Summer 2012

Hydraulic fracturing experiments to investigate circulation losses

Maximiliano Liberman

Follow this and additional works at: http://scholarsmine.mst.edu/masters_theses

🔗 Part of the Petroleum Engineering Commons

Department: Geosciences and Geological and Petroleum Engineering

Recommended Citation

HYDRAULIC FRACTURING EXPERIMENTS TO INVESTIGATE CIRCULATION LOSSES

by

MAXIMILIANO LIBERMAN

A THESIS

Presented to the Faculty of Graduate School of the

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN PETROLEUM ENGINEERING

2012

Approved by

Dr. Runar Nygaard, Advisor
Dr. Ralph Flori
Dr. Baojun Bai
In recent years the oil and gas industry has been drilling more challenging wells due to long deviated wells, drilling through already depleted reservoirs, sub salt wells and increasing water depth. A major challenge these wells create is to prevent fluid loss into the formation and wellbore breakouts by having accurately determined the mud weight operational window. In addition to accurately determine the fracture gradient, additives in the drilling fluid have been used to enhance the fracture gradient in an industry process named wellbore strengthening. In order to study the phenomenon of fracture gradient alteration, a hydraulic fracturing apparatus was developed to replicate downhole conditions. Different lithologies were tested by performing hydraulic fracturing experiments in order to compare and contrast their original breakdowns and re-opening pressures.

Results showed that original breakdown pressures for non-permeable cores tend to vary depending on which fracturing fluid is used. The more viscous fluids, the higher breakdown pressure was obtained. A re-opening pressure cycle was performed after reaching breakdown pressure. The values obtained for re-opening pressures do not present a large variation with respect to the fracturing fluid. Thus, it can be said that the re-opening pressure does not have a significant change with respect to the mechanical properties of the core as well as fluid properties.
ACKNOWLEDGEMENTS

First and foremost, I would like to thank Dr. Runar Nygaard for his guidance and encouragement throughout this work as well as choosing me as a graduate student. I am deeply thankful for him being a great advisor devoting as much of his time was needed. Developing and troubleshooting the new laboratory equipment designed on the premises of this university was extremely challenging. I will always be thankful him for recognizing my potential and being a great mentor and a friend. I would also like to thank Dr. Saeed Salehi for his tremendous support and patience while performing laboratory experiments not only as a colleague but also as a friend. I would also like to thank Mr. Aaron Blue for designing and constructing the hydraulic fracturing apparatus. My officemates Mr. Steven Hilgedick, Mr. Sudarshan Govindarajan, Mr. Mohammed Al Dushaishi, Mr. Anuroop Pandey, for their support and companionship throughout this journey. On a personal note, I would like express my infinite gratitude to my parents Mr. Oscar Liberman and Mrs. Silvia Brun de Liberman as well as my sisters Ms. Cinthia Liberman and Ms. Nicole Liberman for all their encouragement, eternal support and love whom encouraged me not only while embarking as an undergraduate but also a graduate student both achieved at Missouri University S&T, without them I would have not be here. This work has been partially funded by the Department of Energy under grant DE-FE0001132.
TABLE OF CONTENTS

ABSTRACT ........................................................................................................................ iii

ACKNOWLEDGEMENTS ................................................................................................... iv

LIST OF ILLUSTRATIONS ............................................................................................... viii

LIST OF TABLES ................................................................................................................ x

NOMENCLATURE .............................................................................................................. xi

SECTION

1. INTRODUCTION .............................................................................................................. 1

1.1. FRACTURE GRADIENT IN DRILLING – FLUID LOSS .............................................. 2

1.2. FIELD METHODS TO DETERMINE FRACTURE GRADIENT ................................ 4

1.3. WELLBORE STRENGTHENING ............................................................................... 6

1.4. RESEARCH OBJECTIVE ......................................................................................... 8

2. LITERATURE REVIEW OF WELLBORE FRACTURING .............................................. 10

2.1. THEORETICAL MODEL OF WELLBORE FRACTURING ........................................ 10

2.1.1 Kirsch Solution ..................................................................................................... 10

2.1.2. Eaton’s Equation ............................................................................................... 17

2.1.3. Elasto-Plastic Model .......................................................................................... 18

2.1.4. Fracture Resistance Model Based on Non-Invaded Zone. ................................. 20

2.2. HYDRAULIC FRACTURE EXPERIMENTS .............................................................. 21

2.2.1. DEA – 13 Fracturing Experiments .................................................................... 21

2.2.2. GPRI Joint Industry Project Experiments (JIP) ................................................. 22
2.2.3. Concrete Experiments ................................................................. 23

2.2.4. M-I Swaco Experiments .............................................................. 25

2.3. SUMMARY AND CRITICAL REVIEW OF THE LITERATURE ............. 26

3. EXPERIMENTAL METHODOLOGY ...................................................... 28

3.1. EXPERIMENTAL SET UP ................................................................. 28
  3.1.1. Pump System and Fluid Distribution ........................................... 30
  3.1.2. Accumulator ............................................................................. 30
  3.1.3. Hydraulic Piston ........................................................................ 31
  3.1.4. In-line Pressure Regulator ......................................................... 32
  3.1.5. Rubber Sleeve ........................................................................... 33
  3.1.6. Stainless Steel Cylinder ............................................................. 33
  3.1.7. All Thread Rods ......................................................................... 33
  3.1.8. Bottom Flange ........................................................................... 33
  3.1.9. Top Flange ................................................................................. 34
  3.1.10. Hydraulic Fracturing Apparatus Frame ...................................... 35
  3.1.11. Hydraulic Fracturing Apparatus ............................................... 36
  3.1.12. Data Acquisition ..................................................................... 36

3.2. CORE PREPARATION ....................................................................... 37

3.3. EXPERIMENTAL PROCEDURE ....................................................... 38

3.4. TESTING PROGRAM ........................................................................ 40

4. RESULTS ............................................................................................. 42

4.1. TEST # 1 DOLOMITE FRACTURED WITH WATER ......................... 42
4.2. TEST # 2 DOLOMITE FRACTURED WITH 8% BENTONITE MUD .......... 44
4.3. TEST # 3 DOLOMITE FRACTURED WITH COLORED WATER .......... 45
4.4. TEST # 4 ROUBIDOUX SANDSTONE FRACTURED WITH 8% .......... 48
4.5. TEST # 5 CONCRETE CORE FRACTURED WITH 4%
BENTONITE MUD ........................................................................ 50
4.6. TEST # 6 CONCRETE CORE FRACTURED WITH 6%
BENTONITE MUD ........................................................................ 51
4.7. TEST # 7 CONCRETE CORE FRACTURED WITH 6%
BENTONITE – CMC MUD ................................................................. 53
4.8. TEST # 8 CONCRETE CORE FRACTURED WITH 6%
BENTONITE – CMC ........................................................................ 56
5. DISCUSSION .................................................................................. 59
5.1. INITIAL SET UP OF EXPERIMENTS ........................................ 59
5.2. CONCRETE CORE EXPERIMENTS........................................... 62
5.3. KIRSCH SOLUTION VALIDATION ............................................. 65
5.4. EVALUATION OF RESULTS WITH PREVIOUS CONDUCTED TESTS ..... 66
6. CONCLUSIONS ............................................................................... 68
7. RECOMMENDED FUTURE WORK .............................................. 70
7.1 EQUIPMENT ENHANCEMENT .................................................... 71
APPENDICES ...................................................................................... 72
A. FRACTURE PICTURES AFTER CORE HAS BEEN TESTED .......... 72
B. PRESSURE CELL ASSEMBLY AND EXPERIMENTAL SETUP
CHECK LIST .................................................................................... 75
C. HYDRAULIC FRACTURING APPARATUS – PRESSURE RATING ........ 80
BIBLIOGRAPHY ................................................................................. 83
VITA .................................................................................................... 86
# LIST OF ILLUSTRATIONS

<table>
<thead>
<tr>
<th>Figure</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Figure 1.1. Examples of Pore and Fracture Pressure Gradient Reduction</td>
<td>3</td>
</tr>
<tr>
<td>Figure 1.2. Leakoff Test from Southern North Sea</td>
<td>5</td>
</tr>
<tr>
<td>Figure 1.3. ELOT from Southern North Sea</td>
<td>5</td>
</tr>
<tr>
<td>Figure 2.1. An Arbitrary Oriented Wellbore Under In-situ Stress System</td>
<td>11</td>
</tr>
<tr>
<td>Figure 2.2. Schematic of Near Wellbore Stresses and Wellbore Failure Mechanisms</td>
<td>16</td>
</tr>
<tr>
<td>Figure 2.3. Schematic of Wellbore Wall Assuming Plastic Zone</td>
<td>18</td>
</tr>
<tr>
<td>Figure 2.4. Invaded and Non-Invaded Zones for a Fracture in Normal Fault Environment</td>
<td>21</td>
</tr>
<tr>
<td>Figure 2.5. Berea Sandstone Core</td>
<td>22</td>
</tr>
<tr>
<td>Figure 3.1. Hydraulic Fracturing System Schematic</td>
<td>29</td>
</tr>
<tr>
<td>Figure 3.2. Mud Accumulator System</td>
<td>31</td>
</tr>
<tr>
<td>Figure 3.3. Overburden Piston</td>
<td>32</td>
</tr>
<tr>
<td>Figure 3.4. Bleed-Off Valve</td>
<td>32</td>
</tr>
<tr>
<td>Figure 3.5. Bottom Flange</td>
<td>34</td>
</tr>
<tr>
<td>Figure 3.6. Top Flange</td>
<td>34</td>
</tr>
<tr>
<td>Figure 3.7. Hydraulic Fracturing Apparatus</td>
<td>35</td>
</tr>
<tr>
<td>Figure 4.1. Dolomite Core Test 1 before testing</td>
<td>43</td>
</tr>
<tr>
<td>Figure 4.2. Original Breakdown Pressure Test 1</td>
<td>44</td>
</tr>
<tr>
<td>Figure 4.3. Dolomite Core Test 2</td>
<td>46</td>
</tr>
<tr>
<td>Figure 4.4. Original Breakdown and Re-Opening Pressure Test 2</td>
<td>47</td>
</tr>
<tr>
<td>Figure 4.5. Dolomite Core Test 3 before testing</td>
<td>47</td>
</tr>
<tr>
<td>Figure 4.6. Original Breakdown Test 3</td>
<td>48</td>
</tr>
</tbody>
</table>
Figure 4.7. Roubidoux Sandstone Core Test 4 ................................................................. 49
Figure 4.8. Roubidoux Sandstone Fracture Pressure Test 4 ........................................... 50
Figure 4.9. Concrete Core Test 5 ...................................................................................... 52
Figure 4.10. Original Breakdown and Re-opening Pressure Test 5 ................................. 53
Figure 4.11. Concrete Core Test 6 ...................................................................................... 54
Figure 4.12. Original Breakdown and Re-opening Pressure Test 6 ................................. 55
Figure 4.13. Concrete Core Test 7 ...................................................................................... 55
Figure 4.14. Original Breakdown and Re-opening Pressure Test 7 ................................. 56
Figure 4.15. Concrete Core Test 8 ...................................................................................... 57
Figure 4.16. Original Breakdown and Re-opening Pressure Test 8 ................................. 58
Figure 5.1. A Comparison of Non-Permeable Cores (Dolomite) With and Without Intact Boreholes ............................................................................................................. 61
Figure 5.2. A Comparison of Permeable vs. Non-Permeable Cores for 8% Bentonite Mud ................................................................................................................................. 62
Figure 5.3. A Comparison Non-Permeable Cores (concrete) for 4 & 6% Bentonite Mud ................................................................................................................................. 64
Figure 5.4. A Comparison of Non-Permeable Cores (concrete) for 6% Bentonite Mud with and Without Additives ................................................................. 64
LIST OF TABLES

Table | Page
--- | ---
Table 1.1. Summary of Wellbore Strengthening Literature with the Fields Where the Method was Applied | 7
Table 2.1. Fracturing Test Results on Various Borehole Shapes and Sizes with Different Drilling Fluids | 25
Table 2.2. Summary of MI – Swaco Experimental Results | 26
Table 3.1. Table of Rock Mechanical Testing and Fluid Properties | 41
Table 3.2. Table of Testing Parameters and Pressure Values | 41
Table 4.1. Dolomite Fractured with Water | 42
Table 4.2. Dolomite Fractured with 8% Bentonite Mud | 44
Table 4.3. Dolomite Fractured with Colored Water | 45
Table 4.4. Roubidoux Sandstone Fractured with 8% Bentonite Mud | 48
Table 4.5. Concrete Core Fractured with 4% Bentonite Mud | 50
Table 4.6. Concrete Core Fractured with 6% Bentonite Mud | 51
Table 4.7. Concrete Core Fractured with 6% Bentonite – CMC Mud | 53
Table 4.8. Concrete core fractured with 6% Bentonite – CMC and Calcium Carbonate Mud | 56
Table 5.1. Analytical Prediction and Laboratory (Original Breakdown Pressure) Results | 65
Table 5.2. Missouri S&T Results | 66
Table 5.3. Morita et al 1996, Laboratory Results | 67
Table 5.4. Aadnoy et al., 2004, Laboratory Results | 67
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELOT</td>
<td>Extended Leakoff Test</td>
</tr>
<tr>
<td>LCM</td>
<td>Loss Circulation Material</td>
</tr>
<tr>
<td>LOT</td>
<td>Leakoff Test</td>
</tr>
<tr>
<td>$P_p$</td>
<td>Pore Pressure</td>
</tr>
<tr>
<td>$P_w$</td>
<td>Wellbore Pressure (Mud Weight)</td>
</tr>
<tr>
<td>$P_{frac}$</td>
<td>Fracture Breakdown Pressure</td>
</tr>
<tr>
<td>R1</td>
<td>Fracture Invaded Zone</td>
</tr>
<tr>
<td>R</td>
<td>Fracture Length (Diameter)</td>
</tr>
<tr>
<td>r</td>
<td>Radial Distance from Wellbore</td>
</tr>
<tr>
<td>$r_w$</td>
<td>Wellbore Radius</td>
</tr>
<tr>
<td>$T_0$</td>
<td>Rock Tensile Stress</td>
</tr>
<tr>
<td>$\sigma_h$</td>
<td>Minimum Horizontal Stress</td>
</tr>
<tr>
<td>$\sigma_H$</td>
<td>Maximum Horizontal Stress</td>
</tr>
<tr>
<td>$\sigma_v$</td>
<td>Overburden Stress</td>
</tr>
<tr>
<td>$\sigma_{rr}$</td>
<td>Radial Stress</td>
</tr>
<tr>
<td>Symbol</td>
<td>Description</td>
</tr>
<tr>
<td>--------</td>
<td>-------------</td>
</tr>
<tr>
<td>$\sigma_{\theta\theta}$</td>
<td>Hoop Stress or Tangential Stress</td>
</tr>
<tr>
<td>$\sigma_{zz}$</td>
<td>Vertical Stress at Wellbore Wall in Cylindrical Coordinates</td>
</tr>
<tr>
<td>$\sigma_{xx}$</td>
<td>Normal Stress at Wellbore Wall in x Direction in Cartesian Coordinates</td>
</tr>
<tr>
<td>$\sigma_{yy}$</td>
<td>Normal Stress at Wellbore Wall in y Direction in Cartesian Coordinates</td>
</tr>
<tr>
<td>$\sigma_z$</td>
<td>Normal Stress at Wellbore Wall in z Direction in Cartesian Coordinates</td>
</tr>
<tr>
<td>$\tau_{xy}, \tau_{yz}, \tau_{xz}$</td>
<td>Shear Stress at Wellbore Wall in Cartesian Coordinates</td>
</tr>
<tr>
<td>$\tau_{r\theta}, \tau_{\theta z}, \tau_{rz}$</td>
<td>Shear Stress at Wellbore Wall in Cylindrical Coordinates</td>
</tr>
<tr>
<td>$\theta$</td>
<td>Angle of borehole Circumference Measured from Max Horizontal Stress Direction</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Sealing Efficiency Factor</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Poisson’s Ratio</td>
</tr>
</tbody>
</table>
1. INTRODUCTION

To meet the demand for continuous growth in oil and gas production more challenging wells are drilled. Wells are drilled at deeper water depth, with longer horizontal reach, and with multilateral wells drilled out from one mother bore. Geomechanics plays a key role in drilling plans and the casing design of these complex wells. Reducing drilling costs and improving drilling performance have become a priority for the industry when planning these complex wells; however major obstacles are contributing to increasing expenditures and complexity. The first category of obstacles, which is not controllable, is governed by the complex geologic environment present at the time of performing drilling operations, like large scale geology features such as faults and salt diapirs near wellbore which could induce wellbore stability problems if not planned for. The second major obstacle present in drilling operations pertains to wellbore collapse or fluid kick due to low mud weight. The third category of obstacles is fluid losses into the formation due to high mud weight with potential stuck pipe and loss of well integrity as a result. These possible scenarios, where the mud weight has been designed incorrectly, it could ultimately yield not only to get stuck with the drill stem and lose portion of the equipment requiring a sidetrack but create very hazardous conditions if the lost circulation turn into a kick or a blow out. Thus, having a better understanding of the process of mud weight and mud weight operational window is the key factor to achieve lower drilling operation costs as well as creating a higher HSE standard.
1.1. FRACTURE GRADIENT IN DRILLING – FLUID LOSS

There are several mechanisms that can delay or cause serious drilling issues but lost circulation caused by tensile failure is the most common phenomenon present (Aadnoy and Chenevert, 1987) especially in highly deviated wellbores, depleted formations and also in deep offshore basins (Figure 1.1). These scenarios are prone to exhibit reduction in the fracture gradient which narrows the operational mud weight window between pore and fracture pressure, a pivotal feature of drilling design. When the water depth increase in deep offshore basins the total overburden density naturally decreases as the water depth increases, as water is making up for more of the overburden. A reduction in overburden stress results directly in decreased formation fracture gradient for a sedimentary basin with no tectonic stresses (Aadnoy and Chenevert, 1987).
As shown on figure 1.1, fracture gradient decreases for a deviated wellbore. This phenomenon has been explained by Aadnoy and Chenevert, 1987, stating that for deviated well bores, the fracture gradient \( P_{frac-deviated} \) can be estimated by both the vertical fracture gradient \( P_{frac-vert} \) and the wellbore inclination \( \beta \). This particular case assumes isotropic stresses as well as drilling along the minimum horizontal stress direction. Another scenario shown on the same figure is the one of drilling through a depleted formation. During production the reservoir pressure is depleted and the fracture gradient is reduced as a consequence (Economides, 1993). The reduction of pore pressure results in a directly reduction of formation total stresses as well. To avoid mud losses in
the reservoir the mud weight has to be lowered in the reservoir. But the shale section which could be present above or below the depleted zone would not be depleted, thus its pore pressure still remains in it and this formation will require higher mud weight which resulting in high risk for lost circulation in the reservoir. In addition to the scenarios of reduced fracture gradients mentioned above, existing fractures in the formation can also reduce the fracture gradient.

1.2. FIELD METHODS TO DETERMINE FRACTURE GRADIENT

The major field method to calculate fracture gradient is called the Leakoff Test (LOT) shown in figure 1.2. During this method, mud is pumped down the wellbore until the formation is fractured meaning that the fluid has entered the formation, resulting in a pressure drop. When plotting the volume pumped against the pressure, a constant slope is generated, indicating pressure being built inside the wellbore. Once the slope of the line shows a breaking point, indicating that the fluid being pumped has entered the formation, the value obtained is taken as the fracture gradient. In addition to the LOT, there is Extended Leakoff Test (ELOT) shown in figure 1.3 in which fluid is pumped downhole until the formation breaks. Fluid is pumped until a constant propagation pressure is achieved. Then from the instantaneous shut in pressure and closure pressure the minimum horizontal stress could be calculated.
Figure 1.2. Leakoff Test from Southern North Sea (Salehi., 2012)

Figure 1.3. ELOT from Southern North Sea (Okeland et al., 2002)
1.3. WELLBORE STRENGTHENING

Wellbore strengthening is loosely defined as the various methods applied during drilling operations to enhance the fracture gradient when the integrity of the wellbore wall has been compromised either with naturally occurring fractures or wells where the formations have been depleted. These scenarios, as explained earlier, create a narrow operational mud weight window which becomes a complex phenomenon to control. The major drawback to such event is the cost related to fluid loss, kicks control, wellbore collapse and sometimes, loss of the entire wellbore. Thus, in order to prevent such events, different technologies and methodologies have been proposed to enhance the fracture gradient (Table 1.1). The ultimate goal of wellbore strengthening is to seal off the natural occurring fractures or any porosity from depleted formations in order to prevent fluid loss or wellbore collapse. To prevent these undesired events, the use of different loss circulation material (LCM) is encouraged, such as calcium carbonate, gels or other additives (Morita et al, 1996). To address this problem, mixing these LCM’s together with water based mud will yield improve the issue mentioned earlier.

There are several wellbore strengthening theories which describe the physical mechanisms involved in the fracture gradient enhancement. Table 1.1 summarizes the different methodologies for wellbore strengthening and the mechanism involved, material type and strength to be used plus the necessity for tip isolation.

Several important questions about fracturing a wellbore are still not answered. First, to what extend are we able to change the near wellbore stresses of the rock, or are we just healing the fractures and not necessarily altering the rock stress? Second, how important are mud properties and mud additive properties such as material size, type, and
strength? As discussed above, some results support that the technique is successful only when specially selected size materials are used. Some others report successful field applications regardless of material properties. For instance, different materials system, forming gels by cross-linked polymers (Aston et al., 2007), calcium carbonates (Alberty and Mclean, 2004; Fuh et al., 2007), DVCS sealant (Traugott et al., 2007; Wang et al., 2008), DSF (Drill and Stress Fluid) water-based systems (Dupriest et al., 2008) to materials with higher mechanical strength (Aadnoy et al., 2008) were reported for wellbore strengthening applications. Although some authors (Aadnoy et al., 2008) reported poor experimental results using calcium carbonate and polymer based mud systems, successful field applications with significant increase of fracture gradient were reported when these materials were used in the mud system (Fuh et al., 2007; Aston et al., 2007).

Table 1.1. Summary of Wellbore Strengthening Literature with the Fields Where the Method was Applied (modified from Salehi, 2012).

<table>
<thead>
<tr>
<th>Author</th>
<th>Materials</th>
<th>Material Size</th>
<th>Material Strength</th>
<th>Tip Isolation</th>
<th>Rock Stress</th>
<th>Method</th>
<th>Field Applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuh et al., 1992</td>
<td>LPM</td>
<td>Important</td>
<td>Selected Strength</td>
<td>Required</td>
<td>Not Changing</td>
<td>Fracture Pressure Inhibitor</td>
<td>California (Ventura)/Oklahoma (Newkirk)</td>
</tr>
<tr>
<td>Alberty and McLean, 2004</td>
<td>Calcium Carbonate</td>
<td>Important</td>
<td>Important</td>
<td>Not Required</td>
<td>Changing</td>
<td>Stress Cage (SC)</td>
<td>Gulf of Mexico</td>
</tr>
<tr>
<td>Dupriest, 2008</td>
<td>DSF</td>
<td>Unimportant</td>
<td>Unimportant</td>
<td>Required</td>
<td>Changing</td>
<td>Fracture Closure Stress(FCS)</td>
<td>Malaysia (Jerneh field)/East Texas (Trawick field)</td>
</tr>
<tr>
<td>Wang et al., 2007a, 2007b</td>
<td>DVCS</td>
<td>Important</td>
<td>Important</td>
<td>Changing</td>
<td>Stress Cage (SC)</td>
<td>Gulf of Mexico/South Texas</td>
<td></td>
</tr>
</tbody>
</table>
Table 1.1. Summary of Wellbore Strengthening Literature with the Fields where the Method was applied (cont.).

<table>
<thead>
<tr>
<th>Method Details</th>
<th>Importance</th>
<th>Unimportance</th>
<th>Required</th>
<th>Change</th>
<th>Fracture Propagation Resistance (FPR)</th>
<th>Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>Van Oort et al., 2009</td>
<td>Important</td>
<td></td>
<td></td>
<td></td>
<td>Fracture Healing</td>
<td>Gulf of Mexico</td>
</tr>
<tr>
<td>Aadnoy and Belayneh, 2008</td>
<td>Important</td>
<td>Very Important</td>
<td>Not Changing</td>
<td>Fracture Healing</td>
<td>North Sea</td>
<td></td>
</tr>
</tbody>
</table>

1.4. RESEARCH OBJECTIVE

There are several competing theories regarding how to increase the fracture gradient and there are several analytic and numerical methods to calculate the fracture gradient. However, these methods do not include the change in fracture gradient based on drilling fluid types. Using loss circulation materials (LCM) to prevent fluid losses and strengthen the wellbore is the primary method employed by the vast majority of the industry to prevent fluid loss as well as other wellbore-related issues, while drilling. Therefore, conducting hydraulic fracture experiments will yield a deeper understanding of LCM’s as well as measuring the effect of varying drilling fluids and fluid additives on fracture gradient.

The objective of this work is to develop and test a wellbore-scale model under in-situ conditions to be used for comparison and validation of analytical and numerical models that describe the phenomenon of fracture pressure and investigate the most important variables that are present in wellbore strengthening techniques, known as the breakdown and re-opening pressure. To achieve the objectives of this research, the
following three stages will be accomplished respectively; these objectives can be divided into the following three topics:

- Develop and test a scaled wellbore fracturing cell apparatus.
- Validate results with analytical models
- Investigate the effect Bentonite concentration and CaCO₃ has on fracture gradient.

By performing laboratory experiments, one can achieve representation of different formations under a wide range of in-situ stresses. The implications of performing laboratory experiments do not only aid in validating fracture models, but also to test healing efficiencies of different loss circulation materials, and their ability to heal fractures. The experiments could be performed over a wide range of geological formations as well as drilling fluids.
2. LITERATURE REVIEW OF WELLBORE FRACTURING

A comprehensive study of the former and current analytical and numerical models of fracture pressure and fracture propagation has been done in this chapter. In order to conduct wellbore strengthening analysis through laboratory work, one must understand the concept of stress around the wellbore and the different models which describe fracture pressure. Fracture pressure ($P_{frac}$) is the variable that governs fluid loss phenomenon. Understanding the behavior of such variable and the different methodologies that helps predicting it leads to a better estimate of the operational mud weight window and ultimately aids in the optimization of the number of casings needed for a given well design.

2.1. THEORETICAL MODEL OF WELLBORE FRACTURING

In continuation, the Kirsch solution will be derived for a vertical wellbore along the vertical principal stress presented in section 2.1.1.

2.1.1 Kirsch Solution. The first publication regarding stress along the wellbore was titled “The stress distribution around a circular hole in an infinite plate in one-dimensional tension”. This publication, (Kirsch, 1898), commonly known as the “Kirsch solution”, described the stress around a vertical wellbore with uneven far field stresses. The Kirsch solution has later been discussed and modified for general wellbore
orientation by Deiley and Owens (1969), Bradely, (1979), Aadnoy, (1988) and Aadnoy et at., (1987), The corresponding stress transformations for a circular borehole is given in Figure 2.1, The solution assumes linear-elastic conditions and plane strain normal to the borehole axis is presented in the subsequent derivation of equations:

![Image of Figure 2.1: An Arbitrary Oriented Wellbore Under In-situ Stress System (Salehi, 2012)](image)

For an arbitrary oriented wellbore (Figure 2.1) the principal cylindrical polar coordinates can be described as:

\[
\sigma_{\theta} = \frac{\sigma_{xx} + \sigma_{yy}}{2} \left(1 + \frac{r_w^2}{r^2}\right) - \frac{\sigma_{xx} - \sigma_{yy}}{2} \left(1 + 3 \frac{r_w^2}{r^2}\right) \cos 2\theta - \tau_{xy} \left(1 + 3 \frac{r_w^2}{r^2}\right) \sin 2\theta - p_w \frac{r_w}{r^2} \tag{2.1}
\]

\[
3 \frac{r_w^2}{r^4} \sin 2\theta = p_w \frac{r_w}{r^2} \tag{2.2}
\]
\( \sigma_{zz} = \sigma_z - \nu [2(\sigma_{xx} - \sigma_{yy}) \frac{r_w^2}{r^2} \cos 2\theta + 4 \tau_{xy} \frac{r_w^2}{r^2} \sin 2\theta] \)

\[ \tau_{r\theta} = \frac{\sigma_{yy} - \sigma_{xx}}{2} \left( 1 - 3 \frac{r_w^4}{r^4} + 2 \frac{r_w^2}{r^2} \right) \sin 2\theta + \tau_{xy} \left( 1 - 3 \frac{r_w^4}{r^4} + 2 \frac{r_w^2}{r^2} \right) \cos 2\theta \quad (2.3) \]

\[ \tau_{\theta z} = (-\tau_{xz} \sin \theta + \tau_{yz} \cos \theta)(1 + \frac{r_w^2}{r^2}) \quad (2.4) \]

\[ \tau_{rz} = (\tau_{xz} \cos \theta + \tau_{yz} \sin \theta)(1 - \frac{r_w^2}{r^2}) \quad (2.5) \]

Where \( \sigma \) is normal stresses, \( \tau \) is shear stresses, and \( r_w \) is wellbore radius, \( r \) is distance from wellbore and subscripts \( x,y,z,r \) and \( \theta \) denote directions as defined in figure 2.1. The equations 2.1 to 2.5 presented above are meant for a generic case for an arbitrary oriented wellbore at any stress direction, however for a hole along the vertical principal stress direction (i.e. vertical well), a simplified version is presented below, where an angle \( \theta \) measured from the maximum to the minimum (\( \sigma_{H}, \sigma_{h} \)) horizontal stresses for a vertical borehole with far field stresses with the same maximum and minimum horizontal stress:

\[ \sigma_{rr} = \frac{\sigma_{H} + \sigma_{h}}{2} \left( 1 - \frac{r_w^2}{r^2} \right) + \frac{\sigma_{H} - \sigma_{h}}{2} \left( 1 + 3 \frac{r_w^4}{r^4} - 4 \frac{r_w^2}{r^2} \right) \cos 2\theta + p_w \frac{r_w^2}{r^2} \quad (2.6) \]

\[ \sigma_{\theta \theta} = \frac{\sigma_{H} + \sigma_{h}}{2} \left( 1 - \frac{r_w^2}{r^2} \right) - \frac{\sigma_{H} - \sigma_{h}}{2} \left( 1 + 3 \frac{r_w^4}{r^4} \right) \cos 2\theta - p_w \frac{r_w^2}{r^2} \quad (2.7) \]
At the wellbore wall $r_w$ is equal to $r$ which reduces equation 2.6 to 2.10 down to:

\[ \sigma_{rr} = p_w \]  

\[ \sigma_{\theta\theta} = \sigma_H + \sigma_h - 2(\sigma_H - \sigma_h) \cos2\theta - p_w \]  

\[ \sigma_{zz} = \sigma_V - 2v(\sigma_H - \sigma_h) \cos2\theta \]  

\[ \tau_{r\theta} = -\frac{\sigma_H - \sigma_h}{2} \left(1 - 3 \frac{r_w^4}{r^4} + 2 \frac{r_w^2}{r^2}\right) \sin 2\theta \]  

\[ \tau_{\theta z} = \tau_{rz} = \tau_{r\theta} = 0 \]  

Equations 2.11 through 2.15 indicate that the minimum and maximum hoop stresses at the wellbore wall take place at the minimum and maximum horizontal stress orientation, respectively:
These equations shown above pertain to an impermeable (non-penetrating) wellbore wall meaning that a mud cake has been formed, thus preventing fluids from entering the formation.

In the absence of mud cake or permeable (penetrating) wellbore wall, the following equations apply:

\[ \sigma_{\theta\theta_{\text{min}}} = 3\sigma_h - \sigma_H - P_w - P_p \tag{2.16} \]

\[ \sigma_{\theta\theta_{\text{max}}} = 3\sigma_H - \sigma_h - P_w - P_p \tag{2.17} \]

In order to understand the implications of this phenomenon pertaining to a normal fault environment, one must comprehend the mechanics of drilling fluids acting in the wellbore. The mud weight, also known as the pressure exerted by the drilling fluid onto the wellbore wall, plays a key role in preventing both the wellbore wall from collapsing, as well as formation fluids entering the wellbore. Another issue that may take place is if
the equivalent circulating density (ECD) causes the mud weight to rise to a point which can induce tensile failure.

When a normal fault environment is present, vertical fractures occur along the maximum horizontal stress where the hoop stress around the wellbore is at its minimum. Tensile failure will occur when the effective tensile stresses across a plane surpasses a critical limit (Fjaer et al., 2008). Once the critical limit has been reached; it will cause tensile failure, by virtue of exceeding the maximum tensile strength of the rock. Tensile strength is an intrinsic rock property, and it should not be extrapolated to other formations without careful analysis. In continuation, a failure criteria is presented when the tensile strength is exceeded in a principal stress plane as follows:

\[
\sigma' = -T_0
\]  

(2.21)

\[
\sigma_3' = -T_0
\]  

(2.22)

\(\sigma'\) can be denoted as the effective principal stress in the failure plane and the formation tensile strength be defined as \(T_0\). Again it should be noted that this is for a non-penetrating fluids, which has been explained earlier. Tensile failure (also known as the tensile failure criteria) will be reached when the effective tangential stress along the wellbore wall exceeds the formation tensile strength as a direct result of an increase in mud weight. Once the mud weight has reached and surpassed formation tensile strength, the wellbore wall will undergo tensile failure causing fluid loss into the formation as shown in figure 2.2. On the contrary, as it is known that the wellbore wall is in
compressive mode if the mud weight decreases below the compressive stress along the wellbore wall this will undergo shear failure mode ultimately leading to breakouts.

Therefore a mud weight window is established to determine upper and lower mud weight limits. These limits are important to avoid tensile or compressive failure. For the case mentioned above (non-penetrating) where a mud cake forms around the wellbore a tensile failure \( P_{\text{frac}} \) can be derived from equation 2.19 solving it along the minimum hoop stress orientation:

Figure 2.2. Schematic of Near Wellbore Stresses and Wellbore Failure Mechanisms, (Salehi, 2012)
\[ P_{\text{frac}} = 3\sigma_h - \sigma_H - P_p + T_0 \quad (2.23) \]

For a permeable formation with full communication between the wellbore and pore fluids the fracture pressure is given as:

\[ P_{\text{frac}} = \frac{3S_h - S_H - \alpha \left( \frac{1 - 2v}{1 - v} \right) P_p + T_0}{2 - \alpha \left( \frac{v}{1 - v} \right)} \quad (2.24) \]

Where \( \alpha \) is Biot coefficient, and \( v \) is Poisson’s ratio.

**2.1.2. Eaton’s Equation.** In a situation where the formation occur as a 1-D compaction set up, the following definition has been derived (Fjaer et al., 2008).

\[ \sigma_h = \left( \frac{v}{1 - v} \right) \sigma_{ob} \quad (2.25) \]

Equation 2.25 considers the formation to be compacted as a linear-elastic material. Having in consideration fluids in the formation a pore pressure factor is added

\[ \sigma_h - P_p = \left( \frac{v}{1 - v} \right) (\sigma_{ob} - P_p) \quad (2.26) \]

Since the stresses around the wellbore wall are not only affected by pore pressure but there might be some far field events such as tectonic forces equation 2.27 accounts for such events.
Re-arranging equation 2.27 and setting $P_{tec}$ to 0 an analytical solution known as Eaton’s equation is presented:

$$\sigma_h - P_p = \left( \frac{v}{1-v} \right) (\sigma_{ob} - P_p) + P_{tec} \tag{2.27}$$

$$\sigma_h = \left( \frac{v}{1-v} \right) (\sigma_{ob} - P_p) + P_p \tag{2.28}$$

2.1.3. Elasto-Plastic Model. Aadnoy et al., (2004) included an assumption that the wellbore wall was a plastic zone as described in figure 2.3.

Figure 2.3. Schematic of Wellbore Wall Assuming Plastic Zone (Aadnoy et al., 2004)

The model assumes a higher fracturing pressure than the one predicted by the “Kirsch solution”, assuming that either the fluid barrier or part of the wellbore wall may
behave plastically (Aadnoy et al., 2004). The concept behind this idea is based on wellbore pressure as the inner boundary condition for the plastic zone with a pressure match at the plastic and elastic region interface whereas the in-situ stresses act as external boundary condition at infinity. The tangential stress is the controlling factor for the fracturing process, a solution for the tangential stress is presented in equation 2.23.

\[ \sigma_\theta = -P_b + \frac{C^2}{r^2} - (q - P_b) - P_a + \frac{2Y}{\sqrt{3}} \ln \left( \frac{r}{a} \right) + \frac{2Y}{\sqrt{3}} \] 

(2.29)

The plastic zone terms on this equation are being represented by the last two terms. Due to the plastic zone present on this model, there might be an increase in pressure due to the resistance to deform the rock. In order to define failure which is caused when effective tangential load surpasses the tensile strength of the rock the following is presented:

\[ \sigma_\theta - P_0 \leq -\sigma_t \] 

(2.30)

Thus, the fracture pressure for the elasto-plastic model is presented on equation 2.31

\[ P_{frac} = 3\sigma_h - \sigma_H + \sigma_t - P_0 + \frac{2Y}{\sqrt{3}} \ln \left( 1 + \frac{t}{a} \right) \] 

(2.31)

Low permeable samples were tested with different drilling fluids. When samples were tested using water as fracturing fluid experiments showed a good correlation for the poroelastic model (Aadnoy, 2004).

\[ P_{frac} = \sigma + (1 - 2\nu)(\sigma - P_0) + (1 + \nu)\sigma_t \] 

(2.32)
However, when samples were tested with drilling fluids the elastoplastic model in equation 2.25 must be used.

**2.1.4. Fracture Resistance Model Based on Non-Invaded Zone.** Salehi (2012) modified Abe et al. (1976) analytical solution for sealed penny-shaped fracture in an infinitely extended medium. The model has been developed assuming fracture tip is subject to normal stress which separates the faces symmetrically. The derived fracture pressure can be described in the following form,

\[
P_{frac} = (\lambda + 1)\sigma_h - \lambda P_p
\]

(2.33)

The model assumes that the fracture is subjected to minimum horizontal far field stress and an existence of a non-invaded zone at the fracture tip (Figure 2.4). This non-invaded zone has been thoroughly documented in Morita et al. (1990) experiments. Based on the length of the invaded and non-invaded zone an expression can be determined as follows:

\[
\lambda = \frac{1}{1 - \sqrt{1 - \left(\frac{R_1}{R}\right)^2}} \cdot \sqrt{1 - \left(\frac{R_1}{R}\right)^2}
\]

(2.34)

\(\lambda\) is the sealing efficiency factor caused by the non-invaded zone which can take any value from 0 to 1.5 If there is no non-invaded zone the \(\lambda\) is zero and equation 2.29 reduces to the Kirsch solution.
2.2. HYDRAULIC FRACTURE EXPERIMENTS

2.2.1. DEA – 13 Fracturing Experiments. Drilling Engineering Association -13 joint industry project was part of the beginning stages of understanding fluid loss and wellbore strengthening by performing rock fracturing experiments (Morita et al., 1990). Predrilled Berea, Torrey Buff sandstone and Mancos shale samples were employed in fracturing experiments with different oil based and water based muds with densities of 10-lbm/gal and 16-lbm/gal. These experiments revealed that reopening pressure depends upon quantity of mud cake left behind on the wellbore wall (Morita et al., 1990, Onya 1994, Morita et al., 1996a, and Morita et al., 1996b). The cause for this higher reopening fracture is found on the solids present in the drilling fluid which create a bridge in the
fracture opening. It can be stated that water based muds cause a higher reopening pressure when compared to oil based muds as it has been presented in other experiments, however, the original breakdown pressure for both kinds of muds remained similarly close. An increase in fracture propagation from 3.0 to 6.0 ppg was achieved in permeable formations, however it is not as effective in extremely low or non permeable formations (Fuh et al., 1992). Although no detailed explanation of the DEA-13 experimental set up and running procedure was given. A fractured sample from one of the DEA-13 tests is presented in figure 2.5.

Figure 2.5. Berea Sandstone Core – DEA-13 (Wang, 2007b)

2.2.2. GPRI Joint Industry Project Experiments (JIP). The JIP project as described by Van Oort et al., (2009), meant to replicate DEA-13 experiments on a smaller scale to reduce cost and thus further understand the concept of fracture
propagation resistance. The project aimed to compare different drilling mud performances such as SBM (synthetic-based-mud) and WBM (water-based-mud). The tests showed that WBM have an overall fracture propagation pressure efficiency greater than SBM. However, on very specific wellbore strengthening materials (WSM) such as synthetic graphites of specific type and size, were also found to be effective in increasing fracture propagation pressure. Not only the comparison between different mud compositions was studied, but also the effect of hydraulically conductive fractures on fracture re-opening pressures. Results obtained from these experiments revealed that hydraulically conductive fracture yield a lower ideal fracture re-opening pressure to the level of the minimum horizontal stress, which for these kinds of experiments is also the confining pressure.

2.2.3. Concrete Experiments. Hydraulic fracturing experiments were performed by Aadnoy et al. (2004) at Stavanger University using a 10,000 psi fracturing cell with hollow concrete cores each being 10 cm in diameter by 20 cm in length with a borehole diameter of 1 cm. During the first phase of the experiments confining pressure, borehole pressure and axial load were applied simultaneously until desired confining pressure was reached. Once confining pressure and axial load satisfy the set up requirements the second phase involved increasing borehole pressure until breakdown of wellbore takes place.

A repetitive sequence of fracturing experiments was conducted, including an initial fracture propagation followed by two re-opening fracture experiments, the first one after 10 minutes of initial fracture and the second one after 1 hour of initial fracture. Several test were conducted including different borehole geometry, however analysis was
narrowed to three tests on circular geometry although the total number of tests performed was eight. The reason why concrete cores were used is related to their ability to deliver a close representation of low permeable formations such as shale and chalk with consistent material properties. Furthermore, Aadnoy and Belayneh’s work, has shown that pure water delivers a reliable correlation for the poroelastic fracturing model due to the lack of loss circulation material which is in accordance with other studies (Aadnoy et al., 2004). During testing, a concrete core was subject to confining pressure of 4 MPa and tensile strength of 8 MPa. Results are presented in table 2.1 for circular borehole geometry includes fracturing pressure and reopening pressures after 10 and 60 minutes after initial fracture was observed.

Although the linear elastic theory (LET) has predicted 16 MPa and 8 MPa of fracturing pressure for non-penetrating and penetrating respectively, measured results ranged from 5.72 MPa up to 26.58 MPa, considerably higher than those predicted by the LET, thus leading to new fracture model named the elasto-plastic model. Several issues are present while testing. Some are related to the ability of delivering tests with a certain degree of relationship amongst them which is something that has not been possible, especially when trying to replicate core samples. Another drawback is that a lack of data comparison between the Linear Elastic Theory and the Elasto-Plastic model presented. Even though several fluid barrier particles were used such as SiC or CaCO₃, a large range of fractures pressures were presented preventing an accurate understanding of those fractures to its corresponding fracture model.
Table 2.1. Fracturing Test Results on Various Borehole Shapes and Sizes with Different Drilling Fluids (Aadnoy et al., 2004)

<table>
<thead>
<tr>
<th>Well Geometry</th>
<th>Size (mm)</th>
<th>Fracturing (\Delta P) (MPa)</th>
<th>Reopening 10 min (\Delta P) (MPa)</th>
<th>Reopening 60 min (\Delta P) (MPa)</th>
<th>Fluid type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circle</td>
<td>Ø10</td>
<td>26.58</td>
<td>18.4</td>
<td>18.03</td>
<td>fluid</td>
</tr>
<tr>
<td>Circle</td>
<td>Ø20</td>
<td>14.85</td>
<td>6.96</td>
<td>9.66</td>
<td>fluid A</td>
</tr>
<tr>
<td>Circle</td>
<td>Ø20</td>
<td>16.55</td>
<td>6.32</td>
<td>8.24</td>
<td>fluid B</td>
</tr>
</tbody>
</table>

2.2.4. M-I Swaco Experiments. Kaageson-Loe et al. (2007) presented a series of experiments performed by M-I Swaco to analyze and understand the phenomena of lost circulation while drilling. One of the novelties presented by these set of experiments is a high pressure testing device which allows studying an in-house manufactures porous media, a good representation of permeable formations, with either water or oil based muds. As an example, a formation matrix is simulated by two parallel plates of 5 x 0.5 in diameter. Porosity and permeability can be varied by handling the size distribution of particles which are sintered onto the disk, which in the example presented 175 µm of porosity with 100 darcies clearly showing a high permeable formation. The pressure cell can withstand pressures of 6000 psi, an initial fracture aperture of 250, 500 and 1000 µm are created in the sample, since the goal is to test the loss particle material with different mud types. Results for this batch of experiments are presented on table 2.1. The table
below contains the results for the testing done by M-I Swaco where the intention is to ratify the concept of fracture sealing by manipulating LPM, PSD and fluid loss. However, studies on wellbore strengthening are an ongoing work. Conclusions lead to comprehend the advantages of fracture sealing materials by plotting the particle size distribution against maximum fracture seal pressure, as in the table 2.2.

Table 2.2. Summary of M-I Swaco Experimental Results (Kaageson-Loe et al., 2007)

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Resized LCM (um)</th>
<th>Fracture Aperture (um)</th>
<th>Fracture Tip</th>
<th>Flow Rate (mL/min.)</th>
<th>Total Time Before Seal (min.)</th>
<th>Time to 1,000 psi (min.)</th>
<th>Sealed Pressure (psi)</th>
<th>Seal Radial Distance (in.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S2-1</td>
<td>500</td>
<td>500</td>
<td>Open</td>
<td>10</td>
<td>2.5</td>
<td>3.5</td>
<td>1190</td>
<td>0.22–0.34</td>
</tr>
<tr>
<td>S2-1 #2</td>
<td>N</td>
<td>500</td>
<td>Open</td>
<td>10</td>
<td>2.5</td>
<td>2.7</td>
<td>3900</td>
<td>0.22–1.80</td>
</tr>
<tr>
<td>S2-3</td>
<td>250</td>
<td>250</td>
<td>Open</td>
<td>10</td>
<td>3.1</td>
<td>12</td>
<td>1970</td>
<td>0.35–0.65</td>
</tr>
<tr>
<td>S2-6a</td>
<td>500</td>
<td>500</td>
<td>Closed</td>
<td>50</td>
<td>2.5</td>
<td>3.26</td>
<td>1520</td>
<td>1.7–2.6</td>
</tr>
<tr>
<td>S2-6c</td>
<td>250</td>
<td>250</td>
<td>Closed</td>
<td>50</td>
<td>0.25</td>
<td>1.75</td>
<td>1490</td>
<td>0.25–2.5</td>
</tr>
<tr>
<td>S2-6c #1</td>
<td>250</td>
<td>250</td>
<td>Closed</td>
<td>50</td>
<td>0.25</td>
<td>0.75</td>
<td>1710</td>
<td>0.25–2.5</td>
</tr>
<tr>
<td>S2-6d</td>
<td>N</td>
<td>1000</td>
<td>Closed</td>
<td>50</td>
<td>0.83</td>
<td>0.9</td>
<td>1560</td>
<td>0.20–2.5</td>
</tr>
<tr>
<td>S1-1</td>
<td>N</td>
<td>500</td>
<td>Open</td>
<td>10</td>
<td>3</td>
<td>3.6</td>
<td>6132</td>
<td>0.2</td>
</tr>
<tr>
<td>S1-2</td>
<td>N</td>
<td>500</td>
<td>Open</td>
<td>10</td>
<td>2.2</td>
<td>2.5</td>
<td>6131</td>
<td>0.15</td>
</tr>
<tr>
<td>S1-6</td>
<td>N</td>
<td>1000</td>
<td>Open</td>
<td>10</td>
<td>2.45</td>
<td>2.7</td>
<td>3611</td>
<td>0.15</td>
</tr>
<tr>
<td>S1-7</td>
<td>N</td>
<td>1000</td>
<td>Open</td>
<td>10</td>
<td>3.65</td>
<td>4.2</td>
<td>2803</td>
<td>0.12</td>
</tr>
<tr>
<td>S1-9</td>
<td>N</td>
<td>1000</td>
<td>Open</td>
<td>10</td>
<td>3.25</td>
<td>3.7</td>
<td>2037</td>
<td>0.12</td>
</tr>
</tbody>
</table>

2.3. SUMMARY AND CRITICAL REVIEW OF THE LITERATURE

The major and most commonly used method to describe fracture pressure despite of all the methodologies presented during this chapter is the Kirsch solution. For research
purposes and for the validation of laboratory experiments, this analytical model is the one chosen to compare and contrast against the results obtained by the experiments.
3. EXPERIMENTAL METHODOLOGY

In this section the experimental set up, data acquisition system, core preparation and procedure will be explained in detail. The overall goal of the experimental set up is to further understand the concept of fluid loss and wellbore strengthening by means of performing hydraulic fracture experiments under confining pressures thus simulating downhole conditions. This chapter will emphasize the important role of each individual component which together serves the purpose of contributing to the wellbore strengthening phenomenon throughout laboratory results.

3.1. EXPERIMENTAL SET UP

Before performing any kind of experiments, it is important to have a comprehensive knowledge on each component involved in the overall system, as the sum of all parts give life to the whole assembly. Several detailed steps which may seem redundant, have been explained in order to clarify their importance. Underestimating the functionality of any isolated part of the experimental set up, may lead to inadequate results or structural damage. In order to illustrate the system’s complexity a full detailed schematic can be found on figure 3.1.
Figure 3.1. Hydraulic Fracturing System Schematic
3.1.1. **Pump System and Fluid Distribution.** High pressure (10,000 psi) low volume (100 ml) Isco DX100 syringe type pumps are used to build up and apply pressure inside the hydraulic fracturing apparatus, either for confining or fracturing purposes. The fluid which these pumps operate with is obtained from a plastic or stainless steel container used as a reservoir. Each pump has an inlet valve which allows fluid flow to enter the pump piston for refilling or discharging all content as well. Both pumps share the same inlet tubing into the reservoir, allowing refilling both pumps at the same time. The tubing used that allows fluid distribution to and from the pumps as well as into the apparatus is 1/8” and 1/4” OD stainless steel. Each pump has an outlet valve, preventing the system from depressurizing while being refilled.

3.1.2. **Accumulator.** A stainless steel pipe with an internal piston has been designed to accumulate and inject drilling fluids into the core sample. Syringe pumps used for this experiment were not designed to handle drilling fluids, therefore, an accumulator as shown in figure 3.2, is loaded with desired drilling mud and then by means of injecting water beneath the piston, the mud is transferred and injected into the core sample.
From figure 3.2 it can be seen that water is delivered from the pumps to the bottom of the piston in the accumulator. Mud is transferred to the accumulator by filling a plastic cylinder and then applying compressed air to force the mud into the accumulator. Then, pressure is built underneath the piston which displaces the mud into the core sample.

3.1.3. Hydraulic Piston. The hydraulic “hand” pump is connected to a piston located on the top of the apparatus frame (figure 3.3). The sole purpose of this piston is to apply axial load onto the top cap, thus creating overburden stress within the core.
3.1.4. **In-line Pressure Regulator.** A pressure regulator as shown in figure 3.4 is mounted in between the hand pump and the piston is used to bleed off hydraulic fluid in case pressure inside the piston exceeds the desired pressure.
3.1.5. **Rubber Sleeve.** A rubber sleeve is used to apply confining pressure inside the hydraulic fracturing apparatus. Pressure is built up in the gap between the stainless steel cylinder and the rubber sleeve, thus as pressure is increased the rubber sleeve confines the core sample until desired pressure is reached.

3.1.6. **Stainless Steel Cylinder.** A stainless steel cylinder which is placed over the rubber sleeve and rests on the bottom flange is used as a pressure vessel to contain the highly pressurized fluid used to apply confining stresses onto the core sample. It also serves as the seat and support for the top flange.

3.1.7. **All Thread Rods.** Six all thread rods mounted on the I–beam are used to secure and clamp down the top flange onto the stainless steel cylinder, thus creating a seal for the rubber sleeve, which prevents leaks from the confining chamber onto the upper section of the core sample.

3.1.8. **Bottom Flange.** The bottom flange, which is bolted onto an I-beam, serves as the base and foundation of hydraulic fracturing apparatus. The bottom flange has several purposes:

- Serve as a core holder
- Provide support for the stainless steel cylinder
- Provide support for the rubber sleeve

It is important to note that the rubber sleeve is glued with clear silicone onto the core holder to avoid leaks. The bottom flange is shown in figure 3.5.
3.1.9. **Top Flange.** The top flange, shown in figure 3.6, is similar to the bottom flange. It has an opening in the center so that core samples can be placed right into the apparatus. It rests onto the stainless steel cylinder and the rubber sleeve. It provides a seal between these two to avoid leakages, thus preventing confining pressure losses.
3.1.10. **Hydraulic Fracturing Apparatus Frame.** The frame, shown in figure 3.7, serves as a support for the hydraulic fracturing apparatus. The bottom flange rests on an I-beam which can travel in the vertical direction by two hydraulic operated winches. The hand pump, which drives the piston mounted on the top of the frame, is located on the left side of the frame. The frame has several holes allowing the I-beam to rests in different heights.

![Figure 3.7. Hydraulic Fracturing Apparatus](image)
3.1.11. Hydraulic FRACTURING APPARATUS. All of the components mentioned above, comprise an assembly whose purpose is to induce vertical or horizontal fractures to better understand the phenomenon of hydraulic fracturing that takes place while drilling. Original break down and re-opening pressures measured with this apparatus are compared to the Kirsch solution explained above. A complete schematic can be found on figure 3.1 also, a list of all the pressure ratings for the system can be found in Appendix C.

3.1.12. Data Acquisition. In order to record the pressure at which the pump is injecting the fracturing fluid into the core sample, the software provided by the pump manufacturer was employed. This software has the ability to operate and record the pump parameters remotely from a computer. By a special serial cable provided as well by the pump manufacturer, the pump controller is connected to an rs-232 serial port on the computer. The software stores the data generated from the pump, however, the data as it appears on the original file, must be manipulated in a fashion that allows the user to see the actual data. The factors that correspond to such interpretation can be found on the Isco Pump Manual. Besides being able to record the injection pressure from a pump, a pressure gauge has been installed on the injection line in order to compare values and measure head losses in the system.
3.2. CORE PREPARATION

In order to carry out hydraulic fracture experiments a core sample must be manufactured. These experiments require cylindrical core samples made from rock slabs or by forming cement into a mold. The steps to manufacture cylindrical cores from rock slabs are:

1. Gather rock slab from quarry or outcrop
2. Use drill press machine with 5 ¾” diameter cylindrical drill bit to drill out core
3. Use surface grinder to smooth out and square core ends
4. Use drill press machine with ½ ” drill bit in center of core to create wellbore hole

Each core cannot be any taller than 9” due to the pressure cell height limitation. The overall height of the cell is 15”, thus leaving 6” for both top and bottom caps, as well as two spacers and overburden cap. Furthermore, once these four steps have been completed according to the mentioned requirements the core made from a rock slab would be ready to undergo the final preparation before it can be tested. In order to avoid fluid from escaping the wellbore and causing overburden losses, the top and bottom caps are cemented in place. Before the caps can be cemented onto the core a simple cap assembly process takes place:

1. Place Teflon tape over the injection nipple’s threads
2. Screw into one side of top cap the injection nipple
3. Place Teflon tape over the top casing’s threads
4. Screw into the other side of top cap the 1 ½” casing
5. Place Teflon tape over the bottom casing’s threads
6. Screw into the bottom cap the 1 ½” casing

After this short assembly, if the borehole does not align perfectly with the top/bottom cap, a grinding stone designed for small applications such as the Dremel Tool, could be used to enhance the borehole’s diameter. Then, epoxy is used to bond top and bottom caps to the core. The epoxy used for this purpose is the Sikadur 31 Hi Mod Gel 1:1 ratio. Place top/bottom cap with casing in upright position over the C – Clamps. Use masking tape to cover the casing hole; this will prevent excess epoxy from clogging it. Use sand paper of 120/150 grit to make a rough surface on the cap as well as on the casing, allowing a good bond between core and cap. Once both, the cap and casing have been scratched with sand paper, spread epoxy onto the entire surface of cap as well as on the side of the casing. Finally, place core onto the cap and clamp it down in steps, to allow any necessary alignment. Clean excess epoxy and let cure for 24 hours. This process which describes how to bond cap and core should be repeated for the remaining cap. Cement one cap at a time.

3.3. EXPERIMENTAL PROCEDURE

In order to start performing hydraulic fracture experiments set the accumulator valves to injection mode, empty the accumulator so that no other fluid other than the
intended fluid is found on the injection line. Place a core which has been prepared according to instructions on section 3.2.3 into the hydraulic fracturing apparatus.

Overburden and confining pressure are applied to the core before starting to run the experiment. Overburden stress is obtained by a piston pushing down on the top cap and confining pressure is applied through a rubber sleeve in the apparatus by building pressure inside of it. Fracturing fluids are prevented from escaping the bottom and top of the wellbore by placing an o-ring at the seat of the core holder and by bonding bottom and top caps to the core sample as well as each cap having their casings cemented to the wellbore.

The accumulator mentioned above which is mounted on the wall is used to inject drilling mud or other hydraulic fracturing fluid other than water; since water is injected directly from the pumps to the core. Two gauges are located on the hydraulic fracturing apparatus. One gauge is used to control and compare injection pressure as the experiment is being run; the other gauge is used to monitor confining pressure. A computer is used to record the data as the experiment is being run by using the Isco Pump software. At this point the set up is ready for injection. Locate valves on the accumulator as well as on the injection line and set to refill. Refill the accumulator with the desired mud. If water is used to fracture the specimen, put all valves on water injection mode, or switch the valves from refill to mud injection. Make sure the bottom exit valve is open to remove air from wellbore. Once this task is done close bottom exit valve and stop pumping. Open Isco Pump software to record data, head losses in the injection line is 100 psi, this should be taken into account and subtracted accordingly from the data recorded. Assign a name to the file; connect the pump to the software and start running the experiment. In between
cycles, from original break down and re-opening whether a single or multiple re-opening cycles are run, the wellbore must be depressurized by opening the bottom exit valve and closing it right away. A complete check list for the experimental procedure can be found in Appendix B.

3.4. TESTING PROGRAM

In order to summarize the testing program followed throughout this work, a table with all the input parameters can be found in below on table 3.1. This table lists rock mechanical properties of the materials that were tested as well as core dimensions and the material used for each core. It also depicts the fluid used to fracture the cores and its main important properties such as fluid density, yield point and plastic viscosity. Lastly, the stresses applied to the core for each experiment can also be found on the same table.
Table 3.1. Table of Rock Mechanical Testing and Fluid Properties

<table>
<thead>
<tr>
<th>Test #</th>
<th>Mechanical Test</th>
<th>Material</th>
<th>Core L (in.)</th>
<th>Core Diameter (in)</th>
<th>Fracturing fluid</th>
<th>Fluid properties</th>
<th>σ2,3 (psi)</th>
<th>σv (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>TSS 562.3, UCS 27550</td>
<td>Dolomite</td>
<td>8.5</td>
<td>5.75</td>
<td>Water</td>
<td>2 1</td>
<td>8.33</td>
<td>600 48</td>
</tr>
<tr>
<td>2</td>
<td>TSS 562.3, UCS 27550</td>
<td>Dolomite</td>
<td>8.5</td>
<td>5.75</td>
<td>8% Bentonite</td>
<td>12 25</td>
<td>9</td>
<td>200 400</td>
</tr>
<tr>
<td>3</td>
<td>TSS 562.3, UCS 27550</td>
<td>Dolomite</td>
<td>8.75</td>
<td>5.75</td>
<td>Water</td>
<td>2 1</td>
<td>8.33</td>
<td>600 48</td>
</tr>
<tr>
<td>4</td>
<td>TSS 381.6, UCS 10150</td>
<td>Sandstone</td>
<td>8.75</td>
<td>5.75</td>
<td>8% Bentonite</td>
<td>12 25</td>
<td>9</td>
<td>200 400</td>
</tr>
<tr>
<td>5</td>
<td>TSS 101.5, UCS 1338</td>
<td>Concrete</td>
<td>9</td>
<td>5.75</td>
<td>4% Bentonite</td>
<td>4 2</td>
<td>8.6</td>
<td>200 400</td>
</tr>
<tr>
<td>6</td>
<td>TSS 101.5, UCS 1338</td>
<td>Concrete</td>
<td>9</td>
<td>5.75</td>
<td>6% Bentonite</td>
<td>6 8</td>
<td>8.8</td>
<td>200 400</td>
</tr>
<tr>
<td>7</td>
<td>TSS 176.4, UCS 2293</td>
<td>Concrete</td>
<td>9</td>
<td>5.75</td>
<td>6% Bentonite (CMC)</td>
<td>10 18</td>
<td>8.7</td>
<td>200 400</td>
</tr>
<tr>
<td>8</td>
<td>TSS 176.4, UCS 2293</td>
<td>Concrete</td>
<td>9&quot;</td>
<td>5.75&quot;</td>
<td>6% Bentonite (CMC + CaCO₃)</td>
<td>14 28</td>
<td>9</td>
<td>200 400</td>
</tr>
</tbody>
</table>

Table 3.2, presents a summary of the results obtained for each experiment as well as injection flow rate and wellbore diameter.

Table 3.2. Table of Testing Parameters and Pressure Values

<table>
<thead>
<tr>
<th>Test #</th>
<th>Wellbore Diameter (in)</th>
<th>Flow rate (ml/min)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.5&quot;</td>
<td>50</td>
</tr>
<tr>
<td>2</td>
<td>0.5&quot;</td>
<td>50</td>
</tr>
<tr>
<td>3</td>
<td>0.5&quot;</td>
<td>50</td>
</tr>
<tr>
<td>4</td>
<td>0.5&quot;</td>
<td>50</td>
</tr>
<tr>
<td>5</td>
<td>0.5&quot;</td>
<td>5</td>
</tr>
<tr>
<td>6</td>
<td>0.5&quot;</td>
<td>5</td>
</tr>
<tr>
<td>7</td>
<td>0.5&quot;</td>
<td>5</td>
</tr>
<tr>
<td>8</td>
<td>0.5&quot;</td>
<td>5</td>
</tr>
</tbody>
</table>
4. RESULTS

This chapter presents the hydraulic fracturing experimental results with the intention of analyzing and clarifying the hydraulic fracturing phenomenon. Having the ability to replicate downhole stresses and hydraulically fracture specimens gives the advantage of producing real data allowing to build correlations between the numerical model and laboratory results. All tests are performed on samples with 5.75” in diameter with a borehole of 0.5”. The length of the core depends on rock slab thickness but the core length was at least 1:1 ratio between the core diameter and specimen height to avoid end effects.

4.1. TEST #1 DOLOMITE FRACTURED WITH WATER

Table 4.1. Dolomite Fractured with Water

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_V$ (psi)</th>
<th>$q$ (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_V}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Dolomite</td>
<td>600</td>
<td>1150</td>
<td>X</td>
<td>Horizontal</td>
<td>48</td>
<td>50</td>
<td>12.5</td>
</tr>
</tbody>
</table>

Test 1 was conducted on a dolomite core (Table 4.1). Injecting fluid used to fracture the sample was tap water (Figure 4.1). Overburden pressure was applied at 50 psi and confining pressure was set to 600 psi. This set up lead to a horizontal fracture, since these conditions with $S_h > S_H > S_V$ do not represent a normal Andersonian faulting.
environment (Fjaer et al., 2008). The injection pressure vs. time curve is presented next to the fractured sample (Figure 4.2). The breakdown pressure occurred at a lower value (1150 psi) than expected due which may occurred due to natural pre existing fractures in the sample which can be seen in the core before testing (Figure 4.1).

Figure 4.1. Dolomite Core Test 1 before testing
4.2. TEST # 2 DOLOMITE FRACTURED WITH 8% BENTONITE MUD

Table 4.2. Dolomite Fractured with 8% Bentonite Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>( \sigma_{2,3} ) (psi)</th>
<th>( P_{frac} ) (psi)</th>
<th>( P_{re-open} ) (psi)</th>
<th>Fracture Orientation</th>
<th>( \sigma_V ) (psi)</th>
<th>( q ) (ml/min)</th>
<th>( \frac{\sigma_{2,3}}{\sigma_V} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Dolomite</td>
<td>200</td>
<td>3700</td>
<td>2100</td>
<td>Vertical</td>
<td>400</td>
<td>50</td>
<td>0.5</td>
</tr>
</tbody>
</table>

This test was conducted with a dolomite core (Table 4.2). Injecting fluid used to fracture the sample was 8% Bentonite mud (Figure 4.3). Overburden pressure was...
applied at 400 psi and confining pressure was set to 200 psi. This set up lead to a horizontal fracture, since these conditions do not represent a normal fault environment. The injection pressure vs. time curve is presented next to the fractured sample (Figure 4.4). The breakdown pressure occurred at 3700 psi, a much higher value compared to the water injection test mentioned above. The reason for this, is when injecting mud, it creates a mud cake which prevents the fluid from entering the formation (non-penetrating) thus inducing a higher breakdown pressure. The re-opening cycle clearly shows that the re-opening pressure is lower than the original breakdown recorded at 2100.

4.3. TEST #3 DOLOMITE FRACTURED WITH COLORED WATER

Table 4.3. Dolomite Fractured with Colored Water

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_Y$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_Y}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>Dolomite</td>
<td>600</td>
<td>2224</td>
<td>X</td>
<td>Horizontal</td>
<td>48</td>
<td>50</td>
<td>12.5</td>
</tr>
</tbody>
</table>

The third test was conducted on a dolomite core (Table 4.3). Injecting fluid used to fracture the sample was simply water (Figure 4.5). Overburden pressure was again applied at 50 psi and confining pressure remained set at 600 psi. This set up, as explained in Test -1 leads to a horizontal fracture. To be able to identify where the fracture happened along the core a green dye was used in the water. As it can be seen in the
aforementioned figure the core split right horizontally along a single fracture plane. The injection pressure vs. time curve is presented next to the fractured sample (Figure 4.6). The breakdown pressure occurred at higher value than the first horizontal test which can be attributed to the heterogeneous properties of the formation (2224 psi). Since the core has been fractured completely to the edge of the core, a re-opening cycle was not possible to perform since the injected water is pressure with a higher pressure towards the confining sleeve.

Figure 4.3. Dolomite Core Test 2 before testing
Figure 4.4. Original Breakdown and Re-Opening Pressure Test 2

Figure 4.5. Dolomite Core Test 3 before testing (to the left) and after testing (to the right)
4.4. TEST # 4 ROUBIDOUX SANDSTONE FRACTURED WITH 8% BENTONITE MUD

Table 4.4. Roubidoux Sandstone Fractured with 8% Bentonite Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_V$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_V}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>Roubidoux Sandstone</td>
<td>200</td>
<td>1928</td>
<td>1794</td>
<td>Vertical</td>
<td>400</td>
<td>50</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Injecting fluid used to fracture the sample was 8% Bentonite mud (Figure 4.7). Overburden pressure was applied at 400 psi and confining pressure was set to 200 psi.
Different from dolomite, sandstone is a permeable formation thus no water test was performed due to its high permeability. Two cycles were carried out, an original break down and re-opening cycles. The injection pressure vs. time curve illustrating both cycles is presented in Figure 4.8. The breakdown pressure occurred at 1928 psi and re-opening pressure took place at 1794 psi.

Figure 4.7. Roubidoux Sandstone Core Test 4 before testing
4.5. TEST # 5 CONCRETE CORE FRACTURED WITH 4% BENTONITE MUD

Table 4.5. Concrete Core Fractured with 4% Bentonite Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_Y$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_Y}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Concrete</td>
<td>200</td>
<td>1855</td>
<td>1422</td>
<td>Vertical</td>
<td>400</td>
<td>5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

This test was conducted over a concrete core (table 4.5). Forming concrete cores gives the advantage of simulating low permeable formations with a high degree of homogeneity, therefore no pre existing fractures or fissures are present at the time of...
performing the experiment. The concrete mix was calculated by filling up a 6” inside diameter and 1 foot tall of PVC pipe with Quickcrete mortar mix. The amount of water used to mix in the mortar mix was 58 fluid oz. The concrete is poured onto a steel column coated with silicone used as a release agent. Before performing any kind of mechanical procedures or operations, the concrete core has to cure for a 7 day period. An original breakdown cycle was performed injecting 4% Bentonite (Figure 4.9). Overburden pressure was applied at 400 psi and confining pressure was set to 200 psi. The injection pressure vs. time curve illustrating both cycles is presented in figure 4.10. The breakdown pressure occurred at 1855 psi and re-opening pressure took place at 1422 psi.

### 4.6. TEST # 6 CONCRETE CORE FRACTURED WITH 6% BENTONITE MUD

Table 4.6. Concrete Core Fractured with 6% Bentonite Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_V$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_V}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>Concrete</td>
<td>200</td>
<td>2188</td>
<td>1856</td>
<td>Vertical</td>
<td>400</td>
<td>5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Test six was conducted over a concrete core (Table 4.6). The concrete mix used for this experiment is the same as explained in the previous one. An original breakdown cycle was performed injecting 6% Bentonite (Figure 4.11). Overburden pressure was applied at 400 psi and confining pressure was set to 200 psi. The same cycle was applied to ensure repeatability among the testing program. The injection pressure vs. time curve
illustrating both cycles is presented in figure 4.12. The breakdown pressure occurred at 2188 psi and re-opening pressure took place at 1856 psi.

Figure 4.9. Concrete Core Test 5 before testing
4.7. TEST # 7 CONCRETE CORE FRACTURED WITH 6% BENTONITE – CMC MUD

Table 4.7. Concrete Core Fractured with 6% Bentonite – CMC Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_Y$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_Y}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>Concrete</td>
<td>200</td>
<td>2310</td>
<td>2115</td>
<td>Vertical</td>
<td>400</td>
<td>5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Test 7 was conducted over a concrete core (Table 4.7). The concrete mix used for this experiment is the same as explained in the previous concrete experiments. The mud
used for this experiment included Carboxy Methyl Cellulose (CMC), a viscosifier needed to suspend the calcium carbonate particles in the fluid. An original breakdown cycle was performed injecting 6% Bentonite-cmc (Figure 4.13). Overburden pressure was applied at 400 psi and confining pressure was set to 200 psi. Ten minute interval between cycles was applied to be consistent with previous experiments. The injection pressure vs. time curve illustrating both cycles is presented in figure 4.14. The breakdown pressure occurred at 2310 psi and re-opening pressure took place at 2115 psi.

Figure 4.11. Concrete Core Test 6 before testing
Figure 4.12. Original Breakdown and Re-opening Pressure Test 6

Figure 4.13. Concrete Core Test 7 before testing
4.8. TEST # 8 CONCRETE CORE FRACTURED WITH 6% BENTONITE – CMC AND CALCIUM CARBONATE MUD

Table 4.8. Concrete core fractured with 6% Bentonite – CMC and Calcium Carbonate Mud

<table>
<thead>
<tr>
<th>Test #</th>
<th>Material</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{frac}$ (psi)</th>
<th>$P_{re-open}$ (psi)</th>
<th>Fracture Orientation</th>
<th>$\sigma_V$ (psi)</th>
<th>q (ml/min)</th>
<th>$\frac{\sigma_{2,3}}{\sigma_V}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Concrete</td>
<td>200</td>
<td>2363</td>
<td>1863</td>
<td>Vertical</td>
<td>400</td>
<td>5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

This test was conducted over a concrete core (Table 4.8). The concrete mix used for this experiment is the same as explained in the previous concrete experiment as well.
The mud used for this experiment included Carboxy Methyl Cellulose (CMC), a viscosifier needed to suspend the calcium carbonate particles in the fluid with a 5% calcium carbonate by weight added to the mixture. An original breakdown cycle was performed injecting 6% Bentonite-cmc-CaCO$_3$(Figure 4.15). Overburden pressure was applied at 400 psi and confining pressure was set to 200 psi. Ten minute interval between cycles was applied to be consistent with previous experiments. The injection pressure vs. time curve illustrating both cycles is presented in Figure 4.16. The breakdown pressure occurred at 2363 psi and re-opening pressure took place at 1863 psi.

Figure 4.15. Concrete Core Test 8
Figure 4.16. Original Breakdown and Re-opening Pressure Test 8
5. DISCUSSION

The major contribution of hydraulic fracturing experiments explained in chapter 4 is that the re-opening pressure does not reach a higher value than the original breakdown pressure. Moreover, this is not the only observation made but also that the values obtained were higher than those predicted by the Kirsch solution. In order to comprehend the experiments performed in chapter 4, a detailed explanation of the results will be presented in this chapter. In addition, a comparison of the results obtained in this work will be compared and contrasted with those presented in the literature review.

5.1. INITIAL SET UP OF EXPERIMENTS

Once the hydraulic fracturing apparatus was fully functional and ready to be put to test a first batch of experiments were conducted. During the first test, an unexpected horizontal fracture occurred, due to the set up of stresses while running the experiment. Confining pressure governs minimum and maximum horizontal stresses, which in this case are the same, which in case of being larger than the vertical stress a horizontal fracture will be obtained. For the first dolomite experiment, the vertical stress was set to 1000 psi however, due to a difference in area between the piston and the top cap, a much lower pressure is seen in actuality by the core itself, of 48.2 psi. Confining pressure was set to 600 psi, thus a horizontal fracture occurred. In order to produce vertical fractures, the magnitude of the vertical stress has to be greater than the horizontal whether maximum or minimum horizontal stress does not make a difference. At first, it may seem
that the natural occurring fractures or fissures in the dolomite may have induced a horizontal fracture, prior to realize the area difference, which in actuality yields a lower vertical stress on the core. A second dolomite test was performed using green food coloring mixed in the fracturing fluid to track any possible fissures or natural occurring fractures within the core; unfortunately, the test was not successful since a horizontal fracture developed splitting the core into two pieces, however, the analytical model predicts a lower fracture pressure compared to laboratory results. A comparison of a naturally fractured vs. a core with an intact borehole for these two experiments can be seen in (figure 5.1). Following the dolomite experiments, Roubidoux sandstone was tested. Retaining the same parameters used for the previous experiment (Dolomite Test 1 and Test 2) using water as a fracturing fluid the confining pressure started to increase with undesired effect before fracturing the sample. Sandstone being a permeable formation will cause water to travels throughout it very easily due to its high permeability ranging from 63 up to 113 md with as well as having a porosity of 14.7% on average. After building pressure the water simply reaches the outer boundary of the core, therefore no fracture could or will take place. Rearranging stress magnitudes and calculating the area difference between the top steel cap and the overburden piston, a new pressure of 8300 psi on the piston gauge will translate into 400 psi onto the core, which by applying a lower confining pressure of 200 psi, a vertical fracture was obtained, as expected based on the normal fault environment explained earlier. The fracturing fluid was changed from simply water to a water based mud (WBM) of 8% Bentonite by weight, allowing an original breakdown cycle and a reopening cycle with 10 minutes in between cycles to allow healing effects from the mud. However, as it has been shown, the re-opening
fracture pressure was never higher than the original breakdown, something which contradicts other methods explained in this work. Similar results were obtained when a third dolomite test was conducted, although a higher fracture pressure was achieved due to higher rock properties (figure 5.2). Changing the injection flow rate from the first set of experiments of 50 ml/m to 5 ml/m was considered to have a better control of the fracture growth; nonetheless issues have risen by doing so. The pressure curves show a ripple effect. While injecting, the fracture is initiated followed by a pressure drops. Since a small volume of fluid is being injected, the fracture re-pressurizes to continue propagating into the core in steps. The fracture pressure reaches a higher value with each step, where the fluid has not only to propagate the fracture further (overcome fracture gradient) but also has to overcome the mud that was deposited in the fracture as well.

![Figure 5.1. A Comparison of Non-Permeable Cores (Dolomite) With and Without Intact Boreholes](image-url)
Figure 5.2. A Comparison of Permeable vs. Non-Permeable Cores for 8% Bentonite Mud

5.2. CONCRETE CORE EXPERIMENTS

As a direct implication of the uncertainty and uneven geomechanical properties of the dolomite and sandstone used for first batch of testing, concrete was selected as a material that replicates low permeable formations. Since concrete is mixed and poured in house, a much more precise characterization can be made. Original breakdown pressure and re-opening pressure are present within a range of 200 psi, this is achieved due to the homogeneity of the core samples, as it can be seen from the test on 4.5 and 4.6. These two tests (4.5 and 4.6) were performed using a 4 and 6% Bentonite mud. The reason for this testing was to identify changes in original breakdown pressure and re-opening pressure by increasing the Bentonite concentration in the mud. Shown in figure 5.3, by
increasing the Bentonite concentration a higher original breakdown and re-opening pressure was achieved. A concrete fractured core is shown in Appendix A. In continuation with the testing program the test described in 4.7 and 4.8 were conducted, instead of using the “clean” 6% Bentonite test, meaning just Bentonite and water, 5% by weight calcium carbonate (CaCO\(_3\)) from Mi-Swaco was used (Safe Carb 500). When mixing the Bentonite mud, an unexpected phenomenon took place. The calcium carbonate precipitated to the bottom of the mixing cup due to lack of viscosity in the mud. In order to have the calcium carbonate in suspension a viscosifier called CMC (Carboxy Methyl Cellulose) was added following the Baroid Fluids Handbook criteria of 4% CMC by weight on a 500 ml sample. Thus, the calcium carbonate was held in suspension and the results showed a higher breakdown pressure as shown in figure 5.4; however a similar re-opening pressure compared to previous experiments was obtained. Another point to note is that laboratory results were relatively constant for the concrete cores. The last two experiments (Table 4.7 and 4.8) were conducted with cores with over 28 days of cure time, a time frame needed to achieve full cure strength on concrete, thus the higher breakdown pressure, although re-opening pressure did not follow the same trend. Thus, a higher breakdown pressure can be solely attributed to the concrete cure time. However, it is important to denote that the mechanical properties of the concrete did not vary between the different cure times. To illustrate how the different experiment results regarding original breakdown and re – opening pressures compare to each other (figure 5.3 and figure 5.4), the following graphs are presented.
Figure 5.3. A Comparison Non-Permeable Cores (concrete) for 4 & 6% Bentonite Mud

Figure 5.4. A Comparison of Non-Permeable Cores (concrete) for 6% Bentonite Mud with and Without Additives
5.3. KIRSCH SOLUTION VALIDATION

As shown on equation 23, the Kirsch solution (analytical) would predict a fracture pressure of 1762.3 psi (table 5.1) for 600 psi of confining pressure, assuming 0 pore pressure and 0 tectonic stresses. However, due to the ratio of open wellbore height with wellbore diameter with a low rate of injection (5 ml/m) the fracture pressure increases. This phenomenon has taken place as well while performing experiments with a lower confining pressure (200 psi) where the analytical model has predicted a 501.5 psi of fracture pressure. The concrete experiment where calcium carbonate has been added did not yield a closer result between the analytical model (Kirsch solution) with the experimental data.

<table>
<thead>
<tr>
<th>Injecting Fluid</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{\text{breakdown}}$ Analytical (psi)</th>
<th>$P_{\text{breakdown}}$ Laboratory Results (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>600</td>
<td>1762.3</td>
<td>1150</td>
</tr>
<tr>
<td>8% Bentonite</td>
<td>200</td>
<td>962.3</td>
<td>3700</td>
</tr>
<tr>
<td>Water</td>
<td>600</td>
<td>1762.3</td>
<td>2224</td>
</tr>
<tr>
<td>8% Bentonite</td>
<td>200</td>
<td>547.12</td>
<td>1928</td>
</tr>
<tr>
<td>4% Bentonite</td>
<td>200</td>
<td>501.5</td>
<td>1855</td>
</tr>
<tr>
<td>6% Bentonite</td>
<td>200</td>
<td>501.5</td>
<td>2188</td>
</tr>
<tr>
<td>6% Bentonite (CMC)</td>
<td>200</td>
<td>576.4</td>
<td>2310</td>
</tr>
<tr>
<td>6% Bentonite (CMC + CaCO$_3$)</td>
<td>200</td>
<td>576.4</td>
<td>2363</td>
</tr>
</tbody>
</table>
5.4. EVALUATION OF RESULTS WITH PREVIOUS CONDUCTED TESTS

Morita et al., (1996) has performed similar types of experiments as described in chapter 2. The values obtained by Morita et al., (1996) shown on table 5.2, indicate that laboratory results are much higher than the one predicted analytically. It is still uncertain why such discrepancy takes place between the two. Moreover, by performing hydraulic fracturing at Missouri S & T the same phenomenon takes place. Thus, having anisotropic or isotropic horizontal stresses cannot be taken into account as the only contributing factor to a higher breakdown pressure. Following table 5.2 and 5.3 indicates a comparison of breakdown pressure between DEA – 13 and Missouri S&T results. In addition to Morita’s work, Aadnoy et al., (2004) experimental results were higher than those predicted by the LET model (table 5.4), which is in agreement with the work presented.

Table 5.2. Missouri S&T Results

<table>
<thead>
<tr>
<th>Injecting Fluid</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{breakdown}$ Analytical (psi)</th>
<th>$P_{breakdown}$ Laboratory Results (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water</td>
<td>600</td>
<td>1762.3</td>
<td>1150</td>
</tr>
<tr>
<td>8% Bentonite</td>
<td>200</td>
<td>962.3</td>
<td>3700</td>
</tr>
<tr>
<td>Water</td>
<td>600</td>
<td>1762.3</td>
<td>2224</td>
</tr>
<tr>
<td>8% Bentonite</td>
<td>200</td>
<td>547.12</td>
<td>1928</td>
</tr>
<tr>
<td>4% Bentonite</td>
<td>200</td>
<td>501.5</td>
<td>1855</td>
</tr>
<tr>
<td>6% Bentonite</td>
<td>200</td>
<td>501.5</td>
<td>2188</td>
</tr>
<tr>
<td>6% Bentonite (CMC)</td>
<td>200</td>
<td>576.4</td>
<td>2310</td>
</tr>
<tr>
<td>6% Bentonite (CMC + CaCO$_3$)</td>
<td>200</td>
<td>576.4</td>
<td>2363</td>
</tr>
</tbody>
</table>
Table 5.3. Morita et al 1996, Laboratory Results.

<table>
<thead>
<tr>
<th>Injecting Fluid</th>
<th>$\sigma_2$ (psi)</th>
<th>$\sigma_3$ (psi)</th>
<th>$P_{breakdown}$ Analytical (psi)</th>
<th>$P_{breakdown}$ Laboratory Results (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Muds (Ave)</td>
<td>2200</td>
<td>1800</td>
<td>3350</td>
<td>11500</td>
</tr>
<tr>
<td>Muds (Ave)</td>
<td>2500</td>
<td>300</td>
<td>1450</td>
<td>4300</td>
</tr>
<tr>
<td>Water</td>
<td>1100</td>
<td>900</td>
<td>1229</td>
<td>4000</td>
</tr>
</tbody>
</table>

Table 5.4. Aadnoy et al., 2004, Laboratory Results

<table>
<thead>
<tr>
<th>Injecting Fluid</th>
<th>Well bore $\phi$ (mm)</th>
<th>$\sigma_{2,3}$ (psi)</th>
<th>$P_{breakdown}$ Analytical (psi)</th>
<th>$P_{breakdown}$ Laboratory Results (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid</td>
<td>10</td>
<td>580</td>
<td>2320</td>
<td>3855</td>
</tr>
<tr>
<td>Fluid A</td>
<td>20</td>
<td>580</td>
<td>2320</td>
<td>2153</td>
</tr>
<tr>
<td>Fluid B</td>
<td>20</td>
<td>580</td>
<td>2320</td>
<td>2400</td>
</tr>
</tbody>
</table>
6. CONCLUSIONS

Throughout this thesis, hydraulic fracturing test were performed using a pressure cell apparatus developed and tested in the premises of Missouri University of Science and Technology. First and foremost, upon completing a series of tests that aid in the process of troubleshooting the pressure cell apparatus one became not only acquainted with the device and the testing set up but also permitted to train other individuals as well.

During this process several tests were run using dolomite, sandstone as well as concrete cores. As it has been proven throughout laboratory experiments, the heterogeneity of the rock samples gathers from local quarries yield to lower fracture pressures on dolomite (when being naturally fractured) and sandstone when compared to Concrete. Only one dolomite core on Test 2, showed a higher original breakdown pressure. Dolomite and Sandstone having higher mechanical properties than concrete thus they should yield higher breakdown pressures.

However, when a re-opening cycle was achieved, the pressures obtained were very close in value, despite of lithology or fracturing fluid. A reason for this could be directly attributed to the stresses enforced by the fracturing apparatus onto the core, since that is the only mechanism that would have a direct implication in fracture closure.

When increasing the Bentonite concentration from 4 to 6 % a tendency in increase of the original breakdown pressure was identified together with an increase in the re-opening pressure as well.
Although CaCO$_3$ was used in 6% Bentonite water-based-mud it did not show an original breakdown or re-opening pressure significantly higher than a 6% Bentonite water-based-mud with no additives in it. This could be related to a variety of reasons, especially with the cure time of concrete, since test was performed on a fully cured (28 days cure time) core rather than on a 7 day cured time as in the case of the first concrete experiment.
7. RECOMMENDED FUTURE WORK

It is not possible within the research scope to test every single formation and fracturing fluid available, rather to set basis for future testing programs with a fully functional and trouble free system as well as presenting the very first set of experiments with the hydraulic fracturing apparatus as well. It is worth mentioning, that the apparatus has been fully designed and tested in addition to the work presented. However, due to time restrictions the following tests were not completed and it is set as a recommendation for future testing to perform experiments on Berea sandstone cores which holds higher degree of homogeneity not only in the grain matrix of the formation, but also in its mechanical properties.

Another effect that should be investigated in order to identify the discrepancy between Kirsch solution and laboratory results is the scaling factor. To mitigate this uncertainty, it is desired to run experiments with different wellbore diameters ranging from 0.5 up to 2 inches. Thus important contribution could be made not only clarifying Kirsch solution against results obtained earlier in chapter 4 but also to analyze the contribution of wellbore enhancement to LCM healing efficiency. The only LCM tested was calcium carbonate which was held in suspension in the mud by the aid of Carboxy Methyl Cellulose (CMC). It is recommended to try different viscosifiers and LCM in order to illustrate their implication on affecting the breakdown as well as the re-opening pressure. Moreover, it is important to remark that when varying parameters like those mentioned through this work, it should be done one at a time to evaluate each and every one once at a time. At first experiments were performed by injecting at a rate of 50 ml/m
which later was changed to 5 ml/m. It would be interesting to plan a testing program slowly increasing the flow rate to evaluate the role of such variable on breakdown and re-opening pressure.

7.1 EQUIPMENT ENHANCEMENT

The overburden piston’s contact area with the top cap is such that when applying 8300 psi on the piston’s gauge it translates into 400 psi onto the core itself. It is advisable in the near future to modify the piston to one of a larger contact area to reduce the differential area. Other feature improvements would be to add a pressure transducer on the confining pressure line to plot the confining pressure against the fracturing pressure to easily identify when the fracture has reach the outer boundary of the core. Nonetheless, the current set up replicates conditions of up to 450 ft of depth. It is important to make note that the current structural frame will not hold a pressure of 10,000 psi on the core and it should be modified and designed accordingly together with the overburden piston.
APPENDIX A

FRACTURE PICTURES AFTER CORE HAS BEEN TESTED
Concrete Core Fractured After Test Is Performed

Vertical Fracture on Concrete Core
Concrete Core Fracture Profile After Test Is Performed
APPENDIX B

PRESSURE CELL ASSEMBLY AND EXPERIMENTAL SETUP CHECK LIST
1. Raise Pressure Cell

2. Remove Cutter Pins located on the back side of the Clevis Pins

3. Remove Clevis Pins

4. Lower Pressure Cell

5. Place teflon tape onto the injection nipple threads

6. Place teflon tape onto the injection pipe threads

7. Screw injection pipe onto the injection nipple

8. Place o-ring on the bottom of the core holder (inside Pressure Cell)

9. Place the sample carefully inside the Pressure Cell

10. Screw the injection line onto the sample

11. Place Top Spacer 1 onto the sample

12. Place o-ring onto the Top Spacer 1

13. Place Top Spacer 2 onto the Top Spacer 1

14. Place o-ring onto the Top Spacer 2

15. Place Top cap onto the Top spacer 2

16. Raise the Pressure Cell to desired height

17. Place Clevis Pins

18. Drop Pressure Cell onto the Celvis Pins until the hoist cables are no longer in tension
19. Place Cutter Pins located on the back side of the Clevis Pins

20. Screw injection line from the Pressure Cell onto the injection line on the Wall

21. Screw confining line on the wall onto the Pressure Cell confining nipple

22. Screw air flush line from the Pressure Cell onto the air flush line on the Wall

23. Close confining exit valve

24. Open confining intake valve

25. Close air supply valve located on the vacuum pump

26. Close the valve on the overburden pump

27. Apply overburden until desired pressure

28. Fill up confining until desired pressure

29. Empty mud accumulator

30. Refill mud accumulator with desired mud

31. Remove air from the accumulator

32. Open Isco pump software

33. Assign a name to project click on check mark else your file will be saved under DATA.csv

34. Connect the pump to the computer

35. Check that pumps are filled before starting to inject into the accumulator

36. Open mud exit valve on the bottom of the Pressure Cell

37. Inject mud until little to no air comes out of the mud exit valve line
38. Close mud exit valve

39. Start recording data

40. Start first injection cycle until there is a change in the Confining gauge

41. Stop pumping after the first breakdown has been achieved

42. Start timing for how long you are going to wait until your next cycle

43. Open the mud exit valve

44. Close the mud exit valve

45. Check if the pumps must be refilled

46. Start pumping the second cycle until there is a change in the Confining gauge

47. Once all cycles are finished stop recording

48. Put the pumps on Local control

49. Remove Overburden Pressure

50. Open Confining exit valve

51. Close vacuum valve on the vacuum pump

52. Open air intake valve on the vacuum pump

53. Connect air flush hose onto the vacuum pump hose

54. Open the system air flush valve located on the T connection on the vacuum pump

55. Once air comes out of the Confining exit line close all valves at the vacuum pump

56. Remove the air supply hose

57. Close the Confining exit valve
58. Unscrew injection line from the Pressure Cell onto the injection line on the Wall

59. Unscrew confining line on the wall onto the Pressure Cell confining nipple

60. Unscrew air flush line from the Pressure Cell onto the air flush line on the Wall

61. Raise the Pressure Cell

62. Remove Cutter Pins

63. Remove Clevis Pins

64. Lower the Pressure Cell until desired height

65. Remove Top Cap

66. Remove Top Spacer 2

67. Remove Top Spacer 1

68. Unscrew the injection line onto the sample

69. Pull sample out of cell from injection pipe

70. Carefully remove the sample

71. Remove o-ring from bottom of the core holder

72. Clean all residue of mud inside the core chamber

73. Raise the Pressure Cell

74. Place Clevis Pins

75. Drop Pressure Cell onto the Clevis Pins until the hoist cables are no longer in tension

76. Place Cutter Pins
APPENDIX C

HYDRAULIC FRACTURING APPARATUS – PRESSURE RATING
Cell Requirements

<table>
<thead>
<tr>
<th>Tubings</th>
<th>Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/8&quot;</td>
<td>8500</td>
</tr>
<tr>
<td>1/4&quot;</td>
<td>7500</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fittings</th>
<th>Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/4&quot;</td>
<td>8000</td>
</tr>
<tr>
<td>1/8&quot;</td>
<td>10000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Ball Valves</th>
<th>Pressure (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/8&quot;</td>
<td>6000</td>
</tr>
<tr>
<td>1/4&quot;</td>
<td>10000</td>
</tr>
</tbody>
</table>

Accumulator 5000

Burst Pressure of Stainless Cylinder
Working Pressure=1900 and Burst Pressure=2900 (with SF=1.5 and Yield Strength=20,000 psi)

Maximum Confining Pressure
Same as SS Cylinder burst pressure

All threaded rods (in tension)
Tensile Strength 5,213 psi, Yield Strength 2,325 psi, Shear Strength 3,875 psi.
Max Torque=14.5 ft*lbs (using Yield Strength)
Max Torque=32.5 ft*lbs (using Tensile Strength)

Pressure rating for the needle valves
15,000 psi

I-Beam
The I-Beam is designed with safely hold of at least 10 tons

Maximum Cell frame Capacity
The frame is rated for 10 tons
Satinless Steel Caps
Hardness: 135-215 Brinell
Yield Strength: 30,000 to 60,000 psi
Annealed

Stainless Steel Casings
3000 psi

Stainless Steel Injection Pipe
3000 psi

Stainless Steel Injection Nipple
3000 psi
BIBLIOGRAPHY


VITA

Maximiliano Liberman was born in 1984. He received his Bachelor’s degree from Missouri University of Science and Technology (2008). He worked for 8 months at Tenaris USA in Conroe, TX as a Quality Engineer Analyst. In January 2010, he started his Master’s degree in Petroleum Engineering at Missouri University of Science and Technology which was awarded in August of 2012.