JOINT GEOPHYSICAL AND GEOMECHANICAL ANALYSIS
OF IN-SITU STRESS, WATTENBERG FIELD, COLORADO,
USA

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

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ABSTRACT

The Wattenberg Field, Denver Basin, is a prolific oil and gas field currently ranked as the seventh largest domestic gas field within the United States. The Reservoir Characterization Project, in cooperation with Anadarko Petroleum Corporation, undertook an integrated dynamic reservoir characterization of a portion of Wattenberg Field integrating the disciplines of geophysics, geology, geomechanics, petrophysics, and petroleum engineering. My study focuses primarily on the integration of geophysics and geomechanics via relationships between stress, production, and completions. Eleven horizontal wells are present in the study area - seven Niobrara Chalk wells and four Codell Sandstone wells. Several vertical wells exist within the study area as well. Various seismic surveys were acquired over the study area with the intent of carrying out time-lapse (4D) multicomponent reservoir characterization.

The objective of my research is to integrate and correlate geophysical and geomechanical data in an effort to provide a better reservoir characterization in Wattenberg Field. With varying well spacing, completion methods, and target intervals, there are a plethora of variables to be evaluated here. Relationships have been found between various completion parameters, production, stress, and geology that could have an impact on the way in which we drill and complete wells in Wattenberg Field. Through this study I have found that little correlation exists between completions parameters (fluid and proppant injection) and production, or between ISIP and fracture network complexity. The largest control on production variability in the study area appears to be geology, both at the seismic- and sub-seismic scale. I have shown that stress differences within the study area exist due to complex geologic structure and fault systems and could be the reason behind differences in production, seismic attributes, and microseismic trends. Additionally, stress compartments subdivide the study area even further and account for localized stress rotations within complex geologic structures largely controlled by faults. These features control pressure and
stress distribution throughout the reservoir and are considered to be the main driving factors for production variability across the study area.
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LIST OF SYMBOLS

Stress ..........................................

Maximum Principal Stress ......................... $S_V$ or $\sigma_V$ or $\sigma_1$

Maximum Horizontal Stress ...................... $SH_{Max}$ or $\sigma_H$ or $\sigma_2$

Minimum Horizontal Stress ..................... $Sh_{Min}$ or $\sigma_h$ or $\sigma_3$

Young’s Modulus ................................ $E$

Poisson’s Ratio .................................. $\nu$

Shear Modulus .................................... $\mu$ or $G$

Bulk Modulus ..................................... $K$
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<tr>
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<th>Description</th>
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<tr>
<td>APC</td>
<td>Anadarko Petroleum Corporation</td>
</tr>
<tr>
<td>bbl</td>
<td>Barrel</td>
</tr>
<tr>
<td>BOE</td>
<td>Barrel Oil Equivalent</td>
</tr>
<tr>
<td>RHOB</td>
<td>Bulk Density</td>
</tr>
<tr>
<td>CWP</td>
<td>Center for Wave Phenomena</td>
</tr>
<tr>
<td>CSM</td>
<td>Colorado School of Mines</td>
</tr>
<tr>
<td>IDEE</td>
<td>Deep Resistivity</td>
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<tr>
<td>EUR</td>
<td>Estimated Ultimate Recovery</td>
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<tr>
<td>4D</td>
<td>Four-Dimensional</td>
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<tr>
<td>GR</td>
<td>Gamma Ray</td>
</tr>
<tr>
<td>GOR</td>
<td>Gas Oil Ratio</td>
</tr>
<tr>
<td>GWA</td>
<td>Greater Wattenberg Area</td>
</tr>
<tr>
<td>Hz</td>
<td>Horizontal</td>
</tr>
<tr>
<td>HTI</td>
<td>Horizontal Transverse Isotropy</td>
</tr>
<tr>
<td>ISIP</td>
<td>Instantaneous Shut-In Pressure</td>
</tr>
<tr>
<td>MEM</td>
<td>Mechanical Earth Model</td>
</tr>
<tr>
<td>nD</td>
<td>Nanodarcy</td>
</tr>
<tr>
<td>1D</td>
<td>One Dimensional</td>
</tr>
<tr>
<td>OGIP</td>
<td>Original Gas In Place</td>
</tr>
<tr>
<td>PR</td>
<td>Poisson’s Ratio</td>
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<tr>
<td>Term</td>
<td>Abbreviation</td>
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<tr>
<td>-------------------------------------------</td>
<td>--------------</td>
</tr>
<tr>
<td>Reservoir Characterization Project</td>
<td>RCP</td>
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<tr>
<td>Rock Quality Index</td>
<td>RQI</td>
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<td>Shear Wave Splitting</td>
<td>SWS</td>
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<td>SR</td>
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<td>Stimulated Reservoir Volume</td>
<td>SRV</td>
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<tr>
<td>Thermal Neutron Porosity</td>
<td>NPHI</td>
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<tr>
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<td>Trillion Cubic Feet</td>
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him.

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Finally, to Christina Volpi (CSM ‘12), you are my best friend and the love of my life. As a scientist yourself (Volpi, 2014), you pushed me throughout the past two years and made me a better scientist and a better person. I love you and look forward to our future together.
For Robert B. Pitcher (1962-1997)
CHAPTER 1
INTRODUCTION

The Reservoir Characterization Project (RCP) is an industry-sponsored, academic research consortium focused on integrated time-lapse monitoring of unconventional reservoirs. Spanning the disciplines of Geophysics, Geology, and Petroleum Engineering, RCP has built its legacy on multicomponent time-lapse reservoir characterization. The dense datasets that are collected by and available to RCP enable strong scientific evaluations. My work focuses on setting up a 3D geomechanical model over the study area for future use, and using the geomechanical information gleaned from validation datasets to ascertain how in-situ stress changes near faults and fractures affect completions and production within the Niobrara Formation and Codell Member.

Through analysis of the various validation datasets in our possession, I was able to determine that no direct correlation exists between completions parameters (fluid and proppant injection), ISIP values, and well productivity. While there are injection thresholds that correspond to better production, the range of those thresholds is not well constrained. It is clear that abnormally high injection values have a negative effect on production. By interpreting pressure curves recorded during the completion job, I found that ISIP values (used as a proxy for $Sh_{Min}$) have little correlation to spinner production logs, but rather correlate to geologic structure. The implication of this is that structure is driving production variability in the field. Robust seismic analysis is warranted, and may be the way forward for improving completion jobs, production, and understanding exactly what controls stress in the field. This is the first comprehensive study of its type that has been carried out for Wattenberg Field with such a complete dataset.
1.1 Motivation

Recent Energy Independence Administration (EIA) studies predict that natural gas consumption will increase by nearly 70% globally by 2030. Over 50% of proven tight gas reserves in the lower 48 states exist in the Rocky Mountain region, in fields such as Wattenberg Field. In a 2009 EIA study, Wattenberg Field was ranked number 10 out of the top 100 oil and gas fields in the United States, and number 7 for the largest gas fields in the United States. As development from tight resource plays continues to improve, production improves as well. The continuation of this relationship is important to ensure that we meet oil and gas demand as projected by the EIA.

Wattenberg Field, a large tight oil and gas field in the Denver Basin of Colorado, will be an important player in meeting the resource demands of the nation for the foreseeable future. Although the field has been in vertical production since the early 1970’s; horizontal production began only in the mid-2000’s. Target intervals include interbedded chalks and marls, and sandstones - all with low porosity and permeability - 6-8% porosity, and permeability in the nanodarcy range. Operators in the field currently drill horizontal wells anywhere between 20 and 160 acre spacing, with variable well lengths, drilling azimuths, and target intervals. Modern-day maximum horizontal stress direction and lease acreage conditions dictate that most wells are drilled in a north-south orientation to fit an ideal number of wells in a section and intersect the greatest number of natural fractures.

In order to optimize production through drilling and completions techniques, I have developed a three-dimensional structural model that incorporates the subsurface geology and reservoir properties. It will be used as the input for future reservoir and geomechanical simulations. Insights from the model include a greater understanding of stress effects near faults, and ideas of natural and hydraulic fractures. The primary goals of simulating such a model are to determine how the effect of in-situ stress and stress changes relate to production, with specific regard to stress rotations nearby to large-scale faults and graben features, as well as the role that the pressure front plays. The three-dimensional model was populated
via a one-dimensional single-well mechanical earth model (MEM) model that was clustered to vertical well control and seismic. The details of both the 1D and 3D models are presented in chapters 3-4, but the model will be simulated in Visage™ software at a later date as a different master’s thesis. It will also be used as the foundation for reservoir simulations in Eclipse™ software. Pressure curves recorded during the completions were also interpreted in order to gain a stage-by-stage understanding of the stress-state throughout the reservoir. Their relation to the other geophysical datasets are detailed in this thesis.

1.2 Field Background

Wattenberg Field is located approximately 35 miles northeast of Denver, Colorado and covers a large area of the Denver Basin (Figure 1.1). The field produces from sandstones, shales, chalks, and marls of Cretaceous age. Originally discovered in 1970 and exploited vertically, Wattenberg Field has produced over 2.8 TCF of gas. Over 11,000 vertical wells are present in the field, with a shift toward horizontal drilling occurring only as recently as 2007. This shift to horizontal drilling, focused on the Niobrara Formation, has brought new life to the field, with hundreds of horizontal wells already drilled and thousands more planned over the next five years.

The Niobrara Formation is the main development target at general depths of 6500 to 7500 ft. It is comprised of approximately 300 feet of interbedded limestone, chalk, and marl intervals in a complex stratigraphic and structural architecture (Figure 1.2) dominated by normal-faulted grabens. The underlying Codell Sandstone Member of the Carlile Formation is treated as a separate reservoir unit.

At these depths, normal listric faults within the reservoir interval and wrench faults deeper in the subsurface complicate drilling and completions of wells (shown in the background of Figure 1.5). These wrench faults, and wrench fault systems, were originally field-mapped by Bob Weimer in the 1960’s and are fairly well-mapped features within the basin. The RCP study area in Wattenberg Field sits between the Longmont and Lafayette wrench faults (shown in the background of Figure 1.5) and is not directly affected by their distal
Figure 1.1: Wattenberg Field is northeast of Denver, Colorado. The study area is outlined in red.

presence. The next level of faulting, normal faults forming en-echelon graben systems, lead to an increase in fracture density in their proximity. As is the nature of subsurface cracks, some faults here act as conduits of flow while others act as seals. It is important to note that all faults present within the reservoir interval die out in the Lower Pierre Shale, thousands of feet below the surface and any freshwater aquifers. The large number of faults complicate drilling efforts because wells cannot be steered to remain within the target zone at all times. Variability in production results as an effect of the wellbore tortuously traveling through these different intervals. The overpressured nature of the overburden complicates drilling when the well-path encounters faults in the overlying Sharon Springs Formation due to both the overpressure and the mechanical properties of the Sharon Springs. The Niobrara Formation is also overpressured, meaning that the pressure gradient in the field at reservoir depths is above the standard pressure gradient of 0.433 psi/ft (Figure 1.6). Well trajectories for this study were generally kept uniform in hope of making contact with different intervals
Figure 1.2: Cretaceous stratigraphic column showing the multiple pay zones, source rock (SR) intervals, and typical drilling depths (after Sonnenberg, 2012)
of brittle reservoir rock so that hydraulic fractures propagate optimally in the direction of maximum stress, which in this case is $S_V$.

Improvement upon well completions and stimulations would have a significant impact on future reservoir development within the field. Horizontal wells within the Niobrara can have large production variability. Reservoir rock quality is poorly constrained, and the differences between the Niobrara chalks and marls in terms of production are miniscule. Tortuous well paths that travel throughout the Niobrara as well as the Codell Sandstone have similar production to wellbores that travel uniformly through only the Niobrara C Chalk target interval. Overall, identification of optimum reservoir development strategies is important for the future development of the field and unconventional resources in general. These strategies will hinge on insights into drilling and completions parameters, petrophysical and geomechanical studies, and seismic information derived from this project.

Wattenberg Field encompasses a total of approximately 1000 square miles in the west-central part of the Denver Basin (Higley and Cox, 2007). The paleo-geographic setting of the basin was a coastal environment adjacent to an epeiric seaway that flooded much of central North America during the Late Cretaceous period (Figure 1.3). Deposition of geologic strata that we are now drilling took place during the Cretaceous in environments ranging from marine to near shore deltaic and estuarine environments. What was once a marine to coastal environment was transformed into an asymmetric foreland basin by tectonic activity during the Laramide Orogeny. The eastern flank of the basin dips gently throughout eastern Colorado and Nebraska while the western flank dips steeply at the mountain front (Figure 1.9). Basement rock includes igneous and metamorphic rocks of Precambrian age. Faulting and natural fracturing is prevalent throughout the basin.

Oil and gas presence in Wattenberg Field is partially attributed to the regionally anomalous high temperature gradient within the center of the field (Figure 1.5). The higher temperature gradient is related to basement igneous intrusives (Higley and Cox, 2007), which are interpreted to be post-Cretaceous in age. The generation of large oil and gas reservoirs
Figure 1.3: Blakey map showing the Western Cretaceous Interior Seaway during the Coniacian Age of the Late Cretaceous. Yellow star denotes location of present-day Denver Basin (Modified from Blakey, 2014)
resulted from the thermal maturation of organic content in the Mowry, Huntsman, Graneros, Greenhorn, Carlile, Niobrara and Pierre Formations (Sonnenberg, 2013). Reservoirs in Wattenberg Field are found in the Muddy (J), Codell, Hygiene and Terry sandstones, and in dense fractured limestones of the Niobrara Formation (Weimer, 1996) (Figure 1.2). The large number of wells present within the field (and the larger basin) is shown in Figure 1.4, where Wattenberg Field is easily identified as the largest cluster of gas wells (red) near Boulder, Greeley, and Longmont. These wells target reservoirs that are generally characterized by low porosity and permeability, and where natural fracturing is common. The Niobrara Formation is overpressured while the upper Pierre shale and the Muddy (J) Sandstone are underpressured (Figure 1.6). This overpressuring exists throughout the basin primarily because of the kerogen maturation within the Niobrara interval, and is evidenced in other source-rock reservoirs as well. As a self-sourcing tight formation, this pressure signature is expected and beneficial. The top of overpressure is above the Niobrara in the overlying Lower Pierre, while the bottom of overpressure and even an underpressure zone exists below the Codell Sandstone. Both the overpressured Sharon Springs and underpressured Muddy (J) Sandstone form drilling hazards within the basin.

In Wattenberg, the Niobrara Formation is a dense carbonate-rich formation ranging from 200 - 400 feet in thickness with organic rich, calcareous marl members. Depth to the Niobrara is approximately 7500 ft below Denver. The Fort Hays Limestone is characterized by chalk beds separated by layers of calcareous shales and is generally between 10 and 60 ft in eastern Colorado (CGS, 2011). The Niobrara Formation is generally 200 ft thick in eastern Colorado, though it can be thicker than 1400 ft in northwestern Colorado. The Niobrara overlies the Fort Hays Limestone (Figure 1.2) (CGS, 2011).

Production from the Niobrara has existed since the late 1800’s, but production from the Niobrara, specifically in the Denver Basin, became sustainable in the 1970s (CGS, 2011). The majority of historic conventional wells are concentrated in Yuma and Weld Counties, and the majority of the Wattenberg Field falls within the boundaries of Weld County. Drilling
Figure 1.4: Oil (yellow-green), oil and gas (blue), and gas (red) wells across the northern Denver Basin. Major fields within the Front Range area are labeled in white (Higley and Cox, 2007).
Figure 1.5: Geothermal anomaly centered within the basin showing vitrinite reflectance at the level of the conventionally producing D Sand (Higley and Cox, 2007)
Figure 1.6: Depth-pressure graph of Denver Basin stratigraphy showing overpressuring in the Niobrara and related formations. Note that the Dakota Group is underpressured, indicating flow barriers and changes in permeability. (modified from Sonnenberg, 2012, modified from Weimer, 1996)
in Wattenberg started with Amoco targeting the Muddy (J) Sandstone.

Over time, each of the reservoirs within Wattenberg has been drilled, and the innovation of horizontal drilling in the Niobrara has enabled new production in the field. Below the Niobrara Formation is the Carlile Formation which contains the Codell Sandstone and is of Cretaceous age. The Codell Member is a producing interval in Wattenberg Field and has unconformable upper and lower contacts. Maximum thickness is approximately 100 ft. with an average thickness of 15 to 20 ft. The Codell member contains three distinct sandstone settings resulting from varying depositional environments, and most production comes from the middle section. The depths of the productive interval range from 4,000-8,000 ft. (1,219 to 2,438 m) with pay ranges of 3 to 25 ft. (0.9 to 7.6 m) (Weimer and Sonnenberg, 1983). Minor production has been achieved in the lowest interval, which is tight. It is possible that the Codell Sandstone and overlying Fort Hays Limestone are interconnected reservoirs due to in-place fracture networks (Shoup et al., 2013). Below the Carlile Formation is the Greenhorn Limestone, which is of Cretaceous age and is similar to the Niobrara Limestone. Although some oil and gas have been recovered from the Greenhorn, it remains largely unexplored. Drill stem tests, mud gas shows, and geochemical analysis support the potential for plays in this unit. The Greenhorn is estimated to be 300 ft. thick in Denver Basin and may provide new pathways for future production in Wattenberg Field (Weimer et al., 1986).

1.3 Geologic History

The Denver Basin is a large assymmetrical foreland basin extending throughout Colorado, Wyoming, South Dakota, Nebraska, and Kansas. Formed during the Laramide orogeny (Late Cretaceous), the same tectonic episode that formed the ancestral Rocky Mountains, the Precambrian basement rock was uplifted, folded, and faulted throughout the orogeny. These basement tectonics affected the overlying sedimentary layers of the basin, folding and faulting them. Roughly elliptical in shape, the basin is bounded on five sides by structural geologic features. The Front Range Uplift, Hartville Uplift, Chadron Arch, Las Animas Arch, and Apishapa Uplift are the structurally bounding features to the West, Northwest,
Northeast, Southeast, and Southwest, respectively (Figure 1.7). Consequently, the basin formed as an ovoid or elliptical shape as a basin-centered gas field. Dipping steeply along the Rocky Mountains to the west and very shallowly into the Great Plains region to the east, this foreland basin is often considered to be adjoining with the Julesburg basin. With both structural and stratigraphic traps, oil and gas presence in the basin is due to generation of hydrocarbons and presence of reservoir rocks within many of the same intervals.

Figure 1.7: Regional extent of Denver Basin showing bordering uplifts and arches. The synclinal axis (red) is the structurally deepest part of basin (Knepper et al., 2002)
A geologic events chart for the Upper Cretaceous geologic formations in the basin is seen in Figure 1.8. As can be seen in the chart, the Upper Cretaceous formations act as source rocks, reservoir rocks, and seals. The Late Cretaceous source rocks were emplaced, acted as both source and reservoir rocks, and later began to act as stratigraphic seals. The Late Cretaceous to Early Paleogene Laramide Orogeny formed the basin that exists today and emplaced structural traps. Hydrocarbon generation, migration, and accumulation all occurred throughout the Cenozoic Era, from the Paleogene into the Neogene. Figure 1.8 and Figure 1.6 both lead to the interpretation of overpressuring within the basin, especially the source/reservoir intervals near the geothermal anomaly within the center of the basin.

Wattenberg Field is but one of over 1,000 oil and gas fields within the greater Denver-Julesburg Basin. Its location near the western reaches of the basin, proximal to the well-documented geothermal anomaly, has made it one of the more prolific and economic fields in the state and even the nation. The strong production and petroleum reserves that exist within the reservoir can be attributed to the complex geology within the larger foreland basin. Each of the bounding arches, the geothermal anomaly, and the fact that the reservoir interval is self-sourced all contribute to the strong performance of the field. The RCP study area falls between two of these wrench faults and may be less affected than analogous producing sections elsewhere in the field. The geothermal anomaly (Figure 1.5) is believed to exist due to the heat flow generated from igneous intrusions, and is best mapped using vitrinite reflectance values for different producing intervals, such as the D Sand. The wrench fault systems are thought to provide another conduit for heat flow throughout the field, creating isolated fault blocks with different temperature signatures (Recovery, 2012). The difference in heat flow throughout the different regions of the field could be responsible for some of the differences in source rock maturation, hydrocarbon expulsion, and consequently could be a driving factor in the variability that we see in GOR throughout the field.
Figure 1.8: Geologic events chart for Upper Cretaceous formations in the western Denver Basin. Gray intervals mark times of primary events; gradients show possible times of events. Green intervals mark times of generation of oil from the Niobrara, Codell, Carlile, and Greenhorn Formations. Wavy black lines indicate ages of probable unconformities. The Paleocene onset of oil generation from the underlying Niobrara Formation and Carlile Shale is associated with the Laramide orogeny; increased thickness of sedimentary strata occurred during and preceding this 67 Ma event. This stratum is largely the Pierre Shale. Generation of oil is due primarily to the greater depth of burial and associated temperature and pressure. Increased thickness of sedimentary strata before the onset of the orogeny indicates that uplift of the Front Range and associated subsidence of the Denver Basin may have been initiated prior to the major phases of mountain building. Abbreviations: E, Early; L, Late; Paleo, Paleocene; Oligo, Oligocene; PP, Pliocene and Pleistocene (Higley and Cox, 2007)
1.4 Stress History of Wattenberg

Previous RCP theses in other unconventional basins in Colorado have shown that stress and burial history are critical factors to understanding how present day stress will affect producing reservoirs. In Wattenberg, the burial history and deformation of the field lead to an understanding of modern-day stresses. This is the first RCP thesis to study and focus on a geomechanical evaluation of Wattenberg Field, including geologic history, stresses, and pressures. What follows is a synopsis of the burial history of Wattenberg Field as interpreted from the literature.

To describe the burial history and stress state of the modern-day Denver Basin, one must go back to deposition of the source/reservoir rock intervals. The primary reservoir intervals within Wattenberg Field, the Niobrara Formation and Codell Member, were deposited in the Cretaceous era into the Western Cretaceous Interior Seaway (Figure 1.3). These sedimentary layers were deposited horizontally and began burial at that time, forming the foundation of vertical transverse isotropic (VTI) media. As burial continued, vertical loading and vertical effective stress increased and the weight of compaction began to dewater these formations. The rapid (geologically) compaction and dewatering of these horizontal layers formed a basis for the polygonal fault system that is present today within the reservoir interval (Sonnenberg...
The stress of the overburden was relieved in an extensional setting, causing normal faulting of the carbonate layers. Following that, the Laramide Orogeny initiated normal faulting with dual-azimuth splitting joints, due to both Laramide subhorizontal compression and post-Laramide extension. The last fracture mechanism evidenced in the basin is the low-angle listric and planar normal faults that form the basis of the en-echelon graben system we see throughout the entire basin (Davis, 1985; Shelton, 1984). Based upon the greater understanding of complex fault systems available in the literature recently, it could be interpreted that all of these faults contribute to the same complex polygonal fault system. As seen in Cartwright (2011) in case C (Figure 7.5), the complex systems can have contributions from shale compaction and dewatering as well as normal faults that segment the system. This is precisely what we see in the study area - generally listric normal faults combining with smaller-scale normal faults initiated during shale compaction combining to create one complex system with compartmentalization. The manner in which these pockets segment the pressure front and stress field could prove to be one of the driving factors of variable production throughout Wattenberg Field.

As an extensional system, the Denver Basin fits the first case of Anderson’s 1951 theory of faulting (Anderson, 2012). This is the case where \( \sigma_1 \) is vertical and \( \sigma_3 \) is horizontal, or \( S_V > S_H > S_h \) (Figure 3.2). This knowledge allows us to make scientific decisions regarding hydraulic fracturing, as it gives us an idea of how fractures will propagate in the subsurface and how fluids may flow to the wellbore. Mapping the in-situ stress changes within the reservoir, due to both complex burial history/geology and drilling completions could lend a great deal of insight into completion quality and production.

1.5 Objectives

The primary objectives of this study are:

1. To incorporate an existing 1D mechanical earth model into a 3D structural model that can be utilized to run joint reservoir and geomechanical simulations relating to stress
and pressure changes within the reservoir interval.

2. To determine how localized stress changes surrounding faults and natural fractures affect and/or contributes to production.

3. To find correlations between various completions parameters and production on both a stage-by-stage and wellbore basis.

4. To classify relationships between geomechanics and geophysics. That is, to tie the stress insights we see from geomechanical data back to the seismic data.

5. To provide a baseline geomechanical model to Anadarko Petroleum Corporation and the Reservoir Characterization Project that can be utilized for future research with additional data such as time-lapse seismic. This model will provide a foundation that can be gauged against future seismic volumes to determine in-situ stress and pressure changes due to production from the reservoir to determine if stress-refracturing may be completed.

Completing these objectives should lay the groundwork for the geomechanical evaluation of the RCP study area. The baseline and monitor surveys show the effect of the hydraulic fracture job, while an additional monitor would delineate the effect of pressure depletion due to production. Figure 1.10 shows the timeline of data acquisition and what occurred between the time that both seismic surveys were acquired. An additional monitor needs to be shot once draw down pressure is enough to make a noticeable difference in the seismic data. The data evaluated here, and the current state of the structural framework, allows for forward modeling of the hydraulic stimulation and production effects, while an additional monitor would ground-truth the simulation. The data used in this study and included in the structural model are the Turkey Shoot PP baseline seismic data, completions information, microseismic data, well log suites (including image logs), and several others.
Figure 1.10: Data acquisition timeline for RCP Phase XV (White, 2015)
The Reservoir Characterization Project has a long and storied history of using geomechanics as a high-tech reservoir characterization tool for both conventional and unconventional studies. Within the last decade, several theses have come out of this group focused on the geomechanical characterization of tight oil and gas plays. This thesis will be the first produced for the Phase XV Wattenberg Field project, and has been built around a strong interdisciplinary dataset. The reason geomechanical studies are carried out in the field of petroleum geophysics can be attributed to the strong effect that in-situ rock strengths and stresses have on production. Different scales of heterogeneity and anisotropy are sources of change for reservoir properties and production across a field, and even within a small study area such as the one RCP is currently evaluating. Wattenberg Field, in particular, is riddled with normal faults forming en-echelon graben systems at the reservoir level throughout the entire field which will affect in-situ stress. Basement controlled wrench faults have their own effects on the reservoir interval, as do faulting and stress changes in the overburden. Different research areas of geomechanics have emerged out of RCP, all focused on tight unconventionals, as is the industry-standard at this time.

2.1 RCP Theses

The most relevant studies to this research are the 2012, 2006, and 2008 RCP master’s theses by Heather Davey, Shannon Higgins, and Kurtis Wikel, respectively (Davey, 2012; Higgins, 2006; Wikel, 2011). Higgins’ and Wikel’s complementary work on Rulison Field involved the construction of four 1D mechanical earth or geomechanical models that acted as inputs to a 3D geomechanical model over the seismic coverage area. Building upon Higgins’ work, Wikel used 3D modeling with the four geomechanical inputs and time-lapse seismic data to show that slow shear anisotropy has strong correlations to areas of modeled pressure
and stress changes. Wikel (2011) showed that the difference in magnitude between the two horizontal stresses, $S_H$ and $S_h$ lead to different types of fracturing Figure 2.1. In cases where $S_{H_{max}} >> S_{h_{min}}$, hydraulic fracturing will open linear planar fractures. However, if $S_{H_{max}} >= S_{h_{min}}$, then complex fracturing with little to no preferred fracture orientation will propagate, forming the basis of a complex fracture network. These two cases are seen in Figure 2.1 and also detailed in Figure 3.10. Warpinski (2014) states that there are only two outcomes of hydraulic fracturing that increase productivity - large shear fractures that remain unpropped, and large shear fractures that are propped. The second case, in which proppant enters and remains in the hydraulic fracture is clearly the preferred case.

![Figure 2.1: Microseismic from NW Alberta (nitrogen enhanced slickwater) on the left with fairly linear fractures versus the much more complex network growth seen in the Barnett (slickwater) example to the right. Microseismic is from Atkinson, 2010 and King et al, 2008 (Atkinson and Davis, 2011; Wikel, 2011)](image)

Davey’s work on Pouce Coupe Field in Western Alberta involved the classification of reservoir rocks based upon a new rock typing that she developed - Rock Quality Index (RQI). Davey’s RQI is an effort to examine the composition and fabric of rocks and how
they relate to stress anisotropy, fracturing, and rock properties. The ultimate goal of her work was to determine the differences between reservoir quality and completions quality in order to pinpoint the best completions to use in different reservoir rocks. A similar study will commence for this Wattenberg project at a future date with combinations of the seismic, petrophysical, and geomechanical data in RCP’s possession. A key assumption of this study is that the differences between the chalk and marl intervals of the Niobrara are miniscule and do not contribute largely to the variations we see in production. While this is a large assumption it was made here in order to simplify the stress and fracture interpretation. This is validated to a degree by the core interpretation that I carried out, which showed that the characteristics of the Niobrara chalks and marls are very similar. Within the chalks exist a large proportion of marl, and within the marls exist a large proportion of chalk. The Niobrara static mechanical properties and Thomsen parameters reflecting layer anisotropy are not well-constrained at this time, but are currently being evaluated in an ongoing RCP PhD dissertation.

2.2 Stress Refracturing

Roussel and Sharma (2012) showed that in a tight sand Codell reservoir there were two components that reoriented stresses: mechanical effects, or opening of propped fractures; and poroelastic effects, or production/injection of fluids into the reservoir. In this context, the mechanical effects will be constrained to the near-field and the poroelastic effects will mainly affect the far-field. A schematic of the type of reorientation that occurs and what that means for refracturing can be seen in Figure 2.2. Refracturing in this context refers to the process of restimulating the well in order to induce fractures at different locations and/or azimuths than those created during the initial completions job. To provide a quantitative measure of their work, they modeled a Codell Sandstone reservoir that was refractured following a stress-field reorientation for which they had real data. The results of the study are seen in Figure 2.3, and show that due to mechanical and poroelastic induced stress-field rotations, at least locally, a majority of refracturing jobs will create fractures that propagate orthogonal (or at least non-
parallel) to the original hydraulic fracture until the point where they reach virgin rock outside of the depletion zone. This is a particularly interesting case-study as one of RCP’s study areas is that of refracturing. The reorientation that occurs can be attributed to pressure depletion through production. When in-situ pressure declines, both $SH_{Max}$ and $Sh_{Min}$ decrease with it, only $SH_{Max}$ declines more rapidly, bringing the two horizontal stresses closer together (personal communication with Tom Bratton). Should $SH_{Max}$ decrease enough that it becomes lower than $Sh_{Min}$, the reservoir exhibits a stress-field rotation that can be exploited during a refracturing job. In this case, the new hydraulic fracture will propagate in the direction of the newly oriented $SH_{Max}$ and open in the direction of the newly oriented $Sh_{Min}$. Once the boundary of the depleted zone is reached and the stress-field returns to the regional in-situ stress-field, the tip of the fracture will turn back to the direction of regional $SH_{Max}$, creating a complex dual-azimuth fracture. This understanding can be used to fracture matrix rock that was left otherwise unfractured by the initial hydraulic fracture job.

2.3 Physical Desorption

Das (2012) states that cumulative gas produced from tight reservoirs is only around 15% of gas in place. This 15% is the gas that exists within the natural fractures and is produced via the hydraulic fracturing process; the remaining 85% exists in the rock matrix and may only be produced through the process of desorption. Of the two types of absorption, physical and chemical, the one that provides a possibility of increased gas recovery is physical desorption. The process of physical desorption occurs via a decrease in reservoir pressure (which can occur due to production) or an increase in reservoir temperature. Either one of these processes will lower the van der Waals force between the gas phase particles and the clay matrix particles and break the bond attaching the two. Once the gas becomes desorped, it flows with similar permeability through the same pore space as the free gas in the system. The type of flow for desorped gas is considered differently though - it is modeled as Darcy flow, while turbulent gas flow through propped hydraulic fractures is modeled as non-Darcy
Figure 2.2: Detailed depiction of the geometry and dimensions of a typical hydraulic fracture after refracturing following a stress-field re-orientation (Roussel and Sharma, 2012)
Figure 2.3: Example from a Codell Sandstone case study of hydraulic fracture orientation after refracturing following a stress-field re-orientation. Green fractures are hydraulic fractures formed during the initial hydraulic fracture job under virgin stress/pressure conditions. Red fractures are hydraulic fractures formed during the refracturing job after both a mechanical and poroelastic stress-field reorientation (Roussel and Sharma, 2012).
Different studies focused on this topic have found that without factoring adsorbed gas into EUR, type curve estimates will not be as accurate as possible. Thompson et al. (2011) discovered that wells in the Marcellus shale could see increases of up to 17% EUR when physical gas desorption is considered. Mengal and Wattenbarger (2011) found similar results in the Bakken shale - a 17% increase in EUR and a 30% increase in OGIP. Generally, physical gas desorption does not contribute largely to early-time production (IP), but over the lifespan of the well once reservoir pressure has been drawn down significantly, desorbed gas can contribute significantly to the production of the well.

With regards to the process of physical desorption, geomechanics actually has a negative effect on production. Gas desorption occurs when reservoir pressure decreases; this pressure depletion also causes fractures to close. If a natural or hydraulic fracture that has been stimulated during the hydraulic fracturing process is unpropped, no flow from the rock matrix will reach the wellbore once the reservoir pressure declines past closure pressure. Therefore, a strong understanding of the stress-field within the reservoir is an integral component to understanding the contribution to production from gas desorption.

### 2.4 Seismic and Geomechanics

In a paper describing the relevance of seismic data in shale plays, Gray et al. (2012) lists four quantities necessary to design hydraulic stimulation protocols. They are: brittleness, closure pressure, proppant size and volume, and the location of the initiation of the fracture. As he states, each of these four properties may be estimated using seismic data with the exception of proppant size and volume. He also makes mention of the current industry beliefs regarding these properties. Warpinski and Smith (1989) state that in-situ stresses are the most important factor controlling hydraulic fracturing, and Iverson (1995) states that knowledge of shear anisotropy allows for a reformulation of the closure stress equation to account for non-equal horizontal stresses. Then, using a simplified version of Hooke’s law using linear slip theory (Schoenberg, 1995), principal stresses can be derived from wide-angle,
wide-azimuth P-wave seismic data. The modified version of Hooke’s Law takes the form:

\[
\epsilon_i = [S_b + S_f]\sigma_j
\]  \hspace{1cm} (2.1)

where \(\epsilon_i\) are the strains that exist in the rock, \(\sigma_j\) are the stresses that exist in the rock, \(S_b\) is the compliance of the background (matrix) rock, and \(S_f\) is the compliance of both fractures and microfractures (Schoenberg, 1995). The author’s point is that through seismic inversion, it is possible to estimate elastic properties with very few assumptions. With well control in the study area, this estimation becomes even more accurate as the seismic-based predictions we make are constrained by either well log data (dynamic) or core data (static). In my study, elastic well-log data were used to constrain the 3D structural model, though future students will have the possibility of using rock properties derived from pre-stack inversion seismic data.

Hatchell et al. (2003) showed that time-lapse monitoring of producing fields can lead to an understanding of the change in seismic travel-times and amplitudes both within and above the reservoir interval. He lists the three mechanisms that produce time-lapse effects at seismic resolution:

1. Compaction effects due to the change in the effective stress field
2. Changes in compressional and shear velocities due to compaction
3. Changes in the pore-fill properties that depend on pressure

The study showed that in this case a geomechanical model can identify the stress relaxation zones above and below the compacting reservoir that occur as a function of stress arching. The changing total-stress field produces time-shifts in arrivals in two ways: by changing the physical distance to a reflection surface due to compaction, and by changing the intrinsic rock velocity. They estimate the time-shift from real seismic data by expanding
the difference between baseline and monitor surveys as a first order Taylor series. This allows for minimization of the objective function, and then summation over the temporal and spatial domain. The resulting equation for $\tau$, the time-lag constant, takes the form:

$$
\tau = \frac{\sum[M(t) - B(t)]B'(t)}{\sum B'(t)B'(t)}
$$

where $\tau$ is the time-lag constant, $M(t)$ is the monitor seismic survey, $B(t)$ is the baseline seismic survey, and $B'(t)$ is the difference between the monitor and baseline surveys when multiplied by the time-lag, $\tau$. This resulting equation tells us the time-shift that occurs in the overburden due to production within the reservoir. As the reservoir is depleted, it undergoes compaction, and the overburden stress is decreased such that the overburden will expand. Therefore, we expect to see positive shifts as the distance to the reflector is increased, and the velocity is potentially slower than it was originally was.

Hatchell’s work shows that a geomechanical model can predict travel-time time-lag within reasonable tolerances. In Figure 2.4, he shows this with the boundary of the gas-water-contact, and that time-shifts can largely be calculated through geomechanical modeling. While the resolution is poorer using the geomechanical model than using seismic travel-times, it is still a good fit, proving that geomechanical modeling can simulate changes in the stress-field in the overburden and underburden. This method could be used within the RCP dataset to solve multiple problems with one model, and could be compared to time-shifts using the real seismic data for ground truth.
Figure 2.4: Estimated timeshift calculated from geomechanical model (left) and timeshift calculated at the top reservoir horizon from real seismic data (Hatchell et al., 2003).
Stresses within the earth vary for many reasons, including changes in pressure, temperature, fracture density, fluid content, etc. Particularly relevant to the field of reservoir characterization and time-lapse seismic monitoring is pressure depletion. Throughout production of a reservoir, pressure drawdown will affect both production and the in-situ stress-field, which will in a circular fashion affect production in other ways. In order to optimize completions parameters for a given area and maximize production, one must gain a fundamental understanding of how reservoir features will act with regard to a changing stress-field. The complex geology of Wattenberg Field is certainly affected by pressure and stress changes. To gain a fully comprehensive understanding of the geomechanical forces acting both within and on the reservoir, we must start with the basics of pressure, stress, and geomechanics.

3.1 Stress

The most basic definition of stress is a force per unit volume. In this thesis, stress will be defined as the second-rank nine-component tensor which describes both the magnitude and direction of the force acting on any given point within the reservoir. Figure 3.1 shows all of the possible combinations of stress that can act on any given point within the reservoir. From linear algebra and tensor calculus, we know that the tensor is rank-two because it has both covariant and contravariant indices. The number of indices used to describe the tensor is given by a simple equation that relates the dimensionality of the problem with the rank of the tensor. A three-dimensional space (petroleum reservoir) raised to the power of a rank-two tensor gives nine individual tensor components. The generalized form of the stress tensor takes the form:
Figure 3.1: Figure showing 3-dimensional stress state at a point within the earth, with normal and shear stress components in tensor notation. Stress is a second order tensor (Jaeger et al., 2007)
\[
\sigma = \begin{vmatrix}
\sigma_{11} & \sigma_{12} & \sigma_{13} \\
\sigma_{21} & \sigma_{22} & \sigma_{23} \\
\sigma_{31} & \sigma_{32} & \sigma_{33}
\end{vmatrix}
\] (3.1)

Now, of the nine components, three are independent - \(\sigma_{11}, \sigma_{22}, \sigma_{33}\) - the three components along the diagonal axis. The other six components are interdependent, and non-unique. Due to tensor symmetry, the order of the indices does not matter and symmetry can be assumed. That is, \(\sigma_{12} = \sigma_{21}, \sigma_{13} = \sigma_{31},\) and \(\sigma_{23} = \sigma_{32}\). This means that the process of solving for the entire three-dimensional stress-field only requires knowing six of the components, or three of the components and the angular dependence of three more given the chosen coordinate system. Following the notation of Zoback (2007) we will define compressive stress as positive. Keeping with his notation, we will also define our coordinate system to reflect only principal (compressive) stresses. This modified stress tensor takes the form:

\[
\sigma = \begin{vmatrix}
\sigma_{11} & 0 & 0 \\
0 & \sigma_{22} & 0 \\
0 & 0 & \sigma_{33}
\end{vmatrix}
\] (3.2)

Following the classic insights of Anderson (2012), the stress regime in Wattenberg Field is an extensional one that exhibits normal faulting (Figure 3.2). As such, the principal stresses follow the form \(\sigma_v > \sigma_H > \sigma_h\) (Figure 3.3). This stress relationship is discussed in detail in Chapter 6.

Generally, the three principal normal stresses can be defined by:

\[
S1 = (\lambda + 2G)\epsilon_1 + \lambda\epsilon_2 + \lambda\epsilon_3 \\
S2 = \lambda\epsilon_1 + (\lambda + 2G)\epsilon_2 + \lambda\epsilon_3 \\
S3 = \lambda\epsilon_1 + \lambda\epsilon_2 + (\lambda + 2G)\epsilon_3
\] (3.3)
Figure 3.2: Depiction of Anderson’s fault classification system showing the type of faulting that occurs in areas with different stress regimes. The top image, normal-faulting regime, is the stress regime in the Denver Basin (Anderson, 2012; Zoback, 2007)
Figure 3.3: Listing of the principal stress components in each faulting regime as identified by Anderson. Notation is given in the S1, S2, S3 notation and then translated to the proper tensor directions for principal stress directions (after Zoback, 2007)

\[
\lambda = \frac{E\nu}{(1 - 2\nu)(1 + \nu)}
\]

where \(\lambda\) is Young’s modulus, \(E\) is the shear modulus, and \(\nu\) is Poisson’s ratio (Grandi et al., 2001).

Maximum principal stress in this study is vertical, so therefore \(S_1\) is defined as \(S_V\). By the same notation, \(S_2\) is defined as \(S_{H_{max}}\) and \(S_3\) is defined as \(S_{h_{min}}\). This makes it straightforward to solve for maximum principal stress with only elastic well log information. By integrating the bulk density log as a function of depth, from the surface to the bottom of the log, we can obtain maximum principal stress or \(S_V\). For this study, \(S_V\) was integrated easily using MATLAB. That integral takes the form:

\[
S_V = \int_0^z \rho(z)gdz = \bar{\rho}gz
\]  

(3.4)

where \(\rho(z)\) is the bulk density log as a function of depth, \(g\) is the gravitational constant, \(\bar{\rho}\) is the mean overburden density, and \(z\) is depth (increasing downward).

The horizontal stresses are more difficult to constrain, but can be done with a complete dataset. Figure 3.4 shows that within the Denver Basin the regional maximum horizontal stress is to the northwest, though there will certainly be local variations of stress direction.

<table>
<thead>
<tr>
<th>Regime</th>
<th>Stress</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(S_1)</td>
</tr>
<tr>
<td>Normal</td>
<td>(S_V)</td>
</tr>
<tr>
<td>Strike-slip</td>
<td>(S_{H_{max}})</td>
</tr>
<tr>
<td>Reverse</td>
<td>(S_{H_{max}})</td>
</tr>
</tbody>
</table>
within the basin and the field due to heat flow and geologic factors. The World Stress Map Project (Tingay et al., 2008) is a tool that provides a first-order approximation of maximum stress directions. To gain a better understanding, the general industry method is to examine wellbore failure and breakout in vertical wells. In a case where vertical (overburden) stress is the dominant stress, wellbore breakout will occur in the direction of minimum horizontal stress, with maximum horizontal stress direction orthogonal to that in the horizontal plane (Figure 3.5 + Figure 3.6). This is simply because of the loading that the rock matrix places on the wellbore in the direction of $SH_{Max}$. That stress is then redistributed orthogonally and the rock matrix fails in the direction of $Sh_{Min}$, where the Hoop stress is highest. Barton (1988) established in her PhD thesis a methodology for calculating the magnitude of $SH_{Max}$ via the geometry and dimensions of breakout. While this is still a much-debated topic within industry, it is generally accepted as one of the best methods for acquiring both the magnitude and direction of $SH_{Max}$. When correlated to $SH_{Max}$ derived from hydraulic fracturing results, the results from breakout are fairly similar. The shortcomings of estimation from wellbore breakout are the assumptions of a linear elastic model that does not exist in the subsurface, as well as the lack of recognition of the type of rock failure occurring.

Minimum horizontal stress in this study will be approximated using the instantaneous shut-in pressure (ISIP) during the hydraulic fracture jobs. This pressure, which was measured for each completion stage of the horizontal wellbores is the pressure that is measured just after the wellbore is shut-in (Figure 3.7). That is, the completion job is pumped, fractures are induced and propagate through the reservoir, and then the wellbore is shut in before moving to the next stage. The moment that the wellbore is shut-in is the discrete time point that ISIP is measured. This pressure will be higher than the closure pressure, which is also used in the literature as a proxy for $Sh_{Min}$. Now, for any given hydraulic fracture job, we may be stimulating multiple lithologies with different intrinsic properties. If hydraulically fracturing both a shale and a sandstone, we may expect to see multiple closures on the frac record as the shale and sandstone will have different closure stresses. When this occurs, we
Figure 3.4: This modified portion of the World Stress Map shows the direction of maximum horizontal stress, denoted by the azimuth of the line, and the faulting regime as measured by earthquake focal mechanisms, overcoring, breakouts, drilling induced fractures, geologic indicators, etc. The color shows the faulting regime; black is unknown regime. The area denoted by the red oval corresponds to the location of Wattenberg Field and suggests a roughly N20°W modern day stress direction (modified from World Stress Map, 2008).
Figure 3.5: Wellbore breakout as it is related to principal stress directions and the location around the wellbore.
Figure 3.6: Schematic of borehole breakout in a vertical well and its relation to both maximum and minimum horizontal stress. In Wattenberg Field, maximum principal stress is vertical and wellbores are drilled horizontally 20 degrees west of $S H_{\text{Max}}$. Breakout will therefore occur in a plane 20 degrees west of $S H_{\text{Max}}$ due to preferential loading of the wellbore (Zoback, 2007)

gain a much better idea of the lithology variations within the reservoir. Using ISIP as a proxy for $S h_{\text{Min}}$ does not allow us to gain this information though. Once the correct ISIP is interpreted, it may be used as a proxy for $S h_{\text{Min}}$ (Figure 3.7, Figure 3.8).

Once quantitative estimates of $S h_{\text{Min}}$ are made, it is possible to solve for $S H_{\text{Max}}$. Following the classic 1957 Hubbert and Willis equation we obtain:

$$P_b = 3\sigma_h - \sigma_H + T - p_o$$  \hspace{1cm} (3.5)

which is easily rearranged to solve for $S H_{\text{Max}}$:

$$\sigma_H = 3\sigma_h - P_b - p_o + T$$  \hspace{1cm} (3.6)
Figure 3.7: Literature example of a typical frac record. The four data points recovered are breakdown pressure, ISIP, closure stress, and pore pressure (Malik et al., 2014).

Figure 3.8: Zoomed in example of closure stress. Where the derivative of the curve changes, closure pressure is interpreted (after Descroches, 1998).
where \( P_b \) is the breakdown pressure, \( \sigma_h \) is minimum horizontal stress, \( \sigma_H \) is maximum horizontal stress, \( p_o \) is pore pressure, and \( T \) is the tensile strength of the rock formation (Hubbert and Willis, 1972; Shah et al., 2013).

This quantitative estimate of \( SH_{\text{Max}} \) is still difficult to obtain though, as it requires that we know pore pressure. Without a pore pressure model or reliable pre-stack inversion results, it is very difficult to calculate \( SH_{\text{Max}} \).

### 3.2 Pressure

At this point, the relation between stress and pressure becomes quite important. The simplest version of this relationship in the form of Terzaghi’s equation takes the form:

\[
\sigma' = \sigma - P_p
\]

where \( \sigma' \) is the effective stress, \( \sigma \) is the total stress, and \( P_p \) is pore pressure. With regard to pressure change in the reservoir, which is the target of many time-lapse studies, Terzaghi’s equation can be modified into the following forms:

\[
\Delta \sigma'_v = \Delta \sigma_v - \alpha \Delta P
\]

\[
\Delta \sigma'_h = \Delta \sigma_h - \alpha \Delta P
\]

where \( \Delta \sigma'_v \) is the change in the vertical effective stress, \( \Delta \sigma'_h \) is the change in the horizontal effective stress, \( \Delta \sigma_v \) is the change in the total vertical stress, \( \Delta \sigma_h \) is the change in the total horizontal stress, \( \Delta P \) is the change in reservoir pressure, and \( \alpha \) is Biot’s constant (for
simplicity assumed here to be 1).

Thus to determine effective stress in the system, we must subtract out the effect of pore pressure to ensure that its load bearing capabilities are not factored into the estimation. The same formula rearranged would state that total stress is equal to effective stress plus the pore pressure. This version of the equation may seem more intuitive, as it clearly states that pore pressure is included into the total stress calculation. Pore pressure is often forgotten or negated, but a fully comprehensive study must include it for meaningful calculations of effective stress. Pore pressure as seen in the petrophysical or mechanical earth model was determined by normalizing the compressional sonic data to determine its variation from the standard pressure gradient of 0.433 psi/ft.

3.3 Elastic Properties

A requirement of claiming HTI in the system is that we are dealing with anisotropic linearly elastic materials. That is, Hooke’s Law remains valid, and each component of stress will be linearly dependent on each component of strain:

$$\sigma_{ij} = C_{ijkl} e_{kl} \quad i, j, k, l = 1, 2, 3$$  \hspace{1cm} (3.10)

where $\sigma$ is the stress, $C$ is the stiffness tensor, and $e$ is the strain.

Under this assumption, the symmetrical stiffness tensor can be represented in 36 terms:

$$C = \begin{vmatrix} C_{11} & C_{13} & C_{13} & 0 & 0 & 0 \\ C_{13} & C_{33} & C_{33} - 2C_{44} & 0 & 0 & 0 \\ C_{13} & C_{33} - 2C_{44} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{66} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{vmatrix}$$ \hspace{1cm} (3.11)
While certain components of the geomechanical evaluation and data show that the rock formations we are dealing with are inelastic, the linearly elastic assumption must be made to move forward with the study. This assumption then requires that the elastic properties of the subsurface are well constrained. These properties, such as Young’s modulus and Poisson’s ratio, as well as the bulk and shear modulus, are strong indicators of the strength of a rock material, and how that material will deform under failure conditions. They may even be used as lithology predictors as seen in Davey (2012) to even better predict or model how different rocks will perform under various stress conditions. Multiple derivations of Young’s modulus and Poisson’s ratio exist, but due to our dataset including both compressional and shear sonic logs, I chose to calculate them with velocities. Poisson’s ratio is calculated by:

$$
\nu = \frac{V_P^2 - 2V_S^2}{2(V_P^2 - V_S^2)} 
$$

(3.12)

and Young’s modulus by:

$$
E = \frac{\rho V_S^2(3V_P^2 - 4V_S^2)}{V_P^2 - V_S^2} 
$$

(3.13)

where $V_P$ is compressional velocity, $V_S$ is shear velocity, and $\rho$ is bulk density (Perez and Marfurt, 2013).

Young’s modulus, also known as the elastic modulus, is simply a quantitative measure of the stiffness of the rock matrix and gives a measure of the rigidity of the material. Similarly, Poisson’s ratio is a measure of the elasticity of a rock material that describes the ratio of shortening to elongation in orthogonal axes when a load is applied along one of those principal axes. Both of these quantities are standard geomechanical properties that lend
understanding to how a rock will fail under various stress conditions. For instance, in this study they are jointly used to gain understanding of which rocks may fail in a more preferable manner during a hydraulic fracturing job. Crossplots of Young’s modulus against Poisson’s ratio (Figure 3.9) are used similarly to Lambda-Rho/Mu-Rho crossplots to determine the ‘brittleness’ of a specific rock. In this context, brittleness is a measure of how the rock breaks. Under the classification of brittleness used here, a more brittle rock has a higher Young’s modulus and lower Poisson’s ratio. That is, a brittle rock will be a rigid (more inelastic) rock that breaks before it deforms. This becomes an important consideration when attempting to determine differences in the way a chalk will fracture versus a marl. With so few compositional differences between the characteristics of the two types of rocks in the Niobrara Formation, even small differences can make a large impact on completions and production.

Warpinski (2014) succinctly concluded in one of his most recent papers that there are only two fracture cases that we expect to contribute to increased production - large shear, and propped large shear fractures. These cases are shown in Figure 3.10 as fissure opening with no proppant and fissure opening with proppant. The other three fracture types he identifies, extensive slippage, minimal slippage, and no effect, are not expected to contribute to production. Of the data in our possession for this project, the microseismic dataset is the most likely to be useful in interpreting the type of failure that occurred and whether we expect a given fracture to exhibit increased productivity.
Figure 3.9: The concept of using $E$ and $\nu$ for brittleness, where a high $E$ and low $\nu$ indicate the more brittle areas/formations and a low $E$ and high $\nu$ indicate the more ductile. Ductile formations are thought to be better fracture stimulation barriers and reservoir seals. (After Rickman, 2008).
Figure 3.10: Possible outcomes of hydraulic fracturing (Warpinski, 2014)
CHAPTER 4
DATA AVAILABILITY - 1D GEOMECHANICAL MODEL

The dataset acquired by RCP and Anadarko for this study includes seismic surveys and well data. Within the primary study area there are eleven horizontal wells in the reservoir interval - seven targeting the Niobrara and four targeting the Codell and/or Fort Hays. The primary seismic dataset, known as the Turkey Shoot, is a four square mile single-component 3D dataset with 55 foot CDP bins. These high-resolution seismic data were acquired to have high fold over the one square mile section containing the horizontal wells (Figure 4.4). It is a baseline survey for a 4D-9C dataset. Within the survey area, we are in possession of well logs from five vertical wells, including one well with both measured compressional and shear sonic. This well, which we will call Well A, is the foundation for the 1D mechanical earth model. The other four wells have predicted compressional and/or shear sonic logs using a neural network inside MATLAB, which proved to be more accurate than shear velocity estimation via Castagna’s equation due to the increased variability that the method allows. These velocity logs, combined with bulk density, neutron porosity, resistivity, and gamma ray were used to synthesize logs for four other wells, which are referred to as wells B-E using neural networks. This process will be discussed in greater detail later in this chapter. The available seismic data, the location of the five key wells, and the spacing/target intervals of the eleven horizontal wells can be seen in Figure 4.1, Figure 4.2, and Figure 4.3, respectively.

4.1 Methodology for 1D Geomechanical Modeling

Following Higgins (2006), a similar workflow was used for construction of a one-well geomechanical model just outside the section, and on the very edge of the 4D-9C seismic dataset, including:

1. Data audit
Figure 4.1: Seismic data availability in RCP study area. Regional survey is 3D-1C, Anatoli survey is 3D-3C, Turkey Shoot survey is 4D-9C.
Figure 4.2: Five key vertical wells used in the study. One of the five, Well A, had both measured compressional and shear sonic, and was the focus of the study. The other four had measured compressional sonic and mechanical earth models were created for them via neural networks in MATLAB.

2. Lithology determination

3. Empirical correlations for elastic moduli and rock strength

4. Overburden stress

5. ISIP or minimum horizontal stress

6. Pore pressure

7. Horizontal stress magnitudes

4.2 Objectives for Interpretation of Modeling

Similarly, my specific interpretation objectives for the model were to:

1. Measure elastic parameters from well logs.

2. Apply insights into the stress field toward a greater understanding of local/regional geology.
Figure 4.3: Wellbore spacing and layout within the Wishbone section. Wells labeled ‘N’ are Niobrara wells and wells labeled ‘CD’ are Codell wells.
Figure 4.4: Fold of Turkey Shoot PP baseline seismic data. Black lines indicate spatial position of Wishbone horizontal wellbores.
Figure 4.5: 1D mechanical earth model used as an input into the 3D geomechanical model (unpublished work from Bratton, 2015).
3. Understand how hydraulic fractures interact with natural fractures, and what this means for production and completions.

4. Understand zone completion strategies based on stress magnitude variations with lithology.

5. Determine a quantitative measure of stress anisotropy for possible stress re-orientation completions.

6. Visualize spatial variability within the reservoir for optimized wellbore location.

7. Determine how hydraulic fracturing varies per target interval.

8. Use the generated 1D model as an input into 3D model for enhanced visualization and simulations.

These steps will lend insight into the problems we are trying to solve in this project regarding optimization of completions parameters. Knowing what type of rock is being hydraulically fractured and how it will respond to the fracture job is useful for future completions. Understanding the stress field, both near- and far-field, vertical and horizontal, can help to design future completions better. Using a 1D model, or models, in the 3D structural framework will help to increase the seismic resolution to something closer to the well log scale.

4.3 Synthetic Log Generation

Only one out of the five wells in the study area, Well A, had the necessary data required to develop a 1D mechanical earth model. However, each well had four logs in common: bulk density (RHOB), deep resistivity (IDEE), gamma ray (GR), and thermal neutron porosity (NPHI). Using these four well logs, in addition to compressional and shear sonic logs in Well A, it was possible to synthesize via neural networks both compressional and shear sonic estimates for wells B-E. Following Bray and Link (2014), the network that was used within
MATLAB’s Neural Network Toolbox is shown in Figure 4.6. By clustering these four logs, I obtained a cluster class and variance for each point in each log of each well. To optimize the objective function, several different cases were simulated. The first was to take only the four logs from Well A (RHOB, IDEE, GR, NPHI), train the neural network on them, and then apply that objective function to the same four logs in the other wells in order to predict various logs. The second case was to take the four logs, in addition to compressional and shear sonic from Well A, train the neural network on all six of them, and then apply that objective function to four logs from another well in order to predict compressional or shear sonic velocities (or slownesses).

The primary reason behind using a neural network to predict logs that cannot be calculate (including shear sonic) with the given data is to include spatial variability into the study. Otherwise, with only one true mechanical earth model within the four-square mile study area, any 3D model result will be driven toward that well. Well log prediction via neural networks in this case is considered to be a type of statistical inversion or parameter estimation that can bring more confidence to the model.

The neural network setup and method is quite simple and can be implemented in as few as seven steps within the MATLAB Neural Network Toolbox (Beale et al., 2011):

1. Collect data
2. Create the network
3. Configure the network
4. Initialize the weights and biases
5. Train the network
6. Validate the network
7. Use the network
Neural networks can be applied in a variety of fashions such as pattern recognition, data fitting and clustering. The objective here was pattern recognition. This was carried out using a supervised approach. A supervised classification will continue to loop until outputs from the network converge to target values of a desired degree of resolution. The algorithm automatically adjusts the network parameters, both weights and biases, in order to minimize the mean squared error. The following methodology and workflow was taken from Beale et al. (2011) and Celik (2012).

\[ H(x) = E(e^2) = E[(t - a)^2] \]  \hspace{1cm} (4.1)

where \( x \) are network parameters, \( t \) is the target vector, and \( a \) is the output vector from the network. From this point, the process takes on a classical inversion methodology, and we assume that:

\[ d = G(m) \]  \hspace{1cm} (4.2)

where \( d \) is the data, \( G \) is the operator, and \( m \) is the model.

or, more true to our dataset:

\[
\begin{bmatrix}
  d_1 \\
  d_2 \\
  d_3 \\
  d_4
\end{bmatrix} =
\begin{bmatrix}
  G_{11} & G_{12} & G_{13} & G_{14} \\
  G_{21} & G_{22} & G_{23} & G_{24} \\
  G_{31} & G_{32} & G_{33} & G_{34} \\
  G_{41} & G_{42} & G_{43} & G_{44}
\end{bmatrix}
\times
\begin{bmatrix}
  m_1 \\
  m_2 \\
  m_3 \\
  m_4
\end{bmatrix}
\]  \hspace{1cm} (4.3)
Assuming then that the function can be linearized with an initial estimate of \( m_0 \) using a first order Taylor series expansion, we obtain:

\[
    d = G(m_0) + \frac{\partial G(m_0)}{\partial m} \Delta m
\]  

(4.4)

By making the substitutions \( d_0 = G(m_0) \) and \( J = \partial G(m_0)/\partial m \), where \( J \) is the Jacobian matrix containing first partial derivatives, we obtain:

\[
    \Delta d = J \Delta m
\]

(4.5)

It is at this point that an artificial neural network differs from a classic least-squares approach. In a neural network, both the output \( d \) and the input \( m \) are known, while typical inverse theory dictates that a model will be generated based upon observed data. The neural network instead finds an approximation function that can be used to work with various data and models. This distinction allows us to re-write equation 4.5 into:

\[
    \Delta d = J \Delta w
\]

(4.6)

where \( J \) is the matrix of partial derivatives with respect to the network parameters that are represented by weights and biases. Solving this equation gives the optimum network parameters, or weights and biases. By minimizing the squared error between the target values and network outputs we can find the optimal \( w \).

\[
    \Delta w = (J^T J)^{-1} J^T \Delta d
\]

(4.7)
Due to the fact that \( (J^T J) \) is not always invertible, a damping factor \((\mu)\) is implemented.

\[
\Delta w = (J^T J + \mu I)^{-1} J^T \Delta d \tag{4.8}
\]

The solution for network parameters now exists since \((J^T J + \mu I)\) is invertible. That is, the solution for the network parameters now exists since the matrix is invertible. Whereas, in an inversion, we look for the result:

\[
m = (G^T G)^{-1} G^T d \tag{4.9}
\]

To include spatial and geologic variability in the data and model, I replicated as many logs as possible in wells B-E based upon the neural network results from Well A. Additionally, I also tested the option of adding random white noise to each well log, scaled between +/- 5% of the original data to determine if that was a sufficient method for adding variability to the model.

I found that the predicted logs created by incorporating either pseudo-random noise into the model, or by using the cluster number and data point variance each resulted in accuracy of roughly 95% (Figure 4.7). When only the four common logs of Well A were used to predict various properties in other wells, the results were found to be only 85% accurate. I chose not to predict logs using compressional and shear velocity due to the fact that they were synthetic results. That is, I chose not to synthesize logs using the clustering results of any synthetic logs. The final results for each well were generated by training the neural network on Well A with RHOB, IDEE, NPHI, and GR. Elastic properties such as Young’s modulus, Poisson’s ratio, and the bulk and shear moduli were calculated using empirical relationships
with the synthetic compressional and shear velocities and were not predicted.

Figure 4.6: Schematic of the architecture of the neural network used to synthesize various logs for wells B, C, D, and E within the study area.

Once all five of the key wells had both compressional and shear sonic logs, it was possible to derive Young’s modulus and Poisson’s ratio for each well. With these eight fundamental logs in each well (density, resistivity, porosity, gamma ray, compressional sonic, shear sonic, Young’s modulus, and Poisson’s ratio), I can better populate the 3D geomechanical model with the approximated earth properties for the study area. With well data covering a larger spatial area, the model is more accurate and provides a good foundation for both visualization of data and reservoir/geomechanical simulations. The neural network process automatically holds back 20% of the data as a blind test in order to calibrate to the highest accuracy.
Figure 4.7: Regression fit for density, porosity, gamma ray, and resistivity predicted for wells B-E from Well A.
The sonic logs that were synthesized to calculate Young’s modulus and Poisson’s ratio were calculated to an accuracy of 94%. As mentioned earlier, from these logs it is possible to determine a ‘brittleness’, which can be seen in Figure 4.8. It is clear in this image that the different lithologies exhibit different characteristics in terms of brittleness. Generally, in this type of reservoir, a more brittle rock will have a lower Poisson’s ratio and a higher Young’s modulus. It would follow then that a more ductile rock will have a higher Poisson’s ratio and a lower Young’s modulus. What we see in Figure 4.8 is that the Codell Sandstone and Ft. Hays Limestone are some of the most brittle rocks. Within the Niobrara interval itself though, the chalks register as more brittle than the marls, presumably due to their lower clay content. That would make targeting these intervals, such as the Niobara C Chalk, a better option than targeting the marls based on brittleness alone. Targeting the Codell and Ft. Hays should be good options as well, as they are brittle and likely already highly naturally fractured.
Figure 4.8: Cross-plot of Young’s modulus and Poisson’s Ratio colored by formation. Lithologies with higher Young’s Modulus and lower Poisson’s Ratio will be more brittle, and vice-versa.
CHAPTER 5
3D STRUCTURAL AND GEOMECHANICAL MODELING

In order to upscale the 1D mechanical earth model into a 3D earth model, a geologically-accurate structural model was developed. The purpose of constructing a 3D earth model is to simulate it within Visage™ software to gain an understanding of the first-order far-field stresses in the reservoir at the time that the Turkey Shoot PP baseline seismic survey was acquired (Figure 1.10). A broad overview of the completed model is shown in Figure 5.7. ™ software is a powerful interpretation tool for building these structural models, and has the added advantage of being able to run double-coupled simulations between Eclipse™ software (reservoir simulations) and Visage™ software (geomechanical simulations). A model such as this has many uses and the end goal of this work, beyond the scope of this study, is to run both reservoir and geomechanical simulations in order to determine how stresses are changing due to hydraulic stimulations and production. An additional benefit of the structural model is visualization. With an accurate, complete 3D rendition of the reservoir, visualization is greatly increased. It becomes possible to visualize and determine the trajectory of the wellbores and gain a better understanding of production variability and its relationship to geology throughout the section.

My work provides the foundation for another RCP master's student to use the model to complete additional geomechanical work and run simulations within Visage™ software. This model will give detailed insight into the original stress state of the study area and how the in-situ stress field changes due to pressure depletion as a result of production. Additionally, joint simulations between Eclipse™ software and Petrel™ software will give an even better insight into the dynamic system. In this type of joint simulation, the output of the Eclipse™ software simulation will automatically be used as the input for the Visage™ software simulation and this process will loop until which point the model reaches equilibration.
5.1 3D Structural Framework

The process of building the 3D structural model was straightforward. The framework within Petrel™ software is a step-by-step process that allows a high level of user control for each step in the process. Hampson-Russell™ software was used to perform the first three steps of the workflow, and the rest were completed inside of Petrel™ software with the exception of the velocity model which was generated in Transform™ software. Once all of the proper data are loaded into Petrel™ software, the general methodology for building such a model is:

1. Pick well tops.
2. Perform well-to-seismic tie.
3. Use well-tie to pick horizons in seismic data.
4. Pick all faults within the area of interest - for this study the area of interest was primarily the reservoir interval.
5. Build a velocity model to perform time-to-depth conversion.
6. Depth convert time structural framework to create depth structural framework.
7. Model horizons and faults to generate the most geologically accurate, smoothed model that honors geology during gridding.
8. Generate zone model from depth structural framework.
9. Generate geocellular zone model from generic zone model and depth structural framework.
10. Populate geocellular zone model accordingly - either by zone or even finer by layer.

I have not shown each of these individual steps below, but have shown some of the more important ones as well as the final outputs of the model that is ready to be taken and used
by another RCP student. To begin, Figure 5.1 is the seismic-to-well tie that was used to pick horizons in the seismic dataset. Once tops were picked based upon well logs, this step allowed us to tie those picks to the seismic data via a compressional sonic synthetic. The tie performed reached a cross-correlation of 0.837 over 600 milliseconds (ms) with a -30° phase rotation from zero. This tie was performed on Well B (Figure 4.2), toward the southern end of the seismic survey, but was representative of the entire dataset.

![Figure 5.1](image)

**Figure 5.1**: Well-to-seismic tie between Well B and the Turkey Shoot PP baseline seismic volume.

Figure 5.2 show the outline of the model along with the eleven horizontal wellbores, the vertical well control, and the one square mile Wishbone section. In this figure, the bold white outline denotes the limits of the seismic survey, the stippled white outline denotes the Wishbone section, the eleven horizontal Wishbone wells are colored for target interval (Niobrara - green, Codell - pink), and the five vertical wells are shown in cyan. These figures clearly show the spatial locations of the vertical well control used to constrain the model. Again, a map of the seismic fold within Turkey Shoot can be seen in Figure 4.4. What is not shown in these two figures is that there are both vertical and horizontal wellbores in each of the eight adjacent sections. These wells, though not shown in the current model, will have
an effect on the in-situ stress.

Figure 5.2: Study area showing seismic coverage (solid white outline), one square mile Wishbone section (stippled white outline), eleven horizontal wells (Niobrara - Green, Codell - Pink), and five vertical wells (cyan).

The velocity model (Figure 5.3), generated in Transform™ software, was built from the vertical well control in the area in addition to the interval velocity cube used by Sensor Geophysical during migration. The addition of the five vertical wells to the model helped to constrain the velocities better with all five wells now having sonic velocities to fill in the interval velocity cube. The finalized model, as a result of the Transform™ software velocity
model framework, will use the time-depth curves generated for each of the five wells during the seismic-to-well tie process and fill in the remaining areas of the model with the interval velocity cube. The finalized velocity model was loaded into Petrel™ software as an average velocity cube and then used to create a velocity model from the surface to the depth (time) of interest. Additional well control is still being normalized within the area and will be incorporated into the velocity model when it is complete.

The next two figures, Figure 5.4 and Figure 5.5, are the real foundation of the structural model, and incorporate steps 1 - 7 of the ten steps listed above. These images clearly show both the simplicity and complexity of the model, and drive home the visualization aspect of creating such a model. From the shallowest to the deepest, the horizons used as boundaries in the model are:

1. Upper Pierre
2. Terry (Sussex)
3. Hygiene (Shannon)
4. Lower Pierre
5. Niobrara
6. Greenhorn
7. J Sand (Muddy)

With the reservoir interval falling between the Niobrara and Greenhorn Formations, there is a significant amount of overburden and underburden incorporated into the model. This is shown in Figure 5.6. Due to the overpressured nature of the Niobrara, seen in Figure 1.6, the overburden was built in to fully encompass the overpressured region to account for all effects of the overburden. After analyzing the rock properties (Figure 4.5) of the underlying formations, including the bulk and shear moduli, Young’s modulus, and Poisson’s ratio, the
Figure 5.3: Velocity model that was generated from vertical well control and the interval velocity cube used for migration. This model was used to depth convert the Turkey Shoot PP seismic data.
assumption was made that the underburden has a smaller effect on the reservoir interval itself, and was therefore truncated at the J Sand.

Figure 5.4: Zoomed out view of the structural framework of the model. The horizons, coupled with faults, were seismically-derived, while all other properties were derived from well log data. Horizons are color-coded by depth. Faults are individually assigned a unique color automatically.

Figure 5.7 and Figure 5.8 highlight the various finished products that exist for the structural model. Each component is shown in the figures, including modeled horizons, modeled faults, well tops, wellbore interval data (fracture intensity), model zones, and seismic. Each
Figure 5.5: Similar to Figure 5.6, this image shows the foundation of the model with the seismic data in the background. Horizons are color-coded by depth. Faults are individually assigned a unique color automatically.
Figure 5.6: Complete zone model showing all of the intervals to be used in the geomechanical simulations. The reservoir interval (light blue near the bottom) is contained within a large overburden in order to properly model the effect of the overburden observed in the Niobrara.
of these properties is easily brought into the model and used to populate it once it has been
turned into geocells and used for simulations. In list form, all of the products that exist
within the geomechanical model include:

1. Turkey Shoot PP seismic data and seismic attributes
2. 11 Wishbone wells with all available well log data
3. 5 vertical wells within the Turkey Shoot with all available well log data
4. Picked and modeled horizons
5. Picked and modeled faults
6. Image log interpreted fractures and fracture intensity logs for the 2N and 6N wells
7. ISIP values picked from pressure curves
8. Tracer injection/production information
9. Radioactive tracer logs
10. Production logs for the 2N and 6N wells
11. Zone model (interval between horizons)
12. Geocellular zone model

Due to license availability the microseismic data was not able to be loaded at this time. Future students will hopefully have the opportunity to do so.

Figure 5.9 shows maximum principal curvature, just one of the many properties that
can be loaded into the geocellular model. Various ways to populate the model exist, but
one of the main focuses of RCP is the value of seismic data. The modeling process within
Petrel™ software allows for direct seismic resampling of a seismic volume into the geocells
of the model so that attributes may effectively be simulated to determine how they correlate
Figure 5.7: Rendition of the 3D structural framework built over the study area. Modeled horizons, zones, faults, wellbores, and fracture intensity data ((Dudley, 2015)) are all displayed. This model is the foundation of the 3D geomechanical model.
Figure 5.8: Overview of model showing all faults, with Greenhorn horizon and zone models below it.
with field performance. The resolution of the model is based upon the seismic data and was therefore built to have geocells the same size as CDP bins for the seismic data (55 ft). In this study area, we expect that higher curvature will exist near larger graben faults, indicating higher natural fracture density, and therefore higher production. This can be confirmed through the use of validation data such as image logs, tracers, and spinner production data. Once confirmed, curvature can be used to predict production away from well control.

Figure 5.9: Geocellular model showing the capability to populate the model with any property, in this case seismically-derived maximum principal curvature. Disks along the wellbore are fracture intensity logs derived from Dudley (2015).

The completed model, as seen in Figure 5.10 is a fully-encompassing structural model containing all of the features and properties discussed in this chapter. The step-by-step process to build a structural framework in Petrel™ software includes the ten steps listed in Section 5.1 above, which are critical steps in a geophysical interpretation framework that would likely be performed through the course of a study anyway. Therefore, they should be
included in the model, even if it is used solely for visualization.

![Broad overview of the model](image)

Figure 5.10: Broad overview of the model showing different zones above and below the reservoir interval, and how the geocells may be populated with petrophysical properties.

### 5.2 Future Geomechanical Simulation

As stated previously in this chapter, the 3D geomechanical model was not simulated as part of this thesis work. The 3D structural model and five 1D mechanical earth models are fully built and exist within Petrel™ software, ready for a future student to incorporate into geomechanical simulations. Through ongoing thesis work completed by Matthew White, Matthew Bray, and Taraneh Motamedi, we have a solid understanding of the stress-field at the time of the baseline survey and the time of the monitor survey (post-frac), as well as minimum horizontal stress. However, without additional seismic monitor surveys, we will be unable to detect further stress changes within the reservoir. This shortcoming alone is justification for the geomechanical modeling and simulations. If we can use all of the
data already in our possession, including the time-lapse seismic surveys, to simulate flow in the reservoir and determine how pressure depletions and other effects will alter the in-situ stress-field, we can gain a greater understanding of the value of the seismic. We can use this knowledge to predict optimal times to refracture wellbores, as well as optimize well-spacing, stage-spacing, and other completions parameters. With the seismic data currently in our possession, through seismic analysis we can only obtain two snapshots of the stress-field: one at the time of the baseline survey and one at the time of the monitor. Should another monitor survey be acquired, we will obtain an additional snapshot. Through joint reservoir and geomechanical simulations though, we can obtain a time-series of the stress-field from the date of the baseline to the date of the monitor. These additional data showing how the in-situ stresses change as a result of the hydraulic fracture job and production is much more valuable than just the beginning and end stresses.
Pressure curves recorded throughout the hydraulic fracturing process of each well can be used to deduce what has occurred in each stage. Understanding the intricacies of what makes one well produce better than another, or what makes one stage of a well produce better than another stage often can be traced directly back to the completions quality. In this study, the eleven wells not only had variable completion parameters, but variable well spacing and target intervals as well (Figure 4.3). As is depicted in Figure 3.7 and evidenced in Figure 6.1, we can determine hydrostatic pressure, breakdown pressure, fracture extension pressure, initial shut-in pressure, fracture closure pressure, and fracture reopening pressure all from these pressure curves. Any problems that occurred during the hydraulic fracturing job can also be identified, and by analyzing the data we may be able to identify why that problem occurred and how it relates back to the productivity of the well (Figure 6.2).

6.1 ISIP and Minimum Horizontal Stress

Both ISIP and closure stress are often used as a proxy for minimum horizontal stress. Generally, the closure stress is thought to be a closer estimate due to the way it is defined: the pressure at which the induced or stimulated natural fracture mechanically closes. If the fracture closes, then it must have been overcome by the minimum horizontal stress. However, closure is not always recognized in a pressure record, and is much more difficult to identify than ISIP. The difference between ISIP and closure stress is generally defined as the net pressure in the fracture. The larger the difference between the ISIP and the closure stress, the more complex the hydraulic fracture propagation is expected to be in the far field. It follows that the smaller the difference between the ISIP and the closure stress, the less complex the hydraulic fracture propagation is in the far field (Nelson et al., 2007).
Figure 6.1: Representative hydraulic fracture record for one stage of one Niobrara well in the study area. Numbers in red circles refer to the stage of the interval - places where a characteristic change in the completion job is noteworthy.
Due to the completions technique used in ten of the eleven Wishbone horizontal wells, true shut-in was never required. It was possible to only reduce the pump rate down to a lower value ($\sim 10$ bbl/m) and begin pumping the next stage immediately. This is done to save time during the hydraulic fracture job. The effect of this process is that shut-in is never truly realized unless a problem occurs or the client specifically requests a mini-frac or leak-off test. Therefore, the ISIP is read as a higher value than normal due to the continued pressure input into the wellbore and fracture system. If this pressure remains high enough between stages, closure stress may not be reached by the time the next stage begins pumping. For this reason, I chose to use ISIP as a proxy for minimum horizontal stress, which allowed me to measure a value for each stage of each well. The disclaimer must be made though that this proxy acts as an upper bound for minimum horizontal stress, but truly is the closest estimate that could be obtained.

One well (Well 9N) was completed using a different technique. With this completion method, the perforating tool is sent down the wellbore to create perforations in the well casing and then pulled out and the stage is pumped. Before moving on to the next stage, pumping must be stopped completely in order to send the perforating tool back down the wellbore. The result of this process is the ability to measure a true ISIP for each stage of the wellbore. In Figure 7.7 and Figure 7.8 you can see that the ISIP values measured for Well 9N are significantly lower than those measured in the other 10 horizontal wells. This is due to the difference in completion type discussed in this section.

6.2 Pressure and Stress Insights

Instantaneous shut-in pressures were picked for each stage of the eleven study area wells, with particular focus on two wells, Well 2N and Well 6N. These two wells have the best available calibration data, including these pressure records, image logs, microseismic, and tracer studies (including radioactive tracer logs). From the hydraulic fracture report and the pressure curves, it is clear that a problem occurred toward the toe end of Well 2N. An analysis of three stages show that the well screened-out during the fracture job, meaning
that the stages were abandoned and no proppant was pumped and placed in the fractures or formation. This could occur for two separate reasons. Either the breakdown pressure of the formation is too high and the mechanical equipment is limited to a lower pressure, or all pumped pressure is being lost into a natural fracture system or fault. Plotting the treating pressure or calculated bottom-hole pressure against the cumulative volume of fluid pumped (time integral of slurry rate) is one way to determine which case is occurring. Plotting bottom-hole pressure is preferred over treating pressure. This is because once the rock matrix has been penetrated bottom-hole pressure may no longer be a linear product of treating pressure. In Figure 6.2 the break in the slope of the curve indicates that the stiffness of the medium decreases with increasing pressure. This indicates that we have indeed broken into the formation, and are pumping into natural fractures. If the pressure continued to increase linearly, this would suggest that either the breakdown pressure had not been achieved or there was a problem with the completions in which the frac fluid was being pumped against the metal liner. Due to the way this particular job was carried out, no proppant was pumped into the natural fractures, though they do still appear to contribute to the total production of the well. One of the stages that was not pumped has produced 5% of the total production of the wellbore, only a few percentage points shy of the maximum producing stage (8%). My interpretation here is that these natural fractures are either open by a natural physical process, or that one of the adjacent fracture stages was able to reopen and prop enough of the natural fracture network for it to be connected and flow into the wellbore. The image logs show the existence of dense natural fractures in this area ((Dudley, 2015)), as does the seismic analysis.

Taking this analysis further, there are certain empirical relationships that we expect to see between pressure, fluid injection, proppant injection, fractures, and production. For the two main study wells, the results of those relationships are shown in Figure 6.3 - Figure 6.5. There are no values assigned to the axes of these plots due to confidentiality agreements with APC, but the x-axis increases from left to right and the y-axis increases from bottom to top.
Figure 6.2: Crossplot of calculated bottom-hole pressure against cumulative fluid injection (time integral of slurry rate) for the 2N well.
in all plots. Stepping through these interpretations one by one, Figure 6.3 is a crossplot of incremental oil production against fluid injection for each stage of the 2N well (top) and the 6N well (bottom). Figure 6.4 is a crossplot of incremental oil production against proppant injection for each stage of the 2N well (top) and the 6N well (bottom). Figure 6.5 is a crossplot of incremental oil production against ISIP for each stage of the 2N well (top) and the 6N well (bottom).

Pressure and stress have been shown to be highly related in tight unconventional resource plays. Under the assumption that ISIP is used as a proxy for $S_{\text{M}in}$, stages that exhibit a lower ISIP during a mini-frac or leak-off test have a lower minimum stress-field associated with them. Hydraulic fractures in this stress regime propagate in the direction of $S_V$ and open in the direction of $S_{\text{M}in}$. That means when a lower minimum horizontal stress field is associated with a stage, the fracture may have an easier time opening, therefore opening wider and taking more proppant than a higher stress stage. If the induced fracture opens under a lower stress-field, it could propagate a greater distance and have more potential to join with the natural fracture network. If the induced fracture has a larger half-width and takes more proppant, I expect it to contribute more to the production of the wellbore. However, I only found this to be true in two cases. The first is evidenced in the top panel of Figure 6.5, where the stages with the highest ISIP have the lowest incremental production. The highest producing stage has a relatively low ISIP as well, though it is not the lowest in the well. This stage, Stage A we will call it, shows much higher production and a lower ISIP and is directly adjacent to what I identified as a dense natural fracture network in Figure 6.2. Perhaps in this case, the hydraulic fracture job in Stage A was able to connect with the natural fracture network and partially prop it, thereby forming a conduit for communication to the wellbore. The second case in which we see this relationship is evidenced in the bottom panel of Figure 6.4, where the heel portion displays higher production and the lowest ISIP values. On a whole-wellbore scale, this relationship does not hold with any significant statistical relationship. I theorize that this is due to the difference in azimuth of the maximum stress-
field along the wellbore. As the in-situ stress field changes both magnitude and direction along the wellbore, variable production results are likely to occur as the completions quality will vary. At this point, I will make the disclaimer that the aforementioned relationship between ISIP and production should hold for homogeneous, isotropic media. That is not the case in this study, so I expect a fair amount of deviation from the standard which is exactly what I showed in this study. Additionally, the presence of natural fractures and increased heterogeneity in the system will change the compliance of the background rock and alter the way in which the system responds to the hydraulic fracturing process.

The second empirical relationship I evaluated is that between hydrocarbon production and frac fluid injection. Under standard breakdown conditions, we expect to see a positive correlation between the amount of fluid injected into the well during the course of the hydraulic fracture job and the hydrocarbon production from the well. This is due simply to the idea that the increased volume of fluid, and therefore pressure, entering the formation will propagate a larger fracture, linking more of the matrix with the wellbore and causing higher productivity. This relationship is shown in Figure 6.3.

The third empirical relationship I evaluated is that between hydrocarbon production and proppant injection. Similar to fluid injection, under standard breakdown conditions, we expect to see a positive correlation between the amount of proppant injected into the well during the course of the hydraulic fracture job and the hydrocarbon production from the well. Again, this is simply due to an increased volume of proppant remaining in the fractures, and allowing for easier flow between the matrix and the wellbore. This relationship is seen in Figure 6.4.

In this case, I have shown in Figure 6.3 and Figure 6.4 that there were generally two volumes of fluid and proppant injected into each stage of these two wells. While no strong statistical relationship exists, the stages corresponding to significantly higher injection values of both fluid and proppant perform worse, while the best producing stages of each of the two wells are the ones that had lower amounts of fluid and proppant injected into them.
This holds true for the best and worst stages of each well, but not necessarily for any of the stages in the middle range. However, this is the relationship that I would expect to see. The purpose of carrying out this study was not to prove a statistical relationship though, but to identify relationships that hold true in certain cases so that we may be able to predict them based upon other parameters.

Based upon this analysis, I can conclude that the amount of fluid and proppant injected into each stage makes little difference so long as it is not one of the extreme cases. Injecting extremely high or low values of either appears to be a poor completions design, but injection within the average range leads to similar production results. In terms of ISIP value, little difference exists between stages with moderate ISIP’s. Stages with the lowest ISIP values should theoretically produce the best (assuming reservoir homogeneity), and there is evidence of that in this dataset. Stages with the highest ISIP values should theoretically produce the worst, and there is evidence of that in this dataset as well. Targeting reservoir rock with a lower minimum stress field as identified in seismic data could be one way to optimize completions. If an area with a higher stress field is found, the stage could be moved laterally along the wellbore until a lower stress field is realized.

6.3 Tracer Study

Another point of validation for the study area is the chemical tracer study that was completed during the hydraulic fracture jobs and flowback. The next four figures show the tracer study for the two main study wells, Well 6N and Well 2N, broken into two categories. The tracers are evaluated here in terms of both outflow and inflow. What the outflow images are showing is the amount of tracer recovered in the other horizontal wellbores that was injected into the study well, either 6N or 2N. Figure 6.6 shows the outflow for Well 6N, while Figure 6.7 shows the outflow for Well 2N. Similarly, the inflow images show the amount of tracer recovered in the study well, either 6N or 2N, that was injected into one of the other horizontal wellbores. Figure 6.8 shows the inflow for the Well 6N, while Figure 6.9 shows the inflow for Well 2N. The values of tracer recovered are the mass percentage of that
Figure 6.3: Crossplot of stage-by-stage incremental production against stage-by-stage fluid injection in the 2N well (top) and 6N well (bottom)
Figure 6.4: Crossplot of stage-by-stage incremental production against stage-by-stage prop-pant injection in the 2N well (top) and 6N well (bottom)
Figure 6.5: Crossplot of stage-by-stage incremental production against ISIP values in the 2N well (top) and 6N well (bottom)
which was injected. That is, the values rendered in the wellbore bubbles in the next four images are the percentage of tracer recovered in those wells with regard to the total mass injected into the study well.

Examining the two outflow cases, we see different signatures in the tracer study. Figure 6.6 shows that the highest concentrations of tracer that were injected into the 6N well were recovered to the east, suggesting preferential flow in that direction. When compared with Figure 6.7, there is an increased amount of communication with other wellbores. This could mean that the fracture job for Well 6N was more successful and created more complex fracturing, especially to the east. Well 2N, which is farther to the east than 6N, exhibits no preferential flow, with recovered mass nearly equal on either side. Again, I interpret this behavior as meaning that the 2N hydraulic fracture job was not as successful in creating complex fracturing. It is important to recall that three of the stages in the toe of the well were abandoned when interpreting these results. Both of these observations begin to build a foundation for the understanding of the stress field that I make in the next chapter.

Figure 6.6: Amount of tracer injected into 6N that was recovered in other wells.
Examining the two inflow cases shows very similar results to the outflow. The 6N well still shows preferential flow to the east over flow to the west, and exhibits higher recovery than the 2N well. The 2N well shows lower recovery rates, and a fairly uniform east-west distribution (unpublished work from Dang, 2015). Though with only one well to the east of the 2N well this could simply be an artifact of the well density.

The tracer study is just one more validation dataset, and not a conclusive result. Well 2N is the third best producing well in the study area while Well 6N is the second best. Wellbore spacing is decreased for Well 6N relative to Well 2N (Figure 4.3). This could mean that if the hydraulic fracture job for Well 6N was more successful it could be receiving contributions to production from adjacent wellbores. While Well 2N is nearly as good of a producer, it is likely producing only from the rock matrix that was stimulated during its own hydraulic fracturing. This supports the theory that in a tight unconventional play differences may exist in completion quality that lead to differences in fracture network growth and consequently production. Coupled with pressure information, production information, image logs, microseismic data, and seismic analysis, these differences can be quantified and
Figure 6.8: Amount of tracer produced in 6N that was injected in other wells.

Figure 6.9: Amount of tracer produced in 2N that was injected in other wells.
identified. Determining what can be done to improve completion quality throughout a section using the data at hand will hopefully make a difference for future development.
Herein, I make joint interpretations between geomechanics and geophysics. Either study alone will not give all of the information we need to properly characterize the reservoir, but the two combined bring us much closer to the answer. The geophysics brought into this part of the study refers mainly to the analysis that has been carried out using the Turkey Shoot PP time-lapse seismic volumes. I am calling the geomechanics everything else brought into the study including pressure curves, image log information, microseismic data - the validation data. My intent is to find relationships between pressure/stress and production which can be explained through interpretation of the seismic data in our possession. The ability to accurately predict production based upon seismic data has been a goal of the industry for many years. This study shows that certain relationships may be evident in the seismic signature.

To begin with a simple case we looked at in the last chapter, examining the relationship between production and injection on a per-well basis for all eleven wells in the study area reveals the same trends seen in the stage-by-stage analysis. The best producing well had both a lower volume of fluid and proppant injected into it. However, the worst producing well also had both a low volume of fluid and proppant injected into it. It actually had the lowest volume of fluid injected into it, while proppant injection was similar to the other wells and very similar to the best producer. This is evidenced in Figure 7.1. The only well in which non-standard volumes were injected was the 11N well in which we see poor production. This well had twice the volumes of fluid and proppant pumped into it, and it responded to the additional volumes negatively with respect to production. It is, in fact, the third worst producer. Based upon these data points, it can be shown that there are two separate thresholds for fluid and/or proppant injection. If the first threshold is not
reached, the completion job will not be as successful and production will suffer. And if the second threshold is surpassed, production suffers as well, implying that optimal injection limits exist within the bounds. Nine out of the eleven wells were completed between these two thresholds and any variability in production should be attributed to others factors, likely geology. Looking at this larger study area is a good segue into the ties that this analysis has with the various seismic datasets in our possession.

7.1 The Role of Faults and Fractures

From microseismic analysis that I completed for this project, I showed that there may be a stress reversal part-way through the study section that affects hydraulic fracture propagation and fluid flow (Figure 7.2). In fact, this reversal exists somewhere between the two main study wells. In Figure 7.7 you can see the presence of a relief feature that stretches north-south near the shear axis of the graben. This is a normal fault that I have interpreted to have formed as a mechanism of stress release for the large graben system. Due to the stress regime of the area, it forms a shear zone which accounts for the rotation of the east side of the graben relative to the west. It is my belief that this relief feature is actually a bounding fault for the pressure front and stress field, and is the reason for the difference in pressure and stress signatures on either side of it. That is, this fault forms the basis for the stress reversal. There is no noticeable difference in microseismic activity associated with this fault, leading me to believe that it is sealed. The main graben however, trending east-west, has little to no noticeable effect on the system as a whole in the north-south direction, in the microseismic data or elsewhere. This can be explained through a greater understanding of Figure 7.2 and Figure 7.3. I have generated and interpreted these two images together to tell the story of the role of faults within the study area. The north-south trending relief fault acts as a pressure/stress barrier between the wells because it is a sealed fault. Due to its sealed nature, the stress-field, as well as fluids, do not move as easily across the fault plane Figure 7.2. The two normal faults that act as the bounding faults for the graben are interpreted to be open, and therefore act as conduit for fluid flow, the pressure front, and
Figure 7.1: Crossplot of cumulative oil production against total fluid injection (top) and cumulative oil production against total proppant injection (bottom) for all eleven Wishbone wells
the stress field. There is communication between the rock matrix on either side of these faults. I have come to these conclusions following the methodology of Kratz et al. (2012). I calculated b-values for different stages of wells 2N and 6N to determine how and where the hydraulic fracture energy was being displaced following the classic Gutenberg-Richter relationship:

\[
\log_{10} N = a - bM
\]  

(7.1)

where \( N \) is the number of events having a magnitude greater than or equal to \( M \), and \( a \) and \( b \) are both constants describing the seismic activity and the tectonic parameters of the medium, respectively.

In doing so, I found that the hydraulic fracture stages near the bounding faults of the graben do little to hydraulically fracture virgin reservoir rock but instead reactivate the fault plane. In Figure 7.3, I show one stage with 380 events that falls directly on the dominant (south) graben fault. In this plot, both a slope with \( b = 1 \) and \( b = 2 \) are shown in blue and red, respectively. The red curve corresponding to a b-value of 2 is the curve that best fits the data. The Gutenberg-Richter relationship states that a b-value of 1 corresponds to a new fracture that is induced by the hydraulic fracture job, and that a b-value of 2 corresponds to natural fracture or fault plane reopening or reactivation, which is the case of the graben faults. Generally, a higher b-value will correspond to a lower stress field and reduced heterogeneity, while a lower b-value corresponds to a higher stress field and increased heterogeneity. The fact that we see a higher b-value (lower stress, less heterogeneity) near these graben faults indicates that they are open and frac fluid is flowing through them. Another component of the Gutenberg-Richter relationship that can be realized visually is that there are significantly more microseismic events of a smaller magnitude in these fault plane reactivation stages. The hydraulic fracture energy does not dissipate into the rock in
an attempt to create a new fracture, as is the hope in a hydraulic fracture job. Instead, the frac energy and frac fluid dissipate more quickly along the fault plane. Measured microseisms then will be significantly smaller, and will most likely have traveled a greater distance than events recorded during the failure of matrix rock. Stages along both sides of the graben were evaluated, and this relationship is seen throughout the section. Away from the graben though, there is a mix of b-values corresponding to true hydraulic fracture generation as well as the reactivation of other existing fault planes and natural fractures. It is important to note at this point that all microseismic events were recorded from the surface by single-component geophones, so only larger magnitude shear events were recorded. A surface array recording microseismic data at these depths will generally not detect lower magnitude tensile events such as fracture opening.

Image logs associated with the 2N and 6N wells show variable densities and azimuths of open natural fractures along the wellbore. The dominant strike of the fractures in the 2N well is to the northwest, roughly N60°W and aligned with regional \( SH_{\text{Max}} \) (Figure 7.4). The 6N well shows two dominant fracture sets, oriented to N55°E and N85°E. There is a correlation between the fracture presence/location, production, and attributes drawn from seismic data. The 6N well, which is the strongest Niobrara producer in the section, has evidence of complex fracturing (Figure 7.4). It is important when considering this to reiterate the fact that these fractures are most likely vertical, though they will still strike in the direction of \( SH_{\text{Max}} \) and open in the direction of \( Sh_{\text{Min}} \). With evidence of far-field stress rotations, it would follow that the near-field stress also varies significantly. Therefore, in areas where the wellbore is aligned parallel to \( SH_{\text{Max}} \), the induced fracture will still propagate in the direction of \( S_V \) with strike in the direction of \( SH_{\text{Max}} \), but it may be undetectable in an image log. When fractures are parallel to the wellbore, they are generally not seen in image logs. Similarly, if natural fractures exist in the subsurface but are not intersected by the 4.5” wellbore drilled through the matrix rock it will appear as though the rock is unfractured. From the fractures that are evidenced, we can make the observation that the reservoir interval is highly fractured, the
Figure 7.2: Horizontal distance away from the wellbore that microseismic events were measured due to the hydraulic fracturing job in that wellbore for the 1N well (red) and the 6N well (green).
Figure 7.3: Microseismic b-value analysis for stages near the graben fault planes in the 6N well. A b-value of approximately 2 indicates fault activation.
majority of those fractures strike to the northwest, and fractures with different orientations may indicate complex fracturing leading to increased production.

The main graben faults in this study area are listric normal faults, but some of the smaller-scale faults and fractures do not have the length to be considered listric. They form complex systems that can be described as polygonal (Cartwright, 2011) and have the effect of creating pressure and stress pockets. There are multiple levels of the polygonal systems that are identified within the seismic data. The Niobrara corresponds most closely to case C in Figure 7.5, where we have complex faulting involving large-scale normal listric faults combined with smaller-scale normal faults that either formed during dewatering or due to

Figure 7.4: Rose diagram depicting the orientation of maximum horizontal stress in different study area wells derived from image logs (Dudley, 2015).
tectonic reactivation. These systems in 3D form polygonal systems (Figure 7.6). Due to their normal nature they act almost as bowls, where the center of the system is the lowest point and as you move out you step up. Due to this complex geometrical nature, these ‘mini-basins’ act as cells for pressure and stress. In homogeneous isotropic rock the pressure and stress field should propagate equally in all directions from a frac job, but when you have complex geological features that create additional heterogeneity and anisotropy, the pressure front and stress field will propagate non-uniformly. When that complex geology involves geometric features such as these polygonal faults it becomes clear that they can be correlated with variability in production.

Figure 7.6 shows the development and differences in the polygonal fault system at two different depths. The top image is an incoherence time-slice at the top of the Niobrara while the bottom image is an incoherence time-slice at the top of the Greenhorn. The reservoir interval of interest in this study is within that package, primarily the Niobrara C Chalk and Codell Sandstone. The horizontal wells in both images are colored similarly to the rest of this document, by target interval (Niobara - green, Codell - pink). Several polygonal features are seen in the incoherence volume, corresponding to what is interpreted here as a complex polygonal fault system. Within the study area, these systems appear to be more pronounced deeper within the reservoir, and begin to break up in the shallower intervals of the reservoir or even above. The consequence of these fault systems within the reservoir interval is that they act as bounding features for the pressure front and stress field. As the hydraulic fracture job is carried out, the far-field stresses in the area change. When this stress change occurs in matrix rock outside of a fault system, it propagates through the rock until it reaches a barrier. When the stress change occurs within the fault system though, it may become trapped by the bounding faults of the system, and that area may see a much higher stress change than surrounding rock. With p-wave seismic data, we expect to be able to map the stress in the reservoir.
Figure 7.5: Three levels of faulting based upon complexity of the system. The Niobrara in this study area is a classic Case C (Cartwright, 2011).
Figure 7.6: Polygonal faulting in map view as identified in incoherence or fault scan seismic slices. Top Niobara (top) and Top Greenhorn (bottom) are shown. Note how the system is more coherent with depth and begins to break up as it shallows.
7.2 Relating Geomechanics to Seismic

The seismic data in our possession includes compressional, converted-wave, and shear stacks and gathers. Throughout Phase XV of RCP, three of my colleagues, Matthew White, Matthew Bray, and Taraneh Motamedi have carried out research focused on fracture and stress characterization of the study area. Some of their results are seen in Figure 7.7 and Figure 7.8, with various validation data overlaid on the images. Their work consisted of anisotropic 3D amplitude variation with azimuth in the PP data (White and Bray) and the SS data (Motamedi).

Figure 7.7 is one of the key maps that I will show to depict the various relationships between stress, structure, and what we can determine about them both from the seismic data. What is shown are the eleven Wishbone wellbores colored by formation (Niobrara - green, Codell - pink) along with a background incoherence map (white - incoherent, black - coherent) and ISIP values for each wellbore stage (high - red, low - purple). The vector ticks denote the azimuth of the fracture set most closely aligned to $S_{H_{Max}}$ and are therefore interpreted here to be a proxy for the orientation of $S_{H_{Max}}$ at the top of the Niobrara interval. They are colored by azimuth sector. Along with the crossplots that are shown in Figure 6.3 - Figure 7.1, Figure 7.7 helps to understand the correlations between pressure, stress, completions, productions, and geology. Many different interpretations can be made based upon a map with this much data, several of which I will outline here. To begin, making the assumption that the P-wave seismic data is mapping the fracture set closest aligned to $S_{H_{Max}}$, the spatial scale on which the stress-field is changing is quite surprising. With further examination though, it becomes apparent that the stress-field is closely tied to the geology of the study area, evidenced by the nature of the stress changes and their relation to the background incoherence. In areas with uniform geology, the stress-field remains fairly constant, but near faults and features interpreted to be complex polygonal systems the stress-field changes much more rapidly. The primary areas of interest align with or are encompassed by seismic-scale faults and incoherencies. Looking back to Figure 7.6 and remembering how
the polygonal systems change with depth, most stress-field rotations determined from the PP seismic data can be attributed to stress-pocketing within these systems. If the system is as complex as Case C depicted in Figure 7.5, we would expect to see different behavior within the smaller-scale system with respect to the larger-scale system. This is evidenced in Figure 7.7 in that the stress effects seen within the more polygonal areas are much more pronounced and dramatic - that is, at times they act as a basin that fosters a complete 360° stress rotation within the system itself. The same effect can be seen outside of the polygonal systems near the larger graben faults. Due to their larger spatial area the stress rotation is upscaled and thus occurs over a much larger spatial area.

The ISIP values overlaid on each stage of the wellbores help to verify the relationships seen between stress and the seismic data. The variable that appears to have the most control over the ISIP values is the surrounding geology. The easiest way to make this claim is to look at the ISIP values nearby to the large graben faults in Figure 7.7. The ISIP values nearby to the faults, and within the grabens are different from those away from them, and can change drastically as they approach them. The higher ISIP values nearby to the faults are most likely an artifact of the increased stress field due to complexity in the area. It also means that in these regions $Sh_{Min}$ is closer to $SH_{Max}$ and complex fracturing is more likely to occur. With increased complexity due to complex fracturing, we expect to see better production from the surrounding stages (Warpinski, 2014). A lower ISIP value, however, could indicate that the fracture remained open longer, therefore propagating farther and reaching out into more of the virgin rock. This would likely indicate the opening or reopening of one dominant fracture or fracture system though, meaning that while fracture complexity was not achieved fractures were still stimulated and potentially propped. Because of this relationship it is difficult to say whether a higher or lower ISIP value would lead to increased production. When looking back to Figure 6.5 this same conclusion is drawn. There are only a handful of stages that fit either of the relationships discussed, with most stages falling in the middle. Whether or not production is increased due to the type of fracturing that has occurred is something
that I cannot conclusively determine with the current data, but it is possible to determine that higher ISIP and $Sh_{Min}$ values correspond to more complex fracturing. We know from microseismic analysis that this is true as well - the smaller the difference between $SH_{Max}$ and $Sh_{Min}$ the wider the microseismic cloud will be, leading me to believe that a more complex fracture network has been stimulated as opposed to one linear fracture.

Figure 7.7: Wishbone section with background incoherence depicting Niobrara (green) and Codell (pink) wellbores with ISIP values for each stage (red - high, pink - low) and fracture azimuths derived from Turkey Shoot PP baseline seismic gathers (Bray, 2015).

Figure 7.8 is another seismic-based map that leads to many of the same conclusions that were drawn from Figure 7.7 but from a different methodology. The background map is a rendering of the magnitude of minimum horizontal stress derived from far offset travel-time isochrons of the Turkey Shoot PP seismic data (warm colors - high, cool colors - low). The arrows are a minimum horizontal stress vector where the azimuth is the orientation of $Sh_{Min}$.
at that location and the color is stress magnitude (warm colors - high, cool colors - low). The triangles represent the bright azimuth as identified in the near-offsets of the Turkey Shoot PP seismic data - used here as a proxy for $SH_{Max}$ - the azimuth is the orientation of $SH_{Max}$ at that location and the color is the stress magnitude (warm colors - high, cool colors - low). The first point of interpretation I make on this map is the areas where the arrows and the triangles align, and where they are orthogonal. We expect minimum and maximum horizontal stress to be orthogonal at all points, and any divergence (or convergence) from this trend likely indicates the error in which either (or both) can be estimated from seismic data. It could, however, indicate a more isotropic stress-field where the difference in magnitude between $SH_{Max}$ and $Sh_{Min}$ is very small. Nearby to larger-scale structures, such as the graben faults and other large normal faults, the two stresses are generally orthogonal as we would expect. There is little evidence of similar stress directions near these structures. As you move away from structure though both stress-fields exhibit rotations, but not equally. This causes the vectors to become more aligned with respect to azimuth, but not necessarily magnitude. As expressed in Figure 7.7 we expect more complex fracturing when the difference between the two horizontal stresses is smaller, and therefore better productivity.
Figure 7.8: Normalized minimum horizontal stress (warm colors - high, cool colors - low) derived from far offset travel-time isochrons of Turkey Shoot PP seismic data with incoherence overlaid. Arrows are the direction of minimum horizontal stress. Triangles are the direction of the bright amplitude azimuth identified in the near-offsets of the Turkey Shoot PP seismic data used here as a proxy for the direction of maximum horizontal stress. Pink boxes along wellbores are ISIP values being used as a proxy for minimum horizontal stress (Bray (2015), Motamedi (2015)).
CHAPTER 8
CONCLUSIONS

The end goal of this thesis is to tie all the data together into a meaningful interpretation in the form of reservoir characterization. From the 1D mechanical earth models and the 3D structural model, I have built the foundation of a stress-focused 3D geomechanical model that will be used by future RCP students to simulate different cases in the reservoir and to determine how pressure depletion due to production may alter the in-situ stress field. Pressure interpretation was carried out in order to obtain a proxy for minimum horizontal stress via ISIP values. These ISIP values were examined from a statistical standpoint along with other completion parameters and production. They are displayed in Figure 7.7 and Figure 7.8 in order to help determine what inferences can be made about stress from the seismic data.

In summary, conclusions drawn from this research are:

- Geologic structure is the driving factor for production variability within the study area.
- Complex fault systems create stress compartments that inhibit the pressure front during hydraulic fracturing.
- Completion parameters such as fluid and proppant injection have little correlation to well productivity so long as injection levels fall within the standard range.
- Changes in stress within the reservoir are related to geologic structure more than they are influenced by completion and production.
- Fault analysis shows both large open and sealed faults that can act either as a conduit or a barrier for flow. Completion and wellbore spacing should be designed with this in mind.
• Seismic analysis should be carried out in order to identify geologic structure and design completions and wellbore spacing.

• Localized stress orientations vary.

• We gain an understanding of the way in which the stress field changes during hydraulic fracturing from time-lapse seismic analysis. To better understand how in-situ stress is changing, geomechanical modeling should be carried out coupled with reservoir simulations and time-lapse multicomponent seismic surveys to monitor the production effect.

8.1 Stress Information

An understanding of the far-field stress regime is necessary in understanding how wells will perform when drilled into various geologic formations at different depths and azimuths, and with varying completions parameters. I have shown in this study that pressure curves can be used as a strong validation dataset to lend insight into the pressure front and stress-field during the hydraulic fracture jobs. ISIP values, used as a proxy for minimum horizontal stress, can help to quantify the stress magnitudes within the reservoir, and are simpler to derive than maximum horizontal stress. As will be seen in forthcoming theses, the Turkey Shoot seismic data will lead to many observations and conclusions regarding pressure and stress as well as fractures within the study area. $S_{H_{\text{Max}}}$ is aligned to N70°W and fractures tend to be aligned N20°E. However, while this may be the regional stress direction, local perturbations in that stress field are overriding the regional signal as local stress rotations occur both in the near- and far-field due to both mechanical and poroelastic effects. The far-field stress rotations within the Wishbone section could be largely responsible for differences in completions quality, and consequently differences in production. ISIP values vary throughout the study area, as do the character of microseismic events, and image log interpretations. No one case exists for optimum production based upon the stress interpretations that I have made here. Given the small spatial area over which the stress-field changes within the study...
area, it could be possible for two adjacent stages to be completed under starkly different stress conditions. That said, regional $SH_{Max}$ is aligned to N70°W, which conventionally would mean that wellbores should be drilled at N20°E in order to be orthogonal to $SH_{Max}$ and intersect the maximum number of natural fractures. Drilling in a non-cardinal direction is not the ideal case for well placement in a standard section, so drilling in a north-south direction is likely to achieve the best production results as it is close to orthogonal to the maximum horizontal stress direction. Due to the stress-regime of the basin, hydraulic fractures are expected to propagate in the direction of $S_V$ and open in the direction of $Sh_{Min}$. The implication of this is that if portions of the wellbore are not aligned to $SH_{Max}$ then the hydraulic fractures could still intersect a large number of background fractures that are oriented with $SH_{Max}$ and create the complex fracturing that we expect to provide the best production.

8.2 Recommendations and Future Work

Geomechanics is a dynamic field of study that is capable of supporting a plethora of inputs, making any single study only a partial solution. The foundation of this study includes the Turkey Shoot baseline seismic survey, and a monitor survey acquired three months later (post hydraulic fracture job). We are also in possession of 4D Turkey Shoot surveys in converted (PS) and shear (SS) modes. From the converted- and shear-wave datasets, we are able to bring out additional information and draw conclusions that cannot be made with only compressional data. Time-lapse analysis of all wave modes should help to discern pressure, stress, and fracture information - three quantities that have been shown to drive production in Wattenberg Field. The shear (SS) dataset will show the dominant fractures and fracture sets, but may not be as sensitive to stress and pressures as the compressional-mode seismic data. Inversion work will help to constrain thinner reservoir intervals that may have implications for completions and production. We have already shown that inversions in the post-stack domain do little to enhance the resolution of the geologic strata. This means then that all inversion work should be carried out in the pre-stack domain in an effort to increase stratigraphic
resolution. Sensitivity analysis of the pre-stack data has shown promising results suggesting that resolution may be increased dramatically. One of the most important considerations in this RCP phase is the geology of the field and basin. Even in a tight unconventional reservoir where any geologic differences are minimal, those geologic differences may still be the factor that distinguishes better producing wells and stages from worse ones. While the geology of the Denver Basin is a well-published topic, it can be quite variable and depends on proximity to the front range and other bounding features, as well as the Wattenberg geothermal anomaly (Higley and Cox, 2007; Knepper et al., 2002). Additionally, proximity to regional wrench faults is believed to play a role in heat convection, and therefore thermal maturity and GOR for a particular fault block. When lease acreage crosses one of these wrench faults, drastic differences in GOR may be realized on either side of the fault. For this reason, a detailed geologic study of the four square-mile Turkey Shoot study area could benefit the project. My recommendation is to implement the CWP code developed by Hale (2013) in order to gain a better understanding of the formation of the geologic features within the basin, and how they may contribute to reservoir heterogeneity. As this software is within the department, this could be a collaborative effort between consortia. This fundamental understanding could be applied to a full paleo-reconstruction using additional software, which is one item lacking in the literature.

A full 3D geomechanical simulation should also be carried out in the near future. The 3D structural framework that I developed within Petrel™ software, including the 1D mechanical earth model developed by Tom Bratton, will act as the foundation for such a simulation. With the abundance of petrophysical data available to RCP, a master’s student can begin this work immediately. The work is straightforward to carry out, but will provide tremendous insight into the role of pressure and stress and their relation to production. The structural framework needs to be loaded into the Reservoir Geomechanics module within Petrel™ software and turned into a geocellular model within that module. With that part of the modeling completed, there is a clear step-by-step flow that must be followed. Once the
workflow has been completed, the model can be simulated in order to predict geomechanical changes. The first simulation I recommend is a simple equilibration test. This requires that the overburden and sideburden of the model are estimated properly and provides a base-case for the far-field stress in the reservoir at the time of seismic acquisition once equilibration is reached. The clear next step from there is to obtain a time-lapse result. This could be done one of two ways (I recommend both). The first is to run the equilibration simulation on the seismic monitor. This will provide a snapshot of the far-field stress at the time of the seismic monitor. With static results from the baseline and monitor surveys, a plethora of valuable new information could be obtained. The second option is to run a coupled simulation in Eclipse™ software and Visage™ software. By taking the base model and running a flow simulation in Eclipse™ software, one gains the information on how the reservoir is changing due to pressure depletion associated with production. The output of the flow simulation is then used as the input for the geomechanical simulation in Visage™ software. This process iterates until equilibrium has been reached, and the user is now in possession of the results of both a reservoir and a geomechanical simulation. We have all of the necessary tools needed to carry out these simulations within RCP.

Due to the overpressue/underpressure effects that are seen above, within, and beneath the reservoir interval, it is difficult to build a velocity model strictly upon well log data and the interval velocity cube used for migration. It would be ideal to build a seismically-derived pore pressure model to more accurately estimate seismic velocities in the subsurface. The work would shed a great deal of insight into the overpressured nature of the Niobrara, and would allow us to better understand the pressure front and stress field with regard to both regional and local geology. Several master’s students are currently working with the Wattenberg Field dataset.

8.3 Utilization of this Work

This work can be utilized within oil and gas companies as a bridge between geoscience and engineering. In an ever-changing and evolving industry such as this, any additional
information available for integration can be useful. Tying geophysical work to engineering work is the only way to truly move forward in integrated teams. In order for engineers to trust geoscientists and the work that they complete, we as geoscientists need to push the envelope. Showing that seismic-based results can be reliably used as predictive tools within the reservoir is the best way to prove the value of geoscience and high-resolution seismic to unconventional reservoir characterization. The study of geomechanics, both seismic and well-data based, is dynamic and varied. Relationships exist in the data that can be explored by engineers and geoscientists alike. While a geoscientist may use geomechanical modeling and simulations to better understand rock properties, anisotropy, and far-field stresses in terms of how they relate to oil production, and engineer can use the same geomechanical model and simulations to identify the optimal time for refracturing a horizontal wellbore. Joint reservoir and geomechanical simulations can be performed with only one baseline seismic survey, with usable results coming out of them. With seismic monitor surveys, as we have in this dataset, the simulations can be better constrained and ground-truthed. We currently have the ability to image the far-field stresses at the time of the Turkey Shoot seismic baseline survey as well as the Turkey Shoot seismic monitor, which provide snapshots at both of those times and allows the ability to simulate between the two discrete times. Based upon Figure 1.10, this means that the effect of completions on the reservoir can be imaged. With the additional seismic monitor, the simulations could be constrained to include one to two years of production, as well as the effect of completions. For geoscience purposes, this allows the ability to optimally place wellbores based upon geologic and geomechanical properties. For engineering purposes, this allows the ability to optimally space wells and stages as well as time the recompletion. Interdisciplinary work, which is carried out every day in the industry, can be aided by models and simulations such as those described here.
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