Optimizing for Large Planar Fractures in Multistage Horizontal Wells in Enhanced Geothermal Systems Using a Coupled Fluid and Geomechanics Simulator

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Enhanced Geothermal System, reservoir simulation, horizontal well completion, multiple stages hydraulic fracturing, discrete fracture network, complex fracture propagation

ABSTRACT

Enhanced Geothermal Systems (EGS) could potentially use technological advancements in coupled implementation of horizontal drilling and multistage hydraulic fracturing techniques in tight oil and shale gas reservoirs along with improvements in reservoir simulation techniques to design and create EGS reservoirs. In this study, a commercial hydraulic fracture simulation package, Mangrove by Schlumberger, was used in an EGS model with largely distributed pre-existing natural fractures to model fracture propagation during the creation of a complex fracture network. The main goal of this study is to investigate optimum treatment parameters in creating multiple large, planar fractures to hydraulically connect a horizontal injection well and a horizontal production well that are 10,000 ft. deep and spaced 500 ft. apart from each other. A matrix of simulations for this study was carried out to determine the influence of reservoir and treatment parameters on preventing (or aiding) the creation of large planar fractures. The reservoir parameters investigated during the matrix simulations include the in-situ stress state and properties of the natural fracture set such as the primary and secondary fracture orientation, average fracture length, and average fracture spacing. The treatment parameters investigated during the simulations were fluid viscosity, proppant concentration, pump rate, and pump volume. A final simulation with optimized design parameters was performed. The optimized design simulation indicated that high fluid viscosity, high proppant concentration, large pump volume and pump rate tend to minimize the complexity of the created fracture network. Additionally, a reservoir with "friendly" formation characteristics such as large stress anisotropy, natural fractures set parallel to the maximum horizontal principal stress (S_{Hmax}), and large natural fracture spacing also promote the creation of large planar fractures while minimizing fracture complexity.

Introduction

Background

Many potential EGS formations, especially those with ultra-low permeability, tend to share similar characteristics with the unconventional reservoirs in oil and gas industry. However, differences between the two formations such as lithology, formation temperature, pore pressure, and in situ stress states tend to alter many treatment parameters during stimulation operations. Moreover, in unconventional reservoir stimulation, the main goal is to maximize the stimulated reservoir volume (SRV) in order to maximize the hydraulically connected (open) fractures in the formation matrix. This allows the hydrocarbons stored inside the impermeable pore space to be produced.

Heat and Mass Flow Inside EGS

The main goal in EGS operations is to circulate the fluid through the hot formation to extract and produce thermal energy. This process is highly dependent on the interaction of heat conduction inside the rock matrix and heat convection by the injected fluid. Simply maximizing the total stimulated reservoir volume will not guarantee that all the injected

fluid will circulate throughout the complex fracture network. Doe et al. 2014, modeled a complex fracture network set inside a geothermal reservoir and noticed that in early times of heat production, the thermal behavior is highly dependent on the high intensity fracture network within the stimulated volume. However, once the stimulated volume thermally depletes, the entire reservoir acts as a single thermal sink. Since the flowrate inside the reservoir is greatly dependent on the fracture aperture and number of flowing conduits (Gringarten et al. 1975), a complex fracture network containing many non-parallel fractures and various apertures can result in many flow paths with different flow rates and flowing distance. Heated fluid from one fracture can combine with the colder fluid from a different flow path before being produced to the surface eventually reducing the total efficiency of the heat extraction between the injected fluid and the heated matrix.

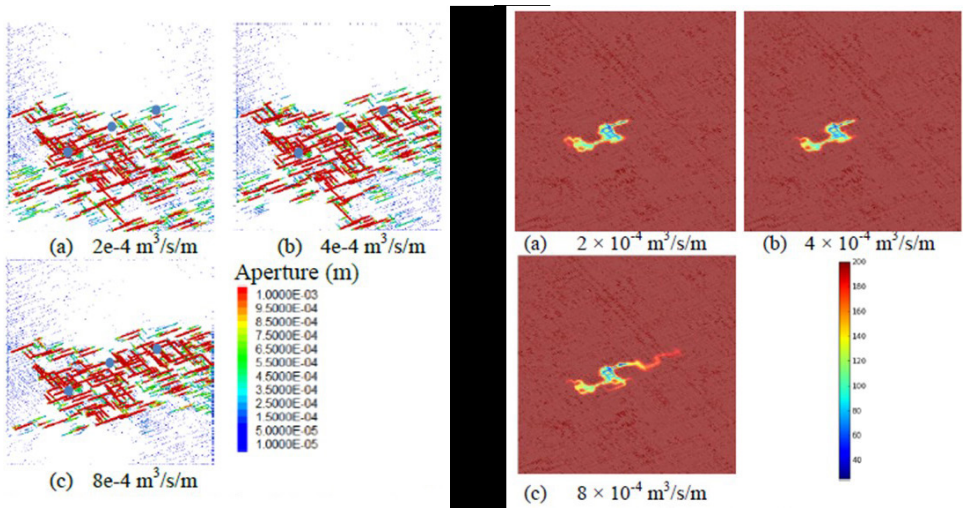

Figure 1. Comparison of shear stimulated volume (left) and rock temperature during circulation (right) for fracture networks created with different stimulation injection rates (Riahi et al., 2014).

High flow rates during heat production in geothermal reservoirs tend to accelerate the early thermal breakthrough effect since the rate of thermal convection between the heated matrix and cold fluid is faster than that of thermal conduction within the heated matrixes. If the flow rate of inject fluid is too high, it is more likely to sharpen the thermal front inside the heated formation and eventually reduces the total heat extraction volume. Therefore a relatively low flow rate is preferred during heat production in order to reduce early thermal breakthrough. Yet, in complex fractured reservoirs, due to the large number of non-uniform fractures and the preferential flow behavior for fluid in finding the least resistant path, it is difficult to artificially control the fluid flow in each fracture conduit to have uniform flow rates. Therefore, the stimulated reservoir volume can be much larger than the actual heat extraction volume in geothermal reservoirs (Figure 1) (Riahi et al. 2014).

Conceptual Design for EGS Solution

Complex fracture networks do not necessarily contribute to a better heat production in EGS application as discussed before. On the contrary, it might result in wasted fluid and proppant during stimulation operations if the created SRV is much larger than the actual heat extraction volume. It also has a potential of accelerating early thermal breakthrough effects if the flow rate inside the complex fractured reservoir is much higher than the expected production rate for effective heat exchange between injected fluid and matrix. Due to the potentially detrimental effects of complex fracture network on reservoir creation and heat production, it is critical to understand the physical mechanisms behind the creation of the complex fracture network and then find effective solutions to reduce the level of complexity of the created fracture network.

Interactions between hydraulically induced fractures (HFs) and pre-existing natural fractures (NFs) are one of the main reasons for the complex fracture network occurrence during the hydraulic fracturing treatments. These interactions also explain the complex fracture networks present in many reservoirs with proved existence of largely distributed natural fractures in the microseismic monitoring of hydraulic fracturing operations. In order to minimize the creation of complex fracture networks during EGS application, it is desirable to perform hydraulic fracturing treatment in reservoir with a relatively small distribution of pre-existing natural fractures. However, case studies of the hydraulic fracture simulations showed

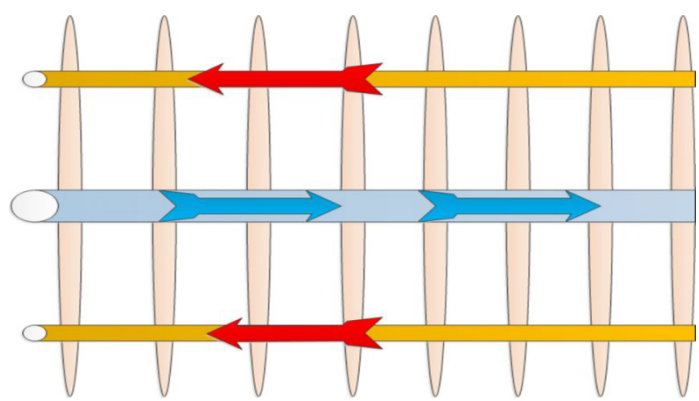

Figure 2. Top view of EGS system conceptual model consisting of horizontal wells connected by multiple planar fractures. Central well is the injection well. Fractures are created from the middle well and intersected on each side by production wells.

a high potential for those largely distributed natural fractures to exist in unconventional reservoirs, and an even higher potential in granitic system (Hannes et al. 2013). Therefore, in order to effectively utilize unconventional stimulation techniques in EGS reservoir creation while avoiding the negative effects from complex fracture network, large planar fractures were considered as the most effective fracture geometries in this study. The target EGS design for this study contains a horizontal injection well in the center connected to one or two horizontal production wells as shown in Figure 2. The induced multiple fractures from the injection well are expected to be planar and large enough to reach the production well on the side.

EGS Model Design

The EGS model design consists of a horizontal well that is 10,000 ft. deep with 10 degree per 100 ft. well deviation and a 3,000 ft. long horizontal section in the simulator. The horizontal section of the well is in the direction perpendicular to the S_{Hmax} (maximum horizontal stress). An illustration of the general design for the well is shown in Figure 3.

Fracture creation was modeled using Mangrove, a commercial software package available from Schlumberger. We started our simulations with a multi-stage hydraulic fracture design of thirteen perforation clusters with 200 ft. spacing as shown in Figure 4. The blue curve represents the injection well with hydraulic fracturing treatment, and the yellow curve represents the production well located 500 ft. lateral to the injection well. It should be noted that we used a symmetrical completion sequence during this simulation, consisting of fracturing from the toe to the heel for the first 6 fractures (fractures 8-13), and then fracturing from the heel to the toe for the last 7 fractures (fractures 1-7). This is not necessarily practical for field operations, but allowed us to observe the effect of no stress shadowing (fractures 1 and 13), stress shadow effects from one side of the fracture being created (fractures 2-6 and 8-12), and stress shadow effects from both sides of the fracture being created (fracture 7). Other examples of using the symmetric sequential fracturing to investigate the role of natural fractures and other critical operational factors have been reported in Hu and Tutuncu (2016). A more practical field completion sequence was included in the optimized designs later. In order to create a successful EGS reservoir, most of the created fractures from the horizontal well must propagate with a fracture half-length long enough to reach the production well.

The goal of the EGS fracture modeling was to identify the parameters that promote the creation of large, planar fractures in a granitic reservoir with a largely distributed pre-existing natural fractures during hydraulic fracturing operations. An idealized granitic system was

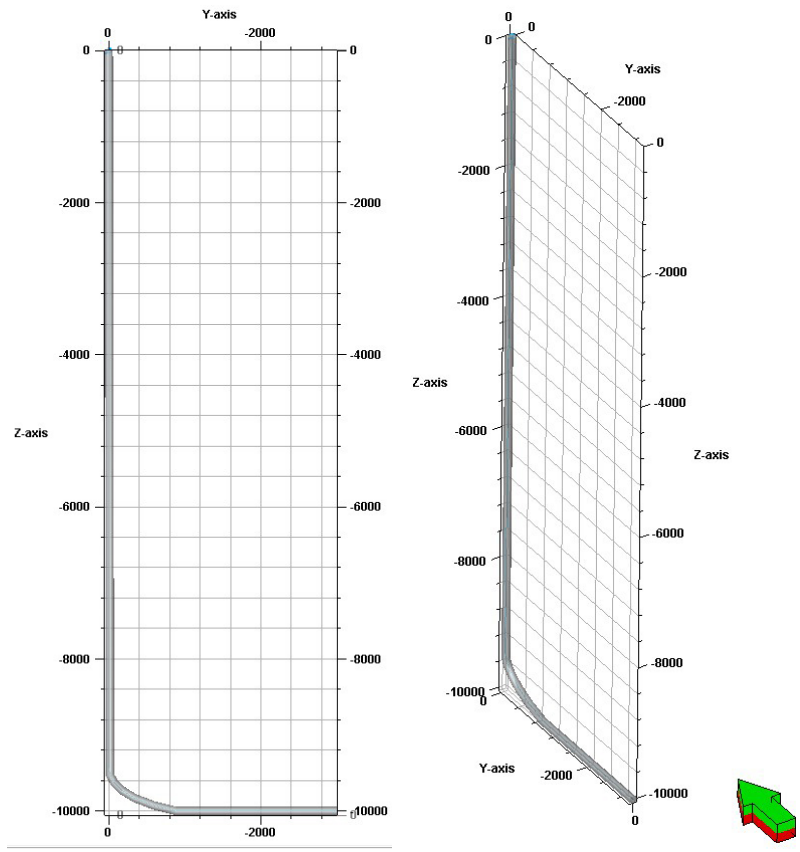

Figure 3. 10,000 ft. deep horizontal well with 10 degree per 100 ft. deviation in simple model. Side view of the model (a), front 3D view of the model (b). Arrow at the right corner points North.

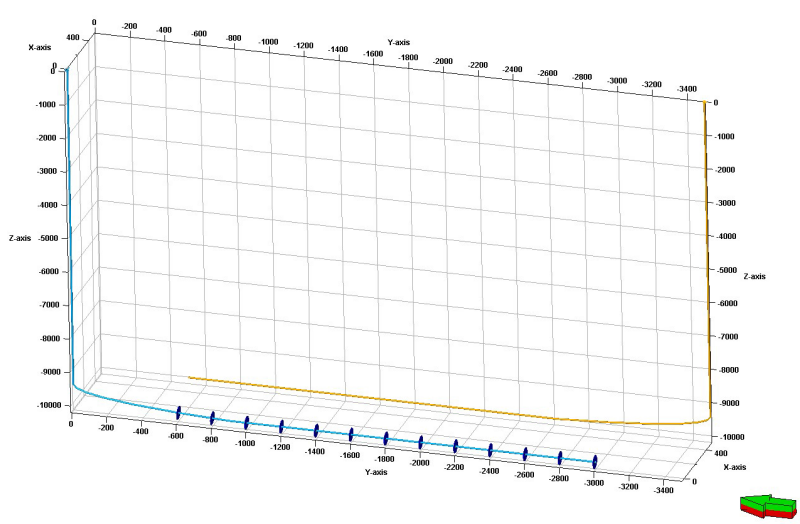

Figure 4. A multi-stage hydraulic fracture design of thirteen perforation clusters with 200 ft. spacing. (Z to Y axis ratio is 1:10)

simulated using average formation parameters from the published literature for granite. The granite material properties and main reservoir input parameters used are listed in Table 1 and Table 2.

We first simulated an ideal reservoir condition where there are no pre-existing natural fractures and stress shadow effect are ignored. The simulation results generated the large planar fracture envisioned in the conceptual EGS design. Fracture half-length for the thirteen stages ranging from 600 ft. to 800 ft. and fracture widths ranging from 0.05 to 0.5 inches were observed as shown in Figure 5a. The fracture widths near the production well were generally smaller than those near the injection well. After this ideal simulation, we started to add complexities step by step, first by including stress shadow effect in the simulation. In these model results, fractures diverged from adjacent fractures due to stress shadow effects under zero stress anisotropy condition as shown in Figure 5b.

Table 1. Input granite material properties used in the reservoir model (EMI 2010 a, b and Morrell 2012).

Granite Material Properties	
Thermal Conductivity (W*m^-1*K^-1)	3.15
Porosity (%)	0.77
Permeability (μD)	0.5
Young's Modulus (GPa)	56.9
Poisson's Ratio (-)	0.32
Total Compressibility (1/GPa)	0.43
Tensile Strength (MPa)	12
Fracture Toughness (MPa m^1/2)	1.5

Complex Fracture Network Simulation

In the next set of simulations, we employed the UFM model in Mangrove to include the effects of stress shadowing and natural fractures with zero stress anisotropy. In this research study, a 2D discrete fracture network (DFN) design simulator was utilized to create a randomly distributed natural fracture set with controllable fracture spacing, height, length and orientation. The left side of Figure 6 below shows a 2D DFN consisting of three thousand natural fractures with a fracture spacing of 60 ± 15 ft. The DFN is made up of a primary natural fracture set consisting of fractures with an average length of 200 ±10 ft. and oriented 90 ± 15 degrees from the direction of S_{Hmax}, and a secondary natural fracture set consisting of fractures with an average length of 150 ± 10 ft. and oriented 0 ± 15 degree from the direction of S_{Hmax}. Using the input parameters in Tables 1 and 2 and considering the combined effects of stress shadowing and primary and secondary natural fracture networks, a fracture network with a relatively high level of complexity was observed in the simulation results as shown in Figure 6b. In this simulation, only four stages of the thirteen stages propagated far enough to intersect the production well located 500 ft. away. Moreover, a significant reduc-

Table 2. Default input parameters for fracture simulations (Hu and Tutuncu, 2016).

Input Treatment Parameters	
Initial Fluid Viscosity (cp)	160
End Proppant Concentration (PPA)	4
Pumping Time for Each Stage (min)	72.43
Maximum Horizontal Stress (psi)	8000
Stress Anisotropy (psi)	0
Rate Per Stage (bbl./min)	60

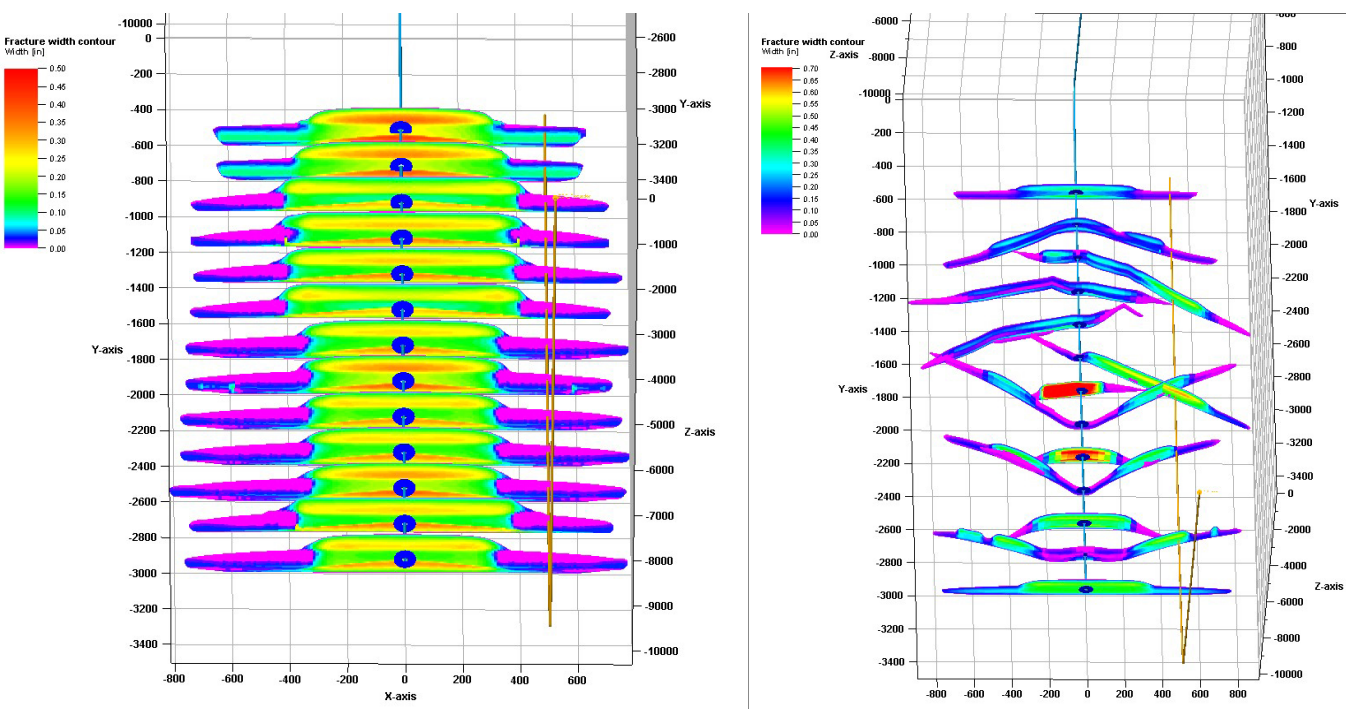

Figure 5. a) Plane top view of simple EGS model consisting of horizontal well with multiple fractures without any natural fractures and stress shadow effect, and b) considering only stress shadow effect.

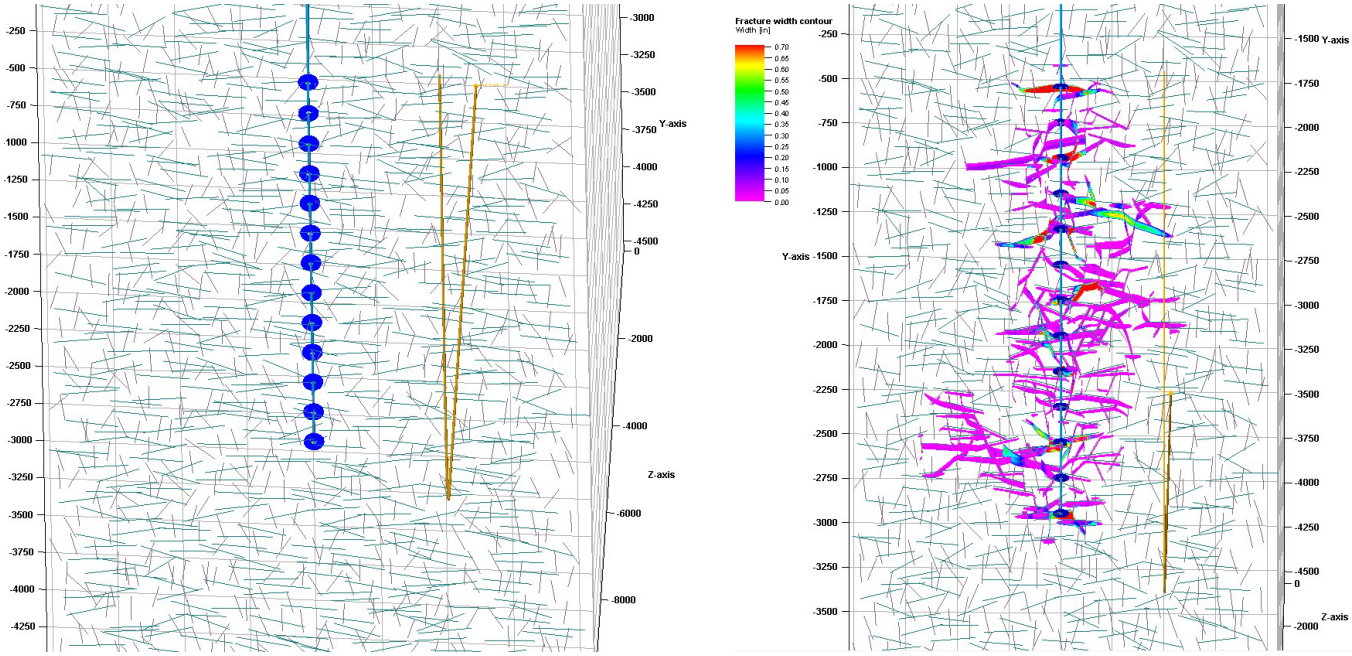

Figure 6. a) Plane top view of simple EGS model consisting of horizontal well with multiple fractures considering natural fractures and b) stress shadow effects.

tion in the average fracture width was observed due to the fracturing fluid leak off from hydraulic fractures into natural fractures and preventing proppant placement in the induced fractures.

The horizontal section of the well was constructed (in the simulator) in the direction perpendicular to S_{Hmax}. From the observations of the prior simulation results, we noticed that though the stress anisotropy value in the reservoir model was assumed to be zero, under ideal conditions, the induced fracture tended to propagate in the direction of the perforations which is also the orientation of S_{Hmax}. However, once the induced hydraulic fractures were affected by stress shadow and intersected with in-situ natural fractures, only a small portion of the induced hydraulic fractures were able to cross the natural fractures and propagate in the original direction since the horizontal minimum stress magnitude (S_{Hmin}) is identical to S_{Hmax} magnitude. Most of the induced fractures tended to either diverge from adjacent fractures or filtrate into the

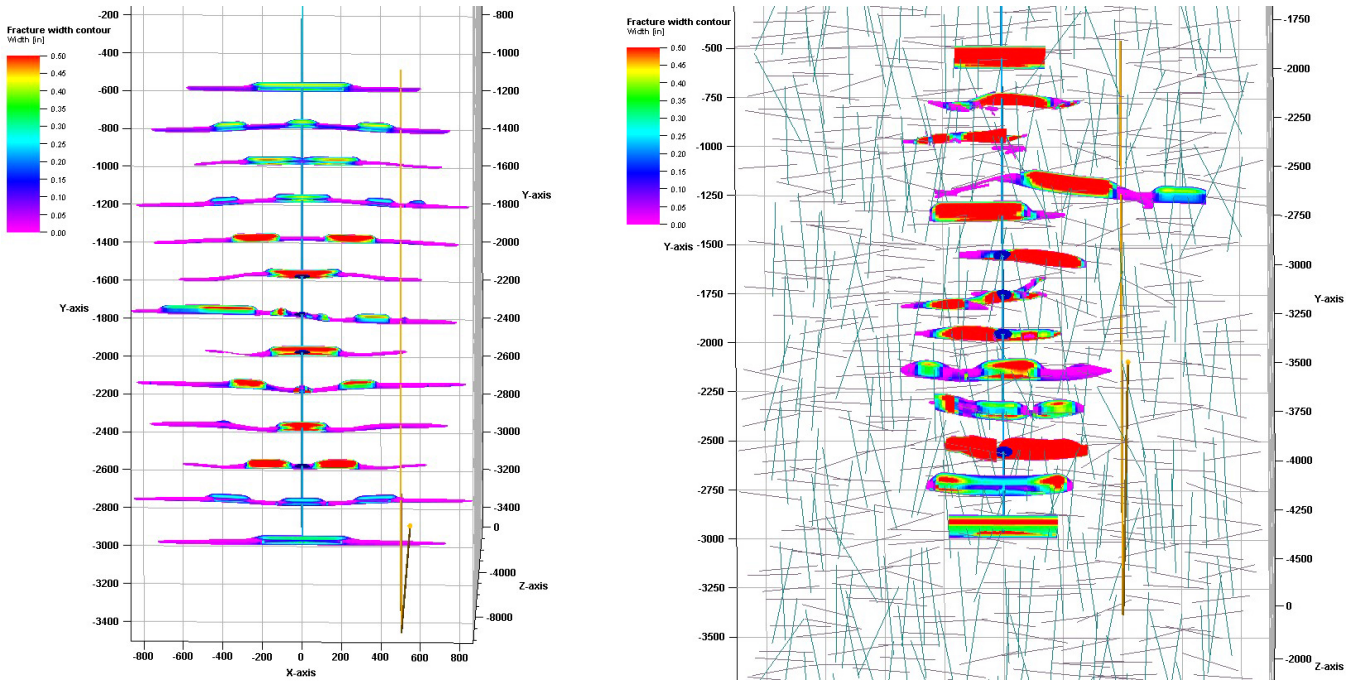

Figure 7. Top view of simulations consisting of horizontal well with multiple fractures assuming stress anisotropy of 500 psi a) without natural fractures, and b) with natural fractures.

natural fractures and eventually arrest inside the natural fractures in a direction different from the orientation of S_{Hmax}. Running simulation cases with various DFN orientations, we noticed that when most of the natural fractures were in the direction perpendicular to S_{Hmax}, the induced hydraulic fractures were initially able to cross the first several natural fractures, but eventually stopped or filtrate into the natural fractures due to the large friction losses while crossing the largely distributed natural fractures. However, when most of the natural fractures were in the direction parallel to S_{Hmax}, natural fractures behaved as pre-opened hydraulic fractures and therefore aided the creation of large planar fractures. When most of the natural fractures were orientated in between the S_{Hmax} and S_{Hmax} direction, most induced hydraulic fractures tended to filtrate into the natural fractures.

The above simulations were carried out assuming zero stress anisotropy. Therefore, we performed another set of simulations assuming a stress anisotropy of 500 psi, both without and with a natural fracture network. Stress shadow effects were included in both simulations. Simulation results for the two cases are shown in Figure 7. Without a natural fracture network, the large stress anisotropy applied nearly eliminated the effects of stress shadowing as shown in Figure 7a.

Figure 7b shows that the level of complexity for the created fracture network is also significantly reduced by increasing stress anisotropy in the reservoir even when a DFN is included. Only one stage was able to achieve the desired fracture half-length, while the rest of the stages were arrested due to large friction losses from crossing the densely distributed natural fractures. Additionally, more proppant was properly placed inside the induced fractures than in the zero anisotropy case. This resulted in an increase in the average fracture widths, as illustrated in the fracture width contours in Figure 7. Hydraulic fractures for most stages had an average fracture width exceeding 0.5 inches.

Sensitivity Analysis

We performed a sensitivity analysis to determine which simulation parameters have the greatest impact on fracture complexity. Simulations were performed to explore the relative impact of simulation parameters and assumptions, illustrated conceptually by the matrix in Table 3.

Based on results from the matrix simulations, the five parameters with the most noticeable impact on fracture network complexity were DFN spacing, fluid viscosity, stress anisotropy, pump rate and proppant concentration. The original input parameters relative to the parameters used in the sensitivity analysis parameters are shown in Table 4. The relative impact on the simulation results is shown in Figures 8 and 9. The numbers in parentheses in the figures show the range parameter values used. Parameters are ordered in terms of significance of their overall impact on the fracture half-length, average fracture width and effective fracture conductivity.

Proppant concentration had the greatest impact on the average fracture width, followed by the fluid viscosity and pump rate as shown in Figure 8a. This is expected since a large pump rate, high fluid viscosity and high proppant concentration should aid in placing proppant in the fractures and creating wider fractures. Stress anisotropy and DFN spacing tend to have less of an impact. The ranking of relative influence on fracture connectivity (Figure 8b) was found to be exactly the same as for fracture width, since effective conductivity tends to have a linear relationship with average fracture width. For the effect in fracture half-length (shown in Figure 9), DFN spacing was determined to be the most significant parameter, followed by fluid viscosity and stress anisotropy. Due to the fixed proppant increment setting inside the UFM model simulation, as proppant concentration increases, the total pumping volume also increases, which is the main contributing factor for adding growth in the fracture half-length. The sensitivity analysis indicated that the pump rate is the least significant contributing factor to fracture half-length.

Table 3. Schematic matrix of simulations under EGS model in investigating effects of various parameters on fracture network complexity.

	Stress State	Fluid Viscosity	Proppant Concentration	Pump Rate
Ideal Condition without NF	Investigate Effects of Various Stress Anisotropy	Water vs. Low Concentration vs. High Concentration	Zero vs. Low Concentration vs. High Concentration	High Pump Rate vs. Low Pump Rate
Pre-existing Natural Fracture	Effects of Various NF Orientation, Density, and Fracture Spacing	Water vs. Low Concentration vs. High Concentration	Zero vs. Low Concentration vs. High Concentration	High Pump Rate vs. Low Pump Rate

Table 4. Comparison of the input parameters used in base case and range of input parameters used in the sensitivity analysis through simulations.

Property	Original Input Parameters	Sensitivity Analysis Parameters
DFN Spacing (ft.)	60	60 - 200
Fluid Viscosity (cp)	160	0.64 - 200
End Proppant Concentration (PPA)	4	1 - 8
Stress Anisotropy Value (psi)	0	0 - 500
Pump rate (bbl./min)	60	15 - 90

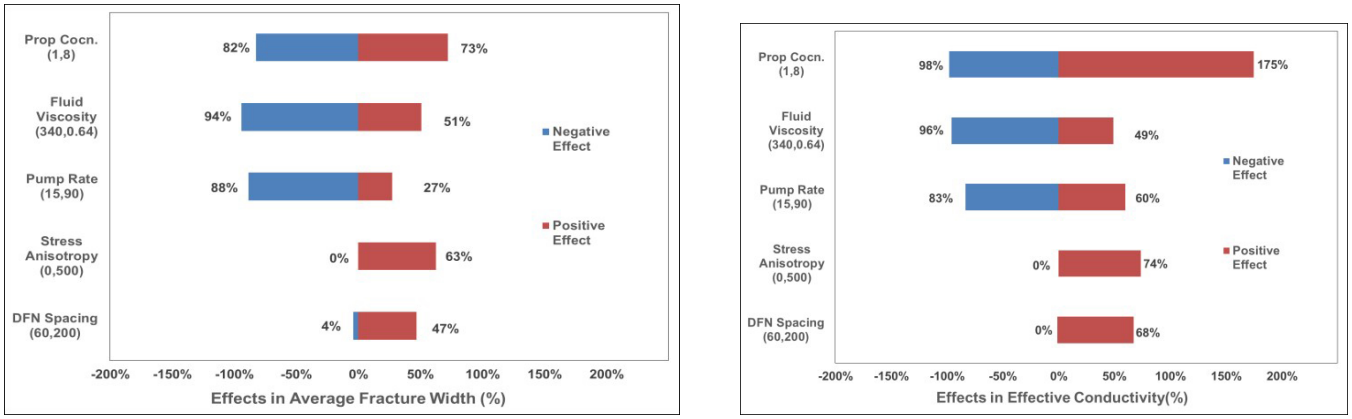

Figure 8. Sensitivity analysis for the effects of various parameters on the average fracture width (a), and effective conductivity (b).

Design Optimization

After obtaining the results from the sensitivity analysis, we performed an "optimum case" simulation. This optimum case simulation combined the simulation reservoir settings and parameters that had the most positive effects on creating large planar fractures (i.e., minimized fracture complexity): a natural fracture network aligned with S_{Hmax}; large reservoir stress anisotropy; relatively large natural fracture spacing; and parameters with values that had the most positive effects in the sensitivity analysis. The DFN design parameters used in the simulations under best case scenario are illustrated in Table 5, and the treatment parameters are shown in Table 6.

A 3D view and top view of the simulated fracture network geometries for the EGS design optimization are shown

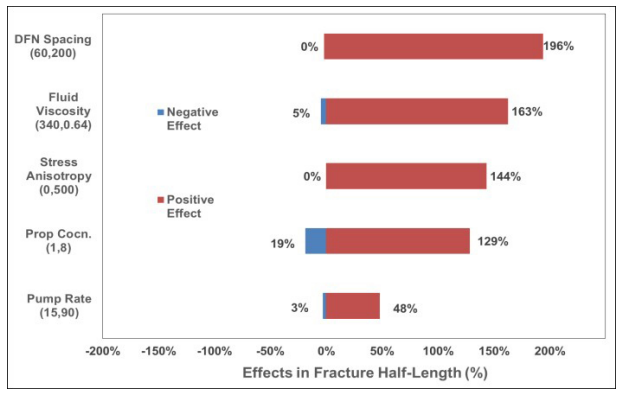

Figure 9. Sensitivity analysis for the effects of various parameters on fracture half-length.

Table 5. 2D DFN design parameters for optimization while considering positive effects of relatively large NF spacing of 120 ft. in the model simulation.

Natural Fracture Set	Number of Fractures	Length (ft.)		Spacing (ft.)		Orientation (degree)	
		Avg	Standard Deviation	Avg	Standard Deviation	Avg	Standard Deviation
Primary	2,000	200	10	120	10	90	15
Secondary	1,000	150	10	120	10	0	15

Table 6. Treatment parameters for design optimization with positive reservoir condition in achieving successful EGS application in the model simulation.

Simulation Case	Design Optimization
Initial Fluid Viscosity (cp)	340
End Proppant Concentration (PPA)	8
Rate Per Stage (bbl./min)	90
Pumping Time for Each Stage (min)	200
Total Slurry Volume (bbl.)	18,032
Total Proppant Mass (lb.)	2,640,000
Total Fluid Volume (gal)	660,000
Stress Anisotropy (psi)	500

Table 7. Simulated numerical results for each stage regarding fracture half-length, average fracture width, and effective conductivity for model simulation in Figure 10.

Stage	Fracture Half-Length (ft.)	Average Fracture Width (inch)	Effective Fracture Conductivity (md ft.)
1	790	0.82	478468
2	628	1.1	562886
3	553	1.3	704428
4	563	1.23	693448
5	562	1.26	718556
6	383	1.45	794198
7	427	1.83	916130
8	496	1.34	883060
9	642	1.05	490323
10	449	1.39	1032015
11	468	1.13	569544
12	425	1.51	897308
13	745	0.9	459280
Average	**549**	**1.25**	**707665**

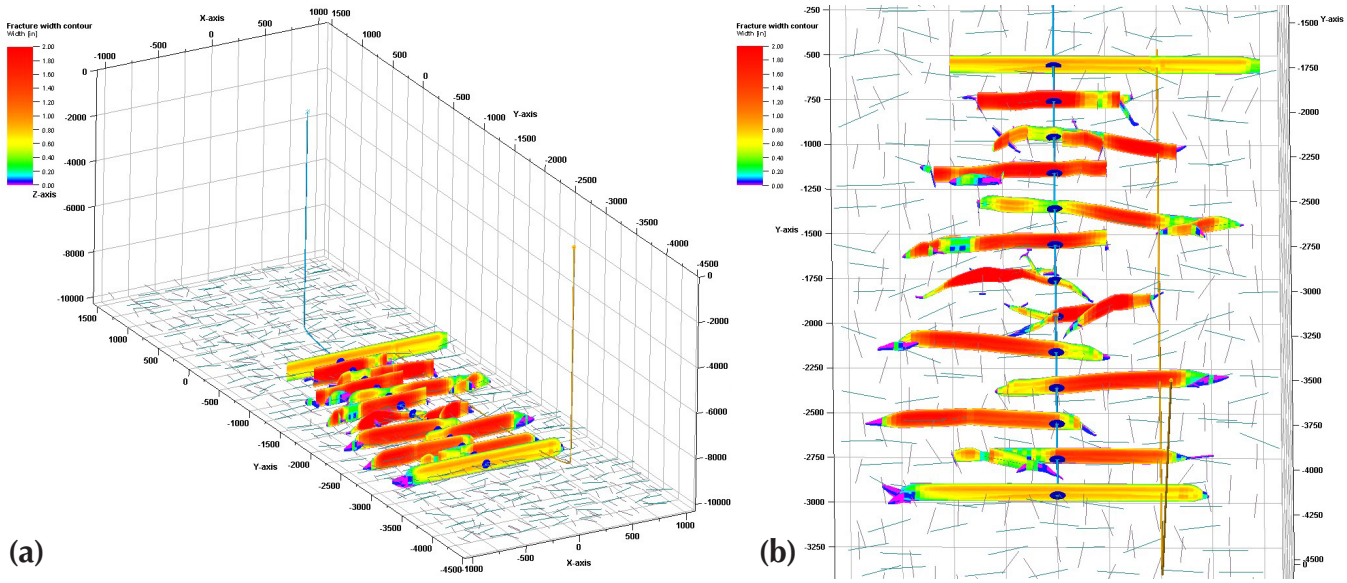

Figure 10. 3D view (a) and top view (b) of EGS design optimization with symmetrical completion order while considering both the positive and negative effects of complex reservoir condition (y to z axis ratio is 5:1).

in Figures 10 and 11. It should be noted that the simulation results for Figure 10 were based on the symmetrical completion sequence. Yet, as this is not practical in actual field operations, one more simulation with a conventional sequential completion from the toe to the heel of the well was performed as shown in Figure 11a. Another similar simulation with the conventional completion sequence was performed with a reduction in the average length of the natural fractures is shown in Figure 11b. The numerical results for the fracture half-length, average fracture width, and effective conductivity of each stage in Figure 10 are listed in Table 7. In summary, the average fracture half-length for all thirteen stages is 549 ft., the average fracture width for all thirteen stages is 1.25 inches, and the average effective fracture conductivity for all thirteen stages is 707,668 md.ft.

Using the coupled geomechanics and fluid flow (UFM) model and considering the negative and positive effects of reservoir and treatment parameters, we were able to simulate an EGS type large planar fracture network with a very low level of complexity while obtaining desirable fracture half-length and large average fracture width. Reservoirs with high stress anisotropy were found to reduce stress shadow effects that cause fractures to diverge from their initial fracture

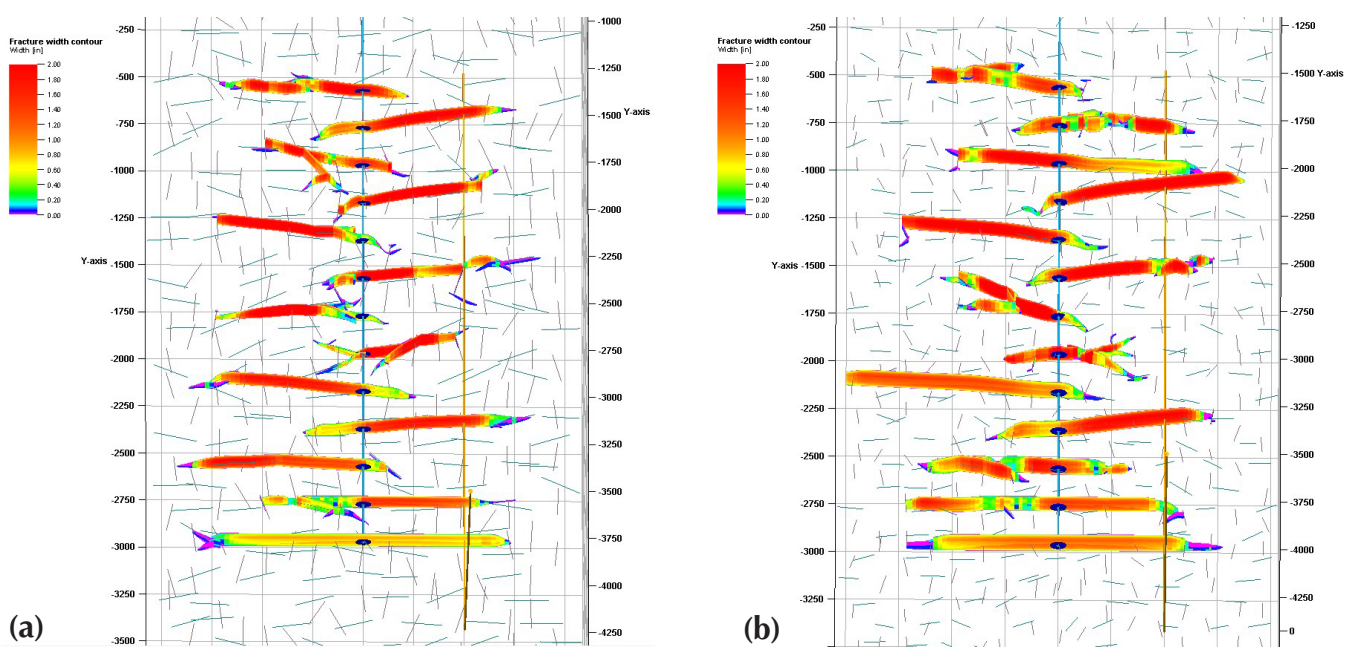

Figure 11. Top view of EGS design optimization with sequential completion order while considering both the positive and negative effects of complex reservoir condition (a), and reduced NF length (b).

pathways. As Figure 11 shows, most fractures tend to propagate in the direction of maximum horizontal stress. Although the stress shadow can still affect the overall fracture half-length, as observed in stages 2 to stages 12. Once an unsymmetrical fracture is generated due to friction loss when crossing natural fractures, fractures from the adjacent stage tend to propagate in the opposite direction from the fractures in the previous stage resulting a "natural zipper pattern" from the single injection well. However, by using different fracture patterns and/or larger fracture spacing, the effects of stress shadowing could be reduced.

Conclusions

Using a coupled geomechanics and fluid flow model, we were able to observe the basic behavior of complex fracture network creation such as the effects of stress shadowing and pre-existing natural fracture networks, and to identify the reservoir and fracture treatment parameters that minimize fracture complexity and promote the creation of large planar fractures. The 2D DFN model enabled us to design pre-existing natural fractures with variable orientations, lengths and spacing and explore their positive and negative effects on the fracture network complexity. When natural fractures are aligned with S_{Hmax}, hydraulic fractures tend to propagate further into the formation, aiding the creation of simple, planar shaped fractures. When the natural fractures are not aligned in the direction of S_{Hmax}, the natural fractures behave like barriers to the hydraulic fractures, forcing the hydraulic fractures to either arrest in the natural fractures, or cross over them resulting in friction losses. Results for the matrix simulation and sensitivity analysis indicate that the hydraulic fracture network complexity can be minimized by selecting reservoirs with large stress anisotropy and natural fracture networks that have large DFN spacing and favorable orientation with S_{Hmax}, and by choosing fracture treatment parameters such as high viscosity fluid, a relatively high proppant concentration and high pump rate.

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