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Natural Fracture Characterization in the Haynesville Shale, East Texas: A Core Study

Frank Leslie Morgan

Louisiana State University and Agricultural and Mechanical College

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NATURAL FRACTURE CHARACTERIZATION IN THE HAYNESVILLE SHALE, EAST TEXAS: A CORE STUDY

A Thesis

Submitted to the Graduate Faculty of the Louisiana State University and Agricultural and Mechanical College in partial fulfillment of the requirements for the degree of Masters of Science

in

The Department of Geology and Geophysics

by

Frank Leslie Morgan
B.S., The University of Texas at Austin, 2011
May 2014
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Abstract

The Haynesville Shale in East Texas and Northwest Louisiana is one of the most studied and explored shale-gas plays in the United States. With new horizontal drilling and completion strategies, energy companies can produce hydrocarbons directly from the source rock making the Haynesville Shale an attractive resource. A key component of enhanced hydrocarbon production is the presence of natural fractures. They may serve as permeable pathways for hydrocarbon flow, especially in tight shales such as in the Haynesville Shale, where the matrix permeability is very low. In the case of the Haynesville Shale, little is known about the occurrence of natural fractures and their effect on hydrocarbon production (Hammes et al., 2011). In this study, natural fractures in a 160 feet continuous, conventional core of Haynesville Shale are imaged and characterized using visual inspection, x-ray computed tomography scans (CT scans), x-ray diffraction (XRD), scanning electron microscopy (SEM) and thin section analysis on selected core plugs. The purpose of this study is to characterize natural fractures in the Haynesville Shale by identifying fracture orientation, fracture fill and how these features correlate with mineralogy. A popular method for determining permeability and porosity in rocks is to use high-resolution x-ray computed tomography (CT). Computed tomography provides nondestructive three-dimensional visualization and characterization, creating images that map the variation of x-ray attenuation within objects, which relates closely to density (Ketcham and Carlson, 2001). Software used in this study to view the CT scans is called Avizo® Fire. The CT scans provide fracture density, fracture orientation and density of the matrix. Scanning electron microscopy, x-ray diffraction and petrographic microscopy are then used to provide petrographical
information on the Haynesville Shale core. The petrographic analysis can be used to make a potential correlation between mineralogy (i.e. clay, calcite and TOC) and fracture density. Both vertical and horizontal fractures are identified in the core along with fossils, burrows and sediment gravity flows. Core and computed tomography scans reveal the presence of seven natural near vertical fractures filled with calcite cement. Porosity is present between the cement and wall rock along fractures and ammonites. Quartz and calcite are the dominant minerals present in the core and contribute to the brittle nature of the rock.
Chapter 1. Introduction

With horizontal drilling technology and the increase in the price of natural gas from 2005-2008, unconventional shale gas formations became economic targets for exploitation by oil and gas companies. The Haynesville Shale of NW Louisiana and East Texas was one of the most sought after of these shale plays (Fig. 1). The Haynesville Shale is a highly geopressured organic-rich mudstone. It has a geopressure gradient of more than 0.9 psi/ft and an average porosity of 8% to 14% (Wang and Hammes, 2010). For comparison, the Barnett Shale in the Fort Worth basin has a pressure gradient of 0.52 psi/ft and an average porosity of 5.5% in organic-rich parts (Bowker, 2007). The Haynesville Shale’s geopressure gradient is about twice that of a normal pressure gradient of 0.465 psi/ft for typical Gulf Coast waters (Schlumberger Oilfield Glossary). The Haynesville Shale was deposited in a partly restricted basin related to a worldwide transgression during the Kimmeridgian Stage of the Upper Jurassic (Wang and Hammes, 2010). Shales deposited during the Upper Jurassic are recognized as rich source rocks containing a large amount of the world’s discovered petroleum (Klemme, 1994). The Haynesville Shale play has estimated resources of several hundred trillion cubic feet and per-well reserves estimated up to 7.5 billion cubic feet (Hammes et al., 2011).

The presence of natural fractures in any hydrocarbon reservoir may result in increased production and recovery of oil and gas and may affect reservoir management, including drilling, well completions, data collection, well placement and enhanced-recovery schemes (Narr et al., 2006). Due to the nanodarcy matrix permeability of the Haynesville and other shale plays around the world, identifying stratigraphic zones that are naturally fractured for hydraulic fracturing procedures can greatly enhance a play’s
success by increasing the permeability and creating pathways for hydrocarbons to flow from the reservoir to the wellbore (Younes et al., 2010). A popular method for characterizing permeability and porosity in rocks, as well as identifying structures like fractures and burrows, is to use high-resolution x-ray computed tomography (CT). CT scanning is a process for imaging the internal structure of materials, such as rock core, by projecting a beam of x-rays through the material and measuring the attenuation of the x-rays (Brown et al., 2008). The apparatus performing the scans is rotated about an axis passing longitudinally through the rock core producing data along individual planes. Avizo® Fire software is used to create multiple 3-D volume-rendering reconstructions of
stacked CT images to reveal the fracture density distribution within the core.

Reconstruction of fracture porosity is of great significance because pore-to-pore throat geometries may affect the migration of hydrocarbons and are significant in the production of hydrocarbons from a reservoir, especially if matrix permeability is low (Ketcham and Carlson, 2001). The purpose of this study is to identify and characterize natural fractures in the Haynesville Shale, as well as other sedimentary structures, using 3-D image analysis and petrographical analysis to further our understanding of the natural hydraulic fractures and the depositional environment of the Haynesville Shale. Based on $\sigma_1$ being vertical in the Gulf Coast and previous research on natural fractures in the Barnett Shale (Gale et al., 2007), natural fractures in the Haynesville Shale should be near vertical and filled with carbonate cement.
Chapter 2. Geologic Overview

2.1 Study Area

The core sample donated by Marathon Oil comes from Shelby County in East Texas (Fig. 1). In Shelby County the Haynesville Shale ranges from 0 feet to 250 feet thick and is located structurally between 10,500 feet and 12,000 feet below mean sea level (Hammes et al., 2011). The Haynesville Shale overlies a Haynesville Carbonate package and the Smackover Limestone and is overlain by the Bossier Shale (Fig. 2).

2.2 The Haynesville Shale

The Haynesville Shale is an organic-matter-rich, clay-poor mudstone that is Late Jurassic (Late Kimmeridgian) in age. Stratigraphically, the lowermost Haynesville Shale transitions upward from a shallow, anoxic and euxinic, sediment starved shelf environment to a deeper, more oxygen-enriched, shallow marine sag basin dominated by retrograding deltaic deposits in the overlying Bossier Shale (Younes et al., 2010). The majority of the Haynesville Shale play occurs over the Sabine Uplift, an area of shallower Jurassic strata, and on the western portion of the North Louisiana salt basin. The Haynesville Shale play is bounded by the East Texas salt basin to the west, the Brazos basin to the southwest and the North Louisiana salt basin to the east. The Haynesville Shale varies in mudstone lithofacies consisting of clay, organic matter, siliceous silt, calcite cement, carbonate bioclasts, and calcite crystals (Hammes et al., 2011). It is dominated by three major facies types on the basis of mineralogy, fabric, biota, and texture: (1) un laminated peloidal siliceous mudstone, (2) laminated peloidal calcareous or siliceous mudstone, and (3) bioturbated calcareous or siliceous mudstone.
Figure 2. Mesozoic stratigraphy of East Texas. Haynesville Shale highlighted in green circle and Haynesville age highlighted in green rectangle. Approximate location of the core sample used in this study is closer to the shelf (Modified after Hammes et al., 2011).
Based on sample analysis and wireline log calculations, the Haynesville Shale is more calcareous in the south and southwest and more siliceous in the north and northeast (Fig. 3) (Hammes et al., 2011). The presence of abundant calcareous fossils contributes to the calcareous nature of the Haynesville mudstones (Joan Spaw, personal communication 2013). Siliciclastic influx in the north is due to deltas prograding from the north and northeast (Fig. 3) (Hammes et al., 2011). The geopressure gradient of more than 0.9 psi/ft is very high, more than twice that of hydrostatic pressure and beginning to approach lithostatic pressure. Pressures in the Haynesville Shale exceed 10,000 psi in certain areas (Fig. 4). Disequilibrium compaction is the primary mechanism for the generation of overpressure (Torsch, 2012).

Figure 3. Paleogeography during Haynesville Shale deposition showing islands (white), carbonate platforms (blue), Haynesville mudstone basin (ochre), evaporates (purple), shallow-water clastics (yellow dots), fluvial sediments (light orange), and prodelta (brown) environments. HVL = Haynesville. (Hammes et al., 2011).
2.3 Type Log of the Haynesville Shale

All of the samples discussed in this study are located within the Haynesville Shale formation (Fig. 5). The log responses can be used to differentiate between the overlying Bossier Shale and the underlying pre-Haynesville carbonate. The top of the Haynesville
Figure 5. Haynesville Shale type log. Track 1 contains gamma ray on a 0-150 GAPI scale (green), apparent water resistivity on a 0-0.5 ohm scale (blue dotted) and tension on a 12,000-2000 lbs scale (pink). Track 2 contains shallow, medium and deep resistivity curves on a 0.2–200 logarithmic ohm-m scale. Track 3 contains neutron (blue dashed) and density (black) porosity on a 0.3–0 (decreasing from left to right) % porosity scale, photoelectric index on a 0-20 scale (green dashed), density correction on a -0.8–0.2 g/cc scale (black dotted) and caliper on a 0–20 inches scale (black dashed) (Courtesy of Marathon Oil).
Shale can be identified based on its neutron and density porosity curves. Neutron porosity is lower and density porosity is higher in the Haynesville Shale than in the overlying Bossier Shale to the point where the two curves begin to stack on top of one another or even cross each other. This stacking effect of the neutron and density curves is due to the lower clay content and higher kerogen content in the Haynesville Shale (Hammes et al., 2011). Another way to distinguish between the three units is with resistivity, which is higher in the Haynesville Shale than it is in the Bossier Shale, but lower than it is in the underlying Limestone.

2.4 Natural Fractures

Organic-rich shales are not only potential source rocks, but frequently owe their production potential to natural fracture systems in an otherwise impermeable rock (Fertl and Ricke, 1980). Little is currently known on the occurrence of natural fractures in the Haynesville Shale and their role in production due to the lack of fractures present in core samples (Hammes et al., 2011). In the case of an extensional regime like the Gulf of Mexico, the least effective stress is horizontal and thus fractures should be vertical (Fig. 6), making it unlikely to intersect fractures with a vertical wellbore (Sibson, 2003). A hydraulic fracture is a fracture that propagates as a result of the migration of highly pressured fluid through a brittle rock (Hubbert and Willis, 1957). In the Haynesville Shale, almost all of these hydraulic fractures are filled with carbonate cement (Younes et al., 2010).

Horizontal fractures are also observed in the Haynesville Shale (R. Nelson, personal communication 2013). As with the vertical fractures in the Haynesville Shale, the majority of the horizontal fractures are filled with carbonate cement (R. Nelson,
Figure 6. Example of a vertical fracture where $\sigma_{\text{max}} = \sigma_{v}$ and $\sigma_{\text{min}}$ is in the horizontal direction (S. Sears personal communication, 2013).

Natural horizontal fractures are more difficult to interpret in core and computed tomography scans due to their thin apertures and a lower resolution in the CT scans, so it is necessary to use a scanning electron microscope, or SEM, in order to interpret these features and determine whether they are natural or man-made. Previous research on fractures by Cobbold and Rodrigues (2007) have shown that bedding-parallel fibrous veins are common to a number of sedimentary basins, especially those containing black shales, such as the Haynesville Shale. These veins, commonly filled with calcite, are caused by upward fluid flow, in response to an overpressure...
gradient, releasing seepage forces that counteract the weight of the rock, even surpassing it, generating a tensile effective stress, which in turn may lead to tensile hydraulic fracturing (Cobbold and Rodrigues, 2007). Most fractures observed in core are horizontal, breaking along bedding planes. They are believed to be due to decompression of the core as it is brought to the surface (R. Nelson, personal communication 2013).

2.5 Bioturbation

Bioturbation is the biological reworking of soils and sediments (Meysman et al., 2006). Burrowing organisms may produce a variety of burrows, tracks and trails, reworking lithic clasts, mineral grains, and organic matter that can modify primary physical sedimentary fabrics (Tonkin et al., 2010). Bioturbation can either enhance or reduce permeability based on the burrow type and the behavior of the burrowing organism (Tonkin et al., 2010). Permeability enhancement can occur in a carbonate reservoir where burrow fills are subjected to different phases of diagenesis creating anisotropic porosity and permeability (Pemberton and Gingras, 2005). The increase in permeability can create connectivity to natural fractures and the wellbore (Herringshaw and Armstrong, 2012).

2.6 Computed Tomography

X-ray computed tomography (CT) is a technology most commonly used in the medical field, but more recently, has been used extensively in geological investigations. Computed tomography provides nondestructive three-dimensional visualization and characterization, creating images that map the variation of x-ray attenuation within objects, which relates closely to density (Ketcham and Carlson, 2001). These images can be stacked sequentially to form three-dimensional volumes (Fig. 7). Avizo® Fire is a
three-dimensional commercial software application for visualizing advanced qualitative and quantitative information on material structure images, such as a rock core (VSG website, 2013). The three-dimensional core volume, created through stacked CT images, can be manipulated digitally in order to measure fracture attributes such as azimuth, orientation, length, area, volume, aperture or width and fracture frequency.

Figure 7. Volume rendering image of a near vertical fracture plane and burrows from a shale core. Image created in Avizo® Fire (Courtesy of Marathon Oil). The change in color of burrows represents change in depth.
Chapter 3. Data and Methods

3.1 Data

Data available for this study includes CT scans through 157.6 feet of vertical Haynesville Shale core, x-ray diffraction (XRD) and total organic carbon (TOC) measurements taken at 28 specific depths, scanning electron microscopy analysis on 14 core plugs (18 samples selected, but only 14 had available core plugs, see Appendix B) and visual core interpretation using thin sections and a hand lens.

3.2 X-Ray Computed Tomography

X-ray computed tomography was performed by Ingrain Inc. The core was scanned while in the core barrel prior to cutting. CT scans cover part of the lower Bossier Shale above the Haynesville Shale as well as the upper Haynesville Carbonate beneath the Haynesville Shale, but only the 157.6 feet of Haynesville Shale CT scans were analyzed. This section of the Haynesville covers measured depths of 12,130’ – 12,288’. The dimensions of an individual voxel in the CT scans are 495 X 495 X 625 microns (X, Y, Z). Any feature smaller than these dimensions is beyond the resolution of the CT scan. Thus, silt-size grains and smaller (< 62.5 microns) cannot be resolved using CT scans (Udden-Wentworth scale).

X-ray computed tomography measures the distribution of density within a sample. The differences in density appear as a gray-scale image with black representing the lowest densities and white representing the highest densities, but colors can vary depending on how the color of the digital image is scaled using 256 shades (Fig. 8).
Figure 8. XY view of a CT scan from Haynesville Shale core. Image shows an ammonite and two vertical fractures filled with calcite cement (red arrows). Calcite cement is whiter than the surrounding rock matrix because it is denser. Image quality is fuzzy due to resolution constraints of the CT scan.

3.3 Avizo® Fire

The software used in this study to image the CT scans is Avizo® Fire. Avizo® Fire is an edition of Avizo® that is used primarily for analyzing material structure images. One data loading advantage of Avizo® Fire is that you can import RAW files directly into it without having to convert the files to a different format. In the case of the CT scans, they are all in RAW file format and are simply imported into Avizo® Fire. The CT scan RAW files are grouped in three foot intervals. After importing files for a specific three foot sample, the next step is to remove the well casing which must be removed in order to analyze the core and not have interference of non-rock material. The well casing is removed in Avizo® Fire using a computational tool called “Volume Edit”. “Volume Edit” is a cropping tool which highlights a specific volume for analysis and removes any unwanted volume, in this case, the well casing. With the well casing
removed, the CT scans can then be viewed as orthoslices in the XY, XZ and YZ orientations (Fig. 9). The Z direction is parallel to the core barrel, which is approximately vertical. Orthoslices allow for the identification of interesting tomographic material that may be present in the sample. This includes fractures, fossils, burrows and sediment gravity flows.

The next step is called segmentation. Segmentation involves delineating a subset of the dataset volume that can subsequently be rendered and measured as a separate object (Avizo Tutorial, 2012). For example, fractures that are segmented out from the rock matrix can then be measured in terms of length, orientation, width, volume and area. Segmentation is performed by using an interactive thresholding tool. The interactive thresholding tool sets a maximum and minimum threshold based on gray scale values, which is based on density. Features which fall in the threshold range are highlighted and may then be segmented out from the rock matrix. This tool is used repeatedly on a sample in order to segment out all features of interest. Once segmentation is complete, a quantification tool is performed on the segmented features that can calculate a large variety of measurements (Avizo®7 Training Manuel, 2012). In this study, the main features that are segmented out are open fractures (natural and drilling induced), cement filled fractures, ammonites and other fossils, and burrows. The segmented features are color coded in order to differentiate between them (Fig. 10).

Fractures are categorized as follows: 1) partially or fully cemented fractures are considered natural fractures; 2) open fractures with an aperture larger than 2 mm are considered induced as it is unlikely that such an open fracture could exist under in situ pressure conditions; and 3) open fractures with an aperture less than 2 mm could be either
Figure 9. Example of the three different orthoslice orientations in Avizo® Fire.

Individual voxel dimensions are 495 X 495 X 625 microns (X, Y, Z)
Figure 10. Example of various core features segmented out from the matrix in Avizo® Fire. Colors represent different features (fractures, ammonites, etc.). In this example, yellow/gold = near vertical fractures, green = horizontal fractures, blue = drilling induced fractures (larger than 2 mm) and red = ammonites.
natural or induced. Thus, the analysis focuses on filled fractures as they are the only group that can unambiguously be categorized as naturally occurring.

3.4 X-Ray Diffraction and Total Organic Carbon

Along with the CT scans, Marathon generously donated x-ray diffraction (XRD) and total organic carbon (TOC) data for twenty-eight selected depths in the Haynesville Shale from 12,132.5 feet – 12,279 feet (Tables 1, 2 and 3). Percentages are in volume% that include kerogen (based on TOC analysis). The two dominant minerals are calcite and quartz, which make up more than 62% of the rock matrix, nearly 40% calcite and over 22% quartz, on average, but mineral percentages vary with depth (Fig. 11). More than 8% of the matrix is composed of kerogen. There are also minor amounts of plagioclase, pyrite, dolomite and K-feldspar. The final 20% of the rock matrix is made up of various clay minerals. Clay percentages are given in weight%. The dominant clay minerals are illite+mica and chlorite, which make up more than 86% of the clay in the rock, nearly 59% illite+mica and more than 27% chlorite. Mica is included in the data because it is too difficult to distinguish mica from illite in XRD data. The rest of the clay is made up of mixed clays and a trace amount of kaolinite. The average TOC throughout the core is 3.71%, by weight, and the average grain density is 2.65 g/cm³. Data from Table 3 are plotted in Figure 12, which shows that grain density decreases as TOC increases in the Haynesville Shale.

3.5 Scanning Electron Microscopy

In order to better identify the mineralogy and sedimentary structures present in the Haynesville Shale core, specific samples were collected for SEM and petrographic
Table 1. XRD data for bulk content in the Haynesville Shale. Abundance in volume percent.

<table>
<thead>
<tr>
<th>Depth (ft)</th>
<th>Quartz</th>
<th>K Feldspar</th>
<th>Plagioclase</th>
<th>Calcite</th>
<th>Dolomite</th>
<th>Pyrite</th>
<th>Kerogen</th>
<th>Total Clay</th>
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Table 2. XRD data for clay content in the Haynesville Shale. Abundance in weight percent of clay fraction.

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<th>Depth (ft)</th>
<th>Smectite</th>
<th>Chlorite</th>
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<th>Kaolinite</th>
<th>Mixed-Layer Clay</th>
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<td>0</td>
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Table 3. Grain density and TOC data for the Haynesville Shale. TOC in weight %.

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<th>TOC (%)</th>
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Core plugs were taken at 14 different locations along the core based on unique features identified using a standard hand lens. Thin sections were made from the core plugs and inserted into the SEM for analysis. A scanning electron microscope works by scanning a fine probe of electrons on a specimen. The impact of the electrons on the
Figure 11. Plot of volume% of mineral vs. depth for 30 selected depths based on XRD.

Figure 12. Plot of total organic carbon vs. grain density with a linear trend line fitted.
Figure 13. SEM image of Haynesville Shale matrix. Image shows the different minerals present in a sample taken from the Haynesville Shale. Typical components include calcite, quartz, various clays, kerogen, pyrite and plagioclase.
specimen produces specific signals, which are collected to form an image (Bogner et al., 2007). Magnified images can be obtained using SEM, which is beneficial when analyzing microscopic structures and minerals in rock core where fine detail is important (Fig. 13). All of the SEM images shown are backscatter electron images.

There were originally eighteen samples selected for analysis. Of those eighteen, four of the samples could not be acquired due to the fragile nature of the core. Two of the remaining 14 samples were damaged during thin section preparation and one sample wasn’t able to be analyzed due to SEM technical problems. The information for the location of each sample is provided in Table 4 including exact depth and the core box that contained the sample (see Appendix B for sample locations).

3.6 Core Interpretation

Prior to taking core plugs for SEM analysis, the core was examined with a hand lens in order to describe the core and identify visible features. Photographs were taken covering the entire length of the core.
Table 4. List of core samples. Only samples with available butt portions have a core number and box number included.

<table>
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<tr>
<th>Sample No.</th>
<th>Core No.</th>
<th>Box No.</th>
<th>Depth</th>
<th>Feature</th>
<th>Butt (Yes/No)</th>
<th>Core No.</th>
<th>Box No.</th>
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</table>
Chapter 4. Results

In this study, CT scans, XRD and TOC data, SEM and core interpretation data are all used to describe Haynesville Shale core taken from a vertical well in Shelby County, East Texas. The samples are numbered by depth with Sample 1 being the shallowest and Sample 17 being the deepest. Sample 18 is out of order because it was acquired at a separate time from the other 17 samples. The samples are discussed in the following order: 1) a sediment gravity flow or bentonite layer; 2) cement filled ammonites, 3) vertical fractures and 4) horizontal fractures.

4.1 Core Descriptions

Sample 6 – Sediment gravity flow or bentonite layer:

Sample 6 is located at 12,177 feet (Fig. 14). Based on XRD data, the matrix is dominated by 41.6% – 44% calcite, 20.2% – 20.4% quartz, 19.6% – 20.4% clay and contains small amounts of pyrite, 1.9% – 2.2%, and plagioclase, 4.6% – 5.3% (Table 1). A feature interpreted as a sediment gravity flow (SGF) is present at 12,177’ (Figs. 14 & 15 – A & B). XRD data of this feature shows that it is made up of pyrite (~58%), clay (~37%) and a small amount of plagioclase (~5%). This feature could also be interpreted as a volcanic ash layer composed of bentonite based on the abundance of clay and pyrite. There are several ammonites located above and below the SGF or bentonite layer that have been cemented with calcite (Figs. 16 & 17). Calcite can be observed by its lighter color in the CT scan (a lighter gray compared to the darker colored, less dense, surrounding rock matrix, due to its higher density). The SGF or bentonite layer has a volume of 1.03 in³, an area of 12.35 in² and a thickness of 0.24 in. The SGF is coarser
Figure 14. Core photo of Sample 6. SGF or bentonite layer = 1, pyrite cluster = 2 and ammonite = 3. Numbers on the left are in 1/10 of a foot.
Figure 15. SEM images of Sample 6. A) Image of SGF or bentonite layer and matrix. B) Zoom in on yellow box in Image A. C) High magnification image of SGF or bentonite layer. D) Image of matrix. Om = organic matter and Py = pyrite. Location of Images B, C and D are labeled in Image A.
Figure 16. CT image of Sample 6 at 12,177 feet. Oriented in the XZ plane. SGF or bentonite layer = 1, pyrite cluster = 2 and ammonites = 3. Each major tick mark on the X and Z scale is equal to ~0.2 inches.
Figure 17. 3-D volume rendering of Sample 6 at 12,177 feet. Oriented in the XZ plane. SGF or bentonite layer = green, pyrite = yellow and ammonites = magenta. Each major tick mark on the X and Z scale is equal to ~0.4 inches.
grained than the surrounding rock matrix and is comprised of pyrite grains, some almost 50 microns, within a matrix of very fine clay (Figure 15 – C). Pyrite is easily detectable in SEM and CT images due to its high density (white in color, much brighter than the surrounding rock matrix) (Fig. 15 – C). Based on SEM, the matrix has higher porosity than the SGF or bentonite layer, estimated at 17.3% and the SGF or bentonite layer is estimated at 13.1%. Porosity values are high due to decompression and cracking after the core is brought to the surface. The matrix contains clusters of pyrite spheres (white spheres, most are less than 10 microns) and is poorly sorted (Fig. 15 – D). The different grain sizes appear to be separated into linear laminations (Fig. 15 – D) and there is a small amount of skeletal debris and burrows present within the matrix.

Sample 7 - Ammonites:

Sample 7 is located at 12,181.5 feet (Fig. 18). Based on XRD, the matrix is similar to Sample 6, dominated by calcite, quartz clay, minor amounts of pyrite as well as more than 10% kerogen (Table 1). Sample 7 contains ammonite shells and ammonite fragments (Figs. 18 & 19). The ammonite shells are almost completely replaced with calcite and pyrite based on the light gray to white color of the mineral cement in the SEM images and CT scans (Figs. 20, 21 & 22). In hand sample and SEM images, three separate ammonite shells are evident, packed very close to one another. The third and lower most ammonite contains pyrite cement surrounding prismatic calcite cement (Figs. 20 – A & B). The other two ammonites appear to lack this prismatic texture in their calcite cement. The calcite cement is shown as a lighter gray color while the pyrite cement is white in color. Again, light gray and white colors indicate the higher density of calcite and pyrite, respectively, compared to the surrounding matrix. There is also
Figure 18. Core photo of Sample 7. Ammonites = 1 and pyrite = 2. Numbers on the left are in 1/10 of a foot.
Figure 19. Ammonite molds in Haynesville Shale core.

porosity along the edges of part of the ammonites (Fig. 20 – B). The matrix is poorly sorted and contains pyrite spheres less than 10 microns in size (Fig. 20 – D). It is bioturbated containing burrows that have been filled with pyrite (Fig. 22). The average porosity of sample 7 is 9.65% with areas surrounding ammonites having higher porosity. The large, porous zones within the ammonites are probably due to damage during thin sections preparation (Fig. 20 – A, B & C). Another example of ammonites can be seen in the appendix under Sample 8.

Sample 11 – Near vertical fractures:

Sample 11 is located at 12,225.5 feet (Fig. 23). At this depth, based on XRD data, quartz has increased to 29.9% – 33.2% and the amount of calcite has decreased to 27.5%, so quartz is the dominant mineral present (Table 1). The first obvious features present in
Figure 20. SEM images of Sample 7. A) Image of three ammonites with calcite and pyrite cement fill. B) Zoom in on yellow box in Image A. C) High magnification image of ammonite and matrix. D) High magnification image of matrix. Om = organic matter, Py = pyrite, Am = ammonite, Mtx = matrix and Cal = calcite cement. Locations of Images B, C and D are labeled in Image A.
Figure 21. CT image of Sample 7 at 12,181.5 feet. Oriented in the YZ plane. Ammonites = 1 and pyrite = 2. The Z axis is 1.83X vertically exaggerated.
Figure 2. 3-D volume rendering of Sample 7 at 12,181.5 feet. Oriented in the YZ plane. Ammonites = purple and pyrite = yellow. Number’s 1 and 2 are burrows filled with pyrite.
Figure 23. Core photo of Sample 11. Near vertical cemented fractures = 1a, 1b and 1c and ammonites = 2. Numbers on the left are in 1/10 of a foot.
Sample 11 are three near vertical fractures, labeled 1a, 1b and 1c which have been almost completely cemented with calcite and minor amounts of pyrite (Fig. 23). Vertical Fractures 1a and 1b grew in both directions until they eventually stopped side by side, overlapping one another. Vertical Fracture 1c is thinner than both 1a and 1b and appears to be continuous, except for the induced horizontal breaks in the core formed during core recovery. The SEM provides magnified views of the three vertical fractures and the matrix (Fig. 24). Figure 24 – A shows vertical Fractures 1a and 1b side by side where the two fractures become thinner. Zooming in on Fracture 1a, you can see porosity cutting down the middle of the fracture where the cement was unable to completely fill and/or the cement wasn’t as strong and reopened upon retrieval of the core (Fig. 24 – B). There is also porosity along the edges of the fracture where the matrix meets the calcite cement, like Sample 7 (Fig. 20 – B) where there is porosity along the edges of the cemented ammonites (Fig. 24 – C). With the previous two samples, there are pyrite spheres present in the rock matrix shown in Figure 24 – D (identified by their white color in CT and SEM images). Porosity in Sample 11 is much lower than in the other samples averaging around 1.85%. A majority of the porosity appears to be around the vertical fractures and not in the matrix. The matrix contains burrows and is bioturbated. Calcite cement is also identified by optical microscopy in Figure 25. Based on Figure 25, cementation of the near-vertical fractures appears to have occurred in multiple stages. The crystal habit of calcite looks distinctly different along the sides of the fracture than down the middle of the fracture, indicating different stages of diagenesis.

CT scans and volume renderings reveal three vertical fractures (with Fractures 1a and 1b side by side), ammonites, possible horizontal fractures (but are more likely breaks
Figure 25. Optical microscopy images of a calcite cement filled vertical fracture from Sample 11. Images A and B are in plane polarized light. Images C and D are in cross polarized light. Images B, C and D are progressively zoomed in and all images are the field of view through the microscope.
Figure 26. CT image of Sample 11 at 12,225.5 feet. Oriented in the XZ plane. Vertical fractures = 1a, 1b and 1c, horizontal fracture/breaks = 2, ammonite = 3 and induced horizontal fracture = 4. CT Image flipped in relation to core photo in Figure 23. Each major tick mark on the X and Z scale is equal to ~0.4 inches.
Figure 27. 3-D volume rendering of Sample 11 at 12,225.5 feet. Oriented in the XZ plane. Vertical fractures 1a and 1b = yellow, horizontal fractures/breaks = light green and ammonites = purple and drilling induced horizontal fracture = blue. Each major tick mark on the X and Z scale is equal to ~0.1 inches.
Figure 28. 3-D volume rendering of Sample 11 at 12,225.5 feet. Random orientation. Vertical fractures 1a and 1b = yellow, horizontal fractures/breaks = light green, ammonites = purple and drilling induced horizontal fracture = blue. Scale is the same as in Fig. 27.
along parallel bedding planes), and a clear drilling induced horizontal fracture (Figs. 26, 27 & 28). Vertical Fracture 1c is present, but it is too thin to be segmented out in
Avizo® Fire. In terms of fracture frequency in Sample 11, there are three clearly defined
vertical fractures present. They are oriented near-vertical at about 88 degrees. Fractures
1a and 1b are spaced 0.15 in apart and Fractures 1a and 1c are spaced 1.17 in apart. They
are nearly filled completely with calcite cement based on hand samples, CT images and
petrographic analysis. Fracture 1a has an observable height or length of nearly 6.5 feet,
Fracture 1b has a height of 2.76 feet and Fracture 1c has a height of 2 feet. Fracture 1a
and 1b have widths or apertures of 0.05 in and Fracture 1c has an aperture of 0.03 in. In
this sample, vertical fractures 1a and 1b have a combined area of 73.8 in² and a combined
volume of 1.75 in³. Because Fracture 1c could not be segmented, area and volume could
not be calculated using Avizo® Fire.

Lastly, there is an abundance of horizontal breaks, or bedding-plane partings, in
this sample that are evident in the CT scans and the volume rendering. It is unclear as to
whether these are natural or induced. Their lengths extend the diameter of the core and
their apertures are less than that of a single voxel in the CT scan, 625 microns, to possibly
apertures of a single voxel, 625 microns. Examples of more vertical fractures can be
found in the appendix under Samples 9 and 10.

Sample 18 – Near vertical fractures:

Sample 18 is located at 12,224.7 feet and is just slightly above Sample 11 (Fig.
29). Based on XRD data, the matrix is similar to Sample 11 in that there is 29.9% -
Figure 29. Core photo of Sample 18. Vertical fractures = 1b and 1c and ammonites = 2. Numbers on the left are in 1/10 of a foot.
33.2% quartz and 27.5% calcite (Table 1). There are pyrite spheres present along with some skeletal debris. Vertical Fractures 1b and 1c that were present in Sample 11 are again present in Sample 18 as the depth is only one foot shallower, but there are two ammonites that intersect the vertical Fracture 1b (Fig. 29 & 30 – A & B). The vertical fracture and the two ammonites are both filled with calcite cement. The porous crack cutting through the center of the vertical fracture in Sample 11 continues up hole into Sample 18 (Fig. 30 – C). It is unclear if the larger black spots in Figure 30 – C represent porosity or loss of material due to thin section preparation. Along with calcite cement replacing the ammonite shells, there is also a substantial amount of pyrite cement present in the ammonites (Fig. 31 – A, B & C). With the vertical fractures, the ammonites also have an open crack down the middle of their cement fill (Fig. 31 – B). Figure 30 shows SEM images of the vertical fracture and Figure 31 shows SEM images of the ammonites. Both figures are from Sample 18. Porosity along the edges of the ammonites and fractures is clearly visible. Overall porosity is higher than in Sample 11, around 15.85%. Calcite and pyrite cement are also identified by optical microscopy in Figure 32.

Two ammonites are identified in the CT scans (Fig. 33). No volume rendering is shown for this sample because the density of the calcite cement filled ammonites is nearly identical to that of the vertical fracture which intersects them. Horizontal breaks, or bedding-plane partings, and a drilling induced horizontal fracture are also present. The horizontal breaks may be natural fractures or an effect of the rock popping apart upon core retrieval. Another example of an ammonite intersecting a vertical fracture can be found in the appendix under Sample 9.
Figure 30. SEM images of Sample 18 – A. A) Image of two ammonites intersecting a vertical fracture. B) Zoom in on yellow box in Image A. C) High magnification image of a vertical fracture filled with calcite cement. D) Image of matrix. Om = organic matter, Py = pyrite, Mtx = matrix and Cal = calcite cement. Location of Images B, C and D are labeled in Image A.
Figure 31. SEM images of Sample 18 – B.  A) Image of two ammonites with pyrite cement. Image B and Image C are magnified images of Image A. D) High magnification image of an ammonite, vertical fracture and the matrix. Location of Image C labeled in Image A. Locations of B and D are outside Image A. Am = ammonite, Mtx = matrix, Py = pyrite, Om = organic matter and Cal = calcite cement.
Figure 32. Optical microscopy images of calcite/pyrite cement filled ammonites and a calcite cement filled vertical fracture from Sample 18. Images A and B are in plane polarized light. Images C and D are in cross polarized light and all images are the field of view through the microscope.
Figure 33. CT image of Sample 18 at 12,224.7 feet. Oriented in the XZ plane. Vertical fractures = 1, ammonite = 2 and drilling induced horizontal fracture = 3. Sample flipped in relation to core photo in Figure 29. Each major tick mark on the X and Z scale is equal to ~0.5 inches.
Sample 2 – Horizontal fractures and burrows:

Sample 2 is located at 12,134.7 feet, which is near the top of the Haynesville Shale (Fig. 34). Based on XRD, the matrix is composed 23.5% – 32.9% quartz, 18.5% – 37.5% calcite and 15.9% – 30.4% clay; 2.8% – 3.8% pyrite and 9.3% – 9.9% kerogen are also present or are accessory constituents. The shale is darker in color, probably due to a higher organic content. TOC content is around 4% (weight %) and matrix porosity is 6.4%.

Sample 2 displays what appears to be horizontal fractures filled with calcite cement (Figs. 34 & 35). It is somewhat difficult to differentiate between a horizontal fracture filled with calcite cement and an ammonite filled with calcite cement. Taking a look with a hand lens at the core and more importantly, the SEM images, the horizontal features present do not display the curvature that ammonite shells display in core and in CT scans. In core and in SEM, these horizontal features appear to be very linear and straight, lacking any type of curvature and have horizontal dimensions that span the diameter of the core (Figs. 35 – A & C), whereas ammonites are slightly smaller than the core barrel. The horizontal fractures are filled with calcite cement based on the lighter color of the cement fill in the SEM image. It appears that the fractures may be open, but some of the cement was probably lost in the thin-section preparation process. The very bottom of Figure 35 – D shows another possible horizontal fracture with a small amount of calcite cement filling the fracture. The bedding-plane partings are visible throughout Figure 35 – A. Aperture sizes of horizontal fractures are just below the resolution of the CT scans, less than 625 microns. Their orientation is near horizontal at 0 degrees and
Figure 34. Core photo of Sample 2. Possible horizontal cement filled fractures indicated by white arrows. Numbers on the left are in 1/10 of a foot.
Figure 35. SEM images of Sample 2. A) Image of two possible horizontal fractures. B) Image of another horizontal fracture. C) High magnification image of the same possible horizontal fracture in Image B. D) Image of a possible horizontal fracture and an ammonite. Location of Image C labeled in Image B. Images B, C & D are outside of Image A. Am = ammonite, Om = organic matter, Py = pyrite and Cal = calcite cement.
their length/width is at least the diameter of the core, three inches. As previously mentioned, the two fractures could not be segmented out in Avizo® so the area and volume could not be measured, but they are identifiable in CT scans (Fig. 36). Another example of a possible natural horizontal fracture is shown in the appendix under Sample 3.

One interesting observation just above and below the observed horizontal fractures are pyrite-filled burrows (Fig. 37). You can clearly see the traces of the pyrite filled burrows through the sediment. They are chaotic and unorganized as the organisms burrowed their way through the sediment. These burrows are not clearly visible in hand sample or SEM, but are clearly visible in CT scans.

4.2 Fracture Attributes

Based on core observations and CT scans, there are seven natural fractures. Of these seven, six of the fractures are oriented near vertical. Fracture 6 is oriented obliquely to the core (Fig. 42). The rest of the fractures present in the core are either clearly induced by drilling and by the core retrieval process based on their unusually large apertures and lack of cement for the depths and pressures in which they are found in the subsurface, or they are horizontal natural fractures filled with cement.

The first of the seven fractures occurs near the top of the Haynesville Shale between 12,131’ – 12,133’ (Figs. 38 and 39). This sample was not available for SEM analysis. The fracture is partially filled with calcite cement and appears open (displays porosity) in certain places. It has an observable length of 2.26 in, and has an aperture of 0.05 in. It appears to terminate into a horizontal break in the core. It is oriented near vertical at 90.25 degrees and has an azimuth of 20ºNE – 200ºSW.
Figure 36. CT scan of Sample 2 at 12,134.7 feet. Oriented in the XZ plane. Possible horizontal fractures = 1 and burrow = 2. Each major tick mark on the X and Z scale is equal to ~0.2 inches.
Figure 37. Volume rendering of burrows located 2.95 in – 10.04 above Sample 2. Burrows are indicated in pink. Each major tick mark on the X and Z scale is equal to ~0.4 inches.
Figure 38. Core photo of Sample 1 and Fracture 1. Fracture 1 is indicated by the white arrow. Numbers on the left are in 1/10 of a foot.
Figure 39. CT image of Fracture 1. Fracture = 1, burrow = 2 and drilling induced fractures = 3. Oriented in the YZ plane. Each major tick mark on the Y and Z scale is equal to ~0.4 inches.
The next four fractures are parallel to one another with an azimuth of 50° NE – 230° SW. The second fracture is located near the middle of the Haynesville Shale between 12,213’ – 12,222’ (Figs. 40 & 41). It is partially filled with calcite and appears open in places. The fracture is over three feet in observable length, has an aperture of just over 0.04 in, and is oriented near vertical at 89.37 degrees. SEM images for Fracture 2 can be found in Appendix A under Samples 9 and 10. The third fracture, Fracture 1c, is located between 12,224’ – 12,227’, has an observable length of 24 in and has an aperture of 0.03 in (Fig. 23). The fourth fracture, Fracture 1b, is located between 12,222.5’ – 12,225.5’, is observed to be 2.76 feet long and has an aperture of 0.05 in (Fig. 23). Both are almost completely filled with calcite cement and oriented near vertical at 88.24 and 88.16 degrees, respectively. The fifth fracture, Fracture 1a, is the longest of the seven fractures and is located between 12,225’ and 12,232’ (Fig. 23). It has an observable length of nearly 6.5 feet and is filled with calcite cement. It has the same aperture and orientation as fracture 1b. The four fractures are spaced, on average, about 1 inch away from one another.

The sixth fracture is located between 12,238.75’ – 12,239.25’ in the lower half of the Haynesville Shale. Of the seven fractures, it is the only fracture that is not near vertical in orientation. ~60° (Fig. 42). The fracture is filled with calcite cement and has an azimuth of 3° E – 183° W. Lastly, Fracture 7 is located between 12,259’ and 12,260’ (Fig. 43). The sample was not available for SEM analysis nor was it identifiable in the CT scans, but visually it is parallel to the core barrel and therefore vertical. Fracture 7 was only identified by hand sample when viewing the core at the Core Labs facility in
Figure 40. Core photo of Sample 9 and Fracture 2. Fracture 2 is indicated by the white arrow. Numbers on the left are in 1/10 of a foot.
Figure 41. CT images of Fracture 2. Open vertical fracture = 1, cement filled vertical fracture = 2, drilling induced fracture = 3, horizontal breaks = 4 and ammonites = 5. Each major tick mark on the X and Z scale is equal to ~0.36 inches.
Figure 42. Core photo of Fracture 6. White arrows indicate oblique fracture. Numbers on the left are in 1/10 of a foot.
Figure 43. Core photo of Sample 16 and Fracture 7. Fracture 7 is indicated by the white arrow. Numbers on the left are in 1/10 of a foot.
Fracture statistics are in Table 5. Fractures 2 – 7 all appear to continue out of the core, so the full length of the fractures cannot be accurately measured.

Table 5. Fracture attributes. Note: Due to the difficulty of segmentation in Avizo® Fire, area and volume weren’t calculated for any fracture except Fracture #1.

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<th>Aperture (in)</th>
<th>Orientation (°)</th>
<th>Area (in²)</th>
<th>Volume (in³)</th>
<th>Fracture Fill</th>
<th>Azimuth</th>
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4.3 Fractures versus Mineralogy

The number of fractures present in CT scans of Haynesville Shale core are counted at 26 different one-foot intervals using CT scans where XRD data has been collected and the results are plotted in Figure 45. The data used to create the plot are shown in Table 6. The type of fractures being counted in the CT scans are any fracture filled or partially filled with cement or with an aperture less than 2 mm. Horizontal, oblique and vertical fractures that might have been naturally formed are counted. The XRD data used to compare with the fractures are quartz, calcite, kerogen and clay. These four materials make up, on average, more than 90% of the core.
With regards to the natural vertical fractures discussed in the previous section, quartz is the dominate mineral present and there is less calcite present than in other sections of the core, based on average XRD data (refer to Table 1). Clay content increases slightly where vertical fractures are present and kerogen content stays about the same.

Figure 44. Plot of fractures vs. mineralogy. The number of fractures at 28 specific depths were counted. The volume% of quartz, calcite, kerogen and clay at each of these 28 depths was recorded. For each depth, there are four colored spheres representing the volume% of mineral that line up parallel to the number of fractures counted at that depth.
Table 6. Number of fractures present compared to XRD data. Kerogen and minerals listed in volume%.

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Chapter 5. Discussion

5.1 Natural Fractures

Six near vertical fractures (probably vertical, but appear a few degrees off because the wellbore isn’t perfectly vertical) and one oblique fracture, but still oriented at a high angle (~60°) were identified. Vertical fractures are expected in the Gulf of Mexico regional stress regime as the direction of maximum principal stress, $\sigma_1$, is expected to be overburden stress and therefore the direction of least principal stress is horizontal, $\sigma_3$ (Sibson, 2003). Based on the orientation and azimuth of vertical Fractures 2, 3, 4 and 5, four of the fractures are parallel to one another and form a fracture set. The orientation and azimuth of this fracture set may provide information on the paleo-stress field in the area. Identification of this fracture set can change well planning from a geologic, drilling and completions standpoint. The lateral extent of this fracture set is unknown because we only have one vertical core. Most of the fractures terminate at one end, but all four fractures continue out of the core on the other end. In order to map out the vertical fracture set, vertical cores from surrounding wells need to be recovered or core would need to be taken from a horizontal well. It is likely that a horizontal core would intersect a high number of vertical fractures based on the tightly spaced fractures intersected by the three inch core in this study. With a horizontal core, fracture density and fracture spacing can be calculated. Other studies on core samples demonstrate that sealed and partially sealed fractures having identical strike can be interspersed over vertical distances that range from a few meters or less to decimeters and over lateral distances of meters to kilometers (Laubach et al., 2010). Identification of these fracture sets is important because partially open vertical fractures may contribute to greater fluid flow and greater
hydrocarbon production, but may also lead to vertical fluid migration out of the
Haynesville Shale and into neighboring formations. Sealed fractures can reopen or the
weak bond between fracture cement and the matrix may break during hydraulic
fracturing.

Horizontal features are present throughout the entire core. The horizontal features
range from drilling induced fractures, bedding-plane partings, horizontal natural fractures
and ammonites. Drilling induced fractures can be identified based on the size of their
apertures (>2 mm), lack of cement, and the presence of barite, drilling mud, in them
(Joan Spaw, personal communication 2013). Drilling mud is observed in CT scans
within the induced fractures and especially along the edge of the core. In CT scans,
barite mud is white in color based on its high density. Ammonites can be identified
based on the curvature of their shells in core and in SEM and their distinct mold in the
CT scans (Fig. 41). Bedding-plane partings can be identified based on core interpretation
and their cup shaped, or being curved up or down at the edge of the core in CT scans
(Ron Nelson, personal communication 2013). Natural horizontal fractures are filled with
cement and may display an anastomosing and bifurcating nature (Ron Nelson, personal
communication 2013). However, it can be difficult to differentiate between what is a
“real” natural horizontal fracture and what may be another bedding-plane parting. In this
study, only horizontal fractures filled with mineral cement are considered to be natural,
e.g. Sample 2 (Fig. 34). Horizontal fractures are linear and filled with calcite cement.
They lack the curvature seen with cemented ammonite shells. Horizontal fractures
present are too thin to see in CT scans, but are visible in the core and in SEM images.
Horizontal fractures may also be created by hydrocarbon generation when the formation pore pressure exceeds the total normal stress (Vernik, 1994). Microcracks formed by this mechanism can significantly aid in the primary migration of hydrocarbons, particularly in the horizontal direction (Vernik and Landis, 1996). Microcracks may be present in the Haynesville Shale, but higher magnification would be needed in optical microscopy and SEM analysis in order to see these features.

Near vertical fractures with varying azimuths and horizontal fractures in the Haynesville Shale suggest that multiple stages of fracturing have occurred and that the regional stress field has varied with time. Fractures propagate in the direction of maximum stress. Thus, changes in the stress field will result in fractures propagating in different directions. For horizontal fractures to occur, the stress field would have to be rotated so that the maximum principle stress is in the horizontal direction or pore pressure must have exceeded overburden pressure, so it is unlikely that vertical fracturing and horizontal fracturing occurred simultaneously. The order of fracture formation cannot be determined because there are no cross-cutting relationships visible and there is no fluid inclusion analysis available to age date the cements filling the fractures.

5.2 Mineralogy and Fractures

No direct correlation can be made between mineralogy (including kerogen) and fractures based on Figure 44, and whether natural fractures are more likely to occur within a specific mineral assemblage. There is an abundance of fractures and lack of fractures at high volumes of each of the four materials plotted (quartz, calcite, clay and kerogen).
The mineralogy of quartz and calcite in the Haynesville Shale varies throughout the core, transitioning back and forth between quartz-rich zones and calcite-rich zones. XRD data reveals greater quartz content near the top of the Haynesville Shale, 23.5% – 38.9% quartz, transitioning into a more calcite rich zone, 41% – 45.8% calcite, followed by a quartz rich zone, 29.6% – 33.2% quartz, and then transitions back into a calcite rich zone, 31.9% – 64.6% calcite, near the bottom of the Haynesville Shale, just above the underlying pre-Haynesville carbonate formation (Table 1 & Fig. 11). Six of the seven near vertical fractures are identified in the quartz-rich zones, but fractures continue outside of the core. Fractures may exist in areas with greater calcite content rather than in areas with greater quartz content, but can’t be certain because fracture terminations aren’t always visible. Although calcite typically contributes to a rock being more brittle (Perez and Marfurt, 2013), the high abundance of calcite in other areas of the formation, along with other factors, may result in a less ideal rock matrix for natural hydraulic fracturing to occur. The higher abundance of quartz in combination with calcite may result in a rock matrix that is more brittle. Clay content varies little throughout the length of the core (Table 1).

All natural fractures in the core are filled with calcite cement. This is probably due to fluids being calcite saturated, calcite outcompeting quartz for nucleation sites and that the emergent threshold for calcite-filled fractures is higher, >2mm, compared to the emergent threshold for quartz-filled fractures, <1mm. (Julia Gale, personal communication 2013). As soon as the fractures open, the pressure drops and calcite starts to precipitate, plugging up most of the fractures, leaving no space for post kinematic quartz (Julia Gale, personal communication 2013). The emergent threshold is an
empirical observation that a kinematic aperture exists below which fractures are completely filled with cement and occluded and above which they are only partially cemented and bridged or completely open (Olsen et al., 2009). Detailed structural petrography and geochemistry analysis, specifically carbonate isotope analysis, on the fracture cements is needed in order to confirm that calcite is the only mineral filling the fractures. Other possible fracture cements may include quartz, pyrite and/or dolomite. Ammonites are filled with both calcite and pyrite cement.

5.3 Fractures, Ammonites and Porosity/Permeability

Porosity values for each sample discussed in the results section were calculated using a porosity calculator called GeoPixel Counter created by Kenrick Mock and Julian Bertmaring from the University of Alaska Anchorage, and Jeffrey Amato from New Mexico State University with the concept created by Sunny Remmy. GeoPixel Counter is based on color values of pixels in thin section images. The porosity values read high because of newly formed fractures in the rock created from drilling, core retrieval and thin section preparation. Also, organic matter or kerogen might be counted as porosity, which will increase porosity values in GeoPixel Counter. Porosity values determined by GeoPixel range from as high as 17.3% in Sample 6 to as low as 1.85% in Sample 11. Average porosity values for the Haynesville Shale vary from 8 – 14% (Wang and Hammes, 2010).

Vertical fracturing postdates deformation and cementation of the ammonites based on cross-cutting relationships and lack of deformation of the fractures. Based on SEM and thin section images, cementation of the fractures occurred in multiple stages. There are at least two different stages of cementation (Figs 25 & 32). The first stage
shows cementation along the right and left side of the vertical fractures while the second stage displays cementation down the center of the fractures, cross-cutting the first stage. Cementation along the edges of the fractures most likely occurred first as calcite attempted to bridge across the fractures. Fluid may have flowed through the center of the fractures until cement was eventually able to completely fill the pore space. Fluid inclusion information is needed in order to reconstruct fluid temperature and pore pressure evolution during fracture opening (Laubach et al., 2010).

Prior to the precipitation of cement across the fractures and through the chambers in the ammonites, these two features provided permeable pathways for hydrocarbon migration and flow through the Haynesville Shale. Upon cementation, porosity and permeability were greatly reduced. However, there is still some amount of porosity and permeability associated with cemented fractures and cemented ammonites (Figs. 20 – B & 24 – B & C). In both fractures and ammonites, there is a characteristic crack or break running down the center of the fractures and ammonites that may have formed in-situ rather than from core retrieval (Figs. 24 – B, 30 – C, & 31 – B). These cracks are likely the result of incomplete cementation. There are also porous zones along the boundary between fractures, ammonites and the surrounding matrix (Fig. 20 – B, 24 – C and 31 – C & D). These are also zones of weakness most likely due to the weak bond between clay in the matrix and calcite in the cement. The Barnett Shale displays these same porous zones between fractures and the wall rock (Gale et al., 2007). These porous zones may act as a plane of weakness that can be reactivated by a hydraulic fracture procedure (Gale et al., 2007). The presence of burrows may also lead to increased permeability of the
shale reservoir if the burrows become connected to natural fractures by a hydraulic fracture procedure that reopens the cement filled burrows.

5.4 Fractures in Other Shale Plays

In the Barnett Shale in north central Texas, natural opening-mode fractures are most commonly narrow and sealed with calcite (Fig. 45) (Gale et al., 2007). Natural fractures in the Barnett Shale appear to be near-vertical in their orientation, but orientation of all the cores used in the study is not provided and therefore accurate fracture orientation is not included (Gale et al., 2007). Compared to the Haynesville Shale, the Barnett Shale generally contains a much higher percentage of quartz, less clay and calcite, and a similar amount of kerogen (Hart et al., 2013). Natural fractures in the Haynesville Shale are similar to natural fractures in the Barnett Shale in their aperture sizes, steeply dipping orientation and calcite cement. Fracture planes in the Barnett Shale are observed to be only half as strong as the host rock during tensile testing (Gale, 2008). Fracture planes in the Haynesville Shale may also be weaker than the host rock based on zones of weakness identified in section 5.2.

In sandstone and siltstones in the middle member of the Bakken Formation in the Williston Basin, a majority of fractures are open (nonmineralized), discontinuous features oriented subparallel (horizontal) to bedding with aperture widths greater than 30 microns (Fig. 46) (Pitman et al., 2001). Vertical extensional fractures are rare and if present, they are filled with pyrite and calcite cement (Pitman et al., 2001). The fracture network of the middle member of the Bakken Formation is different from the Haynesville, and Barnett Shales in that natural fractures are primarily horizontal and open, able to transport
Figure 45. Core image of the Barnett Shale, Fort Worth Basin (Gale et al., 2007). Two overlapping cement filled fractures are present.
Fractures are revealed by wetting of the core. Hydrocarbons throughout the reservoir. It has also been noted that bedding-plane partings are inherent weaknesses in the Bakken Formation arising from thin bedding (laminations), fissility and/or lithologic contacts (Sonnenberg et al., 2010). This could also be the case with bedding-plane partings in the Haynesville Shale suggesting another zone of weakness for hydraulic fracturing treatments.
The Eagle Ford Shale is a frequently fractured, brittle, often micaceous, and fossiliferous shale with some siltstone and with occasionally recrystallized dolomitic lime streaks that exhibit a highly oil-saturated matrix (Fertl and Rieke, 1980). It has a much higher calcite content and lower clay content than the Barnett Shale and the Haynesville Shale (Hart et al., 2013). A petrophysical study by J. Mullen, 2010, revealed natural fractures in the Eagle Ford Shale. Thin sections of a core from the gas-condensate window of the Eagle Ford Shale show numerous bedding-plane fractures and occasional bedding normal fractures and pressure-release fractures (Fig. 47). No natural fractures were identified in core taken from the dry-gas window, but there were indications of a natural fracture pathway. Core taken from a third well in the oil-window of the Eagle Ford Shale revealed open natural fractures of random orientation (Mullen, 2010). The Haynesville Shale displays similar bedding-plane fractures, but it lacks bedding normal fractures at the microscopic level (Fig 47).

Figure 47. Low magnification image in UV light (epifluorescence). A) Bedding-plane fracture from core in the gas-condensate window in the Eagle Ford Shale (modified from Mullen, 2010). B) Bedding-plane fracture in the Haynesville Shale at 12,175.75 feet, Shelby County, East Texas.
5.5 Burrows

A common belief about black shales and especially black shales containing pyrite concretions, is that they were deposited under anoxic conditions and with an absence of benthos (Schieber, 2003). However, these pyrite concretions are actually burrows formed by small organisms moving their way through the sediment that became filled with pyrite later (Schieber, 2003) (Fig. 37). Little evidence of compaction by burial suggests that burrows were filled with pyrite cement prior to deformation. Heavily burrowed areas shown in Figure 37 are from near the top of the Haynesville Shale, but bioturbation and burrows are evident throughout the entire formation (See appendix B). This is evidence that the waters were oxygenated above the seabed during deposition of the Haynesville Shale. Pyritized ammonite fossils are also present throughout the core. Based on these observations, the bottom water conditions during time of Haynesville Shale deposition were closer to dysoxic than anoxic. Haynesville Shale deposition is interpreted to have occurred in a “quiet-water” environment, but the presence of ten possible sediment gravity flows throughout the core suggests that seafloor energy levels were high enough to rework and transport sediment advectively and that sediment dispersal was not just attributed to low-energy suspension settling (Macquaker et al., 2013).
Chapter 6. Conclusions

Core and fracture analysis was completed on 157.6 feet of Haynesville Shale core from one vertical well located in Shelby County, East Texas. Core and computed tomography scans reveal the presence of seven natural near vertical fractures filled with calcite cement. Based on the azimuth and orientation of four of these fractures, a vertical fracture set is identified in the core. Core from a horizontal well is needed in order to calculate fracture density, spacing and identify open and closed fracture sets in the Haynesville Shale.

There are a large number of horizontal features present, some are natural horizontal fractures filled with calcite cement, but most appear to be bedding-plane partings from decompression.

Although porosity and permeability is reduced upon cementation of structures such as fractures, ammonites and burrows, these structures may still contribute to the porosity and permeability by providing pathways for hydrocarbon migration and flow through the Haynesville Shale. There is parting between mineral cement and the matrix throughout the core. Vertical fractures and horizontal fractures may act as a plane of weakness that can reactivate if strategically targeted with a hydraulic fracture procedure, and possibly interconnecting the fracture network.

The presence of pyrite filled burrows indicates that water directly above the seabed was not anoxic, but contained some amount of oxygen. Bottom-water conditions at the time of deposition were closer to dysoxic conditions rather than anoxic conditions and seafloor energy levels may have been high based on possible sediment gravity flows.
Natural fractures in the Haynesville Shale are similar to fracturing in the Barnett Shale in that both shale plays display near vertical fractures filled with calcite cement. Core taken from the middle member of the Bakken Formation and from the Eagle Ford Shale reveal more horizontal fracturing compared to the Haynesville Shale. Many of the fractures in the middle member of the Bakken Formation are open as opposed to filled with cement. Areas high in clay content in the Barnett Shale, the middle member of the Bakken Formation and in the Eagle Ford Shale, tend to act as fracture barriers and make the rock more ductile. Quartz is the most abundant mineral present in the matrix surrounding these fractures along with calcite and clay, but no clear correlation between the mineralogy and the number of open and closed fractures can be made.

While the absence of cross-cutting relations or other age dating does not allow a precise sequence of events, the evidence presented here provides the following constraints: 1) burrows were filled with early pyrite cement prior to deformation by burial; 2) ammonites were compressed by burial prior to replacement by calcite and pyrite; 3) different orientations of fractures (vertical, horizontal or oblique) as well as variation in azimuth among vertical fractures implies that the stress field varied with time.
References


Avizo Tutorial provided by UTCT short course: Basics of 3D Quantitative Analysis of Geological Materials Using CT, July 30 – August 1, 2012, Austin, TX, Jackson School of Geosciences.


Appendix A. Additional Core Samples

Sample 3 – Horizontal fractures

Figure A1. Core photo of Sample 3 at 12,135.05 feet. Horizontal fracture labeled by white arrow. Numbers on the left are in 1/10 of a foot.
Figure A2. SEM images of Sample 3. A) Possible horizontal fracture filled with calcite and pyrite cement. B) Ammonite shell fragment filled with pyrite cement. C) Possible horizontal fracture filled with calcite and pyrite cement. Location of Image C is labeled on Image A. Image B is not shown in Image A. Mtx = matrix, Py = pyrite, Om = organic matter, Am = ammonite and Cal = calcite cement.
Figure A3. Core photo of Sample 8 at 12,209.85 feet. Ammonite filled with calcite and pyrite indicated by white arrow. Numbers on the left are in 1/10 of a foot.
Figure A4. SEM images of Sample 8. Several ammonite shell fragments filled with calcite cement. Locations of Image B, C & D are shown. Mtx = matrix, Py = pyrite, Om = organic matter, Am = ammonite and Cal = calcite cement.
Sample 9 – Near vertical fracture

Figure A5. Core photo of Sample 9 at 12,213.6 feet. Vertical fracture indicated by white arrow. Numbers on the left are in 1/10 of a foot.
Figure A6. SEM images of Sample 9. Image A, B & C show a calcite cement filled vertical fracture. Image D shows the vertical fracture intersecting an ammonite. Locations of Image B, C & D are shown. Mtx = matrix, Py = pyrite, Om = organic matter, Am = ammonite and Cal = calcite cement.
Sample 10 – Near vertical fracture

Figure A7. Core photo of Sample 10 at 12,219.41 feet. White arrow indicates vertical fracture. Numbers on the left are in 1/10 of a foot.
Figure A8. SEM images of Sample 10. Image A, B & C show a calcite cement filled vertical fracture intersecting a calcite cement filled ammonite. Image D shows just the ammonite. Locations of Image B, C & D are shown. Mtx = matrix, Py = pyrite, Om = organic matter, Am = ammonite and Cal = calcite cement.
Sample 15 – Mixed calcite cement and pyrite cement

Figure A9. Core photo of Sample 15 at 12,251.15 feet. Mixed calcite cement and pyrite cement indicated by pencil. Numbers on the left are in 1/10 of a foot.
Figure A10. SEM images of Sample 15. Images show a mixture of calcite and pyrite cement. Locations of Image B, C & D are shown. Py = pyrite cement and Cal = calcite cement.
Sample 17 – Organic material with pyrite cement

Figure A11. Core photo of Sample 17 at 12,267.23 feet. Organic material or burrows filled with pyrite cement prior to compaction, indicated by pencil. Numbers on the left are in 1/10 of a foot.
Figure A12. SEM images of Sample 17. Image A, B & C show pyrite cement surrounded by possible calcite cement and organic material. Image D shows large pyrite grains within a fine-grained matrix. Locations of Image B, C & D are not shown in image A. Py = pyrite, Mtx = matrix and Cal = calcite cement.
Appendix B. Core Log with Sample Locations

Below is an interpretation of the sampled core by Dr. Joan Spaw, Marathon Oil, using CT scans. The locations of the collected samples by Frank Morgan and Dr. Jeffrey Nunn are identified on the log. Sample locations are labeled with red stars. The log was donated by Marathon Oil and Dr. Joan Spaw. All of the interpretation was done by Dr. Joan Spaw. The only modified material are the location text boxes for each sample and the red star on the core (modified by Frank Morgan).
Sample 1 @ 12,131.3

Sample 2 @ 12,134.69

Sample 3 @ 12,135.05

Sample 4 @ 12,136.38

Sample 5 @ 12,151.75
Sample 7 @ 12,181.34
Sample 8 @ 12,209.85
Sample 9 @ 12,213.6
Sample 10 @ 12,219.41
Sample 18 @ 12,224.7
Sample 11 @ 12,225.58
Sample 15 @ 12,251.15

Sample 16 @ 12,259.71

Sample 17 @ 12,267.23
Vita

Frank Morgan was born in Austin, Texas in 1988. Frank spent the next twenty-two years of his life growing up and going to school in Austin. Frank earned a Bachelor of Science degree in geology from the Jackson School of Geosciences at The University of Texas at Austin in August of 2011. He then went on to pursue a Master of Science degree in the Department of Geology and Geophysics from Louisiana State University under the advisement of Dr. Jeffrey Nunn. After completing his degree Frank will work full-time as a geologist for Devon Energy in Oklahoma City, Oklahoma.