PROCEEDINGS, 43rd Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 12-14, 2018
SGP-TR-213

Modeling Potential EGS Signals from a Distributed Fiber Optic Sensor Deployed in a Borehole

Robert J. Mellors, Christopher Sherman, Rick Ryerson, Joseph Morris, Michael Messerly, Charles Yu, and Graham Allen

Lawrence Livermore National Laboratory, 7000 East Avenue, Livermore, CA, 94550, USA

mellors1@llnl.gov

Keywords: EGS, DAS, fiber optic, fracture modeling, microseismic

ABSTRACT

Distributed fiber optic sensors installed in boreholes provide a new and data-rich perspective on the near-borehole environment. These sensors measure strain (or strain-rate) with high spatial resolution and can survive extreme conditions. These sensors should be capable of enduring the high temperatures that exist in Enhanced Geothermal System (EGS) boreholes. Here, we explore the information that these sensors may reveal in a EGS system. Potential EGS subsurface signals are simulated in two ways: 1) a massively parallel multi-physics code that is capable of modeling hydraulic stimulation of heterogeneous reservoir with a pre-existing discrete fracture network, and 2) a parallelized 3D finite difference code for high-frequency seismic signals. The approach matches both the low-frequency strain signals generated during the fracture process and higher-frequency signals from microseismic and perforation shots. Results indicate that quantitative interpretation of the fiber data provides valuable constraints on the fracture geometry and microseismic activity, both of which are key to understanding an EGS system. These sensors are subject to varying types of noise, both external and internal and we evaluate potential sources of noise such as the electronics, fiber/cable, and subsurface to improve interpretation of the signals and the characteristics of each noise type. In addition, we examine the likely failure mechanisms of fiber sensors in the typical EGS environment and provide suggestions on ways to improve performance and durability. Ultimately, a robust system understanding will allow identification of areas for future improvement and possible optimization in fiber and cable design.

1. INTRODUCTION

Distributed Acoustic Sensors (DAS) refers to a fiber optic-based sensor that measures strain (or strain rate) as a function of time along an optical fiber. The basic principle is simple and relies on Rayleigh scattering. An interrogator box sends laser pulses down the fiber, where imperfections in the fiber backscatter small portions of each pulse as they pass through the fiber. These reflections return to the interrogator box where the phase is measured. Variations in the returned phase over time provide measurements of the strain at all points along the fiber (Hartog, 2017). The sensitivity and resolution, both spatial and temporal, are sufficient to capture a wide range of signals, from near DC to transient strains from seismic waves, in ideal conditions.

As the sensor essentially records axial strain along the fiber, the response differs significantly from a standard seismic sensor and depends on the implementation. Some instruments return strain as a function of time while others return strain rate. For both types, the strain (or strain rate) is measured as an average over segments, defined as the gauge length. The gauge length is controlled by the parameters of the laser pulses and implementation but typically ranges between 1 and 15 m. The spacing between measurements, generally referred to as the channel distance, can be shorter than the gauge length. For straight fibers, the response is at a maximum for waves travelling parallel to the fiber but decreases sharply at angle and roughly as $\cos^2\theta$, where θ is the angle with respect to the fiber axis. It is possible to deploy the fiber in a helix to reduce the azimuthal dependency. Another problem occurs when wavelengths are near, or less than the gauge length, in which spatial aliasing will corrupt the signal (Dean et al., 2017). Current DAS sensors have higher instrumental noise floors than seismic sensors but appear to have a wider frequency response than geophones. Sensitivity is likely to improve with newer instruments, as the improvement in recent years has been considerable. An area of some uncertainty is the effect of the coating, cabling, and coupling with surrounding media on the response. Theoretical work by Reinisch et al (2017) suggest that at wavelengths longer than about 22 m the cable should react elastically. Mateeva et al., (2014) indicates that the differences in elastic moduli between the fiber and the surrounding rock should be taken into account when calculating amplitudes.

Fiber sensors are particularly useful in wells, as deployment is easier than deploying strings of geophones and the fiber does not interfere with operations (Mateeva et al., 2014). This has led to widespread adoption in the petroleum industry, where the fibers are frequently installed outside the casing. It is also possible to install fiber inside casing but usually with a significant decrease in sensitivity. In the petroleum industry, the DAS fiber data is used to monitor stimulations, record vertical seismic profiles, microseismic events (Webster et al., 2013a; Karrenbach et al, 2017) and fracture detection (James et al., 2017, Webster et al., 2013b). A more recent development is the ability to measure low-frequency response (< 0.05 Hz) which clearly shows strain associated with the opening and closing of fractures which allows direct imaging of fractures (Jin and Roy, 2017; Hull et al., 2017).

Less use of DAS has been made in geothermal wells, although a related technology, distributed temperature sensing, has been deployed (e.g. Patterson et al., 2017, Petty et al., 2013) and provides useful constraints on injection flow. Reinsch et al., (2016) deployed a fiber optic cable in a well in the Reykjanes geothermal field, Iceland and also recorded surface data from unused telecom fiber. Fiber DAS data was also collected at the Brady geothermal field (Feigl et al., 2017), in conjunction with an extensive deployment of geophones, geodetic measurements, and an active seismic experiment. Most of the DAS data was collected on the surface although 400 m of fiber was deployed inside a well.

An additional advantage of fiber sensors in geothermal wells is their robust performance at high temperatures. As all of the electronics are on the surface, it only the fiber and surrounding cable needs to be resistant. Optical fibers are composed of silica glass surrounding by a coating for mechanical protection and then embedded in a cable. Silica glass is extremely resistant to high temperature (up to 800° C), but typical polymer coatings are not (< 100° C). Polyamide coatings show better resistance (~ 300 °C). For higher temperatures, it is likely necessary to use metal coated fiber, such as aluminum (~400° C, forms oxide but may weaken fiber), copper (~300° C but suffers from corrosion at higher temperatures), or gold (~700° C, expensive and may not adhere well). A secondary issue is hydrogen darkening, which is enhanced at high temperatures and will absorb select wavelengths. Thermal stress caused by differential expansion between silica and coating may also affect the fiber and increase attenuation. Reinsch et al., (2013) tested a custom fiber that combined polyamide with an additional carbon coating and was tested in a geothermal well that reached temperatures up to 280 C at the well head. Overall, performance was satisfactory but fiber degradation, as indicated by OTDR attenuation measurements, increased with time. This was attributed to the effect of the temperature and thermal/mechanical effects (including a severed cable during installation). The increased optical attenuation caused errors in the DTS measurements (DAS was not tested). Palit et al., (2012) tested both polyamide and aluminum coated fibers. The effect of hydrogen darkening was reduced by using a pure silica core and the design temperature is 400 C. A test case was deployed in a well in Nevada. In general, fibers and cables for temperatures in the 300-400 C range (and perhaps beyond) seems feasible but challenging.

For this study we explore, from a modeling perspective, what signals that a high-sensitivity fiber might record if deployed either in a nearby monitoring well or in a geothermal well during an EGS stimulation. We assume that the signal quality is comparable to that recorded from DAS deployed in oil and gas wells. We recognize that completions in a geothermal well differ from oil and gas and that monitoring wells may be difficult from an economic perspective, but this is intended as exploratory first effort and therefore these issues are not addressed in this work.

The goal is to assess whether available software can reproduce likely DAS signals, what information can be obtained from the signals, and what improvements could be made, both in data acquisition and interpretation. We believe, based on recent results, that low-frequency DAS can provide images of fracture propagation, extent, and geometry that is unavailable otherwise. This information could be used to validate and refine geomechanical models for EGS wells in the same field and possibly, if interpretation is available in near real-time, inform an ongoing stimulation. We focus on processes such as fracture and microseismic events away from the borehole. It is likely that borehole signals, including temperature and noise produced by flow or other well operations, will be essential in understanding actual operations but the basic challenge in EGS is creating a fracture system, understanding what was created, and then optimizing use for heat extraction. Consequently, we focus on monitoring reservoir processes.

2. METHODS

As the fiber sensor measures strain or strain rate, we need to model the strain produced from a slowly shearing or opening fracture and also from rapid microseismic events in the vicinity. Several possibilities exist. The simplest is to use analytic, or semi-analytic expressions. These typically (e.g. Mogi, 1958; Okada, 1992; Fialko et al., 2001) calculate stress throughout a 3D homogenous elastic media from a point source, planar fault or fracture, or penny-shaped crack. These methods are fast and simple but require a pre-determined geometry and may yield poor results in complex reservoir with substantial heterogeneities in material properties or stress state. Finite-element or finite difference models provide more flexibility in handling variations in material properties but at additional computational effort and again require definition of the initial fracture geometry and slip distribution. Multi-physics solvers handle the entire problem by including fluid flow, thermal effects, and rock mechanics and provide the benefit of providing solutions that are in theory consistent with more of the underlying physics.

In this work, we primarily use GEOS, a multi-physics package designed for computational rock mechanics (Settgast et al.,2016). This is intended primarily as a demonstration of what is possible rather than a fully realistic EGS model, which is beyond the scope of this paper. In additional to GEOS, we simulate microseismic signals using a 3D finite difference elastic wave propagation code.

2.1 GEOS models

GEOS is a multi-physics software package designed to simulate 3D reservoir stimulation. It employs a fully coupled finite element/finite volume approach to model initiation, propagation, and reactivation of hydraulically driven fractures, both existing and new, within an arbitrarily complex 3D material model (Settgast et al., 2016, Fu et al., 2014). The solid deformation and fluid flow are solved simultaneously by the finite element and finite-volume solvers, respectively. Fractures are enabled with a complex parallelized and updatable meshing scheme. GEOS has been validated with numerous analytic solutions and extensively applied to hydraulic stimulation models for oil and gas and EGS geothermal models.

While exceedingly powerful, the disadvantage is that GEOS models require time and a detailed knowledge of the reservoir to construct and validate. Running realistic models requires copious computational time on rather large computers. As we do not have operational EGS parameters in hand, we will use as a base model a well-tested example (Settgast et al., 2016) originally derived from an idealized oil and gas shale reservoir (Figure 2). This intended as a proof of concept, as we recognize that crystalline EGS reservoirs differ both in material properties and in the style of fracture stimulation (e.g. McClure and Horne, 2014) from a hydraulically stimulated shale reservoir. However, all types of motion along a fracture will create strain detectable by a DAS. We plan to explore models more typical of likely EGS stimulations in the future.

To match the DAS data, we insert 'virtual' fiber DAS sensors into the model (Figure 2) and extract the average axial strain at 10 m intervals along the fiber as an approximation of gauge length. Here we focus on vertical virtual DAS sensors to emulate a monitoring well, but the software is flexible enough to place the virtual sensors at any orientation and location.

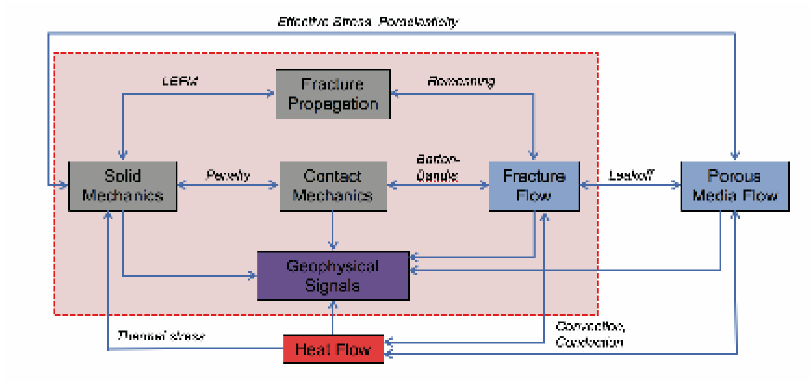

Figure 1: To model the observed signals, we use the GEOS code, a massively parallel multi-physics code designed to model hydraulic stimulation. It models rock mechanics, fluid flow, thermal effects and elastic wave propagation. This is an schematic overview of the GEOS structure.

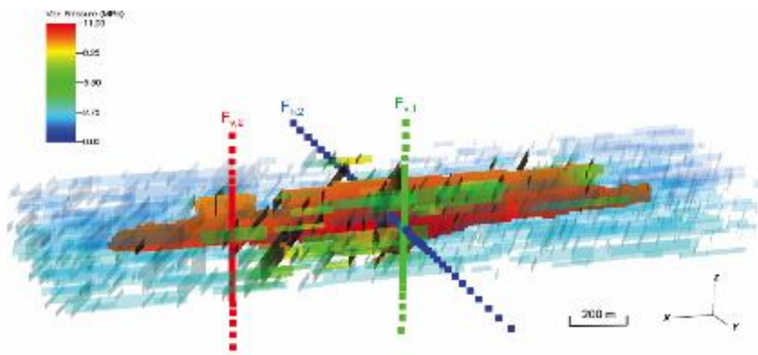

Figure 2: In this model, an existing set of natural fractures with defined orientations exist (a discrete fracture model, or DFN). The stimulation is conducted through a perforation along the horizontal blue dotted line, which is assumed to have a horizontal fiber. We recognize that current EGS schemes do not include horizontal wells but the goal is to estimate the effect from a fracture. We show synthetic data from two vertical monitoring wells, each equipped with fiber are marked by the green and red dotted lines. The extent of fluid flow after 60 minutes of pumping is approximately corresponds to the warmer colors in the figure (where fluid pressure is elevated).

Two models are tested with a fluid injection that lasts for 60 minutes (Figure 3). A vertical fracture propagates out from the initial point and propagates horizontally towards the far vertical well (380 m away). The vertical extent of the fracture, shown by the dotted lines, is controlled by a zone of minimum horizontal stress between 200 and 300 m and therefore constant and symmetric in the vertical direction. The near vertical fiber, which is slightly offset horizontally from the vertical fiber, shows higher amplitude strain changes almost immediately which coincides with fracture initiation. A clear compressional strain rate (blue) that extends roughly the same distance as the vertical extent of the fracture and extension strain rate beyond the vertical extent of the fiber. As the fracture tip propagates away from the vertical fiber, the amplitude of the strain change decrease. The signal at the far fiber is similar but shifted in time. At fracture initiation, no signal is visible because the ongoing fracture process is still 380 m away. As the fracture propagates towards the fiber, a strong signal appears at about 20 minutes into the stimulation. This represents the closest approach of the fracture tip to the fiber. Again, the zone of compressional strain roughly matches the vertical extent of the fiber. From these observations, we can immediately estimate the vertical extent of the fracture from the strain polarity and the fracture propagation speed. If the coupling between the fiber and the surrounding media is calibrated, the fracture aperture could be constrained from the strain amplitude.

The second model is similar to the first model but in this case the *in situ* stress model is changed. A decrease in the minimum horizontal stress gradient is imposed above the fracture initiation point. The decrease continues for 25 m upwards and then the stress abruptly increases. This causes an asymmetry in the fracture propagation and the vertical extent now varies along the fracture, as shown by the dotted lines in the ‘stress complexity’ model. We now see that the blue compressional stress zone is consistent with the fracture extent but does not exactly replicate it. These types of signals, if measured in an EGS stimulation, would provide vital information and constraints on the fracture propagation, extent, and geometry.

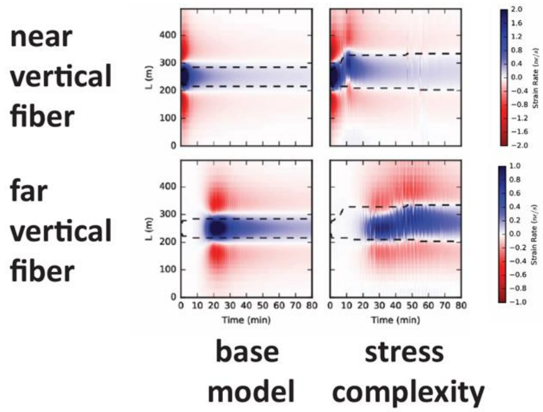

Figure 3. Modeled strain rate as a function of time since pumping (X axis) and distance along monitoring fiber (Y axis). The colors indicate the polarity of the strain rate and the black dashed line indicates the projected fracture extent. The upper row shows the expected strain rate signal as measured by a vertical fiber at stimulation point and lower row shows the signals at a well offset by 380 m. A simple fracture is shown on the left and the effect of a more stress model is shown on the right.

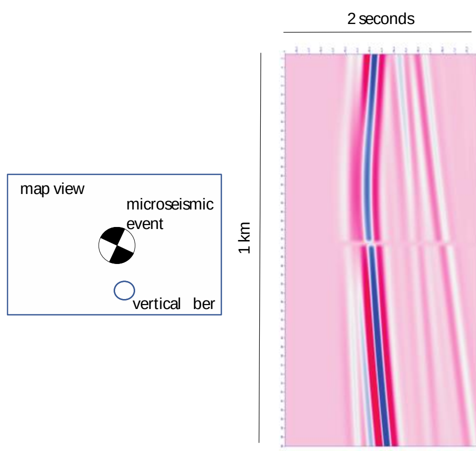

Figure 4: Strain parallel to a vertical fiber (not strain rate) for a microseismic event calculated by differencing displacement seismograms generated by a 3D finite difference code. The horizontal axis is time and the vertical depth. The fiber record extends form the surface to a depth of 1 km and the microseismic event (double couple) is at a depth of 500 m. The strong waves are the primary arrivals and the weaker one on the right are reflections from free surface.

2.2 Finite difference wave propagation models

The goal here is to model specific seismic signals from microseismic events as recorded by fiber. There are two basic approaches: calculate the full strain tensor or approximate by differencing displacement seismograms. We have tried both approaches, and although the full strain tensor is the more complete solution, simply differencing displacement seismograms seems to be simple and effective. Figure 4 shows an example of a synthetic DAS signals calculated on a vertical fiber. The horizontal line marks the depth of the event with respect to the fiber and is also a null on the focal sphere, which produces an artifact. This resembles microseismic signals recorded by vertical fibers from deployments and although we have not yet included the smoothing effect of a gauge length, we are reasonable confident that these signals can be modeled with existing software.

The interesting aspects is that although a DAS records the event on 10's or hundreds of channels, the hypocenter is poorly defined. The distance from the fiber can be estimated from the P arrival moveout or S-P time, but it is not possible on a straight fiber to estimate back-azimuth from particle motions as can be done with a 3-component seismometer in a borehole. The possible locations lie around the fiber. A helical fiber might improve location estimates. Microseismic events can be used as a source of seismic energy to illuminate the neighboring region at high resolution, and the dense channel spacing make this approach more robust. For EGS systems, this may be a way to image faults and fractures directly (James et al., 2017; Cole et al., 2015).

3. CONCLUSIONS

A review of previous work suggests that DAS fiber sensors should be effective in EGS boreholes even at high temperatures. The fiber coating should be polyamide or possibly metal. Additional work needs to be done to refine deployment concept, the effect of high-temperatures and thermal stress on Rayleigh scattering and hence resolution of the DAS, and on expected lifespan of the fiber/cable combination under extreme conditions.

Assuming that it is possible to record high-fidelity signals with a DAS, recent results from oil and gas deployments and modeling suggest that it should be possible to measure EGS fracture extent and geometry from low-frequency DAS signals. We have conducted modeling based on oil and gas deployments and can replicate similar signals as observed on DAS. We expect that EGS stimulations will produce similar signals and that low-frequency DAS will be an essential tool in understanding fracture creation and fluid flow in EGS stimulations. It is likely that a nearby monitoring well be needed to observe the highest quality signals. As high-temperature fiber sensors seem feasible, and fracture strain signals have already been demonstrated, this appears to be a promising new technology and building block for EGS success.

4. ACKNOWLEGEMENTS

This work was performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344 and was supported by the LLNL-LDRD Program under Project No. 17-ERD-015.

REFERENCES

Cole, S., Karrenbach, M., Roche, S., Gumble, J., LaFlame, L., Emuh, M., Yartsev, V. and Bartling, B.: Interferometric Imaging of Microseismic Data, EG New Orleans Annual Meetin, http://dx.doi.org/10.1190/segam2015-5876692.1

Dean, T., Cuny, T., and Hartog, A. H.: The effect of gauge length on axially incident P-waves measured using fibre optic distributed vibration sensing, Geophysical Prospecting, 65, (2017), 184–193. doi:10.1111/1365-2478.12419

Fialko, Y., Fialko Y., Khazan Y., Simons M.; Deformation due to a pressurized horizontal circular crack in an elastic half-space, with applications to volcano geodesy, Geophys. J. Int. 146, (2001) no.1, 181–190.

Fu, P., Settgast, R. R., Johnson, S. M., Walsh, W. D. C., Morris, J. P., and Ryerson, F. J.: GEOS: User Tutorials, LLNL-TR-665515, (2014), 94 pages.

James,,S. R., Knox, H. A., Preston, L., Knox, J. M., Grubelich, M. C., King, D. K., Ajo-Franklin,, J. B. Johnson, T. C., Morris, J. P.: Fracture detection and imaging through relative seismic velocity changes using distributed acoustic sensing and ambient seismic noise, The Leading Edge 36, 12(2017), 1009-1017, https://doi.org/10.1190/tle36121009.1

Hartog, A. H.: An Introduction to Distributed Optical Fibre Sensors, CRC Press, (2017), 442 pages.

Hull, R. A., Meek, R., Bello, H., and Miller, D.: Case History of DAS Fiber-Based Microseismic and Strain Data, Monitoring Horizontal Hydraulic Stimulations Using Various Tools to Highlight Physical Deformation Processes (Part A), URTeC: 2695282, DOI 10.15530/urtec-2017- 2695282.

Jin, G. and B. Roy,L: Hydraulic-fracture geometry characterization using low-frequency DAS signal. The Leading Edge, 36(12), 975–980. https://doi.org/10.1190/tle36120975.1

Karrenbach, M., Ridge, A., Cole, S., Boone, K., Kahn, D., Rich, J. Silver, K., Langton, D.: DAS Microseismic Monitoring and Integration with Strain Measurements in Hydraulic Fracture Profiling, URTeC: 2670716, DOI 10.15530/urtec-2017-2670716

Li D, Li H, Ren L and Song G, Strain transferring analysis of fiber Bragg grating sensors Opt. Eng. 45 (2016) 024402–8

Mateeva, A., Lopez, J., Potters, H., Mestayer, J., Cox, B., Kiyashchenko, D., Wills, P., Grandi, S., Hornman, K., Kuvshinov, B., Berlang, W., Yang Z., and Detomo, R.:Distributed acoustic sensing for reservoir monitoring with vertical seismic profiling, Geophysical Prospecting, (2014), 62, 679–692

McClure, M. and Horne, R.: An investigation of stimulation mechanisms in Enhanced Geothermal Systems, International Journal of Rock Mechanics and Mining Sciences, 72, (2014), 242-260.

Mogi K.; Relations between the eruptions of various volcanoes and the deformation of the ground surfaces around them.Bull. Earthq. Res. Inst. U. Tokyo 36 (1958), 99–134

Okada, Y.: Internal deformation due to shear and tensile faults in a half-space, Bull. Seismo. Soc. Amer., 82, 2, (1992), 1018-1040.

Patterson, J. R., Cardiff, M., Coleman, T., Wang, H., Feigl, K. L., Akerley, J., Spielma, P.: Geothermal reservoir characterization using distributed temperature sensing at Brady Geothermal Field, Nevada, Leading Edge 36, 12(2017), 1024a1-1024a7 https://doi.org/10.1190/tle36121024a1.1

Petty, S., Nordin, Y., Glassley, W., Cladouhos, T. T., and Swyer, M.,Improving geothermal project economics with multi-zone stimulation: results from the Newberry Volcano EGS demonstration, Proceedings, Thirty-eighth Worshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California, Feb. 11-13, 2013, SGP-TR-198

Reinsch, T., Jousset, P., Henninges, J. Blanck, H.,: Distributed Acoustic Sensing Technology in a Magmatic Geothermal Field - First Results From a Survey in Iceland, Geophysical Research Abstracts, (2016), 18, EGU2016-16670, EGU General Assembly 2016

Reinsch, T., T. Thurley, and P. Jousset.: On the mechanical coupling of a fiber optic cable used for distributed acoustic/vibration sensing applications—a theoretical consideration, Meas. Sci. Technol. 28 (2017) 127003

Settgast, R. R., Fu, P., Walsh, S. D. C., White, J. A., Annavaraou, C., and Ryerson, F. J.:A fully coupled method for massively parallel simulation of hydraulically driven fractures in 3-dimensions, Int. J. Numer. Anal. Meth. Geomech., 41, (2017), 627–653. doi: 10.1002/nag.2557.

Webster, P., Wall, J., Perkins, C. and Molenaar, M. Micro-seismic detection using distributed acoustic sensing. SEG Technical Program Expanded Abstracts 2013: pp. 2459-2463., https://doi.org/10.1190/segam2013-0182.1

Webster, P., Cox, B., and Molenaar, M., Developments in Diagnostic Tools for Hydraulic Fracture Geometry Analysis. Unconventional Resources Technology Conference, Denver, Colorado, 12-14 August 2013. 218-224, https://doi.org/10.1190/urtec2013-025