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Modeling of fault activation and seismicity by injection directly into a fault zone associated with hydraulic fracturing of shale-gas reservoirs

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ABSTRACT

We conducted three-dimensional coupled fluid-flow and geomechanical modeling of fault activation and seismicity associated with hydraulic fracturing stimulation of a shale-gas reservoir. We simulated a case in which a horizontal injection well intersects a steeply dipping fault, with hydraulic fracturing channeled within the fault, during a 3-h hydraulic fracturing stage. Consistent with field observations, the simulation results show that shale-gas hydraulic fracturing along faults does not likely induce seismic events that could be felt on the ground surface, but rather results in numerous small microseismic events, as well as aseismic deformations along with the fracture propagation. The calculated seismic moment magnitudes ranged from about −2.0 to 0.5, except for one case assuming a very brittle fault with low residual shear strength, for which the magnitude was 2.3, an event that would likely go unnoticed or might be barely felt by humans at its epicenter. The calculated moment magnitudes showed a dependency on injection depth and fault dip. We attribute such dependency to variation in shear stress on the fault plane and associated variation in stress drop upon reactivation. Our simulations showed that at the end of the 3-h injection, the rupture zone associated with tensile and shear failure extended to a maximum radius of about 200 m from the injection well. The results of this modeling study for steeply dipping faults at 1000 to 2500 m depth is in agreement with earlier studies and field observations showing that it is very unlikely that activation of a fault by shale-gas hydraulic fracturing at great depth (thousands of meters) could cause felt seismicity or create a new flow path (through fault rupture) that could reach shallow groundwater resources.

1. Introduction

The rapid increase in North American shale-gas energy production has been made possible through new technology development, including extended-reach horizontal drilling and multistage hydraulic-fracture stimulation. But these new technologies have also raised concerns related to a range of local environmental problems (Arthur et al., 2008; Zoback et al., 2010). One concern, investigated in this study, is whether shale-gas hydraulic fracturing could activate faults and thereby cause seismicity, opening up flow paths for upward fluid leakage and possible contamination of shallow potable groundwater resources (Arthur et al., 2008; Zoback et al., 2010; Davies et al., 2013; Rutqvist et al., 2013).

A first modeling study to investigate the potential consequences of fault reactivation during shale-gas hydraulic fracturing operations was presented in Rutqvist et al. (2013). Consistent with field observations, the study showed that a hydraulic fracturing operation to stimulate a deep shale-gas reservoir could only give rise to limited fault rupture, along with the possibility of (unfelt) microseismicity. In another study, Flewelling et al. (2013) used injection data and elastic fracture volume and length relationships to bound fracture-height data from 12,000 hydrofracturing stimulations conducted across North America. The hydraulic fracturing data showed that all microseismic events occurred less than 600 m above well perforation, although most were very much closer, and the farthest were usually associated with faults. These studies indicated that shale-gas hydraulic fracturing at great depth (thousands of meters) could not create flow paths for leakage to reach shallow groundwater resources.

Studies have also concluded that the likelihood of inducing felt seismicity during shale-gas hydraulic fracturing operations, while not to be ruled out completely, is extremely small (National Research Council, 2012; Davies et al., 2013). Indeed, after hundreds of thousands of shale-gas fracturing stages conducted to date, only three examples of felt seismicity have been documented (Davies et al., 2013). In Lancashire County, UK, two seismic events of Richter scale magnitude M_L=2.3 and 1.5 were likely induced by direct injection into a fault zone that had not been previously mapped (De Pater and Baisch, 2011). In another case at the Eola Field of Garvin County, Oklahoma, in January 2011 (Holland, 2011), there was a clear temporal correlation between the time of stimulation and the occurrence of 43 earthquakes

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that ranged in magnitude from $M_D=1.0$ to 2.8 (M_D is the duration magnitude). Finally, the third case of felt seismicity occurred at Etsho and Kiwigan fields in Horn River, Canada, where 19 events between $M_L=2$ and 3 occurred having a clear temporal correlation with the shale-gas operation; the largest (and felt) event, occurring in May 2011, had a magnitude of $M_L=3.8$ (BC Oil and Gas Commission, 2012; Davies et al., 2013). Each of these three cases of felt seismicity, as well as a recently reported case of larger than usual events in Ohio (Skoumal et al., 2015), have all been associated with reactivation of faults.

The biggest modeling uncertainty in the previous fault-activation modeling by Rutqvist et al. (2013) was a 2D simplification of the full 3D field settings. In 2D plane-strain simulations, it is difficult to estimate a representative injection rate, and some assumptions have to be made about the shape of the rupture area (e.g., circular with diameter equal to 2D rupture length), which affects the calculated seismic magnitude. In this study we conduct, for the first time, a full 3D model simulation of fault activation associated with shale-gas fracturing. In such a 3D model simulation, the exact injection rate from the 3D field is a direct model input, and the seismic magnitude can be evaluated directly from the calculated rupture area and mean slip without the model uncertainties inherent in a 2D simplification. In this new 3D modeling study, we simulate the case in which a horizontal well intersects a subvertical fault, which then can be reactivated by injection directly into the fault. In addition, we investigate some issues not addressed in the previous 2D modeling in Rutqvist et al. (2013), including how the results correlate with fault and injection depth, fault dip, and fault frictional properties. We conclude with a discussion relating our modeling results to field observations and attempt to explain under which conditions a shale-gas fracturing stimulation could induce a felt seismic event.

2. Model setup

We adopted the modeling approach that was applied in the previous 2D modeling study in Rutqvist et al. (2013). That is, we used the coupled multiphase fluid-flow and geomechanical simulator TOUGH-FLAC (Rutqvist, 2011) to model water-injection and fault responses, and we applied seismological theories to estimate the corresponding seismic magnitude. The fault was modeled as a discrete feature using finite thickness elements having anisotropic elasto-plastic properties. Shear failure was governed by a Mohr–Coulomb constitutive model with strain-softening frictional strength properties, consistent with a seismological slip-weakening fault model (Cappa and Rutqvist, 2011). This allowed us to model sudden (seismic) slip events and to estimate their seismic magnitude. The adopted modeling approach has also been extensively applied for modeling fault activation associated with underground CO_2 injection (e.g. Rutqvist et al., 2007; Cappa and Rutqvist, 2012; Mazzoldi et al., 2012; Rinaldi et al., 2014a).

The model domain and the material properties are presented in Fig. 1 and Table 1, respectively. We model a full 3D-geological system (x, y, z: 2 km × 10 km × 2 km) generally tuned towards conditions that could be encountered in the Marcellus shale-gas play in the Northeastern U.S. This includes model input of in situ stress, fluid pressure, temperature, material properties, and injection rates. In a base-case simulation, we adopt conditions consistent with areas where the Marcellus shale is located at a depth of about 2000 m (6562 ft). The model is representative of the Marcellus shale-gas play with a 30 m thick gas-bearing shale, bounded at the top and bottom by other low-permeability formations (such as inorganic gray shale and limestone). This system is intersected by a steeply dipping fault, which in the base case has a dip of 80°. We simulate a case in which the horizontal injection well intersects the fault, and we inject the fluid volume related to a 3-h hydraulic fracturing stage directly into the fault.

We set the initial conditions assuming linear pore pressure and temperature gradients (9.81 MPa/km and 25 °C/km, respectively), with constant hydraulic boundary conditions (i.e., open to fluid flow), except for the planes $x=0$ and $y=0$ where a no-flow condition is applied (Fig. 1). Mechanical boundary conditions are null displacement at $x=0$ and $y=0$ planes, and constant stress elsewhere. The initial stress field is selected to represent the conditions at the Marcellus shale play as detailed and justified in Rutqvist et al. (2013). We first set the vertical stress gradient (maximum principal stress) to 26,487 Pa/m, corresponding to an overburden density of about 2700 kg/m^3. We then consider the minimum principal stress to be horizontal and oriented parallel to the horizontal well, which would lead to vertical hydro-fractures perpendicular to the well, but which in this case follow the weak planes of the fault. This does also correspond to a normal faulting stress field, in which the minimum horizontal stress (and minimum principal stress) is directed normal to the strike of the fault. We set the magnitude of the initial minimum horizontal stress corresponding to a horizontal-over-vertical stress ratio of $R=\sigma_h/\sigma_V=0.6$. There are uncertainties in the horizontal-over-vertical stress ratio and, as highlighted by Rutqvist et al. (2013), this ratio has an impact on the magnitude of fault shear activation. However, several sources (e.g. Cipolla et al., 2010) indicate a fracture closure stress of about 0.7 psi/ft and this corresponds to a horizontal-over-vertical stress ratio of $R=\sigma_h/\sigma_V=0.6$. In this study, we keep the horizontal-over-vertical stress ratio fixed at $R=\sigma_h/\sigma_V=0.6$, but vary the depth of the system, which also means a variation in stress magnitude at the depth of the injection. The magnitude of the intermediate stress, which in this case of a normal faulting stress regime would be oriented parallel to the fault strike does not affect the potential for shear failure along the fault.

Another important parameter in our analysis is the shear strength of the fault and how it evolves along with the reactivation. Here, we use the strain-softening Mohr–Coulomb model, in which the coefficient of friction and cohesion decreases with slip, i.e., once the peak shear strength is achieved and the fault slips, the cohesion drops to zero and the coefficient of friction drops to a residual value. In the numerical model, this is simulated by reducing the coefficient of friction and cohesion from peak to residual values over a plastic shear strain of 10^{-3} (Cappa and Rutqvist, 2011). In the base case, we use a coefficient of friction of $\mu=0.6$, with a residual value (after slip) equal to $\mu_R=0.4$, whereas the cohesion drops to zero from an initial value of 1 MPa. A larger difference between the peak and residual friction values represents a more brittle behavior that is expected to lead to a larger shear-stress drop and seismic event. The selection of the frictional coefficient parameters are also discussed and justified in Rutqvist et al. (2013), acknowledging that this is one possible set of reasonable values of the frictional coefficient. The fault shear strength and how it weakens with slip is defined by a set of parameters that are varied in this study.

Other fault properties as well as properties of the shale listed in Table 1 are equivalent to those used and justified in Rutqvist et al. (2013). In this study, we assume that the fault is nearly impermeable (hydraulically indistinguishable from the host rock), though the permeability and porosity can increase as a result of fracturing and shear. We consider a nearly impermeable fault a realistic assumption in this case. As pointed out by Flewelling et al. (2013), hydrocarbons cannot accumulate where there are permeable faults serving as pathways for buoyant oil and gas to leak upward. A relevant example of an impermeable fault in shale is a fault zone in Opalinus Clay exposed at the Mont Terri Rock Laboratory, Switzerland (Croisé et al., 2004). This zone is several meters thick, consists of intensively fractured rocks, has an inferred shear offset of 5 m, but is still hydraulically indistinguishable from the host