ANALYSIS OF ROCK MECHANICAL PROPERTIES BY MINERALOGY AND THEIR POTENTIAL EFFECTS ON HYDRAULIC FRACTURING IN THE WOODFORD SHALE, WEST TEXAS

by

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

Golden, Colorado
Date Sept 14, 2009

Signed: [Signature] 8/31/09
Khodir Aoudia

Signed: [Signature] 8/31/09
Dr. Jennifer L. Miskimins
Thesis Advisor

Golden, Colorado
Date Sept 4, 2009

Signed: [Signature]
Dr. Ramona M. Graves
Professor and Head
Department of Petroleum Engineering
ABSTRACT

Shale reservoirs are commonly considered to be fine grained, low permeability rocks with high clay content and little inherent heterogeneity. However, as more shale plays are developed, it is evident that shale reservoirs vary considerably in their mineralogical and geochemical properties and that this variability has consequences for physical properties. Given the fact that shale reservoirs are almost always subjected to hydraulic fracturing treatments, investigating the relationship between the mineralogy and the physical and mechanical properties of these reservoirs is crucial.

The outcome of a small hydraulic pump-in treatment on a well (RTC #1) drilled in the Woodford shale, Permian Basin, west Texas, suggested systematic differences in mechanical properties between the middle and lower Woodford. While the middle, more quartz-rich, section responded positively to fracturing, the lower, more clay rich, zone did not show any improvement. This raised the need for a thorough investigation of why the formations responded in the way that they did and how the mineralogy of the Woodford shale relates to the mechanical properties.

This study was performed using a well log data set from the subject well including gamma ray, photoelectric, resistivity, density, sonic and neutron. Additionally, mineral, geochemical, acoustic and petrophysical data from a 260 ft core from the subject well were used. The core acoustic velocities, $V_p$ and $V_s$, were recorded under surface conditions using a hand-held velocity probe. This resulted in a slight difference between the core $V_p$ and log $V_p$, and an acute difference between the core $V_s$ and log $V_s$. The differences in core and log acoustic velocities translated into differences between core and log mechanical properties. Log data were found to be more representative of the mineralogy of the Woodford and were the ones used in the statistical analysis. Three statistical methods, factor analysis, cluster analysis and stepwise linear regression, were used to evaluate potential relationships between the mechanical properties,
Young's modulus and Poisson's ratio, and the mineral/geochemical elements of the formation. A hydraulic fracturing simulator, GOHFER™, was used in order to evaluate certain hydraulic fracturing treatment designs in the Woodford shale of west Texas.

The results of the study suggest that Young's modulus is influenced by carbonates, clays, feldspars and total organic carbon (TOC). High carbonate content, dolomite and calcite in this case, are more likely to result in high values of Young's modulus, therefore a more brittle rock. High clay and feldspar contents, illite and albite respectively, and TOC, on the other hand, are more likely to cause the formation to be less brittle by causing the Young's modulus values to be slightly lower. However, because of the low correlation coefficients of these elements with Young's modulus, no single element can be considered as the main driver of this mechanical property. Poisson's ratio is controlled by quartz, clay, feldspars and TOC. High quartz content and abundant TOC are more likely to result in low Poisson's ratio values, therefore a more brittle rock, while high clay and feldspar contents are more likely to result in a ductile formation with high Poisson's ratio values. The high correlation coefficients that associate quartz and clays with Poisson's ratio indicate that these minerals are strong controllers of this mechanical property.

Based on the mineralogy of the different zones of the Woodford and the relationships established between the mechanical properties and different mineral components, it is inferred that the upper Woodford, very rich in quartz and very poor in clay, will probably be the region most prone to hydraulic fracturing. The middle Woodford will more likely show little higher resistance to fracture initiation due to its slightly lower quartz content and little higher clay content. The lower Woodford will be the most resistant to hydraulic fracturing because of its high clay content, low quartz and low TOC.

Based on initial hydraulic fracture modeling, hybrid (slickwater/gel) treatments with ceramic proppant appear to be the most appropriate hydraulic fracturing treatments for this formation. Fractures initiated in the middle Woodford showed a tendency to grow upwards. This suggests the existence of a path of
least resistance right above this zone and is an indication of a possible anisotropy in the mechanical properties. This also agrees with the mechanical properties results that show that the upper Woodford is the most prone to hydraulic fracturing.
# TABLE OF CONTENTS

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

LIST OF FIGURES ................................................................................ x

LIST OF TABLES ............................................................................... xix

ACKNOWLEDGMENTS ........................................................................ xx

DEDICATION ....................................................................................... xxi

CHAPTER 1. INTRODUCTION ................................................................. 1

1.1 Geological Setting of the Study Area ........................................... 3

1.2 Thesis Objectives .......................................................................... 6

1.3 Motivation and Research Context ................................................ 8

1.4 Research Contributions and Applications .................................... 9

CHAPTER 2. LITERATURE REVIEW ...................................................... 10

2.1 Formation Evaluation of Shale Gas Reservoirs .............................. 10

2.1.1 Clay Content and Clay-Bound Water ....................................... 11

2.1.2 Total Organic Carbon, TOC ................................................... 13

2.2 Hydraulic Fracturing of Shale Gas Reservoirs .............................. 16

CHAPTER 3. DATA ACQUISITION ......................................................... 22

3.1 Lab Data ..................................................................................... 22

3.1.1 Mineral and Geochemical Data .............................................. 22
3.1.2 Acoustic Travel Times ........................................ 28
3.1.3 Porosity ......................................................... 31
3.1.4 Permeability .................................................... 32
3.1.5 Density ......................................................... 33
3.1.6 Core Mechanical Properties ................................. 34
3.2 Well Log Data .................................................... 36
  3.2.1 Reconstruction of the Sonic Log ......................... 39
  3.2.2 Log Mechanical Properties ............................. 43
3.3 Comparison of Log and Core Acoustic and Mechanical Properties ........................................ 43
CHAPTER 4. FORMATION EVALUATION ............................. 49
  4.1 Shale Volume .................................................. 49
  4.2 Clay Volume .................................................... 52
  4.3 Total Organic Carbon (TOC) Evaluation .................. 54
    4.3.1 Δ Log R Technique (Passey et al. 1990) .......... 56
  4.4 Porosity ....................................................... 57
  4.4 Water Saturation ............................................. 59
CHAPTER 5. DATA ANALYSIS ....................................... 64
  5.1 Investigation of the Reliability of the Data Generated 65
  5.2 Results of Factor Analysis .................................. 66
    5.2.1 Factor Analysis Results for the First Dataset
             (Density, Acoustic Velocities, TOC and
             Mineralogy) .............................................. 67
5.2.2 Factor Analysis Results for the Second Dataset (Mechanical Properties, TOC and Mineralogy) ...................................................... 69
5.3 Results of Hierarchical Cluster Analysis ........................................... 71
5.4 Results of Stepwise Linear Regression Analysis .................................... 76
5.5 Hydraulic Fracture Modeling ............................................................. 84
  5.5.1 Modeling Software ......................................................................... 86
  5.5.2 Model Inputs .................................................................................. 86
  5.5.3 Hydraulic Fracture Modeling Results ............................................. 89
CHAPTER 6. DISCUSSION OF RESULTS .................................................. 96
  6.1 Formation Mechanical Properties ...................................................... 96
  6.2 Factor Analysis .................................................................................. 97
  6.3 Stepwise Linear Regression Analysis ............................................... 99
  6.4 Hierarchical Cluster Analysis .......................................................... 102
  6.5 Hydraulic Fracture Modeling ............................................................ 103
CHAPTER 7. CONCLUSIONS AND RECOMMENDATIONS ....................... 104
  7.1 Conclusions ...................................................................................... 104
  7.2 Recommendations ............................................................................ 106
NOMENCLATURE ...................................................................................... 108
REFERENCES .......................................................................................... 111
CD ROM CONTENT .................................................................................. 117
APPENDIX A: RTC#1 Pump-in, Minifrac, and Surface Tiltmeter Data .............. Back Pocket
APPENDIX B: Mineral and Geochemical Core Data..........................Back Pocket

APPENDIX C: Core Petrophysical, Acoustic Velocities, and Mechanical Properties Data..........................Back Pocket

APPENDIX D: Log Data.....................................................................Back Pocket

APPENDIX E: Statistical Analysis Data..............................................Back Pocket

APPENDIX F: Hydraulic Fracture Modeling Results.............................Back Pocket
LIST OF FIGURES

Figure 1.1 The major shale gas basins located in the continental United States. The Barnett and the Woodford areas can be seen in the lower left (Schlumberger)..........................................................4

Figure 1.2 Location of the subject well, Reliance Triple Crown #1, in relation to the Tobosa Basin, west Texas (Mнич, 2009). Tobosa Basin refers to the name of the basin that occupied the area during the deposition of the Woodford in the Late Devonian (Comer, 1991). Permian Basin is the name currently used to refer to the area..................................................................................................................4

Figure 1.3 Standard gamma ray and resistivity logs of the Woodford shale, RTC #1, showing the distinctive signatures of the different units of the Woodford. The boundaries of the different zones of the Woodford Shale are placed on the repetitive pattern of Rt and the GR readings in the different zones; low in the Upper, high in the Middle and moderate in the Lower (Mнич, 2009). The lower Woodford can be divided into two different parts based on GR, TOC and clay content: Upper part (12,980 – 13,038 ft) characterized by moderate GR, moderate TOC and high clay content, and Lower part (13,038 – 13,097 ft) characterized by low GR, low TOC and very low clay content..............................5

Figure 1.4 TOC vs. hydrocarbon potential in the Woodford Shale suggesting a very mature Type II kerogen that has generated and expelled oil. However, the residual oil has largely cracked to gas which is why hydrocarbon potential values were low and plotting in the gas prone region (Mнич, 2009).................................................................7

Figure 1.5 Injection/mini-frac tests results in the different parts of the Woodford shale in subject well RTC #1 showing a higher fracture gradient in the Lower Woodford..........................................................9

Figure 2.1 Representation of a horizontal cross section of a hydraulically fractured formation. The proppant particles are pushed into the formation (embedded) resulting in less surface for the fluids to flow into the fracture (Haidar, 2003)......................................................19
Figure 2.2  Cross plot of Young’s modulus (YMS_C) and Poisson’s ratio (PR_C) showing the brittleness percentage increasing to the lower left corner of the plot. Young’s modulus increases from the top of the Y-axis to the bottom of the same axis. Poisson’s ratio decreases from the right of the X-axis to the left of the same axis. Britteness is color coded, light green color representing the least brittle and the red color the most brittle (Mullen, 2008)..............19

Figure 3.1  Distribution of the five lithofacies in the RTC #1 Woodford Shale core (Modified from Harris et al., in press)...............................24

Figure 3.2  Mineralogy of the three different units (Upper, Middle and Lower) of the Woodford Shale, west Texas, in the RTC #1 core (Mnich, 2009). Note that the lower Woodford displays the highest clay content and the zone between 13040 ft and 13098 ft shows high carbonates content. The red dashed line separates the upper and lower parts of the Lower Woodford............................................26

Figure 3.3  TOC variations through out the RTC #1 Woodford Shale core (Mnich, 2009). The red dashed line separates the upper and lower parts of the Lower Woodford. Note that the lower zone of the lower Woodford (13040 ft - 13098 ft) that is characterized by high carbonates content is not very rich in TOC; the average TOC in this zone is about 3.5 wt% and the maximum is about 6 wt%..................................................................................27

Figure 3.4  Hand-held velocity probe used to measure acoustic travel times on cores and outcrops (Batzle and Smith, 1992).........................29

Figure 3.5  Depiction of the measurement procedure with a hand-held velocity robe.................................................................29

Figure 3.6  Results of the acoustic compression (V_p) and shear (V_s) velocities measurements on the RTC #1 core, Woodford shale. Core V_p ranges between 12,000 ft/s and 16,000 ft/s and displays two slightly decreasing trends (12,750 ft – 12,900 ft and 12,900 ft – 13,000 ft) and one increasing trend (13,000 ft – 13,050) with respect to core depth. Core V_s ranges between 7,000 ft/s and 10,000 ft/s and shows two different trends with respect to core depth. Between 12,750 ft and 13,000, core V_s decreases slightly with respect to core depth, while below 13,000 ft it can be noticed that core V_s increases slightly with respect to core depth.........31
Figure 3.7  Results of the porosity measurements in the RTC #1 core, Woodford shale. Core porosity ranges between 0 and 0.145 with an average of 0.04. It shows three distinct trends; it increases with depth between 12,740 ft and 12,850 ft, then decreases between 12,850 and 13,000 ft and increases again with respect to depth between 13,000 ft and 13,100 ft. ..................................................33

Figure 3.8  Results of the density measurements in the RTC #1 core, Woodford shale. Notice the circled measurements are off from the density trend. This is due to the fact that the core samples that those data points represent were very small and their volumes were not easy to read on the beaker. Even though the data seems to be scattered, there is still a slight increasing trend of density with respect to core depth........................................35

Figure 3.9  Woodford shale core, RTC #1, Young's modulus determined using acoustic data from the handheld velocity probe and the density measurements. Young's modulus ranges between $6 \times 10^6$ psi – $2.6 \times 10^7$ psi. Young's modulus shows a slightly decreasing trend with respect to core depth between 12,750 and 13,000 ft and an increasing trend below 13,000 ft........................................37

Figure 3.10  Woodford shale core, RTC #1, Poisson's ratio determined using acoustic data from the handheld velocity probe. Poisson's ratio ranges between 0.05 – 0.36. Poisson's ratio does not show any distinctive trend with respect to depth........................................38

Figure 3.11  Comparison of the GR from the first logging run to the GR from the sonic log for the RTC #1 showing no depth shift between the two runs.................................................................39

Figure 3.12  Comparison of the sonic log against the reconstructed sonic log for RTC #1 showing a close match between the two logs. Notice the systematic error between the sonic log travel times and the calculated travel times in the zone between 12,620 ft and 12,780 ft.................................................................41

Figure 3.13  Caliper and gamma ray logs in the RTC #1 well. Notice the dramatic change in the well diameter between 12,400 ft and 12,780 ft.................................................................42

Figure 3.14  Log derived Young’s modulus (E) for RTC #1 from 12,000 ft to 13,150 ft. Notice that E decreases with respect to depth between 12,750 ft and 13,000 ft then increases with respect to depth from 13,000 ft to 13,100 ft.................................................................44
Figure 3.15  Log derived Poisson’s ratio (ν) for RTC #1 from 12,000 ft to 13,150 ft. Notice that ν decreases with respect to depth between 12,750 ft and 12,850 ft then increases with respect to depth from 12,850 ft to 12,910 ft. It decreases again between 12,910 and 13,000 and increases once more between 13,000 ft and 13,040 ft, and finally decreases below 13,050 ft.................................45

Figure 3.16  Log and core acoustic velocities in the RTC #1 well, Woodford shale.................................................................46

Figure 3.17  Log and core calculated Young’s modulus and Poisson’s ratio for the RTC #1 well, Woodford shale. Note that core-derived Young’s modulus is slightly higher than the log derived Young’s modulus throughout the entire Woodford Shale.........................................................47

Figure 3.18  Log and core calculated Young’s modulus and Poisson’s ratio for the RTC #1 well, Woodford shale. Note that the core Poisson’s ratio is most often higher than the log-derived Poisson’s ratio, up to two times higher in some cases.................................................................48

Figure 4.1  Cross-plot of gamma ray (HNGS GR) with uranium (U), thorium (Th) and potassium (k) contents in RTC #1, Woodford shale. The left y-axis representing k, the right y-axis representing U and Th, and the x-axis representing HNGS GR. Even though Th-GR correlation ($R^2=0.18$) is influenced by some outliers, it is still relatively weak compared to U-GR correlation ($R^2=0.96$) indicating organic matter richness and low clay content, respectively........51

Figure 4.2  Shale volume in RTC #1, Woodford shale, showing the highest degree of shaliness in the region from 13,000 ft – 13,050 ft using the Steiber correlation. Note the two peaks in shale volume between 12,850 ft – 12,900 ft and 13,000 – 13,050 ft coinciding the peaks in core clay content described by Mnich (2009)..............52

Figure 4.3  Core $V_{cl}$ compared to CGR $V_{cl}$ and regression analysis $V_{cl}$ in RTC #1, Woodford shale. Notice that although $V_{cl}$ derived from regression analysis best matches the core $V_{cl}$, CGR derived $V_{cl}$ is also a very good approximation. Note the two peaks in clay content between 12,850 ft – 12,875 ft and 13,000 – 13,025 ft that correspond to the two peaks in shale volume seen in Figure 4.3.................................................................55
Figure 4.4  Δ Log R technique derived TOC averaged over 3 ft compared to the Woodford core TOC in RTC #1. It can be clearly seen that TOC from the Δ Log R technique matches the core TOC except for the upper unit and lower part of the lower unit of the Woodford. Note that the lowest calculated TOC is situated between 13,000 ft and 13,025 ft.................................58

Figure 4.5  TOC-corrected log porosity compared to core porosity and non-corrected log porosity in RTC #1, Woodford shale. Notice that TOC-corrected density porosity is in the same range as core porosity and the absence of separation between the TOC corrected log porosity and non-corrected log porosity in the region 13,000 ft – 13,050 ft indicating low TOC in this zone.............60

Figure 4.6  Comparison of $S_w$ from Simandoux (1963) and $S_w$ from Archie (1942) and the true resistivity of the formation in RTC #1, Woodford shale. The results were averaged over 5 ft for smoothness. Notice that $S_w$ calculated with Simandoux's equation displays a consistent opposite trend compared to the true resistivity. Besides the fact that it is always higher than the Simandoux water saturation, $S_w$ calculated with Archie's equation fails to follow an opposite trend with respect to the true resistivity in the region between 12,850 ft – 12900 ft..............................63

Figure 5.1  Comparison of the number of factors to the variance (eigenvalue) in the data for the second dataset that includes density, acoustic velocities and mineralogy. Notice that variance in the data smooths out beyond a number of factors of 13. Also, note that there is only a small decrease in the Eigenvalue on addition of the fourth and higher factors, indicating that factor one through three contribute strongly to reducing variance............................68

Figure 5.2  The first two factors, resulted from factor analysis, that contain the density and acoustic velocities. The two factors explain about 46% of the variance in the data. Correlation coefficients of each variable with its corresponding factor are shown. Correlation coefficients between -0.5 and 0.5 are ignored. The (+) sign represents the variables that are positively correlated with the factor and the (-) sign represents the variables negatively correlated with the factor........................................68
Figure 5.3  Comparison of the number of factors to the variance (eigenvalue) in the data for the second dataset that includes mechanical properties and mineralogy only. Notice that variance in the data smooths out beyond a number of factors of 13, meaning that 13 is the optimal number of factors to be extracted. Also, note that there is only a small decrease in the Eigenvalue on addition of the fourth and higher factors, indicating that factor one through three contribute strongly to reducing variance........................................70

Figure 5.4  The first two factors, resulted from factor analysis, that contain the mechanical properties. The two factors explain about 46% of the variance in the data. Correlation coefficients of each variable with its corresponding factor are shown. Correlation coefficients between -0.5 and 0.5 are ignored. The (+) sign represents the variables that are positively correlated with the factor and the (-) sign represents the variables negatively correlated with the factor. E=Young's modulus, K=bulk modulus, G=shear modulus, ν=Poisson's ratio.................................................................70

Figure 5.5  Cluster analysis dendrogram showing how the 72 core samples of the Woodford shale are distributed throughout the clusters. Each cluster was identified according to the similarity level (on the left hand-side of the graph) of the core samples it includes. The x-axis represents the core samples numbers and the different clusters are numbered from 1 to 10.................................................................72

Figure 5.6  Distribution of the clusters throughout the Woodford formation in RTC #1. Notice that Cluster 4 is the most abundant cluster, and is mainly confined to the middle Woodford and the upper zone of the lower Woodford. The table on the right is a summary of the characteristics of each cluster.................................................................74

Figure 5.7  Dendrogram resulted from cluster analysis on the 54 core samples included in Cluster 4 of the first cluster analysis. Notice the high similarity level (left hand-side of the graph) between the different clusters (>84%) suggesting that these samples have fairly similar mechanical properties.................................................76

Figure 5.8  Distribution of the clusters, resulted from cluster analysis on the core samples included in Cluster 4, throughout the Woodford formation.................................................................77

Figure 5.9  Cross-plot of E versus CaO in RTC#1, Woodford shale, showing an increase in E with the increase of CaO, $R^2 = 0.3$. Notice that for CaO<15% the trend is not very clear and E does not seem to be influenced by CaO.................................................................79
Figure 5.10  Cross-plot of E versus TOC in RTC#1, Woodford shale, showing an increase in E with the decrease of TOC, $R^2 = 0.27$. Even though $R^2$ is not significant, the increasing trend of E is noticeable.................................................................79

Figure 5.11  Cross-plot of E versus the result of the regression equation (Eq. 5.1). Note the improved $R^2$ of 0.58.................................................................80

Figure 5.12  Cross-plot of E versus dolomite content in the upper unit of the Woodford shale in RTC#1. Notice the strong correlation coefficient, $R^2=0.92$ However, there are not enough data points to confirm that strong correlation......................................................80

Figure 5.13  Cross-plot of E versus Mo in the middle unit of the Woodford shale in RTC#1. Although there is a trend of E increasing with the decrease of Mo, the correlation coefficient is very low, $R^2=0.25$.................................................................81

Figure 5.14  Cross-plot of E versus MgO in the lower unit of the Woodford shale in RTC#1. Notice that when MgO is below 4% there is no correlation with E at all. However above 4% MgO, there is a significant increase in E, $R^2=0.61$. Notice that there are not any data points between 4% and 16% MgO, which hinders the understanding of the influence of small increments of MgO on E.................................................................................................81

Figure 5.15  Cross-plot of $\nu$ versus Rho in the entire Woodford shale in RTC#1 showing a clear trend of $\nu$ increasing with the increase of formation density, $R^2=0.45$.................................................................82

Figure 5.16  Cross-plot of $\nu$ versus TOC in the entire Woodford shale in RTC#1. Although $\nu$ seems to increase with the increase of TOC, the correlation coefficient is not that significant, $R^2=0.33$.....................83

Figure 5.17  Cross-plot of $\nu$ versus the result of the regression equation (Eq. 5.2), $R^2 = 0.45$.................................................................83

Figure 5.18  Cross-plot of $\nu$ versus dolomite content in the upper unit of the Woodford shale in RTC#1. There is a relatively strong correlation between $\nu$ and dolomite content. $\nu$ decreases as dolomite content decreases, $R^2=0.65$ However, there are not enough data points to confirm that strong correlation..................................................84

Figure 5.19  Cross-plot of $\nu$ versus P2O5 in the middle unit of the Woodford shale in RTC#1. Notice the very low $R^2=0.20$.................................................................85
Figure 5.20 Cross-plot of $v$ versus TOC in the lower unit of the Woodford shale in RTC#1. $v$ increases as TOC decreases with a fairly strong $R^2=0.68$. ..................................................85

Figure 5.21 Depiction of the input data, calculated by GOHFER™ using well logs, used in the fracture treatments simulation....................88

Figure 5.22 Fracture geometry and proppant concentration (lb/ft$^2$) resulting from slickwater treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded........................................91

Figure 5.23 Fracture geometry and fracture conductivity (md-ft) resulting from slickwater treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded........................................91

Figure 5.24 Fracture geometry and proppant concentration (lb/ft$^2$) resulting from gelled treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded........................................92

Figure 5.25 Fracture geometry and fracture conductivity (md-ft) resulting from gelled treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded........................................92

Figure 5.26 Fracture geometry and proppant concentration (lb/ft$^2$) resulting from hybrid treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded........................................93

Figure 5.27 Fracture geometry and fracture conductivity (md-ft) resulting from hybrid treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded........................................93

xvii
Figure 5.28  proppant concentration in a fracture resulting from a gelled treatment simulation performed simultaneously in the upper and lower Woodford, RTC #1 well. The separation between the middle and lower Woodford is clearly seen between 12,990 ft and 13,030 ft. ........................................................................................................95

Figure 6.1  Cross-plot of E vs. v in RTC #1, Woodford shale. Notice that the upper Woodford and the lowest part of the lower Woodford display the highest values of E. These two regions are both characterized by low TOC content, and high dolomite content in the lowest part of lower Woodford. The upper part of the lower Woodford show high v values, which is probably due to its high clay content. ........................................................................................................98

Figure 6.2  Cross-plots of dolomite content versus CaO in the entire RTC #1 core of the Woodford shale showing a strong correlation between the two parameters, $R^2=0.88$. This indicates that CaO is mostly related to dolomite in the RTC #1 core. .................................................................100

Figure 6.3  Cross-plots of dolomite content versus MgO in the lower unit of the Woodford shale in RTC #1 showing a strong correlation between the two parameters, $R^2=0.98$. Note the lack of data points between 4% and 16% MgO. The correlation suggests that high MgO is associated with high dolomite content. .........................................................................................100
# LIST OF TABLES

<table>
<thead>
<tr>
<th>Table</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1</td>
<td>Gamma Ray Readings, TOC and Clay Content in the Different Units of the Woodford Shale in the RTC#1 Core (Modified From Mnich 2009)</td>
</tr>
<tr>
<td>2.1</td>
<td>Clay Mineral Parameters Important in Formation Evaluation (From Fertl and Frost, 1979)</td>
</tr>
<tr>
<td>2.2</td>
<td>Log Derived Clay Content Indicators (From Fertl and Frost, 1979)</td>
</tr>
<tr>
<td>2.3</td>
<td>Necessary Information for Design of Stimulation Treatment (modified from Mullen, 2008)</td>
</tr>
<tr>
<td>2.4</td>
<td>Types and Scales of Geological Anisotropy in the RTC #1 Woodford Shale Core (Modified from Hemmesch 2009)</td>
</tr>
<tr>
<td>3.1</td>
<td>Summary of Lithofacies Description and Interpretation (Mnich, 2009, Based on Harris et al., in press)</td>
</tr>
<tr>
<td>3.2</td>
<td>Individual Woodford Core Sections Depth Shift (courtesy of Pioneer Natural Resources)</td>
</tr>
<tr>
<td>5.1</td>
<td>Results of the R square Investigation of the Cross-plots of Log Density and Core density with Quartz and TOC</td>
</tr>
<tr>
<td>5.2</td>
<td>Distance of Each Variable from the Cluster Centroids of the Different Clusters</td>
</tr>
<tr>
<td>5.3</td>
<td>Characteristics of the Different Clusters</td>
</tr>
<tr>
<td>5.4</td>
<td>Perforation Setting in the Different Zones of the Woodford Shale</td>
</tr>
<tr>
<td>5.5</td>
<td>Fracture Stimulation Designs Simulated with GOHFER</td>
</tr>
</tbody>
</table>
ACKNOWLEDGMENTS

My special thanks goes to my advisor, Dr. Jennifer Miskimins, for her guidance, support and for always being there, willing to help and encourage me throughout this project. Thanks to Dr. Nick Harris of the Geology Department for his continuing assistance and valuable inputs throughout this project. I also thank Dr. Manika Prasad for her availability and always finding the time to sit with me and provide valuable information. I would also like to thank Dr. Batzle of the Geophysics Department for his time, guidance and use of equipment.

I am grateful to Cheryl Mnich for providing the core and well log data necessary for the accomplishment of this project.

Thank you to Mike Mullen from Halliburton, for giving of his time to provide helpful insight about shale reservoirs.

Funding for this project was provided by the Woodford Consortium: Chesapeake, Devon, Encana, EOG, Newfield, Petrohunt, Pioneer and Whiting.
DEDICATION

This effort is dedicated to my dear family, my parents Amar and Zohra, my fiancée Nadia, and my brothers and sisters, vava Madjid, Tarik, Khaled, Nanna Farroudja, Nanna Nadia, Yasmina, Lynda and Hindouch. Despite the distance, they have always been there for me and showed endless support.

To my great friend Mohamed Sadaoui and his wonderful family.
CHAPTER 1
INTRODUCTION

Unconventional reservoirs have drawn a great deal of interest these last few decades. Because of the ever-growing demand for oil and gas worldwide, what used to be just an aggregate of rock and a potential source rock at best, has become a potential reservoir.

Shale reservoirs in general and shale gas reservoirs in particular fall into this category of unconventional reservoirs. Even though the first gas production from a shale gas reservoir occurred in the early 1820's (Hill and Nelson 2000), real interest in these plays did not start until the late 1980's when production began to grow from two emerging plays, the Barnett Shale in the Fort Worth Basin, Texas, and the Lewis Shale in the San Juan Basin, Colorado and New Mexico (Hill and Nelson 2000). This rather late interest in gas shale reservoirs has led to a significant lack of understanding of this type of unconventional reservoirs (Zahid et al. 2007). One area where this is most obvious is quantitative formation evaluation (Poupon et al. 1971). The existing models in common use for interpretation of logs were developed to evaluate data collected in conventional reservoir rocks such as sandstones and carbonates (Poupon et al. 1971; Poupon et al. 1970; Campbell and Truman 1986). Such models are not well adapted to the evaluation of shale systems due to the complexity of the lithology and the bound water associated with these shales and their typical low porosity and permeability (Poupon et al. 1971; Campbell and Truman 1986; Vanorsdale 1985).

The stimulation aspect of these unconventional reservoirs is quite different from the formation evaluation aspect. As with conventional reservoirs, hydraulic fracturing treatments are being used in shale reservoirs with great success. However, because of unique properties inherent to shale reservoirs, the fluid systems and additives used in conventional wells are not always suitable for
these resources (Zahid et al. 2007). Thus, a good understanding of any given shale reservoir is mandatory before adopting any stimulation technique (Zahid et al. 2007).

Many studies have been done on the matter of hydraulic fracturing of shale reservoirs. The areas of this subject that received most of the attention include: fracture initiation (Suarez-Rivera et al. 2006), fracture geometry (Hopkins et al. 1995), in-situ stresses (Abousleiman et al. 2007), and mineralogy of shale as it relates to fracturing fluids (Paktinat et al. 2007). However, one area that has not received as much attention as it should is the influence of the mineral components and the total organic carbon (TOC) of shale reservoirs on the mechanical properties as they relate to hydraulic fracturing. Some of the attempts towards bridging that gap were carried out by: Vernik and Nur (1992), Vernik (1994), Vernik and Landis (1996), Prasad and Mukerji (2003) and Prasad et al. (2009). These studies have in common the fact that they analyzed the effects of organic matter (kerogen and TOC) and clays on the sonic waves (compression and shear) velocities and the elastic properties in shales.

This work attempts to bridge that gap in the Woodford shale, located in western Texas and southeastern New Mexico. Some of the questions that this work attempts to answer are:

- How do the mineralogy (quartz, clay, carbonates, and pyrite content) and the TOC of the Woodford shale influence the Young's modulus and Poisson’s ratio of the formation?
- Is there a combination of minerals that makes a shale reservoir more susceptible to hydraulic fracturing? Or possibly more resistant?
- Does a high content of clay necessarily mean a less brittle rock?

The study is conducted on a series of data acquired from the well Reliance Triple Crown #1 (RTC #1), completed in the Woodford shale in Pecos county, west Texas. The data set includes geological, mineral, geochemical, acoustic and petrophysical data.
1.1 Geological Setting of the Study Area

The Upper Devonian Woodford formation in the Permian Basin is considered as an important source rock (Comer 1991). Figure 1.1 shows the major shale resources in the continental United States, and Figure 1.2 shows the location of the subject well, RTC #1, in the Permian Basin of western Texas. Because of its richness in organic matter, the Woodford is believed to be a major source for oil and gas currently produced in the Permian Basin. It consists of two lithofacies, black shale and siltstone (Comer 1991). The black shale is characterized by high organic matter content, high radioactivity and is mainly composed of quartz, clay (essentially illite) and an abundant amount of pyrite (Comer 1991). The siltstone lithofacies, on the other hand, is characterized by relatively low organic matter content with low radioactivity and consists predominantly of dolomite and quartz (Comer 1991). Harris et al. (in press) provide a more detailed and specific description of the RTC #1 core based on the core description performed by Nikki Hemmesch, a PhD student at the Geology and Geological Engineering Department at the Colorado School of Mines. Mnich (2009) states that the RTC #1 Woodford Shale core contains five lithofacies: (1) massive carbonate; (2) black shale; (3) siltstone; (4) massive grey mudstone; and (5) laminated carbonate. These lithofacies will be discussed in more detail in upcoming sections.

Ellison (1950) stated that on the basis of lithology and radioactive and electric log patterns, the Winkler County, west Texas, Woodford is divided into three units; upper, middle and lower. The same units are easily noticed in the RTC #1 well, as shown in Figure 1.3.

The upper unit is characterized by relatively moderate gamma ray readings (average of 187 API) and TOC content (average of 3.8 wt%) with very low clay content (about 6 wt%) (Mnich 2009). The middle unit displays a very high radioactivity and a high TOC, about 300 API and 5.4 wt%, respectively (Mnich 2009). The clay content in this second unit averages 13 wt% (Mnich 2009). Finally, the lower part can be divided into two distinct zones based on its
Figure 1.1 The major shale gas basins located in the continental United States. The Barnett and the Woodford areas can be seen in the lower left (Schlumberger 2003).

Figure 1.2 Location of the subject well, Reliance Triple Crown #1, in relation to the Tobosa Basin, west Texas (Mnich 2009). Tobosa Basin refers to the name of the basin that occupied the area during the deposition of the Woodford in the Late Devonian (Comer 1991). Permian Basin is the name currently used to refer to the area.
Figure 1.3 Standard gamma ray and resistivity logs of the Woodford shale, RTC #1, showing the distinctive signatures of the different units of the Woodford. The boundaries of the different zones of the Woodford Shale are placed on the repetitive pattern of Rt and the GR readings in the different zones; low in the Upper, high in the Middle and moderate in the Lower (Mnich 2009). The lower Woodford can be divided into two different parts based on GR, TOC and clay content: Upper part (12,980 - 13,038 ft) characterized by moderate GR, moderate TOC and high clay content, and Lower part (13,038 - 13,097 ft) characterized by low GR, low TOC and very low clay content.
gamma ray readings, TOC and clay content. The upper zone located between 12980.40 - 13038.68 ft is characterized by relatively high radioactivity (238 API), relatively high TOC (4.6 wt%) and high clay content (28 wt%) (Mnich 2009) The lower zone located between 13038.68 - 13097.98 ft shows low radioactivity (160 API), low TOC (2.9 wt%) and low clay content (4.4 wt%) (Mnich 2009). Table 1.1 summarizes the gamma ray values, TOC and clay content in the different zones of the Woodford Shale in the RTC#1 core.

<table>
<thead>
<tr>
<th>Woodford Zone</th>
<th>Core depth (ft)</th>
<th>Gamma Ray (API)</th>
<th>TOC (wt%)</th>
<th>Clay Content (wt%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper</td>
<td>12759.75-12786.75</td>
<td>187</td>
<td>3.8</td>
<td>6.33</td>
</tr>
<tr>
<td>Middle</td>
<td>12786.75-12980.40</td>
<td>300</td>
<td>5.4</td>
<td>13.27</td>
</tr>
<tr>
<td>Lower</td>
<td>12980.40-13038.68</td>
<td>234</td>
<td>4.6</td>
<td>28</td>
</tr>
<tr>
<td></td>
<td>13038.68-13097.98</td>
<td>160</td>
<td>2.9</td>
<td>4.4</td>
</tr>
</tbody>
</table>

Mnich (2009) determined the kerogen type of the Woodford shale from TOC and rock-evaluation pyrolysis data (Figure 1.4). The results suggest that it is a very mature Type II kerogen that has generated and expelled oil. However, the residual oil has largely cracked to gas which is why the hydrocarbon potential values were low and plotting in the gas prone region (Mnich 2009).

1.2 Thesis Objectives

The main objective of this research is to investigate the potential relationship between the mineralogy, TOC and the mechanical properties of the Woodford shale in the RTC #1 well. This is accomplished by statistically analyzing a data set that includes mineral, geochemical and mechanical data. The mineral and geochemical data were generated by a team of students at the Geology and
Figure 1.4 TOC vs. hydrocarbon potential in the Woodford Shale suggesting a very mature Type II kerogen that has generated and expelled oil. However, the residual oil has largely cracked to gas which is why hydrocarbon potential values were low and plotting in the gas prone region (Mnich 2009).

Geological Engineering Department at the Colorado School of Mines that is working on the geological description of the Woodford Shale. The mechanical properties are calculated from both log (sonic and density logs) and core data (acoustic and density measurements). A series of multivariate statistical analysis, including factor analysis, regression analysis and cluster analysis, was performed on the data set to unveil the potential correlations between the mineralogy, geochemistry and TOC, and the mechanical properties of the formation.

Two other important objectives of this study are:

- From a formation evaluation standpoint, determine shale volume, clay content, TOC, porosity and water saturation of the Woodford from well logs; and,
- Simulate the responses of the Woodford formation to different types of hydraulic fracturing treatments, using the hydraulic fracturing simulator.
GOHFERTM, in order to predict the most appropriate hydraulic fracturing treatment for this formation.

1.3 Motivation and Research Context

Because of their inherent low permeabilities, shale gas reservoirs are generally submitted to hydraulic fracturing treatments. These treatments increase production potential by creating fractures that play a role of preferable channel pathways for the fluids to drain towards the wellbore. In addition, hydraulic fractures allow the micro fractures of an already naturally fractured reservoir to connect with the wellbore, via the hydraulically created fractures, therefore increasing the drainage area of the well.

The RTC #1 well underwent hydraulic fracturing injection/mini-frac tests in the middle and lower parts of the Woodford shale to evaluate its potential (for injection/mini-frac tests results refer to Appendix A). The results of those tests showed distinctive responses of the Woodford units (Figure 1.5). The Middle Woodford, where two sets of perforations at different depths were present, responded positively and exhibited a fracture gradient of 0.65 psi/ft. The Lower Woodford, on the other hand, exhibited a much higher fracture gradient of 0.93 psi/ft, indicating a significant stress difference between the Woodford intervals.

These different reactions of the different parts of the Woodford to the hydraulic fracturing tests were the motivation for this study. One assumption made to explain those results lies in the mineralogy and TOC differences between the different zones of the Woodford. It is assumed that the different minerals and TOC have an effect on the mechanical properties of the formation, thus any change in the mineralogy and/or TOC will systematically result in a variation in the mechanical properties. This study attempts to investigate the assumption claimed and shed the light on the relationship between mineralogy, TOC and the mechanical properties as they relate to hydraulic fracturing treatments in the Woodford shale.
Figure 1.5 Injection/mini-frac tests results in the different parts of the Woodford shale in subject well RTC #1 showing a higher fracture gradient in the Lower Woodford.

1.4 Research Contributions and Applications

The outcomes of this research will be of great assistance to the exploitation and development of the west Texas Woodford shale in particular and shale gas reservoirs in general. By knowing the elements that govern the results of hydraulic fracturing treatments, this study will lead to a:

- Better explanation of hydraulic fracturing treatment results in the Woodford shale;
- More reliable hydraulic fracturing treatment designs;
- Realistic expectations on the outcome of hydraulic fracturing treatments in the Woodford shale;
- Reduction in the failure rate of treatments resulting in better economics; and,
- Better understanding of the effect of TOC and different minerals (quartz, clays and carbonates) on the mechanical properties of shales.
CHAPTER 2
LITERATURE REVIEW

Shale gas reservoirs are characterized by their uniqueness. The fact that each reservoir is different from another in: mineralogy, TOC, kerogen maturity, natural fractures, makes it very hard to extrapolate the experiences learned from one reservoir to another. Formation evaluation and hydraulic fracturing of these unconventional gas plays are highly influenced by these differences.

2.1 Formation Evaluation of Shale Gas Reservoirs

Shale is the descriptive name applied to sedimentary rocks with clay size particles and a distinct foliation (Harvey and Tracy 1996). Generally, these sedimentary rocks are composed of a mixture of clay minerals and silt (Asquith 1989). The proportions of these minerals differ from one shale to another. For instance, the Woodford shale that is the subject of this thesis consists mainly of quartz, 9-87 wt%, with low clay content, 0-43 wt%. The Floyd shale of the Black Warrior Basin in Alabama, on the other hand, has a clay content of 32-87 wt% and a quartz content of only 2-23 wt% (Sarkar et al. 2008). And, the Barnett Shale of the Fort Worth basin, east Texas, contains 30-39 wt% clay and 29-38 wt% quartz (Matthews et al 2007).

Because of its small particle sizes, shale is usually characterized by very low porosities, pore sizes in the nanometer, and extremely low permeabilities, often less than 0.01 md (Barree et al. 2009). It is also characterized by thin laminae parallel to the often-indistinguishable bedding plane (Harvey and Tracy 1996). Due to their frequent abundance in organic matter, shale, as well as coalbed methane (CBM) reservoirs have always been considered as potential source rocks (Rickman et al. 2008). However, lately, the mindset towards these types of rocks has changed. Currently, shale gas is considered as an
increasingly large component of future, technically recoverable resources (Curtis and Montgomery 2002). This trend is due to improvements in exploration, completion, and production technologies, aided by wellhead price increases (Curtis and Montgomery 2002). The increasing interest in these types of reservoirs has led to a need for specific models that allow a quantitative formation evaluation of these reservoirs.

The models used for the evaluation of shale gas reservoirs are often derived from the models used to describe conventional reservoirs (sandstones and carbonates). Using these modified models in shale gas reservoirs will lead to a less accurate evaluation of these reservoirs because of the difficulty in accounting for the specificities of these shale gas reservoirs; clay content, clay bound water, organic matter and so forth. But it is still the only approximation possible so far. One example that illustrates this point is the evaluation of the gas content of the reservoir. Conventional models will underestimate the gas content of the shale gas reservoirs since they only account for the gas stored in the pores. However, the few years of experience that the industry has in these reservoirs show that gas in shale reservoirs is not only stored in the pores but it is also adsorbed on the organic matter and dissolved in formation water (Jenkins et al. 2008). Likely, the two main parameters that differentiate shale gas reservoirs from conventional reservoirs evaluation are: clay content and its bound water, and TOC.

2.1.1 Clay Content and Clay-Bound Water

The presence of clay in any reservoir will result in lowering the resistivity measured by the induction electric logs (Asquith 1989). This is due to both bound water associated with the clay and cation exchange capacity (CEC) of the clay (Fertl and Frost 1980). Table 2.1 is a summary of clay mineral parameters that are important in formation evaluation. Based on this fact, the Archie’s water saturation equation as stated by Archie (1942) is no longer applicable. Archie
developed his equation for a clean formation where the only conductor is connate water. Therefore, Archie’s equation has later been modified by Simandoux (1963), Poupon and Leveaux (1971), Waxman and Smits (1968), and others, to account for the specificities of shaly reservoirs that may contain a substantial amount of clay. All these methods considered the electric conductance of the formation as a result of two mediums: shale free matrix + shale.

Table 2.1 Clay Mineral Parameters Important in Formation Evaluation (From Fertl and Frost 1980)

<table>
<thead>
<tr>
<th>CLAY MINERALS</th>
<th>COMPOSITION</th>
<th>REMARKS</th>
<th>DENSITY (g/cc)</th>
<th>HYDROGEN INDEX</th>
<th>CATION EXCHANGE CAPACITY (meq/100g)</th>
<th>SPECTRAL GAMMA RAY DISTRIBUTION (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chlorete</td>
<td>(Mg,Al,Fe),,(Si,Al)O,(OH)</td>
<td>Low water absorptive properties. As coating and/or pore bridging in reservoir pore space. Small effect on resistivity measurement due to moderate surface area.</td>
<td>2.66-2.95</td>
<td>0.34</td>
<td>10-40</td>
<td>Potassium (K), Uranium (U), Thorium (Th)</td>
</tr>
<tr>
<td>Illite</td>
<td>K,(Al,Si)O,(OH)</td>
<td>No adsorbed water. As coating (pore-filling) and pore bridging in reservoir pore space. Reduce resistivity measurement. Moderate surface area.</td>
<td>2.64-2.69</td>
<td>0.12</td>
<td>10-40</td>
<td>4.5</td>
</tr>
<tr>
<td></td>
<td>(K,Mg),,(Fe,Mg,Al,Ti)</td>
<td>Bastite: As pore bridging and/or thin mass seems as laminae in reservoir rock.</td>
<td>2.3-3.2</td>
<td>0.12</td>
<td>6.7-6.3</td>
<td>&lt;0.01</td>
</tr>
<tr>
<td></td>
<td>K,(Al,Si)O,(OH)</td>
<td>Montmorillonite: Drastic effect on vertical permeability.</td>
<td>2.16-3.0</td>
<td>0.13</td>
<td>7.9-9.8</td>
<td>&lt;0.01</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>Al(Si,Al)O,(OH)</td>
<td>“Patch” Kaolinite as discrete particles in reservoir pore space. As migrating fines creating internal formation damage. Small literature effect on resistivity measurements. Most frequently quoted low surface area.</td>
<td>2.60-2.88</td>
<td>0.35</td>
<td>3-15</td>
<td>0.42</td>
</tr>
<tr>
<td>Smaectite</td>
<td>(1/2Ca),,(Al,Fe),,(Si,Al)O,(OH)</td>
<td>Montmorillonite: Montmorillonite as coating and/or pore bridging in reservoir pore space. Critical to physical and chemical formation damage. Large reducing effect on resistivity measurements. High surface area.</td>
<td>2.29-2.70</td>
<td>0.13</td>
<td>80-150</td>
<td>0.16</td>
</tr>
</tbody>
</table>

- Low iron smectite: 2.53
- 3.5% iron content: 2.74
- Bentonite: <0.05, 1-20, 2-50
Clay will also cause the porosities derived from the sonic and the neutron log to be higher than the reality. The water bound in the clay slows the sonic velocities and is interpreted as free water in pores. In the same way, the large amounts of hydrogen contained in the bound water are interpreted as free water in the pore space by the neutron log.

Many models have been developed to account for the presence of clay and its bound water in shale gas reservoirs. Those models are beyond the scope of this research and can be found elsewhere in the literature. A summary of clay volume indicators is depicted in Table 2.2.

2.1.2 Total Organic Carbon, TOC

TOC is the other important parameter that influences the outcome of formation evaluation in shale gas reservoirs. Shale gas reservoirs are characterized by high TOC content, up to 10 wt% in the Woodford (Mnich 2009). Because of the low density of TOC, about 1.2-1.4 g/cc (Utley 2005), the porosities calculated from the density log will be higher than they actually are. Therefore, the water saturation calculated with density porosity will be underestimated and the free gas content overestimated. Campbell and Truman (1986) stated that kerogen has a detrimental effect on free porosity in shales. They claimed that kerogen may occupy part of the free porosity and even inhibit the development of free porosity in shales (Campbell and Truman 1986). Prasad and Mukerji (2003), suggested that increasing kerogen maturity is linked to decreasing sonic velocities on shale core samples (from Bakken shale, Bazhenov shale, and Woodford shale) and that in low porosity shales, velocities correlate better with kerogen content compared to high porosity shales where velocities correlate better with porosity.

Because organic-rich rocks can be relatively highly radioactive compared to organic-poor rocks, mainly due to their high uranium content, high TOC is often related to high gamma ray readings in source rocks. Also, since TOC is
<table>
<thead>
<tr>
<th>LOGGING CURVE</th>
<th>MATHEMATICAL RELATIONSHIP</th>
<th>FAVORABLE CONDITIONS</th>
<th>UNFAVORABLE CONDITIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPONTANEOUS POTENTIAL (SP-curve)</td>
<td>( V_C = 1.0 \cdot \frac{(PSP/SSP) + 1.0 \cdot a}{a} )</td>
<td>Waterbearing, laminated Shaly sands (&lt; R_l)</td>
<td>( R_o/R_n ) approaches 10 thin, &gt;&gt; R zones Hydrocarbon bearing. Large electro-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>kinetic and/or invasion effects</td>
</tr>
<tr>
<td></td>
<td>( V_C = \frac{(PSP-SP_{soil})}{(SSP-SP_{soil})} )</td>
<td>( c &lt; 1.0 ) as function of clay type</td>
<td></td>
</tr>
<tr>
<td></td>
<td>( 1.0 - a = \log \frac{A}{B} \frac{[A - V_C + B]}{1 - V_C - B} )</td>
<td>Knowledge of several parameters required including d, R_l, R_m, R_o, Similar</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Where A = R_o/R_m, B = R_l/R_m</td>
<td>limitation as for straight toward SP-equations</td>
<td></td>
</tr>
<tr>
<td></td>
<td>( 1.0 - a = \frac{(K \cdot V_C \cdot W)}{(K \cdot V_C \cdot W+\Theta \cdot S_w)} )</td>
<td>K = log derived coefficient. W = clay porosity from bulk</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>And matrix p_{soil} S_w = flushed zone water saturation</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Laboratory-derived, too many requirements</td>
<td></td>
</tr>
<tr>
<td>GAMMA RAY</td>
<td>( V_C = \frac{(GR - GR_{min})}{(GR_{max} - GR_{min})} )</td>
<td>Only clay minerals are radioactive</td>
<td>Radioactive minerals other Than clays (mica, feldspar, Silt)</td>
</tr>
<tr>
<td></td>
<td>( V_C = \frac{C (GR - GR_{min})}{(GR_{max} - GR_{min})} )</td>
<td>C &lt; 1.0 frequently approximately 0.5 when</td>
<td>Only potassium-deficient Kaolinite present. Uranium enrichment in permeable</td>
</tr>
<tr>
<td></td>
<td>( V_C = (GR - W) Z )</td>
<td>V_C &lt; 40%</td>
<td>fractured zones.</td>
</tr>
<tr>
<td></td>
<td>( V_C = 0.33(2^{\frac{V_C}{10}} - 1.0) )</td>
<td>W, Z = geologic area coefficient</td>
<td>Radiobalite scales on casing. Severe washouts (&lt; GR)</td>
</tr>
<tr>
<td></td>
<td>( V_C = 0.083(2^{\frac{V_C}{10}} - 1.0) )</td>
<td>Highly consolidated and Mesozoic rocks</td>
<td>Younger, unconsolidated rocks</td>
</tr>
<tr>
<td></td>
<td>Where ( V_C = \frac{(GR - GR_{min})}{(GR_{max} - GR_{min})} )</td>
<td>Tertiary clasics</td>
<td>Older, consolidated rocks</td>
</tr>
<tr>
<td></td>
<td>SPECTRALOG</td>
<td>Gamma ray spectral logging provides individual measurements of</td>
<td>Conditions similar to gamma ray discussion: A = spectrallog readings (K in %, Th in</td>
</tr>
<tr>
<td>Gamma ray</td>
<td>( V_C = \frac{(A - A_{min})}{(A_{max} - A_{min})} )</td>
<td>potassium (K, %) and thorium (Th, ppm) content</td>
<td>ppm), ( A_{min} = ) minimum value (k or Th) in clean zones</td>
</tr>
<tr>
<td>logging provides individual</td>
<td>( V_C = \frac{C (A - A_{min})}{(A_{max} - A_{min})} )</td>
<td>( A_{min} = ) maximum values (K, Th) in essentially pure shales.</td>
<td>Conditions similar to gamma ray discussion.</td>
</tr>
<tr>
<td>mesurements of potassium (K, %)</td>
<td>( V_C = 0.33(2^{\frac{V_C}{10}} - 10) )</td>
<td>Similar to gamma ray discussion. However, uranium enrichment in permeable</td>
<td></td>
</tr>
<tr>
<td>and thorium (Th, ppm) content</td>
<td>( V_C = 0.083(2^{\frac{V_C}{10}} - 10) )</td>
<td>fractured zones and radiobalite build up are no limitations.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Where ( V_C = \frac{(A - A_{min})}{(A_{max} - A_{min})} )</td>
<td>If Th-curve is used, localized bentonite streaks should be ignored.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>RESISTIVITY</td>
<td>If several resistivity logs are available. Use the one which exhibits highest</td>
<td>Low porosity zones (carbonate, marls) pay zones with low (S_w - S_min)</td>
</tr>
<tr>
<td>If several resistivity logs are</td>
<td>( V_C = \left(\frac{R_C}{R_n}\right)^{1/b} )</td>
<td>Low porosity zones (carbonate, marls) pay zones with low (S_w - S_min)</td>
<td>High porosity water sand, High ( R_o = ) values</td>
</tr>
<tr>
<td>available. Use the one which</td>
<td>Where ( b = 1.0 )</td>
<td></td>
<td></td>
</tr>
<tr>
<td>exhibits highest resistivity values.</td>
<td>( b = 2.0 )</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Table 2.2 (continued)

<table>
<thead>
<tr>
<th>LOGGING CURVE</th>
<th>MATHEMATICAL RELATIONSHIP</th>
<th>FAVORABLE CONDITIONS</th>
<th>UNFAVORABLE CONDITIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NEUTRON</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=$</td>
<td>$\frac{[R_{cl}(R_{max} - R_e)]}{[R_e(R_{max} - R_{cl})]^{1/2}}$</td>
<td>In clean hydrocarbon</td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=$</td>
<td>same as above.</td>
<td>Bearing zones one</td>
<td></td>
</tr>
<tr>
<td>$\theta_{sat}$</td>
<td></td>
<td>calculates $V_{CI} = 0$</td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=\frac{(\theta_{sat} - \theta_{min})}{(\theta_{sat} - \theta_{min})}$</td>
<td>High gas saturation or very low reservoir porosity.</td>
<td>$\theta_{sat}$ is low</td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=$</td>
<td>(\theta_{sat} - \theta_{min})</td>
<td>$\theta_{sat}$ can be varied.</td>
<td></td>
</tr>
<tr>
<td><strong>PULSED NEUTRON</strong></td>
<td>$V_{CI} = (\Sigma - \Sigma_{min}) / (\Sigma_{max} - \Sigma_{min})$</td>
<td>Fresh water environment</td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=$</td>
<td>$\frac{(\Sigma_{CI} - \Sigma_{min})}{(\Sigma_{max} - \Sigma_{min})}$</td>
<td>Low porosity and gas and bearing zones.</td>
<td></td>
</tr>
<tr>
<td>$V_{CI}=$</td>
<td>(\theta_{sat} - \theta_{min}) / (\theta_{sat} - \theta_{min})</td>
<td>$V_{CI}$ calculates zero in clean zones.</td>
<td></td>
</tr>
<tr>
<td><strong>DENSITY-NEUTRON</strong></td>
<td>$V_{CI} = \frac{\rho_{w} \cdot \rho_{w} (\theta_{sat} - 1.0) \cdot \theta_{sat} (\rho_{sat} - \rho_{w}) \cdot \rho_{sat} \cdot \rho_{sat} \cdot \Delta \rho_{sat}}{\rho_{sat} \cdot (\theta_{sat} - 1.0) \cdot \rho_{sat} \cdot (\theta_{sat} - 1.0) \cdot \rho_{sat}}$</td>
<td>Too low $V_{CI}$ in prolific gas zone.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Don't use with severe hole conditions.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lithology affected.</td>
<td></td>
</tr>
<tr>
<td><strong>DENSITY-AcouSTIC</strong></td>
<td>$V_{CI} = \frac{\rho_{sat} \cdot (\Delta \rho_{sat} - \Delta \rho_{sat}) \cdot \Delta \rho_{sat} \cdot \rho_{sat} \cdot \rho_{sat} \cdot \Delta \rho_{sat}}{(\Delta \rho_{sat} - \Delta \rho_{sat}) \cdot (\rho_{sat} - \rho_{sat}) \cdot (\rho_{sat} - \rho_{sat}) \cdot (\Delta \rho_{sat} - \Delta \rho_{sat})}$</td>
<td>Less dependent on lithology and fluid conditions than DEN-NEU crossplot</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Use in gauge boreholes.</td>
<td></td>
</tr>
<tr>
<td><strong>NEUTRON-ACOUSTIC</strong></td>
<td>$V_{CI} = \frac{\rho_{sat} \cdot (\Delta \rho_{sat} - \Delta \rho_{sat}) \cdot \Delta \rho_{sat} \cdot \rho_{sat} \cdot \rho_{sat} \cdot \Delta \rho_{sat}}{(\Delta \rho_{sat} - \Delta \rho_{sat}) \cdot (\rho_{sat} - \rho_{sat}) \cdot (\rho_{sat} - \rho_{sat}) \cdot (\Delta \rho_{sat} - \Delta \rho_{sat})}$</td>
<td>Use only in gas bearing Zones with low $S_o$.</td>
<td>Similar effects due to shalliness on both logs.</td>
</tr>
</tbody>
</table>

15
electrically nonconductive, high TOC can increase the resistivity of the formation compared to the same formation devoid of TOC (Kamali and Mirshady 2004). These different signatures of TOC on well logs are the bases of several methods that have been developed to estimate the TOC content of source rocks from well logs. Among those methods, probably the most widespread in the industry include: gamma ray-TOC cross plots (Luning and Kolonic 2003), $\Delta$logR Technique that derives TOC from the sonic and true resistivity logs (Passey et al. 1990) and Schmoker (1979) that takes advantage of the signature of TOC on the density log.

2.2 Hydraulic Fracturing of Shale Gas Reservoirs

In order to obtain commercial production from low permeability shale gas reservoirs, fracture stimulation is required (Matthews et al. 2007). This stimulation helps form flow paths in the reservoir by creating fractures that reach beyond the drainage area of a non-fractured well. The industry’s experience in stimulating these unconventional plays, which is still in its development process, began with the boom of the Fort Worth Basin Barnett Shale, east Texas. Over the last 20 years, the Barnett has been a real laboratory for stimulation of shale gas where many stimulation techniques have been tested. Some of the stimulation methods used in the Barnett include: conventional crosslinked fluids treatments in mid 1980’s-1996 (Matthews et al. 2007) and slickwater treatments, from 1997 to present (Walker et al. 1998). The combination of horizontal wells and very large slickwater treatments, with small mesh proppants, has proven to be the most successful in the Barnett (Matthews et al. 2007). Matthews et al. (2007) argued that the success of this particular combination in the Barnett is due to several factors; mineralogy, presence of hard limestone barriers above and below the reservoir and natural fractures. The mineral composition of the Barnett (relatively rich in calcite, about 10 wt.% on average) makes it a very brittle and easy-to-fracture rock (Matthews et al. 2007). The presence of hard limestone
barriers prevents the fractures from growing into the water rich zones, and the presence of natural fractures permits the contact of a larger reservoir area leading to an increase in production.

With the success of the Barnett shale in mind, many operators have tried to apply the same stimulation techniques used in the Barnett, hoping to obtain the same results in other shale gas plays across the US. Some of the well known reservoirs that are under exploration and development right now include: the Woodford Shale and the Barnett Shale in the Permian Basin, west Texas (Matthews et al. 2007), the Fayetteville Shale and the Woodford/Caney Shale in the Arkoma Basin, Arkansas (Matthews et al. 2007), the Floyd Shale in the Black Warrior Basin, Alabama (Matthews et al. 2007), the Devonian shales including the Marcellus Shale in the Appalachian Basin (Suhy 2008), eastern US; and the Woodford Shale in the Anadarko Basin, Oklahoma (Vulgamore et al. 2007).

Not surprisingly, at least from today’s perspective, the outcomes of those attempts have proved that not all shale gas reservoirs are alike. Even a small difference in the mineral composition of the reservoir can prove to be detrimental to the success of stimulation treatments. There are lessons learned, however, from trying to duplicate the Barnett shale of east Texas in other parts of the US continent which include:

- Each shale gas reservoir is specific and needs to be considered with that uniqueness in mind;
- Slickwater treatments are very effective in low permeability, naturally fractured rock where highly conductive fractures are not needed and fluid imbibition is not an issue (Matthews et al. 2007); and,
- Stimulation trends in shale gas reservoirs are moving away from slickwater only. The use of crosslinked fluids with higher conductivity proppant packs and hybrid fracture treatments (slickwater/crosslink combinations) are all being used (Matthews et al. 2007).

Over the few years that shale gas reservoirs have been of commercial interest, several studies have been done on the matter of hydraulic fracturing of these reservoirs. The areas of this subject that received most of the attention
include: fracture initiation (Suarez-Rivera et al. 2006), fracture geometry (Hopkins et al. 1995), in-situ stresses (Abousleiman et al. 2007), and mineralogy of shale as it relates to fracturing fluids (Paktinat et al. 2007). Table 2.3 is a summary of necessary information for the design of a stimulation treatment.

<table>
<thead>
<tr>
<th>Geomechanical Considerations</th>
<th>Important For</th>
<th>Determined By</th>
</tr>
</thead>
<tbody>
<tr>
<td>How brittle is the shale?</td>
<td>Fluid type selection</td>
<td>Petrophysical model</td>
</tr>
<tr>
<td>What is the closure pressure?</td>
<td>Proppant type selection</td>
<td>Petrophysical model</td>
</tr>
<tr>
<td>What proppant size and volume?</td>
<td>Avoid screenouts</td>
<td>Petrophysical model/tribal knowledge</td>
</tr>
<tr>
<td>Where should the frac be initiated?</td>
<td>Avoid screenouts</td>
<td>Petrophysical model/tribal knowledge</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Geochemical Considerations</th>
<th>Important For</th>
<th>Determined By</th>
</tr>
</thead>
<tbody>
<tr>
<td>What is the mineralogy?</td>
<td>Fluid selection</td>
<td>XRD/LIBS/petrophysical model</td>
</tr>
<tr>
<td>Fluid water sensitivity?</td>
<td>Base fluid salinity</td>
<td>CST/BHN/Immersion Test</td>
</tr>
<tr>
<td>Can acid be used if necessary?</td>
<td>Initiation issues—etching</td>
<td>AST</td>
</tr>
<tr>
<td>Does proppant or shale flow back?</td>
<td>Production issues</td>
<td>Tribal knowledge</td>
</tr>
<tr>
<td>Are surfactants beneficial?</td>
<td>Conductivity endurance</td>
<td>Flow test/tribal knowledge</td>
</tr>
</tbody>
</table>

The mechanical rock properties, Young's modulus and Poisson's ratio, are two key parameters in hydraulic fracturing treatments. Depending on the values of those two parameters, the rock is considered either more brittle or more ductile. A brittle rock is more susceptible to fail under stress and maintain the fracture open after it was created, which makes the brittle rock a good target for hydraulic fracturing (Rickman et al. 2008). On the other hand, a ductile rock is more resistant to fracture initiation, and susceptible to fracture healing and embedment resulting in shorter and less conductive fractures (Figure 2.1), which makes the ductile rock a good barrier preventing the fracture from growing into non-reservoir regions (Rickman et al. 2008). Rickman et al. (2008) suggest that a rock is considered brittle if it has high Young's modulus and low Poisson's ratio (Figure 2.2). Along with pore pressure and overburden stress, Young's modulus and Poisson's ratio are also used in the uniaxial strain model to profile the in-situ
Figure 2.1 Representation of a horizontal cross section of a hydraulically fractured formation. The proppant particles are pushed into the formation (embedded) resulting in less surface for the fluids to flow into the fracture (Haidar 2003).

Figure 2.2 Cross plot of Young's modulus (YMS_C) and Poisson's ratio (PR_C) showing the brittleness percentage increasing to the lower left corner of the plot. Young's modulus increases from the top of the Y-axis to the bottom of the same axis. Poisson's ratio decreases from the right of the X-axis to the left of the same axis. Britteness is color coded, light green color representing the least brittle and the red color the most brittle (Rickman et al. 2008).
minimum horizontal stress (Barree et al. 2009). This minimum horizontal stress is the force that the hydraulic fracturing fluids need to overcome in order for the fracture to be initiated and to propagate in the formation. It is also the minimum horizontal stress that plays the role of the force that is trying to close on the created fracture and minimize the associated conductivity in consequence.

Horizontal to vertical anisotropy, with respect to the bedding plane, in these mechanical properties, which is common to layered shale gas reservoirs, has proven to have an influence on hydraulic fracturing treatments outcomes. Matthews et al. (2007) noted that the Young’s modulus and Poisson’s ratio of West Texas Barnett shale, which was not as successful with slickwater treatments, are not very different from those in the East Texas Barnett. However, the anisotropy in the mechanical properties of the West Texas Barnett shale is very significant; the Young’s modulus parallel to the bedding plane is twice as much as the Young’s modulus perpendicular to the bedding plane. Anisotropy in shale gas reservoirs is not only restricted to differences in horizontal and vertical mechanical properties. The advance of microseismic has allowed better monitoring of hydraulic fractures growth and uncover mechanical anisotropy even in one direction (horizontal stress anisotropy) (Miskimins 2008). Thus, understanding the stress anisotropy in shale gas reservoirs is a key element to an accurate stress profiling and fracture propagation prediction.

Besides anisotropy in the mechanical properties, shale gas reservoirs show different types and scales of anisotropy in their geological properties. Hemmesch and Harris (2009) described these types of anisotropy in the RTC #1 Woodford Shale core. Table 2.4 is a summary of the types and scales of those anisotropies.
Table 2.4 Types and Scales of Geological Anisotropy in the RTC #1 Woodford Shale Core (Modified from Hemmesch and Harris 2009)

<table>
<thead>
<tr>
<th>Type of anisotropy</th>
<th>Scale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depositional</td>
<td>millimeter</td>
</tr>
<tr>
<td>Bedding</td>
<td>centimeter</td>
</tr>
<tr>
<td>Geochemistry</td>
<td>(micro-nano) meter</td>
</tr>
<tr>
<td>Carbonates</td>
<td>centimeter - meter</td>
</tr>
<tr>
<td>Silica</td>
<td>meter</td>
</tr>
<tr>
<td>Fractures</td>
<td>micrometer - meter</td>
</tr>
</tbody>
</table>
CHAPTER 3
DATA ACQUISITION

The main goal of this study is to investigate the potential relationship between the mineral, geochemical constituents of the Woodford shale and its mechanical properties as they relate to hydraulic fracturing. Therefore, a detailed geological and petrophysical description of the formation in question is needed. This study is performed using two different data sets including well and lab data.

3.1 Lab Data

The lab data consists of the mineral, geochemical, and petrophysical data acquired from a 260 ft core of the Woodford shale from the well Reliance Triple Crown #1, Pecos County, west Texas.

3.1.1 Mineral and Geochemical Data

The mineral and geochemical data were gathered by a team of students, Nikki Hemmesch, a PhD Student and Cheryl Mnich, an Msc Student in the Geology and Geological Engineering Department of the Colorado School of Mines, who have been working on the project for over two years. They have produced an extensive suite of geological, mineral and geochemical data from 166 samples of the core. The data include lithology, mineralogy, core log spectral gamma ray, TOC content and geochemistry of the cored formation.

Harris et al., (in press), based on the core description and interpretation performed by Hemmesch and Harris (2009), suggests that the RTC #1 Woodford Shale core contains five lithofacies including two equivalent to Comer’s (1991). These five lithofacies are: (1) massive carbonate; (2) black shale; (3) siltstone;
(4) massive grey mudstone; and (5) laminated carbonate. Table 3.1 is a summary of the lithofacies description and interpretation (Mnich 2009). Figure 3.1 shows the distribution of the different lithofacies in the RTC #1 Woodford Shale core (Harris et al. in press).

<table>
<thead>
<tr>
<th>Lithofacies</th>
<th>Characteristics</th>
<th>Depositional Mechanisms</th>
<th>Systems Tract</th>
</tr>
</thead>
<tbody>
<tr>
<td>Massive Carbonate</td>
<td>Lt grey-tan; structureless; clay-/silt-sized; mud clasts; flame structures; abrupt top and bottom contacts</td>
<td>Distal portion of carbonate debris flows</td>
<td>Lowstand</td>
</tr>
<tr>
<td>Black Shale</td>
<td>Black; parallel laminae; clay-sized; mud clasts; chert/phosphate nodules; abundant pyrite</td>
<td>Deep, quiet water; hemi-pelagic deposition</td>
<td>Transgressive/Highstand</td>
</tr>
<tr>
<td>Siltstone</td>
<td>Lt tan; parallel laminae; &gt;50% silt-sized quartz and carbonate</td>
<td>Silt bypass of carbonate platforms; Distal siliciclastic turbidity current</td>
<td>Highstand</td>
</tr>
<tr>
<td>Massive Grey Mudstone</td>
<td>Lt grey; structureless; clay-sized siliciclastic; basal scour surface or abrupt contact</td>
<td>Distal siliciclastic turbidity current</td>
<td>Highstand/Falling Stage</td>
</tr>
<tr>
<td>Laminated Carbonate</td>
<td>Lt grey; parallel laminae; clay-/silt-sized carbonate; abrupt contacts; climbing ripples</td>
<td>Distal carbonate turbidity current</td>
<td>Highstand</td>
</tr>
</tbody>
</table>
Figure 3.1 Distribution of the five lithofacies in the RTC #1 Woodford Shale core (Modified from Harris et al., in press).
The detailed mineralogical profiles in the RTC #1 core description suggests systematic differences in mineralogy between the different zones (upper, middle and lower) of the RTC #1 Woodford Shale core. The upper Woodford is composed of mainly quartz (average 77 vol%) with low clay content (average 7 vol%) and very low carbonates (average 4 vol%) (Mnich 2009). Apatite is found at its highest content in this region with an average of 9 vol% (Mnich 2009). The middle Woodford shows a slightly higher clay and carbonates contents, 15 vol% and 7 vol% on average, respectively, with a lower quartz content (average 69 vol%) (Mnich 2009). The lower part of the Woodford can be divided, based on its mineralogy, into two different zones, upper zone and lower zone. The upper zone extends from 12,985 ft to 13,040 ft and shows the highest clay content (28 vol%) in the RTC #1 Woodford Shale core with an average quartz content of 55 vol% and minor carbonates (1 vol%) (Mnich 2009). The lower zone that extends from 13,040 ft to 13,098 ft, displays low clay content (5 vol%) with a relatively high carbonates content (49 vol%) and a relatively low quartz content (45 vol%) (Mnich 2009). Figure 3.2 shows the detailed mineralogy of the RTC #1 Woodford Shale core.

The Woodford shale of west Texas and southeast New Mexico is very rich in TOC as suggested by TOC core measurements (Mnich 2009). TOC values fluctuate between 1-10 wt% with an average of 5 wt% (Mnich 2009). Figure 3.3 show the variations in TOC through out the RTC #1 Woodford Shale core. It is important to note that the lower zone of the lower Woodford (13,040 ft – 13,098 ft) that is characterized by high carbonates content is not as rich in TOC; the average TOC in this zone is about 3.5 wt% and the maximum is about 6 wt%.

The geochemical elements that were measured in the RTC #1 Woodford Shale core include: (SiO₂), (Al₂O₃), (Fe₂O₃), (MgO), (CaO), (Na₂O), (K₂O), (TiO₂), (P₂O₅), (LOI), (Ba), (Sr), total carbon (TotC), total sulfur (TotS), (Zn), (Mo), and (Ni) (Mnich 2009). For specific values of these different elements and more detailed geological data refer to Appendix B.
Figure 3.2 Mineralogy of the three different units (Upper, Middle and Lower) of the Woodford Shale, west Texas, in the RTC #1 core (Mnich 2009). Note that the lower Woodford displays the highest clay content and the zone between 13040 ft and 13098 ft shows high carbonates content. The red dashed line separates the upper and lower parts of the Lower Woodford.
Figure 3.3 TOC variations throughout the RTC #1 Woodford Shale core (Mnich 2009). The red dashed line separates the upper and lower parts of the Lower Woodford. Note that the lower zone of the lower Woodford (13040 ft - 13098 ft) that is characterized by high carbonates content is not very rich in TOC; the average TOC in this zone is about 3.5 wt% and the maximum is about 6 wt%.
3.1.2 Acoustic Travel Times

The acoustic measurements consist of lab measurements of the compressional and shear wave travel times, $\Delta t_p$ and $\Delta t_s$ respectively, on the entire 260 ft Woodford core section. This was carried out using a hand-held velocity probe (Figures 3.4 and 3.5). The velocity probe has one emitter end and two receiver ends that are equally separated from one another, one inch between each end (Figure 3.4). The velocity probe is attached to a pulse generator that generates sonic waves, and an oscilloscope that displays the sonic waves. The sonic wave generated by the pulse is picked up by the two receivers of the probe resulting in two sonic waves displayed on the oscilloscope. The difference in the arrival times of the two waves is recorded as the travel time of the sonic wave. The reason for recording the difference in the arrival times of the two waves rather than the straight arrival time of one of them is to filter any noise that may alter the sonic wave. The velocity probe requires a given sample to be slightly over two inches wide with respect to the measurements direction; either vertical or horizontal. In order to avoid alteration of data by any kind of small fractures in the core samples, a thorough examination of the samples is crucial before the measurements can be made. Before the measurements could be taken, the velocity probe was calibrated. This was done by performing measurements on a plastic plug for which the acoustic velocities were known in advance.

The measurements were recorded in a horizontal direction with respect to the bedding plane and in a very detailed manner. First, the locations where the probe points were going to be placed were marked with a pencil on each sample. Then, the $\Delta t_p$ measurements were taken for all samples, each sample was measured three times at the exact same spot and the average value was recorded. Finally, the $\Delta t_s$ measurements were recorded in the same manner as the $\Delta t_p$ measurements. This final step is always delicate when using the hand-held velocity probe. This is due to the uncleanliness of the shear wave on the oscilloscope screen which makes identifying the arrival time of that wave uneasy.
Figure 3.4 Hand-held velocity probe used to measure acoustic travel times on cores and outcrops (Batzle and Smith 1992).

Figure 3.5 Depiction of the measurement procedure with a hand-held velocity probe.
The errors associated with averaging the three recordings, on the same core sample, were up to 20% for both compression and shear travel times. After recording \( \Delta t_p \) and \( \Delta t_s \), the compressional and shear wave velocities, \( V_p \) and \( V_s \) respectively, are calculated using Equation 3.1:

\[
V = 83333.33 \frac{L}{\Delta t} \tag{3.1}
\]

Where:

- \( V \) = velocity in ft/s
- \( \Delta t \) = wave travel time in \( \mu \)s/inch
- \( L \) = distance between the probe receivers, 1 inch
- 83333.33 = conversion factor; inch/\( \mu \)s to ft/s.

The \( \Delta t_p \) and \( \Delta t_s \) measurements and the \( V_p \) and \( V_s \) results calculated with Equation 3.1 are tabulated in Appendix C: Core Acoustic Velocities and Mechanical Properties.xls. Figure 3.6 shows the results of the \( V_p \) and \( V_s \) measurements taken on the 260 ft RTC #1 Woodford Shale core. More than 150 measurements in total were taken. No core was available from a depth of 13044 ft – 13092 ft; therefore no measurements were taken in this interval.

The core \( V_p \) ranges between 12,000 ft/s and 16,000 ft/s and displays two slightly decreasing trends (12,750 ft – 12,900 ft and 12,900 ft – 13,000 ft) and one increasing trend (13,000 ft – 13,050) with respect to core depth. Core \( V_s \), on the other hand, ranges between 7,000 ft/s and 10,000 ft/s and shows two different trends with respect to core depth. Between 12,750 ft and 13,000, core \( V_s \) decreases slightly, while below 13,000 ft it can be noticed that core \( V_s \) increases slightly with respect to core depth.
Figure 3.6 Results of the acoustic compression ($V_p$) and shear ($V_s$) velocities measurements on the RTC #1 core, Woodford shale. Core $V_p$ ranges between 12,000 ft/s and 16,000 ft/s and displays two slightly decreasing trends (12,750 ft – 12,900 ft and 12,900 ft – 13,000 ft) and one increasing trend (13,000 ft – 13,050) with respect to core depth. Core $V_s$ ranges between 7,000 ft/s and 10,000 ft/s and shows two different trends with respect to core depth. Between 12,750 ft and 13,000, core $V_s$ decreases slightly with respect to core depth, while below 13,000 ft it can be noticed that core $V_s$ increases slightly with respect to core depth.

3.1.3 Porosity

Porosity measurements were performed across the entire Woodford core section. The measurement process was done in two separate steps; first, the grain volume of a sample was measured with a pycnometer, then the bulk volume of the sample was measured by immersing it in a graduated beaker of water and the difference in volume was recorded. After recording both the grain volume and the bulk volume of the sample, the porosity was calculated using Equation 3.2:
\[ \phi = \frac{V_b - V_g}{V_b} \] (3.2)

Where:
- \( V_b \) = bulk volume, cc
- \( V_g \) = grain volume, cc
- \( \Phi \) = porosity, fraction

146 porosity measurements were recorded in total. Figure 3.7 is a depiction of those measurements with respect to core depth. Core porosity ranges between 0 and 0.145 with an average of 0.04. It shows three distinct trends; it increases with depth between 12,740 ft and 12,850 ft, then decreases between 12,850 and 13,000 ft and increases again with respect to depth between 13,000 ft and 13,100 ft.

### 3.1.4 Permeability

Only one core sample was found in appropriate condition for permeability measurement, all other samples were either too small or displayed visible fractures. The core sample on which the permeability was measured was located at about 13,041 ft in the RTC #1 well. This zone of the Woodford shale, as already discussed, is described as massive carbonate with high carbonate content (dolomite and calcite) and little clay (Mnich 2009). The permeability was measured at a confining pressure of 5000 psi, and the flow direction was parallel to the bedding plane which is horizontal. The core sample was placed between two reservoir rocks in a single piston pump at a confining pressure of 5,000 psi. The pump injected fluid into the setup (core sample and reservoir rocks) at a constant flow rate and the pressure was recorded in the reservoir rocks (Sarkar 2009). Permeability was then calculated from the pressure decay recorded in the reservoir rocks. In the above mentioned conditions, permeability was found to vary between 0.02 \( \mu \text{d} \) and 0.06 \( \mu \text{d} \) (courtesy of Ritu Sarkar). This is a relatively
Figure 3.7 Results of the porosity measurements in the RTC #1 core, Woodford shale. Core porosity ranges between 0 and 0.145 with an average of 0.04. It shows three distinct trends; it increases with depth between 12,740 ft and 12,850 ft, then decreases between 12,850 and 13,000 ft and increases again with respect to depth between 13,000 ft and 13,100 ft.

A tight formation compared to the Fort Worth Basin Barnett Shale, east Texas, that displays permeabilities in the range of 0.1 - 0.6 μd (Du et al. 2009) and the Appalachian Basin Marcellus Shale which shows permeabilities in the range of 20 μd (Soeder 1988).

3.1.5 Density

The densities of all core samples were recorded by a simple basic procedure. First the sample was weighed, and then its bulk volume was measured in the same way as in the porosity measurements. Once the weight
and the bulk volume of a given sample were recorded, its density was calculated using Equation 3.3:

$$\rho = \frac{W}{V_b}$$  \hspace{1cm} (3.3)

Where:
- \(W\) = weight, g
- \(V_b\) = bulk volume, cc
- \(\rho\) = density, g/cc

Figure 3.8 shows the 146 density measurements recorded across the entire RTC #1 Woodford core section. Note that the circled data points are off the density ranges (outliers). This is due to the fact that the core samples that those data points represent were very small and their volumes were not easy to read on the beaker. The density of the RTC #1 Woodford Shale core ranges between 2.2 g/cc and 2.7 g/cc. Even though the data seems to be scattered, there is still a slight increasing trend of density with respect to core depth.

### 3.1.6 Core Mechanical Properties

The mechanical properties of any rock consist of its Young’s modulus (E), Poisson’s ratio (v), bulk modulus (K) and shear modulus (G). However, as discussed earlier, the two most important properties related to hydraulic fracturing are Young’s modulus and Poisson’s ratio. These two characteristics best describe the likelihood of a rock to fail under stress (strong or weak rock) and the type of failure that the rock is likely to experience (elastic or plastic). The above mechanical properties can all be calculated, provided that density and acoustic velocities are available, using Equations 3.4 – 3.7 (Miskimins 2008):
Figure 3.8 Results of the density measurements in the RTC #1 core, Woodford shale. Notice the circled measurements are off from the density trend. This is due to the fact that the core samples that those data points represent were very small and their volumes were not easy to read on the beaker. Even though the data seems to be scattered, there is still a slight increasing trend of density with respect to core depth.

\[ E = 0.0001450 \times \rho V_p^2 \left[ \frac{3V_p^2 - 4V_s^2}{V_p^2 - V_s^2} \right] \]  

(3.4)

\[ \nu = \frac{0.0001450}{2} \left[ \frac{V_p^2 - 2V_s^2}{V_p^2 - V_s^2} \right] \]  

(3.5)

\[ G = 0.0001450 \times \rho V_s^2 \]  

(3.6)

\[ K = 0.0001450 \times \rho \left( V_p^2 - \frac{4}{3} V_s^2 \right) \]  

(3.7)
Where:

\[
\begin{align*}
E & = \text{Young's modulus, psi} \\
\nu & = \text{Poisson's ratio, dimensionless} \\
G & = \text{shear modulus, psi} \\
K & = \text{bulk modulus, psi} \\
\rho & = \text{density of the rock, kg/m}^3 \\
V_p & = \text{compressional wave velocity, m/s} \\
V_s & = \text{shear wave velocity, m/s} \\
0.000145 & = \text{Conversion factor, from Pascal to psi}
\end{align*}
\]

Figures 3.9 and 3.10 show the Young’s modulus and Poisson’s ratio, respectively, calculated from the RTC #1 Woodford core acoustic and density measurements. Young’s modulus ranges between $6 \times 10^6$ psi – $2.6 \times 10^7$ psi and Poisson’s ratio between 0.05 – 0.36. Young’s modulus shows two slightly decreasing trends with respect to core depth between 12,750 ft - 12,900 ft and 12,900 ft - 13,000 ft, and an increasing trend below 13,000 ft. Poisson’s ratio does not show any distinctive trend with respect to depth.

### 3.2 Well Log Data

The well log data available for this study consist of a wide array of conventional open hole logs; caliper, photoelectric, wellbore temperature, gamma ray, spectral gamma ray, resistivity, bulk density and neutron, and a dipole sonic recorded in RTC #1. The sonic log was run separately from the other logs and stopped at 13,000 ft while the other logs stopped at 13,209 ft. Given the fact that the lower part of the Woodford extends well below 13,000 ft and the RTC #1 was perforated and an injection test was performed in this zone (below 13,000 ft), determining the mechanical properties for this lower part of the Woodford is crucial for this study. Thus, it was necessary to reconstruct the sonic log for the depths below 13,000 ft.
Figure 3.9 Woodford shale core, RTC #1, Young's modulus determined using acoustic data from the handheld velocity probe and the density measurements. Young's modulus ranges between $6 \times 10^5$ psi – $2.6 \times 10^7$ psi. Young's modulus shows a slightly decreasing trend with respect to core depth between 12,750 and 13,000 ft and an increasing trend below 13,000 ft.
Figure 3.10  Woodford shale core, RTC #1, Poisson's ratio determined using acoustic data from the handheld velocity probe. Poisson's ratio ranges between 0.05 – 0.36. Poisson's ratio does not show any distinctive trend with respect to depth.
3.2.1 Reconstruction of the Sonic Log

The reconstruction of the sonic log for the region below 13,000 ft was carried out by regression analysis. Since the sonic log was run separately from the other logs, it was first necessary to verify the depth shift between the two runs (Figure 3.11). Then, a series of cross-plots of the sonic log with the other available logs, for the part above 13,000 ft, were plotted to determine which logs correlated best with the sonic log (see Appendix D, Log Mechanical Properties.xls). Finally, the chosen logs along with the sonic log were introduced into a statistical software (Minitab) and the regression equations for compression travel time (\(\Delta t_c\)) and shear travel time (\(\Delta t_s\)) were generated:

![Gamma Ray (API) vs Depth (ft)](image)

Figure 3.11 Comparison of the GR from the first logging run to the GR from the sonic log for the RTC #1 showing no depth shift between the two runs.
\[ \Delta t_p = 73.2 + 84.9 \Phi_N + 0.7977 \Phi_x - 2.24 PE - 340 K - 255 RLA0 - 13 \Phi_D + 0.0454 GR - 0.257 U - 0.37 R_{mud} \]
\[ S = 3.2, R^2 = 88.5\% \]  \hfill (3.8)

\[ \Delta t_s = 128 + 1.727 \Phi_x + 153 \Phi_N - 239 RLA0 - 1329 R_{mud} - 233 K - 2.53 PE - 0.0488 GR - 14.8 \Phi_D + 0.251 U \]
\[ S = 7.99, R^2 = 76.9\% \]  \hfill (3.9)

Where:

- **PE** = photo electric effect
- **GR** = standard resolution gamma ray
- **\( \Phi_N \)** = high resolution thermal neutron porosity
- **\( \Phi_D \)** = standard resolution density porosity
- **\( R_{mud} \)** = mud resistivity
- **RLA0** = shallow resistivity
- **Th** = thorium from spectral gamma ray
- **K** = potassium from spectral gamma ray
- **U** = uranium from spectral gamma ray

Although the regression equations are not a perfect match for the sonic log recorded, they still are a fair approximation which will help understanding the behavior of the mechanical properties of the Woodford below the 13,000 ft region. The results of this correlation are shown in Figure 3.12. The sonic travel times decrease between 12,750 ft and 12,780 ft then increases between 12,780 ft and 13,050 ft, responding to the core clay content variations (Mnich, 2009). \( \Phi_N \) and Th content were found most correlated with the sonic travel times. The \( R^2 \) of the correlations (\( \Phi_N + \) Th content .vs. \( \Delta t_p \)) and (\( \Phi_N + \) Th content .vs. \( \Delta t_s \)) were 0.8 and 0.7, respectively. Notice the systematic error between the sonic log travel times and the calculated travel times in the zone between 12,620 ft and 12,780 ft. After investigation, the caliper log showed a dramatic change in the well diameter (Figure 3.13), indicating that the systematic error is most likely due to borehole conditions in that particular region.
Figure 3.12 Comparison of the sonic log against the reconstructed sonic log for RTC #1 showing a close match between the two logs. Notice the systematic error between the sonic log travel times and the calculated travel times in the zone between 12,620 ft and 12,780 ft.
Figure 3.13 Caliper and gamma ray logs in the RTC #1 well. Notice the dramatic change in the well diameter between 12,400 ft and 12,780 ft.
3.2.2 Log Mechanical Properties

After the sonic log was reconstructed for the lower part of the Woodford, the Young’s modulus and the Poisson’s ratio were calculated using Equations 3.4 and 3.5, respectively, mentioned earlier in Section 3.1.6. Figures 3.14 and 3.15 show those results. Notice, in Figure 3.12, that E decreases with respect to depth between 12,750 ft and 13,000 ft then increases with respect to depth between 13,000 ft to 13,100 ft. Notice, in Figure 3.13, that \( v \) displays several trends with respect to depth. It decreases between 12,750 ft and 12,850, increases between 12,850 ft and 12,910 ft, decreases again between 12,910 and 13,000, increases for a second time between 13,000 ft and 13,050 ft and finally decreases below 13,050 ft.

3.3 Comparison of Log-Derived and Core-Derived Acoustic Velocities and Mechanical Properties

Before a comparison between the log and the core acoustic and mechanical properties data could be carried out, a core-to-log depth shift needed to be determined. This was performed by Pioneer Natural Resources by plotting the core gamma ray and the log gamma ray together and the depth shift between the two curves was recorded. It is worth noting that the Woodford core was taken in seven different sections resulting in seven different depth shifts corresponding to each section (Table 3.2).

Once the core to log depth shift was determined, the core data and the log data are plotted together (Figures 3.16 - 3.18).

It can be seen in Figure 3.16 that the core shear velocity behaves in two distinct ways when compared to the log shear velocity. Above 13,000 ft, the core \( V_s \) is almost always lower than the log \( V_s \), whereas, below 13,000 ft, the core \( V_s \) is frequently higher than the log \( V_s \). The same remarks could be made about the compression velocity but with less magnitude. This behavior of the core shear
Figure 3.14 Log derived Young’s modulus (E) for RTC #1 from 12,000 ft to 13,150 ft. Notice that E decreases with respect to depth between 12,750 ft and 13,000 ft then increases with respect to depth from 13,000 ft to 13,100 ft.
Figure 3.15 Log derived Poisson's ratio ($v$) for RTC #1 from 12,000 ft to 13,150 ft. Notice that $v$ decreases with respect to depth between 12,750 ft and 12,850 ft then increases with respect to depth from 12,850 ft to 12,910 ft. It decreases again between 12,910 and 13,000 and increases once more between 13,000 ft and 13,040 ft, and finally decreases below 13,050 ft.
Table 3.2 Individual Woodford Core Sections Depth Shift
(courtesy of Pioneer Natural Resources)

<table>
<thead>
<tr>
<th>Core #</th>
<th>Top of Core Section (ft)</th>
<th>Bottom of Core Section (ft)</th>
<th>Log Shift (ft)</th>
<th>Corresponding Log Top (ft)</th>
<th>Corresponding Log Bottom (ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>12758</td>
<td>12778.8</td>
<td>+22.42</td>
<td>12780.42</td>
<td>12801.22</td>
</tr>
<tr>
<td>10</td>
<td>12766</td>
<td>12647.1</td>
<td>+21.75</td>
<td>12607.75</td>
<td>12668.85</td>
</tr>
<tr>
<td>11</td>
<td>12846</td>
<td>12908.2</td>
<td>+23.58</td>
<td>12869.58</td>
<td>12931.78</td>
</tr>
<tr>
<td>12</td>
<td>12908</td>
<td>12935</td>
<td>+21.42</td>
<td>12929.42</td>
<td>12956.42</td>
</tr>
<tr>
<td>13</td>
<td>12938</td>
<td>12998</td>
<td>+24.25</td>
<td>12962.25</td>
<td>13022.25</td>
</tr>
<tr>
<td>14</td>
<td>12998</td>
<td>13043.8</td>
<td>+23.25</td>
<td>13021.25</td>
<td>13067.05</td>
</tr>
<tr>
<td>15</td>
<td>13090</td>
<td>13100.15</td>
<td>24.04</td>
<td>13114.04</td>
<td>13124.19</td>
</tr>
</tbody>
</table>

+: Depth added to core depth to bring to coincidence with log depth

Figure 3.16 Log and core acoustic velocities in the RTC #1 well, Woodford shale.
Figure 3.17 Log and core calculated Young’s modulus and Poisson’s ratio for the RTC #1 well, Woodford shale. Note that core-derived Young’s modulus is slightly higher than the log derived Young’s modulus throughout the entire Woodford Shale.

velocity suggests that the zone below 13,000 ft is less affected by the pressure release, resulting from taking the core out of the deep formation, compared to the zones above 13,000 ft.

Figures 3.17 and 3.18 further emphasize the results suggested by Figure 3.16. The core-derived Young’s modulus, which is predominantly influenced by compression velocity, is slightly higher than the log-derived Young’s modulus throughout the entire Woodford Shale. The slight difference noted could be due to many factors; borehole conditions, borehole temperature, pore pressure, pore fluid saturation (Barree et al., 2009), scale difference between log and core data, and, most likely, pressure release. It is also important to note that the core Poisson’s ratio is most often higher than the log-derived Poisson’s ratio, up to two times higher in some cases. It has also a distinctive behavior from $V_p$ and $V_s$. 

47
Figure 3.18 Log and core calculated Young's modulus and Poisson’s ratio for the RTC #1 well, Woodford shale. Note that the core Poisson’s ratio is most often higher than the log-derived Poisson’s ratio, up to two times higher in some cases.

agreeing with Eq. 3.5 that suggests that Poisson’s ratio is influenced by $V_p/V_s$ rather than $V_p$ or $V_s$ alone.

In order to confirm that the distinctive behavior of the core shear velocity when compared to the log shear velocity is not the consequence of the sonic log reconstruction in the zone below 13,000 ft, the regression sonic log for the entire core section was used in the core-to-log shear velocities comparison. The same remarks made about the core shear velocity still hold true confirming that the reconstruction of the sonic log for the region below 13,000 ft does not influence the conclusions already made.
CHAPTER 4
FORMATION EVALUATION

Formation evaluation is basically the determination of the ability of producing hydrocarbons from a certain formation. This is accomplished by investigating several different questions; 1) what are the amounts of hydrocarbons in the formation? 2) What is the water saturation of the formation? 3) What is the porosity and permeability of the formation? However, the answers to the previous questions are not straightforward. It is rather an indirect way that includes several steps leading to the characterization of the formation.

In shale gas reservoirs, the steps required for a sound formation evaluation are mainly: 1) determination of shale volume and clay volume, 2) estimation of TOC, 3) calculation of porosity and water saturation, 4) evaluation of permeability, and 5) determination of the gas content of the formation. In this study, permeability and gas content are not taken into consideration due to the lack of data necessary to properly estimate those two parameters.

4.1 Shale Volume

Shale volume is an essential parameter for formation evaluation of any kind of reservoir, conventional or unconventional. In conventional reservoirs, $V_{sh}$ is the parameter that differentiates potential reservoir zones from non-reservoir ones; zones with low shale volume are more likely to be considered as completion targets. However, in shale gas reservoirs, that model does not hold true. $V_{sh}$, in shale gas reservoirs, is most likely to be very high, but these formations are targeted for gas production.

$V_{sh}$ is usually positively correlated to the radioactivity of the formation measured by gamma ray logs. The radioactivity of a formation is due to many factors but primarily to its uranium, thorium and potassium content. Uranium is
usually related to the organic matter and precipitated salts, thorium is related to clays, and potassium is associated with potassium-feldspars, salts, and to some clays (Barree et al. 2009). In shale gas reservoirs with low clay content, as in the case of the Woodford shale of west Texas and southeast New Mexico, high gamma ray readings are associated with the uranium content that is in turn an indication of organic matter (Mnich 2009). Therefore, calculated shale volume may be taken as an indication of an organic-rich zone that is a potential gas reservoir. Figure 4.1 compares a standard gamma ray reading and uranium, thorium and potassium readings in the RTC #1 of the Woodford shale of west Texas and southeast New Mexico. Note that even though Th-GR correlation ($R^2=0.18$) is influenced by some outliers, it is still weak compared to U-GR correlation ($R^2=0.96$) indicating organic matter richness and low clay content, respectively.

Many methods have been developed for $V_{sh}$ estimation. The application of one specific method in a particular area will often depend on the geology of that area. The Woodford shale of west Texas and southeast New Mexico is from the Devonian, Paleozoic era, therefore it can be considered as an old rock (Ball, 1995). The most widely used method to estimate $V_{sh}$ of such formations, and the one used in this study, is that of Stieber (1975) and is given by Equation 4.1 (Asquith 1989). Figure 4.2 summarizes the results of the calculations.

$$V_{sh} = 0.5 \frac{I}{1.5 - I}$$

(4.1)

Where:

$$I = \frac{GR_{log} - GR_{cl}}{GR_{sh} - GR_{cl}}$$

$GR_{log} =$ well log gamma ray reading in API

$GR_{cl} =$ 26 API; gamma ray reading of a clean zone, 0% shale, in the Woodford Shale (13,064 – 13,067 ft)

$GR_{sh} =$ 410 API; gamma ray reading of 100% shale zone in the Woodford Shale (12,944 – 12,950 ft)
Figure 4.1 Cross-plot of gamma ray (HNGS GR) with uranium (U), thorium (Th) and potassium (K) contents in RTC #1, Woodford shale. The left y-axis representing K, the right y-axis representing U and Th, and the x-axis representing HNGS GR. Even though Th-GR correlation ($R^2=0.18$) is influenced by some outliers, it is still weak compared to U-GR correlation ($R^2=0.96$) indicating organic matter richness and low clay content, respectively.

It is important to mention that in Figure 4.2 the highest degree of shaliness is not necessarily indicative of the richest region in organic matter. Note that the two peaks in shale volume are located between 12,850 ft – 12,900 ft and 13,000 – 13,050 ft. Based on the core mineralogy description performed by Mnich (2009) on the RTC #1 Woodford shale core, the regions between 12,850 ft – 12,900 ft and between 13,000 ft – 13,050 ft are characterized by relatively high clay content compared to the other zones of the well. Therefore, a close examination of the clay content in the well is crucial before relating $V_{sh}$ to organic matter richness of the formation.
Figure 4.2 Shale volume in RTC #1, Woodford shale, showing the highest degree of shaliness in the region from 13,000 ft – 13,050 ft using the Steiber correlation. Note the two peaks in shale volume between 12,850 ft – 12,900 ft and 13,000 – 13,050 ft coinciding the peaks in core clay content described by Mnich (2009).

4.2 Clay Volume

After determining $V_{sh}$, estimating the clay volume ($V_{cl}$) in a formation is the next step. This parameter will help distinguish between organic matter-rich zones from clay-rich zones. Harvey and Tracy (1996) stated that whenever a spectral gamma ray log is available, the gamma ray curve corrected for uranium, often called computed gamma ray (CGR), should be used for $V_{cl}$ calculations using Equation 4.2. However, the results given by this method need to be calibrated to the core data of the specific formation. This is due to the fact that the most clay-rich zones of the reservoir, as is the case in the Woodford, do not necessarily have 100% clay. Therefore, in this study, a coefficient factor was introduced based on the core mineralogy of the Woodford resulting in Equation 4.3. This
coefficient represents the maximum clay content in the Woodford, which is 0.37 vol\% (Mnich 2009).

\[ V_{cl} = 0.33 \left( 2^{(2t)} - 1 \right) \]  

(4.2)

\[ V_{cl} = 0.37 \times 0.33 \left( 2^{(2t)} - 1 \right) \]  

(4.3)

Where:

\[ I = \frac{CGR_{\text{log}} - CGR_{\text{clean}}}{CGR_{\text{sh}} - CGR_{\text{clean}}} \]

CGR\text{log} = computed gamma ray reading  
CGR\text{cl} = computed gamma ray reading of a clean zone, 0\% clay  
CGR\text{sh} = computed gamma ray reading of 100\% clay  
0.37 = coefficient factor representing the maximum core clay volume in the Woodford core (Mnich 2009).

Before the computed gamma ray can be calculated, uranium, thorium and potassium curves need to be scaled to API units. Several factors for scaling the previous cited curves are available in the literature. For this case the factors used are from Barree et al. (2009):

\[ Th(API) = Th(ppm) \times 4 \]

\[ U(API) = U(ppm) \times 8 \]

\[ K(API) = K(ppm) \times 1500 \]

CGR is then calculated using Equation 4.3:

\[ CGR = Th(API) + k(API) \]  

(4.3)
Since core mineralogy was available, regression analysis was used to estimate $V_{cl}$ as well. The regression equation was derived from the core clay content (Mnich 2009) and clay indicator well logs (GR, k, Th, and $\Phi_N$). The results of the regression analysis suggest that $V_{cl}$ is given by the following equation:

$$V_{cl} = -4.98 + 45.5\Phi_N - 0.00425GR + 665k + 0.789Th$$

$$R^2 = 79.4\%$$

(4.4)

Where:

- GR = standard gamma ray, API
- $\Phi_N$ = neutron porosity
- K = potassium concentration, CF/CF
- Th = thorium content, ppm

Figure 4.3 is a comparison of core $V_{cl}$ (Mnich 2009) and CGR method $V_{cl}$ and regression analysis $V_{cl}$. Clay volumes determined from CGR method and regression analysis are both very similar to core clay volume. However, the drawback of those methods is they both need a prior knowledge of the mineralogy of the formation. Note the two peaks in clay content between 12,850 ft – 12,875 ft and 13,000 – 13,025 ft that correspond to the two peaks in shale volume seen in Figure 4.3.

4.3 Total Organic Carbon

High TOC content is one of the parameters that distinguishes shale gas reservoirs from conventional reservoirs. Since organic carbon is characterized by very low density compared to the formation matrix, its estimation is critical to the correction of the density porosity. In this study the method used to estimate TOC is the $\Delta$ Log R Technique (Passey et al. 1990). This technique has been chosen
Figure 4.3 Core $V_{cl}$ compared to CGR $V_{cl}$ and regression analysis $V_{cl}$ in RTC #1, Woodford shale. Notice that although $V_{cl}$ derived from regression analysis best matches the core $V_{cl}$, CGR derived $V_{cl}$ is also a very good approximation. Note the two peaks in clay content between 12,850 ft – 12,875 ft and 13,000 – 13,025 ft that correspond to the two peaks in shale volume seen in Figure 4.3.
based on the fact that it does not need any core data. Even though core data are available for RTC #1, using this method here is an opportunity to evaluate its reliability in the Woodford shale of west Texas and south east New Mexico.

4.3.1 $\Delta \log R$ Technique (Passey et al. 1990)

In this technique, Passey et al. take advantage of the specific signatures of organic matter on the porosity logs (usually the sonic travel time) and the deep resistivity log. The method consists of overlaying the sonic travel time curve, or any other porosity log, over the deep resistivity curve in a specially scaled graph. The graph is scaled so the response of the sonic log and the deep resistivity log increase in opposite directions and overlay each other in a clean, water saturated zone of the well. Passey et al. (1990) state that, since the sonic log responds to the density and fluids of the formation and the deep resistivity log responds primarily to the formation fluids, the two curves will overlay each other in a clean water saturated zone, but in an organic-rich zone, the two curves will separate. The separation of the two curves is caused by the low density of the organic matter and, in the presence of hydrocarbons, to the pore fluids as well.

TOC values from this method are obtained in two steps that are summarized in Equations 4.5 and 4.6:

$$\Delta \log R = \log_{10}\left(\frac{R}{R_{\text{baseline}}}\right) + 0.02(\Delta t - \Delta t_{\text{baseline}})$$ \hspace{1cm} (4.5)

$$TOC(\text{wt\%}) = (\Delta \log R)10^{(2.257-0.1088xLOM)}$$ \hspace{1cm} (4.6)

Where:

- $R$ = deep resistivity, Ohm-m
- $R_{\text{baseline}}$ = deep resistivity of the overlay zone, Ohm-m
- $\Delta t$ = sonic travel time, $\mu s/ft$
\[ \Delta t_{\text{baseline}} \] = sonic travel time of the overlay zone, \( \mu s/\text{ft} \)

LOM = level of metamorphism that depends on the maturity of the kerogen

Mullen et al. (2007) suggested Equation 4.7 to approximate LOM:

\[ LOM = R_o \times 4.76 + 4.09 \]  \hspace{1cm} (4.7)

Where:

\( R_o = 1.35\% \); thermal maturity of the Woodford kerogen (Mnich 2009)

Figure 4.4 is a comparison of the \( \Delta \log R \) technique results to the Woodford core TOC. The core depths have been shifted. The calculated TOC follows the trend of the core TOC except for the upper Woodford and the lowest part of the lower Woodford where there is an overestimation of TOC. However it is still a good match based on the fact that no core data were used in the calculation method.

Note that the lowest TOC is situated between 13,000 ft and 13,025 ft.

### 4.4 Porosity

Density porosity is the type of measured porosity that is considered in this study, because it is the least influenced by clay content and pore fluids. It is however, strongly influenced by TOC and pyrite content. Organic carbon has very low density, about 1.2 – 1.4 g/cc, therefore increasing the density porosity, whereas pyrite has a very high density, about 5 g/cc, resulting in an underestimation of the density porosity. The only correction that was taken in consideration, in this study, is with regard to TOC and that is accomplished by solving Equation 4.8 (Utley 2005) for porosity in Equation 4.9.
Figure 4.4 Δ Log R technique derived TOC averaged over 3 ft compared to the Woodford core TOC in RTC #1. It can be clearly seen that TOC from the Δ Log R technique matches the core TOC except for the upper unit and lower part of the lower unit of the Woodford. Note that the lowest calculated TOC is situated between 13,000 ft and 13,025 ft.
\[ \rho_{\text{log}} = \rho_{\text{matrix}} (1 - \phi - V_{\text{TOC}}) + \rho_{\text{fluid}} \phi + \rho_{\text{TOC}} V_{\text{TOC}} \]  \hspace{1cm} (4.8)

\[ \phi = \frac{\rho_{\text{matrix}} - \rho_{\text{log}} \left( \frac{\rho_{\text{matrix}} V_{\text{TOC}}}{\rho_{\text{TOC}}} - \frac{V_{\text{TOC}}}{1} + 1 \right)}{\rho_{\text{matrix}} - \rho_{\text{fluid}}} \]  \hspace{1cm} (4.9)

Where:

- \( \rho_{\text{log}} \) = log density, g/cc
- \( \phi \) = porosity, fraction
- \( \rho_{\text{matrix}} \) = matrix density, 2.71 g/cc
- \( V_{\text{TOC}} \) = volume fraction of TOC
- \( \rho_{\text{TOC}} \) = formation density, g/cc
- \( \rho_{\text{TOC}} \) = TOC density, 1.2 g/cc

The results of the TOC-corrected density porosity calculations are compared to the measured core porosity and the non-corrected log porosity in RTC #1 (Figure 4.5). It can be noticed that TOC-corrected density porosity is in the same range as core porosity. The difference between the three porosities is almost inexistent in the zone between 13,000 ft – 13,050 ft, implying very low TOC in this region which is consistent with core TOC (Mnich 2009) and log TOC values.

### 4.5 Water Saturation

Formation water saturation determination is based on the relationship that exists between the true resistivity (\( R_i \)) of a formation and its water saturation (\( S_w \)). Archie’s equation (1942), Eq. 4.10, relates those two parameters for clean, water-saturated sands. The basis of Archie’s equation is that in clean sands, the formation water is the only conductor. Therefore, the true resistivity of the formation can be directly related to the water saturation in the formation. However, in shale gas reservoirs, Archie’s equation requires some modifications
Figure 4.5 TOC-corrected log porosity compared to core porosity and non-corrected log porosity in RTC #1, Woodford shale. Notice that TOC-corrected density porosity is in the same range as core porosity and the absence of separation between the TOC corrected log porosity and non-corrected log porosity in the region 13,000 ft – 13,050 ft indicating low TOC in this zone.
to account for the shaliness of the reservoirs, because in shale gas reservoirs clays and their bound water contribute to the shale conductance as well. To account for those differences between clean sand and shale gas reservoirs, the reservoir should be considered as two mediums; clay-free matrix and clay with its associated water. Therefore the resistivity model should account for those two mediums separately. Simandoux (1963) introduced Equation 4.11 as the water saturation equation appropriate for shaly formations.

\[
\frac{1}{R_t} = \frac{\phi^m S_w^N}{a R_w} \quad \text{(4.10)}
\]

\[
\frac{1}{R_t} = \frac{\phi^m S_w^N}{a R_w} + \frac{V_{sh} S_w}{R_{sh}} \quad \text{(4.11)}
\]

Where:
- \( R_t \) = formation true resistivity, Ohm-m
- \( S_w \) = formation water saturation
- \( \Phi \) = TOC corrected formation porosity
- \( m \) = formation cementation exponent
- \( a \) = formation tortuosity factor
- \( N \) = saturation exponent
- \( V_{sh} \) = shale volume
- \( R_{sh} \) = shale resistivity, 80 Ohm-m
- \( R_w \) = connate water resistivity, Ohm-m

For the calculation of \( S_w \), assumptions needed to be made about the formation cementation exponent (\( m \)), formation tortuosity factor (\( a \)) and the saturation exponent (\( N \)). The values of these parameters used in the calculation, cited below, have been proven to be good approximations in numerous cases where the measured values were not available (Prasad 2008).
\[ m = 2 \]
\[ a = 1 \]
\[ N = 2 \]

Figure 4.6 shows the results of the water saturation calculated with Simandoux’s equation compared to the water saturation calculated with Archie’s equation, and the true resistivity of the Woodford shale in RTC #1. Notice that \( S_w \) calculated with Simandoux’s equation displays a consistent opposite trend compared to the true resistivity. \( S_w \) calculated with Archie’s equation is always higher than the Simandoux water saturation and fails to follow an opposite trend with respect to the true resistivity in the region between 12,850 ft – 12900 ft.
Figure 4.6 Comparison of $S_w$ from Simandoux (1963) and $S_w$ from Archie (1942) and the true resistivity of the formation in RTC #1, Woodford shale. The results were averaged over 5 ft for smoothness. Notice that $S_w$ calculated with Simandoux’s equation displays a consistent opposite trend compared to the true resistivity. Besides the fact that it is always higher than the Simandoux water saturation, $S_w$ calculated with Archie’s equation fails to follow an opposite trend with respect to the true resistivity in the region between 12,850 ft – 12900 ft.
CHAPTER 5
DATA ANALYSIS

The main goal of this study is to determine which mineral components (quartz, clay, carbonates, pyrite, etc.) of the Woodford shale have the most influence on the mechanical properties of the formation and in what manner (i.e. impede or facilitate hydraulic fracturing). This goal was partly achieved by using three different statistical methods available in the Minitab statistical software. The three statistical methods that were considered are:

- **Factor Analysis**: The main applications of factor analytic techniques are: (1) to reduce the number of variables and (2) to detect structure in the relationships between variables, that is to classify variables. Therefore, factor analysis is applied as a data reduction or structure detection method (http://www.statsoft.com/textbook/stfacan.html);

- **Hierarchical Cluster Analysis**: is an exploratory data analysis tool which aims at sorting different objects (e.g. individual samples) into groups in a way that the degree of association between two objects is maximal if they belong to the same group and minimal otherwise. Cluster analysis simply discovers structures in data without explaining why they exist (http://www.statsoft.com/textbook/stcluan.html);

- **Multivariate Regression**: Regression is a generic term for all methods attempting to fit a model to observed data in order to quantify the relationship between two groups of variables. Multivariate regression takes into account several predictive variables simultaneously, thus modeling the property of interest with more accuracy (http://www.camo.com/rt/Resources/statistical-regression-analysis.html)
The different elements integrated in the statistical analysis include: formation density (Rho), TOC, V_p, V_s, E, v, G, K, the following minerals: quartz, dolomite, calcite, pyrite, albite, orthoclase, apatite, magnesite, norsethite, illite, muscovite (Mnich, 2009); and the following geochemical components: (SiO_2), (Al_2O_3), (Fe_2O_3), (MgO), (CaO), (Na_2O), (K_2O), (TiO_2), (P_2O_5), (LOI), (Ba), (Sr), (TotC), (TotS), (Zn), (Mo) and (Ni) (Mnich 2009). Because only 72 of the 166 samples considered had all the data required for the analysis, only those samples were taken into consideration in the statistical analysis. Fortunately, the 72 samples available for the statistical analysis are representative of the entire Woodford shale. A detailed description of the 72 samples can be found in Appendix E.

5.1 Investigation of the Reliability of the Data Generated

Throughout this study, two data sets were generated; well log data (density, sonic velocities and mechanical properties) and core data (density, acoustic velocities, mechanical properties, mineralogy and geochemistry (Mnich 2009). An investigation of the reliability of these data sets was necessary so the most reliable one could be chosen for the statistical analysis. This check was carried out on the basis of some expectations: since TOC is very abundant in the Woodford and has very low density, and quartz is the predominant mineral in most parts of the Woodford Shale, density should be most influenced by TOC and quartz. Cross-plots of formation density versus TOC and quartz content were constructed with both log and core data and the R^2 of the correlations were investigated. The results of this investigation are displayed in Table 5.1.

Table 5.1 Results of the R square Investigation of the Cross-plots of Log Density and Core density with Quartz and TOC

<table>
<thead>
<tr>
<th></th>
<th>R square</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Core formation density</td>
</tr>
<tr>
<td>Quartz</td>
<td>0.002</td>
</tr>
<tr>
<td>TOC</td>
<td>0.009</td>
</tr>
</tbody>
</table>
It can be clearly seen in Table 5.1 that although neither correlation is very strong, the log density is more representative of the mineralogy of the Woodford that is quartz-rich and TOC abundant. Also, as already mentioned in Chapter 3, the measured core $V_s$ and $V_p$ were different from the in-situ $V_s$ and $V_p$ recorded by the log. This difference resulted in dissimilarity between the core mechanical properties calculated from measurements made under surface conditions the log mechanical properties derived from measurements recorded under in-situ conditions. Although, the in-situ mechanical properties have the issue of scale related to them, they are not pinpoint measurements; it is understood they are more representative of the in-situ conditions. Therefore the log data were chosen as the most appropriate dataset for the statistical analysis.

5.2 Results of Factor Analysis

Factor analysis was carried out to reduce the number of variables by grouping those variables based on their degree of association, i.e. two variables that are correlated are likely to be included in the same factor. Therefore the word factor can be defined as a group of variables that are statistically correlated. The maximum number of factors that can be extracted from a dataset is equal to the total number of variables. However, this would not help in the reduction of the number of variables which is one of the main objectives of factor analysis. Therefore the optimal number of factors to be extracted corresponds to the factors that explain most of the variance (eigenvalue) in the data, and adding another factor to those factors will not result in a significant change in the total variance explained by the factors.

Factor analysis was carried out for two different datasets; the first dataset includes the density, TOC, acoustic velocities and the mineralogy of the 72 core samples, and the second dataset includes the mechanical properties, TOC and the mineralogy of the 72 core samples. The reason behind separating the density and acoustic velocities from the mechanical properties in this analysis is to avoid
any redundancy that can be caused by the fact that the mechanical properties
were calculated from density and acoustic velocities. The geochemical data were
left out of this analysis for the same reason, redundancy, because the mineralogy
was calculated based on the geochemical data (Mnich 2009).

5.2.1 Factor Analysis Results for the First Dataset (Density, Acoustic
Velocities, TOC and Mineralogy)

In the case of the second dataset that includes density, acoustic velocities,
TOC and mineralogy only, factor analysis identified thirteen factors that explained
97% of the variance in the data (Figure 5.1). As with the first dataset, the density
and acoustic velocities that are of interest in this study were present only in the
first two factors. Those two factors explained about 46% of the variance in the
data and were the ones investigated (Figure 5.2).

Factor 1 accounts for 26.5% of the variance in the total data set and is
negatively correlated with the acoustic velocities $V_p$ and $V_s$ with strong correlation
coefficients of -0.808 and -0.910, respectively. Quartz is also negatively
correlated with Factor 1 but with a much lower correlation coefficient of -0.505.
Illite and albite are both positively correlated with Factor 1 with a strong
correlation coefficient for illite, 0.908, and a fairly high correlation coefficient for
albite, 0.788. This association indicates that acoustic velocities generally
decrease as clay and feldspar contents increase.

Factor 2 accounts for 19.5% of the variance in the total data set and is
negatively correlated with density and the minerals dolomite and calcite.
Dolomite displays the highest correlation coefficient, with this factor, of -0.811
followed by density with a correlation coefficient of -0.780 and calcite with a
correlation coefficient of -0.731. Quartz and TOC are both positively correlated
with Factor 2 with respective correlation coefficients of 0.744 and 0.646.
Figure 5.1 Comparison of the number of factors to the variance (eigenvalue) in the data for the second dataset that includes density, acoustic velocities and mineralogy. Notice that variance in the data smooths out beyond a number of factors of 13. Also, note that there is only a small decrease in the Eigenvalue on addition of the fourth and higher factors, indicating that factor one through three contribute strongly to reducing variance.

<table>
<thead>
<tr>
<th>% Variance</th>
<th>Factor 1</th>
<th>Factor 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>26.5%</td>
<td></td>
<td>19.5%</td>
</tr>
</tbody>
</table>

| Illite  | 0.908    | Quartz  | 0.744    |
| Albite  | 0.788    | TOC     | 0.646    |
| Vs      | 0.910    | Dolomite| 0.811    |
| Vp      | 0.808    | Rho     | 0.780    |
| Quartz  | 0.505    | Calcite | 0.731    |

Figure 5.2 The first two factors, resulted from factor analysis, that contain the density and acoustic velocities. The two factors explain about 46% of the variance in the data. Correlation coefficients of each variable with its corresponding factor are shown. Correlation coefficients between -0.5 and 0.5 are ignored. The (+) sign represents the variables that are positively correlated with the factor and the (-) sign represents the variables negatively correlated with the factor.
5.2.2 Factor Analysis Results for the Second Dataset (Mechanical Properties, TOC and Mineralogy)

In the case of the second dataset that includes mechanical properties, TOC and mineralogy only, factor analysis identified thirteen factors that explained 97% of the variance in the data. However, the mechanical properties that are the core of this study were present only in the first two factors. Those two factors explained about 46% of the variance in the data and were the ones investigated to unveil the relationship between the mechanical properties and the mineralogy of the Woodford shale. Figure 5.3 illustrates the relationship between the number of factors and the variance (eigenvalue) in the data for the first dataset; and Figure 5.4 shows the two factors that contain the mechanical properties along with their variance, elements included in each factor and the correlation coefficient for each element. It is important to mention that correlation coefficients between -0.5 and 0.5 were not considered strong enough to be included in the analysis.

*Factor 1* accounts for 26.6% of the variance in the total data set and is negatively correlated with the mechanical properties E, K and G with strong correlation coefficients of -0.932, -0.876 and -0.757 respectively. It is also negatively correlated, but less strongly, with the minerals dolomite, -0.593, and calcite, -0.585. Illite, albite and TOC are all positively correlated with Factor 1 but with lower correlation coefficients, 0.542, 0.514 and 0.529, respectively.

*Factor 2* accounts for 19.8% of the variance in the total data set and is positively correlated with the mechanical property $\nu$ with a fairly high correlation coefficient of 0.744. It is also negatively correlated with the minerals illite and albite; Illite displaying a fairly strong correlation, as well, with Factor 2, 0.727, while albite shows a lower correlation coefficient of 0.592 with this factor. Quartz and TOC are both negatively correlated with Factor 2 with quartz being the most correlated element with Factor 2 with a correlation coefficient of -0.794 and TOC a less correlated element with this factor with a correlation coefficient of -0.505.
Figure 5.3 Comparison of the number of factors to the variance (eigenvalue) in the data for the second dataset that includes mechanical properties and mineralogy only. Notice that variance in the data smoothes out beyond a number of factors of 13, meaning that 13 is the optimal number of factors to be extracted. Also, note that there is only a small decrease in the Eigenvalue on addition of the fourth and higher factors, indicating that factor one through three contribute strongly to reducing variance.

<table>
<thead>
<tr>
<th>% Variance</th>
<th>Factor 1</th>
<th>Factor 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>26.6%</td>
<td>0.542</td>
<td>0.744</td>
</tr>
<tr>
<td>19.8%</td>
<td>0.529</td>
<td>0.727</td>
</tr>
<tr>
<td></td>
<td>Albite</td>
<td>Albite</td>
</tr>
<tr>
<td>0.514</td>
<td></td>
<td>0.592</td>
</tr>
<tr>
<td>Illite</td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOC</td>
<td>0.529</td>
<td></td>
</tr>
<tr>
<td>Albite</td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.514</td>
<td></td>
<td></td>
</tr>
<tr>
<td>E</td>
<td>0.932</td>
<td>Quartz</td>
</tr>
<tr>
<td>0.876</td>
<td></td>
<td>TOC</td>
</tr>
<tr>
<td>G</td>
<td>0.757</td>
<td>0.505</td>
</tr>
<tr>
<td>Dolomite</td>
<td>0.593</td>
<td></td>
</tr>
<tr>
<td>Calcite</td>
<td>0.585</td>
<td></td>
</tr>
</tbody>
</table>

Figure 5.4 The first two factors, resulted from factor analysis, that contain the mechanical properties. The two factors explain about 46% of the variance in the data. Correlation coefficients of each variable with its corresponding factor are shown. Correlation coefficients between -0.5 and 0.5 are ignored. The (+) sign represents the variables that are positively correlated with the factor and the (-) sign represents the variables negatively correlated with the factor. E=Young's modulus, K=bulk modulus, G=shear modulus, $\nu$ =Poisson's ratio.
5.3 Results of Hierarchical Cluster Analysis

While factor analysis groups the correlated variables together in factors, hierarchical cluster analysis groups the similar samples, core samples in the case of this study, together in clusters. This is extremely beneficial in identifying the different zones of the Woodford that are likely to behave similarly when subjected to hydraulic fracturing treatments.

Hierarchical cluster analysis was carried out with the mechanical properties (E, K, G, and $\nu$) of the 72 core samples. Ten distinct clusters that behave differently from each other have been identified. Figure 5.5 represents the 10 different clusters and the samples included in each cluster along with their similarity level, and Table 5.2 represents the distance from the cluster centroids of each petrophysical property in the different clusters. A cluster centroid of a given cluster represents the center of the cluster from which the distance of each variable, from that cluster, is calculated. The variables that are nearest to the cluster centroid, i.e., have the smallest values, of a certain cluster are more likely to be included in that particular cluster.

A close examination of the cluster analysis dendrogram (Figure 5.5) and the distance of the variables from the cluster centroids of each cluster (Table 5.2) gives insight on the hierarchy in which the clusters were formed and the reasons why each cluster was separated from another.

First, Clusters 10 and 3 were distinguished from the other clusters based on their high E ($>2.2\times10^7$ psi), K ($>4.8\times10^6$ psi) and G ($>3.3\times10^6$ psi). Those two clusters were then separated due to the low $\nu$, 0.19, associated with Cluster 3 compared to $\nu$, 0.22, associated with Cluster 10. Next, Cluster 2 was separated from the other clusters due to its relatively high G ($>3\times10^6$ psi). Cluster 7 was then identified based on its simultaneously low E ($<1.2\times10^7$ psi) and G ($<2\times10^6$ psi). After that, Clusters 9 and 8 were differentiated from the other clusters based on their relatively high $\nu$ (>0.2) and low G ($<1.55\times10^6$ psi). These two clusters were then separated due the relatively low K, 2.84$x10^6$ psi, associated with
Figure 5.5 Cluster analysis dendrogram showing how the 72 core samples of the Woodford shale are distributed throughout the clusters. Each cluster was identified according to the similarity level (on the left hand-side of the graph) of the core samples it includes. The x-axis represents the core samples numbers and the different clusters are numbered from 1 to 10.

Table 5.2 Distance of Each Variable From the Cluster Centroids of the Different Clusters

<table>
<thead>
<tr>
<th>Variable</th>
<th>Cluster1</th>
<th>Cluster2</th>
<th>Cluster3</th>
<th>Cluster4</th>
<th>Cluster5</th>
<th>Cluster6</th>
<th>Cluster7</th>
<th>Cluster8</th>
<th>Cluster9</th>
<th>Cluster10</th>
</tr>
</thead>
<tbody>
<tr>
<td>E (psi)</td>
<td>1.27</td>
<td>1.38</td>
<td>4.20</td>
<td>-0.31</td>
<td>0.56</td>
<td>0.55</td>
<td>-1.58</td>
<td>0.06</td>
<td>-0.56</td>
<td>3.95</td>
</tr>
<tr>
<td>G (psi)</td>
<td>0.72</td>
<td>1.74</td>
<td>3.70</td>
<td>-0.09</td>
<td>1.67</td>
<td>1.15</td>
<td>-1.96</td>
<td>-1.51</td>
<td>-1.80</td>
<td>2.50</td>
</tr>
<tr>
<td>v</td>
<td>0.87</td>
<td>0.02</td>
<td>1.09</td>
<td>-0.31</td>
<td>-0.55</td>
<td>-0.43</td>
<td>0.10</td>
<td>1.83</td>
<td>1.44</td>
<td>1.76</td>
</tr>
<tr>
<td>K (psi)</td>
<td>1.28</td>
<td>1.09</td>
<td>3.85</td>
<td>-0.34</td>
<td>0.16</td>
<td>0.29</td>
<td>-1.28</td>
<td>0.56</td>
<td>-0.10</td>
<td>3.96</td>
</tr>
</tbody>
</table>
Cluster 9 compared to K, \(>3 \times 10^6\) psi, in Cluster 8. Cluster 1 was identified based on its simultaneously high \(E\) (\(>1.65 \times 10^7\) psi) and \(K\) (\(>3.3 \times 10^6\) psi) while the other two parameters, \(\nu\) and \(G\), remained moderate. Cluster 5 was characterized by its high \(G\) (\(>3 \times 10^6\) psi) and low \(\nu\) (\(< 0.12\)) at the same time. Cluster 6 was distinguished from Cluster 4 due to its high \(K\) (\(>3 \times 10^6\) psi) and relatively low \(\nu\) (\(< 0.14\)). Finally, Cluster 4 is characterized by moderate mechanical properties; \(E\) (\(1.13 \times 10^7 - 1.6 \times 10^7\) psi), \(G\) (\(2.14 \times 10^6 - 2.85 \times 10^6\) psi), \(K\) (\(2.10 \times 10^6 - 3.33 \times 10^6\) psi), and \(\nu\) (0.07 – 0.2).

Figure 5.6 illustrates how the clusters are distributed throughout the Woodford shale. Cluster 4 is the most predominant cluster containing 54 of the 72 core samples and is mainly confined to the middle Woodford with few samples in the upper part of the lower Woodford and only one sample in the upper Woodford. Core samples included in this cluster are characterized by high quartz content (64 wt% on average) and fairly high TOC (5.3 wt% on average). Cluster 1 contains five core samples that are spread throughout the entire Woodford; two samples located in the upper Woodford, one sample in the middle Woodford and two samples in the lower Woodford. Those core samples are characterized by their moderate TOC (about 4 wt%). Clusters 2 and 3, containing two and one core samples respectively, are confined to the upper Woodford and are characterized by their relatively high apatite content (\(>8\) wt%). Clusters 5 and 6, containing one sample each, are contained to the middle Woodford. Cluster 5 is characterized by a relatively high dolomite content (31 wt%) and Cluster 6 is characterized by a relatively high TOC (6.55 wt%). Clusters 7, 8, 9 and 10 are all contained in the lower Woodford. They all contain one core sample each except for Cluster 8 that contains five core samples. Clusters 7, 8 and 9 are all characterized by high clay content (34 wt% on average) and very low TOC (2.8 wt% on average). Cluster 10 displays a very low TOC as well (1.25 wt%) with a very high dolomite content (81 wt%). Table 5.3 is a summary of the characteristics of the different clusters.
Figure 5.6 Distribution of the clusters throughout the Woodford formation in RTC #1. Notice that Cluster 4 is the most abundant cluster, and is mainly confined to the middle Woodford and the upper zone of the lower Woodford. The table on the right is a summary of the characteristics of each cluster.
### Table 5.3 Characteristics of the Different Clusters

<table>
<thead>
<tr>
<th>Cluster</th>
<th># Samples</th>
<th>Samples Location in the Woodford</th>
<th>Mechanical Properties Signatures</th>
<th>Mineralogy and/or TOC Signatures</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5</td>
<td>2 Upper/1 Middle/2 Lower</td>
<td>High E and K. Moderate G and v</td>
<td>Moderate TOC</td>
</tr>
<tr>
<td>2</td>
<td>2</td>
<td>2 Upper</td>
<td>Relatively high G</td>
<td>High apatite</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>1 Upper</td>
<td>High E, G and K. Moderate v</td>
<td>High apatite</td>
</tr>
<tr>
<td>4</td>
<td>54</td>
<td>1 Upper/48 Middle/5 Lower</td>
<td>Moderate E, G, K and v</td>
<td>High Quartz and fairly high TOC</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td>1 Middle</td>
<td>High G and low v</td>
<td>High dolomite</td>
</tr>
<tr>
<td>6</td>
<td>1</td>
<td>1 Middle</td>
<td>High K and low v</td>
<td>High TOC</td>
</tr>
<tr>
<td>7</td>
<td>1</td>
<td>1 Upper</td>
<td>Low E and G</td>
<td>High clay and low TOC</td>
</tr>
<tr>
<td>8</td>
<td>55</td>
<td>Lower</td>
<td>Relatively high v and low G</td>
<td>High clay and low TOC</td>
</tr>
<tr>
<td>9</td>
<td>1</td>
<td>1 Upper</td>
<td>Relatively high v, low G and K</td>
<td>High clay and low TOC</td>
</tr>
<tr>
<td>10</td>
<td>1</td>
<td>1 Upper</td>
<td>High E, G and K</td>
<td>Very high dolomite and very low TOC</td>
</tr>
</tbody>
</table>

E = Young's modulus  
G = Shear modulus  
K = Bulk modulus  
v = Poisson's ratio  

Since 54 of 72 the core samples fell into one cluster, Cluster 4, it was decided to redo the cluster analysis on those 54 core samples only. Figure 5.7 is the dendrogram resulted from cluster analysis on the 54 core samples included in Cluster 4 of the first cluster analysis and Figure 5.8 shows the distribution of the clusters and core samples throughout the formation. The high similarity level (>84%) of the different clusters resulted from the second cluster analysis confirms the results of the first cluster analysis that suggest that the 54 core samples have similar mechanical properties with only slight differences that are inherent to each core sample.
5.4 Results of the Stepwise Linear Regression Analysis

The main characteristic of stepwise linear regression, SLR, that sets it apart from regular regression analysis, is the capability of this technique to determine the best predictor variable or group of variables of another variable. SLR analysis was carried out using the mechanical properties, mineralogy, geochemistry and TOC, and also density for the case of Poisson’s ratio, to identify the mineral and/or geochemical elements that most influence the Young’s modulus, E, and the Poisson’s ratio, ν, of the formation. Note that in the case of predicting the group of minerals that is most correlated with the mechanical properties, the geochemical elements were not included to avoid any redundancy. Results of SLR analysis suggest the following:
Figure 5.8 Distribution of the clusters, resulted from cluster analysis on the core samples included in Cluster 4, throughout the Woodford formation.
Young's Modulus, $E$

On the scale of the entire Woodford formation, the best single predictors of $E$ were found to be the geochemical element CaO and TOC with respective $R^2$'s of 0.30 and 0.27. Although these correlation coefficients are not individually significant, they give an idea about the trend of the behavior of $E$ with respect to CaO and TOC (Figures 5.9 and 5.10). The group of minerals that was found to be best predictor of $E$ include: TOC, illite, apatite, calcite and magnesite. The regression equation relating $E$ to that group of elements is shown in Eq. 5.1. Figure 5.11 is a cross-plot of $E$ versus the result of the regression equation. Note the improved $R^2$ of 0.58.

$$E = -61333(TOC) - 58989(illite) + 217593(apatite) + 2235605(calcite) - 146070(magnesite)$$

$$R^2 = 0.58$$

Where TOC and mineral contents are in wt\%.

However, the investigation of the best single predictors of $E$ on the scale of the different units of the Woodford, upper, middle, and lower, showed different results. In the upper part of the Woodford, $E$ is most correlated with dolomite with $R^2=0.92$ (Figure 5.12), while in the middle part, the most correlated element with $E$ was found to be molybdenum, which is associated with TOC (Mnich 2009), with $R^2=0.25$ (Figure 5.13). It is important to note that despite the strong $R^2$, the few data points that were available in the Upper Woodford hinder any conclusions about the correlation between dolomite and $E$ from this analysis alone. In the lower unit, the geochemical element MgO, that is associated with dolomite, is most correlated with $E$, with $R^2=0.61$ (Figure 5.14). However, there are not any data points between 4% and 16% MgO, which hinders the understanding of the influence of small increments of MgO on $E$. 

78
Figure 5.9 Cross-plot of $E$ versus CaO in RTC#1, Woodford shale, showing an increase in $E$ with the increase of CaO, $R^2 = 0.3$. Notice that for CaO<15% the trend is not very clear and $E$ does not seem to be influenced by CaO.

Figure 5.10 Cross-plot of $E$ versus TOC in RTC#1, Woodford shale, showing an increase in $E$ with the decrease of TOC, $R^2 = 0.27$. Even though $R^2$ is not significant, the increasing trend of $E$ is noticeable.
Figure 5.11 Cross-plot of E versus the result of the regression equation (Eq. 5.1). Note the improved $R^2$ of 0.58.

Figure 5.12 Cross-plot of E versus dolomite content in the upper unit of the Woodford shale in RTC#1. Notice the strong correlation coefficient, $R^2=0.92$. However, there are not enough data points to confirm that strong correlation.
Figure 5.13 Cross-plot of E versus Mo in the middle unit of the Woodford shale in RTC#1. Although there is a trend of E increasing with the decrease of Mo, the correlation coefficient is very low, $R^2=0.25$.

Figure 5.14 Cross-plot of E versus MgO in the lower unit of the Woodford shale in RTC#1. Notice that when MgO is below 4% there is no correlation with E at all. However, above 4% MgO, there is a significant increase in E, $R^2=0.61$. Notice that there are not any data points between 4% and 16% MgO, which hinders the understanding of the influence of small increments of MgO on E.
Poisson's Ratio, \( \nu \)

On the scale of the entire Woodford formation, formation density and TOC were found to be the best single predictors of \( \nu \) with respective \( R^2 \)s of 0.45 and 0.33 (Figure 5.15 and Figure 5.16). The group of minerals that was found to be best predictor of \( \nu \) include: TOC, illite and quartz. The regression equation relating \( \nu \) to that group of elements is shown in Eq. 5.2. Figure 5.17 is a cross-plot of \( \nu \) versus the result of the regression equation.

\[
E = -0.0123(\text{TOC}) + 0.0012(\text{illite}) - 0.00047(\text{quartz})
\]

\( R^2 = 0.45 \)  

(5.2)

Where TOC and mineral contents are in wt%.

![Figure 5.15 Cross-plot of \( \nu \) versus Rho in the entire Woodford shale in RTC#1 showing a clear trend of \( \nu \) increasing with the increase of formation density, \( R^2=0.45 \).](image)
Figure 5.16 Cross-plot of $\nu$ versus TOC in the entire Woodford shale in RTC#1. Although $\nu$ seems to increase with the increase of TOC, the correlation coefficient is not that significant, $R^2=0.33$.

Figure 5.17 Cross-plot of $\nu$ versus the result of the regression equation (Eq. 5.2), $R^2 = 0.45$. 
However, similarly to E, the investigation of the best single predictors of $\nu$ on the scale of the different units of the Woodford, suggested different predictors of $\nu$ in each unit. Dolomite is the best predictor in the upper part with $R^2=0.56$ (Figure 5.18), the geochemical element P$_2$O$_5$ is the most correlated with $\nu$ in the middle unit with $R^2=0.20$ (Figure 5.19), and TOC is the best predictor in the lower unit with $R^2=0.68$ (Figure 5.20).

\[ y = 0.0169x + 0.1359 \]
\[ R^2 = 0.5664 \]

Figure 5.18 Cross-plot of $\nu$ versus dolomite content in the upper unit of the Woodford shale in RTC#1. There is a relatively strong correlation between $\nu$ and dolomite content. $\nu$ decreases as dolomite content decreases, $R^2=0.56$. However, there are not enough data points to confirm that strong correlation.

5.5 Hydraulic Fracture Modeling

The hydraulic fracturing simulator GOHFER$^\text{TM}$ was used to simulate the responses of the Woodford formation to different types of hydraulic fracturing treatment designs to predict the most appropriate one for this formation.
Figure 5.19 Cross-plot of $v$ versus P2O5 in the middle unit of the Woodford shale in RTC#1. Notice the very low $R^2=0.20$.

Figure 5.20 Cross-plot of $v$ versus TOC in the lower unit of the Woodford shale in RTC#1. $v$ increases as TOC decreases with a fairly strong $R^2=0.68$. 
5.5.1 Modeling Software

GOHFERTM which stands for Grid Oriented Hydraulic Fracture Extension Replicator, is a planar 3-D geometry fracture simulator with a fully coupled fluid/solid transport simulator. Similar to a reservoir simulator, GOHFERTM uses regular grid structure to describe the entire reservoir. This allows the modeling of the most complex reservoirs by determining the formation and fracture properties variations in each single grid and at any time (http://gohfer.corelab.com/ gohfer).

5.5.2 Model Inputs

The accuracy of the results of any simulator such as GOHFERTM depends on the accuracy of the input data. GOHFERTM has the capability of importing digital well log data directly from the LAS files and using those data to determine the vertical variations of crucial parameters such as stresses, pore pressure, permeability and porosity, necessary for fracture treatment simulation, thus minimizing the inaccuracy in the input data. It is important to mention that for a sound fracture treatment simulation, both vertical and horizontal variations of the different parameters are needed. While the vertical variations are acquired from well log data, the horizontal variations are usually derived from seismic and crosswell imaging data (http://gohfer.corelab.com/gohfer.aspx). These latter are lacking in this study thus hindering, to some extent, the accuracy of the results.

The well log data that are of crucial importance in a GOHFERTM fracture treatment simulation include gamma ray, true resistivity, formation density, sonic and caliper. These logs are integrated in the model used in the calculation of the total stress profile. Figure 5.21 is a depiction of the input data, calculated by GOHFERTM from well logs, used in the fracture treatments simulation. Although GOHFERTM reads in LAS files directly, the outputs shown in Figure 5.21 correspond well to results from other techniques addressed in this thesis.
The first track includes three differently colored curves, green representing Young’s modulus, blue representing total stress and red representing the effective porosity. The effective porosity shown in this track is not corrected for TOC that is abundant in shale reservoirs; therefore it is most likely to be overestimated. Also, given the fact that permeability and vertical Biot’s constant are both calculated, in GOHFERTM, from this effective porosity, these two parameters will ultimately be off from their real values as well. Since, porosity, permeability, and Biot’s constant are all important inputs to the hydraulic fracturing model, the fact that they are not accurately estimated will ultimately affect the outcomes of the fracturing simulation.

The second track includes Young’s modulus again in green and Poisson’s ratio in red. In the third track we find permeability in red, vertical Biot’s constant in blue and horizontal Biot’s constant in green. Notice that the horizontal Biot’s constant is constant along the wellbore. Horizontal Biot’s constant represents the interaction of pore fluid pressure on horizontal total stress and is recommended to be set at one (1) for all formations because pore fluid is in direct communication with the frac fluid (WinGOHFER User Manual – Version 2007 SP2). The fourth track contains the porosity curve in red, dolomite content in green and limestone content in blue. The lithology variations are calculated from log data using lithology logs such as gamma ray in the case of this study. In the fifth track, Pz stress (process zone stress) is represented by the red curve and the pore pressure by the green curve. Because of the lack of pore pressure data, the water column hydrostatic pressure is considered as the reservoir pressure in this study. This is a simplification that does not take into consideration the zones of overpressure or underpressure that could exist in the reservoir. This simplification can have effect on the outcomes of the fracture simulation because high pore pressure results in low minimum horizontal stress (low fracture gradient) and low pore pressure in high minimum horizontal stress (high fracture gradient). Finally, the total stress curve in red and the CFO pressure in green are depicted in the sixth track.
Figure 5.21 Depiction of the input data, calculated by GOHFERTM using well logs, used in the fracture treatments simulation.
5.5.3 Hydraulic Fracture Modeling Results

One of three different stimulation treatments are usually used in the case of shale reservoirs based on industry experience: slickwater treatments, gelled treatments, and hybrid (slickwater/gelled) treatments. Thirty nine fracture stimulation treatments were designed and simulated for the Woodford shale with GOHFER™ using these treatments. Table 5.4 represents the different zones of the Woodford Shale, in RTC #1, that were perforated and Table 5.5 is a summary of the hydraulic fracturing treatments designed.

<table>
<thead>
<tr>
<th>Woodford Zone</th>
<th>Top Perf (ft)</th>
<th>Bottom Perf (ft)</th>
<th># Holes</th>
<th>Diameter (Inch)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper</td>
<td>12,832</td>
<td>12,836</td>
<td>24</td>
<td>0.5</td>
</tr>
<tr>
<td>Middle</td>
<td>12,928</td>
<td>12,932</td>
<td>12</td>
<td>0.5</td>
</tr>
<tr>
<td>Lower</td>
<td>13,087</td>
<td>13,090</td>
<td>6</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Seventy eight graphs representing fracture geometry, proppant concentration and fracture conductivity of each fracture stimulation design were generated. A few example graphs are presented in Figures 5.22 - 5.27. For a complete review of the fracture simulation results refer to Appendix F. Figure 5.22 is a representation of the fracture geometry and proppant concentration in the fracture, resulting from a slickwater treatment simulation with a 30/50 badger sand proppant in the three parts of the Woodford shale, and Figure 5.23 is a depiction of the fracture geometry and fracture conductivity resulted from the same stimulation treatment simulation. Figure 5.24 shows the fracture geometry and proppant concentration in the fracture, resulting from a gelled treatment simulation with a 30/50 badger sand proppant in the three parts of the Woodford shale, and Figure 5.25 is a depiction of the fracture geometry and fracture conductivity resulting from the same stimulation treatment simulation. Figure 5.26 represents the fracture geometry and proppant concentration in the fracture,
resulted from a hybrid treatment simulation with a 30/50 badger sand proppant in the three parts of the Woodford shale, and Figure 5.27 is a depiction of the

<table>
<thead>
<tr>
<th>Fracture Stimulation Fluid</th>
<th>Target Zone</th>
<th>Flow Rate (bpm)</th>
<th>Fluid Volume (gal.)</th>
<th>Proppant Type</th>
<th>Total Proppant (lb)</th>
<th>Max. Proppant Concentration (ppg)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slickwater (2% KCl)</td>
<td>Upper</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Lower</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Middle+Lower</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle+Lower</td>
<td>80</td>
<td>500,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>312,500</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Badger sand 40/70 Econprop 30/50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>20# guar gel</td>
<td>Upper</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Lower</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Middle+Lower</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle+Lower</td>
<td>80</td>
<td>200,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>300,000</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Badger sand 40/70 Econprop 30/50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hybrid treatment (100,000 gals slickwater pad followed by 200,000 gals 20# guar gel with sand)</td>
<td>Upper</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Lower</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Middle+Lower</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Upper+Middle+Lower</td>
<td>80</td>
<td>350,000</td>
<td>Badger sand 30/50 Econprop 30/50</td>
<td>550,000</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Badger sand 40/70 Econprop 30/50</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.22 Fracture geometry and proppant concentration (lb/ft$^2$) resulting from slickwater treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded.

Figure 5.23 Fracture geometry and fracture conductivity (md-ft) resulting from slickwater treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded.
Figure 5.24 Fracture geometry and proppant concentration (lb/ft²) resulting from gelled treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded.

Figure 5.25 Fracture geometry and fracture conductivity (md-ft) resulting from gelled treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded.
Figure 5.26 Fracture geometry and proppant concentration (lb/ft²) resulting from hybrid treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the proppant concentration is color coded.

Figure 5.27 Fracture geometry and fracture conductivity (md-ft) resulting from hybrid treatment simulation with a 30/50 badger sand proppant, in the three parts of the Woodford, RTC #1 well. The fracture geometry and half-length can easily be seen and the fracture conductivity is color coded.
fracture geometry and fracture conductivity resulted from the same stimulation treatment simulation.

Slickwater treatments (Figures 5.22 and 5.23) displayed relatively longer fractures (1,500 ft) compared to the hybrid treatments (1,200-1,400 ft) and the gelled treatments (1,000-1,200 ft). However, the fracture resulting from the latter two treatments seem to display much more significant height growth when compared to the slickwater treatments. Interestingly, the proppant concentrations and the fracture conductivities appear to be similar in all three treatments with an average proppant concentration of 0.7 lb/ft² and an average fracture conductivity of 400 md-ft, in the case of a 30/50 badger sand proppant. Substituting the 30/50 badger sand proppant with the ceramic Econoprop 30/50 proppant resulted in a significant increase in fracture conductivity, up to three times higher in some cases, even though the proppant concentration did not show any significant increase. On the other hand, the replacement of the 30/50 badger sand with a 40/70 badger sand did not show any improvement in the fracture properties. Fractures in the middle Woodford appear to grow upwards following the path of least resistance. Finally, when treated simultaneously, the middle and lower Woodford seem to be disconnected indicating that these two regions may be separated by a layer of rock that is resistant to hydraulic fracturing between 12,990 ft and 13,030 ft. Figure 5.28 represents the proppant concentration in a fracture resulting from a gelled treatment simulation. The separation between the middle and lower Woodford is clearly seen.
Figure 5.28 proppant concentration in a fracture resulting from a gelled treatment simulation performed simultaneously in the upper and lower Woodford, RTC #1 well. The separation between the middle and lower Woodford is clearly seen between 12,990 ft and 13,030 ft.
CHAPTER 6
DISCUSSION OF RESULTS

The data generated in this study and the results of the statistical analyses performed provide information on the relationship between mineralogy and geochemistry, and the mechanical properties of the Woodford Shale.

6.1 Formation Mechanical Properties

The formation mechanical properties that were of interest in this study, as already stated, are Young's modulus and Poisson's ratio. These two mechanical properties were calculated from both log and core data using acoustic velocities and formation densities. Core acoustic velocities and formation density were recorded on RTC #1 core samples, under surface conditions and on a much smaller scale compared to log data. This resulted in a slight dissimilarity between core Young's modulus and log Young's modulus, and more substantial difference between core Poisson's ratio and log Poisson's ratio. The slight difference between core and log Young moduli can be explained by one or more of several factors: scale, confining pressure, borehole conditions and temperature and pore fluids saturation (Barree et al. 2009). But probably, the most important point that should be made is that the core and log Young's moduli are fairly similar. This suggests that the factors mentioned above have minimal effect on Young's modulus in the Woodford shale.

The differences between core and log Poisson' ratios are probably due to the low core $V_s$. The consistently lower values of core $V_s$ relatively to log $V_s$ in all parts of the Woodford, except for the lowest part of the lower unit (13,038 – 13,097 ft), are an indication that the zones of the Woodford above 13,000 ft are
more affected by the pressure release, resulted from taking the core out of the deep formation, than the zones below 13,000 ft.

It was shown that the choice of using log data (mechanical properties, density and sonic velocities) instead of core data (mechanical properties, density and acoustic velocities) was more appropriate, in this study, based on the fact that core $V_p$ and log $V_p$ were very similar and log formation density was the most representative of the mineralogy of the Woodford. Figure 6.1 is a cross-plot of Young’s modulus and Poisson’s ratio in the different zones of the Woodford. It can be clearly seen that the upper Woodford (12760 - 12787 ft) and lower zone of the lower Woodford (13040 – 13100 ft) display the highest ranges of Young’s modulus. Besides the fact that these two regions are characterized by low TOC, the lower zone of the lower Woodford displays high dolomite contents as well. The upper part of the lower Woodford shows high Poisson’s ratio values, which is probably due to its high clay content. Knowing that a brittle rock is characterized by high Young’s modulus and low Poisson’s ratio, it can be concluded that the upper and middle Woodford are the most brittle regions of the formation. Because of its high Poisson’s ratio, the lower Woodford can be considered as more ductile.

6.2 Factor Analysis

Factor analysis results, where acoustic velocities and density are related to TOC and mineralogy, suggest that illite and albite are strongly correlated with $V_s$ and $V_p$, the velocities that are included in the equations used to determine the mechanical properties. Interestingly, even though illite and albite are strongly correlated with the acoustic velocities, their effects on the mechanical properties $E$, $K$ and $G$, are not very significant. However the effect of these minerals on the acoustic velocities is translated to a significant effect on Poisson’s ratio. This distinction between $E$, $K$ and $G$, and $\nu$ is probably due to the effect of density. Density is part of the equations used to calculate $E$, $K$ and $G$ but not of $\nu$.  

97
Figure 6.1 Cross-plot of E vs. $\nu$ in RTC #1, Woodford shale. Notice that the upper Woodford and the lowest part of the lower Woodford display the highest values of E. These two regions are both characterized by low TOC content, and high dolomite content in the lowest part of lower Woodford. The upper part of the lower Woodford show high $\nu$ values, which is probably due to its high clay content.

Therefore the acoustic velocities are not the only parameters governing the behavior of the mechanical properties (E, K and G), but density as well. This is confirmed by the appearance of dolomite, calcite and TOC in the same factor as density in the first factor analysis, and in the same factor as E, K and G in the second factor analysis.

The factor analysis carried out with the mechanical properties, TOC and the mineralogy data suggest that variations in Young’s modulus (E), bulk modulus (K) and shear modulus (G) are all related to dolomite, calcite, illite, TOC and albite. An increase in illite, albite or TOC causes the mechanical properties E, K and G to decrease while an increase in the carbonate minerals dolomite or
calcite causes them to increase. However, the relatively small correlation coefficients indicate that, individually, none of those elements has a strong influence on those mechanical properties. Poisson's ratio, on the other hand, showed strong correlation coefficients with quartz and illite. Poisson's ratio decreases with an increase in quartz content and increases with an increase in illite content. It is also influenced by albite and TOC but with lower effect. It increases with an increase in albite and decreases with a decrease in TOC. Knowing that a brittle rock, which is considered as more prone to hydraulic fracturing, is characterized by high Young's modulus and low Poisson's ratio, it is inferred that high contents in clays and feldspars will result in more ductile rocks compared to rocks with high quartz and carbonates. TOC has a double effect on the formation brittleness. While high TOC will result in a low Poisson's ratio, it will also cause the Young's modulus to be slightly lower.

6.3 Stepwise Linear Regression Analysis

Stepwise linear regression analysis results confirm the results of the factor analysis. The geochemical element CaO, a component of dolomite in the RTC #1 core (Figure 6.2), was found to be the first predictor of E on the scale of the entire Woodford shale and TOC the second best predictor of E on the same scale. Further investigation of the best predictors of E in the different units of the Woodford confirmed the fact that dolomite is correlated with E. The correlation coefficient between dolomite and E in the upper unit of the Woodford was about 0.92 and the correlation coefficient between MgO, which is associated with dolomite (Figure 6.3), and E in the lower part of the Woodford was about 0.61. The fact that neither TOC nor dolomite showed any correlation with E in the middle part of the Woodford is probably due to the cancellation effect that those parameters had on each other. High TOC would have driven the magnitude of E slightly down while the low dolomite content would have driven it slightly up. This
Figure 6.2 Cross-plots of dolomite content versus CaO in the entire RTC #1 core of the Woodford shale showing a strong correlation between the two parameters, $R^2=0.88$. This indicates that CaO is mostly related to dolomite in the RTC #1 core.

Figure 6.3 Cross-plots of dolomite content versus MgO in the lower unit of the Woodford shale in RTC #1 showing a strong correlation between the two parameters, $R^2=0.98$. Note the lack of data points between 4% and 16% MgO. The correlation suggests that high MgO is associated with high dolomite content.
conçurs with the results of Mnich (2009) that states that when TOC increases
dolomite content decreases and vice versa.

The best single predictors of Poisson’s ratio were found to be formation
density and TOC, respectively, on the scale of the entire Woodford. The relatively
strong correlation between Poisson’s ratio and formation density is believed to be
the result of the association of density with TOC and quartz content. Density,
which is mostly influenced by quartz and TOC, has coupled the effect of those
two parameters, resulting in a stronger correlation with Poisson’s ratio even
though density is not part of the Poisson’s ratio equation.

The investigation of the best single predictors of Poisson’s ratio on the
scale of the different units of the Woodford further confirmed the effect of TOC on
Poisson’s ratio. In the lower unit, where the variation in TOC is much dramatic,
TOC is the best predictor of Poisson’s ratio with a correlation coefficient of 0.68.
The carbonate mineral dolomite seems to have the highest effect on Poisson’s
ratio in the upper unit of the Woodford. An increase of dolomite content resulted
in a significant decrease in Poisson’s ratio with $R^2=0.56$. In the middle unit of the
Woodford, there was no real predictor of Poisson’s ratio. The most correlated
element with $\nu$ in this region was found to be $P_2O_5$ with a very low correlation
coefficient, $R^2=0.20$. This region is characterized by fairly consistent quartz
content, TOC and dolomite content. This consistency is believed to have caused
the effect of $P_2O_5$ to be magnified to some degree. Interestingly, neither illite nor
quartz was found to be predictor of Poisson’s ratio despite the fact that they
showed fairly strong correlations in the factor analysis results. However, both illite
and quartz were part of the regression equation (Eq. 5.2) indicating that the effect
of those two minerals is intertwined.

Finally, the low correlation coefficients that relate the mechanical
properties to the different elements that influence them and the improvement in
the $R^2$ resulted from predicting the mechanical properties with a set of elements
(TOC and mineralogy) rather than only one element suggests that the
mechanical properties of the formation are not governed by one type of mineral
or geochemical element. Therefore, any formation should not be considered as
an amalgam of minerals that have individually exclusive effects, but rather as a complex, intertwined structure of minerals.

6.4 Hierarchical Cluster Analysis

Cluster analysis was carried out using the mechanical properties of the Woodford and defined 10 clusters that are different from each other. The fact that most of the samples (54 out of 72) fell into one cluster (Cluster 4) is due to two reasons: (1) most of the core samples (49 out of 72) that were analyzed were contained to the middle Woodford which is the biggest zone in the case of RTC #1, and (2) this part of the Woodford is characterized by consistently high TOC and a consistent mineralogy that is mainly quartz and clay with few spikes in pyrite and dolomite in some areas. Interestingly, apart from Clusters 3 and 10 that showed low similarity level with the other clusters (<55%), all other clusters were in fact very similar (>84%).

Given the fact that most of those clusters were distinguished based either on their TOC, clays, feldspars or carbonates contents indicates that, indeed, those parameters are the ones influencing the mechanical properties as already suggested by factor analysis and stepwise linear regression results. Also, the fact that the similarity level between most of the clusters was high, despite their differences in mineralogy is a confirmation that even though TOC, feldspars and carbonates influence the mechanical properties, small variations in those elements will result in only small variations in the mechanical properties. With this said, factor analysis results showed that illite is strongly correlated with Poisson’s ratio. However, the low illite content variation in the Woodford shale (13 wt% on average in the middle Woodford and 20 wt% on average in the lower Woodford) is believed to have resulted in the small variations in the Poisson’s ratio through the different zones of the Woodford.
6.5 Hydraulic Fracture Modeling

Fracture stimulation treatments modeled in this study provide an insight on the formation responses to different hydraulic fracturing treatments and should be considered as a first step towards more complex and detailed fracture modeling.

The main goal of any hydraulic fracturing treatment is to connect the wellbore to the optimum reservoir surface through the fracture, to allow the production of the maximum amount of the desired fluids. In the case of the Woodford shale of west Texas, hybrid (slickwater/gel) treatments displayed the highest developed contact surface between the reservoir and the fracture. Although slickwater treatments resulted in slightly longer fractures, the heights of these latter were much smaller resulting in lower overall surface area. Gelled treatments, on the other hand, displayed approximately the same fracture heights as hybrid treatments but with smaller fracture lengths.

The low fracture conductivities resulted from using 30/50 Badger sand proppant are probably due to the high stresses that prevail in this deep formation. These have certainly caused crushing of this type of proppant and degraded it, causing the fractures to have less width compared to the fractures resulted from using artificial ceramic proppant that is known to be resistant to high stresses. Illite content is playing a huge effect on the development of the fractures. Fractures initiated in the middle Woodford have a tendency to grow upwards towards the upper Woodford that is characterized by very low illite content. Also, the middle and lower Woodford seems to be separated by a layer of rock that is resistant to hydraulic fracturing. After investigation of the mineralogy of that part of the Woodford, illite was found to be at its highest content at that specific region (37 wt%).
CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

The mechanical properties of the Woodford shale of west Texas and their relationships to the mineral and geochemical elements of the formation have been analyzed in this study. The study suggests the following conclusions and recommendations.

7.1 Conclusions

- The comparison of core acoustic velocities to log acoustic velocities showed that the core $V_s$ behaves in two distinct ways when compared to the log $V_s$. Above 13,000 ft, the core $V_s$ is almost always lower than the log $V_s$, whereas, below 13,000 ft the core $V_s$ is frequently higher than the log $V_s$. This suggests that zone of the Woodford below 13,000 ft is less affected by the pressure release compared to the zones above 13,000 ft.

- Statistical analysis suggests that Young's modulus is influenced by many minerals and TOC. High carbonate content, dolomite and calcite in this case, are more likely to result in high values of Young's modulus, therefore a more brittle rock. High clay and feldspar contents, illite and albite, respectively, and TOC, on the other hand, are more likely to cause the formation to be less brittle by causing the Young's modulus values to be slightly low. However, because of the low correlation coefficients of these elements with Young's modulus, no single element can be considered as individually a strong driver of this mechanical property.
• The statistical analysis also suggests that Poisson’s ratio is controlled by quartz, clay, feldspars and TOC. High quartz content and abundant TOC are more likely to result in low Poisson’s ratio values, therefore a more brittle rock, while high clay and feldspar contents are more likely to result in a ductile formation with high Poisson’s ratio values. The high correlation coefficients that associate quartz and clays with Poisson’s ratio indicate that these minerals are strong controllers of this mechanical property.

• The improvement in the $R^2$ resulted from predicting the mechanical properties with a set of elements (TOC and mineralogy) rather than only one element suggests that the mechanical properties of the formation are not governed by one type of mineral or geochemical element. Therefore, any formation should not be considered as an amalgam of minerals that are individually exclusive but rather as a complex, intertwined structure of minerals.

• Based on the mechanical properties and the mineralogy of the different zones of the Woodford, it is inferred that the upper Woodford, very rich in quartz and very poor in clay with high Young’s modulus and moderate Poisson’s ratio, will probably be the most prone region to hydraulic fracturing (more brittle). The middle Woodford, characterized by moderate Young’s modulus and low Poisson’s ratio, will more likely show slightly higher resistance to fracture initiation (less brittle) due to its slightly lower quartz content and higher clay content. The lower Woodford will be probably the most resistant to hydraulic fracturing (more ductile) because of its high Poisson’s ratio due to high clay content, low quartz and low TOC.

• Hybrid (slickwater/gel) treatments with ceramic proppant seem to be the most appropriate hydraulic fracturing treatments for this formation. While
slickwater will result in longer fractures, adding gelled fluids will help extend the heights of the fractures allowing the fractures to contact larger reservoir surfaces. Ceramic proppant will result in high fracture conductivities by being more resistant to crushing in this high stress region.

- Fractures initiated in the middle Woodford showed a tendency to grow upwards. This suggests the existence of a path of least resistance right above this zone and is an indication of a possible anisotropy in the mechanical properties.

### 7.2 Recommendations

This study was performed with core and log data from a single well, RTC #1, in the Woodford shale of west Texas. Therefore, its results can not necessarily be extrapolated to the other regions of this potential reservoir. Also, throughout the study some crucial data were lacking and some of the results need further investigation. Therefore it is recommended for future work to consist of:

- Acquiring pore pressure data in the different zones of the Woodford to help in unveiling any abnormal pressure behavior and allow an accurate determination of the total stress profile.

- Performing permeability measurements on more core samples will be of huge interest. This will allow a better calibration of the permeability used in the GOHFERTM simulator allowing, in consequence, better modeling of fracture fluid loss and fracture extension.

- Hydraulic fracture modeling results showed that the fractures initiated in the middle Woodford had a tendency to grow upwards suggesting
possible anisotropy in the mechanical properties in this zone. Investigating this anisotropy will help in predicting the growth of the fractures in this particular zone.

- Investigation of the type of relationships that relate Young's modulus to clays and feldspars, and Poisson's ratio to quartz, clays and feldspars, which are not linear as suggested by stepwise linear regression results.
NOMENCLATURE

a = Formation tortuosity factor
CGR_{log} = Computed gamma ray reading, API
CGR_{cl} = Computed gamma ray reading of a clean zone, 0% clay
CGR_{sh} = Computed gamma ray reading of 100% clay zone
E = Young’s modulus, psi
G = Shear modulus, psi
GR_{cl} = Gamma ray reading of a clean zone, 0% shale
GR_{log} = Gamma ray reading
GR_{max} = Maximum gamma ray, API
GR_{min} = Minimum gamma ray, API
GR_{sh} = Gamma ray reading of 100% shale zone with
K = Bulk modulus, psi
k = Potassium concentration, CF/CF
LOM = Level of metamorphism that depends on the maturity of the kerogen.
m = Formation cementation exponent
N = Saturation exponent
PSP = Pseudo static spontaneous potential
PE = Photo electric effect
R = Deep resistivity, Ohm-m
R_{cl} = Clay resistivity, Ohm-m
R_{baseline} = Deep resistivity of the overlay zone, Ohm-m
RLA0 = Shallow resistivity, Ohm-m
R_{max} = Maximum non-invaded zone resistivity, Ohm-m
R_{mf} = Mud filtrate resistivity, Ohm-m
R_{mud} = Mud resistivity, Ohm-m
R_{o} = Thermal maturity of the Woodford kerogen, %
R_{sh} = Shale resistivity, Ohm-m
R_{t} = Formation true resistivity, Ohm-m
$R_w$ = Connette water resistivity, Ohm-m
$R_{xo}$ = Flushed zone resistivity, fraction
$S_{P_{min}}$ = Minimum spontaneous potential, mV
$SSP$ = Static spontaneous potential, mV
$S_w$ = Water saturation, fraction
$S_{wir}$ = Irreducible water saturation, fraction
$S_{xo}$ = Flushed zone water saturation, fraction
$Th$ = Thorium content, ppm
$TOC$ = Total organic carbon, wt%
$V_{TOC}$ = Volume of TOC, fraction
$U$ = Uranium, ppm
$\nu$ = Poisson's ratio, dimensionless
$V$ = Acoustic velocity, ft/s
$V_b$ = Bulk volume, cm$^3$
$V_{cl}$ = Clay volume, fraction
$V_g$ = Grain volume, cm$^3$
$V_p$ = Compressional wave velocity, m/s
$V_s$ = Shear wave velocity, m/s
$V_{sh}$ = Shale volume, fraction
$W$ = Weight, g
$\Delta t$ = acoustic wave travel time, $\mu$s/inch
$\Delta t_{baseline}$ = Sonic travel time of the overlay zone, $\mu$s/ft
$\Delta t_f$ = Pore fluids acoustic travel time, $\mu$s/inch
$\Delta t_{ma}$ = Matrix acoustic travel time, $\mu$s/inch
$\Delta t_p$ = Compression wave acoustic travel time, $\mu$s/inch
$\Delta t_s$ = Shear wave acoustic travel time, $\mu$s/inch
$\phi$ = Porosity, fraction
$\phi_D$ = Standard resolution density porosity, fraction
$\phi_{MIN}$ = Minimum neutron porosity, fraction
$\phi_N$ = Neutron porosity, fraction
$\phi_{Ncl}$ = Clay neutron porosity, fraction
\( \Phi_{Nma} \) = Matrix neutron porosity, fraction
\( \Phi_{Nsh} \) = Shale neutron porosity, fraction
\( \rho_B \) = Bulk density, g/cc
\( \rho_I \) = Pore fluids density, g/cc
\( \rho_{log} \) = Log formation density, g/cc
\( \rho_{ma} \) = Matrix density, g/cc
\( \rho_{matrix} \) = Matrix density, 2.71 g/cc
\( \rho_{sh} \) = Shale density, g/cc
\( \rho_{TOC} \) = TOC density, 1.2 g/cc
\( \rho \) = Density of the rock, kg/m\(^3\)
\( \Sigma \) = Neutron pulse reading
\( \Sigma_{cl} \) = Clay neutron pulse reading
\( \Sigma_{MAX} \) = Maximum neutron pulse reading
\( \Sigma_{MIN} \) = Minimum neutron pulse reading
REFERENCES


WinGOHFER User Manual – Version 2007 SP2


http://gohfer.corelab.com/gohfer

http://www.slb.com/content/services/solutions/reservoir/unconventional_gas_4.as

http://www.statsoft.com/textbook/stfacan.html

http://www.statsoft.com/textbook/stcluan.html

CD-ROM CONTENT

1. APPENDIX A: RTC-1 Pump-in – Mini-frac - Surface Tiltmeter Data
   - Reliance Triple Crown 1 Final Report.pdf
   - RTC-1 M-Wdfd Mini-Frac Tracer Survey.pdf
   - Reliance Triple Crown 1 Results.ppt
   - RTC-1 Pump In - Minifrac Review.ppt
   - RTC 1 Pump In lessons learned Apr08 LN Rev.ppt
   - RTC #1 Lower Barnett DFIT 4 Injection Test Analysis.ppt
   - RTC #1 Upper Barnett DFIT 5 Injection Test Analysis.ppt
   - pioneer triple crown #1 Minifrac #2 PJR.doc
   - pioneer triple crown #1 Injection #1.doc
   - pioneer triple crown #1 Injection #3.doc
   - pioneer triple crown #1 Injection #4.doc
   - pioneer triple crown #1 Minifrac #1.doc

2. APPENDIX B: Mineral and Geochemical Core Data
   - RTC1_Core_Geochemistry.xls
   - RTC1_XRD_LPNorm_Mineralogy.xls
   - TOC_RE_NH_08-190-A.xls

3. APPENDIX C: Core Petrophysical Acoustic Velocities Mechanical Properties Data
   - Core Acoustic Velocities and Mechanical Properties.xls
   - Core Density and Porosity.xls
4. APPENDIX D: Log Data
   - Reliance Triple Crown #1 anisot.xls
   - Reliance Triple Crown #1 mu_ml.xls
   - Reliance Triple Crown #1 sonic.xls
   - Reliance_Triple_Crown_1_Run2_TLD_MCFL_CNL_ECS_020PUP.xls
   - Reliance_Triple_Crown_01_Spectral_Gamma_02-26-07.xls
   - Delta log R technique for TOC.xls
   - Log Mechanical Properties.xls
   - RTC1_Core_to_Log_Shift.xls

5. APPENDIX E: Statistical Analysis Data
   - Statistical Analysis Data.xls

6. APPENDIX: Hydraulic Fracture Modeling Results
   - GOHFER Results 30_50 vs 40_70 Sand.ppt
   - GOHFER Results Guar Gel.ppt
   - GOHFER Results Hybrid1.ppt
   - GOHFER Results Slickwater.ppt