significant untapped opportunity to apply the results from friction experiments to help relate induced seismic hazard to lithology and depth. For example, differences in frictional properties may be the reason why hydraulic fracturing in granite has led to much greater induced seismic hazard than hydraulic fracturing in sedimentary formations. Assessments of induced seismic hazard from fluid injection in sedimentary formations (e.g. CO_2 sequestration or wastewater disposal) would benefit from efforts to identify lithologies where fault frictional properties are most favorable for seismic slip. Zhang et al. (2013) identified an apparent correlation between induced seismicity hazard and injection into basal aquifers.

The third requirement is that faults must be large enough to host significant-sized events. Seismic imaging and stratigraphic study can be used to identify major faults in layered formations. But in nonlayered formations such as crystalline basement rock, these techniques are limited because of the lack of seismic reflectors and discernible stratigraphic offsets. A very thick fault zone is required to generate a visible reflection at significant depth in crystalline rock. Faults in the basement may not extend into the overlying sediments. Even in layered sedimentary formations, hidden faults may be capable of hosting significant induced seismicity.

In this paper, we investigate whether wellbore observations could be used to estimate induced seismic hazard by assessing the degree to which large, brittle faults are present in a formation. Wells only sample the formation locally and may not intersect the most seismically important faults. However, formations that contain large faults are likely to contain abundant faults at all levels of development, and the overall degree of fault development in the formation should be observable at the wellbore. This theory is supported by the general observation that induced seismicity typically follows a Gutenberg–Richter distribution (Baisch et al., 2009, 2010; Bachmann et al., 2011), that large faults are surrounded by sizable damage zones, and that fracture size distributions are usually found to obey a power law or exponential distribution (Chapter 3 of Scholz, 2002). The mechanistic reason is that faults develop from accumulated deformation over time, starting with small, isolated cracks, which eventually link up and develop into large, continuous features (Chapter 3 of Segall and Pollard, 1983; Scholz, 2002; Mutlu and Pollard, 2008). We refer to formations that have significantly developed faults that have linked up and formed larger features as having a high "degree of fault development."

To test whether the degree of fault development may be correlated to induced seismic hazard, we reviewed six projects where hydraulic stimulation (high rate fluid injection) was performed in granitic rock for the exploitation of geothermal energy: the projects at Cooper Basin, Australia; Soultz, France; Ogachi, Japan; Rosemanowes, United Kingdom; Basel, Switzerland; and Fjällbacka, Sweden. Projects using hydraulic fracturing to develop geothermal energy reservoirs are sometimes called "Enhanced Geothermal Systems,", or EGS. Some well-known EGS projects in granite, such as the projects at Fenton Hill, USA and Hijiori, Japan, were not included in this study because we were unable to find references that would permit an assessment of the degree of fault development. The Rosemanowes and Fjällbacka projects were performed for research purposes and targeted lower temperature reservoirs than would be typical for geothermal exploitation.

To control for the possible effect of lithology on the frictional properties of the faults, only projects in granite were included. To minimize the potential effect of fault orientation, we included only hydraulic stimulation tests where large injection pressures were used. The bottomhole fluid pressure likely reached or exceeded the minimum principal stress at every project considered, except possibly Basel, where estimates of the minimum principal stress are not available (McClure and Horne, submitted for publication). At these elevated pressures, faults with a

Table 1
Summary of experiences with induced seismicity at six EGS projects. Supporting references are given in the text below. The assessments of "volume of fluid injected" are not necessarily complete because in some projects a variety of different injection operations were carried out over many years. We have not made an extensive effort to document all of the injections performed at these projects.

	Depth range	Maximum magnitude	Temperature	Degree of fault development	Volume of fluid injected during stimulation
Basel	4.6–5.0 km	3.4	190 °C at 5.0 km	High	11,570 m^3
Cooper Basin (Habanero 1)	4.1–4.4 km	3.7	250 °C at 4.4 km	High	20,000 m^3 in 2003, 25,000 m^3 in 2005
Fjällbacka	0.5 km	−0.2	16 °C at 0.5 km	Low	400 m^3 in Fjb1 and 36 m^3 in Fjb3
Ogachi (OGC-1)	0.99–1.0 km	−1.0 except a 2.0 outlier	230 °C at 1.0 km	Low	10,140 t (approximately 9200 m^3)
Rosemanowes	1.7–2.65 km	0.16	100 °C at 2.6 km	Low	100,000 m^3 over two months in RH11 and RH12 (1982) and 5700 m^3 in RH15 (1985)
Soultz (shallow)	2.8–3.4 km	1.9	150 °C at 3.4 km	High	Two stimulations of 20,000 m^3 each
Soultz (deep)	4.5–5 km	2.9	200 °C at 5.0 km	High	Three wells stimulated at volumes between 20,000 and 35,000 m^3