LABORATORY-SCALE STUDY OF HYDRAULIC FRACTURING IN HETEROGENEOUS MEDIA
FOR ENHANCED GEOTHERMAL SYSTEMS AND GENERAL WELL STIMULATION

by
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A thesis 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 Doctor of Philosophy (Civil and Environmental Engineering).

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ABSTRACT

The primary objectives of this research were to experiment with hydraulic fracturing in the laboratory to gain additional understanding of the fracturing process in unconventional rocks having low natural permeability and heterogeneous structures. Focus topics of this research included experimentation with a mechanical impulse hydraulic fracturing method, measurement of critical state hydraulic fracture aperture, laboratory scale modeling of EGS, and an investigation of grain-scale effects on 3D hydraulic fracture geometry. Fractured materials included acrylic, concrete, granite and limestone with specimen sizes up to 300×300×300 mm³ cubical blocks. Fracturing fluids included water, brine, oil and epoxies. Applied boundary conditions varied between experiments from unconfined to true-triaxially confined with heating applied in some instances. Data collected during experiments included pressures, flow rates, acoustic emissions (AE), temperatures, strains and video with intended future application for calibration of models. Cross-sections were cut through the test specimens after hydraulic fracture stimulation to investigate and measure fracture geometry at both the grain-scale and macro-scale. Procedures for using the true-triaxial apparatus and associated control systems developed for this project are detailed in appendices to guide future use of the equipment. Supplemental data and results from the hydraulic fracture of 13 specimens are also included.
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CHAPTER 1
INTRODUCTION

Hydraulic fracturing is an effective well stimulation method used by the oil, gas, geothermal, mining and waste disposal industries. The method involves injection of fluid into a targeted reservoir rock at sufficient pressure and flow rate such that new fractures can be created. These fractures can function as high-permeability pathways to increase well productivity or injectivity. Substantial hydraulic fracturing knowledge has been gained through application in sedimentary rocks by the oil and gas industry. Comparatively less experience has been acquired with igneous and metamorphic rock types. Uncertainties regarding the influence of in-situ rock properties, discontinuities and injection parameters on fracture effectiveness complicate the design of hydraulic fracturing treatments and cause associated predictions to be unreliable. Critical topics of interest for the advancement of hydraulic fracturing technology include better understanding the effect of discontinuities on fracture propagation, injection fluid parameter optimization, fracture monitoring methods and predictive modeling technologies. The focus of this research is directed towards improving understanding the hydraulic fracturing process and subsequent flow in application to unconventional oil, gas and geothermal resources. Hydraulic fracturing experiments were performed in laboratory scale specimens to produce the data necessary to pursue this improved understanding. Associated results and conclusions are supported within the context of current theories and published studies.

1.1 Background

Hydraulic fracturing is an established well stimulation method with intentional use predating 1949 when the first example for an oil and gas application was published (Clark, 1949). It is known that hydraulic fracturing in water wells was performed prior to this experiment (Valkó and Economides, 1995). It is also expected that hydraulic fractures can be occasionally stimulated during well drilling due to high pressure mud pumped into the wellbore for cooling the cutting bit, removing rock cuttings, stabilizing the wellbore and lubricating the drill string. The fluid pressure required for hydraulic fracturing is known to be a function of rock stresses and strength (Hubbert and Willis, 1957). A diagnostic fracture injection test (DFIT), or minifrac test, is a low-fluid-volume hydraulic fracturing method developed and standardized as a means for evaluating in-situ stress state (ASTM D4645, 2008). DFIT results are commonly used for underground mine design and well stimulation design.

Unconventional oil, gas and geothermal reservoirs can be defined as resources which require stimulation to achieve economic production rates. These reservoirs are often characterized by in-situ rocks with naturally low-permeability, low-porosity or high-viscosity pore fluids. These conditions reduce
fluid flow between the rock and wells. Stimulations methods, such as hydraulic fracturing, can increase
the permeability of rock near the wellbore or even further into the formation depending upon the
treatment’s design and successful execution. Examples of unconventional oil and gas reservoirs include
tight gas sands, coal bed methane, shale gas and gas hydrates. Examples of unconventional geothermal
reservoirs include low-permeability geothermal systems, hot dry rock anomalies and supercritical
geothermal systems (Friðleifsson et al., 2012).

Enhanced Geothermal Systems (EGS) represents a special case of energy technology where
stimulation is used to create an economically productive geothermal reservoir in an unconventional hot
rock resource (Tester et al., 2006). Complete EGS involves cold fluid injection and hot fluid production
from a stimulated hot rock reservoir to extract heat for electrical power generation. Some controversy
exists regarding the most appropriate definition for EGS with some experts defining the term as
Engineered Geothermal Systems instead of Enhanced Geothermal Systems, but both definitions are
nearly synonymous. Additional controversy exists regarding classification of EGS reservoirs because
reinjection can be applied to improve productivity from conventional geothermal reservoirs and
stimulation can be used to enable economic energy production from the unconventional fringes of
conventional geothermal systems. Generally, EGS in this document refers to geothermal energy
production from a hydraulically stimulated hot rock using both fluid injection and production.

Common rock types for unconventional oil and gas include tight sandstone, carbonate and shale.
Examples of unconventional oil and gas reservoirs in the United States include the Bakken, Marcellus,
Barnett, Eagle Ford, and Niobrara plays (EIA, 2011). EGS can target additional rock types from
sedimentary to igneous including granite, diorite and volcanic tuffs. Examples of field EGS sites include
Soultz-sous-Forêts (France & Switzerland), Desert Peak (Nevada), Hijiori (Japan), Ogachi (Japan),
Landau (Germany), Cooper Basin (Australia), the Geysers (California), and Fenton Hill (New Mexico).
Industrial EGS for power generation remains limited and experimental due to the high capital cost of
wells and the uncertainty of heat production from these wells. EGS technology is thought to have the
potential to provide a significant contribution to base load electricity generation in the future (Tester et al.,
2006).

Fluids used for field hydraulic fracturing treatments are typically staged and varied (Miskimins,
2011). Common injection fluids include water, oils, and high viscosity gels. Proppant particles such as
sand, ceramics, or other similar products are commonly added to the treatment fluid with the intent of
filling created fractures to maintain high residual fracture permeability after completion of the stimulation
treatment. Additional chemicals such as hydrochloric acid and hydrofluoric acid can be added in some
cases to improve the success of a treatment through acid etching and dispersion of clays. Biocides, such
as formaldehyde, are also a commonly necessary chemical additive to mitigate issues with bacterial and
microbial contamination of the well and reservoir. Some emerging gas stimulation technologies are also in development with potential fluids including liquid nitrogen, supercritical carbon dioxide and liquefied petroleum gas (Gandossi, 2013; LeBlanc et al., 2011). Environmental health and safety concerns over the chemicals used in hydraulic fracturing jobs has led to disclosure through FracFocus (GWPC & IOGCC, 2014), a free public database.

A generic setup for a hydraulic fracturing treatment as implemented for EGS is shown in Fig. 1.1. This diagram shows the creation of a simple hydraulic fracture in deep hot rock anomaly. The hydraulic fracture creates a high surface area heat exchanger in the subsurface where in injection wells supply cold fluid and production wells extract hot fluid. Ideally the flow rate and fluid enthalpy is sufficient for net energy production at the surface. Fracturing in this example is performed through perforations cut into steel casing along a targeted stimulation interval. Other methods of stimulation include open-hole fracturing when the rock has high integrity and sliding-sleeve technologies for multi-fracturing. Wells can be drilled at any alignment from vertical through horizontal. Horizontal wells are increasingly popular in oil and gas applications where more reservoir volume can be accessed from a single well pad on the surface and more production can be achieved from a single well. Real hydraulic fracture treatments are significantly more complex than this basic diagram implies where complex geological conditions complicate hydraulic fracture geometry and monitoring trucks are required to control the fracturing process. Available monitoring methods include measurement of flow rates and pressures, acoustic emissions or micro-seismicity, and tiltmeter survey data.

![Fig. 1.1. EGS using hydraulic fracturing.](image-url)
1.2 Literature Review

A multitude of studies have previously been performed in pursuit of understanding hydraulic fracturing and to validate associated theories. Laboratory scale experiments are the most common physical studies due to convenient sample size, greater control over variables, rapid execution and ability to test new stimulation methodologies with low cost relative to field scale studies. A literature review was performed to evaluate the current state-of-the-art for hydraulic fracturing, identify other well stimulation technologies and identify focus areas for this research effort.

Ideal Conventional Hydraulic Fracturing Treatment

Idealized injection pressure \( P \) and flow rate \( Q \) data for a conventional hydraulic fracturing treatment is shown in Fig. 1.2. This example shows three stages of injection into a single borehole interval using constant flow rate control. Flow rate controlled injection is standard for field hydraulic fracture treatments because it is easier than the alternative of pressure controlled injection. The three injection stages are modeled after ASTM D4645 (2008) where the third stage of injection uses a lower injection rate than the initial two stages.

![Ideal hydraulic fracture treatment plot with three injection stages into one well interval.](image)

Injection began with the well at a low pressure \( P_0 \), equal to the in-situ pore-pressure if the well was initially hydrostatic. Pressurization of the well occurs as long as the injection rate exceeds the leak-off rate. The slope of the pressure response is a function of leak-off and well hydraulic compliance, a phenomenon known as ballooning in the petroleum industry. If the injection rate is sufficient, hydraulic fracture initiation (breakdown) can occur with a corresponding decrease in the slope of the pressurization curve. This decrease is not to be confused with the peak pressure which is dependent upon the fracture growth rate and frictional effects in addition to the fracture initiation pressure. Continued fracture propagation occurs after initiation as long as injection rate exceeds the leak-off rate and pressures remain within operational limits. Transient pressure falloff can be monitored after pumping is stopped and the well is shut-in. Methods have been developed estimate the fracture closure stress \( P_s \) fissure opening stress and bulk permeability using the falloff data (Baree et al., 2009). A comparison of the initial breakdown pressure \( P_b \) in the first stage and the reopening pressure \( P_r \) in the second stage provides an
estimate of the tensile strength or fracture toughness for the targeted rock formation. Correlation between
the rock properties and the injection data is most accurate if the treatment is performed in an open interval
of the well as opposed to a perforated interval of well casing.

Field hydraulic fracture treatments are rarely as simple as this treatment plot implies. Rock
heterogeneity, discontinuities in the rock, staging of fluids and indirect measurement of treatment
pressures and flow rates all cause increased uncertainty and difficulty in subsequent data analysis.

Hydraulic Fracture Theory and Modeling

Multiple approaches to modeling hydraulic fractures have been developed (Whittaker et al., 1992;
Warpinski et al., 1994; Valkó and Economides, 1995). Three dominant approaches include continuum
based models using stress failure criterion, fracture mechanics based models using fracture toughness
criterion and discrete element models using empirically calibrated failure models. These approaches are
not equal due to incompatibility between the base assumptions but correlations between the models have
been derived. A general overview of existing fracture models is presented in this subsection with details
provided for selected models used in this research effort.

Fracture Initiation (Breakdown) Pressure Models

Fracture initiation and reopening pressures are important values to estimate for the design of
hydraulic fracturing equipment and procedures. A simple analytical model was developed by Hubbert and
Willis (1957) to relate fracture initiation pressures and stresses near the wellbore. The model was later
extended by Haimson and Fairhurst (1967) to incorporate pore pressures and permeable fluid flow. The
respective relations for this model are:

\[
\begin{align*}
P_T &= 3\sigma_h - \sigma_H + T - P_0 \\
P_s &= \sigma_h \\
P_r &= 3\sigma_h - \sigma_H - P_0
\end{align*}
\]

where, \(T\) is the material tensile strength, \(\sigma_h\) and \(\sigma_H\) are the minimum and maximum horizontal principal
stresses respectively, and \(P_0\) is the in-situ pore pressure. Eqs. 1.1 through 1.3 are recommended in ASTM
D4645 (2008) for a standard method to estimate in-situ rock stresses. This model assumes a vertical intact
open borehole, vertical planar fracture orientation, linear-elastic isotropic rock deformation, pseudo-static
loading and tensile stress failure criterion. This model fundamentally predicts that breakdown pressures
are not scale dependant, based on continuum mechanics theory, but experimental work contradicts this
expectation (Haimson and Zhao, 1991).

This theory was extended for oriented wells by Valkó and Economides (1995) using rotation
matrices. The respective relations using the vector space defined in Fig. 1.3 are as follows:
\[
\begin{pmatrix}
\sigma_{xx} \\
\sigma_{yy} \\
\sigma_{zz} \\
\sigma_{xy} \\
\sigma_{xz} \\
\sigma_{yz}
\end{pmatrix}
= \begin{pmatrix}
\sin^2 \beta & \cos^2 \beta \cos^2 \alpha & \cos^2 \beta \sin^2 \alpha \\
0 & \sin^2 \alpha & \cos^2 \alpha \\
\cos^2 \beta & \sin^2 \beta \cos^2 \alpha & \sin^2 \beta \sin^2 \alpha \\
0 & -\sin \alpha \cos \alpha \sin \beta & \sin \alpha \cos \alpha \sin \beta \\
-\sin \beta \cos \beta & \sin \beta \cos \beta \cos^2 \alpha & \sin \beta \cos \beta \sin^2 \alpha \\
0 & -\sin \alpha \cos \alpha \cos \beta & \sin \alpha \cos \alpha \cos \beta
\end{pmatrix}
\begin{pmatrix}
\sigma_x \\
\sigma_y \\
\sigma_z
\end{pmatrix}
\]

(1.4)

\[
\sigma_{RR} = P_b
\]

(1.5)

\[
\sigma_{\theta \theta} = (\sigma_{xx} + \sigma_{yy} - P_b) - 2(\sigma_{xx} - \sigma_{yy}) \cos(2\theta) - 4\sigma_{xy} \sin(2\theta)
\]

(1.6)

\[
\sigma_{ZZ} = \sigma_{zz} - 2\nu(\sigma_{xx} + \sigma_{yy}) \cos(2\theta) - 4\nu\sigma_{xy} \sin(2\theta)
\]

(1.7)

\[
\sigma_{\theta z} = 2(\sigma_{xx} \cos \theta - \sigma_{xz} \sin \theta)
\]

(1.8)

\[
\sigma_1 = \sigma_{RR}
\]

(1.9)

\[
\sigma_2 = \frac{(\sigma_{\theta \theta} + \sigma_{ZZ})}{2} + \frac{1}{2} \sqrt{(\sigma_{\theta \theta} - \sigma_{ZZ})^2 + 4\sigma_{\theta z}^2}
\]

(1.10)

\[
\sigma_3 = \frac{(\sigma_{\theta \theta} + \sigma_{ZZ})}{2} - \frac{1}{2} \sqrt{(\sigma_{\theta \theta} - \sigma_{ZZ})^2 + 4\sigma_{\theta z}^2}
\]

(1.11)

\[
\sigma_3 = P_0 + \sigma_T
\]

(1.12)

where, \(\sigma\) are the Cauchy stress tensor components and \(\nu\) is Poisson’s ratio. Note that \(\sigma_x\), \(\sigma_y\) and \(\sigma_z\) represent far field principal stresses and \(\sigma_1\), \(\sigma_2\) and \(\sigma_3\) represent principal stresses at the borehole wall. The minimum breakdown pressure can be estimated iteratively by solving these equations varying \(\theta\) from 0 to \(\pi\). Borehole failure (breakout) due to external stresses is expected if this equation predicts a breakdown pressure less than zero. The initial fracture plane is assumed parallel with the angle, \(\theta\), corresponding with minimum theoretical breakdown pressure. The initial fracture orientation is expected to parallel with the borehole axis if the tangential stress at the borehole wall, \(\sigma_{\theta \theta}\), is less than the axial stress, \(\sigma_{ZZ}\), otherwise the fracture is expected to propagate perpendicular to the borehole axis. The fracture is expected to reorient with propagation away from the borehole if the borehole axis is not parallel with one of the far field principal stresses. Some studies observed that this reorientation can be either a smooth transition or a rough stepwise progression depending upon the heterogeneity of the material, degree of reorientation, and several other factors (Behrmann and Elbel, 1991, and Weijers et al., 1994).

Breakdown pressures estimated from these two models can be taken as theoretical maximum down-well treatment pressures where increased injection rate balances with increased fracture growth.
rates. Frictional fluid pressure losses and permeable matrix leak-off are not factored into this simple model.

![Fig. 1.3. Ordinate vector definitions for general borehole breakdown pressure theory.](image)

**Origin of Subsurface Stresses**

It is well known that subsurface rock is subjected to stresses created by overburden, stress-strain interactions, tectonic activity, and other geologic processes. The associated three-dimensional stress state can be described in tensor form by the magnitudes and orientations of the maximum, intermediate and minimum principal stresses. True-triaxial equipment (Mogi, 2007; Kwaśniewski et al., 2013) was developed to simulate an environment where the three principal stresses have different magnitude. This is not to be confused with conventional triaxial equipment which is only capable of applying two different principal stress magnitudes for the axial and radial directions respectively.

**Wellbore and Fracture Fluid Flow Models**

It is important to consider pressure losses occurring with flow through the well and fracture in addition to the treatment pressure within the hydraulic fracturing interval of the well. Pressure measurements are typically easiest to acquire at the surface so corrections must be applied to estimate down-well pressures.

Pressure losses occurring with flow through the borehole and near-well zone can be estimated using Bernoulli equations assuming dominantly single phase flow. This relation can be simply stated using the following relation (Miskimins, 2011):

\[
P_{\text{surf}} = (P_s + P_{\text{net}}) + \Delta P_f + \Delta P_{\text{nb}} - P_g
\]  

where \( P_{\text{surf}} \) is the wellhead pressure, \( P_s \) is the fracture closure pressure, \( P_{\text{net}} \) is the fracture net pressure, \( \Delta P_f \) is the frictional pressure loss occurring with flow through the well, \( \Delta P_{\text{nb}} \) is the near wellbore
pressure loss, and $P_g$ is the gravitational pressure. The $\Delta P$ terms are known to be functions of fluid viscosity and flow rate which can be estimated using fluid mechanics (e.g., White, 2008). Increased accuracy estimations can be gained from calibrated frictional flow relations specific to the fracturing fluids, perforation system, and well casings used. Increased fluid leak-off into the reservoir is expected with an increase in $P_{net}$ as predicted with Darcy flow theory. Therefore, this relationship implies a practical economic limit to how much pressure can be transmitted to the fracture simply by increasing the injection flow rate.

Pressure losses with fracture flow are more difficult to estimate than simple contained flow through the well. Various relevant flow regions can be defined as shown in Fig. 1.4. Linear fracture flow locally dominates during successful fracture stimulation while long term flow can be modeled as pseudo-radial far-field flow on the reservoir scale. The most common methods for estimating pressure losses with linear fracture flow are parallel plate flow theory and dimensionless fracture conductivity theory. Parallel plate flow is most applicable when the fracture is open. Dimensionless fracture conductivity is typically applied after the fracture is closed.

The following parallel plate flow relationship can be derived (White, 2008):

$$Q = H \frac{\pi w^3 \Delta P}{12 \mu L}$$

where, $H$ is the height of the plate transverse to the flow direction, $w$ is the aperture between the plates, $\Delta P$ is the pressure gradient parallel with the flow direction, $\mu$ is the dynamic viscosity of the fluid and $L$ is the length of the plate parallel with the flow direction. It is important to note the cubic relationship
between aperture and volumetric flow rate. This solution assumes laminar flow, parabolic flow velocity profile, infinite plates and zero-slip impermeable boundaries.

Dimensionless hydraulic fracture conductivity (FCD) is a calibrated parameter used to design fracture treatments for optimal post-stimulation fracture flow. This value can be defined as:

\[
F_{\text{CD}} = \frac{k_f w_f}{k x_f}
\]

where, \(k_f\) is the fracture permeability, \(w_f\) is the propped fracture width, \(k\) is the formation permeability, and \(x_f\) is the length of a single fracture wing assuming a bi-wing symmetric fracture. The numerator of the right hand side is referred to as the fracture conductivity and the denominator is referred to as the formation deliverability. Fracture conductivity is typically estimated with reference to laboratory proppant pack test data (API RP 61, 1989) and calibrated with pressure-history matched field data. This theory is typically applied as an optimization parameter where the theoretically optimal fracture design would have a dimensionless fracture conductivity of 1. Practical implementation targets dimensionless fracture conductivity values in the range of 10 to 20 to compensate for losses in fracture conductivity occurring with complex fracture phenomena (Vincent, 2011).

Field and laboratory studies show that pressure losses with flow through the fractures are significantly greater than models would predict (Warpsinski, 1985; API RP 61, 1989; Vincent, 2011). It is expected that fracture roughness, tortuosity, multiple stranding and degradation of proppant effectiveness are all dominant factors causing the discrepancy between theoretical fracture conductivity and actual fracture conductivity. Complex fracture growth, self-propping and shearing induced permeability (Detwiler and Morris, 2014) all complicate fracture conductivity modeling and prediction. Improved understanding of hydraulic fracture geometry is critically important to the advancement of fracture conductivity estimation and modeling.

Advanced Models and Computer Simulations

The Haimson and Fairhurst model and the generalized solution by Valkó and Economides are only valid for estimating fracture initiation pressures and fracture reopening pressures. Fracture extension and geometry modeling is significantly more complex. Common approaches include fluid volume models, linear-elastic fracture mechanics (LEFM) models, and discrete element method (DEM) models. Coupled modeling linking a combination of fluid mechanics, solid mechanics, thermo-mechanics and chemical kinetics into unified solutions have been also been attempted with many still in development (e.g., Kumar and Gutierrez, 2011; Tomac, 2013; Wang, 2008). Complex geological conditions, fluid parameters and other unknowns for respective model input values lends to prominent use of the simplest models for first estimates and analysis.
Popular linear-elastic continuum and volume based hydraulic fracture propagation models include the Perkins, Kern and Nordgren (PKN) solution (Perkins and Kern, 1961; Nordgren, 1972) and the Geertsma and de Klerk (GDK) solution (Geertsma and de Klerk, 1969). These two solutions assume fixed height, bi-wing, symmetric and elliptical fracture geometries where length and aperture are variable. The three-dimensional fracture geometry assumed in the PKN solution is shown in Fig. 1.5. These models do not incorporate fracture toughness or rock mass heterogeneity. More advanced three-dimensional volume based approaches have been developed using finite element methods or similar approaches (Barree, 1983; Warpinski et al., 1994; Miskimins, 2011) such that anisotropy and vertical heterogeneity from well logs can also be included in calculations.

Fracture Modeling with LEFM

LEFM can be used to analyze and predict fracture growth in homogeneous brittle rocks which exhibit negligible scale-dependence and highly linear stress-strain behavior prior to fracture. LEFM fracture criteria are characterized by the relative displacement vectors of the two created fracture surfaces (Fig. 1.6) at the crack tip which are referred to as Mode I, II and III for tensile opening, in-plane shearing and out-of-plane shearing (tearing), respectively. Mixed mode fractures including all three displacement vectors are common in rock because of heterogeneities and discontinuities. An understanding of these fundamental fracture types is instrumental for subsequent three-dimensional fracture geometric analysis. These displacement modes are also related to induced seismicity and acoustic emissions (AE) occurring with hydraulic fracture stimulation. A simplified moment-tensor analysis (MTA) method for distinguishing between tensile and shear fractures using acoustic emissions during stimulation was detailed by Ohtsu (1995). Application of MTA to this research effort was detailed by Hampton (2012).

Fig. 1.5. Assumed geometry for PKN model.
Fracture extension pressures can be estimated using LEFM. Analytical solutions have been derived for simple fracture geometries (Valkó and Economides, 1995; Whittaker et al., 1992) and more complicated cases can be solved using the principal of superposition, extended finite element method (XFEM) or boundary element methods (BEM). These solutions can also be applied to fracture initiation pressure prediction if appropriate initial fracture lengths are assumed (Anderson, 1991). The influence of fracture toughness and tensile strength on fracture propagation pressures is expected to be insignificant at the field-scale (Johnson and Cleary, 1991; de Pater et al., 1994) but they can be influential at the laboratory-scale (Haimson and Zhao, 1991).

**Scalability of Hydraulic Fracture Models and Laboratory Data**

Quantitative comparison between laboratory-scale hydraulic fracture experiments and the field-scale implores the development of scaling laws. Factors affecting scalability include fluid viscosity, rock fracture toughness, rock grains and heterogeneity, relative dimensions of specimen size, discontinuities and the borehole, confining stress and fluid pressure ratios, injection rate and injection duration. Previous studies used non-dimensional analysis based on simple and ideal fracture geometries to develop scaling laws (Johnson and Cleary, 1991; de Pater et al., 1994; Detournay et al., 2007). These studies generally assumed continuous, homogenous, isotropic and linear-elastic rock properties and concluded that field scalable results can be produced by laboratory experiments if high viscosity fluids, low toughness materials and large specimen dimensions with negligible heterogeneity are used. However, the applicability of the scaling laws proposed in these studies is limited to the assumed fracture geometries at both the laboratory and field scales. These studies effectively recommend that laboratory scale specimens be selected based on how closely they obey the assumptions used for simple and idealistic hydraulic fracture models.
True-scale fractures are not likely to exhibit the simple geometries assumed for the development of dimensionless groups. Grain-scale heterogeneity, discontinuities, high frictional fluid pressure losses, and absolute dimensions are all expected to have a significant impact on final fracture geometry and complexity. Previous experiments (Daneshy, 1973; Behrmann and Elbel, 1991; Warpinski et al., 1982; Zoback et al., 1977; Hallam and Last, 1991; Abass et al., 1996; Romero et al., 1995; Weijers et al., 1994) and field data (Warpinski et al., 1982; Warpinski, 1985; Warpinski and Teufel, 1987; Jeffrey et al., 1995) all exhibit significant complexity in produced fracture geometries due to rock heterogeneity and discontinuities. Improved understanding of the fracturing process and fracture scaling can potentially be gained by studying the interaction between heterogeneities and macro-scale fracture geometry. More realistic evaluations of scalability between the laboratory and the field can be achieved by development and validation of new models which do not neglect complexities arising from heterogeneous rock structure.

Factors Affecting Fracture Geometry

Field hydraulic fracture geometries are expected to be complex (Warpinski, 1985; Jeffery et al., 1995) with associated phenomena including mechanical, hydraulic, geologic, thermal, and chemical effects. The most difficult data to acquire from fracturing experiments is the full geometry of the fractures including length, height, width and three-dimensional shape. This geometry data is also the most important due to its direct effect on flow and post-stimulation reservoir mechanics. Many laboratory-scale hydraulic fracture experiments have been performed in rock specimens subjected to polyaxial stress conditions. Some of these studies also present data regarding hydraulic fracture geometry. These studies generally found that hydraulic fracture geometry depends upon the rock stress-state, borehole and perforation geometry, fluid viscosity and injection rate, and rock structure and scale.

Rock stresses are expected to be the dominant factor affecting fracture geometry where fractures preferentially propagate perpendicular to the minimum principal stress direction (parallel with the maximum principal stress) (Haimson and Fairhurst, 1967; Zoback et al., 1977; Warpinski et al., 1982). Influence of the near-wellbore zone can add complexity to the fracture. Examples show that fractures tend to initiate with orientations parallel with the borehole axis even if the borehole is drilled subparallel with the minimum principal stress (Hallam and Last, 1991; Abass et al., 1996; Romero et al., 1995; Weijers et al., 1994). Perforations can affect fracture growth where offset between the perforations and the maximum principal rock stresses can add tortuosity (Daneshy, 1973; Behrmann and Elbel, 1991). Twisting fractures can form as the fracture lengthens and far-field stress effects become dominant (Valkó and Economides, 1995).

Fluid viscosity and injection rate have a strong influence on geometry. The effect of viscosity can be broadly summarized as an increase in fracture aperture, decrease in fracture extents and decrease of...
fracture tortuosity with increasing viscosity (Ishida et al., 2004). Higher injection rates can induce brittle fracture behavior (Haimson and Zhao, 1991; Safari et al., 2013) and produce more fracture branching (Cuderman and Northrop, 1986). High viscosity fluids can also aid proppant transport by decreasing settling velocities. Fluid-rock interactions such as permeation, chemical etching, osmotic pressures and imbibition can also directly affect the fracture geometry.

Scale, size, and rock structure can affect fracture geometry and roughness. At the molecular-scale, fractures propagate by breaking atomic bonds which have finite strengths, dimensions and crystalline structures. Molecular-scale fracturing aggregates into the grain-scale through preferred cleavage planes dependant upon the local mineral type and orientation (Anderson, 1991). At the grain-scale, heterogeneity among intragranular and intergranular bond strengths can influence the fracture geometry. When the strength of grains is significantly stronger than the bonds between them the fractures can propagate between the grains, rather than through them, likely producing a rougher fracture. At the macro-scale, discontinuities can influence fracture geometry where propagation can occur along pre-existing joint sets and bedding planes in addition to through the rock matrix (Warpinski and Teufel, 1987; Athavale and Miskimins, 2008; Taleghani and Olson, 2014). Excessive leak-off can occur when high permeability zones are intersected by the fracturing interval of the borehole or the hydraulic fracture itself, potentially stunting additional hydraulic fracture propagation. Field scale experiments show the true complexity of hydraulic fractures in real rock (Warpinski et al., 1982; Warpinski, 1985; Jeffrey et al., 1995). Uncertainty and complexity regarding the structure of in-situ rock consequentially adds uncertainty to hydraulic fracture modeling efforts.

**Definition of grain-scale**

Specifying the dimensions corresponding with the grain-scale and macro-scale is difficult. This difficulty arises from heterogeneities and discontinuities existing at multiple scales ranging from irregularities in crystalline structures of atoms to tectonic faults. In this document, grain-scale will refer generally to discrete mineral grains having a typical size in the range of 0.0005 mm to 1.0 mm. The lower size limit is a function of the resolution for the instruments used in this study. Many larger grains contained internal discontinuities and impurities which affected structural behavior during hydraulic fracturing. Macro-scale typically refers to the full fracture dimensions and includes any features larger than the grain-scale.

**Alternative Well Stimulation Methods**

Alternative well stimulation methods to conventional hydraulic fracturing have also been developed (Gandossi, 2013). Many of the alternative stimulations also involve injection of fluids into the wellbore to modify the hydraulic properties of the rock formation or the near wellbore zone. Some of the
methods most relevant to this research effort include high-strain rate fracturing, shear stimulation, acid stimulation, and thermal stimulation. The means of applying these methods vary and multiple methods can be combined to improve the success of a treatment. The optimal stimulation treatment for a given well is understood to be site specific, dependent upon local rock properties, heterogeneities and in-situ stresses.

Rock fracture mechanisms are loading rate dependent. High strain rate fracturing (HSRF) methods take advantage of dynamic failure phenomena where increased loading rates can induce increasingly brittle behavior and more fracture wings (Safari et al., 2013). HSRF can produce multiple fractures with varied orientations, increasing in number as a function of loading rate (Cuderman and Northrop, 1986). These multiple fractures are expected to have a significant effect on near wellbore hydraulic conductivity and also have a greater potential than conventional hydraulic fractures to intersect nearby natural fractures with orientations perpendicular to the minimum principal in-situ stress. HSRF is known to be controlled by the combination of shockwaves and pressurized fluid flow. A crushed zone of rock can be created near the wellbore when treatments are performed at greater than sonic velocities. This zone, referred to as a stress cage, can reduce well productivity or injectivity and therefore limits the applicability of explosive HSRF methods. A detailed description of the HSRF growth process as applied to modeling explosive fracturing is presented by Dehghan Banadaki and Mohanty (2012) and references cited therein.

Many HSRF methods have been developed with examples including compressed gas impulse stimulation (Kabishcher and Ass, 2011), high-energy gas fracturing (Nilson et al., 1985; Cuderman and Northrop, 1986; Wieland et al., 2006), explosive fracturing (Huang et al., 2006), and even nuclear stimulation (DOE, 2014). The general energy sources for these methods are compressed gasses, conflagrant chemicals, explosive compounds, and specialized nuclear explosive devices, respectively. The terminology in this selection of HSRF methods is intended to be general with direct reference to the relative energy source used, rather than specific treatments or trade names which vary. Distinction between pulse and impulse stimulation is generally vague, almost used interchangeably, because the terms refer to relative pressure rise times while the response of the well is likely more accurately a function of the entire treatment pressure profile, including pressure decay which can be a much slower process. Impulse treatments in this document refer to processes having pressure rise times near or exceeding sonic velocity.

Additional methods for increasing well injectivity or productivity include shear stimulation, acid stimulation, and thermal stimulation. Shear stimulation can be performed using long-term injection of fluid into a reservoir at pressures below the hydraulic fracturing threshold. Pore pressure increase with injection can induce shear slippage along pre-existing discontinuities (Hoek, 2007). An increase of
hydraulic conductivity through the discontinuities can result from the shearing displacement. Acid stimulation involves chemically etching the rock with injection of reactive fluids such as hydrochloric or hydrofluoric solutions. This process can increase the porosity of the rock through dissolution of in-situ minerals leading to increased permeability but its success is strongly dependent upon rock type. Rock types which are reactive with acid include limestone, chalk and other calcareous rocks. Thermal stimulation involves altering the temperature of the target reservoir rock to induce mechanical deformations. Injection of cold fluid into a hot rock causes contraction of the rock with an associated potential for dilation of existing discontinuities or creation of new cracks (Grant et al., 2013). Cryogenic fracturing with liquid nitrogen injection is an example of a specialized thermal stimulation method having the objective of maximizing temperature change for increased fracturing potential. Shear, acid, and thermal stimulation can be concurrent with hydraulic fracturing or HSRF whether by design or as secondary effects.

1.3 Motivations

The current state-of-the-art for hydraulic fracturing knowledge has significant potential for advancement even with the long history of research and field application after its first published use in 1949 (Clark). Significant areas of interest include better understanding the geometry of hydraulic fractures in non-ideal conditions, the application of hydraulic fracturing to EGS, and the testing of new hydraulic fracturing methodologies.

Questions persist regarding the influence of heterogeneous rock structure on hydraulic fracture geometries, the effect of viscosity and injection rate on fracture geometry, and the prediction of these effects. It is expected that hydraulic fractures can be affected by rock structure but experimental evidence (Ishida et al., 2004) indicates that this interaction is viscosity dependant. Current simplified models typically over-predict fracture permeability and under-predict complexity (Miskimins, 2011; Warpsinski and Teufel, 1987; Vincent, 2011) as a consequence of neglecting the influence of rock structure and other complex phenomena. Better understanding of complex fracture networks requires new physical testing in addition to modeling efforts on the topic.

Applied to geothermal energy, the success of hydraulic fracture stimulations for EGS development remains uncertain. Concerns include excess fluid loss, induced seismicity, prediction and estimation of the fracture zone location, flow short-circuiting and clogging with mineral scale, and optimal design of borehole layouts for energy production. The limited number of field sites necessitates new laboratory-scale testing of EGS to provide experience with the technology and to produce data needed for respective modeling efforts.
There is potential for advancing stimulation technology through the development of new hydraulic fracturing methods. Potential areas of advancement include new high-strain rate fracturing methods and improvement injection schedules for increased post-stimulation fracture conductivity. Physical testing is necessary to validate new hydraulic fracturing methods and build confidence for their potential at the field-scale.

1.4 Research Objectives

The general objective of this research effort is to perform physical hydraulic fracturing experiments at the laboratory-scale and analyze the results to develop an improved understanding of complex hydraulic fracture processes in heterogeneous media. Data collected from these experiments included injection fluid pressures and flow rates, acoustic emissions (AE), stresses and strains, temperatures and hydraulic fracture geometries with a secondary objective of future application to the validation of hydraulic fracture models. Specific models of interest were true-three dimensional solutions in development by Colorado School of Mines, Idaho National Laboratory, and Los Alamos National Laboratory where results with simple and complex hydraulic fracture geometries were required.

Sub-objectives were also devised to guide the research effort and associated dissertation organization. These objectives are as follows:

1. Develop a new heated true-triaxial apparatus for laboratory simulation of EGS.
2. Validate a theoretical mechanical impulse hydraulic fracturing method by physical testing and compare results with conventional hydraulic fracture stimulation.
3. Obtain and analyze physical laboratory-scale data for critical state hydraulic fracture length, height, aperture and three-dimensional complexity. Compare the results with simple hydraulic fracture model assumptions and predictions.
4. Model EGS reservoirs at the laboratory-scale using crystalline rock specimens, multi-well injector and producer layouts, drilling and injection methods comparable to the field-scale, and AE monitoring. Evaluate geothermal fluid flow and heat transfer through these model reservoirs.
5. Investigate the influence of grain-scale fracture mechanisms on macro-scale hydraulic fracture complexity using physical experiments. Acquire data from multiple different specimens using a variety of materials, injection fluids and boundary conditions.

1.5 Organization of the Thesis

This dissertation is organized into 7 chapters. Introduction of hydraulic fracturing theory, EGS technology, terminology and other stimulation technologies was presented in this first chapter. The
second chapter details the materials and equipment used to perform the research. Test materials were
selected to model a variety of hydraulic fracture applications and were characterized by element tests.
Custom heated true-triaxial equipment and hydraulic systems developed in the early stages of this
research are described. The third chapter presents a new mechanical impulse hydraulic fracture (MIF)
stimulation method. Results from experimental application of this method in granite specimens are
presented, analyzed and discussed with field-scale feasibility considered. The fourth chapter presents two
studies of hydraulic fracture geometry using acrylic and granite specimens with epoxy injected to create
the fractures. Hydraulic fracture mechanisms, aperture data, fluid penetration distances and general
complexity are discussed. The fifth chapter presents two experiments with laboratory-scale model EGS
reservoirs. These experiments were performed using the equipment detailed in Chapter 2 and included
thermal evaluation of binary and triplet EGS well layouts. Wells were drilled in a manner similar to that
expected for the field-scale where acoustic emissions (AE) from hydraulic fracture stimulation provide
guidance for deciding production well alignments. The sixth chapter presents a detailed investigation of
grain-scale hydraulic fracture propagation mechanisms, the influence of these mechanisms on complex
macro-scale fracture structures and discussion of how complex fracture geometry can influence fracture
conductivity. This chapter compiles its findings from all specimens tested through the course of this
research project. Conclusions drawn from this research and respective implications are detailed in the
seventh chapter. Recommendations for future studies are also presented in this final chapter.
CHAPTER 2
MATERIALS AND EQUIPMENT

The laboratory-scale hydraulic fracturing experiments used a variety of specimen materials, injection fluids and applied boundary conditions. Material samples subjected to stimulation experiments or element tests are referred to as specimens. Intended boundary conditions were true-triaxial and heated, necessitating the development of new custom equipment. Details regarding the tested materials, equipment specifications and design validation of the equipment are provided in this chapter. Additional information relevant to operation of the true-triaxial apparatus is provided in Appendix A.

2.1 Specimen Materials

Typical and preferred test specimens were 300×300×300 mm³ cubes but smaller specimens were also used when available. Test materials included PMMA acrylic, concrete, granite and limestone with respective material properties given in Table 2.1. Material properties were measured using element tests following the procedures detailed by Frash (2012) and Mokhtari et al. (2014) which are closely based on relevant ASTM standards (ASTM D3967, 2008; ASTM D7012, 2010). Not all properties were measured for all materials.

<table>
<thead>
<tr>
<th>Property</th>
<th>Commercial Concrete</th>
<th>Custom Concrete</th>
<th>Granite</th>
<th>Acrylic</th>
<th>Limestone</th>
</tr>
</thead>
<tbody>
<tr>
<td>Elastic Modulus (GPa)</td>
<td>9.9 ±0.5</td>
<td>24.3 ±5.0</td>
<td>56.9</td>
<td>3.3 ±0.1</td>
<td>-</td>
</tr>
<tr>
<td>Poisson’s Ratio</td>
<td>-</td>
<td>0.22 ±0.03</td>
<td>0.32</td>
<td>0.38 ±0.01</td>
<td>-</td>
</tr>
<tr>
<td>Density (g/cm³)</td>
<td>1.95 ±0.01</td>
<td>2.12 ±0.03</td>
<td>2.63 ±0.03</td>
<td>1.18 ±0.01</td>
<td>2.42 ±0.2</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>31.1 ±0.5</td>
<td>18 ±2</td>
<td>0.8 ±0.1</td>
<td>0</td>
<td>6.3 ±0.8*</td>
</tr>
<tr>
<td>Permeability (µD)</td>
<td>10 to 100</td>
<td>1 to 10</td>
<td>≤1.2</td>
<td>0</td>
<td>0.7 to 7.0*</td>
</tr>
<tr>
<td>Uniaxial Compression Strength (MPa)</td>
<td>53.2 ±3.7</td>
<td>135 ±13</td>
<td>152 ±19</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Indirect Tensile Strength (MPa)</td>
<td>2.47 ±0.25</td>
<td>4.8 ±0.9</td>
<td>7.5 ±1.8</td>
<td>-</td>
<td>7.1 ±3.2*</td>
</tr>
<tr>
<td>Shear Wave Velocity (km/s)</td>
<td>-</td>
<td>2.28 ±0.01</td>
<td>2.62</td>
<td>-</td>
<td>2.6 ±0.2</td>
</tr>
<tr>
<td>Compression Wave Velocity (km/s)</td>
<td>-</td>
<td>3.59 ±0.03</td>
<td>4.45</td>
<td>-</td>
<td>4.7 ±0.7</td>
</tr>
<tr>
<td>Thermal Conductivity (W/m²)</td>
<td>-</td>
<td>2.1 ±0.4</td>
<td>3.1 ±0.05</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Data from (Mokhtari, 2014).

PMMA acrylic (Poly(methyl methacrylate)), shown in Fig. 2.1, was selected as a test material for its homogeneity, transparency and brittle fracture behavior. This material was used to validate laboratory

---

hydraulic fracturing methods where fracture growth could be visually observed. Acrylic specimens included commercially available cylinders of 38 or 76 mm diameter. Fig. 2.1 includes a borehole in the acrylic exhibiting drilling induced fractures in the near-well region. These flaws extended a maximum of 3 mm radially away from the borehole wall. Percussive drilling was used to induce flaws with the intent of producing a near-well damage zone at the laboratory-scale and to provide hydraulic fracture initiation locations. A drilling induced damage zone is expected at the field-scale (Porter, 1989).

![Fig. 2.1. PMMA acrylic with 5.6 mm diameter percussively drilled borehole.](image)

Concretes used included commercially available FastSet® AllSet® grout mix and a custom mix designed for high strength and low porosity, shown in Fig. 2.2 and Fig. 2.3, respectively. The custom concrete was a low-water mix strengthened with high-range water reducer, air remover and microsilica (silica fume). Both concretes included only fine aggregates with the commercial mix containing up to 0.42 mm diameter (40 mesh) sand grains and the custom concrete containing up to 0.30 mm diameter (50 mesh) sand grains. Fine grains were used to reduce the ratio of grain diameter to specimen size for scaling purposes. Specimens produced from these concretes exhibited high homogeneity and higher permeability than the natural rock materials. A 300×300 mm$^2$ rigid steel form was used to cast specimens where excess material from the top was trimmed by diamond sawing to give 300 mm specimen height. Additional details for the custom concrete mix and its development are provided in Frash (2012).
Fig. 2.2. Commercial FastSet® AllSet® concrete grout, rulings are cm.

Fig. 2.3. Custom concrete.
Granite, shown in Fig. 2.4, was obtained from the Liesveld Quarry in Lyons, CO. This material was extracted from an outcrop using water jet cutting and trimmed to size with a diamond wire saw. Major minerals included quartz, feldspars, muscovite, and biotite. Typical crystal grain sizes ranged up to 30 mm in length where larger grains were composites structures containing sub-grains, striations and inclusions. Sub-grains were estimated to have a size range of 0.001 to 0.1 mm from inspection of photomicrographs having 0.0005 mm/pixel maximum resolution.

![Fig. 2.4. Colorado Rose Red Granite.](image)

Limestone, shown in Fig. 2.5, was obtained from the Cemex quarry in Lyons, Colorado, USA. This material was extracted from the Niobrara shale formation using open pit mining methods, which included drilling and blasting. Intact specimens with minimal damage were preferred. Selected specimens sourced from the Fort Hays member of the Niobrara formation, an Upper Cretaceous Age rock and an oil and gas bearing formation. The mineral composition for this material is approximately 86% calcite, 5% quartz and 5% illite with 2.6 total organic content by weight (Mokhtari et al., 2014). This material is also referred to as chalk, shale or marlstone depending upon context and its association with the general Niobrara shale formation. The structure of this limestone included horizontal bioturbated bedding planes, marine fossils and three dominant joint sets with calcite infilling. Two of the joint sets were sub-vertically oriented and crossing at 65º. One of these sub-vertical joint sets was oriented within 10º of the maximum horizontal principal stress during laboratory experiments with true-triaxial conditions applied. The third joint set was dipping at 25º with a strike sub-parallel with the applied maximum horizontal stress.
Bedding planes were oriented horizontally in the true-triaxial apparatus. Joint spacing was varied with a typical range of 10 to 40 mm. Average grain size was less than 0.0005 mm for this calcareous rock however included quartz grains were measured at up to 0.30 mm.

![Fig. 2.5. Ft. Hays limestone member of the Niobrara shale formation.](image)

### 2.2 Injection Fluids

Injection fluids included water, brine, oil, and epoxy with respective properties given in Table 2.2 (White, 2009; ASTM D341, 2009; Valvoline, 2012; Loctite, 2012; Loctite, 2012). These fluids represent a wide viscosity range of 0.35 to 40,000 cP. Hydraulic fracturing with epoxy provided the best geometric data which included clear results regarding fluid penetration, fracture branching and open fracture widths (aperture). Ballotini® glass beads ranging from 0.045 to 0.090 mm diameter (170 to 325 mesh) were added to the injection fluid for proppant in some experiments. The reported viscosity for Do-It-Best® marine epoxy in Table 2.2 is an estimate with an expected accuracy of ±25%.

Hydraulic fracturing experiments using epoxy injection were performed with pre-mixed two part systems. The syringe mixer shown in Fig. 2.6 was used for quality control over the mixing process and to aid placement of epoxy into the injection hydraulic system.

Tap water was selected because it was anticipated that dissolved minerals would buffer chemical reaction with minerals in the granite. No detailed chemical analysis of the tap water was performed due to time and cost constraints. No significant chemical dissolution or precipitation was observed in post-test
cross-sections indicating that fluid residence times and chemical buffering were sufficient to neglect geochemical effects. Water also gave the advantage of well-known thermo-mechanical properties (White, 2009).

Table 2.2. Fluid properties.

<table>
<thead>
<tr>
<th>Fluid</th>
<th>Temperature (°C)</th>
<th>Viscosity (cP)</th>
<th>Density (g/mL)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tap water</td>
<td>23 °C</td>
<td>9.42 \cdot 10^{-1}</td>
<td>0.998</td>
</tr>
<tr>
<td></td>
<td>50 °C</td>
<td>5.46 \cdot 10^{-1}</td>
<td>0.988</td>
</tr>
<tr>
<td></td>
<td>80 °C</td>
<td>3.54 \cdot 10^{-1}</td>
<td>0.971</td>
</tr>
<tr>
<td>Valvoline® 80W90 oil</td>
<td>23 °C</td>
<td>3.23 \cdot 10^{2}</td>
<td>0.887</td>
</tr>
<tr>
<td></td>
<td>50 °C</td>
<td>7.15 \cdot 10^{1}</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>80 °C</td>
<td>2.26 \cdot 10^{1}</td>
<td>-</td>
</tr>
<tr>
<td>Do-It-Best® Marine epoxy</td>
<td>25 °C</td>
<td>\sim 4.00 \cdot 10^{4}</td>
<td>\sim 1.1</td>
</tr>
<tr>
<td>Loctite® E-120HP epoxy</td>
<td>25 °C</td>
<td>\sim 3.00 \cdot 10^{4}</td>
<td>1.1</td>
</tr>
<tr>
<td>Loctite® E-60NC epoxy</td>
<td>25 °C</td>
<td>\sim 8.00 \cdot 10^{3}</td>
<td>1.05</td>
</tr>
</tbody>
</table>

Fig. 2.6. Epoxy mixing syringe.

2.3 Heated True-Triaxial Equipment

Fig. 2.7 shows the heated true-triaxial system for laboratory-scale simulation of multi-borehole hot dry rock (HDR) reservoirs that was developed and tested in the early stages of this research effort. This device applies independently controlled principal confining stresses and elevated temperatures to 300x300x300 mm³ rock specimens. Specimens can be drilled and hydraulically fractured while confinement and heating is applied. This enables simulation of multi-borehole EGS layouts having at least one injection well and one production well. The details regarding the equipment and experimental methodologies used are presented in this subsection. Further details regarding the operation of the apparatus are presented in Appendices A and B.
The true-triaxial system consists of a heated true-triaxial apparatus, a drilling apparatus, a hydraulics system, and an instrumentation system. The combined system features the following capabilities:

1. conﬁning stresses up to 13 MPa
2. externally applied dual-zone heating up to 180 °C
3. continuous ﬂuid injection rates from 0.00001 to 60 mL/min
4. constant pressure injection with proportional-integral-derivative (PID) control at pressures up to 70 MPa
5. high viscosity ﬂuid and proppant-slurry injection
6. oriented multiple-borehole drilling at reservoir conditions
7. digital monitoring of pressure, temperature, and ﬂow rate
8. specimen strain and temperature monitoring
9. acoustic emission (AE) monitoring with source location

**True-Triaxial Apparatus**

A multitude of designs for true-triaxial equipment with application to geomechanics research and material characterization are available in the literature (Mogi, 2007; Kwaśniewski et al., 2013; Johnson and Cleary, 1991; Behrmann and Elbel, 1991; Bo Ibsen and Praastrup, 2002; Chrisholm et al., 1994; Coccia and McCartney, 2012; Daneshy, 1973; de Pater et al., 1994; Ishida et al., 2004; Rawlings et al., 1993; Wieland et al., 2006; Zoback et al., 1977). Rock specimens for these devices are typically rectangular blocks or cylinders. True-triaxial loading conditions are typically developed through hydraulic pistons, flexible bladders or passive conﬁnement (e.g., steel casing). None of the designs found in the literature were suitable for simulation of multi-borehole systems in HDR conditions.
The new apparatus was designed with a mixed flexible bladder (flat jack) and passive confinement system, shown in Fig. 2.8. Each principal stress is applied via one active flat jack per principal axis when using the typical configuration for the apparatus. Specimen faces directly loaded by the flat jacks and the opposing reaction faces supported by the frame are hereby referred to as active and passive faces, respectively. The steel top lid was furnished with a 63 mm diameter port to pass electrical sensor wires and hydraulic tubing for internal sensors and jacks. The reaction ring of the central body was constructed from A36 structural steel with minimum yield strength of 250 MPa. The lids were constructed from A514 steel with minimum yield strength of 700 MPa to reduce thickness requirements following stress design criteria. Sufficient lid thickness was provided to permit drilling multiple non-intersecting 10 mm holes through the lid while maintaining a safety factor of no less than 2.0. Collectively these design elements reduced the cost of fabrication relative to alternative options considered. This was especially important when considering that the structural elements would require replacement after drilling holes eventually compromises structural integrity. The lid of the cell was effectively considered to be a sacrificial component.

Fig. 2.8. Configuration of the true-triaxial apparatus.

Active face stresses are provided by 350 mm diameter circular Freyssinet® flat jacks and an assembly of two 300 mm diameter round steel platens and one 300 mm square steel platen. Circular jacks were selected rather than square because of budgetary constraints. Each flat jack is pressurized via an independent hand pump with active digital pressure monitoring. Using separate pumps bypasses pressure control issues which occur in single pump systems with manifold valves. Specifically, hydraulic systems
tend to leak despite best prevention efforts and valves displace fluid causing associated pressure changes when opened or closed. The square platen’s inward edges were beveled to mitigate binding with adjacent platens. A 25 mm thickness was specified for the square platens referencing elastic stress-deflection analysis and limit yield criterion for stress transmission to the specimen corners. The square platen also provided a protective housing for AE sensors, as shown in Fig. 2.9. This design decision improved AE data quality by ensuring good face-to-face sensor contact with the specimen, reducing noise transmission through the sensor housing and reducing assembly time. A typical alternative AE sensor installation method in similar true-triaxial devices involves cutting shallow holes into the specimen with consequentially increased sensor alignment difficulty, increased assembly time, decreased stress uniformity and likely reduced AE measurement quality.

![Fig. 2.9. AE sensor housing in square platen using open-cell foam to dampen noise transmitted through the steel platen.](image)

Passive faces were supported by a steel platen on the vertical axis and cast-in-place concrete platens on the horizontal axes. The initial design included steel passive platens for all three axes but preliminary testing revealed that tolerances resulted in poor stress uniformity and difficult assembly with this approach. A concrete grout mix with a working time of 6 to 24 hours was poured into plastic bags that filled the gaps on the passive faces. While the concrete remained plastic, the top lid was rapidly installed and a seating vertical stress of 0.1 to 0.5 MPa was applied. The concrete required at least 24 hrs cure time to sufficiently strengthen prior to application of full confinement stresses. Experiments performed using the concrete platens were found to give acceptable stress uniformity through specimen strain gage measurements and AE source distributions during flat jack pressurization. A physical stress calibration was also attempted using pressure sensitive film.
The choice of using only three flat jacks was decided for the typical configuration because it permitted drilling oriented boreholes through all three passive faces of the specimen, enabling borehole orientations ranging from vertical through horizontal. EGS requires flexibility in borehole alignments because fracture-intercepting boreholes are drilled after hydraulic fracture stimulation. Passive faces also enabled drilling at HDR conditions which better simulates field conditions and minimizes complications arising from alternative methods which introduce thermal cycling and cyclic loading. A popular alternative design provides one square flat jack per face of the specimen and requires a specialized open-centered flat jack on the top face for borehole passage. This loading method is expected to develop improved stress uniformity especially when any platens between the flat jack and rock specimen are thin or flexible. In this case, the top flat jack option was too limiting for multi-borehole EGS reservoir simulation. Opposing horizontal axes flat jacks remain an option for the new true-triaxial apparatus and could readily be implemented given the large 63 mm diameter port on the top lid for passage of hydraulic lines. Initial experiments performed with the apparatus have not utilized the opposing flat jack option.

**Heating System**

Heating of the specimen is provided by flexible electrical elements mounted on the external surface of the apparatus. Two 900 W parallel heating elements were mounted on the cylindrical body giving approximately 1800 W of lateral heating capacity. An additional 750 W round heating element was mounted on the bottom plate. Dual-zone PID control allowed different temperature set-points for the lateral and bottom elements. This functionality provided additional control of the vertical temperature gradient through the granite specimen. Firebrick insulation enclosed the whole assembly while heated, improving safety and reducing thermal losses. Thermal conductivity from the electrical elements to the true-triaxial apparatus was assisted by heat sink compound and thermally conductive putty.

**Drilling Apparatus**

Boreholes were drilled into the rock specimen through the true-triaxial apparatus and any intersecting passive platens. A custom rotary hammer drill press (Fig. 2.7) was used to perform the drilling and provide control of borehole trajectory. Care was taken to ensure selected trajectories did not intersect any of the flat jacks or critical internal sensors. Borehole orientation and rate of penetration were controlled with selectable deviation angles of 0°, 15°, 30° or 45° and a screw-actuated shuttle. Rotary-only mode was used for drilling through steel and rotary-hammer mode was typically used for drilling through test specimens. Cobalt Size-X (10.1 mm) drill bits were used to drill through steel. 3/8 in. (9.5 mm) SDS-plus® Bosch® hammer carbide drill bits were used to drill through the test specimens. The percussive drilling action with rotary-hammer mode increased the rate of penetration through rock specimens and created a damage zone in the near wellbore region. Near-wellbore damage due to drilling is typical in
field wells. It is anticipated that having near wellbore damage could influence the hydraulic fracturing process, as predicted by linear elastic fracture mechanics. Millimeter accuracy of borehole alignments was possible with this drilling apparatus.

*Borehole Fluid Injection/Production System*

A diagram of the borehole fluid injection and production system is provided in Fig. 2.10. Dual TELEDYNE ISCO® 65 DM syringe pumps, a computer controlled valve system, a rotationally mixed accumulator, and a high pressure borehole sealing system allowed controlled injection of clean fluid or slurry into a rock specimen for both reservoir flow and stimulation purposes. A vacuum pump and condenser were used for pumping fluids from production boreholes during fluid circulation testing.

![Diagram of the borehole fluid injection and production system.](image)

Fig. 2.10. Borehole hydraulics system showing (a) pump reservoir, (b) valves, (c) syringe pumps, (d) slurry reservoir, (e) rock specimen, (f) condenser, (g) injection borehole and (h) production borehole.

Injection borehole fluid pressures and flow rates were precisely controlled using a custom LABVIEW® program to communicate with the syringe pump controller. An image of the program in operation is shown in Fig. 2.11. Photographs similar to Fig were used to synchronize data across multiple data acquisition platforms, most notably between the hydraulic pump data files and the AE monitoring system. This program featured simultaneous continuous data acquisition and sub-programmable control of the pumps and valves. Sub-programmable control signifies the ability to write or edit pumping programs within the parent LABVIEW® program while the parent program is active. Current features of the injection system and sub-programs include:
1. continuous constant flow rate injection  
2. continuous constant PID controlled pressure injection  
3. stepped constant pressure or stepped constant flow rate injection  
4. conditional pump operation  
5. real time referencing to externally collected data  
6. multi-day operation with uninterrupted 1 Hz appending data output  
7. date-time referencing for multi-sensor synchronization  
8. real-time pump status graphical display with history plotting  
9. internalized editing while the main program is running to prevent real-time data loss  
10. automated switching from clean to slurry fluid injection

Fig. 2.11. Screenshot of the LABVIEW® control program operating a continuous constant flow routine.

The automated valve system consisted of pneumatically-operated hydraulic valves which were operated by a chain of components ultimately controlled by the same program used to operate and monitor the syringe pumps. A horizontal-axis rotationally-mixed piston accumulator with high pressure rotary fittings was used to store and inject proppant slurry into the borehole. The one liter capacity
accumulator was operated in a liquid-liquid mode. Proppant concentration was controlled by rotating the accumulator at experimentally determined homogenous mixing speeds. Fig. 2.12 shows an example calibration of the optimal mixing speed for a slurry of 100 mesh silica sand in water using rotation speeds of (a) 0, (b) 35, (c) 80, (d) 70, (e) 125 and (f) 160 RPM. The internal diameter of the transparent calibration test chamber shown in Fig. 2.12 was equal to that of the high pressure accumulator.

![Fig. 2.12. Sand proppant and water mixing tests at varying RPM.](image)

Injection boreholes were sealed for high pressure fluid injection and hydraulic fracture stimulation using the method shown in Fig. 2.13. The upper borehole was cased with 3/8 in. (9.52 mm) 316 stainless steel tubing installed into a 10 mm diameter borehole and grouted in place using epoxy. The tubing was externally threaded to strengthen the hydraulic seal. Threads were cut with a 3/8-16 hand die to a partial depth where a rough flat tipped thread was produced. Epoxy grout was placed in the borehole using Size-00 gelatin capsules filled with a measured quantity of pre-mixed two-part epoxy. Sufficient epoxy volume was placed to fill the annulus between the tubing and the borehole wall. The capsules were broken at the bottom of the borehole using the tubing with a pre-cured epoxy plug sealing the end. This method reduced the risk of accidentally bonding the tubing to the true-triaxial apparatus. A nominal 5.6
mm diameter uncased hydraulic fracturing interval was drilled to the desired borehole depth after the epoxy was fully cured. This method was experimentally proven to maintain a hydraulic seal at pressures up to 49 MPa. Other methods, such as concrete grouting, were unsuccessful and unreliable.

A different sealing method and pumping system were used for production boreholes, as shown in Fig. 2.14. This system used a combination of ¼ in (6.35 mm) O.D. nylon tubing and a section of larger 3/8 in (9.52 mm) O.D. vinyl tubing for a sheath. A ferrule installed on the inner nylon tubing was pulled into the vinyl sheath to expand the vinyl into the borehole wall and create an air seal. The seal was strengthened using silicon vacuum grease. This method was capable of applying sustained vacuum to the production borehole where fluid was drawn from near the bottom of the borehole. Vacuum was provided by a diaphragm pump and produced fluids were passed through a condenser. A digital mass balance was used to continuously monitor and record the mass of produced water stored in the condenser.

Fig. 2.13. Injection borehole sealing system.

Fig. 2.14. Production borehole sealing system.
**Instrumentation System**

An array of sensors and four data acquisition systems were used to monitor and record test data. A list of the sensors used to monitor the reservoir is provided in Table 2.3 along with a brief description of respective applications, measurement range and accuracy. The data acquisition system included components for measuring temperature, pressure, flow rate, strain, AE and self-potential (SP) (Haas et al., 2012). Acquired data was extensive with intended application to calibration of true three-dimensional hydraulic fracture and EGS models. Sensor accuracies were generally not an issue during experiments because heterogeneities, unknowns about the fracturing process, and other issues led to significantly greater uncertainties.

Table 2.3. List of sensors used during experimentation with ranges and accuracies.

<table>
<thead>
<tr>
<th>Measurement</th>
<th>Mfg. and model</th>
<th>Purpose / Location</th>
<th>Measurement Range</th>
<th>Measurement Accuracy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure</td>
<td>Omega PX309-10KG5V</td>
<td>Wellhead, intermediate confining jack pressure, load frame pressure</td>
<td>0 to 70 MPa</td>
<td>±2% FSO</td>
</tr>
<tr>
<td>Pressure</td>
<td>Omega PX309-3KG5V</td>
<td>Minimum confining jack pressure</td>
<td>0 to 20 MPa</td>
<td>±2% FSO</td>
</tr>
<tr>
<td>Pressure</td>
<td>Omega PX40-50BH5V</td>
<td>Outflow condensing reservoir pressure</td>
<td>0 ± 6.7 kPa</td>
<td>±0.95% FS</td>
</tr>
<tr>
<td>Temperature</td>
<td>Omega TFE-T-24-500</td>
<td>General use type-T thermocouple</td>
<td>-250 to 350 ºC</td>
<td>±0.5 ºC or 0.4%</td>
</tr>
<tr>
<td>Temperature</td>
<td>Omega 5TC-GG-J-24-72</td>
<td>General use type-J thermocouple</td>
<td>0 to 750 ºC</td>
<td>±2.2 ºC or 0.75%</td>
</tr>
<tr>
<td>Strain</td>
<td>Omega SGD-13/120-RY93</td>
<td>Sample surface strain rosettes.</td>
<td>0 to 30000 µs</td>
<td>±(5% + Temp. Effects)</td>
</tr>
<tr>
<td>Acoustic</td>
<td>Physical Acoustics Corporation WSα</td>
<td>AE monitoring</td>
<td>100 to 900 kHz</td>
<td>±1.5 dB directionality</td>
</tr>
</tbody>
</table>

AE events were monitored using a Physical Acoustics Corporation (PAC) AE monitoring system with six WSα sensors and three PCI-2 cards mounted in a Micro-II chasis. AE sensors were typically placed on test specimen surfaces using the arrangement shown in Fig. 2.15. The sensors were attached directly to the specimen faces, using a thin layer of vacuum gel for coupling, to attain direct AE measurements with minimal reflection, surface interference, sensor orientation error, or attenuation effects. The use of six sensors also enabled application of moment-tensor analysis to classify recorded AE events according to failure mode, being tensile dominated, shear dominated, or mixed-mode. Simplified moment-tensor analysis (Ohtsu, 1995) requires p-wave first arrival characteristics at a minimum of six locations to calculate the six unknown components of the respective moment-tensor. The accuracy of this approach improves when positioning the sensors around the volume of interest at varying orientations and with maximum volumetric coverage. Placing the sensors near the corners of the specimen (Fig. 2.19) and including orientations parallel to all principal axes optimizes the six sensor system to produce data with
sufficient quality for simplified moment-tensor analysis. AE data quality was improved when a buffer layer of open cell foam was inserted between the sensor body and the steel platen housing to dampen AE signals transmitted through the steel platens. Specimen materials with low attenuation and nearly-isotropic acoustic velocity produced the most successful simplified moment-tensor results (Hampton, 2012).

Fig. 2.15. AE sensor positions for true-triaxial testing.

2.4 Test Procedures

A typical setup for the simulation of EGS using the true-triaxial equipment is described in this section and additional details are given in Appendix A. EGS simulation tests can generally be described according to the three stages of:

1. rock specimen preparation
2. reservoir simulation
3. post-test analysis

Procedures used in each of these stages are described following sequential order. Typical reservoir simulations performed using this equipment were long in duration to reduce risk of thermal cracking during heating, to allow for epoxy and concrete cure times (typically 24 hours or less each) and to execute the hydraulic fracture stimulations, reservoir flow tests, and re-stimulations necessary for detailed EGS reservoir evaluation. Most tests lasted from 3 to 90 days.
Rock Specimen Preparation

Rock specimens with poor surface tolerance were capped with a thin molded layer of non-shrink concrete grout. Experiments using this concrete capping technique successfully provided improved stress uniformity as evident from strain gage measurements. The following typical steps were used for rock specimen preparation and assembly of the true-triaxial equipment:

1. the rock specimen was prepared to the nominal dimensions of 300x300x300 mm³ with a surface tolerance of ±0.5 mm and perpendicularity of ±1°
2. sensors were installed on the specimen and attached wires were routed to the corners or edges of the specimen to avoid damage from the active and passive platens
3. active platens and flat jack assemblies were installed into the cell while the top lid was removed, as shown in Fig. 2.8
4. the rock specimen was carefully lowered into the cell and pressed into the flat jack assemblies to close tolerance gaps
5. passive concrete platens were placed and the top lid was installed
6. a vertical seating stress of no more than 0.5 MPa was applied and maintained
7. passive concrete platens were given 24 hours to achieve sufficient early cure strength
8. the rock specimen was heated to the target temperature at a rate no faster than 10 °C per day
9. confining stresses were applied at proportional increments of more than 0.7 MPa
10. stresses and temperatures were monitored for at least 48 hours to verify equilibrium

Reservoir Stimulation

EGS simulation was performed after targeted HDR conditions were applied and equilibrated. Typical EGS simulations used the following procedure which was designed to be flexible and adaptive to observations recorded during the process:

6. the injection borehole was drilled along the desired trajectory
7. casing was installed into the injection borehole and sealed with epoxy grout
8. the epoxy was given at least 24 hours to achieve full cure
9. the open interval of the injection borehole was drilled
10. constant 2 MPa injection was performed to evaluate leakage and measure pre-stimulation well injectivity
11. hydraulic fracture stimulation was performed
12. AE source location data was used to estimate induced fracture geometry
13. a fracture intercepting production borehole alignment was selected and drilled
14. the borehole was swabbed to verify fracture interception by evidence of fracturing fluid
15. hydrothermal flow testing experiments were performed
16. additional stimulation treatments and flow testing was performed as needed to create and characterize a simulated EGS reservoir

Experiments identified that an injection rate of 0.05 mL/min was suitable for creating hydraulic fractures fully contained within the confines of most 300 mm rock specimens. PKN modeling (Kumar and Gutierrez, 2011; Frash, 2012) was initially used to determine that flow rates in the range of 0.01 to 0.10 were suitable for creating slow and controlled fractures in 300 mm rock specimens. Respective results from the PKN modeling are shown in Table 2.4 where shaded values indicate fractures extending beyond 150 mm where breakthrough at the surface of the specimen would occur. Assumptions for this modeling included a fracture height of 20 cm, fluid viscosity of 0.9 cP (water), isothermal temperature of 25 ºC, rock elastic modulus of 57 GPa, and Poisson’s ratio of 0.32. The goal of these numerical models was to identify a suitable injection rate for design such that hydraulic fractures were expected to propagate on a timescale which could be captured adequately by a 1 Hz sampling rate data acquisition system. Faster injection rates were applied if the initial rate failed to stimulate a hydraulic fracture. Faster rates were typically necessary for specimens exhibiting high initial injectivity or high fracture toughness, as could be predicted by combining fracture initiation theory with transient flow theory for porous media.

Table 2.4. PKN model results for approximating suitable hydraulic fracturing injection rates.

<table>
<thead>
<tr>
<th>Pumping Time (min)</th>
<th>Fracture half-length (mm) at given injection rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.01 mL/min</td>
</tr>
<tr>
<td>5</td>
<td>30</td>
</tr>
<tr>
<td>10</td>
<td>52</td>
</tr>
<tr>
<td>15</td>
<td>72</td>
</tr>
<tr>
<td>20</td>
<td>90</td>
</tr>
<tr>
<td>25</td>
<td>108</td>
</tr>
<tr>
<td>30</td>
<td>124</td>
</tr>
</tbody>
</table>

Hydrothermal Flow Testing Procedure

Hydrothermal flow testing typically included a series of injection-production tests with constant pressure or constant flow rate control. Injections were performed as single stage tests or programmed stepped interval tests. Programmed pumped injection modes included constant flow rate (CF), constant pressure (CP), stepped constant flow rate (SCF) and stepped constant pressure (SCP) injection. A series of flow characterization tests were typically performed before and after each stimulation treatment. The specific characterization tests for a given experiment were selected based upon the observed reservoir behavior and the experimental variables being investigated.

Data produced by stepped injection tests was analyzed by a fixed routine intended to reduce bias. Step intervals were typically 15 or 30 minutes in duration but longer injections were sometimes necessary.
for achieving thermal equilibrium. Example raw data from a SCP test is shown in Fig. 2.16. Individual steps were isolated as shown in Fig. 2.17 and data from the final 30% of each step was used for analysis. Pressures were determined as the average value over the 30% intervals and flow rates were calculated by linear regression of the pumped volume data for injection and condenser mass data for production. Results from all the steps were compiled into representative curves for each test as shown in Fig. 2.18.

![Fig. 2.16. Example raw data from SCP test.](image1)

![Fig. 2.17. Example analysis of single step data.](image2)
Post-test Analysis

The true-triaxial apparatus was unloaded after completion of reservoir simulation using the following procedure:

1. true-triaxial stresses were slowly released while AE monitoring was active
2. temperatures were reduced to ambient at no greater than 10 °C per day
3. the top lid and top passive platen were removed
4. the rock specimen was slowly ejected from the cell using a hydraulic jack
5. the rock specimen was inspected
6. cross-sections were cut from the rock specimen for geometric analysis of the created fractures

This procedure ensured minimal secondary damage to the specimen during unloading and overcame residual stresses produced by the lateral flat jacks. Alternative to cut cross-sections, non-destructive techniques (e.g., computed X-ray tomography) could be used at expectedly higher cost. Cross-sectioning was the preferred fracture geometry analysis method for this project due to budget.

Procedure Variations

The specific procedure applied for a given test was varied according to relevant experimental objectives and observed results. Data acquisition was continuously active, whenever possible, to record any events occurring from initial assembly through to final disassembly. This method ensured that thermally induced fractures, creep phenomena and other secondary processes to stimulation and flow were captured for identification. This approach was applied during multi-day testing resulting with extensive data produced for each test. Data was synchronized and date-time referenced for subsequent analysis and comparison between any data types.
2.5 True-Triaxial Calibration

A notable consequence of the three-flat-jack design used for this true-triaxial apparatus is the potential for increased frictional effects between the rock specimen and platens. Friction is known to affect stress uniformity which is of critical concern for conventional true-triaxial testing (e.g., evaluation of material yield criterion in anisotropic stress conditions). Rock stresses are also important in EGS and reservoir simulation because they are known to be the dominant factor controlling hydraulic fracture growth (Warpinski et al., 1982). Principal stress directions control fracture propagation direction and stress magnitudes affect fluid pressures and flow. The rock specimen stress conditions relevant to preliminary experiments performed with this true-triaxial equipment were evaluated using computer modeling, a physical calibration test and strain gage measurement.

Optimal Borehole Placement

Hydraulic fracturing for EGS is intended to target deep reservoirs (e.g., 3 to 10 km) which are reasonably assumed to have pseudo-infinite lateral extent for modeling purposes. A discrete reservoir boundary is inherent to laboratory testing but boundary effect’s influence can be reduced if created hydraulic fractures are fully contained within the confines of the rock specimen. Optimal placement of an injection borehole for producing contained fractures would therefore be the center of the specimen. Most experiments performed for this study used vertical centered borehole alignments.

Finite Element Stress Modeling

Finite Element (FE) modeling was performed to evaluate the combined effects of friction, AE sensor housings, unloaded edges and platen corners on the stresses inside the rock specimen. The model was constructed as shown in Fig. 2.19 with geometry and material parameters approximating the real true-triaxial apparatus (Frash, 2012). The steel comprising the loading plates and the cell assembly were assigned an elastic modulus of 200 GPa and a Poisson’s ratio of 0.26, representing ASTM A36 mild steel. The rock specimen was modeled as granite with an elastic modulus of 56.9 GPa and a Poisson’s ratio of 0.32, referencing values measured from element tests. Loading was applied with a constant force boundary condition on the 300 mm diameter round platens to induce a targeted average rock specimen stress state of 13, 8, and 4 MPa for the vertical and horizontal directions respectively. These same targeted stresses were applied during some actual laboratory experiments. Multiple simulations were performed to evaluate the effect of friction along the platen-rock interface. Frictional coefficients of 0.005, 0.02, and 0.30 were assigned to represent states of negligible friction, two-layer Teflon sheets with silicone grease (Demiris, 1987) and typical steel-steel contact, respectively. A fully bonded model representing maximum friction was also analyzed. All numerical simulations were performed using SolidWorks® Simulation.
Fig. 2.19. Finite element model for stress uniformity evaluation.

Fig. 2.20 provides a plot of the FE results for the minimum horizontal stress along a line traversing vertically through specimen’s center. These results indicate clamping stresses near the boundaries which could potentially aid in hydraulic fracture containment. They also indicate a non-uniform stress distribution with the most significant stress deviations near the active face. Stresses were more uniform through the center of the specimen up through interception with the passive face. Frictional effects were found to be negligible for the minimum horizontal stress state implying that use of Teflon sheets or other friction reduction methods would have little effect on hydraulic fracture propagation.

Fig. 2.20. Modeled minimum horizontal stress profile traversing vertically through specimen center.
Fig. 2.21 presents a plot of the modeled vertical and horizontal normal stresses with an assigned friction coefficient of 0.30. These results indicate that the principal stress directions were consistent through the rock specimen, which is important for fracture propagation and final geometry. All three stress axes exhibited relatively uniform distribution near the center of the specimen.

The platen corners and AE sensor housings were the dominant factor causing reduced stress uniformity on the active faces. This effect is evident in Fig. 2.22 through the low stresses predicted at the specimen corners. These plots represent the FE model results assuming low friction and high friction contact models with distributed loading applied to the circular platens. Applied forces are shown as red vectors in the figure where the loading areas of the 300 mm diameter platens are evident. One corner of the cubical specimen is not included in the plot to aid visualization of the specimen’s interior stresses. All plotted values represent the calculated stresses in the $x$-direction which corresponds with the least principal horizontal stress ($\sigma_h$). The target stress for the minimum principal axis was 4.0 MPa and is indicated by the arrow on the color bar scale.

Using square flat jacks would improve stress uniformity but this option was unfortunately beyond the available budget. It is fortunate that the modeling results indicate some level of stress uniformity inside the specimen despite the use of circular flat jacks. This relatively uniform stress zone is visible in both Fig. 2.20 and the interior of Fig. 2.22.
Strain Gage Measurement

Specimen strain gage data was acquired during some of the experiments performed with this true-triaxial apparatus. The configuration of the surface mounted gages varied with each experiment dependant upon respective objectives. Resulting strain gage data generally indicated poor stress homogeneity on the specimen surfaces. Stress uniformity was observed to improve when the specimen faces were capped with concrete to improve surface tolerances. Data collected from the strain gages was not very reliable due to issues with damaged sensor wires, fragile electrical connections between the sensor wires and the gages, and high sensitivity to temperature changes. Difficulties with strain gages are common when the fragile gages are incorporated into heavy equipment such as this true-triaxial apparatus. Attempts to modify procedures to improve the reliability of strain gage readings were only slightly successful. Less than 80% of the installed gages typically provided reliable data when implemented because of incidental damage during installation and assembly.

Physical Test of Stress Uniformity

A physical test of stress uniformity inside the true-triaxial apparatus was attempted using a split concrete specimen and pressure sensitive photo-film. The cast concrete specimen is shown in Fig. 2.23 and was oriented to have a split-face perpendicular with the least principal stress axis, following the expected plane of tensile hydraulic fracture propagation. The concrete specimen was cast in two halves separated by a thin sheet of plastic. The bottom-half of the specimen was allowed to set prior to placement of concrete for the upper-half within the concrete form. This method was selected to achieve tighter contact tolerances than would be expected for a single specimen sawed into two halves.
Fig. 2.23. Cast concrete specimen for physical stress calibration test.

Results from the photo-film are shown in Fig. 2.24 where pink colored areas indicate zones of higher stress. These results were ultimately inconclusive due to a slight misalignment of the two halves of the concrete specimen. Stresses were consequentially attracted to a minor irregularity in the cast concrete faces and zones where adjacent sections of pressure-sensitive film were slightly overlapping.

Fig. 2.24. Result from physical test of stress uniformity.

A second series of tests was performed to experiment with the accuracy of the FujiFilm® pressure sensitive film. These tests used a hydraulic loading frame and stack of 101 mm diameter steel platens as
shown in Fig. 2.25. A color correlation chart for calculating contact stresses from color density is included in Fig. 2.25. This color chart was provided by the film supplier and is used along with additional plots and humidity data in a method to quantify the contact stresses. Surface roughness and clamping stresses caused significant stress localization along the interface even in this relatively ideal testing environment. The target stress for this test was 700 psi (4.8 MPa) and the color scale ranges from 350 to 1400 psi (2.4 to 9.7 MPa). White indicates negligible stress transfer. A comparison of this relatively ideal test data with the data from the true-triaxial test brings the reliability of this calibration test into question, especially in regard to quantitative calibration.

Fig. 2.25. Experimentation with pressure sensitive film using machined steel platens.

**Final Design Rationale**

The motivation for using 350 mm diameter flat jacks with 300 mm square steel platens was budgetary. Modifying the apparatus to a 300 mm square flat jack system would be a simple task and would mitigate most of the undesired stress concentration issues. Preliminary experiments did not utilize specialized friction reduction options such as Teflon sheets. The sheets were expected to increase difficulty of assembly and induce errors in AE data through refraction and reflection through the additional material interface. The benefit to stress uniformity in the minimum principal stress plane, being the expected hydraulic fracture propagation plane, was expected to be less important than attaining higher quality AE data.
CHAPTER 3
MECHANICAL IMPULSE HYDRAULIC FRACTURING

Mechanical impulse hydraulic fracturing (MIF) is a high strain-rate fracturing (HSRF) method for well stimulation that was developed and tested during this research effort. MIF uses a mechanical energy source as an alternative to rapid-gas expansion which is common to other HSRF methods (e.g., propellant combustion, gas impulse stimulation, explosive fracturing etc.). Laboratory tests of MIF were performed in two granite specimens with dimensions of $300 \times 300 \times 240$ mm$^3$ and $300 \times 300 \times 300$ mm$^3$, respectively. The first specimen was unconfined at room temperature conditions while the second was subjected to heating and true-triaxial confinement. Applied conditions for the confined specimen were selected to simulate EGS. Stimulation treatments included conventional hydraulic fracturing, re-fracturing and MIF, sequentially. Stimulated well injectivity was evaluated with a series of step constant pressure (SCP) and step constant flow (SCF) injection tests. Field-scale viability of MIF was evaluated using elastic mechanics and thermodynamics.

3.1 MIF Method

Hydraulic impulses in a wellbore can be generated mechanically using accumulators, hammers, or high velocity pistons. Respective devices can be installed at the surface or down hole. Working fluids can be isolated from the well fluids dependant upon design form. Mechanical impulses generated by these devices can be calibrated and controlled to create targeted pressure impulse magnitudes in the wellbore. This direct control capability contrasts with conventional hydraulic fracturing where pressures are controlled by the rock’s response to injection and frictional losses, estimable using Eqs. 1.1 and 1.13 or more advanced modeling methods.

MIF Using Surface Accumulator

MIF in this study used a surface accumulator with the simple hydraulic system shown in Fig. 3.1. This system includes a minimum of a fluid reservoir, pump, valves, accumulator and well. MIF was performed by first closing the well isolation valve and pressurizing the upstream hydraulics system to the target treatment pressure. The downstream hydraulics and well were maintained at a lower pressure aqueous state, being hydrostatic during laboratory experiments. Next, the pumps were stopped while the upstream hydraulic pressure was maintained. The pump isolation valve can be closed after the pumps are stopped to maintain the stored fluid pressure and energy in the accumulator and to protect the pump from potential damage. Finally, the MIF impulse was generated by opening the well isolation valve and

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2 Modified from paper by Luke P Frash, Marte Gutierrez and Jesse Hampton submitted for peer review and publication in SPE Journal.
allowing the upstream fluid to contact the downstream fluid. Rapid contact between high and low pressure fluids produced a dynamic pressure impulse in the well followed by a transient pressure decline with associated fluid flow into the well. The volume of fluid injected with this MIF method is a function of the upstream fluid pressure and the hydraulic compliance of the accumulator system, well and connecting hydraulics.

![Simplified hydraulic system for MIF.](image)

An idealized MIF treatment plot is shown in Fig. 3.2 where conventional hydraulic fracture data is overlain for comparison. An impulse pressure greater than the conventional hydraulic fracture breakdown threshold was selected for this example to emphasize that MIF can allow for treatment pressures to be specified values rather than a consequential result of and reservoir rock response and pumping capacity. The following linear hydraulic compliance relationship was applied to create the plots for each treatment:

\[
V_{\text{stored}} = mP_{\text{well}}
\]

(3.1)

where, \(V_{\text{stored}}\) is the stored volume of fluid in the hydraulics due to compliance, \(m\) is a hydraulic compliance coefficient expressed as change in stored fluid volume per unit pressure change and \(P_{\text{well}}\) is the well pressure. The slope of the initial pressure rise in the conventional hydraulic fracture curve was used as an estimate for \(m\) assuming minimal fluid leakoff. Injected fluid volumes for both MIF and conventional hydraulic fracture curves were calculated using the same value for \(m\). The conventional hydraulic fracture data was produced by a physical laboratory test in concrete. Element tests measured an indirect tensile strength of 2.5 ± 0.3 MPa for the concrete.
The MIF pressure falloff curve in Fig. 3.2 was created from the following assumed three-term explicit finite-difference relationship:

\[ P_i = P_{i-1} - \left( P_{\text{max}} - P_{\text{EQ}} \right) e^{(-Ct)} \times \Delta t - BP_{i-1}\Delta t \]  

(3.2)

where \( P \) is the well pressure at a given time step, \( P_{\text{max}} \) is the maximum MIF impulse pressure set at 8000 kPa, \( P_{\text{EQ}} \) is an assumed asymptotic well pressure for the exponential term taken as 1000 kPa, \( C \) is a constant taken as 20, \( B \) is a constant taken as 0.3 and \( \Delta t \) is a time step for advancing from \( t_0 \) to \( t_i \) which was set at 0.01 min. This relationship used the following empirical relationships:

\[ \frac{\partial P}{\partial t} = \left( \frac{\partial P}{\partial t} \right)_A + \left( \frac{\partial P}{\partial t} \right)_B \]  

(3.3)

\[ \left( P \right)_A = \left( P_{\text{max}} - P_{\text{EQ}} \right) e^{-Ct} \]  

(3.4)

\[ \left( \frac{\partial P}{\partial t} \right)_B = -BP\Delta t \]  

(3.5)

which assume an asymptotic pressure decay function for the dynamic impulse and a linear pressure decay function for pseudo-steady flow following a linear Darcy flow model. This model is intended only to visually approximate observed data from physical tests, not quantitatively model the physics of a MIF treatment. Increased MIF treatment fluid volumes can be achieved by increasing the maximum impulse pressure or the hydraulic compliance coefficient. Adding an accumulator upstream of the well isolation valve or increasing the volume of the accumulator are simple methods for increasing the hydraulic compliance coefficient.
Laboratory-Scale MIF

MIF functionality in the laboratory experiments was achieved using the hydraulics system detailed in Fig. 2.10. A single syringe pump used for pressurization. It was discovered that the small treatment volumes needed for MIF at the laboratory-scale could be provided by hydraulic compliance of the pump, valves cavities and tubing alone. The accumulator was therefore removed from the hydraulics system for the laboratory-scale MIF experiments. The filter element was also removed from the injection tubing to reduce flow constriction and decrease pressure damping. The valve immediately upstream of the filter element was closed for upstream pressurization and opened to initiate the hydraulic impulse. No pump isolation valve was needed because the pumps were not susceptible to damage from the impulse.

3.2 Experimental Results

Each granite test specimen was unique, subjected to different confinement conditions, and injected with an extensive series of stimulation and injectivity characterization tests. Well injectivity was observed to increase in both specimens after stimulation treatments but a dominant increase was associated with MIF. Results from each specimen are presented along with insights gained from analysis of cross-sections cut after testing.

Unconfined Granite Experiment, G01-00

The unconfined 300×300×240 mm³ granite specimen is shown in Fig. 3.3. An identifying ID of G01-00 was assigned to this specimen for easier referencing. Fluid injection was performed through a vertical borehole with an upper 101 mm deep cased interval and a lower 51 mm length uncased (open) interval, giving a total borehole depth of 152 mm. This specimen contained heterogeneity which interacted with fracture growth.

Fig. 3.3. G01-00 granite specimen showing borehole placement and sensor positions.
Multiple stimulation and injection tests were performed at 25 °C room temperature over a period of 25 days following the schedule provided in Table 3.1. The general sequential plan for this experiment procedure was to hydraulically fracture the specimen, evaluate the stimulated injectivity, perform MIF, and re-evaluate injectivity.

Table 3.1. Injection schedule for G01-00

<table>
<thead>
<tr>
<th>General Stage</th>
<th>Fluid</th>
<th>Stage Type and Number</th>
<th>Stage Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Setup</td>
<td>Air</td>
<td>CP #1</td>
<td>2000 kPa</td>
</tr>
<tr>
<td>Fracturing</td>
<td>SAE 80W90 Oil</td>
<td>CF #1</td>
<td>0.05 mL/min (hydraulic fracturing)</td>
</tr>
<tr>
<td></td>
<td>321 cP @ 23 °C</td>
<td></td>
<td>Drilling intercept borehole</td>
</tr>
<tr>
<td>Injectivity</td>
<td>Water</td>
<td>CP #2</td>
<td>2000 kPa</td>
</tr>
<tr>
<td>Testing</td>
<td>0.94 cP @ 23 °C</td>
<td>CP #3</td>
<td>8000 kPa</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #2</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #1</td>
<td>9000 kPa maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #1</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #2</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #3</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #4</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #5</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #3</td>
<td>0.1 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #4</td>
<td>0.3 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #5</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #2</td>
<td>9000 kPa maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #6</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #7</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #8</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #9</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td>MIF</td>
<td>Water</td>
<td>MIF #1</td>
<td>76,000 kPa upstream</td>
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<tr>
<td></td>
<td>0.94 cP @ 23 °C</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Injectivity</td>
<td>Water</td>
<td>CF #10</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td>Testing</td>
<td>0.94 cP @ 23 °C</td>
<td>CF #11</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #12</td>
<td>1.0 mL/min</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #6</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #7</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCF #8</td>
<td>1.0 mL/min maximum</td>
</tr>
<tr>
<td>Injectivity</td>
<td>SAE 80W90 Oil</td>
<td>SCP #3</td>
<td>2000 kPa maximum</td>
</tr>
<tr>
<td>Testing</td>
<td>321 cP @ 23 °C</td>
<td>SCP #4</td>
<td>4000 kPa maximum</td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #5</td>
<td>10,000 kPa maximum</td>
</tr>
</tbody>
</table>

Results from the hydraulic fracture stimulation are shown in Fig. 3.4. Fracturing was performed with constant flow rate injection of Valvoline® DuraBlend® SAE80W90 Gear Oil at 0.05 mL/min. This oil has a viscosity of 321 ± 70 cP at 23 ± 2 °C, estimated following ASTM D341 (2009). Injection was continued for 14 hrs in an unsuccessful attempt to reach a stable flow condition. Multiple pressure peaks were observed indicating continued fracture growth despite the first visual indication of fracture breakthrough to the surface of the specimen occurring within the first 2 hrs of injection. Also of note was
the high initial breakdown pressure of 33 MPa and peak pressure of 49 MPa while the theoretically predicted breakdown pressure was 7.5 ± 1.8 MPa by Eq. 1.1. Other experimental works also observed higher breakdown pressures during scaled experiments where smaller borehole diameters result with increased required breakdown pressures (Haimson and Zhao, 1991).

![Graph of Pressure and Flow Rate over time](image)

**Fig. 3.4.** Hydraulic fracturing of G01-00 with SAE 80W90 oil injection.

Localized AE events from the initial 2 hours of hydraulic fracturing are shown in Fig. 3.5. These events were filtered with a minimum correlation coefficient of 0.99 and minimum amplitude of 35 dB. Correlation coefficient is statistical term ranging from 0 to 1 which provides and indication of confidence in location as estimated by regression analysis. A correlation coefficient of 1 indicates no calculable error in the AE event hypocenter. The location of the borehole is shown in black on Fig. 3.5 and most AE events were located within a close proximity to the injection borehole. AE events generally coincide with the actual fracture locations observed from post-test cross-sections.

After hydraulic fracturing, the injection fluid was changed to tap water at 23 ± 2 ºC with corresponding viscosity of 0.94 ± 0.05 cP (White, 2009). A series of injection tests were performed to flush the bulk of the oil out of the stimulated fractures and to characterize the well injectivity after stimulation. The last three SCP injections were performed with SAE 80W90 oil but the resulting data was poor quality due to mixed phase flow. Results from SCP #3, #4, and #5 are therefore neglected from this analysis.
Fig. 3.5. AE source locations for first 2 hours of hydraulic fracturing in G01-00.

Results from the MIF stimulation are shown in Fig. 3.6. This data was acquired at 1 Hz due to limitations of the digital acquisition system. The pressure decline curve was successfully recorded and indicates a steady flow of fluid into the granite specimen following the impulse. Note that this flow was produced by hydraulic compliance rather than active pumping. Unfortunately the acquisition rate was too slow to precisely characterize the pressure impulse and peak treatment pressure.

An analysis of subsequent SCP and SCF data showed a significant two-order magnitude injectivity increase after MIF (Fig. 3.7). Overlap of SCP data across consecutive tests indicated that the stimulated fractures were nearly stable during water injection. Minimal AE activity during injection provided additional evidence that the fractures were stable and not propagating. SCP injection was found to produce more repeatable results than SCF, plotted with circle and triangle points respectively. Additional analysis of the data with a focus on flow repeatability and its expected significance is given in Frash et al. (2013a).
Fig. 3.6. MIF pressure and injected fluid volume for G01-00 with reference to hydraulic fracture (HF) data.

Fig. 3.7. Analyzed injection data for G01-00 exhibiting a significant injectivity increase after MIF.

The granite specimen was sliced horizontally into 25 mm thick sections after the completion of injection testing. An example cross-section with highlighted fracture lines is provided in Fig. 3.8 along with a diagram of the final three-dimensional fracture network. Cross-sections revealed that multiple fracture wings were created, all of which originated at the uncased interval of the wellbore. Ten radial fractures were identified in the near wellbore region and these fractures were observed to transition into
four dominant fracture planes, three sub-vertical and one dipping at approximately 60°. Surface expression of the fractures indicated that the dominant wings propagated during conventional hydraulic fracturing.

Evidence of fracture short circuiting was identified near the wellbore by close inspection of the cross-sections. Fracture short circuiting can be characterized by multiple sub-parallel fracture strands where one strand dominates over others while also exhibiting a shorter flow path. A short circuiting fracture can be expected to exhibit a higher permeability than the more tortuous adjacent fractures. Short circuiting indicated that new fractures were likely created by the MIF treatment.

Confined and Heated Granite Experiment, G01-90

The 300×300×300 mm³ granite specimen used for the heated and true-triaxially confined experiment is shown in Fig. 3.9. An identifying ID of G01-90 was assigned to this specimen. A discontinuous band of quartz-rich material is visible in the specimen. The quartz band was later observed to resist fracture growth. The specimen was heated to 50 °C and subjected to confinement of 12.5, 8.3, and 4.1 MPa for the vertical, intermediate and minimum principal stresses, respectively. These conditions simulate a dry, tectonically stressed, and low-temperature EGS reservoir at roughly 460 m depth. A centered vertical injection borehole with 107 mm cased depth and 74 mm uncased length was drilled into the specimen while confined and heated conditions were maintained.

The schedule of stimulation and injection tests applied to G01-90 is detailed in Table 3.2. These injections included one conventional hydraulic fracture stimulation, two hydraulic fracture re-stimulations, and one MIF stimulation. All injection tests were completed over a period of 106 days.
<table>
<thead>
<tr>
<th>General Stage</th>
<th>Fluid</th>
<th>Stage Type and Number</th>
<th>Stage Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Setup</strong></td>
<td>Air</td>
<td>-</td>
<td>Heating to 50 ºC</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-</td>
<td>Application of confining stresses</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-</td>
<td>Drilling injection borehole</td>
</tr>
<tr>
<td><strong>Hydraulic Fracturing</strong></td>
<td>SAE 80W90 Oil 68 cP @ 51 ºC</td>
<td>CP #1 2000 kPa</td>
<td>0.05 mL/min (hydraulic fracturing)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #1 0.05 mL/min</td>
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<tr>
<td></td>
<td></td>
<td>-</td>
<td>Drilling production borehole</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP #2 2000 kPa</td>
<td>(excess leakage)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP #3 3000 kPa</td>
<td>(excess leakage)</td>
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<tr>
<td></td>
<td></td>
<td>CP #4 4000 kPa</td>
<td>(excess leakage)</td>
</tr>
<tr>
<td><strong>Re-fracture #1</strong></td>
<td>SAE 80W90 Oil 68 cP @ 51 ºC</td>
<td>CF #2 0.05 mL/min (re-fracture #1)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP #5 4000 kPa</td>
<td>(excess leakage)</td>
</tr>
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<td></td>
<td></td>
<td>SCP #1 2000 to 6000 kPa</td>
<td>(excess leakage)</td>
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<td></td>
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<td>SCP #2 2000 to 6000 kPa</td>
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<tr>
<td><strong>Re-fracture #2</strong></td>
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<td>CF #3 0.05 mL/min (re-fracture #2)</td>
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<td></td>
<td></td>
<td>SCP #7 2000 to 6000 kPa</td>
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<td></td>
<td>SCP #1 Stepped constant flow #1</td>
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<tr>
<td><strong>Injectivity Testing</strong></td>
<td>Water 0.55 cP @ 50 ºC</td>
<td>CF #4 0.05 mL/min</td>
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<td></td>
<td></td>
<td>CF #5 0.10 mL/min</td>
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<tr>
<td></td>
<td></td>
<td>SCF #2 0.05 to 3.0 mL/min</td>
<td></td>
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<td></td>
<td></td>
<td>CP #6 2000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #8 2000 to 6000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP #8 2000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #9 2000 to 4000 kPa (interrupted)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #10 2000 to 6000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #6 0.05 mL/min</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>CF #7 1.0 mL/min</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CP #9 2000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #11 2000 to 6000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #12 500 to 10,000 kPa</td>
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<td></td>
<td></td>
<td>SCP #13 500 to 10,000 kPa (interrupted)</td>
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<tr>
<td></td>
<td></td>
<td>SCP #14 500 to 10,000 kPa</td>
<td></td>
</tr>
<tr>
<td><strong>MIF</strong></td>
<td>Water 0.55 cP @ 50 ºC</td>
<td>SCP #15 500 to 7000 kPa</td>
<td></td>
</tr>
<tr>
<td><strong>Injectivity Testing</strong></td>
<td>Water 0.55 cP @ 50 ºC</td>
<td>SCP #16 500 to 6000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #8 0.5 mL/min</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #9 1.0 mL/min</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #10 3.0 mL/min</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #11 5.0 mL/min</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCP #17 500 to 6000 kPa</td>
<td></td>
</tr>
</tbody>
</table>
Resulting pressure and flow curves from the three hydraulic fracture stimulations are provided in Fig. 3.10. SAE 80W90 oil with a viscosity of $68 \pm 6$ cP at $51 \pm 2$ ºC (ASTM D341, 2009) was injected for stimulation at a rate of 0.05 mL/min for all three of these stimulations. The initial breakdown was brittle with a peak pressure of 18.0 MPa and the two re-stimulation peak pressures were 15.4 and 17.4 MPa, sequentially. All of these peak pressures were greater than the theoretically predicted breakdown at 11.8 MPa calculated with Eq. 1.1. The similar magnitude peak pressure between each treatment indicated that fracture toughness effects were secondary to fluid viscosity and borehole scaling effects. Work by de Pater et al. (1994) suggested that hydraulic fracture scaling laws could be satisfied, in part, if fracture toughness effects were negligible relative to flow effects. The injected fluid volume data in Fig. 3.10 was corrected using a linear hydraulic compliance relation with a slope, $m$, of $5.7 \times 10^{-2}$ mL/kPa following Eq. 3.1.

AE event locations associated with these three treatments are shown in Fig. 3.11. Extension of event locations away from the borehole with successive treatments indicated new fracture growth with each stimulation stage. The hydraulic fracture was expected to have been fully contained within the
reservoir after completion of the initial stimulation treatment. Breakthrough of the fracture to the surface of the specimen was expected to have occurred during the re-stimulations. The dominant wing of the bi-wing hydraulic fracture changed during the first re-stimulation treatment. This transition was likely influenced by a second borehole that was drilled to intercept the initial dominant fracture wing. The second borehole was drilled to simulate a geothermal production well which recovered injected fluids after they had been heated by the laboratory scale EGS reservoir.

Fig. 3.10. G01-90 hydraulic fracture and re-fracture treatment curves.
The injection fluid was changed from oil to water after the re-stimulations. Water has a viscosity of 0.55 cP at 50 ºC (White, 2009). Oil was purged from the fractures by subsequent SCP and SCF injectivity tests. Table 3.2 details the timing for the injection fluid change with respect to the test schedule.

Pressure and flow results from the MIF stimulation in G01-90 are shown in Fig. 3.12. The precise impulse pressure profile and peak were not acquired as a consequence of the 1 Hz sampling rate used for respective data acquisition channels. A steady pressure decline with outflow of fluids through the fractured specimen occurred after MIF. The residual pressure at 0.2 min after MIF was 2.2 MPa, compared to the residual of 0.3 MPa from G01-00. The increase in residual pressure was expected with the application of confining stresses.

Injected fluid volume data in Fig. 3.12 was estimated using the following hydraulic compliance relationship:

\[
V_{\text{stored}} = 7.517 \cdot 10^{-11} P_{\text{well}}^2 - 4.529 \cdot 10^{-5} P_{\text{well}}
\]  

(3.6)

This relationship was obtained by polynomial regression of the pump pressure and volume data during initial pressurization. The plot used for this regression analysis is provided in Fig. 3.13. In this case a polynomial regression provided a better curve fit than a linear regression. Substitution of a linear regression slope following Eq. 3.1 causes only a minor increase in error.
Additional information regarding the MIF impulse pressure profile was provided by the strain data, shown in Fig. 3.14. Strains were recorded from 15 gages installed on the surface of the granite specimen. Strains were recorded at a sampling rate of 5000 Hz and smoothed into 50 Hz bins for plotting. Locations and orientations for the three plotted strain gage values are indicated in the legend by matching color. A spike in the strain data indicates the precise time of impulse arrival. Exponential extrapolation of the pressure data to the impulse arrival time indicated a peak impulse pressure of at least 18.7 MPa which exceeds the maximum pressure reached by conventional hydraulic fracturing.

Fig. 3.12. G01-90 MIF treatment pressure and injected fluid volume data.

Fig. 3.13. Curve for calibration of hydraulic compliance for MIF in G01-90.
AE events recorded during MIF stimulation are shown in Fig. 3.15. These results show that a single large magnitude event was induced at the base of the well casing concurrent with arrival of the hydraulic impulse. Distributed AE events of diminishing magnitude were observed after the initial impulse. This AE activity indicated a sudden large magnitude tensile fracture opening followed by shearing activity associated with resettling and closure of the fracture.

SCP and SCF well injectivity data corresponding with each stimulation treatment is shown in Fig. 3.16. These results show a significant increase to injectivity after transitioning from oil to water injection. A second significant increase is evident after MIF stimulation. Flow was stable and repeatable during SCP testing after the second re-stimulation treatment and the MIF treatment. No additional fracture growth was indicated by the hydraulic or AE data between stimulations even with water injection at 3.0 mL/min and 11 MPa for 50 minutes. Note that 11 MPa represents 93% of the theoretical breakdown pressure and 61% of the peak pressure observed during actual hydraulic fracture stimulation. These results indicate that hydraulic fracture re-stimulation with water injection was not practical given the maximum deliverable flow of 60.0 mL/min from the available pumps. MIF was successful at increasing well injectivity even with the pre-existing hydraulically conductive fractures.

Plots of fracture profiles observed from cross-sections cut after testing are shown in Fig. 3.11. Close inspection of the cross-sections identified two parallel bi-wing fractures in the near wellbore region, four fracture wings in total. The primary bi-wing fracture (red) was large and dominant while the secondary bi-wing fracture (magenta) was smaller and offset from the primary fracture. One wing of the...
primary fracture (red) propagated to the boundary of the specimen. Both the primary and secondary fractures appeared to initiate from the injection borehole (yellow) and both intercepted the production borehole (blue). The geometry of the secondary fracture directly intersected the production borehole with a twisted alignment that closely matched the borehole axis. The primary fracture appeared to be pierced by the production borehole but was otherwise minimally influenced by its presence. This geometry suggests that the secondary fracture propagated after the production borehole was drilled and also that the secondary fracture hydraulically short circuited the primary fracture by providing a higher conductivity and more direct flow path between the two wells. Significant increases to both injectivity and production observed after MIF likely indicate that the secondary fracture was created or substantially altered by the MIF treatment.

Fig. 3.15. AE event locations for MIF of G01-90.
3.3 Basic Field Feasibility Analysis

A basic feasibility study was conducted to evaluate viability for the actual use of MIF in the field. Accumulator volumes necessary for MIF are of critical concern for field viability. The feasibility study used an analytical approach to evaluate the accumulator volume required for a hypothetical field-scale well. The respective analytical solution uses linear elastic thin wall pressure vessel theory and ideal gas law. Validation of the analytical solution was performed using laboratory data and numerical modeling. An experimentally measured buffer factor was appended to the analytic predictions to compensate for errors in the solution which were a consequence of neglecting gas in the wellbore, well geometry and damping of the hydraulic impulse. Design of actual field scale MIF can benefit from applying a more detailed analysis using advanced models that consider dynamic damping, fluid impulse propagation phenomena (Bessem et al., 2008) and the reservoir rock’s response. Development and application of these advanced models was attempted but beyond the scope of this study.

Thin wall pressure vessel theory for generic cylindrical vessels (Young and Budynas, 2002) was applied to estimate hydraulic compliance of the well casing:

\[
\Delta R = \frac{P_{\text{well}} R^2}{E_b} \tag{3.7}
\]

\[
\Delta V = N \times \pi L \left( (R + \Delta R)^2 - R^2 \right) \tag{3.8}
\]
where $\Delta R$ is the change in casing radius, $R$ is the initial casing radius, $E$ is elastic modulus, $b$ is the casing wall thickness, $\Delta V$ is the change in casing volume, $N$ is a dimensionless buffer factor and $L$ is the casing length. Thin wall solutions are most accurate given wall thicknesses less than 10% of the radius. The equation assumes an axial plane stress condition and no external pressures, which neglects additional stiffness provided by cementing and external pressures. Inclusion of external pressures can reduce calculated radial displacements and therefore lead to smaller required treatment volumes. Larger predicted treatment volumes are desired in this study to more conservatively evaluate field scale feasibility. Alternative analytic compliance models can be derived using continuum mechanics but the associated improvement in accuracy was not found to be significant.

The accuracy of Eq. 3.8 was validated with laboratory data using pressurization data for an uncemented $540 \pm 20$ mm length of $6.35$ mm O.D. × $3.18$ mm I.D. $316$SS stainless steel tubing. The tubing was pressurized using two $65$DM Teledyne Isco syringe pumps with one needle valve installed between each pump and an end of the tubing segment, two valves in total. The elastic modulus was assumed at $200$ GPa, a typical value for carbon steel (Beer et al., 2006). The pumps were pressure cycled with pressure and fluid volume data recorded for all combinations of valve positions to produce the data shown in Fig. 3.17. The compliance of the tubing segment was then derived as $5.61 \times 10^{-9}$ mL/kPa/mm, normalized by the $540$ mm tubing length.

![Fig. 3.17. Experimentally measured compliance of 3.18 mm I.D. 316SS stainless steel tubing.](image_url)
The dimensions of the tested tubing segment were input into Eq. 3.8 and a SolidWorks® FE model giving compliance values of $2.93 \times 10^{-10}$ mL/kPa/mm and $1.54 \times 10^{-10}$ mL/kPa/mm, respectively. The analytical relation agreed well with the finite element model but under-predicted the physical laboratory measurement by a factor of 19. Consequentially, a rounded buffer factor of 20 was applied to give a conservative estimate of the required accumulator volume. The disagreement between the measured and modeled compliance estimates was likely a consequence of trapped compressible gasses in the hydraulics system, emphasizing the importance of minimizing gas concentration in the well for successful MIF.

The initial volume of clean gas needed in the accumulator to mobilize $\Delta V$ can be approximated by ideal gas law using the relation:

$$V_1 = \frac{P_2 \Delta V}{P_1 - P_2}$$

where $V_1$ is the initial volume gas in the accumulator, $P_1$ is the initial pressure of the accumulator and $P_2$ is the target well treatment pressure. This relation assumes isothermal conditions, no outflow of fluids from the hydraulic system, and no pressure intensification between the liquid and gas in the accumulator. The total required fluid volume of the accumulator can be calculated by summation of $V_1$ and $\Delta V$.

The theoretical accumulator volume necessary for field-scale MIF as a function of maximum accumulator pressure and target treatment pressure is illustrated in Fig. 3.18. Well casing dimensions were set at 5 km length, 152 mm O.D. and 15 mm wall thickness. The assigned casing wall thickness was calculated following ASTM A822 (2004) with a maximum gauge pressure of 70 MPa and allowable casing stress of 350 MPa. Practical concerns for safety and corrosion tolerance can demand greater wall thickness resulting in decreased compliance and less required fluid volumes. This analysis assumes initially balanced pressure conditions where the gage pressure across the pipe wall is negligible.

Applying Fig. 3.18 in an example using the same well casing dimensions, a 6400 L fluid volume accumulator would likely be suitable to achieve a target treatment pressure of 35 MPa with a maximum permissible surface accumulator pressure of 55 MPa. This target treatment pressure is expected to exceed the breakdown pressure threshold, predicted by Eq. 1.1. The injected fluid volume associated with this treatment would be 2300 L and represents roughly 0.012 % of a conventional hydraulic fracturing treatment with an assumed fluid volume of $1.9 \times 10^7$ L (GWPC & IOGCC, 2014). Larger accumulator volumes with lower initial pressures could be used to achieve the same target treatment pressure and deliver a larger fluid volume. A review of existing equipment on the market shows that a 6400 L tank volume is feasible (Weatherford, 2012) but new specialized designs for transportable high pressure and large volume tanks would benefit implementation of MIF in the field.
3.4 Valve Displacement Correction

Opening and closing of the valves in the hydraulic system requires displacement of fluid. Injected fluid volume plots were corrected for the fluid volume displaced by the valve. Valve fluid displacement volumes were estimated by physical measurement during the series of measurements performed to evaluate tubing compliance. Fig. 3.19 shows a plot of the fluid volumes displaced by the valves during the testing series corrected for hydraulic compliance. The average displacement volume was 0.12 mL between fully opened and fully closed. Time data is included on the plot to show the delay from issuing the command for valve opening and the actual opening event. This delay was had an average duration of 7 sec, an important value which was incorporated into a continuous constant flow sub-program installed in the LabVIEW® pump control/monitoring program.

3.5 Discussion

These results demonstrate that MIF can successfully stimulate a well even after conventional hydraulic fracturing has been performed. MIF fundamentally enables pressure controlled fracture stimulation beginning with a pressure impulse and also features adjustable treatment pressures and fluid volumes depending upon accumulator configuration. This study presents an above-ground accumulator implementation which is anticipated to be the simplest means for performing MIF. Required equipment in
this case includes a high pressure pumping unit, an accumulator, valves, high pressure well steel, and appropriate safety devices. This equipment is effectively very similar to what is already used for conventional hydraulic fracturing treatments. It is possible that similarly functioning equipment could be developed for placement down the well at a target stimulation zone, reducing damping and hydraulic compliance concerns. Performing a series of consecutive MIF treatments in a single well is also practical with this method when considering the short duration of the treatment in relation to conventional hydraulic fracturing. Target MIF treatment pressures and volumes can be adjusted through consecutive treatments to optimize a given job, given adequate consideration in equipment design. Benefits and detriments of MIF in comparison with other treatments are expected to be a complex function of in-situ rock characteristics and fluid parameters. Advanced modeling is necessary to predict the optimal stimulation treatment for a given well.

Fig. 3.19. Data for valve fluid displacement vs. time after remotely issuing the command to open.
CHAPTER 4
CRITICAL STATE HYDRAULIC FRACTURE GEOMETRY

Accurate hydraulic fracture geometry knowledge is crucial for predicting fluid flow dynamics and stimulation effectiveness. The extents of fracture length and height control the stimulated reservoir volume. Fracture aperture (width) affects the hydraulic conductivity of the fracture. Proppant and shearing displacement between the fracture faces can increase the post-stimulation hydraulic conductivity of the fracture. Branching (stranding) and tortuosity can lead to greater pressure losses (Warpinski, 1982), poor proppant placement, and possibly increased stimulated reservoir volume. Multiple fractures and discontinuities can interact through arresting, diverting, coalescing and stress-shadowing giving associated increases or decreases to production.

Physical measurement of field hydraulic fracture geometry beyond the borehole is difficult and typically cost prohibitive. Laboratory experiments provide an opportunity to accurately quantify hydraulic fracture geometry benefiting from smaller specimen sizes and more measurement capabilities. This chapter presents laboratory-scale hydraulic fracture treatments performed in acrylic and granite specimens. The treatments were performed using epoxy injection to preserve critical state fracture aperture data and to clearly mark the fluid penetrated zone. Micro-measurements of final created fracture geometries are presented and analyzed with reference to associated pressure, flow rate, strain, acoustic emission (AE) and video data. Estimation of fracture initiation using each data set for the acrylic is discussed with validation by synchronized video evidence. Linear-elastic finite element (FE) analysis was applied to model the 3D fracture aperture and better understand the results. Effects of rock heterogeneity and near-wellbore damage on the propagated fracture are analyzed and discussed.

4.1 Defining Critical State Fracture

Understanding the geometry of hydraulic fractures in the critical state is important for validating assumptions used for fundamental models (Perkins and Kern, 1961; Geertsma and de Klerk, 1969; Nordgren, 1972). Critical state in this context refers to the condition at or exceeding the stress threshold required for fracture propagation. Expressed in terms of linear-elastic fracture mechanics (LEFM), the critical state represents the limit where the crack-tip stress intensity factor, $K_I$, approaches the fracture toughness of the rock, $K_{IC}$. The crack can be pseudo-stable or actively propagating at the critical state. Fracture aperture in this condition directly relates to friction factor estimation and can also affect estimations regarding proppant flow and placement. Hydraulic compliance of the well and fracture is a concern at the critical state where transient flow can be associated with changes in the well and fracture.

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3 Modified from paper manuscript by Luke P Frash, Marte Gutierrez, John Hood, Hai Huang and Earl Mattson under internal review for submission to Journal of Petroleum Technology.
pressures. Note that the critical state in a permeable reservoir can be reached using steady injection of fluid at a pressure approaching the fracture growth threshold.

4.2 A01-05: Hydraulic Fracturing of Acrylic with Epoxy Injection

The setup for the unconfined acrylic fracturing experiment is shown in Fig. 4.1. This specimen was assigned a reference ID of A01-05. Fig. 4.1 includes two orthogonal perspectives with a mirror on the right. The specimen was 76 mm in diameter with a length of 127 mm. A sub-vertical borehole was percussively drilled through the center of the specimen to a total depth of 82 mm. The upper borehole interval was cased to a depth of 49 mm. A deviation of 2.8° between the borehole axis and the specimen axis was incurred due to fabrication error. Percussive drilling created multiple small fractures with radial extent up to 3 mm away from the borehole wall. This fractured zone was included to investigate the effects of drilling induced damage and small-flaws in the near-wellbore region. Modeling was later applied to investigate the influence of this damage zone on fracture complexity.

![Fig. 4.1. A01-05 at fracture initiation.](image)

Strain was measured at two tangentially aligned gages bonded on the surface of A01-05. The gages were offset by 90° and positioned along the center circumference of the cylindrical specimen. AE was monitored using six piezoelectric sensors. Three sensors were positioned on the top of the specimen, two on the sides, and one supported by a machined steel platen on the bottom. A thin layer of silicone sealant was used for AE sensor couplant. Video was recorded at 30 fps.
The injection fluid was white colored Do-It-Best® Marine Epoxy having an estimated viscosity of 30,000 to 45,000 cP at 25 °C. This fluid was selected for its slow set time of 240 min which permitted adequate time for setup, bleeding of the hydraulics and stimulation with minimal risk of premature curing. High viscosity fluid was preferred to improve scalability of the measured fracture dimensions (Johnson, 1991; de Pater et al., 1994; Ishida et al., 2004).

The injection schedule for the test is detailed in Table 4.1 and associated results are shown in Fig. 4.2. Note that compressive strains and stresses are considered to be positive values. Injection was initiated with a constant 2 MPa interval to check for leakage from the hydraulic system. Fractures were created during a stimulation stage where epoxy was injected at a constant rate of 0.05 mL/min. The control mode was switched to constant pressure injection at 4 MPa after breakdown and while the fracture was visually observed to continue propagating within the bounds of the acrylic specimen. Fracture breakthrough to the surface of the specimen occurred during constant pressure injection but growth continued in all fracture wings after this event. Continued fracture growth after breakthrough confirms that the fracture aperture was maintained at near critical state during the epoxy cure.

![Synchronized data for A01-05 hydraulic fracture.](image)

Fig. 4.2. Synchronized data for A01-05 hydraulic fracture.
Table 4.1. Injection schedule for acrylic experiment.

<table>
<thead>
<tr>
<th>Description</th>
<th>Test Time (min)</th>
<th>Pressure (MPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Epoxy mixed and placed</td>
<td>-32.0</td>
<td>0</td>
</tr>
<tr>
<td>Constant 2 MPa injection start</td>
<td>0.0</td>
<td>1.5</td>
</tr>
<tr>
<td>0.05 mL/min injection start</td>
<td>39.4</td>
<td>1.9</td>
</tr>
<tr>
<td>Fracture initiation</td>
<td>44.7</td>
<td>6.1</td>
</tr>
<tr>
<td>Peak injection pressure</td>
<td>58.2</td>
<td>8.9</td>
</tr>
<tr>
<td>Injection stopped</td>
<td>73.8</td>
<td>7.5</td>
</tr>
<tr>
<td>Fracture breakthrough surface</td>
<td>77.0</td>
<td>5.1</td>
</tr>
<tr>
<td>Constant 4 MPa injection start</td>
<td>79.5</td>
<td>4.0</td>
</tr>
<tr>
<td>Estimated ceased propagation</td>
<td>107.5</td>
<td>4.0</td>
</tr>
<tr>
<td>Estimated epoxy set time</td>
<td>208</td>
<td>4.0</td>
</tr>
<tr>
<td>Pumping Stopped</td>
<td>1790.7</td>
<td>4.0</td>
</tr>
</tbody>
</table>

The fracture created during this experiment was slow and controlled with a clean breakdown curve. AE activity initiated at breakdown which correlates precisely with a decrease in the slope of the pressure data, a sudden increase in strain and visual confirmation of fracture propagation in the associated video. The injected fluid volume data shown in Fig. 4.2 was corrected for leakage and hydraulic compliance (ballooning) using the following relationship:

\[
V_{ic} = V_i + \sum_{j=0}^{n} \frac{\partial V}{\partial \Delta t} \Delta t_j + \frac{\partial V}{\partial P} P_j
\]

\[
\frac{\partial V}{\partial \Delta t} (\text{mL/min}) = -6.88 \times 10^{-7} P_j (\text{kPa}) - 1.52 \times 10^{-10} P_j^2 (\text{kPa})
\]

\[
\frac{\partial V}{\partial P} (\text{mL/kPa}) = -5.81 \times 10^{-5} P_j (\text{kPa})
\]

\[
\Delta t = 0.0167 \text{ min}
\]
Video stills of the fracture growth in A01-05 are shown in Fig. 4.3 and the respective video is available online (Frash et al., 2013). Fracture initiation occurred with simultaneous propagation of multiple small fractures in the near-wellbore damage region. These initial fractures coalesced into four prominent tensile dominated wings. Dominant wings were given letter references as shown in Fig. 4.3. Wing-A propagated to the boundary of the specimen and Wing-B and Wing-C were both fully contained. Offset sub-parallel proximal fracture planes coalesced through transverse shear fractures. Coalesced fractures propagated vertically-radially away from the borehole. Shear fractures in the propagation plane created a plumose/flabellate surface texture. A plumose structure is considered to be a common characteristic for tensile fracture surfaces (Anderson, 1991). Shear fractures lagged behind the tensile fracture front as evident with localized reductions of radial fracture length (e.g., Wing-B). Simultaneous tensile, shear and mixed mode fracture growth was witnessed during propagation. A non-penetrated/non-wetted zone was confirmed at the tip of the fracture.

![Video stills for hydraulic fracture of A01-05.](image)

Fig. 4.3. Video stills for hydraulic fracture of A01-05.
Fig. 4.4 shows photomicrographs and measurements taken from Wing-A at the rupture surface. Aperture as a function of length follows a smooth elliptical profile despite the presence of shear zones, offsets and fracture undulations. An elliptical profile indicates uniform fluid pressure along the fracture height. Offset in the plot was measured as the distance between the center of the hydraulic fracture and a reference line between the two fracture tips. Fig. 4.4 includes a photomicrograph showing a prominent shear zone in Wing-A where the tensile surfaces are interrupted by a shear fracture having a 49º angle relative to the tensile plane. An angle exceeding 45º signifies that the shear fracture was created by tearing (out-of-plane shear). Distance measurements had a maximum resolution of 0.0018 mm and accuracy of ± 3%.

Fig. 4.4. Photomicrograph measurement of A01-05 Wing-A aperture at surface rupture.

Photomicrographs from the center cross-section of the fracture are shown in Fig. 4.5 with magnifications provided for two areas of interest. The left magnification provides an example of near-wellbore tortuosity in Wing-A. This tortuosity was a consequence of fractures preferentially propagating along pre-existing drilling induced discontinuities. Flaws in the propagating fracture front were traced back to local complexities in the near-wellbore zone. The prominence of these flaws tended to diminish with propagation away from the near-wellbore zone. Tortuous fluid flow through the near-wellbore zone and across propagated flaws likely reduces hydraulic fracture conductivity and hinders proppant transport.
The right magnification provides an example of fracture coalescence in Wing-C much further into the propagation direction. A first look at this image is deceptive because the image is two-dimensional while the driving effect is three-dimensional. Two prominent offset tensile dominated fractures were vertically separated near this zone of interest and the branching and coalescence phenomena was observed near the merging point. This coalescence feature is therefore expected to result from tearing (mode-III) interaction driven by the dominant fractures nearby. Aperture data in branched zones was taken as a summation of each fracture strand, resulting in a smoother aperture profile as a function of length.

Fig. 4.5. Photomicrographs of A01-05 center cross-section.

Micro-CT data for the acrylic specimen was acquired at a resolution 32.6 µm/px and an example cross-section is shown in Fig. 4.6. Extensive near-wellbore tortuosity was observed in the CT data along the length of the open fracturing interval. This data served to provide a redundant estimation of fracture aperture and to compile an improved perspective of the three-dimensional fracture profile. Measuring the fracture aperture at the borehole wall gives 0.16, 0.10, and 0.16 ± 0.03 mm for wings A, B, and C respectively. Note that the CT data was collected prior to cutting cross-sections from the specimen.

Fig. 4.7 provides the aperture data for each dominant fracture wing as a function of radial distance from the borehole wall. These profiles were found to be less elliptical than the vertical profile from Wing-A. The non-elliptical portions of the aperture profile indicate interaction between the three dominant fracture wings and non-uniform pressure distributions as a function of radius. The tip of Wing-C was observed to be elliptical while the tip of Wing-B was much sharper. Increased sharpness of the Wing-B tip suggests partial fracture closure due to compressive hoop stresses induced by Wing-A and Wing-C. Aperture flaring near the wellbore was also evident. The length of the flared zone was approximately equal to the radius of the damage zone so the damage zone was expected to be the primary cause. Finite element (FE) modeling was applied in an attempt to investigate this hypothesis.
Fig. 4.6. CT image from center of uncased borehole in A01-05.

Fig. 4.7. A01-05 fracture aperture profiles as a function of distance from the borehole.
4.3 FE Modeling of A01-05

Linear-elastic FE analysis was applied in an attempt to better understand the role of borehole damage and fluid pressure distributions on the observed radial fracture aperture profiles in A01-05. The analysis was performed using two model geometries. The first geometry represented a simplified case where Wing-\(C\) was modeled as an elliptical symmetric bi-wing hydraulic fracture. The second geometry attempted to model the full 3D specimen with all three dominant fractures and the oriented injection borehole. All fractures were assumed to be elliptical with semi-major and semi-minor axes matching laboratory measured length and height. Flow in Wing-\(B\) and Wing-\(C\) was assumed to be negligible with a uniform fluid pressure distribution to represent the final geometry with fully cured epoxy. The fluid pressure distribution through Wing-\(A\) was modeled with either a uniform distribution or a linear distribution varying with horizontal distance from the injection borehole. The linear distribution assumed the injection well pressure at the borehole wall and atmospheric pressure at the external boundary. Borehole damage was modeled with frictionless rectangular fractures parallel with the borehole axis and extending 3 mm radially away from the borehole wall. Damage zone fractures were equally spaced along the borehole wall between adjacent fracture wings, giving a nominal arc-angle spacing of 30º. Table 4.2 summarizes the parameters of each FE model variant and Fig. 4.8 presents the respective results from Wing-\(C\) as a function of length from the borehole wall. The results plot includes physical measurements (\(a\)) for comparison with the FE model results (\(b\) to \(i\)). Letter associations for each series in Fig. 4.8 follow those in Table 4.2. Note improved agreement in the full 3D model assuming a linear pressure distribution.

Table 4.2. Summary of FE model parameters.

<table>
<thead>
<tr>
<th>Model</th>
<th>Geometry</th>
<th>Near Well Damage</th>
</tr>
</thead>
<tbody>
<tr>
<td>(b)</td>
<td>Simplified symmetric with rectangular boundary</td>
<td>No</td>
</tr>
<tr>
<td>(c)</td>
<td>Simplified symmetric with cylindrical boundary</td>
<td>No</td>
</tr>
<tr>
<td>(d)</td>
<td>Simplified symmetric with cylindrical boundary</td>
<td>Yes</td>
</tr>
<tr>
<td>(e)</td>
<td>Simplified symmetric with cylindrical boundary</td>
<td>Yes(^{†})</td>
</tr>
<tr>
<td>(f)</td>
<td>Full model with uniform Wing-A pressure</td>
<td>No</td>
</tr>
<tr>
<td>(g)</td>
<td>Full model with linear Wing-A pressure</td>
<td>No</td>
</tr>
<tr>
<td>(h)</td>
<td>Full model with linear Wing-A pressure</td>
<td>Yes</td>
</tr>
<tr>
<td>(i)</td>
<td>Full model with linear Wing-A pressure and finer mesh</td>
<td>Yes</td>
</tr>
</tbody>
</table>

\(^{†}\) Uniform fluid pressure in damage fractures.

Fig. 4.9 shows the half-aperture displacement (\(\delta_{1/2}\)) and ultimate resultant displacement (\(\delta_u\)) plots from Model-\(e\) and Model-\(i\), respectively. In the full model, the \(x\)-axis was set parallel with Wing-\(A\) and the \(z\)-axis was set parallel with the cylindrical specimen’s axis. Post-processing was required to calculate the differential displacement between each face, giving the fracture aperture. The post-processing method involved filtering the point displacement data exported from the SolidWorks\(^{®}\) simulations and calculating vector projection lengths perpendicular to the respective fracture planes.
Fig. 4.8. A01-05 Wing-C aperture estimated by FE compared with physical measurement.

Fig. 4.9. Example A01-05 FE displacement calculations from Model-e (left) and Model-i (right).
The FE results indicate that borehole damage, fluid pressure distributions and specimen boundary geometry are all important factors affecting the final hydraulic fracture aperture. Inclusion of the damage zone fractures resulted with increased hydraulic fracture aperture in both the simplified and full specimen models. It is reasonable to consider the damage zone as effectively reducing material stiffness near the wellbore. Fluid pressure distributions were also a significant factor affecting the fracture aperture. Interaction between the fractures produced a stronger than expected effect when comparing the simplified model with the full model. These results indicate that the fractures were too large relative to the specimen size for accurately modelling the apertures without also coupling the solution to fluid flow. The boundary geometry was a significant factor affecting the fracture geometry as evident by comparing Model-\(b\) and Model-\(c\). Additional factors that could affect the geometry but were not part of this study include alteration of the material properties near the wellbore by heat during drilling and the possibility of a vacuum pressure at the fracture tip as predicted by zipper crack theory (Valko and Economides, 1995). SolidWorks does not incorporate the extended finite element method (XFEM) so errors are introduced by not including elements capable of accurately solving the crack-tip stress singularity problem.

4.4 G01-91: Hydraulic Fracture of Granite with Epoxy Injection

The 300×300×300 mm\(^3\) specimen used for the G01-91 granite hydraulic fracturing experiment with epoxy injection is shown in Fig. 4.10. A discontinuous zone is highlighted where the rock contained a higher than average quartz concentration. A vertical borehole was percussively drilled through the center of the specimen to a total depth of 203 mm. The upper borehole interval was cased to a depth of 101 mm. Hydraulic fracturing of G01-91 was performed at unconfined room temperature conditions. Strain gages and AE sensors were positioned on the surfaces of the specimen as shown in Fig. 4.11. Arrangement of the 20 strain gages was selected to increase the probability that a propagating fracture would intercept at least one strain gage at surface rupture. Previous hydraulic fracturing experiments in granite under similar conditions showed a tendency for fractures to propagate vertically away from the borehole towards the center of the specimen’s faces as a consequence of the boundary geometry.

The injection fluid was amber colored Loctite® Hysol® E-120HP epoxy having a viscosity of 30,000 cP at 25ºC (Loctite, 2008). This fluid was selected for its long working life of 120 min. The injection schedule for this experiment is detailed in Table 4.3. Injection was initiated with a constant 2 MPa interval to evaluate pre-stimulation well injectivity and check for leaks in the hydraulic system. Hydraulic fracturing was performed with constant flow rate injection at 0.10 mL/min. Breakdown occurred at a high pressure of 50.9 MPa and was followed by rapid fracture growth to the surface of the specimen. Critical state aperture was not successfully preserved.
Table 4.3. Injection schedule for G01-91 experiment.

<table>
<thead>
<tr>
<th>Description</th>
<th>Test Time (min)</th>
<th>Pressure (MPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Epoxy mixed and placed</td>
<td>-10.0</td>
<td>0</td>
</tr>
<tr>
<td>Constant 2 MPa injection start</td>
<td>0.0</td>
<td>2.6</td>
</tr>
<tr>
<td>0.10 mL/min injection start</td>
<td>17.7</td>
<td>2.0</td>
</tr>
<tr>
<td>Fracture initiation</td>
<td>46.9</td>
<td>48.5</td>
</tr>
<tr>
<td>Peak injection pressure</td>
<td>48.6</td>
<td>50.9</td>
</tr>
<tr>
<td>Fracture breakthrough surface</td>
<td>50.1</td>
<td>16.2</td>
</tr>
<tr>
<td>Injection stopped</td>
<td>63.3</td>
<td>0.5</td>
</tr>
<tr>
<td>Estimated epoxy set time</td>
<td>110</td>
<td>0</td>
</tr>
<tr>
<td>Epoxy full cure time</td>
<td>1430</td>
<td>0</td>
</tr>
</tbody>
</table>

Fig. 4.10. G01-91 300×300×300 mm³ granite specimen prior to hydraulic fracturing.

Resulting data from the hydraulic fracture is shown in Fig. 4.12. Note the extended time scale for the first plot showing the full hydraulic fracture treatment. The subsequent plots are shown on a smaller timescale focused on the breakdown event where a period of fracture extension lasting 3.2 min is evident. Loss of signal from two strain gages occurred at 50.1 min into the test. This event gives the precise time at which the propagating fracture ruptured through the specimen’s surface.
In Fig. 4.12, the injected fluid volume data was corrected for a leak-off and hydraulic compliance using Eq. 4.1 with the following inputs:

\[
\frac{\partial V}{\partial t} (\text{mL/min}) = -3.98 \times 10^{-7} P_j (\text{kPa}) \quad (4.5)
\]

\[
\frac{\partial V}{\partial P} (\text{mL/kPa}) = -6.11 \times 10^{-5} P_j (\text{kPa}) \quad (4.6)
\]

\[
\Delta t = 0.0167 \text{ min} \quad (4.7)
\]

The leakage rate was approximated using data from the final 30% of the 2 MPa CP injection interval's flow data. Hydraulic compliance estimated from the linear portion of the hydraulic fracture pressurization curve between 18.5 and 47.5 min. Data for strain gages #4, #6, and #19 are presented in Fig. 4.12. Gage #4 was aligned parallel with the fracture propagation direction. Gage #6 was perpendicular to the fracture and was intercepted by the fracture when it propagated to the boundary of the specimen. Gage #19 was perpendicular to the fracture and located on the face opposite gage #6. Gages #6 and #8 both failed when the fracture reached the boundary of the specimen.
AE event location data indicated two zones of high activity as shown in Fig. 4.13. The green highlighted zone corresponds with the observed hydraulic fracture plane and the magenta zone corresponds with the quartz-rich discontinuity identified prior to the experiment and highlighted in Fig. 4.10. No penetration of injected epoxy into the discontinuity was observed despite the high level of AE activity. This plot presents data from the time interval of 46.0 to 51.0 min relative to Fig. 4.12 and Table 4.3. A total of 1618 events were recorded during this time so filtering was applied to pass only events with high correlation coefficient (low locational error) and high amplitude, values greater than 0.99 and 50 dB respectively. Event colors vary with amplitude showing to emphasize high magnitude events.
Fig. 4.13. Located AE events in G01-91 from 46 to 51 min highlighting correlation with the hydraulic fracture zone (green) and discontinuity band (magenta).

Fig. 4.14 shows the final hydraulic fracture geometry measured from 25 mm thickness cross-sections cut from the granite specimen. A simple planar vertical bi-wing fracture was produced that nearly severed the rock specimen into two halves. Only a 28 mm nominal thickness hinge of rock remained intact along the fracture plane. The zone of rock penetrated by epoxy resembled an asymmetric penny shaped fracture with longer radii extending towards the ruptured surface (y=0 mm face). The total fluid volume in the fracture was estimated at 4.71 mL, 1.30 mL of which was injected after surface rupture. Therefore, the fluid penetration distance measured from cross-sections was expected to be longer than the fluid filled fracture length during fracture propagation. The lack of fluid penetration into the quartz-rich discontinuity band confirms that AE data can be misleading when attempting to determine stimulated reservoir volume or the geometry of fluid stimulated fracture networks.
Fig. 4.14. Geometry of G01-91 hydraulically stimulated fracture (red) and penetration of epoxy (blue).

The center cross-section from G01-91 is shown in the left of Fig. 4.15 with photomicrographs overlain. The right of Fig. 4.15 highlights the fracture path through the section. Select photomicrographs of the epoxy penetrated hydraulic fracture zone are shown in Fig. 4.16.

Fig. 4.15. Center cross-section from G01-91 at 145 mm depth (z = 155 mm).
Fig. 4.16. Fracture geometry from G01-91 cross-section at 145 mm depth (z = 155 mm) showing (a) fracture branching and coalescence, (b) multiple branching, (c) shear and tensile interaction, and (d) grain boundary fracturing.
Complex fracturing phenomena were observed in photomicrographs and close inspection of the cross-sections from G01-91 even with the mostly planar macro-scale geometry. These phenomena included transgranular and intergranular fracturing, fracture branching and coalescence, and a combination of tensile, shear and mixed-mode fracture displacements. Chapter 6 presents a detailed study of the interaction between complex grain-scale fracturing phenomena and macro-scale fracture geometries.

4.5 Discussion

A01-05 and G01-91 provided quantitative measurements of hydraulic fracture geometries and associated fluid penetrated fracture zones. The acrylic fracture was slow and controlled while the granite fracture was rapid and less controlled, even though similar high-viscosity injection fluids were used in both cases. This result suggests that fracturing speed is a function of fluid viscosity, injection rate and rock stiffness. It is possible that hydraulic compliance of the injection system also has an effect on fracture propagation where instantaneous flow rates into a fracture can be expressed as a function of compliance and injection rate.

In the acrylic test it was possible to maintain critical state geometry through constant pressure injection. The same did not hold true for the granite because of the extreme extents of the created fracture. Critical state fracture aperture data obtained from A01-05 demonstrated that an elliptical fracture aperture profile is a reasonable assumption for the vertical cross-section of propagating hydraulic fractures in linear-elastic homogenous materials. This observation validates the geometric assumptions used for basic hydraulic fracture models such as the Perkins and Kern and Nordgren solution (Perkins and Kern, 1961; Nordgren, 1972). The radial or lengthwise fracture aperture profile was found to be more complex with effects such as near wellbore damage and interaction between adjacent fractures directly influencing the geometry. Heterogeneity further complicated the fracture geometry as observed in G01-91 with increased surface roughness, a mixture tensile and shear fracture displacements, and fracture branching and coalescence.

Injection of epoxy aided in evaluation the final hydraulic fracture geometry where interactions between separate fractures and the material matrix could be studied. FE modeling of the final fracture geometry indicated uniform fluid pressures as a function of height but non-uniform pressure as a function of length through a flowing fracture wing. The FE model also showed that near-wellbore damage had the potential to cause increased fracture aperture in the near-well zone.

Shear and tensile fractures were observed to propagate simultaneously through video data attained from A01-05. In this experiment, shear fractures lagged behind the tensile fracture front and connected offset tensile fracture planes. Continued fracture propagation resulted with a decrease in the
size of the shear fractures as offset tensile fractures coalesced more. This result differed from G01-91 where fracture branching tended to increase with distance away from the borehole. These results from G01-91 show that structural heterogeneities in the rock fabric can cause fracture roughness which can aggregate into fracture branching. Macro-scale interaction of fracture branches tended to create shear fracture zones behind the tensile fracture front, coalescing proximal fractures.

Fracture initiation was identifiable in both A01-05 and G01-91 through analysis of the injection pressure, AE, strain or video. Initiation was most easily identified in the pressure data through an associated decrease in the slope of the pressure-time curve. The initiation event also coincided with a sudden increase in AE activity and specimen strain. Identification of fracture initiation in real-time with pressure data was simple but the same was not true for the AE and strain data. Distributed AE events occurred during constant pressure injection and the pressurization interval prior to hydraulic fracture breakdown. The breakdown event was associated with a sudden increase in AE event frequency and strain-rate but these trends could not be identified easily in real time. AE events occurred in the matrix, along discontinuities near the injection site and at the injection site due to hydraulic fracture initiation and propagation. It is possible that advanced post-processing of the data could distinguish between fractures initiating at the borehole distal activation of discontinuities but these advanced methods have not been applied to the data produced by these experiments. Video data from A01-05 provided clear visual confirmation of fracture initiation where epoxy could be seen entering and extending cracks near the uncased injection wellbore. Fracture initiation did not correlate with a pressure peak likely due to pseudo-plastic fracture propagation.
CHAPTER 5
LABORATORY MODELING OF ENHANCED GEOTHERMAL SYSTEMS

Multi-well EGS technology has the potential to enable economic recovery of energy from underutilized HDR resources. Hydraulic fracturing is a promising stimulation method to enable fluid flow and heat extraction for EGS. Laboratory simulations of EGS were completed in two 300×300×300 mm$^3$ granite blocks. The first experiment implemented a binary well layout with an injector and producer. The second experiment implemented a triplet well layout with one injector and two producers. Selection of production well trajectory so as to intersect the hydraulic fractures was guided by AE events produced during hydraulic fracture stimulation. The rock specimens were subjected to sustained heating and true-triaxial stress confinement throughout a series of drilling, stimulation, and thermal fluid flow tests. Simulation methods included conventional hydraulic fracturing, hydraulic re-fracturing, and mechanical impulse stimulation. Stimulated reservoir flow was characterized by a series of CP, CF, SCP and SCF injection tests. Injection schedules for each test were tailored according to the observed response of the reservoir to successive injection and circulation treatments. Rock specimens were cross-sectioned after testing to measure the final 3D geometries of induced fractures. Creation of EGS reservoirs was successful in both experiments but the need for improvements to the stimulation process and well design was also apparent. Suggestions are presented for future EGS design following lessons learned from these experiments.

5.1 G01-90: Binary Well Test

Details regarding the setup of G01-90 were provided in Section 3.2 with images of the G01-90 specimen prior to hydraulic fracturing shown in Fig. 3.9. The discontinuous band characterized by a relatively dense concentration of quartz was measured at roughly 20º dip. No persistent discrete fractures were visible in the specimen prior to hydraulic fracturing. The specimen was heated to 50 ºC and subjected to confinement of 12.5, 8.3, and 4.1 MPa for the vertical, intermediate and minimum principal stresses, respectively. Heating was applied slowly to reduce risk of thermal fracturing. These conditions represent an idealized 460 m deep HDR reservoir in an anisotropic stress state.

An overview of the injection schedule for G01-90 was provided in Table 3.2. Drilling, hydraulic stimulations and injection tests were all performed while HDR reservoir conditions were continuously maintained and monitored, when possible. A temporary lapse in acquisition and application of heating occurred between CF #5 and SCF #2 during an extended power loss due to a wind storm.

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4 Modified from paper by Luke P Frash, Marte Gutierrez, Jesse Hampton and John Hood submitted for peer review and publication in Geothermics.
Fig. 5.1 shows well pressure and injected fluid volume data from each of the four stimulation stages, including MIF stimulation. A constant pumped flow rate of 0.05 mL/min was used for the hydraulic fracture and re-fracture stimulation treatments. The upstream pressure for MIF stimulation was set at 65 MPa. Injected fluid volume data was corrected for hydraulic compliance following Eq. 3.1 with compliance coefficients of $5.7 \times 10^{-5}$ mL/kPa for the hydraulic fracture and re-fracture stimulations, and $4.0 \times 10^{-5}$ mL/kPa for the MIF stimulation. The linear compliance coefficients were calibrated from the pressurization data recorded when outflow through the injection well was negligible or blocked by a closed valve. This condition was valid during well pressurization prior to the first hydraulic fracture and during pressurization of the pumps for MIF. Note that that a polynomial compliance relationship was used for the previously shown MIF treatment plot given in Fig. 3.12. Variance was expected in hydraulic compliance as a function of fluid compressibility and volume of trapped gas in the hydraulic system.

AE event source locations acquired for all stimulations are shown in Fig. 5.2. Alternative perspectives for this same data were presented in Fig. 3.11 and Fig. 3.15. AE data from the initial hydraulic fracture stimulation was used to estimate the hydraulic fracture location for selection of the production borehole alignment, as shown in Fig. 5.3. Clustering of AE events indicated that the fracture was likely bi-wing with a dominant wing propagating in the negative $y$-direction, perpendicular to the minimum principal stress direction ($x$-axis). The surface position of the production well relative to the injection well was 58 mm in the negative $y$-direction and 68 mm in the negative $x$-direction with a declination angle of $60^\circ$ from the $x$-axis. This alignment intercepted the hydraulic fracture at approximately 118 mm depth into the granite specimen and provided a distance of at least 58 mm between the axes of the injection and production wells. A well separation distance of at least 50 mm was preferred to reduce the superposition of stress concentration effects on fractures located between the two wells (Frash, 2012).

Hydraulic re-fracturing treatments were observed to continue propagation of the bi-wing fracture as evident in extension of the AE event cloud. Fracture breakthrough at the rock specimen’s surface is expected to have occurred during the second re-fracturing treatment. This hypothesis is supported by the significant well injectivity increase observed after the second re-fracture (Fig. 3.16). Injectivity was negligible after the primary hydraulic fracture treatment and first re-fracture treatment. MIF produced a distinctive large magnitude AE event coincident with the arrival of the pressure impulse. The hypocenter of this event was located at the base of the injection well casing.

Fig. 5.2 also includes the final fracture geometry observed from cross-sections cut from the specimen after the conclusion of the test. Correlation between recorded AE events and the fracture location is clearly evident. The curvature of the hydraulic fracture matches the curvature indicated in the AE data.
Fig. 5.1. G01-90 stimulation pressures and fluid volumes.
Fig. 5.2. AE events recorded during G01-90 stimulations and final fracture location.
Fig. 5.3. Estimated fracture location in G01-90 after primary hydraulic fracture treatment.

Fig. 5.4 compiles and compares all SCP and SCF results from G01-90. SCP control with programmatically timed steps was found to produce more repeatable results than SCF. Injectivity was observed to diminish with time during each step and with total injection time. Individual steps did not exhibit a simple asymptotic behavior approaching a steady state but instead exhibited a continuous degradation of injectivity with total flow time. Similar fracture flow degradation behavior has been observed in previous work regarding proppant pack conductivity testing (API, 1989). Typical hysteresis in SCP tests indicated higher injection rates associated with decreasing pressure steps than with increasing steps (Fig. 2.18). Overlap of results between consecutive SCP tests shows non-permanence of both the hysteresis effects and the time-dependent decreases to injectivity. Low levels of AE activity during SCP and SCF injections indicated negligible new fracture growth. Significant and permanent increases to injectivity were observed after stimulations with the highest injectivity achieved by MIF.
Oil injection data is highlighted to distinguish the effects of viscosity from those of stimulations. The arrow in Fig. 5.4 highlights a series of four SCP tests conducted with a count of 9 steps starting at 2 MPa from a series of three SCP tests conducted with a count of 21 steps starting at 0.5 MPa. A reduction in flow rate when comparing these two SCP test series shows decreased injectivity with total flow time.

Fig. 5.4. SCP and SCF summary for G01-90.

Production was insufficient for acquisition of EGS thermal flow data until MIF was performed. Fig. 5.5 shows the production rate from the reservoir as a function of injection rate using data from SCF tests. A maximum ratio of fluid production rate to injection rate was measured at 18% for water injection at a rate of 0.5 mL/min. Higher injection rates resulted in a larger percentage of fluid leak-off. Fluid leak-off was expected to be dominated by flow through the fracture to the surface of the granite specimen. Flow through the granite matrix was also evident from staining proximal to the hydraulic fracture (Fig. 5.6). Staining appeared to result from penetration of oil into the granite matrix and typically extended less than 25 mm from the nearest fracture surface.

Consequences of high fluid loss include accelerated cooling of the reservoir, excess required pumping power and fluid volume (parasitic energy loss), and the possibility for increased risk of induced seismicity. An optimized injection scheme can potentially be achieved by balancing injection rates with production rates. Balanced flow rates were not possible in this HDR experiment as a consequence of atmospheric pore pressure and the inability to produce vacuum lower than 32 kPa using available equipment. Absolute vacuum is 101.4 kPa relative to standard atmospheric pressure at sea level.
Fig. 5.5. Fluid production rates from G01-90.

Fig. 5.6. G01-90 cross-section from 123 mm depth showing four fracture wings.
Temperatures, pressures, and flow rates measured during SCF tests were used to estimate fluid enthalpy and energy transfer rates through elements of the simulated EGS reservoir (Fig. 5.7). Energy transfer rates were estimated as enthalpy change multiplied by flow rate through each reported interval. Leak-off fluid was assumed to equilibrate with the average boundary temperature for the granite specimen at an atmospheric pressure of 83±1 kPa, local to Rocky Mountain Metro Airport (NOAA, 2014). Note the boiling temperature of water at 83 kPa is approximately 94 ºC (Borgnakke and Sonntag, 2009). Leak-off rate was estimated as the difference between the measured rates of injection and production. The results in Fig. 5.7 show that most of the heating occurred through conduction of heat through the well casing into the injection fluid. Sufficient flow velocities were not achieved to counteract this dominant heat flow pathway due to the low hydraulic conductivity of the stimulated fractures and the high thermal conductivity of both the steel and the granite.

Flow from the production well was observed to be non-steady with fluctuating temperatures (Fig. 5.8). Temperature fluctuations were caused by the low absolute pressure at 31.5±2.0 kPa in the production well and the high reservoir temperature at 50±3 ºC. Steam tables show that this state is near the boiling point for water (Borgnakke and Sonntag, 2009). Therefore, both liquid water and steam were being produced and associated evaporation accelerated by the vacuum produced an unstable cooling effect. Uncertainty regarding the steam quality of the fluid causes uncertainty in the enthalpy estimate at the bottom of the production well. Temperature data from a thermocouple on the top of the granite specimen was substituted in place of the direct production well data for bottom hole enthalpy calculation.
Fig. 5.6 shows a cross-section cut from the granite specimen at 123 mm depth after injection testing was completed. Two bi-wing fractures were observed in the cross-sections. One wing of the dominant bi-wing fracture propagated to the boundary of the specimen in the positive y-direction. A different wing from the secondary bi-wing fracture appeared to propagate directly between the production and injection wells with a twisting curvature becoming roughly parallel with and intersecting both wellbore axes. All four fracture wings propagated perpendicular to the minimum principal stress axis (x-axis). The production well successfully intercepted wings from both the dominant and secondary fractures. The final fracture geometry suggests that the secondary bi-wing fracture propagated after the production well was drilled. It is expected that the secondary fractures were created or substantially extended by the MIF treatment as indicated by the significant increase to both injectivity and production shown in Fig. 5.4 and Fig. 5.5.

5.2 G01-93: Triplet Well Test

Images of the G01-93 granite specimen prior to testing are shown in Fig. 5.9. A single band of discontinuous material characterized by a higher than average quartz concentration was observed dipping at a 70º angle, striking at 20º from the x-axis, and passing near the center of the specimen. No other large or persistent discontinuities were observed in the surfaces of the specimen. A thin concrete cap with a thickness of 3 mm or less was applied to the specimen’s faces to improve surface tolerance for stress.
uniformity. The concrete cap also provided protection for thermocouples embedded on the surfaces of the granite specimen. Positions of installed thermocouples and AE sensors are shown in Fig. 5.9. No strain gages were installed for this experiment. The specimen was heated to 80 °C and subjected to confinement stresses of 13.0, 8.0, and 4.0 MPa for the vertical, intermediate, and minimum principal stresses, respectively.

Table 5.1 provides an overview of the fluid injection schedule for this test which included one hydraulic fracture stimulation stage and a series of SCP and SCF injection tests, lasting 28 days in total. Reservoir conditions were maintained throughout with 24 hour monitoring. Hydraulic fracturing was performed using SAE 80W90 oil with 170 to 325 mesh Ballotini glass beads added at a loosely packed (gravity settled) concentration to serve as proppant. A heat exchanger (Fig. 5.10) was installed on the injection wellhead after SCP #37 to cool fluid prior to entry into the true-triaxial cell. Thermally conductive heat sink compound was added to improve heat transfer. Cold tap water continuously flowed through the copper tubing to transport heat away from the wellhead.
Table 5.1. G01-93 testing schedule.

<table>
<thead>
<tr>
<th>General Stage</th>
<th>Fluid</th>
<th>Stage Type and Number</th>
<th>Stage Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Setup</td>
<td>Air</td>
<td>-</td>
<td>Heating to 80 °C</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-</td>
<td>Application of confining stresses</td>
</tr>
<tr>
<td></td>
<td></td>
<td>-</td>
<td>Drilling injection borehole</td>
</tr>
<tr>
<td>Hydraulic Fracturing</td>
<td>80W90 Oil &amp; Proppant 22 cP @ 80 °C</td>
<td>CP #1 2000 kPa</td>
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</tr>
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<td></td>
<td></td>
<td>CF #1 0.05 mL/min (hydraulic fracturing)</td>
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<td>-</td>
<td>Drilling production well #1</td>
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<tr>
<td></td>
<td></td>
<td>SCP #1 2000 to 8000 kPa</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>-</td>
<td>Drilling production well #2</td>
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<tr>
<td></td>
<td></td>
<td>SCP #2 2000 to 8000 kPa</td>
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<tr>
<td></td>
<td></td>
<td>SCP #3 to #4 2000 to 8000 kPa</td>
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</tr>
<tr>
<td>Injectivity Testing</td>
<td>Water 0.35 cP @ 80 °C (Typical)</td>
<td>SCP #5 to #9 2000 to 8000 kPa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CF #3 0.10 mL/min</td>
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<td></td>
<td></td>
<td>SCP #10 to #13 2000 to 8000 kPa</td>
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<td></td>
<td></td>
<td>CF #4 0.20 mL/min</td>
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<td></td>
<td>SCP #14 to #20 2000 to 8000 kPa</td>
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<tr>
<td></td>
<td></td>
<td>CF #5 0.40 mL/min</td>
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<td>SCP #21 to #24 2000 to 8000 kPa</td>
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<td>CF #6 0.80 mL/min</td>
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<td>SCF #1 0.05 to 2.20 mL/min</td>
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<td>SCP #33 to #37 2000 to 18,000 kPa</td>
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<td>Wellhead heat exchanger installed</td>
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<td>SCF #2 to #3 0.05 to 2.20 mL/min</td>
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<td>SCP #41 to #44 2000 to 18,000 kPa</td>
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<td></td>
<td>SCF #4 0.05 to 2.20 mL/min</td>
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<td>SCP #45 to #47 2000 to 18,000 kPa</td>
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<td></td>
<td></td>
<td>SCF #5 0.05 to 6.40 mL/min</td>
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<tr>
<td></td>
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<td>SCP #48 to #49 2000 to 16,000 kPa</td>
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</table>

Fig. 5.10. Copper tube heat exchanger installed on injection wellhead for G01-93.
The injection well was drilled with a 75º declination angle from the negative x-axis along an alignment that passed through the center of the specimen. The respective surface coordinates were 190 mm and 150 mm in the positive x and y-directions, respectively. An oriented alignment was chosen with the intent of producing complex curving fractures which were expected to reorient perpendicular to the applied minimum confining stress (x-axis) with growth away from the near wellbore region.

Fig. 5.11 shows well pressure and injected fluid volume data for the initial hydraulic fracturing treatment and a selection of additional water injection tests. Hydraulic fracturing was performed with a constant oil injection rate of 0.05 mL/min and exhibited multiple breakdown events with a peak pressure at 30.1 MPa. A pressure pulse with a magnitude of 30.9 MPa occurred at the end of the hydraulic fracture treatment resulting from closure of two valves in the hydraulic system when power to the pump controller was briefly interrupted.

AE event locations from the initial hydraulic fracture stimulation (Fig. 5.12) were used to select fracture-intercepting production well alignments. A significant amount of AE activity was observed throughout stimulation and a spike in event frequency was associated with the pressure breakdown event. A second AE event frequency spike was associated with the valve closure event.

SCP and tests performed after hydraulic fracturing indicated poor injectivity but did confirm flow between the injection and production wells, as shown in Fig. 5.13. Re-stimulations with water injection were performed in an attempt to increase hydraulic conductivity between the wells. These re-stimulations used constant injection rates of 0.05, 0.10, 0.20, 0.40, and 0.80 mL/min, sequentially. Well pressure instability and breakdown events were observed during the first water re-stimulation at 0.05 mL/min, as shown in Fig. 5.11. These events suggested new fracture growth but associated AE activity was low and minimal permanent increase to injectivity were measured by SCP testing. Higher flow rate re-stimulations approached pseudo-steady flow conditions and also failed to induce significant permanent increases to injectivity and productivity. These observations justified implementation of high pressure SCP and high flow rate SCF tests. Significant additional stimulation was not expected but higher production rates and greater cooling of the reservoir could be achieved for heat transfer study.

An unexpected pressure response was observed during high rate SCF testing where increased injection rates were associated with lower injection pressures but minimal new fracture stimulation. This result suggests a transitional flow condition, possibly an indicator for a transition from laminar to turbulent flow along a portion of the flow path. It is also possible that this phenomenon is a consequence of thermal flow effects. The transitional pressure-flow phenomenon was observed with and without vacuum pumped production. Two-phase flow effects were introduced when vacuum pumping the production well induced boiling. Modeling is necessary to reveal insight on this observed transitional flow behavior but this work has not yet been attempted.
Fig. 5.11. G01-93 pressures and fluid volumes for CF #1, CF #2, CF #6 and SCF #5.
Fig. 5.12. AE events during selected stages and fracture location for G01-93.
AE events recorded during the initial hydraulic fracture treatment were colored in Fig. 5.12 based on association with the fracture breakdown. Breakdown events (red) were plotted separately from other events (green). Breakdown events were clustered indicating a created fracture with an orientation perpendicular to the minimum principal stress (x-axis). Other events were clustered near the discontinuity band identified in the specimen prior to testing. The alignments of these two groups of events suggested a shear stimulated zone and a tensile hydraulic fractured zone.

AE activity recorded during water re-stimulations and SCF tests was much lower than during the initial stimulation. Event locations throughout all injections tended to follow the same locational trend as the initial hydraulic fracture. Inspection of cut cross-sections identified a fracture plane co-located with the breakdown AE events but no prominent fractures were found in the shear zone.

The first production well was drilled into the tensile zone and the second was drilled into the shear zone enabling a comparison of production rates between the two. Production Well #1 was drilled at \( x \) and \( y \) top surface coordinates of 206 and 193 mm, respectively, to a depth of 120 mm, with a dip of 60° from the negative \( x \)-axis. This alignment intercepted the mid-plane of the breakdown AE event cluster at an approximate depth of 100 mm. Production Well #2 was drilled at top \( x \) and \( y \) surface coordinates of 45 and 174 mm, respectively, to a depth of 162 mm, along an azimuth of 315° from the \( x \)-axis, with a dip of 60°. This alignment intercepted the mid-plane of the other AE event cluster at an approximate depth of 150 mm. Production was ultimately successful only from Production Well #1 which was confirmed to intersect the stimulated hydraulic fracture in post-test cross-sections.
Fig. 5.14 shows production rate as a function of injection rate using data from SCF #3 and SCF #5. Production rates were measurable with vacuum pumping at most injection rates. Passive artesian production was successful only at high rates of injection. Fluid was not successfully produced from Production Well #2 so vacuum pumping was only installed in Production Well #1. A maximum fluid production rate to injection rate ratio of 34% was measured at a water injection rate of 2.20 mL/min. This fluid recovery ratio decreased at lower injection rates and when the production well was maintained at artesian pressures rather than vacuum. It is expected that the lower net fracture pressures associated with vacuum pumping reduced the leak-off pressure gradient and directly contributed to higher fluid recovery ratios. Higher in-situ pore pressures and in-well artificial lift technologies available at the field-scale enables mitigation of issues with fluid leak-off, vacuum induced boiling and imbalance between injection and production rates.

Bottom temperatures in Production Well #1 were observed to be unstable during vacuum pumping with values ranging from 48 to 80 °C while respective injection rates and production rates remained relatively constant. The absolute pressure in Production Well #1 during vacuum pumping was measured at 31.5±2.0 kPa. This low pressure and the rock temperature of 76±3 °C indicated that boiling and accelerated evaporation were the likely cause of the observed temperature variance (Borgnakke and Sonntag, 2009). The enthalpy of the produced fluid could not be directly determined in this condition.
because the quality of the steam in the production well was unknown. Therefore an approximation for the enthalpy of the produced fluid was obtained by extrapolation of the thermal conditions measured in Production Well #2.

Fig. 5.15 shows the estimated energy transfer rates to and from the injected fluid through selected flow intervals. Low-flow fluid production rates for SCF #5, in which vacuum pumping was not applied, were estimated by linear interpolation between zero and the directly measured artesian production rates associated with injection at 6.4 mL/min. Most fluid heating occurred through the injection well casing and only minimal heating was measured across the fracture flow interval. These results demonstrate the importance of achieving high hydraulic conductivity through the stimulated reservoir such that parasitic energy losses can be reduced and heat transfer from the rock to the circulated fluid can be improved. The results also demonstrate the significant role of steel casing in the well as a heat transfer element. Generally the thermodynamic system was expected to be conduction dominated.

![Energy transfer rate graph](image)

Fig. 5.15. Rate of energy transfer through selected zones in G01-93.

A cross-section from G01-93 at 103 mm depth is shown in Fig. 5.16. One bi-wing fracture propagated away from the injection well and this fracture was intercepted by Production Well #1. The fracture extended sub-vertically and parallel with the alignment of the injection well. The fracture length away from the injection well was not extensive enough to produce a twisted fracture surface. Injected dye aided in fracture identification but highlighting was needed for better contrast in the photograph. The discontinuity collocated with the assumed shear zone is highlighted in Fig. 5.12. No prominent fractures or evidence of fluid penetration were identified in the discontinuity band.
5.3 Discussion

G01-90 and G01-93 provide examples of successful model EGS reservoir simulation where hydraulic fractures were created within initially intact HDR specimens, production wells were drilled using AE for guidance, thermal flow data was acquired and created fracture geometries were measured. The applied reservoir conditions represent shallow low-temperature EGS in natural crystalline rock having negligible initial permeability and porosity. Successful reservoir creation was therefore dependant upon stimulation of hydraulically conductive fractures between a set of injection and production wells. The difficulty of EGS simulation was further increased by leak-off which was increased by the lack of pressurized pore fluid and the extension of created fractures to the boundary of the specimen. Hydraulic fracturing contained within the bounds of the specimen was attempted but unsuccessful for effective EGS simulation due to poor hydraulic conductivity through the small associated fractures. General difficulties
encountered with these experiments included challenges with accurately estimating fracture locations and extents, understanding the effects of natural discontinuities and achieving high enthalpy fluid production at high rates while also minimizing fluid loss and secondary seismic stimulation. These same challenges exist at the field scale.

Drilling successful production wells in these experiments was reliant on understanding the AE events produced during stimulation. Selected production well alignments were chosen using AE guidance alone where knowledge of the stress state relative to the plotted axes was blinded to reduce bias. Estimation of the stimulated fracture locations was improved by correlation of AE events with pressure data where events concurrent with pressure breakdown were analyzed separately from others. This procedure was critical with G01-93 where a significant number of events occurred during pressurization along a different alignment than the breakdown events. Subsequent SCP and SCF tests in G01-93 found that production was significant from a well which intersected the breakdown AE event cluster but negligible from a second well which intersected another clustering of AE events. The breakdown event cluster was interpreted as a tensile hydraulic fractured zone and the other cluster was interpreted as shearing along a pre-existing discontinuity.

Thermal flow though the simulated EGS reservoir was observed to be a complex function of geometry, injection pressure, temperatures, and flow history. Geometry was expected to be the dominant factor controlling flow were production required successful intersection of a production well with stimulated fractures from the injection well. Flow was increased by secondary stimulations in both experiments with the most significant improvement observed after MIF which was performed as a dynamic impulse treatment rather than as a pseudo-static conventional hydraulic fracturing treatment. The effect of adding proppant to the injection fluid was undetermined by these experiments. Significant injectivity and productivity changes followed treatments which caused high levels of AE activity, indicating displacements and new fracture growth. Comparison of SCP and SCF data demonstrated that flow through the fractured specimens was better represented as a function of pressure than as a function of flow rate. Pressure controlled injection tended to produce pseudo-steady flow conditions while flow rate control produced unsteady fluctuating pressures and possibly additional stimulation. It is also expected that continuous constant pressure injection was more likely to induce clogging behavior as indicated by the steady decrease in flow with time during each SCP test step. Temperatures directly affected flow through the reservoir with the most prominent example attained during SCP #39 from G01-93 (Fig. 5.17) where interruption of water supply to the wellhead heat exchanger directly affected injectivity data. Additional testing and analysis is still needed to better understand the relationship between flow and temperature through fractures. Flow history was also observed to have a significant effect during SCP tests were increasing pressure steps produced systematically lower injectivity than
decreasing pressure steps. It is expected that time dependence of flow is a consequence of fracture hydraulic compliance in the fracture which could produce an apparent self-propping effect. Flow is fundamentally time dependent, being a time derivative of fluid volume, so other factors not considered here could also have affected the observed results.

Fig. 5.17. G01-93 SCP #39 exhibiting direct flow response with change to injected fluid temperature.

Fracture geometries observed from cross-sections after testing showed a tendency for hydraulic fractures to match the alignments of wellbores that they intersected and fracture growth was also found to be directly affected by discontinuities and heterogeneities. In G01-90 a secondary bi-wing fracture was found to curve and directly intersect the alignments of both the injection well and production well which it intersected. In G01-93 the created fracture followed the injection well alignment matching the 75° dip but otherwise propagating semi-perpendicular to the minimum principal stress axis. These fracture propagation trends agree with the results of similar previous studies (Zoback et al., 1977; Berhmann et al., 1991; Weijers et al., 1994; Athavale and Miskimins, 2008).

Pre-existing discontinuities were observed to directly affect the fracture geometries and observed AE activity during these tests. The sub-horizontal discontinuity in G01-90 inhibited upward fracture growth. In G01-93 the sub-vertical discontinuity was observed to generate significant AE activity without any associated hydraulically conductive fracture growth. It is expected that deformations in this discontinuity were a factor contributing to the resisting growth of the primary bi-wing hydraulic fracture. Predicting the influence of discontinuities is difficult due to unknowns regarding strength and permeability relative to the surrounding rock matrix. Grain scale heterogeneity was observed to have a direct effect on fracture roughness when comparing these results with similar tests in acrylic (Frash et al., 2013a).
CHAPTER 6
GRAIN-SCALE INFLUENCE ON 3D FRACTURE GEOMETRY

Geometry is a dominant factor controlling hydraulic fracture conductivity, stimulated reservoir volume and consequently well productivity or injectivity. Fracture geometries are expected to be complex due to the influence of rock structure. A better understanding of complex fracturing can lead to an improved means of evaluating both real and synthetic three-dimensional (3D) hydraulic fracture stimulation effectiveness. This in turn can lead to improved design of stimulation treatments for higher fluid flow and better proppant placement.

Laboratory scale hydraulic fracturing experiments were performed using a variety of specimen materials, boundary conditions and injection fluids to produce a range of final hydraulic fracture geometries. 3D fracture structural trends were identified and analyzed from cut cross-sections. Grain-scale fracture mechanisms were inspected using photomicrographs. Observed 3D fracturing phenomena included branching, coalescence and self-propping. Implications of the complex fracture geometries for increasing and decreasing hydraulic conductivity are analyzed and discussed. Scaling phenomena and the influence of pre-existing discontinuities and grain-scale heterogeneity on fracture geometry were investigated. Large discontinuities were found to cause fracture divergence and complexity while far-field stresses and small heterogeneities tended to induce convergence.

6.1 Summary of Experiments

Table 6.1 overviews the completed hydraulic fracturing experiments. A total of 13 specimens were tested. Auxiliary objectives for each experiment are included to explain the selected parameters. Experiments A01-03, A01-04, G01-00, G01-90 and G01-93 included a series of injection tests performed at pressures less than the hydraulic fracturing threshold. CF, CP, SCF and SCP injections were used to evaluate borehole injectivity and productivity for these experiments. Multiple hydraulic fracture stimulations were executed for P01-00, E01-00, E02-00, G01-00, G01-90, G01-92 and G01-93. 13 boreholes were drilled into P01-01, 5 of which were hydraulically fractured. Hydraulic fracturing of all other specimens was performed through only one borehole. Multiple stimulations were performed in a single borehole if the first attempt was unsuccessful or increased injectivity was required. All stimulations were monitored for AE to evaluate new fracture growth. Self-potential monitoring (Haas et al, 2012) was applied for P01-01 and G01-00. The focus of this chapter is directed towards the structure of the final fracture and the influence of grain-scale fracturing phenomena on the macro-scale geometry.

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5 Modified from paper manuscript by Luke P Frash, Marte Gutierrez, Azra Tutuncu, Jesse Hampton, John Hood, Hai Huang and Earl Mattson under internal review for submission to International Journal of Rock Mechanics and Mining Sciences.
Table 6.1. Summary of laboratory experiments and parameters.

<table>
<thead>
<tr>
<th>ID</th>
<th>Material and dimensions (mm(^3))</th>
<th>Stresses (&lt;\sigma_v, \sigma_H, \sigma_I&gt;) and temperature</th>
<th>Injection fluids</th>
<th>Auxiliary objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>P01-00</td>
<td>Commercial Concrete 305x305x275</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Brine, water, oil</td>
<td>Testing laboratory hydraulic fracture methods</td>
</tr>
<tr>
<td>P02-00</td>
<td>Commercial Concrete 300x300x300</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Oil</td>
<td>Practice working with acoustic emission monitoring system</td>
</tr>
<tr>
<td>E01-00</td>
<td>Custom Concrete 300x300x293</td>
<td>(&lt;0, 6.1, 3.1&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Brine, water</td>
<td>Validation of true-triaxial confinement system</td>
</tr>
<tr>
<td>E02-00</td>
<td>Custom Concrete 300x300x300</td>
<td>(&lt;13.3, 8.6, 4.4&gt; \text{ MPa at } 35 \degree \text{C})</td>
<td>Oil</td>
<td>Validation of heated true-triaxial confinement system</td>
</tr>
<tr>
<td>A01-03</td>
<td>Acrylic 380x140</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Oil</td>
<td>Visualization of fracturing with oil</td>
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<tr>
<td>A01-04</td>
<td>Acrylic 760x127</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Oil with proppant</td>
<td>Validation of laboratory proppant injection method</td>
</tr>
<tr>
<td>A01-05</td>
<td>Acrylic 760x127</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Marine epoxy</td>
<td>Validation of laboratory epoxy injection method</td>
</tr>
<tr>
<td>G01-00</td>
<td>Granite 300x240x300</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>Oil, water</td>
<td>Testing laboratory hydraulic fracture methods in granite</td>
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<td>(&lt;12.8, 8.6, 4.3&gt; \text{ MPa at } 50 \degree \text{C})</td>
<td>Oil, water</td>
<td>Simulation of doublet enhanced geothermal system</td>
</tr>
<tr>
<td>G01-91</td>
<td>Granite 300x300x300</td>
<td>(&lt;0, 0, 0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>E-120HP epoxy</td>
<td>Hydraulic fracture with high-viscosity fluid in granite with enhanced fracture visualization</td>
</tr>
<tr>
<td>G01-92</td>
<td>Granite 300x300x300</td>
<td>(&lt;13.0, 8.0, 8.0&gt; \text{ MPa at } 25 \degree \text{C})</td>
<td>Water with proppant and dye</td>
<td>Hydraulic fracture with low-viscosity fluid in granite with enhanced fracture visualization</td>
</tr>
<tr>
<td>G01-93</td>
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<td>(&lt;13.0, 8.0, 4.0&gt; \text{ MPa at } 80 \degree \text{C})</td>
<td>Oil with proppant, water</td>
<td>Simulation of triplet enhanced geothermal system</td>
</tr>
<tr>
<td>S01-00</td>
<td>Limestone 300x300x300</td>
<td>(&lt;13.0, 10.0, 5.0&gt; \text{ MPa at } 23 \degree \text{C})</td>
<td>E-60NC epoxy</td>
<td>Fracture geometry study in complex rock structure</td>
</tr>
</tbody>
</table>

* Dimensions in length\x2d*width\x2d;height or diameter\x2d;height

### 6.2 Non-granular Fracture Structures

Simple and relatively ideal hydraulic fracture geometries were observed in the unconfined acrylic experiments. Fig. 6.1, Fig. 6.2 and Fig. 6.3 show images of the final fractures observed in the acrylic specimens. Fracture wings in all three experiments were semi-penny shaped and propagated radially outwards, parallel with the borehole axis. The number of fracture wings was different for each experiment where A01-03, A01-04 and A01-05 had with one, two and four dominant fracture wings, respectively.
Drilling induced flaws near the wellbore were found to increase the complexity of the final fracture geometry. Flaws propagated radially with fracture growth causing a plumose/flabellate texture in the fracture faces.

Fig. 6.1. Fracture in A01-03 with oil injection.

Fig. 6.2. Fracture in A01-04 with oil and proppant slurry injection.
Tensile, shearing, tearing and mixed fracture propagation modes were all identified in A01-05. Fig. 6.4 shows photomicrographs of each fracturing mode along with interpreted tip displacement vectors and propagation direction. The fractures are filled with off-white epoxy. Tensile opening was clearly the dominant mode of fracturing. Shearing fractures were prominent near the wellbore where drilling induced flaws were propagated. These shear fractures likely increased flow tortuosity through the near wellbore zone. Tearing was the most difficult fracturing mode to identify. Most examples of tearing were located between parallel and offset tensile fracture planes. Tearing tended to connect adjacent tensile fractures. The photomicrograph of tearing in Fig. 6.4 shows a cross-section through an upper tensile fracture plane while a lower offset tensile fracture plane is also visible through the transparent acrylic material.

Photomicrographs and video data (Frash et al., 2013) show that the fracture geometry was highly elliptical with respect to length, height and aperture (Frash et al., 2014). The elliptical shapes became smoother and more planar as the fractures lengthened and grew out of the near well zone. The fracture tip was observed to lag behind the elliptical fracture front at some localized points with an example highlighted in Fig. 6.3. These lagging fracture tips were co-radial with tearing mode fractures which could be traced back to drilling induced flaws near the injection well. The near well flaws were expected to be the cause of the initial offset between parallel fracture planes. Video of the fracture growth shows that the tensile fracture front preceded the tearing fracture which indicates that the tearing fractures required more energy to propagate.
Fracture growth in A01-05 was slow and controlled where a total of 32 min elapsed between fracture initiation and breakthrough at the surface of the specimen. Video of the fracture shows that all fracturing modes were propagating simultaneously beginning at multiple initiation locations. It is expected that simultaneous propagation of multiple fracture modes can also occur in rocks where the tensile front likely precedes the shearing front. This expectation assumes the mechanisms observed in these acrylic experiments are indicative of comparable processes in real rock.

### 6.3 Grain-scale Fracture Structures

Grain-scale fracturing was clearly identifiable in cross-sections cut from G01-91 and S01-00, shown in Fig. 6.5 and Fig. 6.6, respectively. The epoxies injected for these experiments in-filled and preserved the hydraulic fractures providing a clear contrast between the fracture and the surrounding rock.
Fig. 6.5. Simple fracture geometry in G01-91.

Fig. 6.6. Complex fracture geometry in S01-00 with vertical tensile plane and propagation along pre-existing discontinuities.

G01-91 resulted with a simple hydraulic fracture having relatively ideal planar bi-wing geometry. Fractures in G01-91 are filled with translucent epoxy which typically exhibits a light-gray or light-pink color in photomicrographs. S01-00 resulted with a complex hydraulic fracture including a vertical tensile plane and propagation along three pre-existing discontinuities. One of the propagated discontinuities was a member of the 25º dipping joint set. The remaining two propagated discontinuities followed bedding
planes. Fractures in S01-00 are filled with black epoxy and are typically bordered with a darkened permeation zone having 0.2 mm nominal depth.

A summary of grain-scale fracturing mechanisms observed in these experiments is shown in Fig. 6.7. Void nucleation and coalescence, transgranular fracturing, and intergranular fracturing (Anderson, 2008) are the basic grain-scale fracture propagation mechanisms.

<table>
<thead>
<tr>
<th>Granular Fracture Mechanism</th>
<th>Initial State</th>
<th>Fractured State</th>
<th>Laboratory Scale Examples</th>
</tr>
</thead>
<tbody>
<tr>
<td>Void Nucleation and Coalescence</td>
<td><img src="image1" alt="Void Diagram" /></td>
<td><img src="image2" alt="Fractured Void Diagram" /></td>
<td><img src="image3" alt="Void Example" /></td>
</tr>
<tr>
<td>Transgranular Fracturing</td>
<td><img src="image4" alt="Transgranular Diagram" /></td>
<td><img src="image5" alt="Fracture Through Grains" /></td>
<td><img src="image6" alt="Transgranular Example" /></td>
</tr>
<tr>
<td>Intergranular Fracturing</td>
<td><img src="image7" alt="Intergranular Diagram" /></td>
<td><img src="image8" alt="Fracture Along Grain Boundaries" /></td>
<td><img src="image9" alt="Intergranular Example" /></td>
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<td>Granular Fracture Bifurcation</td>
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<td><img src="image11" alt="Single Fracture" /></td>
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<td>Transportable Grain Release</td>
<td><img src="image13" alt="Transportable Diagram" /></td>
<td><img src="image14" alt="Released Grains" /></td>
<td><img src="image15" alt="Transportable Example" /></td>
</tr>
</tbody>
</table>

Fig. 6.7. Granular fracture mechanisms.
Void nucleation and coalescence is conventionally considered as a mechanism for ductile fracture propagation (Anderson, 2008) but a similar effect can occur in brittle rock when heterogeneities, voids and pre-existing micro-fractures are present. A microindentation study in granite (Ramirez, 2014) measured elastic modulus values of 29, 76 and 99 GPa for biotite, feldspar and quartz, respectively. These minerals are common in all granites. It is reasonable to expect comparable grain-scale variation of mechanical properties in other natural rocks as well. Local strength and stiffness heterogeneity implies a significant potential for fractures to form and dilate proximal to the hydraulic fracture zone prior to coalescing with a propagating fracture plane. This concept is supported by AE source localization which commonly shows a ‘cloud’ of AE events (micro-fractures) near a hydraulic fracture zone. An example showing AE activity proximal to a hydraulic fracture is shown in Fig. 6.8 using data from G01-90.

Fig. 6.8. Correlation of AE events with coalesced hydraulic fracture plane in G01-90.
Transgranular fracturing and intergranular fracturing are both expected to occur in heterogeneous rocks. These fracturing mechanisms are dependent upon the bond strengths between grains relative to the strength of the grains themselves. Photomicrographs from G01-91 and S01-00 identified multiple examples of both transgranular and intergranular fracturing but the absolute scale at which this distinction occurs was not determined. Intergranular fracture growth can be considered to occur through grains consisting of a single mineral type if the fracture follows the grain’s substructure. The substructure of a grain can include laminations, contaminants, inclusions or crystalline lattices which give preferred cleavage planes. These substructures can be large in scale or as small as atomic structure. Note that the photomicrographs used in this study have 0.5 µm maximum resolution. This represents a linear span of roughly 2000 atoms as calculated for pure quartz at 25 ºC using a mean specific atomic volume of 13 Å³/atom (Kihara, 1990).

A combination of the three basic grain-scale fracturing mechanisms can result with granular fracture bifurcation (GFB) and transportable grain release (TGR) phenomena. GFB refers to the splitting of a fracture plane into two or more strands due to the influence of grain-scale structure. Potential scenarios for GFB include interception of the fracture with a strong grain or interaction between the fracture and an adjacent unbounded or weakly bonded grain boundary. In these instances and with suitably oriented grain boundaries two parallel fractures can be initiated. The multiple fracture strands do not necessarily overlap as the phenomenon is three-dimensional. TGR refers to the liberation of unbounded grains from the rock matrix. The occurrence of this phenomenon is similar to GFB except that the intercepted grain maintains no bonds with the rock matrix. Transportable grains can be moved by the fracturing fluid, potentially having the effect of clogging or self-propping the fracture.

6.4 Macro-scale Fracture Geometries

Each laboratory-scale hydraulic fracture experiment resulted with a unique 3D geometry. Common trends were identified among the final hydraulic fracture structures. Raw data associated with the observed trends is presented in the appendices. General fracture structures included simple planar fracture, discontinuity activation, lengthwise branching and coalescence, transverse strand coalescence, rotation and twisting, and complex fracture network stimulation. These structures are illustrated in Fig. 6.9 alongside examples from physical specimens. Note the common applied true-triaxial stress directions for the 3D and sectional perspectives where the x-axis is parallel with the minimum principal stress (σh), the y-axis is parallel with the intermediate principal stress (σHy) and the z-axis is parallel with the maximum principal stress (σv). The 3D and sectional plots for the complex fracture network were produced directly from measurement of the S01-00 specimen. The other 3D and sectional plots were produced from synthetic data which was closely based on laboratory observations.
Fig. 6.9. Three-dimensional fracture geometrical structures.
Simple planar fracture represents the simplest fracture geometry and a commonly assumed shape for modeling (de Pater et al., 1994; Perkins and Kern, 1961; Nordgren, 1972; Geertsma and de Klerk, 1960). This geometry resulted from tensile dominated fracture propagation radially away from the borehole and often exhibited a semi-elliptical fracture front. This was also the most commonly observed macro-scale fracture geometry with examples identified in all specimens except for E01-00, G01-92 and G01-93. More complex fracture structures were typically observed as substructures within the tensile dominated fracture plane. These laboratory results support the expectation that rock stresses, borehole orientation and fluid parameters dominate over the influence rock structure, particularly when high viscosity fluids were used (de Pater et al., 1994).

Discontinuity activation was observed at some scale in all experiments with the most prominent examples identified in G01-00, G01-92 and S01-00. In G01-00, an off-vertical discontinuity was intersected and propagated while seven additional vertical tensile hydraulic fracture wings also propagated away from the injection borehole. In G01-92, the low-viscosity injected water flowed through a pre-existing fracture network. Distributed AE events recorded during this injection indicated activation and likely propagation of pre-existing fractures. In S01-00, the hydraulic fracture interacted with bedding planes and one pre-existing calcite filled joint dipping at 25° from x-axis (Fig. 6.6). Indirect tensile strength testing measured a reduction of tensile strength along the calcite filled joints (Mokhtari et al., 2014). A similar reduction of tensile strength was evident along the bedding planes because several other limestone specimens cracked along these planes during preparation. It is important to note that a vertical planar hydraulic fracture was also created in S01-00 despite the presence of the pre-existing structural discontinuities. This vertical fracture crossed multiple parallel calcite filled fractures with negligible interaction.

Lengthwise fracture branching and coalescence was observed in all specimens. The prominence of this structure supports description of the stimulated fractures as a hydraulic fracture zone (Warpinski and Teufel, 1987) or as a fracture band (Aydin et al., 2006). This structure typically appeared in cross-sections as branching of a single fracture strand into multiple fracture strands (Fig. 6.9) or through a union of parallel fracture strands. Fracture strands in cross-sections were often not hydraulically connected in the viewing plane, especially when viewed in sections normal to the propagation direction. The 3D geometry of fracture strands was more complex than the 2D cross-sections implied. Branched vertical tensile fracture strands were frequently laterally offset and overlapping for only a portion of the total height. The tensile fractures strands changed dominance through the overlapping zone. A single tensile fracture strand tended to dominate the hydraulic fractured zone beyond the overlapping zone. Fracture strands typically shared a single and hydraulically connected fracture plane when traced back to the injection borehole. The geometry of the acrylic fractures suggests that branching occurs with a sudden
change along the length of the fracture while coalescence tends to be more gradual. The number of strands in heterogeneous rock tended to increase with distance away from the injection well.

Transverse strand coalescence represents a special case of fracture branching and coalescence in which sub-parallel tensile fracture strands are linked with an out-of-plane shear (tearing-mode) fracture. Examples of transverse coalescence were identified in A01-05, G01-91 and S01-00. The transverse fractures observed in these examples tended to form along pre-existing discontinuities, as visible for S01-00 (Fig. 6.9). The transverse fractures observed in these structures are not well understood at this time but they do provide a means for vertical hydraulic conductivity between offset vertical fracture strands and they also appear to gain likelihood of propagating with increased fracture growth.

Rotation and twisting fracture structures were observed in E01-00, G01-90, and G01-93. All three of these experiments included boreholes which were drilled at non-perpendicular angles relative to the minimum principal confining stress. Rotating and twisting fractures typically formed with reorientation influenced by local and far-field stresses. Fractures tended to initially propagate on a plane parallel with the borehole axis but would rotate and twist to become perpendicular to the far-field minimum principal stress direction. This phenomenon was most prominent in E01-00 where the injection well’s axis was parallel with the minimum principal far-field stress. Fracture initiation in E01-00 was parallel with the well axis even though basic theory predicted transverse fracture initiation (Haimson and Fairhurst, 1967). Some twisting fracture structures included branching effects resulting in multiple tensile dominated fractures with significant lateral offset. Fig. 6.9 shows a magnified example of this effect and a second example from E01-00.

Fig. 6.10. Second example of rotation and twisting fracture structure.
Combination of these fracture structures can occur to produce complex fracture networks. A prominent example of a complex fracture network was observed in S01-00. This limestone experiment produced a simple planar bi-wing fracture, discontinuity activations along pre-existing joints and bedding planes, lengthwise branching and coalescence, and transverse strand coalescence. Most fracture branching occurred at the small scale but some branching also occurred at the macro-scale with influence from activated discontinuities. When offset fracture branches were traced back to the injection borehole they were found to share a common plane. Transverse strand coalescence was observed along a pre-existing discontinuity. No significant rotation or twisting was identified in this experiment likely due to drilling the injection well parallel with the maximum principal stress.

6.5 Discussion

This series of 13 hydraulic fracture experiments provided insight on the geomechanical mechanisms contributing to complex hydraulic fracture geometries. It is important to understand these mechanisms because of the direct relationship between fracture geometry and stimulated well productivity or injectivity. Results from these experiments are discussed following implications regarding scale-dependence of fracture growth and influence of grain-scale and macro-scale fracture complexity on fluid flow.

Scale-dependence of hydraulic fracture growth

Hydraulic fracture growth is scale-dependent. Macro-scale fracture geometry results from an aggregation of grain-scale fractures. Grain-scale fractures result from an aggregation of severed atomic bonds. Fracture complexity at the large-scale is therefore a consequence of structural heterogeneity at smaller scales.

It is reasonable to assume that rock heterogeneity can be expressed stochastically, presumably following a power law distribution (Leary, 2003). Large-scale discontinuities tend to cause divergence of fracture growth, forming complex structures, while small-scale discontinuities tend to result with gradual convergence (e.g. central limit theorem in probability theory). This behavior was observed when comparing fractures in the acrylic with those in granite. Near wellbore drilling induced discontinuities in the acrylic induced significant local hydraulic fracture complexity but this complexity diminished with propagation of the fracture through the relatively homogenous bulk acrylic matrix. This was most evident in the plumose texture of the acrylic fractures which diminished with radial propagation. Fractures in the granite exhibited the inverse behavior where complexity tended to increase with length. The increase in complexity was likely due to the influence of grain-scale discontinuities and heterogeneities.
Influence of grain-scale on macro-scale geometry and flow

Mixed-mode fracturing at the grain-scale resulted in fracture roughness. Intergranular fracturing was typically attributed to higher surface roughness than transgranular fracturing, likely the result of increased prevalence of shearing fractures along the grain boundaries. Fracture roughness has a direct affect on fracture permeability especially when the aperture is small. Increased roughness corresponds with more localized changes in flow direction which has the effect of increased frictional pressure losses. Permeability reduction due to surface roughness is expected to decrease with increasing fracture aperture especially when laminar flow can be assumed (Valkó and Economides, 1995; Warpinski, 1982). Fracture roughness can also result with increased permeability when shearing displacements occur at the macro-scale. Asperities between offset fracture surfaces can create open flow channels which persist after hydraulic fracture closure (Deteiler and Morris, 2014).

Granular fracture bifurcation (GFB) is expected to be the primary mechanism for macro-scale fracture branching. Most observed instances of granular fracture bifurcation resulted with localized fracture branching and were followed immediately with fracture coalescence. However, some examples (Fig. 6.7) were observed to initiate fracture stranding. Stranded fractures are expected to be less permeable than single fractures assuming smooth total aperture as a function of length. This relationship is shown in Fig. 6.11 where permeability was calculated assuming parallel plate flow (Eq. 1.14). Fracture dimensions were modeled after A01-05. The apertures of strands A and B were varied from 0 to 0.14 mm such that the summed aperture was constant and equal to 0.14 mm. Relative aperture is therefore expressed as a percentage of the maximum. Calculated permeability was normalized by the single fracture solution. This simple calculation predicts a 75% reduction in permeability when two fracture strands of equal aperture replace a single fracture having the same total aperture.

![Diagram showing permeability through stranded fracture flow](image)

Fig. 6.11. Relative permeability through stranded fracture flow.
Transportable grain release (TGR) is another mechanism with the potential to increase or decrease fracture permeability. Transportable grains freed from the matrix can act as proppant after fracture closure. These particles can therefore maintain a residual permeable fracture aperture even when no proppant is added to the injection fluid. The in-situ source also ensures chemical compatibility with pore fluids giving reduced potential for chemical dissolution of the proppant. Transportable grains also have the potential to clog fracture flow, similar to tip screen out. The grains can get trapped on asperities and in pore throats causing a reduction in permeability.
A total of 13 test specimens were hydraulically fractured to study complex fracture propagation, experiment with mechanical impulse hydraulic fracturing, advance EGS technology, and acquire data for validation of new fracture models. Specimen materials included acrylic, concrete, granite and limestone. Injection fluids included water, brine, oil, epoxy and slurries with proppant. Confinement conditions included unconfined and true-triaxial with heating applied in three of the experiments. An overview of the completed tests with respective objectives was outlined in Table 7.1. Results from these tests provided insight on the hydraulic fracturing process benefiting from the direct comparison of pressure, flow rate, acoustic emissions (AE), strain, temperature, self-potential (SP), and fracture geometry data.

7.1 Mechanical Impulse Fracturing

Mechanical impulse hydraulic fracturing (MIF) was applied as a re-stimulation method to increase well injectivity for G01-00 and G01-90. Both of these specimens were granite, included an injection well and a production well, used a vertical centered injection well alignment, and were initially hydraulic fractured with SAE 80W90 oil injection. G01-00 was unconfined and maintained at a room-temperature of 23 °C. G01-90 was subjected to true-triaxial stress confinement and a 50 °C average boundary temperature. MIF successfully, significantly and permanently increased well injectivity in both specimens as evident from well injectivity data acquired before and after MIF, as shown in Fig. 7.1.

![Fig. 7.1. Water injectivity data for G01-00 and G01-00.](image)
Table 7.1. Overview of hydraulically fractured specimens and experiment parameters.

<table>
<thead>
<tr>
<th>ID</th>
<th>Material and dimensions* (mm³)</th>
<th>Stresses &lt;σ_v, σ_H, σ_h&gt; and temperature</th>
<th>Injection fluids</th>
<th>Auxiliary objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>P01-00</td>
<td>Commercial Concrete 305x305x275</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Brine, water, oil</td>
<td>Testing laboratory hydraulic fracture methods</td>
</tr>
<tr>
<td>P02-00</td>
<td>Commercial Concrete 300x300x300</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Oil</td>
<td>Practice working with acoustic emission monitoring system</td>
</tr>
<tr>
<td>E01-00</td>
<td>Custom Concrete 300x300x293</td>
<td>&lt;0, 6.1, 3.1&gt; MPa 23 ºC</td>
<td>Brine, water</td>
<td>Validation of true-triaxial confinement system</td>
</tr>
<tr>
<td>E02-00</td>
<td>Custom Concrete 300x300x300</td>
<td>&lt;13.3, 8.6, 4.4&gt; MPa 35 ºC</td>
<td>Oil</td>
<td>Validation of heated true-triaxial confinement system</td>
</tr>
<tr>
<td>A01-03</td>
<td>Acrylic 380x140</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Oil</td>
<td>Visualization of fracturing with oil</td>
</tr>
<tr>
<td>A01-04</td>
<td>Acrylic 760x127</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Oil with proppant</td>
<td>Validation of laboratory proppant injection method</td>
</tr>
<tr>
<td>A01-05</td>
<td>Acrylic 760x127</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Marine epoxy</td>
<td>Validation of laboratory epoxy injection method</td>
</tr>
<tr>
<td>G01-00</td>
<td>Granite 300x240x300</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>Oil, water</td>
<td>Testing laboratory hydraulic fracture methods in granite</td>
</tr>
<tr>
<td>G01-90</td>
<td>Granite 300x300x300</td>
<td>&lt;12.8, 8.6, 4.3&gt; MPa 50 ºC</td>
<td>Oil, water</td>
<td>Simulation of doublet enhanced geothermal system</td>
</tr>
<tr>
<td>G01-91</td>
<td>Granite 300x300x300</td>
<td>&lt;0, 0, 0&gt; MPa 23 ºC</td>
<td>E-120HP epoxy</td>
<td>Hydraulic fracture with high-viscosity fluid in granite with enhanced fracture visualization</td>
</tr>
<tr>
<td>G01-92</td>
<td>Granite 300x300x300</td>
<td>&lt;13.0, 8.0, 8.0&gt; MPa 25 ºC</td>
<td>Water with proppant and dye</td>
<td>Hydraulic fracture with low-viscosity fluid in granite with enhanced fracture visualization</td>
</tr>
<tr>
<td>G01-93</td>
<td>Granite 300x300x300</td>
<td>&lt;13.0, 8.0, 4.0&gt; MPa 80 ºC</td>
<td>Oil with proppant, water</td>
<td>Simulation of triplet enhanced geothermal system</td>
</tr>
<tr>
<td>S01-00</td>
<td>Limestone 300x300x300</td>
<td>&lt;13.0, 10.0, 5.0&gt; MPa 23 ºC</td>
<td>E-60NC epoxy</td>
<td>Fracture geometry study in complex rock structure</td>
</tr>
</tbody>
</table>

* Dimensions in length×width×height or diameter×height

The practical feasibility of MIF at the field-scale was evaluated using an analytical method based on estimating hydraulic compliance of the well hydraulic system. The derived method assumed that a hydraulic impulse in the well was generated using a pressurized accumulator on the well pad and a rapid opening valve. Alternative means of MIF with down-hole equipment are expected to be possible and likely preferable but were not considered in this feasibility study. Results from this analysis concluded that the accumulator volume needed to perform MIF in the field was reasonable. Modeling the propagation of the hydraulic impulse from the accumulator and through the well was also attempted. This
model used finite differences to solve the one-dimensional wave equation with sonic wave speed assumed. Results from this model were inconclusive due to over-simplification and were therefore discarded from this study. Actual testing of MIF at the field scale is possible if suitable wells and willing clients are available. An actual field experiment is expected to require only minor modification of existing pumps, tanks, valves and other hydraulic equipment.

It is expected that MIF has the potential to significantly increase well injectivity and productivity based on the observations from these laboratory-scale experiments. Water volumes necessary for MIF is expected to be less than conventional fracturing due to reduced leak-off occurring with the faster treatment times. The method appears to be capable of creating new fracture growth from the wellbore even if the well was previously stimulated or intersects pre-existing permeable fractures. High-strain rate (short pressure rise time) and high fluid pressures are expected to be the key elements for a successful MIF treatment. With adequate consideration in design, it is likely that MIF stimulation treatments can be optimized for different reservoir conditions and rock properties. Alternative designs to the surface accumulator method, such as a down-hole hydraulic pressure impulse device, are also possible with future research and development. Treatment pressures for MIF are expected to be a controllable parameter with less dependence on the rock response than conventional hydraulic fracturing. The potential for MIF as a primary or initial well stimulation method is uncertain at this time because it was only applied as a re-stimulation method in G01-00 and G01-90.

7.2 Critical State Hydraulic Fracture Geometry

Epoxy injection for hydraulic fracturing was used to produce critical state hydraulic fracture geometry data. Specimens using epoxy injection included A01-05, G01-91 and S01-00 with materials of acrylic, granite and limestone respectively. Geometry data collected during these experiments included fracture length, height, aperture and characteristics of fracture complexities. Results from A01-05 provided valuable data regarding fracture aperture profiles as a function of height and length. Results from G01-91 provided insight regarding the influence of stiffness and material heterogeneity on fracture complexity.

In A01-05, fracture height was bounded by intact material and exhibited an elliptical aperture profile. This profile combined with linear-elastic mechanics models indicates uniform internal fluid pressure distribution as a function of height. No significant flow along the height was expected during the epoxy cure but flow did occur along the length of Wing-A. An elliptical fracture aperture profile agrees with the PKN and penny-shaped models. The elliptical profile was smooth and continuous despite included shear zones and undulations, shown as offset measurements from the fracture tip-to-tip centerline in Fig. 7.2. Data collected from A01-05 included X-ray computed tomography (CT).
Aperture measurements in A01-05 as a function of length followed a roughly elliptical profile with an added flaring effect in the near-wellbore damage zone (Fig. 7.3). Fracture lengths were bounded by intact material in two of three dominant fracture wings, being Wing-B and Wing-C. FE modeling of the fractures predicted an aperture profile similar to the observed results. These models also indicated that fluid pressure distribution through Wing-A had a significant impact on all fracture aperture profiles and that near-wellbore damage was a factor contributing to the observed flaring effect. Fracture interaction was expected due to the discrete specimen boundary effects and the stress-displacement fields induced by opening of the fractures. These interactions appeared to close Wing-B and stunt its growth through inspection of the tip profile. Actively propagating fracture tips were elliptical while the Wing-B tip was more wedge-shaped. Linear and uniform fluid pressure distributions were modeled through the length of Wing-A. The linear distribution produced results more closely matching physical measurements. Improved FE modeling accuracy can be attained through coupled fluid flow and solid mechanics modeling but this work was not performed at this time.

Results from G01-91 showed that material heterogeneity has a significant effect on fracture geometry. Heterogeneity caused increased AE activity during injection and increased fracture tortuosity/branching effects in the rock specimens. Fluid penetrated fractures in this experiment best
coincided with AE events recorded during the pressure indicated breakdown event. A second zone of concentrated AE activity was located along a pre-existing discontinuity and no evidence of fluid penetration into this zone was observed. This result suggests that sorting located AE events by association with concurrent pressure breakdown events can improve estimations of fluid penetrated fracture locations when analyzing fracture growth in complex geological conditions. Increased fracture complexity is expected with heterogeneous materials and this topic was further investigated through photomicrographs. Complex fractures included tensile, shear and mixed failure modes but summative fracture aperture as a function of length was still expected to follow a smooth aperture profile. This expectation was supported by the pseudo-elliptical fluid penetrated zone observed in G01-91 cross-sections.

![Graph showing aperture profile for A01-05 with emphasis on flaring effect near wellbore.](image)

Fig. 7.3. Aperture profile for A01-05 with emphasis on flaring effect near wellbore.

The most tortuous fracture geometry region in the acrylic specimen was in the near wellbore region while fractures in the granite tended to increase in complexity with fracture length. Fractures tended to coalesce with propagation away from the borehole in the acrylic specimen. These trends indicate that heterogeneity was the primary cause for increased fracture complexity while macro-scale effects were a driving factor for fracture coalescence.

Increased material stiffness in the granite was expected to be a primary factor contributing to the faster fracture propagation speed in comparison with the acrylic specimen which used a similar viscosity fluid for injection. The fracture in G01-91 propagated a distance of 150 mm in 3.2 min while the fracture in A01-05 propagated 38 mm in 32.3 min. These values correspond to average tip propagation speeds of 47 and 1.2 mm/min respectively. The elastic modulus of the granite was 57 GPa while acrylic was only
3.3 GPa. Differences in plasticity and peak treatment pressure are also potential factors affecting the fracture propagation speed. These results emphasize the importance of rock stiffness and hydraulic compliance in simple hydraulic fracture models.

### 7.3 Laboratory Modeling of EGS

Two laboratory experiments were performed to simulate EGS production from binary and triplet well layouts in hot dry crystalline rock, being the G01-90 and G01-93 granite experiments, respectively. Specimens were initially intact with injectivity induced through hydraulic fracturing, re-fracture stimulations and MIF. Successful production was dependent upon intercepting created hydraulic fractures with a production well using AE event locations for guidance. Improved estimation of the fracture location was gained by correlating AE data with the injection well pressures. Production rates were found to be directly linked with injection rates. Higher fracture fluid pressures relative to the boundary pore pressures resulted in higher leak-off rates. Use of vacuum to decrease net fracture pressure resulted with higher ratios of produced fluid relative to injected fluid volumes. Flow rates were observed to be a direct function of injection pressure but pressure was not observed to be uniquely dependent upon flow rate. Flow was also observed to be strongly dependent upon hydraulic fracture geometry, temperature, and flow history. Stepwise decrements to injection pressures were associated with higher injectivity than increments, a hysteresis effect. Heat exchange through the injection well was observed to dominate the thermal system in both experiments but this phenomenon was expected to be highly dependent upon flow rate and relative thermal conductivity through the well casing and the rock. Fracture geometries were strongly influenced by well alignments, discontinuities and stresses where fractures tended to propagate parallel with the well axis, have propagation stunted by discontinuities and propagate perpendicular to the minimum principal stress.

A complex transitional flow effect was observed in G01-93 where injectivity disproportionally increased with increasing injection rate beyond a threshold. This injectivity increase was not observed to be permanent when comparing SCP data before and after high flow rate injections. It is expected that a transition to turbulent flow or thermo-mechanical fracture aperture effects with faster injection of cold fluid were driving the injectivity increase. Future multi-physics fracture modeling could reveal more insight on this topic but this work was beyond the scope of this research effort.

### 7.4 Grain-Scale Influence on Hydraulic Fracture Geometry

Hydraulic fracture geometry in natural heterogeneous rock is scale dependent where grain-scale fracturing can add significant complexity to macro-scale fractures. Fracture modes in homogenous materials include tensile, shearing, tearing and mixed-mode displacements. These displacement modes
occur in heterogeneous materials as well but grain structure and discontinuities can strongly influence the mode of propagation. Constitutive grain-scale fracture mechanisms include void nucleation and coalescence, transgranular fracturing, and intergranular fracturing. These mechanisms can combine into the special cases of granular fracture bifurcation and transportable grain release. Grain-scale fractures aggregate to form macro-scale fracture geometries. Macro-scale geometries commonly observed in laboratory experiments included simple planar fracturing, discontinuity activation, lengthwise branching and coalescence, transverse fracture coalescence, and rotation and twisting. These structures can combine to produce complex fracture networks. Factors controlling fracture geometry include stress state, borehole orientation, fluid parameters, and rock structure.

Flow through hydraulic fractures is controlled by 3D fracture geometry. Potential means for increasing conductivity through hydraulic fractures include proppant, macro-scale shearing displacements, fracture coalescence, and transportable grain release followed by self-propping. On the contrary, increased roughness with intergranular fracturing, fracture branching, and screen out from transportable grains can all result in decreased fracture permeability.

### 7.5 Recommendations for Future Studies

Observations from these experiments and associated analyses raise questions regarding the potential of MIF, complex hydraulic fracture modeling, EGS technology, specific observations from this research study and other general inquiries. The following represents some questions recommended for future study. Questions are organized by topic of study.

**Questions Regarding MIF**

1. How does an MIF pressure impulse propagate from a surface accumulator, through the well casing and into the rock formation?
2. What is a representative down-hole pressure forcing function for an MIF treatment?
3. What is the expected pressure rise time for an MIF treatment at the field-scale?
4. Does MIF actually produce new fractures from the borehole?
5. Can MIF be implemented as a primary stimulation method?
6. What would be the effect of repeated MIF treatments on the same well interval?
7. Is there industry interest for attempting MIF on a full-scale well?

**Questions Regarding Complex Fracture Modeling**

1. Can a simple hydraulic fracture model be developed which incorporates fluid properties, rock properties and heterogeneity to predict possible fracture geometries?
2. Can a stochastic model be developed to characterize multi-scale rock heterogeneity?
3. What is a criterion for the relative influence of fluid viscosity versus rock structure for predicting fracture complexity?
4. What are reasonable absolute limits for grain-scale mechanics versus other scales?

Questions Regarding EGS Technology
1. Are discrete hydraulically stimulated zones a feasible means for EGS or are complex high-conductivity fracture networks a necessity?
2. Can high strain rate fracturing (HSRF) methods produce better results than conventional hydraulic fracturing in application to EGS reservoir creation?
3. Can non-steady flow result with higher net reservoir conductivity in field-scale EGS?
4. Is heat transfer conduction dominated or conduction limited at the field-scale?
5. What is an optimal borehole layout for EGS?

Questions Specific to Observed Results
1. What is the cause of the transitional flow region observed in Fig. 7.4?
2. What was the fracture growth sequence in G01-00 and what is the meaning of each pressure peak observed during stimulation?
3. Were balanced injection and production rates possible if pore pressures were simulated in G01-90 and G01-93?

![Fig. 7.4. Injectivity analysis for G01-93 highlighting transitional flow region.](image-url)
General Questions

1. Can reservoir stimulation treatments be designed to take advantage of dynamic flow and complex hydraulic fracture growth to create larger volumes of fractured rock?

2. Can forced non-steady injection and production rates be applied to improve total recovery volume for oil and gas applications?

3. Why does fracture initiation pressure increase for small-scale borehole diameters?
REFERENCES CITED


APPENDIX A
OPERATION OF TRUE-TRIAXIAL APPARATUS

Operation of the custom true-triaxial apparatus developed in the early stages of this research requires the execution of a critical sequence of steps which must be followed sequentially. This section details the associated steps and provides a series of figures illustrating the process. Variations from this procedure were tested but ultimately less successful.

A.1 Rock Specimen Preparation

Rock specimen preparation typically involved concrete capping 4 of 6 specimen faces with concrete to improve surface tolerances. Strain gages and thermocouples could be installed before or after capping. Installing strain gages was typically most successful prior to capping while thermocouples were easier to install after capping. Fig. A.1 shows the S01-00 after trimming with a wet diamond saw was completed by Camp Stone in Westminster, Colorado. The original rock specimen collected at the Cemex quarry in Lyons, Colorado was roughly 280×600×800 mm³. This specimen was the largest intact and hand portable specimen located during a visit to the quarry. Trimmed dimensions were slightly less than 300×300×260 mm³. It is recommended to trim specimens to give 290 to 300 mm on a side. Specimens exceeding 300 mm on a side are difficult to load into the true-triaxial apparatus and don’t permit much tolerance for concrete capping.

![Fig. A.1. S01-00 specimen prior to concrete capping.](image)

Initial concrete capping of rough rock specimens can be aided using the adjustable concrete form shown in Fig. A.2. This form can be set to cast precision concrete rectangular prismatic specimens up to 380 mm on a side. Proper use of the form requires lubrication with oil. Typically silicone spay lubrication was successful in preventing bondage between cast concrete and the steel form.
Strain gages and thermocouples were also installed during specimen preparation. The preferred method for thermocouple installation used the Rockwell® VersaCut® saw as shown in Fig. A.3. Grooves were cut to a depth of 3 to 4 mm to provide adequate space for inserting thermocouple wires. Installed thermocouples were secured in place using epoxy or silicone sealant. Layout lines drawn before cutting are useful for improving the quality of sensor installations. Specimen orientation relative to later installation into the cell was decided and referenced when choosing suitable sensor placements. Sensor locations were selected so as to not intersect likely well drilling alignments unless redundant sensor systems are used.

An image of the capped S01-00 specimen is shown in Fig. A.4. This specimen required a significant thickness of added concrete on the top surface to compensate for initially rough cut surfaces. A concrete mix was designed for the fill targeting acoustic velocities similar to the limestone material. This criterion was important for later localization of AE event sources.
A.2 Installation of Specimen into True-Triaxial Apparatus

Tolerances in the true-triaxial apparatus were tight. Permissible deflection of the flat jacks was less than 3 mm to ensure reusability. Difficulties achieving acceptable tolerances with steel passive lateral platens led to the adoption of concrete passive platens and development of the specimen installation procedure detailed in this subsection.

It is pertinent to emphasize the safety warnings given in Fig. A.5. Failure to properly follow the suggested precautions can result in serious injury or death. Weight information is included because it is relevant for proper use of the engine hoist. This list is intended to highlight critical concerns, not provide a full legal list of all possible risks. Proper safe use of the true-triaxial apparatus requires diligent awareness to possible risks and real-time evaluation of potential hazards.

WARNING!

- Wear steel toe boots and safety glasses
- Do not attempt this procedure alone
- Do not get fingers etc. between movable heavy objects
- Be aware that hydraulic lifting equipment can fail
- Inspect lifting hardware prior to use
- Steel platens weight: 18 kg (40 lb)
- Rock specimen weight: up to 75 kg (160 lb)
- Top lid weight: 220 kg (480 lbs)
- Loaded reaction cylinder weight: up to 1000 kg (2200 lb)
First, AE sensors were installed into the steel platens as shown in Fig. A.6. AE data quality was improved by inserting a buffer of open cell packing foam between the AE sensor housing and the steel platen. A cylindrical foam insert was placed at the back of the sensor prior to attachment of the cover plate. AE sensor installation quality was typically tested on the rock specimen prior to full assembly using auto-sensor tests, a functionality of the associated AEwin data acquisition software.

Second, the active face platen and flat jack assemblies were placed inside the true-triaxial apparatus as shown in Fig. A.7. Hollow steel spacers were positioned to support the weight of the jack and platen assemblies and to center the bottom active platen. Only one configuration of the steel spacers provides proper support where the flat jacks rest at a height centered relative to the steel platens and below the rim of the reaction cylinder’s top. Flat jacks were positioned with the hydraulic lines bundled at one corner for passage through the top lid hydraulic/sensor port. Care was taken to ensure the filling ports on the jacks did not protrude above the rim of the reaction cylinder.

Fig. A.6. Installation of AE sensors.

Fig. A.7. Assembly of active platens and jacks (left) and application of silicone grease (right).
Silicone vacuum grease was generously applied to the lateral AE sensors as shown in Fig. A.7. Vacuum grease acted as couplant for the AE sensor and was important for attaining high quality AE data. A generous amount was required to permit shifting of the specimen relative to the platens. Also note the use of duct tape to support the platen and jack assemblies. Tipping of the active platens is likely to damage AE sensor cables.

Next, the test specimen was installed in the true-triaxial apparatus aided by an engine hoist as shown in Fig. A.8. The engine hoist was important to provide a slow and controlled decent of the specimen into the true-triaxial reaction frame. Care was taken to separate the specimen from the AE sensors to avoid scraping vacuum grease off the sensor faces. Lifting straps were removed after the specimen contacted the bottom steel platen. Lifting straps were removed by pulling the buckle end up while simultaneously supporting the specimen from lateral movement using flat rolled steel segments or similar tools (no fingers). Note that removal of the specimen becomes difficult after removal of the lifting straps. The specimen was pressed and seated into the active platens after removal of the lifting straps by a diagonal lateral sliding motion to minimize scraping against the AE sensors. Fig. A.8 (right) shows the positioning of the specimen after this process is completed.

![Fig. A.8. Installation of specimen into true-triaxial reaction cylinder.](image)

Two large heavy-duty plastic freezer storage bags were placed on the two passive faces to receive mixed (plastic) concrete, as shown in Fig. A.9. The bags were placed such that the full passive face of the rock specimen was covered and that wrinkles along the specimen’s faces were minimized. Tubular space holders (e.g. PVC pipe, flexible conduit, etc.) were placed at each end of the plastic bag. These space holders maintained an open access through the corners which was important for ease of disassembly after testing. Sensor wires were routed to the edges of the specimen’s faces and platen positions were adjusted to minimize risk of damaging the sensor wires. The top passive platen was installed for this process. Platen overlap was corrected if occurring.
The next stage of assembly involved concrete pouring and was therefore time sensitive. Setup for the concrete pour included measuring and proportioning the concrete mix ingredients, placing sponges and clean water nearby, routing sensor wires through the top lid hydraulic port and placing loose bolts in the top lid with washers. The typical concrete mix used 7.4 kg 100-mesh silica sand, 6.8 kg type-III cement, 3.3 kg water, 1.0 kg microsilica and 0.15 kg Eucon 37 high-range water reducer. This mix had a working time of more than 2 hr and a set time of less than 24 hr. This setup stage typically required 2 hr. Sponges and additional water were critical to clean excess concrete off the true-triaxial apparatus prior to installation of the top lid. Installation of the lid was performed immediately after the concrete was mixed and poured into the plastic bags. Lid installation involved lifting the lid over the hydraulic lines, lowering the lid such that the hydraulic lines smoothly passed through the hydraulics port, aligning the bolt holes and fastening the bolts to a suitable torque. Over-torque was avoided using hand wrenches with no more than 100 cm (36 in) leverage. A vertical seating stress of 0.5 MPa (100 psi on the respective analog pressure gage) was applied immediately after the lid was installed and maintained until concrete set.

Secondary tasks were performed during this final stage of assembly. Excess plastic was removed from the concrete platen bags and sensor wires were carefully routed along the top of the specimen to the hydraulics port location, as shown in Fig. A.10. Zip ties were used to secure sensor wires to the hydraulic lines. Hydraulic lines were labeled with oil-resistant tags to indicate the respective axis of control inside the cell. The specimen orientation was marked with permanent ink. Positioning lines were traced on the flange of the true-triaxial apparatus to show the enclosed specimen position and orientation. Tags and trace lines were placed at locations still visible with the top lid installed. Duct tape used to secure the platens during assembly was removed from between the platens and the specimen. The cell was cleaned of excess concrete along contact locations for the top lid. Final assembly of the apparatus with hydraulic lines connected is shown in Fig. A.11.
A.3 Borehole Drilling

Borehole drilling was performed using the tool shown in Fig. A.12. This tool uses a Bosch® 11224VSRC rotary hammer drill, a hand screw actuated depth control, a Rockwell® rotary speed controller, steel spacers, cutting oil and three 200 mm (8 in.) C-clamps. The drill was secured in a shuttle on the drilling apparatus using hose clamps. C-clamps were used to secure and stabilize the drill with one clamp per leg of the drilling apparatus. Spacers were added at the clamped positions to avoid conflict with bolt heads and washers. Depth and feed rate was controlled manually by hand crank speed. Rotational drilling speed was set using the rotary speed control. 70% power was used for cutting through steel and 100% power for cutting through rock. The 30% reserve power was used only if the drill bit jammed. Cutting oil was applied when drilling though steel. Oriented drilling was initiated vertically and adjusted to the target deviation in increments of 15º. Each orientation increment was drilled for 3 to 8 mm into the steel lid to reduce walking of the drill bit.
A.4 True-Triaxial Apparatus Disassembly

The first step of disassembly involved removing the wellhead hydraulic fittings to prepare for removal of the top lid. The exposed casing interval was cut close to the lid to remove attached hydraulic fittings. Removal of the steel casing passing through the top lid was performed by reaming if necessary. The top lid and top passive platen containing AE sensors were carefully removed with care to avoid damage to electrical cables.

Next, the lower flange was unbolted and the cylindrical reaction frame was lifted with the specimen still loaded inside. Friction and residual stresses (after hydraulic pressure was relieved) from the flat jacks retain the specimen at this time. Adequate clearance between the lower flange and the bottom lid was reached to permit placement of eight cylindrical spacers of 100 mm length between the two components, as shown in Fig. A.13. 25 mm (1 in.) diameter threaded rod was passed through these spacers and associated bolt holes. The threaded rods were fastened in place with nuts and washers. This setup now supports both extension and compression loading and is stable for internal work.

A hydraulic piston and thin 300×300 mm² steel platen were inserted into the bottom of the cylindrical reaction frame. The platen and jack were positioned and centered on the base of the specimen as shown in Fig. A.14. The specimen was then carefully extracted using multiple strokes of the piston with one 25 mm length hardened steel solid cylindrical spacer installed after each stroke.
Insertion of the 25 mm spacers on the hydraulic piston was a balancing act which required physical dexterity and awkward body positions. A sectional view of this process is illustrated in Fig. A.14. As indicated, the spacers were loosely stacked so it was helpful to use the engine hoist simultaneously with the hydraulic piston to improve stability of the specimen and square platens. Using the hoist required passing straps through the cylindrical reaction frame around the contained specimen. This was only possible if space holders along the sides of the concrete platens were successfully installed as shown in Fig. A.9. This extraction process overcomes the residual flat jack stresses and enables recovery of the full test specimen with minimal secondary damage. Note that the engine hoist alone was not capable of removing the specimen from the cell.
Extensive data sets were collected from the stimulation and flow studies performed in the 13 test specimens. This data was stored on an external hard drive in files organized by specimen ID. Subdivisions of the data were typically separated into folders titled Predictive Data, Raw Data, Organized Data, AE Data and Analyzed Data. Predictive Data contains calculations used to estimate the pressure required for hydraulic fracturing as a function of stress state and borehole geometry. Raw Data contains all measured parameters digitally acquired during the experiments, except for AE and SP. Organized Data contains sorted raw data with reorganized and renamed files in sequential order of acquisition. AE Data typically contains AE event and hit information with associated plots. Analyzed data contains a series of spreadsheets with plots and other analysis within. Supplementary files recording the detailed experiment procedures are included with files named ‘test notes.txt’ or ‘schedule.xls’. 

An Excel VBA program was used to perform the bulk of analysis and a copy of this program is included in the external hard drive. Individual plots produced by this program and used to build the results presented in this dissertation were estimated to number at 800 to 1000 for G01-93 alone. Inclusion of the respective plots and data in this document was therefore not deemed practical or beneficial to the reader. Instead, digital data can be accessed directly from the database in raw or analyzed formats. Raw data gives sensor voltages where calibration relationships are required to convert this information into physical values. These relationships can be acquired from the manufacturer of the respective sensors or viewed by inspection of the associated VBA code in the analysis program. The Teledyne Isco pump manual is useful reference for interpreting the raw data acquired for P01-00 and E01-00.

The main file containing the VBA program is the most recent version of ‘Sys_Analyzer v##.xls’. When operated, this script performs data sorting, querying by time stamp, automated analysis of user selected data segments and automated plotting functions. Manual inputs are required to specify query time intervals and to select sections of data for analysis. Note that some tests included months of continuously acquired data at 1 Hz resolution across 3 to 60 channels (excluding AE) giving billions of data points. A data compression routine was embedded into the query operation to limit output data sets to lengths less than 30,000 samples. The 30,000 limit is an artifact of Excel VBA limitations with standard use of 16 bit signed integer variables having a respective maximum value range of ±32,768. Queries exceeding 24 hr intervals are not advised due to excessive compression requirements. Time formats for the input data must be specified where 01/01/1900 date-time format (default for Excel 2003) is typical. Fig. B.1 shows the front end of the program with the typical sequence of operations briefly described.
This program was built to correct for computer clock re-synchronization events, daylight savings time conversion and a variety of other systemic errors occurring with long term data acquisition. Query operations performed by the program reference the file modification dates to operate correctly. This function necessitates that the raw data files are never modified and that the computer clock for both the data acquisition computer and the data analysis computer both be set to UTM standard time reference. The embedded organization routine automates the process of sorting raw data files according to data type and date. This algorithm completes the process by copying the raw data files to a new directory and renaming them sequentially. Organization only needs to be performed once for a given set of raw data files.
VITA

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