A COUPLED GEOMECHANICS AND FLOW MODELING STUDY
FOR MULTISTAGE HYDRAULIC FRACTURING
OF HORIZONTAL WELLS IN ENHANCED
GEOTHERMAL SYSTEMS APPLICATIONS

by

Xiexiaomeng Hu
A thesis proposal submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science (Petroleum Engineering).

Golden, Colorado

Date____________________     Signed: ______________________

Xiexiaomeng Hu

Signed: ______________________

Dr. Azra N. Tutuncu
Thesis Advisor

Golden, Colorado

Date____________________

Signed: ______________________

Dr. Erdal Ozkan
Professor and Head
Department of Petroleum Engineering
ABSTRACT

The US has significant amount of underutilized geothermal resources that have recently gained more attention due to the technological advancements and practical knowledge brought from the horizontal drilling and multistage hydraulic fracturing operations in tight oil and shale gas reservoirs. The learnings from these unconventional efforts are the subject of this research study in order to conduct the feasible transformation of applying the technical and operational expertise into Enhanced Geothermal System (EGS).

A commercial hydraulic fracturing simulation model coupled with geomechanics and fluid flow concepts was used in a geothermal case study, allowing the simulating of hydraulic fracture creation while considering natural fracture network. First, concepts of the coupled unconventional model were studied in a shale reservoir with input parameters obtained from drilling, completion, and stimulation treatments utilizing well logs and production data to validate the integrated model. Then, a coupled Unconventional Fracture Model (UFM) was used for creating a suitable fracture network to be implemented for design in an EGS application. The role of in-situ stress state, pre-existing fracture network characteristics, injection fluid and proppant properties was investigated to optimize the design parameters and the economics for the EGS feasibility study.

The effects of various distribution patterns in natural fractures, complex fracture geometries, stress anisotropy, injection rates, surface and bottom holes pressures, fluid viscosity and fracturing proppant concentration were studied through simulations of hydraulic fracturing treatment. Modeling results confirmed that when designing for EGS, a widely distributed pre-existing natural fracture network can lead to interactions between hydraulic fractures and natural fractures and therefore raise the level of complexity of the total fracture network, which is not the desired fracture geometry for a successful EGS application. Though the overall complexity of the fracture network is also depended on many other factors such as lithology, temperature, formation fluid pressure and in-situ stress state, results from optimized simulation indicated that it can be minimized by utilizing treatment parameters such as proper fluids viscosity, proppants concentration, pumping rate, fracture stage spacing and well spacing during actual stimulation operations.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABSTRACT</td>
<td>iii</td>
</tr>
<tr>
<td>LIST OF FIGURES</td>
<td>vii</td>
</tr>
<tr>
<td>LIST OF TABLES</td>
<td>xv</td>
</tr>
<tr>
<td>ACKNOWLEDGEMENTS</td>
<td>xviii</td>
</tr>
<tr>
<td>CHAPTER 1  INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>1.1 Geothermal Energy Background</td>
<td>1</td>
</tr>
<tr>
<td>1.2 Introduction to Enhanced Geothermal System</td>
<td>3</td>
</tr>
<tr>
<td>1.3 Motivation and Objectives</td>
<td>4</td>
</tr>
<tr>
<td>1.4 Model Limitation</td>
<td>5</td>
</tr>
<tr>
<td>1.5 Research Workflow</td>
<td>6</td>
</tr>
<tr>
<td>CHAPTER 2 LITERATURE REVIEW</td>
<td>8</td>
</tr>
<tr>
<td>2.1 Thermal Breakthrough in Geothermal Production</td>
<td>8</td>
</tr>
<tr>
<td>2.2 Analytical Solution for Enhanced Geothermal System</td>
<td>10</td>
</tr>
<tr>
<td>2.3 Discrete Fracture Network Modeling</td>
<td>12</td>
</tr>
<tr>
<td>2.4 Comparison between Shale and Granite Formation</td>
<td>14</td>
</tr>
<tr>
<td>2.5 Gemechanic and Fluid Flow Concepts</td>
<td>18</td>
</tr>
<tr>
<td>2.5.1 Stress Shadow Effect</td>
<td>18</td>
</tr>
<tr>
<td>2.5.2 Lamination Effect</td>
<td>20</td>
</tr>
<tr>
<td>2.5.3 Near Wellbore Tortuosity</td>
<td>21</td>
</tr>
<tr>
<td>2.5.4 Interaction between Hydraulic and Natural Fractures</td>
<td>22</td>
</tr>
<tr>
<td>2.5.5 Flow Regime in Fractured Reservoirs</td>
<td>24</td>
</tr>
</tbody>
</table>
LIST OF FIGURES

Figure 1.1: Geothermal potential map for the United States (Billy, 2009, original source NERL for the US Department of Energy 2015). ..........................................................2

Figure 1.2: Overview of simulation process of hydraulic design for EGS .....................6

Figure 2.1: Conceptual model of the Gringarten et al. (1975) analytical solution; outer blocks have the half-spacing X ..........................................................10

Figure 2.2: Example thermal contours for high rate and low rate flow cases (Doe et al., 2014) ..........................................................11

Figure 2.3: Thermal decline for a complex fractured reservoir (Doe et al., 2014) ..........................................................13

Figure 2.4: Shear-Stimulated Volume (left) vs. rock temperature during circulation (right) as a function of stimulation injection rate for modeling by (Riahi et al., 2014) ..........................................................13

Figure 2.5: Overview of the main parameters and processes involved in the hydraulic fracturing simulations (Hannes et al., 2013) ..........................................................15

Figure 2.6: Schematic of 2D fracture model used for calculating stress field with fracture half-length h/2 (Kresse et al. 2012) ..........................................................19

Figure 2.7: Schematic of computing stress shadow effect from opened (blue) HFN and closed (grey) of intercepted NFs using DDM methods (Kresse et al. 2013) ..........................................................20

Figure 2.8: Ideal vertical fracture trace with offsets at laminations vs realistic vertical fracture trace (Mangrove, 2015) ..........................................................21

Figure 2.9: Schematic of fracture reorientation due to near wellbore tortuosity ..........................................................22
Figure 2.10: A schematic diagram of the HF–NF interaction (left) and result of the computed HF/NF interaction with the initiation of two secondary fractures (SF) and their subsequent propagation (right) (Weng et al. 2014)……………………………………………………….24

Figure 2.11: Schematics of flow regimes for a vertical well intersecting a fully or partially penetrating fracture parallel to and with an angle to the wellbore axis. (Kuchuk et al. 2015).........................25

Figure 2.12: Schematics of common flow regimes for a vertical well intersecting a fully or partially penetrating fracture parallel to and with an angle to the wellbore axis. (Kuchuk et al. 2015).....................26

Figure 2.13: Schematic of the trilinear-flow model used for the analytical solution of multiple-fractured-horizontal-well performance. (Ozkan et al. 2011)..................................................................................27

Figure 3.1: Conceptual model of EGS reservoir consisting of horizontal well with multiple fractures. Side view of the conceptual model (left), front view of the model (right).........................................................31

Figure 3.2: Plane view (from above) of conceptual model of EGS system consisting of horizontal well with multiple fractures. Central well is injection well. Fractures are made from this well and intersected on either side by production well.................................31

Figure 3.3: 10,000 ft deep horizontal well with 10 degree per 100 ft deviation in simple model. Side view of the model (left), front 3D view of the model (right). Arrow at the right corner refers north............................32

Figure 3.4: Viscosity vs Exposure Time for YF 100Flex fluid from Mangrove user data base.............................................................34

Figure 3.5: Friction Pressure vs Flow for YF 100Flex fluid in various inner diameter (2 in to 6.4 in).................................................................35

Figure 3.6: Wall Building vs Permeability for YF 100Flex fluid from Mangrove user data base.................................................................35
Figure 3.7: Proppant Permeability (md) vs Closure Stress (psi) for CarbonProp from StimLAB data base.

Figure 3.8: Three thousand randomly assigned 2D Discrete Fracture Network (DFN) with 320 degrees orientation in simple model (Top view).

Figure 3.9: Three thousand randomly assigned 2D Discrete Fracture Network (DFN) with 50 degrees orientation in simple model (Top view).

Figure 3.10: Conceptual model of fluid leakoff from HF into NF during HF-NF intersection (Kresse et al. 2013).

Figure 3.11: Conceptual model of four possible conditions of fluid invasions from HF into NF during HF-NF intersection (Kresse et al. 2013).

Figure 3.12: Proposed algorithms for decoupled approach in accounting for HFs-NFs interaction (Kresse et al. 2013).

Figure 4.1: Side view of single stage simple model with 4 perforations of 700 feet apart from each other (Z-axis to Y-axis ratio is 1:10).

Figure 4.2: Predicted fracture geometry using MLF_P3D model without considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10).

Figure 4.3: Predicted fracture geometry using Planar3D model without considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10).

Figure 4.4: Predicted fracture geometry using UFM model without considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10).
Figure 4.5: Predicted fracture geometry using UFM model with considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10)…………………………………………..57

Figure 4.6: Predicted fracture geometry using UFM model in Mangrove for a formation containing 45 degree orientation and 5 degree deviation natural fractures.…………………………………………..59

Figure 4.7: Predicted fracture geometry using UFM model in Mangrove for a formation containing 30 degree orientation and 5 degree deviation natural fractures……………………………………………….59

Figure 4.8: Predicted fracture geometry using UFM model in Mangrove for a formation containing 90 degree orientation and 5 degree deviation natural fractures……………………………………………….60

Figure 4.9: Predicted fracture geometry using UFM model in Mangrove for a formation containing 0 degree orientation and 5 degree deviation natural fractures……………………………………………….60

Figure 4.10: Predicted multistage hydraulic fracturing geometry in the presence of randomly distributed natural fractures utilizing the UFM model in Mangrove for two horizontal wells 500 ft apart. (Z-axis to Y-axis ratio is 1:10)………………………………………………….61

Figure 4.11: A multi-stage hydraulic fracture design of thirteen perforation clusters with 100 ft spacing under UFM model in Mangrove Hydraulic Fracture Design. (Z to Y axis ratio is 1:10)…………………………….63

Figure 4.12: Plane view (from above) of multi-stage fracture design under UFM model without considering natural fracture and stress shadow effects…………………………………………….63

Figure 4.13: Plane view (from above) of simple EGS model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress shadow effects…………………………….64
Figure 4.14: Predicted fracture geometry under complex fracture model in Mangrove with 45 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects………………………………………..65

Figure 4.15: Predicted fracture geometry under complex fracture model in Mangrove with 30 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects………………………………………..66

Figure 4.16: Predicted fracture geometry under complex fracture model in Mangrove with 90 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects………………………………………..67

Figure 4.17: Predicted fracture geometry under complex fracture model in Mangrove with 0 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects………………………………………..68

Figure 4.18: 3000 artificially assigned primary natural fractures (green) and 2000 artificially assigned secondary fractures (red) for 2D DFN design under UFM model in Mangrove………………………………………..69

Figure 4.19: Plane view (from above) of complex fracture model with primary and secondary DFN while considering both natural fracture and stress shadow effects………………………………………..70

Figure 5.1: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 50 psi……………………………………………………………………………..73

Figure 5.2: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 100 psi……………………………………………………………………………..73

Figure 5.3: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 200 psi……………………………………………………………………………..74
Figure 5.4: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 500 psi………………………………………………………….74

Figure 5.5: Top view of UFM model consisting of horizontal well with multiple fractures with considering natural fracture and considering stress anisotropy of 500 psi………………………………………………………….75

Figure 5.6: Top view of complex fracture networks generated under UFM model with high fluid viscosity of 342.22 cp while considering stress shadow and natural fracture effects. ………………………………………77

Figure 5.7: Top view of complex fracture networks generated under UFM model with low fluid viscosity of 21.33 cp while considering stress shadow and natural fracture effects. ………………………………………77

Figure 5.8: Top view of complex fracture networks generated under UFM model using slickwater with viscosity of 0.64 cp while considering stress shadow and natural fracture effects…………………………………………………………………….78

Figure 5.9: Top view of complex fracture networks generated under UFM model with low pump rate of 15 bbl./min while considering stress shadow and natural fracture effects…………………………………………………………………….80

Figure 5.10: Top view of complex fracture networks generated under UFM model with low pump rate of 30 bbl./min while considering stress shadow and natural fracture effects…………………………………………………………………….80

Figure 5.11: Top view of complex fracture networks generated under UFM model with low pump rate of 45 bbl./min while considering stress shadow and natural fracture effects…………………………………………………………………….81

Figure 5.12: Top view of complex fracture networks generated under UFM model with low pump rate of 90 bbl./min while considering stress shadow and natural fracture effects…………………………………………………………………….81

Figure 5.13: Top view of complex fracture networks generated under UFM model with low proppant concentration of 1 PPA while considering stress shadow and natural fracture effects. ……………………………………………………83
Figure 5.14: Top view of complex fracture networks generated under UFM model with proppant concentration of 6 PPA while considering stress shadow and natural fracture effects. .......................................................... 83

Figure 5.15: Top view of complex fracture networks generated under UFM model with proppant concentration of 8 PPA while considering stress shadow and natural fracture effects. .......................................................... 84

Figure 5.16: Top view of complex fracture networks generated under UFM model with 2500 artificially designed NFs while considering stress shadow and natural fracture effects. .......................................................... 87

Figure 5.17: Top view of complex fracture networks generated under UFM model with 1000 artificially designed NFs while considering stress shadow and natural fracture effects. .......................................................... 87

Figure 5.18: Top view of complex fracture networks generated under UFM model with 120 ft average NF spacing while considering stress shadow and natural fracture effects. .......................................................... 89

Figure 5.19: Top view of complex fracture networks generated under UFM model with 200 ft average NF spacing while considering stress shadow and natural fracture effects. .......................................................... 90

Figure 5.20: Top view of complex fracture networks generated under UFM model with 400 and 300 ft average NF length while considering stress shadow and natural fracture effects. .......................................................... 92

Figure 5.21: Top view of complex fracture networks generated under UFM model with 100 and 75 ft average NF length while considering stress shadow and natural fracture effects. .......................................................... 92

Figure 5.22: Sensitivity analysis result of effects of various parameters on fracture half-length. .......................................................................................................................... 96

Figure 5.23: Sensitivity analysis result of effects of various parameters on average fracture width. .......................................................................................................................... 96
Figure 5.24: Sensitivity analysis result of effects of various parameters on effective conductivity.................................................................97

Figure 6.1: 3D view of EGS design optimization generated under UFM model while considering both the positive and negative effects of complex reservoir condition (y to z axis ratio is 5:1).................................102

Figure 6.2: Top view of EGS design optimization with symmetrical completion order under UFM model while considering both the positive and negative effects of complex reservoir condition.................................102

Figure 6.3: Top view of EGS design optimization with sequential completion order under UFM model while considering both the positive and negative effects of complex reservoir condition.................................103

Figure 6.4: Top view of EGS design optimization with sequential completion order and reduced NF length under UFM model while considering both the positive and negative effects of complex reservoir condition.........................................................103
LIST OF TABLES

Table 2.1: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges (Hannes et al. 2013)..........................16

Table 2.2: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges (Hannes et al. 2013)..........................16

Table 2.3: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges (Hannes et al. 2013)..........................17

Table 3.1: Summary of granite material properties and reservoir input parameters used in the simple model simulations. Several granite parameters have been obtained from EMI (2010 a, b) and Morrell (2012)..........................33

Table 3.2: General properties of proppant CarboProp 6/10 from StimLAB database.......................................................................................................................................................36

Table 4.1: General descriptions of available fracture models inside Mangrove Hydraulic Fracture Design (Mangrove manual 2015)..........................53

Table 4.2: Fracture simulation results comparisons among the MLF_P3D, Planar3D, and UFM models in Mangrove simulator (N/A are due to different output information for each model)..........................54

Table 4.3: Input parameter of DFN Design for four simple UFM model simulation cases with various DFN orientations. (Orientation degree is based on direction of $S_{Hmax}$)........................................................................................................58

Table 4.4: Granite material properties and reservoir input parameters used in the multi-stage hydraulic fracture design under UFM model. Several granite parameters have been obtained from EMI (2010 a, b) and Morrell (2012)........................................................................................................62
Table 4.5: Input parameters of DFN design for complex fracture design under UFM model (Orientation degree is based on direction of $S_{\text{Hmax}}$) ..........................69

Table 5.1: Schematic matrix of simulations under UFM model in investigating effects of various parameters on successful EGS design.................................72

Table 5.2: Pump schedule for four simulation cases with various pump rate and fixed fluid volume under UFM complex fracture model.................................79

Table 5.3: Pump schedule for three simulation cases with various proppant concentrations and changing fluid volume under UFM complex fracture model.................................................................................................................82

Table 5.4: Input parameters of two cases of DFN design with various distribution density under UFM model (Orientation degree is based on direction of $S_{\text{Hmax}}$).................................................................................................................86

Table 5.5: Input parameters of two cases of DFN design with various averages DFN spacing under UFM model (Orientation degree is based on direction of $S_{\text{Hmax}}$).................................................................................................................88

Table 5.6: Input parameters of two cases of DFN design with various averages DFN spacing under UFM model (Orientation degree is based on direction of $S_{\text{Hmax}}$).................................................................................................................91

Table 5.7: Comparison between input parameters used in base case and range of input parameters used in sensitivity analysis through matrix of simulations.................................................................97

Table 6.1: Reservoir parameters for design optimization while considering positive effects of stress anisotropy of 500 psi under UFM model simulation.................................................................98

Table 6.2: 2D DFN design parameters for design optimization while considering positive effects of relatively large NF spacing of 120 ft Under UFM model simulation.................................................................99
Table 6.3: Treatment parameters for design optimization with positive effect in achieving successful EGS application under UFM model simulation.

Table 6.4: Simulated numerical results for each stage regarding fracture half-length, average fracture width, and effective conductivity in design optimization under UFM Model Simulation.
ACKNOWLEDGEMENTS

I would like to sincerely thank my entire committee member, Dr. Azra N. Tutuncu, Dr. Alfred W. Eustes, Dr. Luis E. Zerpa, and Dr. Chad Augustine for their patient instructions, friendly support, and valuable opinions in helping me with my research study. Without their proper guidance, I wouldn’t have achieved what I have done today.

I would also like to recognize Pascual, Toni, Qi Yan and other members of Mangrove training from Schlumberger for their generous support and graciously allowing me to use their software. Their contribution to our research consortium is much appreciated.

Finally, I would like to express my gratefulness to the UNGI CIMMM consortium and sponsors from NREL for giving me this valuable opportunity in conducting this research study.
For my father and my mother, who dedicated the best time of their life to me

I hope I can always make you proud

Like I always do
CHAPTER 1
INTRODUCTION

This research study mainly focuses on applying unconventional techniques, such as multistage hydraulic fracture design and horizontal well completion, from the shale oil industry into Enhanced Geothermal System (EGS) development using coupled methods of geomechanics and fluid flow concepts through reservoir simulation. The EGS geothermal model aims to study and compare fracture propagation, complex fracture network development and fluid flow between unconventional shale formation and granite formation. The constructed coupled EGS model in this research study was developed using the Mangrove Petrel simulation software from Schlumberger which allows simulator to consider complex parameters such as stress shadow effects and pre-existing natural fractures in order to create a more realistic fracture pattern. The simulated model is based on an ideal geothermal reservoir using published data from geothermal industry to compare the similarities and differences between shale and granitic formation during hydraulic fracture design, and also to study main factors affecting the resulted fracture geometry. The optimum EGS design was analyzed and evaluated based on a detailed matrix of simulations, in order for a proper sensitivity analyses on main parameters such as in-situ stress state, pre-existing fracture networks, stress shadow effects, pump rate, fluid viscosity, and proppant concentration.

1.1 Geothermal Energy Background

The earth contains a large volume of heat bearing formations, and this heat from deep formations can be valuable and has the potential to supply a large amount of energy if applied with appropriate extracting techniques. It could be used to generate electricity for large power stations, or it can simply be enjoyed as a hot spring. This heat energy inside the underground formation is called geothermal energy, which had been utilized in parts of the world as a clean and sustainable energy source to reduce the high demand on fossil fuels, global warming effects and public health risks resulting from the use of fossil fuels. Flow of the earth mantle drives the superhot magma to rise into the surface, which heats the underground fluids that are trapped inside porous
formations, and therefore creates a large number of reservoirs containing very hot water and steam. These geothermal resources are spread around European countries such as Iceland and Italy, Asian countries such as Japan and Indonesia, and also in North America and South America, where the United States and Mexico, already have a well-developed geothermal energy industry.

The majority of the United States’ geothermal resources are in the western region, including Alaska and Hawaii, as seen in the geothermal potential map in Figure 1.1. According to the 2015 annual U.S & global geothermal power production report, as of 2005, the United States had constructed more than 38 geothermal power projects adding nearly 700 MW to the U.S. electricity capacity, through which the vast majority of geothermal power was produced in California; As of 2014, the geothermal industry in the United States had about 3.5 GW of installed nameplate capacity and 2.7 GW of net capacity; By the end of 2015, the global market for geothermal industry was at about 12.8 gigawatts of operating capacity, throughout 24 countries (GEA 2015).

![Geothermal Resource of the United States](image)

**Figure 1.1: Geothermal potential Map for the United States (Billy 2009, original source NREL for the US Department of Energy 2015).**
1.2 Introduction to Enhanced Geothermal System

Similar to the formation characteristics of shale gas and tight oil reservoirs, geothermal formations, especially those from deep formations with ultra-low permeability also have the potential to be developed a sustainable, and renewable energy solution to the increasing demand in heat and electricity ever since the Second Industrialization. In a long term view, our mother earth has been emitting its heat from the center core ever since its birth and it is still very likely to sustain for a very long time in the future as well. However, compared with commercialized energy sources such as shale gas and tight oil from unconventional industry, it is still not economical enough to exploit heat from those hot, ultra-low permeability formations without applying certain stimulation technologies, such as horizontal injection and production wells with multistage hydraulic practice (Tester 2016). Enhanced Geothermal Systems, or EGS technology, as the name itself indicates, is being developed to enhance the produced heat energy from those unconventional geothermal resources, even those with hard, hot rocks with almost no heated fluid inside. From using stimulation technologies such as multi-stages hydraulic fracturing and horizontal well completion, EGS would expand the geothermal powering capabilities in a much bigger extent.

EGS system is based a combination of conductive heat transport from the rock matrix to flowing fractures, and convective heat transport through these fracture networks to producing wells (Doe et al. 2014). Although it is practical to apply the same well completion and reservoir simulation techniques into EGS for creating multiple fractures from horizontal wells after optimum stimulation design through numerical simulation studies, engineers have to implement different formation characteristics from unconventional oil and gas reservoirs in order for effective use of the same technologies in enhanced geothermal system applications. These differences include reservoir lithology, formation temperature, pore pressure, in situ stress states as well as the variations resulting from the optimum selection of fracturing fluid, proppant, pumping rate, well spacing in these two diverse applications.

Another significant difference between these two energy systems is the conduit where production takes place; In unconventional tight oil and shale gas operations,
permeable conduits are created through the hydraulic fracturing operations in order to connect the existing natural fractures and pore space together for creation of production pathways inside the formation matrix; While heat exchange inside the geothermal system needs to be established between the injected fluid and the heated formations through the conducted conduit. The effectiveness of the heat exchange in geothermal system is dependent on the total heat extracting volume among heat bearing matrixes and cold injected fluids under a reasonable flow rate throughout the production life.

1.3 Motivation and Objectives

The motivation of this research originates from the essential need of a clean, sustainable energy solution for society, reducing global warming effects, and health risks resulted from the consumption of traditional fossil fuel, while maintaining the growing demand in energy such as heat and electricity in U.S and worldwide as a result of the increasing population. Though solar, hydro energy and wind power had been maturely developed and positively supported by the US government as the clean, green energy alternatives for decades, limitations in those natural energy supplies still exist due to weather conditions and geological constraints and therefore are still not able to be economically produced worldwide for a long time. On the other hand, geothermal energy, especially enhanced geothermal system (EGS), is relatively young and immature compared with other types of sustainable energy system, as there is a large potential and space of development, especially its potential to be applied with unconventional stimulation technologies for a more economical heat production due to its similar characteristics with the shale formation.

Objectives for this thesis research study are as follows:

1. Develop a coupled geomechanics and fluid flow model for modeling of fracture creation and propagation in unconventional reservoirs and enhanced geothermal systems.
2. Compare different fracture models and fracture designs between conventional and unconventional reservoir formations.
3. Study main input parameters and determine their roles on the creation of fracture geometry and its effectiveness in geothermal field.
4. Investigate the feasibility of implementing shale gas and tight oil reservoir hydraulic fracturing practices in EGS applications based on sensitivity analysis.

1.4 Model Limitations

When evaluating a mature field of its potential performance, reservoir modeling technology, especially numerical simulation can be an useful tool, with integration of large amount of data from various aspects in either petrophysics, geomechanics, rock fluid analysis, drilling and completion studies, which provides a logical prediction of future development plan calibrated with history match. Also, the accuracy of numerical simulation can be improved as more and more data is obtained.

However, when evaluating field of interest where data acquisition is still insufficient or immature, reservoir modeling can be hard or inaccurate due to lack of important input parameters and uncertainties in complex reservoir conditions. Just like the current situation of EGS, which a less mature system compared with than in oil and gas industry, and we were not able to integrate field logging data into our EGS model. Therefore, general formation parameters were assumed or simplified based on recent published literatures from the geothermal industry and academia.

Also, as the simulation software Mangrove Petrel was originally designed for unconventional oil and gas reservoir, it is powerful in capturing the fracture propagation and fluid flow inside fractured conduits during hydraulic fracture operation. Yet it is less powerful in describing the thermal conduction and convection effects during heat circulation, which are important factors to be considered in the geothermal industry, therefore the model has a limitation in capturing general thermal front movement inside the reservoir. Instead, the model will be studied mainly on fracture geometry, fracture network complexity and average fracture conductivity as alternative criteria when evaluating EGS feasibility, since well designed hydraulic fractures are also vital for a successful EGS application.
1.5 Research Workflow

In reaching the main goals of this research, a literature review had been conducted to understand the critical geomechanics and fluid flow concepts for unconventional development, the physical mechanisms behind the fracturing model during the simulations, and the suitability for conducting hydraulic fracturing in EGS applications. Also, previous case studies in discrete fracture network (DFN) modeling were reviewed as to determine main factors contributing the main differences of hydraulic fracture design between a shale reservoir and a granite formation. Case studies and later on model simulation will be based on the detailed overview for simulation process as shown in Figure 1.2 below.

Figure 1.2: Overview of simulation process of hydraulic design for EGS.
A simple model was developed after studying previous hydraulic fracture modeling cases, in order to compare the different fracture geometry generated from the classic Planar3D model, Pseudo-3D model, and Unconventional Fracture Model in EGS system. Once a good match was found between the simulated fracture networks with realistic complex fracture networks, a multi-stage hydraulic fracture model was then developed in order to analyze resulting fracture geometry in a more realistic scenario by considering pre-existing natural fractures and stress shadow effects.

A detailed matrix of simulations, including the complex fracture geometries, stress shadow, stress anisotropy, injection rates, fluid viscosity, fracturing proppant concentration, as well as the presence of various distributed natural fractures with altering length and spacing, was then conducted in order to find most important parameters in affecting the EGS performance, especially those in affecting the resulted average fracture width, fracture permeability and fracture conductivity. Finally by strictly following the above research workflow, confident conclusions and recommendations regarding the feasibility of applying unconventional techniques for an EGS type reservoir were given, along with a reasonable potential application and future work of this research study between unconventional system and EGS system.
CHAPTER 2
LITERATURE REVIEW

A literature review related to thermal breakthrough and matrix thermal depletion in geothermal production, analytical solution for EGS, Discrete Fracture Network modeling, geomechanics and fluid flow concepts, fracture crossing criterion and the theories and methods of integrating the fracture propagation and flow through fracture behavior into one simulator for more complex and realistic scenario.

2.1 Thermal Breakthrough in Geothermal Production

In the geothermal industry, positive circulations of heat extraction are always wanted, by reinjecting the used fluid back into the hot formation. Besides following the environmental regulations of used hot fluid disposal, reinjection of used fluid also helps to keep stable reservoir pressure and maximize the heat extraction life period of the geothermal reservoir.

Usually the reservoir rock should be much hotter than the injected fluid in order for reasonable heat production, injection of cold fluid absorbs heat from the region surrounding the injection wells, due to temperature difference. The rate of thermal conduction between the hot matrix and cold fluid can be different than that of thermal convection within the hot matrixes, which is to say that the amount of heat extracted from circulation of reinjection of cold fluid could be reduced during in a long period of heat production, eventually the temperature difference between the cold fluid and regions in production wells will not be able to sustain high enough heat production, therefore causing thermal breakthrough in the producing well, which would then reduce the later generation of electricity. Early thermal breakthrough is the least thing wanted in geothermal production; since it could mean a poor circulation of heat production, which leads to a relatively small total heat extraction volume. Usually, a sharp thermal front with high flowing velocity signals a high potential of reaching early thermal breakthrough effect in the geothermal reservoir. In order to avoid this effect, proper prediction of the
propagation and velocity of thermal front inside the hot formation before and during heat production is necessary.

The research articles such as Bodvarsson 1972; Gringarten 1978; Shock 2001, had analytically studied the propagation and movement of thermal front, under an assumed single-phase liquid geothermal system in homogeneous rock formation. However, in order to study this effect in a heterogeneous model with multiple phases and changing formation characteristics, larger amount of calculations from codes of numerical simulation is needed, and such codes can be found and studied in articles from Vinsome and Shook 1993; Hayba and Ingebritsen 1994; and Pruess 2004.

Bodvarsson (1972), neglected thermal conduction, developed analytical solutions to calculate thermal front propagation and found an important fact: that the fluid front is usually faster than the temperature front in the matrix, and the ratio between the two front velocities is dependent on the ratio of volumetric heat capacities between matrix and water. Woods and Fitzgerald (1993), investigated similar topics while considering the thermal conduction effect and noticed that the effect from this can be relatively small when compared with many other factors most of the time. When studying thermal front movement in a heterogeneous reservoir, complex flowing conduits can lead to interaction between the originally injected fluids and re-injected fluid, causing a much higher possibility of premature thermal breakthrough, and according to studies from Beall et al. 1994 Parini et al. 1996 and Ocampo et al. 1998 they observed similar effects in many geothermal reservoirs, such as The Geysers, Miravalles, and Cerro Prieto.

In conclusion, though a uniform thermal front sweeping during heat extraction in geothermal industry is a large part of an optimum production strategy, it can only be possible in an ideal reservoir with a very low level of heterogeneity; however, it is still the main goal of all geothermal injection plans, in order to delay the thermal breakthrough in produced fluid as much as possible, which is to say, a longer life of the heat production of the geothermal reservoir. In realistic heterogeneous geothermal reservoir, due to the complex fluid flow paths in the reservoir and the resulting non-
uniform heat sweeping, it is very easy to reach undesired premature thermal breakthrough, without optimum injection strategy.

2.2 Analytical Solution for EGS

During EGS application, network of fractures can be created and enhanced through the use of stimulation techniques. To determine heat and mass flow in the fractured conduits in EGS, it is essential to understand the properties of formation blocks containing the thermal resource and to analyze the geometry of the fracture networks which deliver hot fluids for heat production (INL 2006). Before getting into complex fractured reservoir scenario, a simple, analytical model in supporting successful commercial geothermal production is needed.

One of the well-known analytical solutions for EGS was developed by Gringarten et al. (1975). Although it was idealized, it nonetheless provided fundamental concepts in heat and fluid flow between rock and conductive fractures. In order for generalized illustrations, the solution was presented in a compact form using dimensionless variables, where actual dimensions and units can be determine separately depending on different assumption and condition of each geothermal reservoir. Gringarten et al. (1975) had based their solution start from one fracture that is part of a parallel set with a uniform half-spacing $x_e$, as shown in Figure 2.1. The fractures were in a reservoir with height $y$, width $x$, and distance between the water inlet and outlet $z$. Fluid with a total rate $Q$ was assumed to enters each uniform aperture fracture at one end, and exits through the other. And $q$ represents the flow rate inside each fracture and can be calculated directly.

![Figure 2.1: Conceptual model of the Gringarten et al. (1975) analytical solution; outer blocks have the half-spacing $x_e$.](image)
Later on, Doe et al. (2014) extended the work of Gringarten, using numerical code, they first modeled Gringarten's case of parallel networks, then develop a Discrete Fracture Network (DFN) approach in considering more realistic fracture networks with non-uniform aperture and spacing in a various distributed orientations, to understand the properties of natural, induced, and reactivated fractures that are necessary for good circulation of heat from the hot formation to fluids produced through fracture networks for successful Enhanced Geothermal Systems (EGS).

When modeling Gringarten's case of homogeneous, constant spacing fractures, Doe et al. (2014) noticed that a higher intensity of uniform-property fractures tends to delay the thermal breakthrough due to the lower flow rate inside each fracture, since the thermal front in a fracture moves higher rate than in formation. As the flow rate in each fracture is reduced, the thermal front within the formation matrix is better able to keep the thermal front than that of the fracture, as illustrated in Figure 2.2.

In Gringarten's model which assumed uniform fracture aperture, when there are enough fractures to keep the desired low flow rate in the analytical model, the thermal front in the matrix will arrive essentially at the same time as in the thermal front within the fractures. Under this ideal condition, the fast reduction in the measured production temperature tend to indicate a higher degree of thermal interference between fractures. However, this would not be true when applied in a more realistic reservoir, where the fractures are not necessarily with uniform apertures or parallel.

![Figure 2.2: Example thermal contours for high rate and low rate flow cases (Doe et al. 2014).](image)
2.3 Discrete Fracture Networks Modeling

Traditional hydraulic fracturing models focus on a single planar fracture (Warpinski et al. 1987), which is usually not suitable to describe realistic fracture geometry in unconventional reservoir models. This is because when hydraulic fractures are induced in the wellbore, where a natural fractures (NFs) set exists, the hydraulic fractures (HFs) introduced are expected to intersect and interact with the in-situ natural fractures. If the hydraulic fracturing fluid has high enough energy to cross the natural fractures, it will remains as a single planar fracture (Weng et al. 2014). If the hydraulic fractures get arrested or filtrate into the natural fractures, a more complex fracture network may be created (Meng et al. 2010). In general, the crossing criterion determines the complexity and geometry of the overall fracture network, and more details regarding the crossing criteria will be discussed in the later section.

To understand the limitations of the conclusions obtained from simple uniform, parallel fracture networks, it is important to extend the analysis by integrating heat and mass flow within realistic fracture network geometries. The DFN models (Long et al. 1982; Dershowitz 1985; Dershowitz and Miller 1995) directly represent conducting fractures as discrete planar features in three dimensions with realistic geometry and hydraulic property of individual fracture, which provides more realistic description of fracture propagation during stimulation, is a methodology to effectively capture the heterogeneity and the changing connectivity of fracture networks.

In recent years, with the wide applications of DFN modeling approaches, many have developed codes to include modules that simulate natural fracture opening due to hydraulic fracture simulation (Cottrell et al. 2013), which gave better definition of stimulated reservoir volume (SRV) for unconventional shale as well as EGS. Doe et al. (2014), found using FracMan modeling that introduces complex networks produced through a mix of network and single fracture like behaviors. The earlier time thermal behavior is introduced by the higher intensity fracture network within the stimulated volume. Once the stimulated volume thermally depletes, the entire volume acts as a single thermal sink, as shown in Figure 2.3. Riahi et al. (2014) introduced shear-stimulated volume of the reservoir that can be much larger than that of the actual heat
extraction volume due to preferential flow through a relatively small number of fractures in the stimulated fracture network as shown in Figure 2.4.

Figure 2.3: Thermal decline for a complex fractured reservoir (Doe et al. 2014).

Figure 2.4: Shear-stimulated volume (left) vs. rock temperature during circulation (right) as a function of stimulation injection rate for modeling by (Riahi et al. 2014).
This concept is relevant for EGS applications as fractures must be connected between wells. The goal in EGS operations is circulating the fluid through the reservoir, not draining it out of the reservoir as in unconventional reservoirs nor in conventional porous geothermal reservoir. While fracture complexity in shale gas is needed to increase the volume of reservoir formation disturbed and available for gas recovery, it’s possible that fracture complexity does not aid in thermal heat recovery due to thermal breakthrough and single fracture flow behavior for fluid flow in non-uniform aperture fracture systems.

2.4 COMPARING DFN MODEL BETWEEN SHALE AND GRANITE FORMATION

As discussed in the previous sections, from unconventional perspective, certain level of stimulating treatment is needed for oil, gas or heat production in ultra-tight formations like shale and granite, and the idea is logical to apply stimulation techniques in hot dry rock geothermal systems which share similar characteristics in low porosity and low permeability with that of the unconventional shale formation.

However, it should always be noticed that EGS and unconventional shale are two different types of reservoir bearing different types of energy resources, where the former tends to have a higher temperature and pressure due to a deeper zone of interest during energy extraction, and also different stress state due to different locations and rock type. Simply treating the EGS as one of the unconventional shale play would possibly increase risks of failure during stimulation operation and later on production. In order to have a more feasible hydraulic stimulation design for the EGS, simulations and model comparisons between the two geological conditions are definitely needed.

Hannes et al. (2013) demonstrated a complex fracture network model which is able to model hydraulic fracture treatment in shale formations and granite rock formations that are naturally fractured. They described the use of numerical simulation to analyze different performance of DFN between these two different lithological formations. Using simulation software, they have provided reservoir input parameters valuable for these simulations.
Two reservoir models were built during Hannes’ DFM simulations; one is a shale formation reservoir containing gas that’s 2500 meters deep, the other is a granite formation reservoir bearing heat 5000 meters underground. The reservoir parameters and assumptions used in their modeling study are listed in Tables 2.1, 2.2 and 2.3. Their typical DFN simulation process is presented in Figure 2.5.

Figure 2.5: Overview of the main parameters and processes involved in the hydraulic fracturing simulations (Hannes et al. 2013)
Table 2.1: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges. (Hannes et al. 2013)

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
<th>Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young's modulus (GPa)</td>
<td>55 (40-70)</td>
<td>30 (10-80)</td>
</tr>
<tr>
<td>Poisson's ratio (-)</td>
<td>0.2 (0.1-0.3)</td>
<td>0.2 (0.1-0.3)</td>
</tr>
<tr>
<td>Fracture toughness (Mpa m$^{1/2}$)</td>
<td>1.5 (1.3-1.7)</td>
<td>1.5 (1-2)</td>
</tr>
<tr>
<td>Tensile strength (Mpa)</td>
<td>12 (9-15)</td>
<td>4 (2-6)</td>
</tr>
<tr>
<td>Permeability (μD)</td>
<td>0.5 (0.1-1)</td>
<td>0.5 (0.1-1)</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>1 (0.5-1.5)</td>
<td>5 (0-10)</td>
</tr>
<tr>
<td>Total compressibility (1/GPa)</td>
<td>0.43 (0.32-0.54) [cal., no gas]</td>
<td>33 (30-36)</td>
</tr>
<tr>
<td>Reservoir fluid viscosity (mPa s)</td>
<td>0.3 (0.2-0.4)</td>
<td>0.02</td>
</tr>
<tr>
<td>Fluid viscosity filtrate (mPa s)</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 2.2: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges. (Hannes et al. 2013)

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
<th>Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture sets (-)</td>
<td>≥ 2 subvert</td>
<td>≥ 2 subvert</td>
</tr>
<tr>
<td>Fracture spacing (m)</td>
<td>1.5 (0.3-4)</td>
<td>25 (5-300)</td>
</tr>
<tr>
<td>Fracture width (mm)</td>
<td>0 (0.1-1)</td>
<td>0 (0.001-0.265)</td>
</tr>
</tbody>
</table>
Table 2.3: Typical rock properties of granites and shale. Bold numbers show the values used for the base case scenario and numbers in parentheses show parameter ranges. (Hannes et al. 2013)

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
<th>Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_p$ (MPa)</td>
<td>49</td>
<td>24.5</td>
</tr>
<tr>
<td>$\sigma_V$ (MPa)</td>
<td>130 (128-132)</td>
<td>65 (64-66)</td>
</tr>
<tr>
<td>$\sigma_h$ (MPa)</td>
<td>69 (58-85)</td>
<td>35 (29-42)</td>
</tr>
<tr>
<td>$\sigma_H$ (MPa)</td>
<td>69 (58-132)</td>
<td>35 (29-66)</td>
</tr>
<tr>
<td>$\sigma_H-\sigma_h$ (MPa)</td>
<td>0 (0-61)</td>
<td>0 (0-30)</td>
</tr>
</tbody>
</table>

In order to find the reservoir and treatment parameters with most effect on the fracture network development during the simulation of the two formations, Hannes conducted a detailed sensitivity analysis. Their simulation results showed that, in low permeability rocks, main parameters in aiding the complexity of developed fracture networks were as follow: discrete fracture network (DFN), as a largely distributed pre-existing natural fractural network that are very closed with each other; in situ stress state with low anisotropy values; rock properties with high tensile strength; high Young's modulus and low viscosity fluid (slickwater) with large injection volumes.

According to Hannes' article of simulation cases, by comparing their model simulation results between the two systems, main differences in reservoir parameters that affect the treatment designs, especially in the creation of complex fracture network between the shale and granite were identified as follows: The reservoir temperature, in-situ stresses, tensile strength, Young's moduli, formation pressure, and surface treatment pressure in granites are usually much larger than that in shale, due to the deeper and more complex environment of granite formation; However, the total reservoir compressibility and the resulted fluid leak-off effects in granites tend to be significantly lower than that in shale. Therefore based on their sensitivity analysis, Hannes et al. 2013, concluded that for stimulation treatment in granite system, the stimulated fracture network is expected to be more complex than that in shale system.
This in turn proved that it is necessary to study and analyze those complex reservoir conditions in preventing us from creating the desired single, large, planar fractures in a successful EGS application.

2.5 Gemenanics and Fluid Flow Concepts

Modern simulation technique enable engineers to model complex fracture geometry; In order to deliver the most accurate and effective coupled model, it is vital to understand the physical mechanism behind the simulation software and include the following gemenanical and fluid flow concepts.

2.5.1 Stress Shadow Effect

The stress shadow refers to the interaction between hydraulic fractures when propagating in close distance. In conventional case of a single, planar fracture, the fracture induced a “stress contour” at the surrounding rock region of a distance which is about the induced fracture’s vertical length, and the extent of this effect is usually depending on the net pressure it induces to the surrounding matrixes (Kresse et al. 2012). The induced “stress contour” can cause reduction in width of nearby fractures that propagates into the stress shadow region, also, stress shadow can cause the fracture path to change by following the new induced “stress contour”. Under certain condition, when two fracture tips are approaching each other, the fractures can bend toward each other (Olson 2008). In summary, stress shadow is likely to cause divergence of the adjacent parallel fractures from propagating in the original direction.

Therefore, studying effects from stress shadow is necessary for the optimum design of fracture spacing for the close, parallel, multi-stage fracture from a horizontal wellbore in low permeability shale formation (Wu et al. 2012). And this is also true in the case for EGS applications, in order to maximizing the contact area between heated matrix and fracture conduits allowing injected fluid to extract as much heat as possible, while keeping the simplicity of the general fracture network geometry in order to reduce pre-mature thermal breakthrough due to preferential flow behavior in complex fracture reservoir.
In order to properly model parallel fractures and analyze stress shadow, Sneddon (1946), and Sneddon and Elliott (1946) had a conceptual 2D fracture model to estimate the stress field around it, and their equations for calculating the stress that is impacting the fracture width is presented below:

\[
\sigma_x = p \left[ 1 - \frac{L}{\sqrt{L_1L_2}} \cos \left( \theta - \frac{\theta_1 + \theta_2}{2} \right) - \frac{L}{(LL_1)^{\frac{3}{2}}} \sin \theta \sin \left( \frac{3}{2} (\theta_1 + \theta_2) \right) \right] \quad (2.1)
\]

\[
\theta = \arctan \left( -\frac{x}{y} \right) \quad (2.2)
\]

\[
\theta_1 = \arctan \left( -\frac{x}{1+y} \right), \theta_2 = \arctan \left( -\frac{x}{1-y} \right) \quad (2.3)
\]

Where \( \sigma_x \) is the stress that has direct effect in created fracture width, \( p \) represents the inner pressure in the 2D fracture, and \( x, y, L, L_1, L_2 \) represent the coordinating location and distances in 2D fracture schematic as shown in Figure 2.6, where \( h/2 \) is the fracture half-length. \( \theta_1 \) and \( \theta_2 \) represented the different angles between the two fracture tip with a desired location of coordinate.

Figure 2.6: Schematic of 2D fracture model used for calculating stress field with fracture half-length \( h/2 \) (Wu et al. 2012)
However, Sneddon and Elliott’s methods can only be applied in determining average effective stress, which was considered as part of the effective closure stress between single, parallel fracture. In the scenario where a network of complex fractures is presented, the fractures would tend to have different orientation and intersect with each other; therefore a more accurate and efficient method is needed to determine the effective stress on each fracture branch, instead of just estimating an average effective stress for the overall fracture network. In unconventional fracture model developed by Kresse et al. 2012, they molded a much detailed interactions among each element of fracture, and their calculations was based on method of 2D Displacement Discontinuity (DDM) (Olson 2004) in order to determine the induced stresses on each element, as shown in Figure 2.7.

![Figure 2.7: Schematic of computing stress shadow effect from opened hydraulic fractures and closed natural fractures with intersections using DDM methods (Kresse et al. 2012)](image)

**2.5.2 Lamination Effect**

When a hydraulic fracture that propagates in the vertical direction is induced in the formation containing many weak bedding planes, and lamination effects from those fragile beddings may cause the fracture to be arrested or filter into the interface and slip...
the interface. This can potentially result in a reduction of vertical extension of the fracture or it can create a T-shaped fracture when the fluid pressure inside the bedding interface exceeds the over-burden stresses, or the fracture can keep growing upward beyond the interface; during hydraulic fracturing in shale formation, those laminated interfaces with various thicknesses can always be found. And effects of those laminations can be a potential cause for the fracture height determined from seismic data is much less than predicted from conventional Pseudo-3D fracture simulation model, or the net pressure observed during drilling and completion can be much greater than the predicted net pressure.

Figure 2.8: Ideal vertical fracture trace with offsets at laminations vs realistic vertical fracture trace (Mangrove manual 2015)

Engineer can use fracture offset value to represent an averaged value of fraction loss or height reduction as the fracture crosses or filtrates into laminated interfaces in the bedding planes. Since a fracture path is not shifting every time when propagates vertically through the laminated interfaces, the user input offset value can be bigger than the real offsets. For practical use during model simulation, this parameter can be modified in order to match the measured fracture height and net pressure if the predicted results without lamination effect do not agree with the measured data.

2.5.3 Near-Wellbore Tortuosity

During operation of hydraulic fracturing, it is well known that the induced fracture tends to propagate in the direction of maximum horizontal stress, which is also the
direction that is perpendicular of minimum horizontal stress, where resisting compression stress is minimized (Zoback 2007). If a fracture is induced from the perforation cluster in a direction that is between the direction of minimum horizontal stress $\sigma_h$ and maximum horizontal stress $\sigma_H$, as shown in Figure 2.9, in the near wellbore region, fractures would more likely to propagate in the direction of perforation at first then gradually turn its propagation path into the direction of maximum horizontal stress during later propagation, this effect can be considered as near wellbore tortuosity. According to Abass et al 1992, for a fracture induced and started from the wellbore, main parameters determining the level of tortuosity for this fracture are: wellbore placement, perforation direction, near wellbore stress state and orientation.

Effect of near wellbore tortuosity tends to have negative effects for hydrocarbons to flow into the wellbore in the desired flow rate and can cause unnecessary friction and pressure loss during the operation of injection and production, resulting potential reduction in long term production. Also, the tortuous fracture path tends to add up the difficulties in proper placement of proppant, which can result in premature screen outs during fracturing treatment. (Surjaatmadja et al 1994).

![Figure 2.9: Schematic of fracture reorientation due to near wellbore tortuosity (Chen et al. 2010)](image-url)
2.5.4 Interaction between Hydraulic and Natural Fractures

In formations with largely distributed in-situ natural fractures, interaction between these natural fractures and the induced hydraulic fractures can raise the level of complexity for created fracture network, which can in turn affect the accuracy in predicting fracture geometry and subsequent reservoir performance. Therefore it is vital to understand the physical mechanisms behind hydraulic-natural fracture interactions.

As the applications of stimulation technologies in unconventional production are spreading within the decades, more and more studies were conducted, from both the oil industry and academia, regarding the HF-NF interaction. Research publications such as Blanton 1982, 1986; Warpinski and Teufel 1987; Renshaw and Pollard 1995, had focused on many experimental works in the early 80s and 90s and contributed to a lot of classic and fundamental criteria regarding the HF-NF interaction. Later on, more research studies such as Beugelsdijk et al. 2000; Potluri et al. 2005; Zhao et al. 2008; Gu and Weng 2010; Gu et al. 2011, started to summarize previous experimental works in theories and constructed analytical models in mathematically determining HF-NF interaction with assumptions under certain reservoir conditions.

Recently, due to the development in numerical simulation technologies and popularization in reservoir simulation software, many research studies and simulation models such as : Zhang and Jeffrey, 2008; Thiercelin and Makkhyu 2007; Zhang et al. 2009; Zhao and Young, 2009; Chuprakov et al., 2010; Meng and de Pater, 2010; Dahi-Taleghani and Olson, 2011; Sesetty and Ghassemi, 2012; Chuprakov et al. 2013a, are developed, especially focusing on numerically analyzing fracture propagation, interaction and the later on production prediction in typical complex fractured reservoirs.

According to Weng et al. 2014, there are many factors involved during the interaction between HF and NF: the stress state of the reservoir, such as stress anisotropy and stress shadow; mechanical properties of the formation rock such as Young’s modulus, and rock tensile strength; natural fracture spacing and orientation; and also treatment parameters during the operation of hydraulic fracturing, such as fluid viscosity and pumping rate. In order to consider all of the factors stated above in
resulting in a complex fractured network, Weng claimed that typically there are three most possible cases when a hydraulic fracture intersects a natural fracture: That the hydraulic fracture can either crosses over, filtrate into, or simply got arrested at the natural fractures.

The three possible cases during HF-NF interaction stated above can be well described in an analytical model developed by Chuprakov et al. 2013a, also known as the OpenT model, which is integrated inside the simulator in modeling fracture interactions for this study. The OpenT can be used to solve for the elastic problem by the time when the HF tip contacts a NF in determining the boundary of open and sliding zone as shown in Figure 2.10. Solutions in the OpenT model indicated that the fluid pressure inside NF can have a huge impact on the opening and sliding conditions during HF-NF interaction.

Equation in determining the average fracture width \( \bar{W} \) at the opening HF tip with injection rate \( Q \) and fluid viscosity \( \mu \) can be found from Valko and Economides 1995, as shown below, where \( E' \) represents the effective Young’s modulus, \( \nu \) represents the Poisson’s ratio. However, this is only applicable in a KGD fracture model with a fixed fracture half-length \( L \) and height \( H \).

\[
\bar{W} = 2.53 \left[ \frac{Q \mu L^2}{E' H} \right]^{1/4} \tag{2.2}
\]
2.5.5 Flow Regime in Fractured Reservoirs

Before discussing flow regime in fractured reservoir, according to Kuchuk et al. 2010, it is common in pressure-transient testing to divide standard flow regime as three periods: (1) early-time period, (2) middle-time period, and (3) late-time period. These flow regimes are presented in details as shown in Figure 2.13 of Kuchuk et al. 2010, for a fully penetrated circular well in a 1D radial reservoir with the constant-pressure or no-flow outer-boundary condition, the early-time-period derivatives resemble an unsymmetrical bell-shaped curve with four distinct periods: (1) a unit-slope (m=1) period, (2) a maximum-arch interval, (3) a negative-slope (m=-1) period, and (4) a transition period occurs before the infinite-acting radial-flow regime. Kuchuk then described possible flow regime when vertical well intersects a fracture that is parallel to the wellbore axis: (a) fracture linear flow, (b) bilinear, (c) formation linear, and (d) trilinear, and other likely flow regimes when a vertical well intersects a finite-conductivity fracture with an angle that is less than 90 degrees: (e) fracture radial flow and (f) formation linear flow, as shown in Figure 2.11.

Figure 2.11: Schematics of flow regimes for a vertical well intersecting a fully or partially penetrating fracture parallel to and non-parallel to the wellbore. Kuchuk et al. (2015)
Kuchuk then described possible flow regime in continuously fractured reservoir when the contrast between the fracture permeability and matric permeability is high, as shown in Figure 2.12. However, in order to understand the pressure-transient behavior of fractured reservoir, researchers have to understand the behavior of a single wellbore that intersects fracture with skin and storage effects at the first place. Relevant research topics can be learned from Evans 1971; Raghavan 1976; Cinco-Ley and Samaniego-V. 1977, 1981 a; and Wong et al. 1986, all provided methods in identification of flow regimes that take place around the single wellbore and fractures. In reality, the effects of fractured-reservoir tend to interact with each other, and the complexity of the behavior is increased when wellbore storage and skin effects are added.

Figure 2.12: Schematics of common flow regimes for a vertical well intersecting a fully or partially penetrating fracture parallel to and non-parallel to the wellbore. Kuchuk et al. (2015)

2.5.6 Tri-Linear Flow Model in Fractured Horizontal Well

Camacho-V. 1984, 1987, which provided similar ideas in identifying producing well response for vertical fractured wells with consideration of various fracture length, introduced analytical models and calculations for pressure and conductivity for the commingled reservoir. Later on the trilinear-flow model introduced by Ozkan et al. 2011,
provided analysis of a possible production response for a multi-stage fractured horizontal well in low permeability shale reservoir, and indicated the contributions of natural fracture properties such as fracture density and fracture conductivity in the productivity while comparing the differences of that in a conventional reservoir. As shown in Figure 2.13, the trilinear-flow model by Ozkan et al. 2011, delivered analytical solutions for the combination of linear flows in three flow regions that are close to each other: the flow region in the outer reservoir, flow region in the inner reservoir between fractures and the flow region inside the hydraulic fracture.

![Figure 2.13: Schematic of the trilinear-flow model used for the analytical solution of multiple-fractured-horizontal-well performance. (Ozkan et al. 2011)](image)

The trilinear-flow model assumed a horizontal well containing many induced hydraulic fractures that are uniform with each other, and natural fractures that are artificially distributed inside the shale reservoir model, which also assigned a dual-porosity grid property as to ideally represent to difference between the naturally fractured medium and the shale matrix medium, as to effectively simulate and analyze the performance in ultra-tight shale formations. At last, results from the trilinear-flow model confirmed that besides inducing relatively high conductivity to the hydraulic fracture and increasing permeability in the surrounding matrixes, it is also important, or more important for the existence of largely distributed natural fractures in improving productivity, especially in ultra-low permeability shale reservoir (Ozkan et al. 2011). Relevant understanding can be applied to EGS as well, since the granite formation...
shares similar reservoir characteristics such as ultra-low porosity and permeability, therefore it is more preferable for the fluid flow inside the complex fracture network than that in the surrounding formation matrixes.

### 2.6 Model Coupling Method

Conventional simulation methods tend to consider pore compressibility as a geomechanical parameter for simulation and assume permeability and porosity as pressure-dependent variables. However, these methods are insufficient to accurately predict reservoir performance and recovery in unconventional reservoir, especially in naturally fractured reservoir, without accounting for both the fluid flow and geomechanical factors using certain levels of coupling methods (Jalali and Dusseault 2008). A brief description of several different levels of coupling methods of geomechanics and fluid flow concepts was introduced, ordered from simple to complex.

The first method is called as “decoupled” method, which is the loosest among all. In this method, stress change effect is introduced to the flow model through parameters like compressibility and permeability, and then the deformation is calculated in a geomechanical model with pressure history as an external load. This calculation is then repeated until reaching a suitable estimation for pressure and temperature. This method does not require heavy computational and is used in most conventional simulators for quick estimation and physical insight into the coupled problem.

The second one is called “pseudo coupling” method, which is based on an empirical model of absolute permeability and porosity that are pressure sensitive. During the processing of the empirical model, the conventional reservoir simulator can compute some geomechanical parameters such as horizontal stress and porosity change through relationship between porosity and stress as well as vertical displacement. This method can be fairly unrealistic, except in cases where computational costs for fully coupled modeling are prohibitive.

The third one is termed as “explicit coupling” method, also called the one-way coupling method, this is because of during explicit coupling method, input data from the
reservoir simulator are sent to a geomechanics model, and results obtained from the computations stay inside this geomechanics model, while the model keep performing calculations and receiving data from the reservoir simulator mono-directionally. Under the one-way coupling method, mechanical effects determined from the geomechanics model were not able to influence the fluid flow inside the reservoir flow model, and only geomechanics variables will be affected by changes in reservoir flow variables. This method is an efficient and time-saving approach for subsidence problems since calculations from the two models can be performed on a different time scale. On the other hand, time step restrictions during model simulation might be needed in order to maintain the stability and accuracy of this method.

The fourth one is an iterative coupling method, also known as the two-way coupling method. Unlike the one-way coupling, computed information are exchanging bi-directionally between the reservoir model and geomechanics model through non-linear iterations during each time step in simulation. At the end of each time step, results such as multiphase fluid displacement and flow in porous medium are computed accordingly from non-linear iteration and coupled through calculations of pore volumes from another independent simulator. The advantage of this method is its flexibility since the two systems can be solved from different numerical methods; however, this method require of a large number of iterations, which should be considered as the main disadvantage of this method.

The last method is the full coupling method; using finite element method in handling both fluid-flow variables and displacement variables, computations of these two variables can be performed simultaneously, though this method can be slow in overall computation period on some questions compared with those in the explicit and iterative methods. Still, this approach is the “gold standard” during numerical model coupling, and can be used to evaluate results obtained for other coupling methods. On the other hand, in order for this method to be efficient in coupling fluid flow model and geomechnics model generated from existing commercial simulator, more complex code development is then required (Jalali and Dusseault 2008).
CHAPTER 3
METHODOLOGY

Main objective of this thesis research is to numerically model fracture creation and propagation in a granitic formation while capturing the fracture growth as a function of the reservoir properties. As stated in the prior research studies, complex fracture network is important for stimulating production in unconventional reservoirs. Yet, such fracture complexity does not necessarily aid in thermal heat recovery in geothermal field due to thermal breakthrough and single fracture flow behavior for fluid flow in non-uniform fracture aperture system, as discussed from previous literature review session. Therefore, the main goal for this research study is to design large fractures, in order to maximize the contact area between the matrix and injected fluid, and also reduce early thermal breakthrough effects simultaneously.

However, case studies of simulating hydraulic fracture in granitic systems similar to the unconventional reservoirs indicated that there exists significant potential for extensive pre-existing natural fracture network in granitic system. Though simple, planar fractures are preferred for the EGS system applications, during hydraulic fracture treatment, there is a greater chance for complex fracture network occurrence that will affect reservoir performance. Since the program of EGS is relatively immature compared with unconventional shale play from the oil industry with more than half century of real field development, lacking of real field studies and history data became a major obstacle for the development of EGS application. Therefore, it is important to study and analyze the most feasible design before actual field operation under help from the cost effective simulation software.

The Mangrove engineered stimulation package is A Schlumberger application in the Petrel platform utilized to design hydraulic fracture for a horizontal well in granitic system in this research study, also allowing coupling of fluid flow and geomechanics concepts discussed in the previous sessions. A description of the design process and detailed discussion of physical mechanism of the Unconventional Fracture Model (UFM) for EGS application are also included.
3.1 Conceptual Model Design

The conceptual model chosen for this project is a horizontal well with multi-stage fracturing implementation along with a horizontal well with the learnings from the unconventional oil operations as shown in Figure 3.1 and Figure 3.2. A second horizontal well is anticipated to be drilled an optimum distance away from the first horizontal well to be fractured. The fractures from the first well is expected to intersect the second horizontal well for creation of the complexity and the conduit needed between the two horizontal well from heat transfer. This conceptual model has been applied into a simple geothermal reservoir model within the simulator.

Figure 3.1: Conceptual model of EGS reservoir consisting of horizontal well with multiple fractures. Side view of the conceptual model (left), front view of the model (right)

Figure 3.2: Plane view (from above) of conceptual model of EGS system consisting of horizontal well with multiple fractures. Central well is injection well. Fractures are made from this well and intersected on either side by production well.
3.2 Simple Model Design

A simple model built in Mangrove was initiated with a generic horizontal well that is 10,000 ft. deep in the vertical section with a 10 degree per 100 ft well deviation containing a 3,000 ft long horizontal section. The P110 casing with 9 5/8” OD (8.535” ID) with a weight of 53.5 lb/ft has been used for the tubular design. And the horizontal section of the well is in the direction perpendicular to the $S_{H\text{max}}$ (maximum horizontal stress). An illustration of the general design for the well is shown in Figure 3.3.

![Figure 3.3: 10,000 ft deep horizontal well with 10 degree per 100 ft deviation in simple model. Side view of the model (left), front 3D view of the model (right). Arrow at the right corner refers north.](image)

Since the simple model was built mainly to find effects of pre-existing natural fracture network for hydraulic fracturing design in granitic system, no actual logs were available to utilize in the simulator, assumptions have been made based on average published reservoir parameters to be used in this typical granitic systems simulation as
an input. A list of granite material properties and main reservoir input parameters for this simple model design is listed in Table 3.1.

Table 3.1: Summary of granite material properties and reservoir input parameters used in the simple model simulations. Several granite parameters have been obtained from EMI (2010 a, b) and Morrell (2012).

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poisson’s ratio (unitless)</td>
<td>0.32</td>
</tr>
<tr>
<td>Young’s Modulus (GPa)</td>
<td>56.9</td>
</tr>
<tr>
<td>Density (g/cm$^3$)</td>
<td>2.63</td>
</tr>
<tr>
<td>Minimum Horizontal Stress (psi)</td>
<td>8000</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>0.77</td>
</tr>
<tr>
<td>Permeability (μD)</td>
<td>0.5</td>
</tr>
<tr>
<td>Fracture Toughness (MPa m$^{1/2}$)</td>
<td>1.5</td>
</tr>
<tr>
<td>Tensile Strength (MPa)</td>
<td>12</td>
</tr>
<tr>
<td>Thermal Conductivity (W m$^{-1}$K$^{-1}$)</td>
<td>3.15</td>
</tr>
<tr>
<td>Total Compressibility (1/GPa)</td>
<td>0.43</td>
</tr>
<tr>
<td>Rate Per Stage (bbl/min)</td>
<td>30</td>
</tr>
<tr>
<td>Initial Fluid Viscosity (cp)</td>
<td>160</td>
</tr>
<tr>
<td>End Proppant Conc. (PPA)</td>
<td>5</td>
</tr>
<tr>
<td>Pumping Time (min)</td>
<td>278.31</td>
</tr>
</tbody>
</table>

3.3 Defining Fluid

The main objective of fracturing fluids is to open fractures and transport proppants to keep the fractures open as far as possible, and the viscous nature of the fluids and their ability to disappear rapidly after treatment while staying cost effective, are also important to a good fracturing job.

One of the major considerations in the fluid definition stage is selecting the correct fluid with the most desirable viscosity, which has a huge impact on the fracture width, transmission of the proppant, and controlling fluid loss. It is also important that the selected fluid to endure minimum effects from the reservoir pressure, reservoir fluids, rock matrix, and the cleanliness after flow back to produce the maximum post-fracture conductivity during the stage of operation.
Since the main goal for this research study is to design large fractures, in order to maximize the contact area between the matrix and injected fluid, one of the borate crosslinked gel fracturing fluid, YF 100Flex-M117 fluid from the Mangrove user database was used in this simple model. The borate ions in the fracturing fluid can effectively improve fluid viscosity by cross connecting the hydrated polymers before and during injection operation. This crosslink effect resulting from borate ion was designed to be invertible for engineering purposes, as soon as the proppant carried in the borate fluid is properly placed in the fracture conduit, the crosslink effect can be significantly reduced by simply reversing the pH level in the borate fluid in the later cleanup operation, which then minimized the movement of properly placed proppant, in maintaining the desired fracture propped width and permeability (Mangrove 2015).

General properties of the fluid including rheology, leak off, and friction behaviors are shown in Figure 3.4, Figure 3.5 and Figure 3.6. Note that those properties are also data recorded from the Mangrove user data base inside the simulator.

![Figure 3.4: Viscosity vs exposure time for YF 100Flex fluid from Mangrove user data base.](image)
Figure 3.5: Friction pressure vs flow for YF 100Flex fluid in various inner diameter (2 in to 6.4 in)

Figure 3.6: Wall building vs permeability for YF 100Flex fluid from Mangrove user data base.
3.4 Defining Proppant

When a proppant is pumped into a fracture, it can open the fracture and aid in the propagation of the fracture, which is only possible after the pumping fluid pressure exceed in-situ stresses in the formation. During production from the wellbore, the closure stresses in the formation tend to close the fracture again and resulted in crushed proppant. The crushed proppant are likely to give negative effects which drops the permeability of the formation. In order to prevent such conditions from happening, proppant must possess high enough strength to both propagate in the fracture and sustain closure pressure from the fractures. Therefore by having a good understanding of any particular formation, a correct proppant that is suitable for the formation has to be used, and ideally, the proppant should possess the function to last the producing life of the well (Mangrove 2015).

A ceramic type proppant CarboProp was selected from the StimLAB database in order to sustain the high pressure high temperature condition in the granite system. General properties of the proppant are listed in Table 3.2 and the general behavior of proppant permeability versus closure stress is shown in Figure 3.7 below. Note that information of the general properties and behavior of proppant CarbonProp was obtained from the StimLab database inside the simulator.

<table>
<thead>
<tr>
<th>Proppant Name</th>
<th>CarbonProp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mesh Size (ratio)</td>
<td>6/10</td>
</tr>
<tr>
<td>Mean Diameter (inch)</td>
<td>0.1</td>
</tr>
<tr>
<td>Specific Gravity (ratio)</td>
<td>3.25</td>
</tr>
<tr>
<td>Bulk Density (lb/gal)</td>
<td>14.9722</td>
</tr>
<tr>
<td>Propped Fracture Conc. (lbm/ft^2)</td>
<td>1</td>
</tr>
<tr>
<td>Young’s modulus (psi)</td>
<td>3000001</td>
</tr>
<tr>
<td>Stress on Proppant (psi)</td>
<td>3085</td>
</tr>
<tr>
<td>Pack Porosity (%)</td>
<td>35</td>
</tr>
</tbody>
</table>
3.5 Discrete Fracture Network Design

As discussed from the previous section, for ultra-low permeability shale reservoir, it is vital to understand the property of fracture network resulted from the hydraulic fracture and natural fracture interaction, since the overall fracture connectivity affects the total stimulated reservoir volume, which is widely used to estimate reservoir performance in oil industry. Even with the modern seismic interpretation techniques, it is not easy to perfectly capture the existence and therefore even harder to understand the properties of all the pre-existing natural fractures in reservoir that is hundreds or thousands meter deep, needless to say the later on interaction between the hydraulic fractures and natural fractures.

Therefore, a model of discrete fracture network is necessary when simulating the performance of naturally fractured reservoir. In this research study, a 2D DFN design platform inside Unconventional Fracture Model (UFM) under Mangrove Petrel simulator
was used to artificially design a randomly distributed natural fracture set with controllable fracture spacing, height, length and orientation. In the case of simple model development, 3000 randomly assigned primary fractures (green), with an average length of 500 ft, with 50 +/− 10 degrees orientation with respect of the $S_{Hmax}$ direction was first distributed in the simple model. The production well is represented by the blue curve in the center of the reservoir. Then, 3000 secondary fractures (red) were distributed following the primary fracture sets, with an average length of 250 ft, with 320 +/−10 degree orientations with respect of the $S_{Hmax}$ direction, as shown in Figure 3.8 and 3.9 below.

Figure 3.8: Three thousand randomly assigned 2D Discrete Fracture Network (DFN) with 50 degrees orientation in simple model (Top view).

Figure 3.9: Three thousand randomly assigned 2D Discrete Fracture Network (DFN) with 320 degrees orientation in simple model (Top view).
The 2D fracture network represents natural fracture distribution pattern, where the output 2D fracture network is organized in the DFN 2D folder under the Mangrove node in the input panel. Users can generate the 2D fracture network statically by assigning the maximum number, the average length, orientations and the spacing in between the DFN in the reservoir simulator, since the 2D DFN is a mandatory input to run the UFM hydraulic simulation in Mangrove, and the later on predicted fracture geometry would also depend partially on this DFN geometry.

Advantage of 2D DFN is that it gives simulator the ability to consider effects of pre-existing natural fractures inside the reservoir simulator and can be manipulated statically once seismic data from the operations are available. One of the disadvantages of this approach is that the 2D DFN assumes all the natural fracture are vertical with fixed fracture height, where in reality pre-existing natural fractures can be non-vertical or even horizontal due to specific geological environment, and this could be considered as a potential source of error or limitation of the model.

3.6 Complex Fracture Network Simulation

During microseismic monitoring of hydraulic stimulation operations in many reservoirs with proofed existence of largely distributed natural fractures, it is not rare for a complex fracture network to be observed. As the wide spreading of unconventional technology in recent decades, many research studies were conducted focusing on explaining the driven mechanisms of this event, in order for a better prediction of reservoir performance. According to Weng et al. 2011, interaction between the hydraulic induced fractures (HFs) and pre-existing natural fractures (NFs) is believed as one of the main reasons for resulting the complex fracture network during hydraulic fracturing treatments, and this HFs-NFs interaction is determined and influenced by many factors: such as general properties of the in-situ natural fracture set including its primary and secondary orientation, average length, spacing, etc.; in-situ stress state and its later on changes from stress shadow effect; reservoir and mechanical properties of the formation rock including Young’s modulus, tensile strength, permeability, porosity, etc.; and treatment parameters during the actually operation including pump rate, fluid viscosity, proppant properties, etc.
Besides the complex flowing conduits resulted from HFs-NFs interaction, natural fracture itself, on the other hand, can have significant effects on the overall productivity. As in tight formation with very low matrix permeability, under certain conditions, natural fracture’s conductivity can be much larger than that of the reservoir matrix, which can cause many problems during stimulation process, such as enhanced leakoff of the injected fluid and the resulted pre-mature screenout of the proppant carried by the fluid. And many research studies such as Nolte et al. 1981, 1991; Castillo et al. 1987; Warpinski et al. 1991; and Barree et al. 1996, had been conducted in investigating the conditions of opening and leakoff for those in-situ fractures, and all tended to share similar perspective, that the enhanced fluid leakoff effect of natural fractures is pressure sensitive or can be effectively determined from pressure interpretations, such as pressure diagnostic plots, and pressure falloff analysis, etc.

In this research study, a complex fracture network model was constructed in the Mangrove Petrel simulation package from Schlumberger, also known as the Unconventional Fracture Model (UFM), which is designed and developed based numerous research studies (Gu et al. 2010, 2011; Kresse et al. 2012, 2013; Wu et al. 2012; Weng et al. 2011, 2014, etc.), for the purpose of numerically capturing fracture propagation as complex fracture network is creating during hydraulic fracture treatment, and determining parameters with most impacts in EGS applications.

The UFM model also satisfied the need in solving the coupled geomechanics and fluid flow problem for this research study, though using similar mathematical equations and assumptions as conventional pseudo-3D model that can only simulate single planar fracture, advantages in the UFM model showed are the ability to simulate the initialization of complex fracture network resulted from interactions between hydraulic fractures and pre-existing natural fractures, by originally applying the HFs-NFs crossing criterion (Renshaw and Pollard 1995) which was validated against the experimental results, then integrating the OpenT model (Chuprakov et al. 2013) which considered more impacting parameters such as fluid viscosity and pump rate. A detailed coupling processes and basic governing equations during the complex fracture network simulations are introduced in the below sub-sessions.
3.6.1 Modeling Leakoff from HF into NF

During hydraulic fracturing in conventional reservoir, where a set of natural fracture existed in the near wellbore region, it is possible for a induced fracture to intersect with one or several of those in-situ natural fractures, during this process, some of the fracturing fluid could leak in to the surrounding permeable matrix, while the rest stayed inside the hydraulic fracture and these fluid can exert pressure to the surrounding natural fracture. Due to leakoff effect from the permeable matrixes and different in-situ stress state around the natural fractures, the fluid pressure inside the hydraulic fracture tends to be smaller than the normal effective stress on the natural fracture, and the natural fracture could then remain closed, which would then avoid the later on HFs-NFs interaction.

However, in unconventional reservoir where formations tended to have very low porosity and permeability, it is possible for the opened or closed permeable natural fracture to have a relatively higher conductivities compared with that in the surrounding matrixes, which then increased the potential for fracturing fluid in leaking and filtrating into the natural fractures and then pressurized the reservoir fluid inside the NFs (Kresse et al. 2013). A conceptual model of this leakoff and filtration process between HF and NF is shown in Figure 3.10.

![Figure 3.10: Conceptual model of fluid leakoff from hydraulic fracture into natural fracture during HF-NF intersection. (Kresse et al. 2013)](image)
If the fracturing fluid did filtrate into the bi-wing natural fracture instead of crossing and propagating along its original pathway, enhanced leak off effects from NF was then resulted, meaning a portion of the fluid and proppant (if carried by the fluid) in HF was lost, which then resulted in growth reduction of this HF and the later on complex interaction between this HF and NF. According to Kresse and Weng 2013, four possible conditions along this natural fracture could happened at the same time and effects of these four conditions should be analyzed individually:

At first, filtrated fluid HF induced a pressure that’s larger than the effective normal stress on the NF, and opened a section of the NF that is closest to the point of HF-NF intersection; Second, as the filtrated fluid keep invading the NF, at some point the fluid pressure dropped below the closure pressure and resulted a closed section of NF with invaded fluid; Third, though invaded fluid from previous NF section could not filtrate into the NF any further, it could still pressurized the original reservoir fluid in the neighboring NF section ; Last, effects from invaded fracturing fluid disappeared and the rest of the NF section is closed and undisturbed. A conceptual model for these four possible conditions is illustrated in Figure 3.11 below, and during complex fracture simulation, the first three conditions should be modeled with separate approach due to the various pressure, conductivity and flow conditions.

Figure 3.11: Conceptual model of four possible conditions of fluid invasions from HF to NF during HF-NF intersection. (Kresse et al. 2013)
3.6.2 Assumptions in UFM model

Four possible conditions during leakoff from HF into NF were introduced from the previous sub-section, it is then logical to claim that the effective conductivity in the different regions along the invaded NF should also be varied depending on the level of deformation within the NF aperture, which can be affected by the fluid pressure inside the NF conduits and the effective normal stress on the NF outer surface.

On the other hand, as fracturing fluid invades and opens the NF, it doesn’t necessarily always induce tensile fracture, since shear failure and fracture sliding inside NF can also happen if the effective normal stress on part the NF is reduced, which would then affect in-situ stress state near the HF-NF intersection region, and result in a more complex condition when evaluation effects of complex fracture network during simulations. Therefore, assumptions with certain levels of idealization were needed and made by Weng et al. 2013, in order to efficiently computing the process of complex HF-NF interaction, and the resulted enhanced leakoff effect during the actual UFM simulation, while considering all other reservoir and treatment parameters:

- All the flow inside the natural fracture is one-dimensional.
- If there is a set of natural fractures, those natural fractures are all vertical and in the same elevation as the hydraulic fractures are.
- All the natural fractures designed in the UFM are assumed to be closed but permeable from the very beginning, due to their pre-existing apertures and surface toughness, etc.
- The nature fractures have a relatively higher conductivity than that of the surrounding matrix in shale formation.
- Reservoir fluid does exist inside the NF, even without fluid invasion or filtration, and the reservoir fluid is Newtonian fluid which is also compressible.
- The formation matrix is elastic and permeable.
- If the fluid pressure inside the NF is larger than the normal effective stress on the NF, the NF can be opened, or sliding if local normal stress is reduced.
• All the original, undisturbed NFs contain reservoir fluid with pressure that are equal to pore pressure.
• When the induced HF intersects a NF, there are only three possible conditions for the HF, it can either cross the NF, filtrate into the NF, or get arrested by the NF.
• If the fracturing fluid invade and filtrate into the NF from the original HF, it can only filtrate, propagate or be arrested along the direction of this NF, only when it reach a another NF with different orientation, can it be possible for the invaded fluid to re-initiate by filtrate into the other NF from this point of intersection. Therefore, it is not possible for fluid inside NF to reinitiate without the above stated condition during UFM simulation; even it is possible in realistic reservoir condition (Weng et al. 2013).

During the later on simulations in this research, some more assumptions or potential limitations, especially during the complex fracture network simulations, were found by the author of this research and will be discussed in the later on limitation sections.

3.6.3 Fluid Mass Continuity

According to (Weng et al. 2013), the equation for the incompressible fluid mass continuity used for the UFM model has the form:

$$\frac{\partial q_{\text{NF}}}{\partial s} + \frac{\partial A}{\partial t} + q_L = 0 \quad (3.1)$$

$$q_L = \frac{2hc_{\text{rock}}}{\sqrt{t-\tau(s)}} \quad (3.2)$$

$$A = \bar{w}h \quad (3.3)$$

Where $q_{\text{NF}}$ represents the per unit length flow rate volume in a natural fracture with cross section area $A$, $q_L$ represents the per unit length rate of the leakoff volume,
$ar{w}$ represents the average hydraulic fracture width, $h$ represents the assumed fracture height, and $C_{tot}^{rock}$ represents the total leakoff coefficient from the natural fracture wall.

While equation 3.1 is true only for incompressible fluid, as for compressible fluid, density $\rho_f$ and mass flux $q_m$ should then be included. Also by considering the volumetric fluid mass rate of change along the fracture of constant length, equation for the fluid mass continuity inside the fracture has the form:

$$\frac{\partial q_m}{\partial s} + \frac{\partial (\rho_f \bar{w} h)}{\partial t} + \rho_f q_L = 0$$

(3.4)

Where $s$ represents the axial location in the total length of NF, $t$ represents the amount of time during the mass flow, and $C_{tot}^{rock}$ in this case represents total leakoff coefficient of the natural fracture walls and is determined from the combined leakoff coefficient (Dean et al. 1983)

### 3.6.4 Pressure Change in Closed NF

Using Darcy’s law, pressure alteration inside the closed NF can be represented and determined as:

$$q_{NF} = -\frac{k_{NF} A}{\mu_f} \frac{\Delta p}{L(t)}$$

(3.5)

Or for mass flux:

$$q_{NF} = -\rho_f \frac{k_{NF} A}{\mu_f} \frac{\partial p}{\partial s}$$

(3.6)

The pressure can then be calculated from:

$$\frac{\partial p}{\partial s} = -\frac{\mu_f}{\rho_f k_{NF} A} q_m = -\frac{\mu_f}{\rho_f k_{NF} \bar{w} h} q_m$$

(3.7)

$$p = p_{in}(t), \text{at the inlet}$$

(3.8)
Where $k_{NF}$ represents the natural fracture’s permeability, $\mu_f$ represents the viscosity of filtrate fluid, $\rho_f$ represents the density of filtrate fluid, $A$ shared similar meaning with stated above, represents the cross sectional area of closed NF, and $p_{in}$ represents the inlet fluid pressure.

### 3.6.5 NF permeability

According to Walsh et al. 1981, the NF permeability, highly depended on pressure on of the invading fluid if it is larger the pore pressure while smaller than the closure pressure, which directly affecting the enhanced fluid leakoff in the NF; In terms of representing NF permeability in a mathematical form of solutions, fluid pressure, shear stress and normal stress should be considered in the function as a final product of normal stress induced permeability and shear slippage induced permeability.

$$k_{NF} = f(k_{NF}^n, k_{NF}^s)$$

$$k_{NF}^n = f_1(k_0, \sigma_n, p)$$

$$k_{NF}^n = f_2(u_s, \phi_{dit})$$

$$k_{NF}^n = k_0 \left\{ \text{Cl} \ln \left[ \frac{\sigma^*}{\sigma_n - p} \right] \right\}^3$$

Where the constants is represented as alphabet C and $\sigma^*$ represents relative stress state, as to correlate with field results, $k_0$ represents the initial NF permeability, which is undisturbed by invaded fluid in HF, $\sigma_n$ represents the normal stress acting on the NF, $p$ represents the fluid pressure inside NF, and $u_s$ represents the displacement induced from shear slippages.

### 3.6.6 Hydraulic Aperture of Closed NF

The hydraulic aperture $\bar{w}$, which is the width induced from invaded fluid from the HF into the closed NF, according to Zhang et al. 2009, can be straightly connected to the NF permeability that is pressure dependent.
\[
\bar{w} = \sqrt{12k_{NF}}
\]  

(3.13)

And according to analytical models from Hossain et al. 2000; Beugelsdijk et al. 2000; and Tezuka et al. 2005, the hydraulic aperture \(\bar{w}\) of the closed NF can be mathematically represented in the Barton-Bandis model.

\[
\bar{w} = \frac{\bar{w}_0}{1+9\frac{\sigma_{eff}}{\sigma_{n}}_{ref}} + \bar{w}_s + \bar{w}_{res}
\]  

(3.14)

\[
\bar{w}_s = |u_s|\tan(\phi_{dil}^{eff})
\]  

(3.15)

\[
\phi_{dil}^{eff} = \frac{\phi_{dil}}{1+9\frac{\sigma_{eff}}{\sigma_{n}}_{ref}}
\]  

(3.16)

\[
\sigma_{eff} = \sigma_n - p_f(s)
\]  

(3.17)

Where \(\sigma_{eff}\) represents the effective normal stress on NF, \(\sigma_{n}^{ref}\) represents the reference effective stress on NF which is equal to effective normal stress subtracting the stress induced from fluid pressure \(p_f(s)\), \(\bar{w}_0\) represents the in-situ hydraulic fracture aperture which is directly determined from the fracture surface roughness, \(u_s\) represents the shear displacement, and \(\phi_{dil}\) represents the angle of dilation.

**3.6.7 Shear Fracture**

In Equation 3.16, \(\phi_{dil}\) represents the angle of shear-induced dilation that is directly connected with the NF permeability calculated from Equation 3.9. As the shear stress increase and exceeding the NF’s frictional shear strength, which can be determined from \(\tau_s = \lambda(\sigma_n - \nu)\). Unfortunately, the propagation of NF resulted from the shear slippage effects is not included in the UFM model during simulation, however, according to Crouch et al. 1983; Olson 2004; and Kresse et al. 2013, an enhanced 2D
DDM method was included in determining the effect of shear induced slip on improving the NF permeability.

\[
\sigma_n^i - p^i = \sum_j A^{ij} C_{nn}^{ij} D_n^j + \sum_j A^{ij} C_{ns}^{ij} D_s^j \tag{3.18}
\]

\[
\tau^i = \sum_j A^{ij} C_{sn}^{ij} D_n^j + \sum_j A^{ij} C_{ss}^{ij} D_s^j \tag{3.19}
\]

\[
A^{ij} = 1 - \frac{d_{ij}^{2.3}}{(d_{ij}^2 + h^2)^{2.3/2}} \tag{3.20}
\]

The shear induced slippage of the fracture surface is represented as \(u_s\), which is determined as discontinuity in shear displacement, represented as \(Ds\) in Equation 3.18 and 3.19. And in 2D DDM method, by considering the elastic opening in HFs, this \(Ds\) can be solved from elasticity calculations for the closed sliding fracture surface elements that follows the Coulomb frictional law \(\tau \geq \tau_s = \lambda (\sigma - p)\) in determining stress shadow effects.

According to Crouch et al. 1983, \(C^{ij}\) in Equation 3.18 represent the coefficients of plane strain elastic effect in a two dimensional system, this coefficients describes the interactions between the elements \(i\) and element \(j\) in the open part of the NF, as shown in Figure 2.7. And according to Olson 2004, in a three-dimensional system, the fracture height \(h\) can be affected by the distance between element \(d_i\) and \(d_j\). In order to account for this effect in the two-dimensional system, a three-dimensional correction coefficient, represented as \(A^{ij}\), was multiplied in front of the each set of the equations.

### 3.6.8 Fluid Flow in Opened NF

According to Kresse et al. 2011, in opened parts of the NF, the fluid pressure in the NF should exceed the effective normal stress on the NF and should be treated as
fluid flow in HFs while considering effects from different flow regime. And according to Mack et al. 2000, Poiseuille law can be applied in solving laminar flow regime:

\[
\frac{\partial p}{\partial s} = -\alpha_0 \frac{1}{\bar{w}^{2n'+1} H_{fl}} \left| \frac{q}{H_{fl}} \right|^{n'-1} 
\]

(3.21)

\[
\alpha_0 = \frac{2K'}{\varphi(n')n'} \left( \frac{4n'+2}{n'} \right)^{n'} 
\]

(3.22)

\[
\varphi(n') = \frac{1}{H_{fl}} \int_0^{H_{fl}} \left( \frac{w(z)}{\bar{w}} \right)^{2n'+1} \frac{1}{n'} dz 
\]

(3.23)

Where \(\bar{w}\) represents the average fracture opening, and the index \(n'\) and \(K'\) represent exponents for fluid power law.

As in turbulent fluid flow regime where Reynolds number, represented as \(N_{Re}\) for fluid following power law between parallel plates, is larger than four thousand, the following equations applied, where \(V\) represents the fluid velocity, \(f\) represents the Fanning friction factor and \(\epsilon\) represents the roughness height of surface:

\[
\frac{\partial p}{\partial s} = -f \rho_f \frac{q}{\bar{w}^3 H_{fl}} \left| \frac{q}{H_{fl}} \right| 
\]

(3.24)

\[
q = H_{fl} \left( -\frac{\bar{w}^3}{f \rho_f} \frac{dp}{ds} \right)^{\frac{1}{2}} 
\]

(3.25)

\[
N_{Re} = \frac{3^{1-n'}2^{-n'}2^{-n'} \rho V^{2-n'} \bar{w}^{n'}}{K' \left( \frac{2n'+1}{3n'} \right)^{n'}} 
\]

(3.26)

\[
f \approx \frac{1}{16 \left[ \log_{10} \left( \frac{\epsilon}{7.4\bar{w}} \right) \right]^2} 
\]

(3.27)
For Darcy fluid flow in the proppant package where height is represented as $h$:

$$\frac{\partial p}{\partial s} = -\frac{q\mu_{fl}}{khw} \tag{3.28}$$

However, Darcy fluid flow will only take place if the minimum flow thickness in the vertical direction exceeded that of the fluid in the fracture. Equations for determining the minimum fluid vertical thickness for turbulent and laminar flow are defined as:

**Laminar flow:**

$$h_{fl}^{min} = \left(\frac{k\alpha_0(n')H_{fl}}{w^{2n'}\mu_{fl}}\right)^{1/n'} \frac{1}{q^{n'-1}} \tag{3.29}$$

**Turbulent flow:**

$$h_{fl}^{min} = \left(\frac{kH_{fl}f\rho q}{w^{2}\mu_{fl}}\right)^{1/2} \tag{3.30}$$

Where $k$ represents proppant pack permeability, and $\mu_{fl}$ represents the dynamic fluid viscosity, and $p_f$ represents the obtained fluid pressure at the HF-NF intersection point. And the pressures inside the NF and at the tip of NF are defined as:

$$p = p_f(t) \tag{3.31}$$

$$p_{tip} = \sigma_n^{tip}(t) \tag{3.32}$$

### 3.7 Numerical Approach for Coupling Method

For the Unconventional Fracture Model (UFM) inside the Mangrove simulation software for this research study, it used a combination of both the decoupled and fully coupled methods, depending on several factors, such as the level of accuracy requirement, computation stability and CPU time. A conceptual algorithm of the decoupled methods process used in the UFM model is presented as below. General descriptions and comparisons among different levels of coupling methods had been included in the literature review from Chapter two.
Figure 3.12 Conceptual algorithms for decoupled approach in UFM model in accounting for HFS-NFs interactions (Kresse et al. 2013).
CHAPTER 4
SIMPLE TO COMPLEX MODEL DEVELOPMENT

During the hydraulic fracture design modeling process, we started with the single stage simple model as discussed above in Section 3.1 using a general simulation case where no pre-existing natural fracture networks presented in the reservoir, during this process, models such as Conventional Planar 3D, Pseudo 3D, and Unconventional Fracture Model (UFM) were compared regarding their unique characters in capturing fracture propagation. Then, by taking consideration of the in-situ discrete fracture network but no stress effect, UFM was determined as the most accurate model which proved the effects of the pre-existing natural fracture networks towards a more realistic fracture geometry and fracture propagating prediction during simulation. Finally, a multi-stages hydraulic fracture design under UFM model was created with consideration of complex reservoir parameters such as natural fractures and stress shadow effects.

4.1 Simple Models Development

There are several models available inside the Mangrove hydraulic fracture design simulation software; Table 4.1 gave a general introduction of those models, in order for efficient simulation, only three models: Planar3D, MLF_P3D, and UFM models were used in Mangrove to investigate the fracture initiation and propagation. A single stage with four perforation clusters that are 700 feet apart has been simulated for the simple model, as shown in Figure 4.1. Note that the Z-axis to Y-axis ratio is 1:10, in order to have the figure fit in. The reservoir and treatment parameters for the simple model were shown in Table 3.1 from section 3.2.

Three candidate models: MLF_P3D, Planar3D and UFM models were run separately and the simulated fracture geometry were compared with each other under the same reservoir condition and same treatment parameters. Note that the simple model did not account for the pre-existing natural fracture and stress shadow effects, as to observe basic similarities and differences among the three models such as their predicted fracture half length, average fracture width and average fracture conductivity.
Table 4.1: General descriptions of available fracture models inside Mangrove hydraulic fracture design (Mangrove 2015).

<table>
<thead>
<tr>
<th>Fracture Geometry Model</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>P3D</td>
<td>A single initiation point planar fracture model used for horizontal or vertical wells.</td>
</tr>
<tr>
<td>Planar3D</td>
<td>A multi-initiation point planar model used for horizontal or vertical wells. Also a full 3D model that creates planar fracture simulations in formations with complex stress profiles.</td>
</tr>
<tr>
<td>MLF_P3D</td>
<td>A multi-initiation point planar model used for horizontal or vertical wells generates multi-initiation point planar fractures.</td>
</tr>
<tr>
<td>PKN</td>
<td>A simple, fixed-height fracture geometry model used only for vertical wells.</td>
</tr>
<tr>
<td>KGD</td>
<td>A simple fixed height type of 2D fracture geometry model used only for vertical wells.</td>
</tr>
<tr>
<td>UFM</td>
<td>A multi-initiation point fracture geometry model based on a discrete fracture network. It is used for horizontal or vertical wells in shale reservoir. Provides rigorous gridding of the hydraulic fracture. Also includes interaction with natural fractures.</td>
</tr>
<tr>
<td>WIREMESH</td>
<td>A multi-initiation point fracture geometry model based on a user-entered grid. It is used for horizontal or vertical wells in shale reservoir. Creates two orthogonal fractures and is semi analytical.</td>
</tr>
</tbody>
</table>

Figure 4.1: Side view of single stage simple model with 4 perforations of 700 feet apart from each other (Z-axis to Y-axis ratio is 1:10)
4.2 Simple model comparison

By comparing the predicted fracture geometry and properties, all three models were proved to be able to produce large planar fractures for hydraulic design as shown in Figure 4.2, 4.3, and 4.4. Note that the color legends in the figures represent fracture width, range from 0 inch to 0.5 inches. Detail simulation results are presented in Table 4.2 below.

Table 4.2: Fracture simulation results comparisons among the MLF_P3D, Planar3D, and UFM models in Mangrove simulator (N/A are due to different output information for each model).

<table>
<thead>
<tr>
<th></th>
<th>MLF_P3D</th>
<th>Planar3D</th>
<th>UFM</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOJ Total Fracture Volume (ft^3)</td>
<td>N/A</td>
<td>N/A</td>
<td>37919</td>
</tr>
<tr>
<td>EOJ Total Leakoff Volume (ft^3)</td>
<td>N/A</td>
<td>N/A</td>
<td>11651</td>
</tr>
<tr>
<td>EOJ Hydraulic Fracture Half Length (ft)</td>
<td>273.79</td>
<td>338.4</td>
<td>N/A</td>
</tr>
<tr>
<td>Max Hydraulic Fracture Half Length (ft)</td>
<td>389.02</td>
<td>410.32</td>
<td>487.81</td>
</tr>
<tr>
<td>EOJ Hydraulic Height at Well (ft)</td>
<td>580.7</td>
<td>556.74</td>
<td>672.01</td>
</tr>
<tr>
<td>Propped Fracture Half Length (ft)</td>
<td>300</td>
<td>292.31</td>
<td>246</td>
</tr>
<tr>
<td>Propped Width at Well (in)</td>
<td>0.25</td>
<td>0.22</td>
<td>0.85</td>
</tr>
<tr>
<td>Average Propped Width (in)</td>
<td>0.13</td>
<td>0.06</td>
<td>0.09</td>
</tr>
<tr>
<td>Effective Conductivity (mD.ft)</td>
<td>14198.89</td>
<td>1802.29</td>
<td>7374.52</td>
</tr>
<tr>
<td>Fluid Efficiency (%)</td>
<td>77.4</td>
<td>78.64</td>
<td>76.5</td>
</tr>
</tbody>
</table>

Out of the three models, the UFM model has the largest predicted fracture half length, while the MLF_P3D model has the largest predicted propped fracture half-length and the largest average propped width, therefore giving relatively high average conductivity for the predicted fracture. Simulation results predicted from the Planar3D lies somewhere between the UFM and MLF_P3D model, however, it has the lowest predicted average fracture width, and this might due to the Planar3D model assumes perfectly planar fracture and only consider fracture propagation in the direction of maximum horizontal stress while neglecting the fractures in the direction of minimum horizontal stress.
Figure 4.2: Predicted fracture geometry using MLF_P3D model without considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10)

Figure 4.3: Predicted fracture geometry using Planar3D model without considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10)
Computation time is efficient and acceptable for all three models, and all had shown possibilities in simulating large, planar fractures as the optimum fracture geometry for the EGS application under very simple reservoir condition. However, none of those models had included the in-situ natural fracture network shown in Figure 3.4 and 3.5 from the previous section as input parameters when predicting fracture geometry. As we started to take consideration of the discrete fracture network pattern introduced in Section 3.5, only the UFM model was able to consider the 2D DFN and simulate fracture propagation while integrating effects of pre-existing natural fractures, in this case specifically, we can see from Figure 4.5 in the next section that when hydraulic fractures intersect with pre-existing natural fractures, they tend to filtrate into as well as crossing the natural fractures in order to from a non-planar complex network of fractures, therefore causing changes in maximum fracture half-length, proppant distribution, average fracture and effective conductivity. More discussions of the effects or pre-existing natural fracture will be included in the UFM model development section and also in later complex fracture model development section.
4.3 UFM Model Development

As pointed out from the last section’s simple model comparisons and also shown in Figure 4.5 below, only UFM model inside Mangrove were able to consider effects of discrete fracture network while simulating fracture treatment, with physical mechanisms and governing equations for the UFM model covered in section 3.6. This section mainly focuses on studying the how exactly do in-situ natural fractures affect fracture propagation and resulting fracture geometry.

Figure 4.5: Predicted fracture geometry using UFM model with considering DFN in Mangrove for simple model hydraulic fracture design. (Z-axis to Y-axis ratio is 1:10)

The Mangrove software use 2D discrete fracture network (DFN) design to simulate the actual in-situ natural fractures in the formation. Main input parameters for 2D DFN design are:

- Fracture density (the maximum number of natural fractures distributed inside the zone of interest)
- Average fracture length
- Orientation (the angle difference between natural fractures and horizontal wellbore or the direction of maximum horizontal stress)
- Fracture spacing (the average distance between two natural fracture in a DFN pattern)

For the last three parameters, a standard deviation value can be assigned in order to represent the nature of randomness for the natural fracture distribution. Also, the software allows generating a secondary or even multiple fracture sets when the distributions of natural fractures tend to diverge into two or more groups. In this section, only the effect of DFN orientation on predicted fracture geometry in the simple UFM model was analyzed as to test the simple UFM model. A detailed study on the rest of the DFN parameters will be included in the later chapter as detailed matrixes of simulations for the complex fracture model were constructed.

In order to investigate the effect of DFN orientation towards predicted fracture geometry, four more simulations for the UFM simple model had been conducted. The model used the same input parameters with DFN orientation as the only changing variable in all simulation cases to compare simulation results to determine the effect of pre-existing natural fracture network in reservoir fracture propagation and fracture network geometry. Major input parameters for the DFN design were presented in the Table 4.3 below, note that orientation of NF in this case means orientation regarding the direction of the wellbore, which is also the direction of maximum horizontal stress.

<table>
<thead>
<tr>
<th>Simulation Case</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Standard Deviation</td>
<td>Average</td>
</tr>
<tr>
<td>1</td>
<td>3000</td>
<td>250</td>
<td>50</td>
<td>60</td>
</tr>
<tr>
<td>2</td>
<td>3000</td>
<td>250</td>
<td>50</td>
<td>60</td>
</tr>
<tr>
<td>3</td>
<td>3000</td>
<td>250</td>
<td>50</td>
<td>60</td>
</tr>
<tr>
<td>4</td>
<td>3000</td>
<td>250</td>
<td>50</td>
<td>60</td>
</tr>
</tbody>
</table>
Figure 4.6: Predicted fracture geometry using UFM model in Mangrove for a formation containing 45 degree orientation and 5 degree deviation natural fractures.

Figure 4.7: Predicted fracture geometry using UFM model in Mangrove for a formation containing 30 degree orientation and 5 degree deviation natural fractures.
Figure 4.8: Predicted fracture geometry using UFM model in Mangrove for a formation containing 90 degree orientation and 5 degree deviation natural fractures.

Figure 4.9: Predicted fracture geometry using UFM model in Mangrove for a formation containing 0 degree orientation and 5 degree deviation natural fractures.
By comparing the four predicted fracture geometries with various natural fracture orientations, it is reasonable to say that as most of the natural fractures are in the same direction as $S_{H\text{max}}$, the inclusion of DFN helps hydraulic fractures to propagate farther into the formation, which enables the desired simple, planar shaped fractures. As most of the natural fractures are not necessarily in the direction of $S_{H\text{max}}$, DFN behave like the barriers of hydraulic fractures as force the hydraulic fractures to either filtrate into the natural fracture, or actually cross over them, which would result in more friction loss while pumping fluid.

Preliminary results from the simple model proved the importance of effect of natural fractures towards fracture geometry and had a better description of actual fracture propagation inside the simulator. The next step is to build a complex model with a second horizontal well next to the primary well, shown in Figure 4.10, as to model optimum hydraulic fracture design introduced in section 3.1 for EGS system applications.

![Figure 4.10: Predicted multistage hydraulic fracturing geometry in the presence of randomly distributed natural fractures utilizing the UFM model in Mangrove for two horizontal wells 500 ft. apart. (Z-axis to Y-axis ratio is 1:10)](image-url)
4.4 Multi-Stage Fracture Model Development

Effects of natural fractures towards fracture propagation were confirmed after obtaining the preliminary results from the single-stage simple model. A multi-stage hydraulic fracture design of thirteen perforation cluster with 100 ft spacing was then simulated under the UFM model, as shown in Figure 4.11. Input and operation parameters were shown in Table 4.4. Note that stress anisotropy is assumed to be zero and $S_{H\text{max}}$ is identical with $S_{H\text{min}}$ in this case. However, we referred the stress perpendicular to the wellbore direction as $S_{H\text{max}}$ as large stress anisotropy will be considered in later matrix of simulations.

Table 4.4: Granite material properties and reservoir input parameters used in the multi-stage hydraulic fracture design under UFM model. Several granite parameters have been obtained from EMI (2010 a, b) and Morrell (2012).

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poisson's ratio (-)</td>
<td>0.32</td>
</tr>
<tr>
<td>Young's Modulus (GPa)</td>
<td>56.9</td>
</tr>
<tr>
<td>Minimum Horizontal Stress (psi)</td>
<td>8000</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>0.77</td>
</tr>
<tr>
<td>Permeability ($\mu$D)</td>
<td>0.5</td>
</tr>
<tr>
<td>Fracture Toughness (MPa $m^{1/2}$)</td>
<td>1.5</td>
</tr>
<tr>
<td>Stress Anisotropy (psi)</td>
<td>0</td>
</tr>
<tr>
<td>Tensile Strength (MPa)</td>
<td>12</td>
</tr>
<tr>
<td>Thermal Conductivity ($Wm^{-1}K^{-1}$)</td>
<td>3.15</td>
</tr>
<tr>
<td>Total Compressibility (1/GPa)</td>
<td>0.43</td>
</tr>
<tr>
<td>Rate Per Stage (bbl/min)</td>
<td>60</td>
</tr>
<tr>
<td>Initial Fluid Viscosity (cp)</td>
<td>160</td>
</tr>
<tr>
<td>End Proppant Concentration (PPA)</td>
<td>4</td>
</tr>
<tr>
<td>Pumping Time for Each Stage (min)</td>
<td>72.43</td>
</tr>
</tbody>
</table>

Similar as previous development strategy, we started our simulation under the simple conditions without considering complex reservoir condition such as pre-existing natural fractures or stress shadow effects, so the treatment sequence was simply from stage 1 to stage 13. Simulation results proofed that the model was able to provided simple, planar fractures with half-length all ranging from 600 ft to 800 ft, which satisfied
desired well spacing for EGS application. The predicted average fracture width is 0.22 inches and the simulated fracture geometry was shown in Figure 4.12.

Figure 4.11: A multi-stage hydraulic fracture design of thirteen perforation clusters with 100 ft spacing under UFM model in Mangrove Hydraulic Fracture Design. (Z to Y axis ratio is 1:10)

Figure 4.12: Plane view (from above) of multi-stage fracture design under UFM model without considering natural fracture and stress shadow effects.
The multi-stages model then started to consider only the stress shadow effect without account for the 2D DFN during simulation. Note that the completion sequence in this case and later on cases of simulation started from stage one to stage six, then stage thirteen to stage eight, and stage seven was conducted eventually in order to consider stress shadow from both side of the adjacent fractures. We were able to simulate the interaction between hydraulic fractures as they propagate in close proximity. Effects form increased stress in the surrounding rock tended to cause a reduction in width for an adjacent fracture that propagates within the stress shadow. Stress shadow also causes change in the fracture path to either diverges away from or towards to the adjacent parallel fractures, depending on the order of stage operation. As shown in Figure 4.13, due to fracture path divergence, we can still observe the occurrence of minor level of complex fracture network when just considering stress shadow effects without any pre-existing natural fractures.

![Fracture width contour](image)

Figure 4.13: Plane view (from above) of simple EGS model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress shadow effects.

Effect of stress shadow toward fracture geometry can greatly depend many on many parameters, such as fracture spacing, stress anisotropy, and pre-existing fracture path, as the input parameters inside the simulation model gets more complex, resulted simulated fracture geometry would also tend to be more complex.
4.5 Complex Fracture Model Development

The next step is to consider both stress shadow and pre-existing natural fracture effects toward hydraulic fracture simulation, assuming everything else is the same. Followed from the last section, four more simulations had been conducted to investigate effect of DFN orientation towards predicted fracture geometry when considering stress shadow effect in the complex fracture model. The model used the same input parameters for the DFN design and operation as shown in Table 4.3 and Table 4.4.

For scenario with 45 degrees orientation natural fractures, as shown in Figure 4.14 below, only two stages were able to have the hydraulic fracture reach the production well 500 ft away on the right. Stage 9, though with a desirable length, has preferable extension to the left due to stress shadow effect from previous stages, which can be reached if a third horizontal is placed on the left side of the primary well 500 ft away, similar as the EGS conceptual model shown in Figure 3.2.

![Figure 4.14: Predicted fracture geometry under complex fracture model in Mangrove with 45 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects.](image)
For scenario with 30 degree orientation natural fractures, as shown in Figure 4.15 below, none of the stages were able to achieve the desired hydraulic fracture length in order to intersect the production well 500 ft on the right. Most of the induced fractures either infiltrate into the natural fractures or got arrested when intersect with the natural fractures, therefore produced a complex fracture network. Also, seven out of the thirteen stages were able to generate an average fracture width above 0.5 inches, this might due to the large tensile strength of the granitic formation, as the pre-closed natural fractures once opened by induced fractures infiltrating into the natural fractures, it is harder for the opened fractures to be closed again than that of shale formation.

![Figure 4.15](image)

**Figure 4.15:** Predicted fracture geometry under complex fracture model in Mangrove with 30 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects.

For scenario with 90 degrees orientation natural fractures, which means most of the natural fractures are parallel with the maximum horizontal stress, as shown in Figure 4.16 below and similar fracture geometry had been observed like the EGS ideal model in Figure 4.12, where no natural fractures were considered in the simulation. However,
by comparing the two simulation results, it is noticed that the stress shadow effect were reduced to a certain extent, when the induced fractures filtrate into the natural fractures, it is more preferable for hydraulic fractures to follow the direct of natural fracture instead of diverging due to stress shadow effect. On the other hand, though the direction of natural fractures in this case are almost parallel with the direction of $S_{H\text{max}}$, though stress anisotropy was still assumed to be zero, where $S_{H\text{max}}$ and $S_{H\text{min}}$ are identical, it was expected that the natural fracture should help planar fracture propagation similar as Figure 4.8, where all the stages have planar fractures reach half-length 500 ft above; However, only six out of thirteen stages had reached the desired fracture half-length, and this is less than what was observed in the case shown in Figure 4.13, where only stress shadow effect was considered during fracture simulation. From the above observations, we noticed that as both the stress shadow and natural fracture effects are contributing to a more complex fracture network, the two effects were also affecting each other. In this case specifically, the two effects tended to reduce each other's impact, which leads to a simple model scenario with less stages of desired half-length.

Figure 4.16: Predicted fracture geometry under complex fracture model in Mangrove with 90 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects.
For the scenario with 0 degrees orientation natural fractures, which is completely opposite as the last scenario, most of the natural fractures are perpendicular with the maximum horizontal stress. Under the case of zero stress anisotropy ($S_{H_{\text{max}}} = S_{H_{\text{min}}}$), only two stages were able to generate enough fracture length to intersect with the production well 500 ft on the right, and both had an average fracture widths less than 0.1 inch on the fracture tips, as seen in Figure 4.17. Though the model used high viscosity fluid, as shown in Table 4.4, due to the high density of pre-existing natural fractures, the induced fractures were able to cross the first several natural fractures, eventually the induced fractures were either filtrating into the natural fractures or simply got arrested due to large friction losses from crossing the previous natural fractures. Similar as the last scenario shown in Figure 4.16, it was also observed that stress shadow effects got reduced by natural fractures, but in a completely opposite way. In this scenario, natural fractures were acting more like a barrier that is preventing the induced fractures to reach the desired extension, while having the most of the induced fractures eventually filtrate into the natural fractures that are almost perpendicular to the maximum horizontal stress.

![Figure 4.17: Predicted fracture geometry under complex fracture model in Mangrove with 0 degree orientation and 5 degree deviation natural fractures while considering both natural fracture and stress shadow effects.](image-url)
However, in reality, natural fractures have a more complex behavior inside the reservoir, and a single natural fracture set in one primary direction with certain degree of deviation does not necessarily represent realistic natural fracture behavior. Figure 4.14 below shows an artificially designed 2D Discrete Fracture Network. In this scenario, besides having just a primary natural fracture set with a certain degree of deviation, the model also considered a secondary natural fracture set as observed from many case studies in seismic imaging and interpretation, and this will also increase the level of complexity for the later simulated fracture geometry. Parameters for the 2D DFN design are shown in Table 4.5 (The orientation was based on the direction of $S_{H\text{max}}$).

**Table 4.5: Input parameters of DFN design for complex fracture design under UFM model (Orientation degree is based on direction of $S_{H\text{max}}$).**

<table>
<thead>
<tr>
<th>Natural Fracture Set</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Standard Deviation</td>
<td>Average</td>
</tr>
<tr>
<td>Primary</td>
<td>3000</td>
<td>200</td>
<td>10</td>
<td>60</td>
</tr>
<tr>
<td>Secondary</td>
<td>2000</td>
<td>150</td>
<td>10</td>
<td>60</td>
</tr>
</tbody>
</table>

Figure 4.18: 3000 artificially assigned primary natural fractures (green) and 2000 artificially assigned secondary fractures (red) for 2D DFN design under UFM model in Mangrove.
By considering stress shadow effects with primary and secondary natural fracture networks during fracture simulation, a more complex fracture network had been generated, as shown in Figure 4.19.

![Figure 4.19: Plane view (from above) of complex fracture model with primary and secondary DFN while considering both natural fracture and stress shadow effects.](image)

In this case of simulation, only four out of the thirteen stages had achieved the desired fracture half-length in order to intersect with the designed production well on the right hand side 500 ft away, which is less successful compared with the cases with exact same treatment parameters in Section 4.4, all of the thirteen stages reached fracture half-length above 500 ft when simulating without considering any stress shadow or natural fracture effect, and ten out of thirteen stages reached fracture half-length above 500 ft when simulating with considering only stress shadow effect. By analyzing the simulation process of simple to complex model development, we noticed that most of the time the stress shadow and natural fracture effects tend to act as a barrier to our desired large planar fracture for EGS application. Under certain occasions, such as case shown in Figure 4.16, when the two effects are reducing each other's level of
impact, it is possible to achieve optimum EGS fracture geometry. While the stress shadow effect can be artificially reduced to certain levels by having engineered fracture pattern such as the Zipper or Modified Zipper pattern or larger fracture spacing, effects from in-situ DFN can be hard to avoid, once seismic interpretation had proved the existence of largely distributed natural fractures, and the combination of natural fracture with other reservoir condition such as stress anisotropy, high temperature high pressure, higher tensile strength might lead to a more complex scenario in EGS application. Therefore, it is vital and reasonable to conduct sensitivity analysis regarding effects of pre-existing natural fracture during various treatment parameters and different reservoir conditions using simulation techniques in order for an optimum EGS application design.
CHAPTER 5
MATRIZ OF SIMULATIONS

In order to determine the reservoir and treatment parameters with the greatest effects on successful EGS design, a matrix of simulations, illustrated in Table 5.1, were performed under the UFM model inside Mangrove simulator. Main parameters determined include: Stress state, fluid viscosity, proppant concentration, pump rate and properties of pre-existing natural fractures such as its distribution density, orientation, average length and fracture spacing. Effect of each parameter determined was based on simulations performed under several conditions from normal to extreme, as to find a reasonable frame of operation before the actual EGS application in the future.

Table 5.1: Schematic matrix of simulations under UFM model in investigating effects of various parameters on successful EGS design.

<table>
<thead>
<tr>
<th>Ideal Condition without NF</th>
<th>Stress State</th>
<th>Fluid Viscosity</th>
<th>Proppant Concentration</th>
<th>Pump Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Investigate Effects of Various Stress Anisotropy</td>
<td>Water vs. Low Concentration vs. High Concentration</td>
<td>Zero vs. Low Concentration vs. High Concentration</td>
<td>High Pump Rate vs. Low Pump Rate</td>
<td></td>
</tr>
<tr>
<td>Pre-existing Natural Fracture</td>
<td>Effects of Various NF Orientation, Density, and Fracture Spacing</td>
<td>Water vs. Low Concentration vs. High Concentration</td>
<td>Zero vs. Low Concentration vs. High Concentration</td>
<td>High Pump Rate vs. Low Pump Rate</td>
</tr>
</tbody>
</table>

5.1 Effect of Stress Anisotropy

During multi-stage complex fracture simulations, no stress anisotropy effect was considered initially; therefore horizontal minimum stress equals maximum horizontal stress. In this section, five simulation cases regarding various stress anisotropy values were performed, the first case assumed a stress anisotropy value of 50 psi, the second case assumed a stress anisotropy value of 100 psi, the third case assumed a stress anisotropy value of 200 psi, the forth case assumed a stress anisotropy value of 500 psi, and the last case assumed a stress anisotropy value of 500 psi with consideration of natural fractures. As seen from Figure 5.1 to 5.5. During simple condition, it is noticed that as the stress anisotropy effect increase, it tends to reduce the stress shadow effect, as more fractures became planar instead of diverged from adjacent stages.
Figure 5.1: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 50 psi.

Figure 5.2: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 100 psi.
Figure 5.3: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 200 psi.

Figure 5.4: Top view of UFM model consisting of horizontal well with multiple fractures without considering natural fracture but considering stress anisotropy of 500 psi.
When consider stress anisotropy value of 50 psi, the simulated fracture started to have less divergence path compared with zero stress anisotropy condition shown in Figure 4.13, yet a minor complex fracture network due to the stress shadow effect can still be observed. When stress anisotropy value increased to 100 psi, simulation results showed that though still with a minor degree of fracture path divergence, no complex fracture network was generated, However, strong stress shadow effects from adjacent stages can still be observed as stage 3, 5, 7, 9, 11 were not able to reach the desired fracture half-length. As stress anisotropy value increased to 200 psi, most of the stages had override stress shadow effects and achieved desired fracture half, at stress anisotropy of 500 psi, the resulted fracture geometry is pretty much the same as ideal EGS model shown in Figure 4.12. However, when considering large stress anisotropy condition with pre-existing naturals, though most of the stages have fractures propagate in the direction of $S_{H\text{max}}$, only one stage had achieved the desired fracture half-length, since most fractures got arrested after crossing the densely distributed natural fractures.
5.2 Effect of Fluid Viscosity

As introduced in the section 3.3, main objective of fracturing fluids is to open fractures and transport proppants to keep the fractures open as far as possible, therefore selecting the correct fluid with the most feasible viscosity is one of the major considerations in the fluid definition stage, which will then affect the average fracture width, proppant transmission, and effective conductivity of the fracture. During complex fracture simulation under UFM model, one of the borate crosslinked gels fracturing fluid with an initial viscosity of 160 cp was used, in order to design large fractures which maximize the contact area between the matrix and injected fluid. However, as a vast majority in the unconventional production is also interested in low viscosity fluid or combinations of linear gel and crosslinked gel that is very rapidly degraded to water once in the formation, due to the unique stimulated fracture geometry combined with larger stimulated reservoir volume under situation with largely distributed natural fractures.

Since the fractures created using crosslinked gel under simple condition satisfy the ideal EGS design, in this section, three simulation cases based on different fluid viscosity were performed, all with consideration of stress shadow and natural fracture effects, in order to investigate how the stimulate fracture network would behave differently under effects from different fluid viscosity. The first case assumed a fluid with high viscosity of 342.22 cp, the second case assumed a fluid with relatively low viscosity of 21.33 cp, the third fluid assumed slickwater with very low viscosity of 0.64 cp. Simulation results are shown in Figure 5.6, 5.7, and 5.8. Due to the presence of natural fractures, all three simulation cases generated complex fracture networks, however, significant effect of fluid with different viscosity can still be observed. In very high fluid viscosity condition, as seen in Figure 5.6, though with relatively wide fractures overall, none of the stages achieved desired fracture half-length. In relatively low fluid viscosity condition, as seen in Figure 5.7, it is noticed that 5 out of 13 stages achieved desired fracture half-length. In slickwater treatment, as seen in Figure 5.8, 8 out of 13 stages achieved desired fracture half-length. In general, stimulated complex fracture network area tends to increase as treatment fluid’s viscosity decrease, when considering NFs.
Figure 5.6: Top view of complex fracture networks generated under UFM model with high fluid viscosity of 342.22 cp while considering stress shadow and natural fracture effects.

Figure 5.7: Top view of complex fracture networks generated under UFM model with low fluid viscosity of 21.33 cp while considering stress shadow and natural fracture effects.
When focusing on the resulted fracture half-length while neglecting the desired fracture half-length, it is noticed that as fluid viscosity decrease, the general propped fractures width are also decreasing, this might because of the high viscosity fluid tend to carry more proppant and last for a longer period while fracturing the matrix and interacting with pre-existing natural fractures, though it is easier for the induced fractures got arrested after crossing several natural fractures, still more proppant tend to be placed along the path where fractures were created. As seen in Figure 5.6, although none of the stages achieved fracture half-length of 500 ft. Yet most of the stages achieved fracture half-length of 250 ft, with an average fracture width of 0.25 inches, which could be a potential alternative for optimum EGS design. On the other hand, as seen in Figure 5.7 and 5.8, low viscosity fluid are more willing to filtrate into the natural fractures and therefore propagate longer in all direction, resulting a much larger stimulated reservoir volume and complex fracture network area. However, the average fracture width for the low fluid viscosity cases are all below 0.1 inches, which won’t be able to provide good enough conductivity and contact area between the matrix and fluid.
5.3 Effect of Pump Rate

Within the same total pumping volume, four simulation cases with various pumping rate were performed. The model only simulates effect of different pump rate and the rest of the input parameters were assumed to be the same as shown in Table 4.4. The first case assumed a pump rate of 15 bbl/min, the second case assumed a pump rate of 30 bbl/min, the third case assumed pump rate of 45 bbl/min, and the last case assumed a relatively high pump rate of 90 bbl/min. Shown in Table 5.2, as the pump rate increases, due to fixed pump volume, the resulted pumping time for each stage is decreasing, therefore reduced the period of interaction between matrix and fluid during each stage of treatment.

Table 5.2: Pump schedule for four simulation cases with various pump rate and fixed fluid volume under UFM complex fracture model.

<table>
<thead>
<tr>
<th>Simulation Case</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Per Stage (bbl/min)</td>
<td>15</td>
<td>30</td>
<td>45</td>
<td>90</td>
</tr>
<tr>
<td>Initial Fluid Viscosity (cp)</td>
<td>160</td>
<td>160</td>
<td>160</td>
<td>160</td>
</tr>
<tr>
<td>End Proppant Concentration (PPA)</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Total Proppant Mass (lb)</td>
<td>340000</td>
<td>340000</td>
<td>340000</td>
<td>340000</td>
</tr>
<tr>
<td>Total Slurry Volume (bbl)</td>
<td>4346.09</td>
<td>4346.09</td>
<td>4346.09</td>
<td>4346.09</td>
</tr>
<tr>
<td>Pumping Time for Each Stage (min)</td>
<td>289.74</td>
<td>144.87</td>
<td>96.58</td>
<td>48.29</td>
</tr>
<tr>
<td>Total Fluid Volume (gal)</td>
<td>170000</td>
<td>170000</td>
<td>170000</td>
<td>170000</td>
</tr>
</tbody>
</table>

Simulation results are shown in Figure 5.9, 5.10, 5.11, and 5.12. Under condition with largely distributed natural fractures and stress shadow, increasing pump rate doesn’t reduce the resulted fracture network complexity and no major differences regarding the fracture half-length and DFN geometry were observed. However, as pump rate increases, by comparing fracture width contour in Figure 5.9, 5.10 with those in Figure 5.11, 5.12. It is very obviously that stage 1, 2, 4, 6, 8, 10, 11, 12, 13 had a significant increase in the near wellbore fracture width as well, which can also mean increase in effective fracture conductivity. Under an ideal condition where the resulted fractures had already achieved desired fracture half-length, increase in pump rate would definitely contribute to better EGS application in creating wider fracture aperture and therefore larger contact area between matrixes and inject fluid.
Figure 5.9: Top view of complex fracture networks generated under UFM model with low pump rate of 15 bbl/min while considering stress shadow and natural fracture effects.

Figure 5.10: Top view of complex fracture networks generated under UFM model with low pump rate of 30 bbl/min while considering stress shadow and natural fracture effects.
Figure 5.11: Top view of complex fracture networks generated under UFM model with low pump rate of 45 bbl/min while considering stress shadow and natural fracture effects.

Figure 5.12: Top view of complex fracture networks generated under UFM model with low pump rate of 90 bbl/min while considering stress shadow and natural fracture effects.
5.4 Effect of Proppant Concentration

The original proppant concentration was assumed to be 4 PPA (pounds of proppant additives per gallon), as shown in Table 4.4. In this section, three simulation cases were performed with assumption of various proppant concentrations while keeping other parameters fixed. The first case assumed a very low proppant concentration with only 1 PPA, the second case assumed a proppant concentration of 6 PPA, which is 50 percent higher than the original assumed concentration, the third case assumed a relatively high proppant concentration of 8 PPA, which is twice as much as the original assumed concentration. Due to the constant increment of proppant concentration, as final proppant concentration increases, the total pumping and proppant mass time were also increasing. Table 5.3 below gave a detail pumping schedule and information of related input parameters.

Table 5.3: Pump schedule for three simulation cases with various proppant concentrations and changing fluid volume under UFM complex fracture model.

<table>
<thead>
<tr>
<th>Simulation Case</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>Original</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate Per Stage (bbl/min)</td>
<td>60</td>
<td>60</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Initial Fluid Viscosity (cp)</td>
<td>160</td>
<td>160</td>
<td>160</td>
<td>160</td>
</tr>
<tr>
<td>End Proppant Concentration (PPA)</td>
<td>1</td>
<td>6</td>
<td>8</td>
<td>4</td>
</tr>
<tr>
<td>Total Proppant Mass (lb)</td>
<td>25000</td>
<td>74500</td>
<td>132000</td>
<td>340000</td>
</tr>
<tr>
<td>Total Slurry Volume (bbl)</td>
<td>1212.42</td>
<td>6610.77</td>
<td>9015.9</td>
<td>4346.09</td>
</tr>
<tr>
<td>Pumping Time for Each Stage (min)</td>
<td>20.21</td>
<td>110.18</td>
<td>150.27</td>
<td>72.43</td>
</tr>
<tr>
<td>Total Fluid Volume (gal)</td>
<td>50000</td>
<td>250000</td>
<td>330000</td>
<td>170000</td>
</tr>
</tbody>
</table>

Simulation results are shown in Figure 5.13, 5.14, and 5.15. For simulated fractures propagation under low proppant concentration, as seen in Figure 5.13, it is noticed that the most of the stages failed to achieve desired fracture half-length; also most of the fractures created have a relatively low average fracture width below 0.05 inches. Though stage 8 did achieve a fracture half-length of 500 ft away to the production well on the right, due to a “friendly” orientated natural fracture set around the this stage, most fracturing fluid tend to filtrate into the natural fracture and simulation result showed zero proppant concentration in fracture created under stage 8, without the support of properly placed proppant, created fracture tend to close again under closure stress effect, therefore the final effective conductivity is almost zero mD.ft.
Figure 5.13: Top view of complex fracture networks generated under UFM model with low proppant concentration of 1 PPA while considering stress shadow and natural fracture effects.

Figure 5.14: Top view of complex fracture networks generated under UFM model with proppant concentration of 6 PPA while considering stress shadow and natural fracture effects.
For simulated fracture network under proppant concentration of 6 PPA, as seen in Figure 5.14, though none of the stages achieved the desired fracture half-length, still significant improvement in overall behavior of created fractures were observed, in both created fracture half-length and average fracture width, compared with the scenario with 1 PPA proppant concentration. When simulate fracture propagation under proppant concentration of 8 PPA, as seen in Figure 5.15, stage 1, 4, 6, 8, 9 had achieved the desired fracture half-length, and stage 7 also achieved reasonable fracture-length to the left hand side due to stress shadow effect from stage 6. Among those stages with desired fracture half-length, stage 1, 4, and 8 had achieved a relatively large average fracture width above 0.5 inches. Therefore it is reasonable to claim that increasing proppant concentration can effectively aid in creating large planar fracture as design in EGS application. Also, as proppant concentration is increasing, due to a constant increment in proppant concentration, total volume of pumping fluid are also increased, which allowed more interaction between matrix and fluid once a fracture was induced and therefore increase the possibility of proper proppant placement during the treatment.
On the other hand, though increase in proppant concentration and pumping volume can effectively aid in creating large planar fracture under natural fractured reservoir condition, still those fracture have certain degree of deviation, and it is also noticed that stage 2, 3, 5, and 12 had hardly generating any desired fractures due to combing effects of stress shadow from adjacent “successful” stages and poorly distributed natural fractures near these stages. And how to create the most effective and cost efficient design for EGS application would be the next step in the further research study.

5.5 Effect of Pre-Existing Natural Fractures

Effect of orientation of pre-existing natural fractures had already been analyzed section 4.5 when introducing complex fracture model development. In summary, as most of the natural fractures are in the same direction as $S_{Hmax}$, the inclusion of DFN helps hydraulic fractures to propagate farther into the formation enabling the desired simple, planar shaped fractures. As most of the natural fractures are not necessarily in the direction of $S_{Hmax}$, DFN behave like the barriers of hydraulic fractures forcing the hydraulic fractures to either filtrate into the natural fracture, or crossing over them resulting friction loss while pumping fluid. This section mainly focused on effects of several other properties of natural fractures such as distribution density, average fracture length, and fracture spacing towards simulated fracture geometry.

5.5.1 Effect of DFN Density

One of the main reasons for induced fractures to get either diverged or arrested when interacting with pre-existing natural fractures is due to its large distribution density. During observation of the previous simulation, though high viscosity fluid was able to cross natural fractures initially when near wellbore, however due to friction loss, after crossing the first several natural fractures, the fracturing fluid was not able to sustain the initial high viscosity and therefore got either diverged or arrested from original fracturing path eventually, unless the DFN orientation happened to be the same as desired fracturing direction. Therefore it is essential to run matrix of simulation with various distributing density of natural fractures, in order to understand a general relationship between natural fracture density and the optimum EGS style fracture geometry.
As shown in Table 5.4, two simulation cases regarding the effects of DFN density (represented by number of total natural fractures) toward resulted fracture geometry were performed, as to compare the case studied in Section 4.5, where the original DFN design parameters are shown in Table 4.5.

Table 5.4: Input parameters of two cases of DFN design with various distribution density under UFM model (Orientation degree is based on direction of \( S_{\text{Hmax}} \)).

<table>
<thead>
<tr>
<th>Natural Fracture Set</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Average</td>
<td>Average</td>
</tr>
<tr>
<td>Case 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary</td>
<td>1500</td>
<td>200</td>
<td>60</td>
<td>90</td>
</tr>
<tr>
<td>Secondary</td>
<td>1000</td>
<td>150</td>
<td>60</td>
<td>0</td>
</tr>
<tr>
<td>Case 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary</td>
<td>600</td>
<td>250</td>
<td>60</td>
<td>90</td>
</tr>
<tr>
<td>Secondary</td>
<td>400</td>
<td>150</td>
<td>60</td>
<td>0</td>
</tr>
</tbody>
</table>

Simulation results are shown in Figure 5.16 and 5.17, by assigning under different density of NFs, the resulted fracture geometry are different from each other. As the distribution density of DFN decreases, resulted fracture geometry tend to be less complex, since from a statistic point of view, reducing the number of total natural fractures in the reservoir tend to reduce the possibility of interaction between hydraulic fractures and natural fractures, however, significant differences regarding fracture half-length and average fracture width were not observed. This is due to fact that though total number of natural fractures in the reservoir is reduced significantly, number of natural fractures reached by hydraulic fractures induced from the multi-stages might not be affected, since the single wellbore can only reach a small portion of the total reservoir volume. Unfortunately, the 2D DFN design is not able to artificially distribute NFs only in the near wellbore region; otherwise, simulation results might be different. Another important thing regarding 2D DFN inside Mangrove is that the 2D natural fracture design was originally designed to represent the very nature of random behavior of DFN, though user can artificially define general DFN properties, detailed distribution of DFN cannot repeat with each other. In other word, by changing the number of fractures while keeping other parameters fixed doesn’t guarantee exact same near natural fracture distribution pattern, especially near wellbore and stage of interest, which could be a source of error for simulation in this section.
Figure 5.16: Top view of complex fracture networks generated under UFM model with 2500 artificially designed NFs while considering stress shadow and natural fracture effects.

Figure 5.17: Top view of complex fracture networks generated under UFM model with 1000 artificially designed NFs while considering stress shadow and natural fracture effects.
5.5.2 Effect of DFN Spacing

As observed from the last sub-section, when trying to decrease the distributed density of pre-existing natural fractures, the 2D DFN design would reduce the maximum number of natural fracturing throughout the whole reservoir, which has a much larger area than the region reached by hydraulic fractures induced from single multi-stages well, therefore the general possibility of interaction between hydraulic fractures and natural fractures is still very high even with more than 50 percent reduced natural fracture density. However, it is noticed from the previous simulation that the average spacing between natural fractures is 60 ft with a standard deviation of 10 ft. By increasing the average spacing inside DFN, it is more likely to reduce the possibility of interaction during complex fracture network generation.

In this section, two cases of simulation were performed specifically focused on effect of various DFN spacing towards fracture network complexity while keeping other of the DFN property and the rest of the input parameters fixed. Treatment parameters still follow the initial UFM model design as shown in Table 4.4. 2D DFN design parameters are shown in Table 5.5 below.

Table 5.5: Input parameters of two cases of DFN design with various averages DFN spacing under UFM model (Orientation degree is based on direction of SHmax).

<table>
<thead>
<tr>
<th>Natural Fracture Set</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Average</td>
<td>Average</td>
</tr>
<tr>
<td>Case 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary</td>
<td>3000</td>
<td>200</td>
<td>120</td>
<td>90</td>
</tr>
<tr>
<td>Secondary</td>
<td>2000</td>
<td>150</td>
<td>120</td>
<td>0</td>
</tr>
<tr>
<td>Case 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary</td>
<td>3000</td>
<td>250</td>
<td>200</td>
<td>90</td>
</tr>
<tr>
<td>Secondary</td>
<td>2000</td>
<td>150</td>
<td>200</td>
<td>0</td>
</tr>
</tbody>
</table>

Simulation results are shown in Figure 5.18, and 5.19. By reducing the average spacing in DFN, a significant reduction in distributed natural fractures near wellbore area was observed, as shown in Figure 5.18, stage 1 was able to produce almost large planar fractures since less interaction with the pre-existing fractures and stage 13, in this case of simulation, was very lucky enable to avoid interacting with any natural fractures before reaching the desired fracture half length, and the general level of
fracture network complexity was also reduced to a large extend. With less interaction with the natural fracture, obvious increase in average fracture width was also observed.

Figure 5.18: Top view of complex fracture networks generated under UFM model with 120 ft average NF spacing while considering stress shadow and natural fracture effects.

The model then increasing the fracture spacing to 200 ft, as seen in Figure 5.19, it is clearly observed that the effect of pre-existing natural fractures got reduced to a very large extend, and stress shadow became the dominant effect in this case of simulation, as stage 1, 2, 3, 4, 5, 12, 13 had induced similar fracture geometry as shown in Figure 4.13 when simulating without considering natural fracture effect. However, though the reduction in natural fracture spacing can significantly reduce the chance of complex fracture network interaction, significant effect from natural fracture can still happen, depending on the location of natural fracture. As seen in stage 11, a natural fracture with 0 degree orientation happened to be distributed just near perforation cluster on the left hand side; induced fracture then followed the natural fracture’s orientation right away and propagated right next to the perforation cluster at stage 10. Due to a combination effect of both stress shadow and natural fractures, stage 10 was able to produce a very long and also diverged planar fracture. However, the long and
diverged fracture combined with stress shadow effect from this stage then prevented fractures of the rest of the stages from propagating to the desired length and location. In summary, fracture network complexity can be reduced significantly under large enough DFN fracture spacing, while effect of natural fractures can still be profound depending on the location and orientation and should still be considered carefully.

Figure 5.19: Top view of complex fracture networks generated under UFM model with 200 ft average NF spacing while considering stress shadow and natural fracture effects.

5.5.3 Effect of DFN Length

Besides investigating effects of the primary and secondary orientation, distributed density, and fracture spacing during DFN design, effect of average fracture length should also be considered. In this section, two cases of simulation were performed with various average lengths in natural fractures while keeping other of the DFN property and the rest of the input parameters fixed. Treatment parameters still follow the initial UFM model design as shown in Table 4.4. 2D DFN design parameters are shown in Table 5.6 below.
Table 5.6: Input parameters of two cases of DFN design with various averages DFN spacing under UFM model (Orientation degree is based on direction of $S_{H\text{max}}$).

<table>
<thead>
<tr>
<th>Natural Fracture Set</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Average</td>
<td>Average</td>
</tr>
<tr>
<td>Case 1</td>
<td>Primary</td>
<td>3000</td>
<td>400</td>
<td>60</td>
</tr>
<tr>
<td>Case 2</td>
<td>Primary</td>
<td>3000</td>
<td>100</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td>2000</td>
<td>300</td>
<td>60</td>
</tr>
<tr>
<td></td>
<td>Secondary</td>
<td>2000</td>
<td>75</td>
<td>60</td>
</tr>
</tbody>
</table>

Simulation results are shown in Figure 5.20 and 5.21, the first case of simulation has an average natural fracture length twice as much as the initial designed average length as shown in Table 4.5, as seen in Figure 5.20, average length of natural fractures are about the same as the desired fracture half-length in ideal EGS model, and due to the very nature of random distribution of natural fracture inside 2D DFN design, most natural fractures tend to intersect perforation cluster near the wellbore and therefore cause most induced fractures to filtrate into natural fracture at the first place. In this situation, the induced fracture length geometry would highly depend on the orientation of pre-existing natural fractures, which usually won’t give the desired EGS type of large planar fractures. On the other hand, the filtration dominant fracture geometry tend to raise the average fracture width on stages where natural fracture oriented in the direction of $S_{H\text{max}}$, due to the large average natural fracture length. The second case of simulation has an average natural fracture length half as much as the initial designed average length as shown in Table 4.5, as seen in Figure 5.21, smaller average length in natural fracture tend to increase the possibility of interactions between hydraulic fracture and natural fractures in different orientation; also, due to the relatively large distribution density of 2D DFN combined with stress shadow effect in this model, high level of complexity in the simulated fracture network can still be observed, therefore reduce the average fracture width as compared with that in the first case of simulation. In summary, effect of average length in natural fracture regarding ideal EGS fracture geometry also depends on many other factors such as orientation and fracture spacing, and more simulations regarding the combination effect of those natural fracture properties should be performed and analyzed in the future work of this research study.
Figure 5.20: Top view of complex fracture networks generated under UFM model with 400 and 300 ft average NF length while considering stress shadow and natural fracture effects.

Figure 5.21: Top view of complex fracture networks generated under UFM model with 100 and 75 ft average NF length while considering stress shadow and natural fracture effects.
5.6 Limitations in 2D DFN Design

Though able to numerically model the generation of complex fracture geometry propagation while considering interaction between hydraulic fractures and natural fractures, one of the major limitations in UFM model regarding complex fracture network simulation is the 2D Discrete Fracture Network design. Since under the condition where seismic interpretation data is not available or not accurate enough, the UFM model has to include the artificially designed 2D DFN in order to consider effects from pre-existing natural fractures during complex fracture network simulation. And all the 2D DFN were assumed to be perfectly vertical fractures inside the formation with a fixed height across the zone or layer of interest, in order to fully interact when reached by the hydraulic fracture from a 3D perspective, which is to say that all the pre-existing natural fractures designed inside the UFM model, regardless of length and orientation, had a fixed height of 500 ft and zero inclination. This is not exactly how nature fractures tend to behave in real field cases, since natural fracture does not necessarily has to be vertical in the formation, and it would be not physically logical to have a natural fracture with relatively small fracture length while having an extremely large fixed height, due to compression effect from overburden stress in the formation.

Also, the 2D DFN assumed all the pre-existing natural fractures are closed but conductive and can be opened by fluid with pressure larger than the normal stress acting on them, or it can experience Coulomb type shear slippage (Weng et al. 2012), which didn’t consider the fact that many natural fractures are also observed to be opened due to large tensile strength and sealed with mineral deposition.

The third limitation regarding 2D DFN design is that it assumed the propagation direction of the hydraulic fractures is not affected (unless intercepted) by closed and not invaded natural fractures (Weng et al. 2012), which means that though UFM model consider stress shadow effects from adjacent stage of hydraulic fracture, it didn’t consider the stress shadow effects from pre-existing natural fractures. As natural fractures were created partially due to various changes in stress states throughout geological history, the UFM model should also consider effects in stress state when
artificially assigning 2D DFN in order for a more realistic simulation of complex
interaction between hydraulic fracture and pre-existing natural fractures.

As the UFM model under Mangrove simulator was specifically designed to
numerically capture fracture propagation and complex fracture geometry in
unconventional shale play, production prediction regarding the resulted stimulated
reservoir volume (SRV) was also focused on oil and gas. Though able to consider
temperature effect towards fluid and proppant properties, unfortunately, it is hard for the
UFM model under Mangrove simulator to capture thermal front movement during water
production, which is one of the limitations within this simulation software. However, as
discussed from previous literature review and methodology sections, during geothermal
production, the stimulated reservoir volume can be much larger than the actual heat
extracting volume, because of the single flow behavior due to preferential flow through a
relatively small number of fractures in the stimulated fracture network as shown in
Figure 2.4. And this is why the main goal for this research study is to design large
planar fractures, in order to maximize the contact area between the matrix and injected
fluid, and also reduce early thermal breakthrough effects simultaneously.

In other words, if the stimulated fracture network from simulation tends to behave
like single, planar fracture with large fracture width and high conductivity, it then proved
the high potential for a successful EGS design and vice versa. Although this estimation
method is not very accurate, this is still very straight forward due to the very nature of
low porosity and low permeability in deep geothermal formations. Unlike the oil industry,
which has to crack the underground matrix in order to extract hydrocarbon during
unconventional production, the EGS focuses on producing heat from underground hot
dry rock by injecting and circulating cold water into the formation, and heat can be
transported from the formation matrix through conduction and convection effects to the
injecting and producing fluid without a permeable flowing conduit. As long as a fracture
network with desirable fracture half-length connect between the injection and production
well and with a reasonably large contact area between the matrix and injected fluid is
generated, it would then indicate a big potential in achieving efficient and economic heat
production for EGS application.
5.7 Sensitivity Analysis

Based on results from matrix of simulations, 5 main parameters with the most obvious effects on successful EGS application were selected in sensitivity analysis, the parameters included in this analysis were the following: DFN spacing, fluid viscosity, stress anisotropy, pump rate and proppant concentration. The numbers in parentheses in the following figures represent the feasible range of possible values for every parameter with DFN spacing in feet, fluid viscosity in centipoise, stress anisotropy in psi (the stress anisotropy value represents the difference of maximum horizontal stress subtract minimum horizontal stress), proppant concentration in pound per proppant additive, and pump rate in barrel per minute. Parameters are ordered in terms of the significance of their overall impact on fracture half-length, average fracture width and effective fracture conductivity, as shown in Figure 5.22, 5.23, and 5.24. Table 5.7 showed a comparison of original input parameters with sensitivity analysis parameters.

For effects in fracture half-length as seen in Figure 5.22, DFN spacing was determined to be the most significant parameters, followed with fluid viscosity and then stress anisotropy. One thing to notice is that, due to the fixed proppant increment setting inside UFM model simulation, as proppant concentration increases, the total pumping volume is also increasing, which is the main contributing factor in adding growth of fracture half-length. As follows, the pump rate is the least significant contributing factor to fracture half-length.

For effects in average fracture width as seen in Figure 5.23, proppant concentration was determined to be the most significant parameters, followed with fluid viscosity and pump rate as it’s reasonable to use large pump rate with high fluid viscosity and high proppant concentration in creating wider fracture and better placement of proppant inside the fractures. Stress anisotropy and DFN spacing tend to have fewer impacts as compared with the previous three parameters. For effects in effective conductivity, as seen in Figure 5.24, the order determined was exactly the same as that in Figure 5.23, since effective conductivity tend to have a linear relationship with average fracture width.
Figure 5.22: Sensitivity analysis result of effects of various parameters on fracture half-length.

Figure 5.23: Sensitivity analysis result of effects of various parameters on average fracture width.
Figure 5.24: Sensitivity analysis result of effects of various parameters on effective conductivity.

Table 5.7: Comparison between input parameters used in base case and range of input parameters used in sensitivity analysis through matrix of simulations.

<table>
<thead>
<tr>
<th>Property</th>
<th>Original Input Parameters</th>
<th>Sensitivity Analysis Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>DFN Spacing (ft)</td>
<td>60</td>
<td>60 - 200</td>
</tr>
<tr>
<td>Fluid Viscosity (cp)</td>
<td>160</td>
<td>0.64 - 200</td>
</tr>
<tr>
<td>End Proppant Conc (PPA)</td>
<td>4</td>
<td>1 - 8</td>
</tr>
<tr>
<td>Stress Anisotropy Value (psi)</td>
<td>0</td>
<td>0 - 500</td>
</tr>
<tr>
<td>Pump rate (bbl/min)</td>
<td>60</td>
<td>15 - 90</td>
</tr>
</tbody>
</table>
CHAPTER 6
DESIGN OPTIMIZATION

Complex reservoir condition such as natural fracture density, spacing, length and stress anisotropy were assumed in the worst case scenario through most cases of simulation from the previous sections, also, treatment parameters were not optimized either in order to determine major barriers in designing successful EGS application.

After obtaining the results in matrix of simulations and sensitivity analysis, the UFM model then performed the ultimate simulation for optimum EGS design under a best case scenario, which is to say while considering the negative effects of most complex reservoir parameters, such as secondary natural fractures with orientation against $S_{H_{\text{max}}}$ and stress shadow effects; the positive side of effects regarding complex reservoir parameters were also considered, such as large reservoir stress anisotropy and relatively large natural fractures spacing. And the final design recommendations were based on main objectives in creating large, planar, conductive fracture in order to achieve economic heat production for EGS application. Table 5.6 and Table 5.8 below showed reservoir parameters and DFN design parameter used for simulation under best case scenario. And Table 5.9 below showed treatment parameters with greatest effect in achieving successful EGS application under UFM model simulation.

Table 6.1: Reservoir parameters for design optimization with positive effect in achieving successful EGS application under UFM model simulation

<table>
<thead>
<tr>
<th>Property</th>
<th>Granite</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poisson's ratio (-)</td>
<td>0.32</td>
</tr>
<tr>
<td>Young's Modulus (GPa)</td>
<td>56.9</td>
</tr>
<tr>
<td>Density (g/cm$^3$)</td>
<td>2.63</td>
</tr>
<tr>
<td>Minimum Horizontal Stress (psi)</td>
<td>8000</td>
</tr>
<tr>
<td>Stress Anisotropy (psi)</td>
<td>500</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>0.77</td>
</tr>
<tr>
<td>Permeability ($\mu$D)</td>
<td>0.5</td>
</tr>
<tr>
<td>Fracture Toughness (MPa m$^{1/2}$)</td>
<td>1.5</td>
</tr>
<tr>
<td>Tensile Strength (MPa)</td>
<td>12</td>
</tr>
<tr>
<td>Thermal Conductivity (W*m$^{-1}$K$^{-1}$)</td>
<td>3.15</td>
</tr>
<tr>
<td>Total Compressibility (1/GPa)</td>
<td>0.43</td>
</tr>
</tbody>
</table>
Table 6.2: 2D DFN design parameters for design optimization while considering positive effects of relatively large NF spacing of 120 ft under UFM model simulation.

<table>
<thead>
<tr>
<th>Natural Fracture Set</th>
<th>Number of Fractures</th>
<th>Length (ft)</th>
<th>Spacing (ft)</th>
<th>Orientation (degree)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td>Standard Deviation</td>
<td>Average</td>
</tr>
<tr>
<td>Primary</td>
<td>2000</td>
<td>200</td>
<td>10</td>
<td>120</td>
</tr>
<tr>
<td>Secondary</td>
<td>1000</td>
<td>150</td>
<td>10</td>
<td>120</td>
</tr>
</tbody>
</table>

Table 6.3: Treatment parameters for design optimization with positive effect in achieving successful EGS application under UFM model simulation.

<table>
<thead>
<tr>
<th>Simulation Case</th>
<th>Design Optimization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Fluid Viscosity (cp)</td>
<td>340</td>
</tr>
<tr>
<td>End Proppant Concentration (PPA)</td>
<td>8</td>
</tr>
<tr>
<td>Rate Per Stage (bbl/min)</td>
<td>90</td>
</tr>
<tr>
<td>Pumping Time for Each Stage (min)</td>
<td>200</td>
</tr>
<tr>
<td>Total Slurry Volume (bbl)</td>
<td>18032</td>
</tr>
<tr>
<td>Total Proppant Mass (lb)</td>
<td>2640000</td>
</tr>
<tr>
<td>Total Fluid Volume (gal)</td>
<td>660000</td>
</tr>
</tbody>
</table>
3D view and top view of simulated fracture network geometries for the EGS design optimization are shown in Figure 5.25, 5.26, 5.27, and 5.28. Note that the simulation results for Figure 5.25 and 5.26 were based on the symmetrical completion order, however, as this is not realistic in actual field operation, one more simulations with the normal sequential completion order was performed as shown in Figure 5.27. After that another similar simulation with the sequential completion order was performed with a reduction in the average length of natural fractures, in order to further more reduce the negative effects of natural fractures. The simulated numerical results for each stage regarding fracture half-length, average fracture width, and effective conductivity are shown in Table 5.11 below. In summary, the average fracture half-length for all thirteen stages is 549 foot, the average fracture width for all thirteen stages is 1.25 inches, and the average effective fracture conductivity for all thirteen stages is 707668 milli-darcy-feet.

By considering both the negative and positive effects of the possible complex reservoir conditions such as large stress anisotropy and large natural fracture spacing, while simulating using effective treatment parameters such as large fluid viscosity and pumping volume, and high proppant concentration, the UFM model was able to simulate a typical EGS type of large planar fracture network with very low level of complexity while giving desirable fracture half-length and large average fracture width. As seen in Figure 5.26, the fracture width contour legend was ranged from 0 to 2 inches, and most of the fractures were able to achieve an average fracture width above 1 inch, due to high proppant concentration during fracturing treatment, also, large fluid viscosity and high pump rate enabled most stages to achieve fracture half-length above 500 foot, also under the positive effects from large stress anisotropy in the reservoir. Though obvious effects from pre-existing natural fractures were still observed from stage 6, 7, and 12, by assuming a larger but reasonable DFN spacing, it is very possible for all the stages to overcome most negative effect from natural fractures.

On the other hand, though high stress anisotropy type reservoir tend to reduce stress shadow effect in diverging from initial fracture pathway, as seen in Figure 5.26 that most fractures tend to propagation in the direction of maximum horizontal stress,
the stress shadow effect can still affect the overall fracture half-length, as observed from stage 2 to stage 12, once a unsymmetrical fracture was generated due to friction loss when crossing natural fractures, fractures from adjacent stage tend to propagation in the opposite direction as fractures from the previous stage, and therefore resulting a “natural zipper pattern” from the single well of injection. However, by assigning better fracture patterns such as zipper and modified zipper pattern, it is also possible to overcome the combination effects from stress shadow and natural fractures which would aid in a long fracture half-length.

### Table 6.4: Simulated numerical results for each stage regarding fracture half-length, average fracture width, and effective conductivity in design optimization under UFM model simulation.

<table>
<thead>
<tr>
<th>Stage</th>
<th>Fracture Half-Length (ft)</th>
<th>Average Fracture Width (inch)</th>
<th>Effective Fracture Conductivity (md.ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>790</td>
<td>0.82</td>
<td>478468</td>
</tr>
<tr>
<td>2</td>
<td>628</td>
<td>1.1</td>
<td>562886</td>
</tr>
<tr>
<td>3</td>
<td>553</td>
<td>1.3</td>
<td>704428</td>
</tr>
<tr>
<td>4</td>
<td>563</td>
<td>1.23</td>
<td>693448</td>
</tr>
<tr>
<td>5</td>
<td>562</td>
<td>1.26</td>
<td>718556</td>
</tr>
<tr>
<td>6</td>
<td>383</td>
<td>1.45</td>
<td>794198</td>
</tr>
<tr>
<td>7</td>
<td>427</td>
<td>1.83</td>
<td>916130</td>
</tr>
<tr>
<td>8</td>
<td>496</td>
<td>1.34</td>
<td>883060</td>
</tr>
<tr>
<td>9</td>
<td>642</td>
<td>1.05</td>
<td>490323</td>
</tr>
<tr>
<td>10</td>
<td>449</td>
<td>1.39</td>
<td>1032015</td>
</tr>
<tr>
<td>11</td>
<td>468</td>
<td>1.13</td>
<td>569544</td>
</tr>
<tr>
<td>12</td>
<td>425</td>
<td>1.51</td>
<td>897308</td>
</tr>
<tr>
<td>13</td>
<td>745</td>
<td>0.9</td>
<td>459280</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>549</strong></td>
<td><strong>1.25</strong></td>
<td><strong>707665</strong></td>
</tr>
</tbody>
</table>
Figure 6.1: 3D view of EGS design optimization generated under UFM model while considering both the positive and negative effects of complex reservoir condition (y to z axis ratio is 5:1).

Figure 6.2: Top view of EGS design optimization with symmetrical completion order under UFM while considering both the positive and negative effects of complex reservoir condition.
Figure 6.3: Top view of EGS design optimization with sequential completion order under UFM while considering both the positive and negative effects of complex reservoir condition.

Figure 6.4: Top view of EGS design optimization with sequential completion order and reduced NF length under UFM while considering both effects of complex reservoir condition.
CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

By summarizing all the studies from the coupled geomechanics and fluid flow UFM model, matrix of simulations, sensitivity analysis, and design optimization, conclusions and recommendation for a most successful horizontal multi-stages hydraulic fracture design in enhanced geothermal system application are presented, followed with potential applications and future work in this research study.

7.1 Summary in EGS Application Study

This research in using a coupled geomechanics and fluid flow model to study applications of horizontal well with multistage hydraulic fractures in enhanced geothermal system started with a background study in the geothermal industry. Geothermal energy is being utilized in parts of the world as an affordable and sustainable solution to global warming and public health risks, as well as reducing dependence on fossil fuels. With similar formation properties to shale gas and tight oil reservoirs, deep hot low permeability formations were also found to have the potential to be economically produced if applied with mature unconventional techniques from the oil industry. This motivated the need for optimum design in enhanced geothermal system (EGS).

The research was then followed with literature reviews in order to understand the critical geomechanics and fluid flow concepts for unconventional development and the physical mechanisms behind the fracturing utilized in the simulations and their suitability for hydraulic fracturing in EGS applications. Previous simulation case studies were also reviewed to determine main differences of hydraulic fracture design between an unconventional reservoir and a geothermal reservoir, which is the different desired fracture geometry as oil industry are aiming for maximizing the stimulated reservoir volume and this is usually larger than the total heat extracting volume in enhanced geothermal system due to thermal breakthrough effects and single fracture flow behavior for fluid flow in non-uniform aperture fracture systems.
Therefore, large, planar and conductive fractures that can maximize contact area between injected fluid and heated matrix is required for optimum design in EGS application, which leads to the study in methodology of designing a conceptual EGS model using engineered stimulation software that allows coupling of fluid flow and geomechanics concepts to analyze and predict the most feasible EGS type fracturing treatment before actual field operation. Finally the unconventional fracture model (UFM) utilized inside the simulation software was studied and used as the most feasible model that can capture rock deformation, fracture propagation and fluid flow in the complex fracture network generated during hydraulic fracture operation in EGS, due to the high potential in occurrence of pre-existing discrete fracture network (DFN) in both shale and granitic formation.

Once the development from simple to complex multistage fracture simulations under UFM model was achieved, a matrix of simulations was then performed and studied in order to determine the reservoir and treatment parameters with the greatest effects on successful EGS design. Sensitivity analysis showed that DFN spacing (space between natural fractures) tend to have the greatest effects in fracture half-length followed by fluid viscosity and then stress anisotropy. For effects in average fracture width and effective fracture conductivity, proppant concentration was determined to be the most significant parameter, followed by fluid viscosity and pump rate.

After obtaining the matrix of simulations and sensitivity analysis result, the UFM model then performed the ultimate simulation for optimum EGS design under a best case scenario, which considered the negative effects of most complex reservoir parameters, such as secondary natural fractures with orientation against $S_{H\text{max}}$ and stress shadow effects, and the positive side of effects regarding complex reservoir parameters such as large reservoir stress anisotropy and relatively large natural fractures spacing. Results in optimum design showed that the UFM model was able to simulate a typical EGS type of large planar fracture network with very low level of complexity while giving desirable fracture half-length and large average fracture width. However, limitations regarding for EGS design under UFM model were also observed, such as the 2D DFN design cannot fully represent realistic natural fractures behavior.
7.2 Conclusions in UFM Model

In conclusion, the Mangrove UFM model was found to be an effective model capable of capturing the basic characteristics of complex reservoir conditions such as the effects stress shadowing and pre-existing natural fracture geometry and fracture propagating prediction when compared with conventional type of cartesian grid structured simulator.

The 2D DFN design under UFM model enabled users to artificially design pre-existing natural fractures with desirable orientation, length and space under the circumstance where seismic data is not valid, and it can help reservoir engineer investigating positive and negative effects of natural fractures toward fracture network complexity, as most of the natural fractures are in the same direction as $S_{H_{\text{max}}}$, the inclusion of DFN helps hydraulic fractures to propagate farther into the formation, which enables the desired simple, planar shaped fractures. As most of the natural fractures are not necessarily in the direction of $S_{H_{\text{max}}}$, DFN behave like the barriers of hydraulic fractures as force the hydraulic fractures to either filtrate into the natural fracture, or actually cross over them, which would result in more friction loss while pumping fluid.

As commercial simulation software requires efficient simulation period during business and project delivering, two main limitations in UFM model were observed:

- The 2D Discrete Fracture Network (DFN) design inside the UFM can be used in artificially distribute pre-existing natural fractures by assigning certain properties such as maximum number of fractures, fracture set orientations, average fracture length, average fracture spacing. However, all the natural fractures designed under 2D DFN can’t be assigned with exact locations in the reservoir, due to the very nature of random behavior of those in-situ NFs.

- Only stress anisotropy and stress shadow effects from adjacent fracture stages during hydraulic fracturing treatment were considered regarding in-situ stress changes, stress state alteration induced from those pre-existing NFs are not modeled at this time.
However, simulations under the UFM model did provide a reasonable and logical sample of prediction and analysis in optimum EGS design, and the prediction would become more accurate as integrating more real field data after actual field application. Matrix of simulation and sensitivity analysis results indicated that the hydraulic fracture network complexity can be overcome or reduced to a minimum level, depending on the potential of positive effects from complex reservoir condition such as large stress anisotropy and larger DFN spacing with “friendly” orientation, by utilizing optimum treatment parameters such as large pumping volume of high viscosity fluid with a relatively high proppant concentration and high pump rate, in order for a successful EGS application.

7.3 Design Recommendations

The design optimization section indicated the potential to overcome or reduce the level of fracture complexity in favor of the EGS type of large, planar fractures in economic heated water production. It is noticed that the predicted fracture could actually be even bigger and longer when simulated using conventional type planar fracture model, under condition where positive and negative effects from complex reservoir condition can offset each other to a certain degree.

Since the UFM model was specifically designed to model complex fracture propagation in reservoirs with high potential of pre-existing natural fractures, it tended to be extra sensitive in reacting toward DFN effects, especially natural fractures that intercept the perforation cluster near wellbore region, and due to the very nature of random location distribution in 2D DFN design, when assigning heavily distributed natural fractures, almost all stages had at least one or two natural fractures intercept the perforation cluster before inducing hydraulic fractures. Though it is hard to image all the natural fractures in the whole reservoir, natural fractures near wellbore perforation clusters can be avoided during real field applications by observing the drilled core data before the actual completion operation.

Also, stress shadow effects were indicated as another significant effect in complex fracture geometry creation, even under condition where stress anisotropy is
relatively large enough to force most fractures in propagating in the desired direction. Optimum design for EGS application only considered a simple fracture pattern ordered from stage 1 to 6, and 13 to 8, and then finally stage 7 in order to create a symmetrical fracture network, more progress in effectively reducing the level stress shadow effects can be achieved when applied with engineering designed zipper pattern and modified zipper pattern.

**7.4 Future Work and Potential Applications**

With the integrated results of the sensitivity analysis and design optimization, the UFM model provides an effective tool to numerically capture complex fracture propagation in EGS application; however, the UFM model was originally designed for unconventional shale play simulations. By simply changing the input reservoir parameters from granite in this project to parameter from shale in other projects, this research study can be effectively continued for geomechanics and fluid flow study in unconventional shale applications, as a conventional type simulator was not able to simulate fracture propagation inside cartesian grid system, and it would be interesting to compare the difference in production prediction between the two reservoir simulations in unconventional shale play.

On the other hand, though UFM model inside the Mangrove simulation software is better in capturing complex fracture propagation when compared with CMG, the CMG simulator, especially STARS inside CMG, has a better capture of thermal font movement during reservoir simulation. As for future study in the research of EGS application, it would be better to combine advantages of the two simulators together, such as optimizing hydraulic fracture design from the UFM model in Mangrove, and then import the simulated fractured geometry into CMG STARS for thermal breakthrough prediction in future heat production.
## LIST OF SYMBOLS

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A$</td>
<td>Cross-Sectional Area of the Natural Fracture ($m^2$)</td>
</tr>
<tr>
<td>$b_o$</td>
<td>Boundaries of the opening zones (dimensionless)</td>
</tr>
<tr>
<td>$b_s$</td>
<td>Boundaries of the sliding zones (dimensionless)</td>
</tr>
<tr>
<td>$C_{tot}$</td>
<td>Total Leakoff Coefficient from the Wall of Natural Facture (unitless)</td>
</tr>
<tr>
<td>$d$</td>
<td>Well Diameter (ft)</td>
</tr>
<tr>
<td>$E$</td>
<td>Young’s Modulus (Mpsi)</td>
</tr>
<tr>
<td>$FcD$</td>
<td>Dimensionless Fracture Conductivity</td>
</tr>
<tr>
<td>$f$</td>
<td>Fanning Friction Factor (unitless)</td>
</tr>
<tr>
<td>$h$</td>
<td>Fracture Height (ft)</td>
</tr>
<tr>
<td>$h/2$</td>
<td>Half Height (ft)</td>
</tr>
<tr>
<td>$k$</td>
<td>Formation Permeability (mD)</td>
</tr>
<tr>
<td>$K'$</td>
<td>Consistency Index (unitless)</td>
</tr>
<tr>
<td>$k_f$</td>
<td>Fracture Permeability (mD)</td>
</tr>
<tr>
<td>$k_{NF}$</td>
<td>Permeability of Natural Fracture (mD)</td>
</tr>
<tr>
<td>$k_o$</td>
<td>Initial Permeability of Natural Fracture (mD)</td>
</tr>
<tr>
<td>$k_r$</td>
<td>Permeability of Rock Matrix (mD)</td>
</tr>
<tr>
<td>$l$</td>
<td>Perforated Length (ft)</td>
</tr>
<tr>
<td>$L$</td>
<td>Coordinate Length (in)</td>
</tr>
<tr>
<td>$N_{RE}$</td>
<td>Reynolds Number (ratio)</td>
</tr>
<tr>
<td>$n'$</td>
<td>Fluid Power Law Exponent</td>
</tr>
<tr>
<td>$p$</td>
<td>Pressure in the Natural Fracture (psi)</td>
</tr>
<tr>
<td>$p_{in}$</td>
<td>Inlet Fluid Pressure (psi)</td>
</tr>
<tr>
<td>$p_f$</td>
<td>Fluid Pressure at Intersection with Natural Fracture (psi)</td>
</tr>
<tr>
<td>$p_r$</td>
<td>Reservoir Pressure (psi)</td>
</tr>
<tr>
<td>$\mu_f$</td>
<td>Filtrate Fluid Viscosity (cp)</td>
</tr>
<tr>
<td>$\mu_{fl}$</td>
<td>Dynamic Fluid Viscosity (cp)</td>
</tr>
<tr>
<td>$\mu_r$</td>
<td>Reservoir Fluid Viscosity in Porous Media (cp)</td>
</tr>
<tr>
<td>$q$</td>
<td>Total Flow Rate (bbl/day)</td>
</tr>
<tr>
<td>Symbol</td>
<td>Definition</td>
</tr>
<tr>
<td>--------</td>
<td>------------</td>
</tr>
<tr>
<td>$q_{NF}$</td>
<td>Volumetric flow rate through a cross section area of natural fracture ($m^3/s$)</td>
</tr>
<tr>
<td>$q_L$</td>
<td>Volume rate of the leakoff per unit length ($m^3/s$)</td>
</tr>
<tr>
<td>$q_m$</td>
<td>Mass Flux ($m^3/s$)</td>
</tr>
<tr>
<td>$\rho_f$</td>
<td>Fluid Density ($kg/m^3$)</td>
</tr>
<tr>
<td>$S_{Hmax}$</td>
<td>Maximum Horizontal Stress (psi)</td>
</tr>
<tr>
<td>$S_{Hmin}$</td>
<td>Minimum Horizontal Stress (psi)</td>
</tr>
<tr>
<td>$T$</td>
<td>Temperature (°F or °R)</td>
</tr>
<tr>
<td>$u_s$</td>
<td>Shear Induced Slippage (psi)</td>
</tr>
<tr>
<td>$v$</td>
<td>Fluid Velocity (ft/s)</td>
</tr>
<tr>
<td>$W_T$</td>
<td>Blunt Tip (dimensionless)</td>
</tr>
<tr>
<td>$w$</td>
<td>Fracture Opening by Fluid Pressure Exceeding Normal Stress (ft)</td>
</tr>
<tr>
<td>$\bar{w}$</td>
<td>Average Opening Fracture Width (ft)</td>
</tr>
<tr>
<td>$X_e$</td>
<td>Half-Spacing between Fractures (ft)</td>
</tr>
<tr>
<td>$\bar{x}$</td>
<td>Coordinates (dimensionless)</td>
</tr>
<tr>
<td>$\bar{y}$</td>
<td>Coordinates (dimensionless)</td>
</tr>
</tbody>
</table>

**Greek Letters**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha$</td>
<td>Biot’s Parameter (dimensionless)</td>
</tr>
<tr>
<td>$\varepsilon$</td>
<td>Surface Roughness Height (length)</td>
</tr>
<tr>
<td>$\theta$</td>
<td>Angle from Well Trajectory (degree)</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Fluid Viscosity (cp or Pa-s)</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Poisson’s Ratio (dimensionless)</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Density ($g/cm^3$)</td>
</tr>
<tr>
<td>$\sigma$</td>
<td>Tensile Stress (psi)</td>
</tr>
<tr>
<td>$\sigma_x$</td>
<td>Stress in the $x$-axis that affects fracture width (psi)</td>
</tr>
<tr>
<td>$\sigma_n$</td>
<td>Normal Stress (psi)</td>
</tr>
<tr>
<td>$\sigma_v$</td>
<td>Vertical Stress (Overburden Stress) (psi)</td>
</tr>
<tr>
<td>$\tau$</td>
<td>Shear Stress (psi)</td>
</tr>
<tr>
<td>$\varphi$</td>
<td>Friction Angle (degree)</td>
</tr>
<tr>
<td>$\phi_{dil}$</td>
<td>Dilation Angle (degree)</td>
</tr>
</tbody>
</table>


EMI. 2010. Brazilian Tensile Strength Test Datasheet for Orica Core ID 4, Colorado School of Mines Earth Mechanics Institute.

EMI. 2010. Uniaxial Compressive Strength Test Datasheet for Orica Core ID 4, Colorado School of Mines Earth Mechanics Institute.

Evans, J.G. 1971. The Use of Pressure Buildup Information To Analyze Non-Respondent Vertically Fractured Oil Wells. Presented at the SPE Rocky Mountain Regional Meeting, Billings, Montana, USA, 2–4 June. SPE-3345-MS. http://dx.doi.org/10.2118/3345-MS.


