3D MODELING AND CHARACTERIZATION OF HYDRAULIC FRACTURE EFFICIENCY INTEGRATED WITH 4D/9C TIME-LAPSE SEISMIC INTERPRETATIONS IN THE NIOBRARA FORMATION, WATTENBERG FIELD, DENVER BASIN

by

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

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ABSTRACT

Hydrocarbon recovery rates within the Niobrara Shale are estimated as low as 2-8%. These recovery rates are controlled by the ability to effectively hydraulic fracture stimulate the reservoir using multistage horizontal wells. Subsequent to any mechanical issues that affect production from lateral wells, the variability in production performance and reserve recovery along multistage lateral shale wells is controlled by the reservoir heterogeneity and its consequent effect on hydraulic fracture stimulation efficiency. Using identical stimulation designs on a number of wells that are as close as 600ft apart can yield variable production and recovery rates due to inefficiencies in hydraulic fracture stimulation that result from the variability in elastic rock properties and in-situ stress conditions.

As a means for examining the effect of the geological heterogeneity on hydraulic fracturing and production within the Niobrara Formation, a 3D geomechanical model is derived using geostatistical methods and volumetric calculations as an input to hydraulic fracture stimulation. The 3D geomechanical model incorporates the faults, lithological facies changes and lateral variation in reservoir properties and elastic rock properties that best represent the static reservoir conditions pre-hydraulic fracturing. Using a 3D numerical reservoir simulator, a hydraulic fracture predictive model is generated and calibrated to field diagnostic measurements (DFIT) and observations (microseismic and 4D/9C multicomponent time-lapse seismic). By incorporating the geological heterogeneity into the 3D hydraulic fracture simulation, a more representative response is generated that demonstrate the variability in hydraulic fracturing efficiency along the lateral wells that will inevitably influence production performance.

Based on the 3D hydraulic fracture simulation results, integrated with microseismic observations and 4D/9C time-lapse seismic analysis (post-hydraulic fracturing & post production), the variability in production performance within the Niobrara Shale wells is shown to significantly
be affected by the lateral variability in reservoir quality, well and stage positioning relative to the target interval, and the relative completion efficiency. The variation in reservoir properties, faults, rock strength parameters, and in-situ stress conditions are shown to influence and control the hydraulic fracturing geometry and stimulation efficiency resulting in complex and isolated induced fracture geometries to form within the reservoir. This consequently impacts the effective drainage areas, production performance and recovery rates from inefficiently stimulated horizontal wells.

The 3D simulation results coupled with the 4D seismic interpretations illustrate that there is still room for improvement to be made in optimizing well spacing and hydraulic fracturing efficiency within the Niobrara Formation. Integrated analysis show that the Niobrara reservoir is not uniformly stimulated. The vertical and lateral variability in rock properties control the hydraulic fracturing efficiency and geometry. Better production is also correlated to higher fracture conductivity. 4D seismic interpretation is also shown to be essential for the validation and calibration hydraulic fracture simulation models. The hydraulic fracture modeling also demonstrates that there is bypassed pay in the Niobrara B chalk resulting from initial Niobrara C chalk stimulation treatments. Forward modeling also shows that low pressure intervals within the Niobrara reservoir influence hydraulic fracturing and infill drilling during field development.
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Biot’s poroelastic constant ........................................................................... \( \alpha \) or Biot V

Breakdown Pressure (psi) .................................................................................. \( P_{bd} \)

Brittleness Factor ............................................................................................. BRF

Bulk Density (g/cm\(^3\)) ...................................................................................... RHOB or \( \rho \)

Closure pressure (psi) equal to minimum horizontal stress ............................... \( P_c \)

Critical Fissure Opening Pressure (psi) ......................................................... CFOP

Diagnostic Fracture Injection Test ................................................................. DFIT

Dimensionless Fracture Conductivity ............................................................. \( F_{CD} \)

Dynamic Poisson Ratio ................................................................................... \( PR_{Dyn} \)

Dynamic Young’s Modulus .............................................................................. \( E_{Dyn} \)

Effective Stress ............................................................................................... \( \sigma_{eff} \)

Estimated Permeability Log (mD) .................................................................. Perm

Estimated Ultimate Recovery .......................................................................... EUR

Fracture Gradient (psi/ft) or Fracture Pressure (psi) ......................................... FG

Fracturing Pressure (psi) ................................................................................ P\(_f\)

Friction Pressure (psi) .................................................................................... P_{friction}

Gamma Ray (API) ............................................................................................. GR

Horizontal Strain in the direction of \( \sigma_{H\text{max}} \) .............................................. \( \varepsilon_H \)

Horizontal Young’s Modulus ......................................................................... \( E_h \)

Hydraulic Fracture Half Length (ft) ................................................................. \( X_f \)

Hydraulic Fracture Proppant Permeability (mD) ............................................... \( K_f \)

Hydraulic Fracture Width (inch) ................................................................... \( W_f \)

Instantaneous Shut-In Pressure (psi) ............................................................. ISIP

Maximum Horizontal Stress ........................................................................... \( \sigma_{H\text{max}} \) or \( S_{H\text{max}} \)

Minimum Horizontal Stress .......................................................................... \( \sigma_{h\text{min}} \) or \( S_{h\text{min}} \)

Net Pressure (psi) .......................................................................................... \( P_{Net} \)
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CHAPTER 1
INTRODUCTION

1.1 Introduction to the project study area

The Niobrara unconventional reservoir is a successful shale resource play due to the advances in horizontal drilling and hydraulic fracturing (Sonnenberg, 2013a). The Niobrara Formation is a self-sourcing interval of chalks and marls. The formation extends into several basins within the central US from Colorado, Wyoming, Nebraska and Kansas (Figure 1.1) (Sonnenberg, 2011a). The predominant exploration and development targets are located within the Denver Basin consisting of oil, condensate and gas accumulation. The purpose of this study is to assess the Niobrara reservoir stimulation treatment within one square mile section of Wattenberg Field (Figure 1.2). The analysis will be focused over the Reservoir Characterization Project (RCP) consortium data sets within a section that is targeting the Niobrara and Codell with 11 Horizontal wells.

The Niobrara Formation is an organic-rich, self-sourcing unit, predominantly made of carbonate deposits in the form of alternating layers of chalks and marls. The Niobrara resource play is typically compared to the Eagle Ford Shale due to its high carbonate content. Earlier production can be dated back to 1976 from vertical wells in Wattenberg Field, although not deemed commercially viable at the time. The shale play has become more attractive with the move towards horizontal drilling and multistage hydraulic fracturing allowing for the Niobrara to successfully be developed with overall success in the Denver basin ever since 2009 (Sonnenberg, 2013a).

The Wattenberg Field, located within the Denver Basin, is the most active area producing from the Niobrara Formation. The Wattenberg area covers approximately 3200 square miles, and
has a resource estimate of 3-4 billion barrels equivalent (Sonnenberg, 2013). The generalized stratigraphic column shown in Figure 1.1 shows the predominant members within the Niobrara Formation (alternating layers of chalk, in blue, and marl, in grey). The Niobrara Formation (Smoky Hill Member) consists of four limestone (chalk) units and three intervening marl intervals ranging in depth from 6200 - 7800ft MD (Sonnenberg, 2013). Within the study Reservoir Characterization Project study area (Figure 1.2), the Niobrara A chalk is not present. The main Niobrara reservoir intervals within the focused RCP study area are the Niobrara B chalk and Niobrara C chalk. The Niobrara Formation is bounded by the Sharon Springs member of the Pierre Shale above, and the Codell below. The Codell sandstone is also considered to be a tight reservoir that is usually targeted by horizontal drilling and hydraulic fracturing along with the Niobrara for its hydrocarbon bearing potential.

Figure 1.1 Niobrara resource play extent within Colorado, Wyoming, Nebraska and Kansas. Stratigraphic column to the right illustrating the Niobrara A, B, and C chalk layers interbedded between layers of marl from (Sonnenberg, 2011a)
1.2 Project objective

The Niobrara Shale play is calculated to have a total of technically recoverable reserve around 3.7 billion barrels of oil and 46.5 Tcf of gas (IHS, 2016). These estimates are based on a 2-8% recovery rate per well. Advances in geological and geomechanical reservoir characterization, integrated with simulation modeling, has allowed the industry to improve recovery by modeling and analyzing the effectiveness of the hydraulic fracture stimulation to increase recovery factors from shale reservoirs (Wallace et al., 2016).

This project proposes the use of 3D hydraulic fracture simulation models for the characterization of hydraulic fracturing treatments in unconventional shale reservoirs. This project will focus on analyzing the changes in stress and pressure within the reservoir as a result of the hydraulic fracturing and production. The goal is to analyze the variations of in-situ stress and pore pressure using a 3D numerical reservoir simulation guided by microseismic and 4D time-lapse
seismic interpretation to assess the dynamic stress state of the reservoir for potential infill drilling and refracturing opportunities.

The motive behind this project is to characterize the hydraulic fracturing within the Niobrara to provide better insight into improving well spacing and hydraulic fracturing efficiency within Wattenberg Field. The project focuses on analyzing the changes in elastic rock properties, pressure and stress within the reservoir and their influencing effect on hydraulic fracturing using a 3D numerical reservoir simulator. The simulation results are integrated with microseismic observations in the area, along with the 4D seismic interpretations, to analyze and determine the effect of geological heterogeneity on hydraulic fracturing. The objective of this work is to understand how the in-situ stress variations within the reservoir affected the initial stimulation treatments. The insight provided by this study will help assess areas within the reservoir that are potential for infill drilling or re-fracturing.

The use of the 3D numerical hydraulic fracture simulator coupled with 4D/9C time-lapse seismic interpretation shows that there is still room for improvement to be made in optimizing well spacing and hydraulic fracturing efficiency within the Niobrara Formation. By understanding the reservoir complexity in regard to stress anisotropy, strength variation and natural fracture density, exploitation and optimization plans can proceed with better efficiency for potential increase in recovery from the Niobrara unconventional reservoir.

1.3 Project workflow

This integrated project will be conducted using different methods to obtain a sensible understanding of the hydraulic fracturing efficiency within the Wishbone section of the Wattenberg Field. The workflow for this project can be simply described as follows:
1) Generate a 1D geomechanical mechanical earth model to assess the vertical stress distribution within the Niobrara and Codell Formations.

2) Generate a 3D geomechanical model to represent the lateral geologic and geomechanical heterogeneity within the Niobrara and Codell Formations.

3) Input the 3D geomechanical model into a 3D numerical reservoir simulator for hydraulic fracture characterization.

4) Integrate results from simulation modeling results with microseismic observations, along with 4D/9C time-lapse analysis to assess hydraulic fracturing efficiency.

5) Assess area for potential infill drilling and refracturing opportunities based on integrated the simulation results with the 4D seismic interpretations.

1.4 Data availability

The 3D seismic surveys and well log data within this study area was provided through the Reservoir Characterization Project (RCP) along with Anadarko Petroleum Corporation (Figure 1.3). The well logs provided for this project include the GR, RHOB, NPHI, Resistivity logs, along with some DT logs. Synthetic DTP and DTS logs were generated around the Wishbone section from Neural Network analysis based on empirical relationships established from offset wells that included real sonic data (Bray & Link, 2015; Pitcher, 2015). Core data taken from the Niobrara interval was also provided by Anadarko for several wells around the study area (Figure 1.3). All drilling and completion data, along with the production information (Figure 1.5), within the Wishbone section are also provided by Anadarko.

The 9C multicomponent 4D time-lapse seismic data (Baseline, Monitor 1, Monitor 2) was acquired by the RCP consortium over the Turkey Shoot area to obtain full fold over the Wishbone section, with a bin size of 50ft x 50ft (Figure 1.3) (RCP, 2016). The time-lapse nature of the seismic acquisition was acquired at different time steps within the life span of the field (Figure 1.4). The
first 9C seismic survey (Baseline) was acquired after drilling the 11 horizontal wells in the section (Figure 1.6 & Figure 1.7). Surface microseismic was captured while hydraulic fracturing of the 11 horizontal wells was being conducted (Figure 1.8). The following 9C seismic survey “Monitor 1” was acquired right after hydraulic fracturing was completed in the area to assess the seismic response caused by hydraulic fracturing and estimate a stimulated reservoir volume (SRV). Following 2 years of production, “Monitor 2” seismic survey was acquired to analyze the productive reservoir volume and assess the area for potential bypassed reserves.

The acquisition and processing of the time-lapse surveys focused on preserving the repeatability and consistency in regard to acquisition and processing to reduce the effect of noise caused by any inconsistencies in acquisition or processing. The time-lapse Baseline and Monitor surveys were processed simultaneously by Sensor Geophysical for the PP, PS and SS seismic data (RCP, 2016). Cross equalization of surveys was also applied on the overburden sections within the surveys to remove any noise resulting from any dissimilarities in acquisition. The cross equalization is an essential process for obtaining reliable differences at the reservoir level.
Figure 1.4 4D Time-lapse seismic timeline modified from (White, 2015)

Figure 1.5 Normalized Niobrara Production (left), Normalized Codell Production (right) showing over 50% variability in production performance between Niobrara Wells, and over 30% difference in production performance in the Codell wells (RCP, 2017)
Figure 1.6 Cross section through the lateral wells relative to the target intervals. Cross section depicted in Figure 1.7 (RCP, 2017)

Figure 1.7 Variation in well landing intervals due to geologic heterogeneity and faulting. Modified from (Pitcher, 2015)
Figure 1.8 Acquisition geometry for surface microseismic FracStar™ array. The survey has 14 arms and 3396 channels (RCP, 2016)

1.5 Previous work

Several projects have been conducted within Wattenberg Field by the Reservoir Characterization Project (RCP) within Colorado School of Mines. The information provided by many of these projects helped develop a better understanding of the geological heterogeneity within the study area. The work provided by Matthies (2015) helped provide a regional understanding of the Niobrara depositional system. Brugioni (2017) described the core to observe the facies distribution within the Niobrara closer to the RCP study area. Their work was helpful in creating a fundamental understanding of geological heterogeneity within the Niobrara Formation.

Insight into characterizing the geomechanical complexity within the Niobrara over the RCP study area was previously provided by several RCP students. The FMI analysis was conducted within the study area to assess the direction of natural and induced fracturing along the study
wells by Dudley (2015). While Mabrey (2016) provided insight into the lateral variability in geological heterogeneity along the horizontal wellbores targeting the Niobrara and their impact on the near wellbore stresses and geomechanical properties. A 3D seismic driven geomechanical model was also generated by Grazulis (2016) that helped provide valuable insight into the lateral distribution on stress within the Niobrara Formation in the same given study area. Grazulis (2016) provided a glimpse into the effect of hydraulic fracturing and production on the reorientation of stress around select wellbores in the area. The insight provided by these students will help me develop a better understanding of the lateral distribution of in-situ stress within the Niobrara reservoir.

A 3D structural model including several faults and was generated by Ning (2017) to be used for production history matching. The structural model consisted of several seismic derived horizons that were depth converted using a 3D velocity model generated Payson Todd. The structural model generated by Ning (2017) will be used for my project to generate a 3D geostatistical model as well as a 3D hydraulic fracture simulation result that can be used as an input into Ning (2017)'s production history matching in the near future.

Dang (2016) assessed and analyzed the production tracers within the study area. She also provided some early insight into the geometry generated by hydraulic fracturing the Niobrara using a simple 1D geomechanical model. Her analysis will be taken into consideration to help further my understanding of the hydraulic communication between the wells and their potential impact on production from the Niobrara and Codell Formations.

Seismic interpretations from White (2015) generated using pre-stack seismic inversion to assess the time-lapse effect on the PP seismic data due to hydraulic fracturing. This work was then revisited and carried forward by followed by Utley (2017) to analyze the 4D PP time-lapse response from a pre-stack seismic inversion for the effects of production within this study area.
The 4D-seismic multicomponent effects caused by hydraulic fracturing were also assessed by Mueller (2016) for mapping the stimulated reservoir volume through the application of time-lapse seismic shear wave inversion within the same study area. By integrated their work into the results provided by the 3D numerical reservoir simulator for hydraulic fracturing, I am able to develop a better understanding of the hydraulic fracturing efficiency in the area. The integration will also be important for assessing areas for potential enhanced recovery through infill drilling and refracturing.

This insight provided by many of the projects that were previously conducted over the same study area will constructively help guide the interpretation and analysis of my results. The goal of this project is to make use of previous work by integrating the information into a simulation model for hydraulic fracture characterization within the Niobrara. The potential recommendations that will be provided by this project will allow for better field development, increased hydrocarbon recovery, and increased overall production from the Niobrara through infill drilling and refracturing.
2.1 Summary

The Niobrara Formation is an organic rich and mature source rock interval. With advances in horizontal drilling and hydraulic fracturing, the Niobrara has become a valuable resource for hydrocarbon production. The variability in success within the Niobrara is driven by the reservoir quality and location of relative “production sweet spots” within the basin. The ability to characterize the Niobrara reservoir and produce from these “production sweet spots” can have a significant effect on the production rates from such wells, along with the overall hydrocarbon recovery. Understanding the effect of the geological heterogeneity within the Niobrara, and the effect of such heterogeneity on potentially increasing reserves and recovery is critical to any shale exploration or development program targeting the Niobrara Formation.

2.2 Introduction

The Niobrara unconventional resource has become an attractive and successful shale reservoir targeted ever since 2009 due to the advances in horizontal drilling and hydraulic fracturing, while early production can be dated back to 1979 (Sonnenberg, 2013a). The Niobrara resource play extends in several basins within the central US from Colorado, Wyoming, Nebraska and Kansas. The predominant exploration and development targets are located within the Denver Basin consisting of oil, condensate and gas accumulation.

Resource assessment for the Niobrara are predominantly focused on the DJ basin considering that it is also the main basin for this play. Based on the IHS calculated estimates, the Niobrara shale play is calculated to have a total of technically recoverable reserve around 3.7
billion barrels of oil and 46.5 Tcf of gas, or 11.5 billion barrel of oil equivalent as shown in Figure 2.1 (IHS, 2016; U.S. Energy Information Administration, 2011). Comparing this estimated volume to database for the main shale resources, it can be observed that recoverable gas in the Niobrara is range in the middle of the group. For recoverable oil, the Niobrara is comparable to the Bakken and Eagle Ford.

The Niobrara Formation acts as its own reservoir and source interval (Figure 2.2). The self-sourcing nature of this reservoir target, along with the low permeability of the formation, makes for an attractive unconventional hybrid system to be targeted for hydrocarbon extraction using horizontal wells and hydraulic fracture treatments. The Niobrara Formation (Smoky Hill Member) consists of four limestone (chalk) units and three intervening marl intervals ranging in depth from 6200 - 7800ft MD within the Denver-Julesburg (DJ) Basin, Colorado, with thicknesses ranging from 150ft - 1500ft. The Niobrara Formation is a self-sourcing unit that has TOC values ranging from 1-5%. The organic matter is of type II kerogen (oil prone) (Sonnenberg, 2013a).

Figure 2.1 Resource estimate compared (U.S. Energy Information administration, 2011)
2.3 The Niobrara petroleum system

The Niobrara Formation (Late Cretaceous age) was deposited in a foreland basin setting in the Western Interior Cretaceous Seaway of North America during a time of a major marine transgression (Sonnenberg, 2013a). The present-day basins in which the Niobrara deposits currently reside formed during the Late Cretaceous to Early Tertiary Laramide orogeny within the Rocky Mountain Regions. The sediment deposits that formed the Niobrara Formation (Smoky Hill Member) consist of four limestone (chalk) units and three intervening marl units (Figure 1.1). The alternating layers of chalk and marl make the Niobrara Formation a prime target for unconventional resource exploitation due to the self-sourcing nature of the reservoir and low permeability that allows for the hydrocarbons to be trapped soon after generation (Figure 2.2).

![Figure 2.2 Niobrara Petroleum System Event Chart (Finn & Johnson, 2005)]

The Niobrara Formation is predominantly located within areas northeast Colorado, and parts of Wyoming, Nebraska, and Kansas (Figure 1.1). The Niobrara Formation is actively drilled and being developed in the Denver-Julesburg Basin, Colorado, using horizontal drilling and hydraulic fracturing to yields oil and gas from the unconventional shale accumulations (Michaels & Budd, 2014). The Niobrara Formation is an organic-rich, self-sourcing, basin-centered hydrocarbon accumulation predominantly made of carbonate deposits in the form of alternating layers of chalks
and marls. The Niobrara resource play is typically compared to the Eagle Ford Shale due to its high carbonate content.

The generalized stratigraphic column in Figure 1.1 shows the alternating layers of chalk, in blue, and marl, in grey, within the Niobrara. The Niobrara Formation is made up of two members, the Smoky Hill Member and the Fort Hays member. The Smoky Hill member is a target for unconventional resource exploitation. The Smoky Hill member consists of limestone (chalk) units and intervening marl intervals ranging in depth from 6,200 – 7,800ft MD within the DJ Basin, Colorado. The Niobrara Formation is bounded by the Sharon Springs-Pierre Shale above (top seal), and the Codell Sandstone below (Sonnenberg, 2013a).

The Wattenberg Field within the Denver Basin is the most active area producing from the Niobrara Formation. The Wattenberg area covers approximately 3200 square miles, and has a resource estimate from the Niobrara of 3-4 billion barrels equivalent (Sonnenberg, 2013a). The formation averages a thickness of 3,500ft. Composed of Cretaceous carbonate deposits, the Niobrara can range in thickness from 150ft to 1,500ft thick with a general thinning direction towards the east of the Rocky Mountain Region. Organic content within the Niobrara is of Type II (oil prone) kerogen (Figure 2.3), with TOC values in the range from 1% to 5% (Sonnenberg & Weimer, 1993).

Based on thermal maturity mapping, the Niobrara shale has predominantly entered the proper maturation windows for generating oil and gas. The Niobrara Formation is immature to the east of the Denver Basin and more mature to the west with production varying accordingly. Vitrinite reflectance values range from 0.6-1.3 R₀ within the Denver basin (Figure 2.4). Both thermogenic and biogenic petroleum accumulations can occur within the Niobrara. The accumulations in the deep part of the basin are thermogenic oil and gas; whereas, the accumulations along the shallow east flanks of the basin are biogenic gas (Sonnenberg, 2013a).
The Niobrara is observed to be abnormally pressured within the Denver Basin with pore pressure gradients ranging between 0.41-0.67 psi/ft (Figure 2.5) (Sonnenberg, 2011a; Luneau, Longman, Kaufman, & Landon, 2011).

Petrophysical evaluation of the well logs shows that the chalks possess higher porosity values that average between 11-13% than the marls that have average porosities less than 11%. FESEM analysis confirmed the presence of organic pores, interparticle and intraparticle pores that vary in morphology (ranging in size from 3 microns to less than a micron) within the Niobrara Formation (Elghonimy, 2015). These micro pores range from 1.4%-10% porosity (Figure 2.6) (Michaels & Budd, 2014). These nanoscale pores capture and entrap the hydrocarbons within the formation right after the generation of hydrocarbons occurs. The hydrocarbons have a difficulty to escape from these nanoscale pores due to the very low permeability within the shale reservoir that predominantly range below 0.1mD (Sonnenberg, 2012).

Figure 2.3 Kerogen type classification for the Niobrara Shale (Sonnenberg & Weimer, 1993)
Figure 2.4 Thermal maturity map of the active source rocks within the DJ basin modified from (Higley & Cox, 2007)
Figure 2.5 Overpressure trend within the Niobrara (Sonnenberg, 2011a) modified from (Weimer, Sonnenberg, & Young, 1986)

Figure 2.6 SEM images interparticle porosity (left) and kerogen porosity (right) from the Niobrara Formation. Left image is 12.7 microns across, right image is 8.5 microns across (Michaels & Budd, 2014)
2.4 Faults and fractures within the Niobrara

Various stages of tectonic activity had an influence on the faulting and fracturing of the Niobrara Formation within the Denver Basin as a result of the Laramide Orogeny and the Neogene extension (Figure 2.2). The region has undergone uplift, strike slip wrench faulting, and normal faulting as result of the tectonic activity in the area (Figure 2.7). Faults and fractures that resulted from the tectonic events within the region caused several fault patterns to occur in different directions. These faults and fractures can significantly enhance the permeability of the formations and favorably impact production within many parts of the basin. The Niobrara Formation is observed to exhibiting polygonal faulting in some areas within the basin as result of the compaction and dewatering of the shale units (Sonnenberg & Underwood, 2013). These fault patterns observed in seismic sections within the Niobrara are of small extent (10-50m, 30-70° dip), layer bounded, and randomly oriented (Sonnenberg & Underwood, 2013).

The natural fractures within the Niobrara Formation are very important for their significant effect on production and hydraulic fracture propagation within shale reservoirs. Natural fractures enhance the flow permeability within the Niobrara Formation. The matrix permeability is very low in shales. Having an abundance of natural fractures pre-existing within the rock fabric is very good for enhancing the flow of hydrocarbons from the shale formation to the wellbore. The abundance of natural fractures within the Niobrara can significantly affect the hydraulic fracturing within the formation. The natural fractures can help with maximizing the reach of the hydraulic fracture treatment and help enhance the conductivity within the reservoir. Natural fractures can enhance flow conductivity and permeability to allow for more hydrocarbons to be produced from the reservoir through the natural fractures.
Figure 2.7 Regional wrench faulting (strike slip faults) within the Wattenberg area modified from (Sonnenberg & Weimer, 2003; Weimer & Sonnenberg, 1996)
2.5 Geomechanical considerations for hydraulic fracturing

The Niobrara Formation consists of an abundance of calcite (chalk), quartz, feldspar, and clay minerals (marls). Figure 2.8 shows an example of the variation in mineral distribution within the Niobrara through a vertical section crossing through the Niobrara A, B, C and Fort Hays. The amount of clay is variable throughout the vertical section ranging from 5-20%, averaging at 10% for the entire interval. Clay content is shown to decrease in the chalk intervals, and increase in the marl intervals. Having low clay content within the Niobrara Formation makes it more favorable for hydraulic fracturing.

The variability in clay (ductile minerals) versus brittle minerals has a significant effect on the strength of the formation and the ability to hydraulically fracture it. The effect of both the stress magnitude and the strength of the formation both play an important role in allowing for an effective hydraulic fracture treatment to take place. Strength anisotropy within the Niobrara is directly affected by the lateral heterogeneities within the shales mineralogical composition and stress condition. The amount of clay, silica, carbonate and organic content within the shale reservoir significantly affect the hardness or brittle nature of rock (low clay content), or soft ductile behavior (high clay content) that the reservoir can have as a result of hydraulic fracture treatments.

The diagram in Figure 2.9 from Sonnenberg’s lecture series on the Niobrara Formation illustrates the distribution of calcite, feldspar and clay minerals within the Niobrara Formation relative to other successful shale plays within the US. The diagram also separates between the clay rich shales and the brittle shales thus illustrating that the Niobrara is believed to react in a brittle manner to hydraulic fracturing similar to the Eagle Ford due to its high calcite content and low clay content.
Figure 2.8 XRD analysis of the Niobrara core sample within the DJ Basin (Elghonimy, 2015; Sonnenberg, 2012)

Figure 2.9 Mineral content in the Niobrara vs. other US shale plays (Sonnenberg, 2012)
The mineralogical strength related properties within the Niobrara Formation are stress dependent. In-situ stress conditions affecting the shale reservoir play a significant role in the ability to hydraulically fracture the formation. Understanding the regional and local stress variations affecting the reservoir, exploitation and optimization operations can make use of the regional and local stress variations to propagate larger fracture treatments within the reservoir and allow for a larger stimulated reservoir volume to be induced onto the reservoir.

Using the stress affecting the reservoir, the reservoir can be exploited by drilling a lateral well (horizontal well) in the direction of minimum horizontal stress, and hydraulically fracturing the reservoir in the direction of maximum stress. The induced fracture network will dilate in the direction of minimum horizontal stress, and be more likely to stay open after hydraulic fracturing. The stress regime affecting the reservoir helps with initiating and maximizing the extent of the hydraulic fracture in the direction with least resistance (in the direction of maximum horizontal stress). The transverse induced fracture network helps with enhancing conductivity and permeability between the wellbore and the formation. This encourages flow within the reservoir to the wellbore, and increases the size of the stimulated reservoir volumes that favorably impact EUR and production rates.

Current day stress regimes are thought to have significant effect on the fracturing and the conductivity of the open fractures within the areas. As observed in Figure 2.10, the maximum horizontal stress direction within the regional extent of the Denver Basin is approximately in the WNW-ESE direction. Local stress variations can occur and change in azimuth from section to section throughout the Denver Basin. Understanding the current day stress regime is very important for the drilling and hydraulic fracturing operations to be conducted to be taken advantage of when hydraulically fracturing the Niobrara Formation.
Figure 2.10 Principal horizontal stress distribution and orientation within the US (Zoback & Zoback, 1980)

The local variations in stress directions play a significant role in controlling the ability for a fault to act as a barrier, or a conduit, to flow within the reservoir. Given that induced hydraulic fractures tend to dilate in the direction of minimum stress, any faults or fractures oriented parallel to the direction of maximum stress are more likely to act as conduit to flow and enhance the stress dependent permeability within the Niobrara Formation. Faults and fractures oriented perpendicular to the maximum stress direction are more likely to be sealing faults. Assessing the local variations in stress orientation is very important to drilling and hydraulic fracturing, as well as making use of these complex fracture networks within the Niobrara Formation for generating larger SRV and PRV areas around the horizontal shale wells.
2.6 Production “sweet spots” based on reservoir quality

Prospectivity within the Niobrara unconventional play, similar to any other unconventional resource, is highly dependent on the geological heterogeneity. The ability to understand the reservoir heterogeneity and make use of the geological and geomechanical information to best assess the area for production sweet spots can favorably affect production rates. In order to detect these production sweet spots within Niobrara Formation, the reservoir must be assessed for properties pertaining to organic richness, maturity, mineralogy, brittleness, thickness, pore pressure, porosity, permeability, natural fractures (Figure 2.11).

The key reservoir properties of the Niobrara reservoir and other main unconventional shale plays are compared in Table 2.1. Similar to every other successful unconventional shale gas/oil in the US, the Niobrara Formation has all the required properties to be technically and commercially produced. Identifying the local sweet spots within the Denver Basin can favorably increase and enhance production, and EUR from the Niobrara reservoir.

Figure 2.11 Shale resource parameters controlling production (Sonnenberg, 2011b)
Table 2.1 Comparison between Niobrara Formation to other unconventional shale based on EIA, 2011 assessment (U.S. Energy Information Administration, 2011)

<table>
<thead>
<tr>
<th></th>
<th>Barnett</th>
<th>Bakken</th>
<th>Marcellus</th>
<th>Niobrara</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>6500-8500ft</td>
<td>1000-9000ft</td>
<td>4000-8000ft</td>
<td>6800-7100ft</td>
</tr>
<tr>
<td>Net thickness</td>
<td>100-600ft</td>
<td>20ft</td>
<td>50-250ft</td>
<td>120ft</td>
</tr>
<tr>
<td>TOC</td>
<td>4.5%</td>
<td>5-20%</td>
<td>1-5%</td>
<td>1-6%</td>
</tr>
<tr>
<td>Clay content</td>
<td>&lt;35%</td>
<td>&lt;20%</td>
<td>20-35%</td>
<td>10%</td>
</tr>
<tr>
<td>Porosity</td>
<td>Average ~4.5%</td>
<td>5.5-9%</td>
<td>1.6-7%</td>
<td>2-8%</td>
</tr>
<tr>
<td>Lithology</td>
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<td>Shale, Dolomite,</td>
<td>Shale, Limestone</td>
<td>Chalk, Marl</td>
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<tr>
<td></td>
<td>Calcareous layer</td>
<td>Siltstone</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

2.7 Drilling & completion strategy within Wattenberg Field

Within the Denver Basin, horizontal wells are most common and will soon replace all the vertical well as it proves to be more effective for producing from tight oil reservoirs similar to the Niobrara (Hughes-Fraire & Olmstead, 2015). The Niobrara Formation has a similar completion procedure and technique to any other unconventional play. The typical drilling and spacing unit for the new horizontal wells is generally 640 acres. The wells are generally oriented perpendicular to the maximum horizontal stress direction within the area to optimize the fracture stimulation and align the induced fractures with the current principal stress direction. The Niobrara Formation is a comprise of chalk and marl. Hydraulic fracturing will focus on the chalk layer which result in a better stimulated fracture network. Figure 2.12 shows the comparison of drilling parameters and cost between the Niobrara and Bakken.
Figure 2.12 Comparison of drilling parameters and cost between the Niobrara and Bakken (Sonnenberg, 2012)

Within the RCP study area, horizontal wells targeting the Niobrara and Codell reservoirs are drilled in a single layer interval, such as the Niobrara B, C, and Codell. An array of horizontal wells typically alternates between two formations such as the Niobrara C and Codell. The fracturing is then performed in the first well and then the second well which is drilled on the adjacent formation, and then the third well which is drilled in the same formation as the first well. By alternatively fracturing between two formations, operators can use the occurrence of stress shadow in order to stimulate a larger reservoir volume and induce a more complex fracture network. In addition, fracturing stage sequence such as zipper fracturing can also be performed to enhance SRV. Fracture staging can be as high as 30+ stages per horizontal well.

“Sliding sleeve” and “plug and perf” fracturing methods commonly used in the Niobrara (Paterniti & Losacano, 2013). Choosing which technique to use is dependent on a company’s preference such as time, cost and trial and error experience. Sliding sleeve involves less operation cost, time and effort as all the fracturing process can be done within a single string of sleeves and no casing and perforation are required. On the other hand, even though the plug and perf requires more effort the benefit of doing plug and perf is that you will be able to customize
your perf zone and can always go back and re-perf the zone of interest (Fry, Roach, Kreyche, Yenne, & Geoffrey, 2016).

Persons (2015) discussed fracturing techniques in the Niobrara and mentioned that there is no conclusion on which method is better in the Niobrara as horizontal drilling is now in the early stage and there is not enough statistical information (Persons, 2015). Hybrid fracturing operations using the two techniques can also be performed but it will require a relatively higher operating cost. However, RCP’s study would indicate that plug and perf is the better option at this time.

2.8 Conclusions

The Niobrara Formation is a self-sourcing reservoir that consists of inter-bedded layers of chalk (reservoir rock) and marl (source rock). The Niobrara Formation has a relatively low clay content and is considered to be an attractive target for oil and gas production. Economic production from the Niobrara reservoir requires the use of horizontal drilling along with hydraulic fracturing. The depth ranges around 6,200 - 7,800ft MD with the net thickness of at least 120ft which are in the range and thickness that horizontal drilling and fracturing can be effectively performed.

The Niobrara has gone through a number of active tectonic phases throughout geological history, and is likely to be highly fractured and faulted in many areas within the basin. The effect of these faults is still uncertain, but the common belief is that these faults can act as baffles and conduits to flow depending on a number of geological and stress dependent factors. The Niobrara reservoir formation is brittle, naturally fractured, thermally mature to generate oil, condensate & gas. Overall, just like every other producing unconventional shale resource in the U.S., the Niobrara has all the required properties to be technically and commercially produced Table 2.2.
Table 2.2 Shale reservoir properties as compared to other successful shale plays within the U.S. (Luneau et al., 2011)

<table>
<thead>
<tr>
<th></th>
<th>Niobrara (DJ Basin)</th>
<th>Bakken</th>
<th>Eagle Ford</th>
<th>3rd Bone Spring/Wolfcamp</th>
</tr>
</thead>
<tbody>
<tr>
<td>Age</td>
<td>Upper Cretaceous</td>
<td>Mississippian-Devonian</td>
<td>Early Cretaceous</td>
<td>Permian (Leonardian – Wolfcampian)</td>
</tr>
<tr>
<td>Depth</td>
<td>5500’ – 8500’</td>
<td>8500’ – 11500’</td>
<td>5000’-11500’</td>
<td>4,000’ - 11,100’</td>
</tr>
<tr>
<td>Thickness (net)</td>
<td>~300’ (~40’)</td>
<td>75’-130’ (40’-70’)</td>
<td>140’-450’ (250’)</td>
<td>450’ - 550’ (250’ - 300’)</td>
</tr>
<tr>
<td>Prospective area</td>
<td>14,000 sq miles</td>
<td>14,000 sq miles</td>
<td>56,000 sq miles</td>
<td>9,000 sq miles</td>
</tr>
<tr>
<td>Natural fractures</td>
<td>Locally abundant</td>
<td>Very localized</td>
<td>Present</td>
<td>Very localized</td>
</tr>
<tr>
<td></td>
<td>May be critical for success</td>
<td>Not essential for success</td>
<td>Not essential for success</td>
<td>Not essential for success</td>
</tr>
<tr>
<td>TOC weight %</td>
<td>2.4% Disseminated through Niobrara</td>
<td>10-12%+ in Upper/Lower Bakken</td>
<td>3-7%</td>
<td>2 - 9%</td>
</tr>
<tr>
<td>Total Porosity (FF)</td>
<td>8-10% (~2-3%)</td>
<td>5-10% (3-5%)</td>
<td>6-9%</td>
<td>4 - 16% (~3-8%)</td>
</tr>
<tr>
<td>Hydrocarbon Type</td>
<td>Oil to Condensate (32°- 62°)</td>
<td>Oil (42°)</td>
<td>Oil (30-50°) to Dry Gas</td>
<td>Oil to Condensate</td>
</tr>
<tr>
<td>Pressure Gradient</td>
<td>0.41 – 0.67</td>
<td>0.50 – 0.70</td>
<td>0.40 – 0.70</td>
<td>0.43 - 0.60+</td>
</tr>
<tr>
<td>Well Cost$</td>
<td>$3.5 MM</td>
<td>$5.7 MM</td>
<td>$5.5-8.5 MM</td>
<td>Vertical: $3.7 - 4.3MM</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Horizontal: $8MM</td>
</tr>
</tbody>
</table>

The Niobrara resource play is calculated to have a total of technically recoverable reserves of 3.7 billion barrels of oil and 46.5 Tcf of gas (IHS, 2016). These estimates are based on typical reserve recovery factors within these unconventional reservoirs can range as low as 2-8%. There is still much improvement to be done in order to increase the recovery from the Niobrara reservoir. Through geological and geomechanical characterization, reservoir and production sweet spots can be identified within the Niobrara Formation to allow for better hydrocarbon recovery and production to occur.
CHAPTER 3

ASSESSING THE NIOBRARA SHALE RESERVOIR FOR HYDRAULIC FRACTURE COMPLETION QUALITY USING WELL LOGS

3.1 Summary

The Niobrara requires the use of hydraulic fracturing to be productive. Multistage hydraulic fracturing is needed to yield economic production from the Niobrara Formation. Evaluating the intervals within the Niobrara Formation for favorable hydraulic fracturing is essential for generating an efficient connection between the hydrocarbon bearing formation and the producing wellbore through hydraulic fracture stimulation. Determining the geomechanical properties within in-situ conditions along with the reservoir pressures is the first step to evaluating unconventional shales for hydraulic fracturing. This chapter discusses methods used to characterize and predict the reservoir elastic rock properties, pore pressure, and magnitude of stress affecting the Niobrara and Codell Formations using well log data to assess which intervals within the reservoirs should be targeted for better containment and more favorable stimulation treatments to take place.

3.2 Introduction

Shale reservoirs require hydraulic fracturing to be successful and productive at economical rates. Identifying the ideal target intervals for hydraulic fracturing is an essential first step before drilling generally takes place. Targeting and stimulating the more favorable layers within a reservoir for hydraulic fracturing can significantly increase the production performance out of a treatment well. Shale reservoir intervals that are more favorable for hydraulic fracturing typically have low clay content (brittle formations), and are bounded above and below by higher stress layers that allow for hydraulic fracturing to be contained within the target interval and formation. Assessing the vertical stress profile within the Niobrara from a 1D log perspective allows for a
better understanding of the vertical level of heterogeneity that will have an effect on the optimum well placement for better containment and more effective fracturing to take place.

Stress modeling and prediction within shale reservoirs is a critical and important step required to understand the hydraulic fracture containment within the target intervals. As previously discussed in Chapter 2, the Niobrara Formation is abnormally pressured (Figure 2.5). The pore pressure trend surrounding the Niobrara Formation will have an influencing role on the vertical and lateral stress distribution within the target formation. Quantifying and predicting the reservoir elastic rock properties, pressures and stress profiles within the Niobrara Formation is essential for characterizing the Niobrara Shale Reservoir for hydraulic fracturing. Estimating the elastic rock properties, pressures and stress distribution above and below the Niobrara Reservoir is equally as important to assess the fracture containment within the reservoir, and predict which intervals within the Niobrara are more optimum for hydraulic fracturing.

3.3 Data available for well log analysis

The vertical wells surrounding the Wishbone study area are used for assessing the Niobrara from a geomechanical perspective. The wells shown in Figure 3.1 are selected for containing the logs necessary for this analysis to be conducted. The logs available are Gamma Ray (GR), Density (RHOB), Neutron Porosity (NPHI), Deep Resistivity (ILD). Sonic logs (DTP & DTS) were estimated from Neural Network correlation (Bray & Link, 2015; Pitcher, 2015). Figure 3.1 shows the location of these wells relative to the study area. The 11 lateral wells within the section only consist of Resistivity and GR logs that were used to geosteer the wells into their landing intervals.
Figure 3.1 Top Niobrara depth map over model area. The wells (colored in black) represent the 13-vertical used for predicting the geomechanical properties

3.4 Estimating elastic moduli from well logs

The fundamental purpose of this step in the project is to derive the geomechanical properties that will go into the calculation of the minimum horizontal stress equations. The log derived geomechanical parameters within the Niobrara are stress and time dependent. The properties that are calculated within this chapter represent the static reservoir conditions at the time of drilling. Considering that the area is actively drilled and hydraulically stimulated, the properties might be altered at a later stage and will have a considerable effect on any infill drilling or hydraulic fracturing that proceeds this study. The geomechanical properties estimated using the well log data represent the static geomechanical properties in-situ before hydraulic fracturing or production. These measurements will represent the initial state condition of the reservoir units and will be used as a baseline for the dynamic modeling of the hydraulic fracture simulation model in Chapter 5.
The most important parameters for the derivation of the minimum horizontal stress magnitude are the Young’s Modulus (the ratio of extensional stress to extensional strain in a uniaxial stress state), and the Poisson’s Ratio (the negative ratio of the radial strain to the axial strain in a uniaxial stress state) Equations (3.1) & (3.2) (Mavko, Makerji, & Dvorkin, 2009). Both these properties are stress dependent parameters. The change in overburden stress and formation pore pressure (effective stress) directly influences the measurements of Poisson’s and Young’s moduli in-situ conditions.

\[
\text{Young’s Modulus } \quad E = \frac{\sigma_{\text{axial}}}{\varepsilon_{\text{axial}}} \quad \text{(Eq. 3.1)}
\]

\[
\text{Poisson Ratio } \quad \nu = -\frac{\varepsilon_{\text{radial}}}{\varepsilon_{\text{axial}}} \quad \text{(Eq. 3.2)}
\]

The measurement of these elastic properties is typically derived from laboratory experiments applied onto core samples of rock to obtain static and dynamic measurements. In areas with little to no core samples, the dynamic elastic properties can be calculated using P-wave and S-wave velocities (Mavko et al., 2009) using equations (3.3) & (3.4). The dynamic log properties can then be calibrated to core samples when made available to infer a static type measurement. Generally, core (static) measurements are observed to be lower than the log (dynamic) obtained estimates for Young’s modulus and Poisson ratio (static measurements < dynamic obtained estimates). Using the static converted measurements is very important, the use of dynamic properties might be very misleading.

\[
\nu = \frac{1}{2} \left( \frac{V_p}{V_S} \right)^2 - 2 \quad \text{(Eq. 3.3)}
\]

\[
E = 2\rho V_S^2 (1 + \nu) \quad \text{(Eq. 3.4)}
\]

33
Although these elastic moduli can easily be obtained from dynamic logs, they require proper matching to core data (static measurements) to be used to calculate the minimum horizontal stress magnitude pressures. The correlations developed by Eissa and Kazi (1988) are generally considered to be a reliable method for obtaining a static conversion from dynamic log calculated data. The dynamic to static correlation has been modified by van Heeran (1987) along with Barree (2009) to produce a more reliable correlation between static and dynamic moduli measurements in the laboratory modified from (Eissa & Kazi, 1988).

The plot depicted in Figure 3.2 shows a comparison between these widely used techniques at predicting the static measurements from dynamic velocity data through core experiments data (Barree, Gilbert, & Conway, 2009). Converting the Poisson’s Ratio measurements from dynamic to static log data on the other hand appears to be less important as apparent in Figure 3.3 (Barree, Gilbert, et al., 2009). The relationship between PR\textsubscript{dynamic} and PR\textsubscript{static} is very close to 1:1.

\[
\begin{align*}
E_s &= 0.74 \, E_d - 0.82 \quad \text{linear correlation} \quad \text{(Eissa & Kazi, 1988)} \quad \text{(Eq. 3.5)} \\
\log(E_s) &= \log(\rho_b E_d) - 0.55 \quad \text{log-linear correlation} \quad \text{(Barree et al., 2009)} \quad \text{(Eq. 3.6)} \\
E_s &= 0.1832(E_d)^{1.5795} \quad \text{power law model} \quad \text{(van Heerden, 1987)} \quad \text{(Eq. 3.7)}
\end{align*}
\]

The calculated values for Poisson’s ratio and Young’s modulus from the conversion from dynamic to static are depicted in Figure 3.4. The static converted values using the log-linear correlation are in accordance with observations made from core analysis by (Bridges, 2015; Maldonado, 2011). These static converted measurements will be used as input parameters to the calculation of the minimum horizontal stress equations in the following sections within this chapter.
Figure 3.2 Correlations between dynamic to static Young’s modulus from core data (Barree, Gilbert, et al., 2009)

Figure 3.3 Correlation between dynamic to static Poisson’s ratio measurements from observed core data (Barree, Gilbert, et al., 2009)
A brittleness factor (BRF) is also computed using correlations based on Young’s modulus and Poisson’s ratio (Rickman, Mullen, Petre, Grieser, & Kundert, 2008). The brittleness factor is used as a reference to the fracability of the formation, it does not go into the stress calculations. It helps to identify intervals within the Niobrara that are more favorable for hydraulic fracturing. According to Rickman et. al. (2008), shale intervals with low Poisson ratio's and higher Young’s Modulus are more favorable for hydraulic fracturing and will tend to react in a more brittle manner (Figure 3.5).

\[ BRF = (0.071 \times E_{static}) - (1.43 \times PR_{static}) + 0.5 \]  
(Rickman et al., 2008)  
(Eq. 3.8)

Figure 3.4 Example of well log processing and prediction for Poisson Ratio (PR), Young’s Modulus (E), Brittleness Factor (BRF), Biot V, and Permeability estimation
Figure 3.5 Relationship between Young’s Modulus and Poisson Ratio established by (Rickman et al., 2008) for brittle vs. ductile rock behavior due to hydraulic fracturing of shale reservoirs

3.5 VTI and HTI anisotropy within the Niobrara

The level of anisotropy form vertical to horizontal can have a significant effect on the elastic moduli in shales due to their intrinsic laminated structure. (Bridges, 2015) shows that the Niobrara is anisotropic at low confining pressures (8Mpa), and becomes more isotropic at higher confining pressures (42Mpa). Although the Niobrara shows some slight effect of vertical to horizontal anisotropy in the measurement of elastic moduli, the Niobrara chalKS can be considered isotropic in-situ conditions (Bridges, 2015). The $E_v:E_h$ measured by in the chalk layers has an average of 1.03, and the $PR_v:PR_h$ averages at 1.07. While the Marl intervals in the Niobrara have a $E_v:E_h$ ratio of 1.07 and a $PR_v:PR_h$ ratio of 1.14 under high confining stress as shown by core laboratory studies (Bridges, 2015).

Analysis by Bridges (2015) shows that the Niobrara Formation is weakly anisotropic in this area in regards to vertical transverse isotropy (VTI). The horizontal anisotropy observed from the DTSM fast vs slow shear velocity curves show a 1% difference in lateral anisotropy (Figure 3.6). No considerable effects can be observed from assessing the DTSM logs for horizontal transverse
isotropy (HTI). Although calculating the minimum horizontal stress using an anisotropic solution would be the most optimum solution for quantifying the stress anisotropy within the Niobrara Formation. Considering that the Niobrara assessed over this study area is weakly anisotropic, this might be neglected by assuming that the Niobrara is isotropic in nature under high stress compaction in-situ reservoir conditions.

Figure 3.6 Assessing the lateral landing point in the Niobrara Formation based on stress gradient contract and potential stress barriers (Alfataierge et al., 2018)

Figure 3.7 Visual representation of anisotropic VTI and HTI symmetry (Tsvankin, 2001)
3.6 Overpressure mechanism determination

As previously mentioned in Chapter 2, the Niobrara pore pressure within the Denver Basin ranges between 0.41-0.67psi/ft (Luneau et al., 2011). Determining the cause of overpressure in the subsurface is essential for determining the method used to predict the reservoir pressures within the Wishbone study area. Abnormal pressures within the subsurface can be explained through disequilibrium compaction, or fluid expansion.

Disequilibrium compaction, or undercompaction, occurs due to a rapid deposition of low permeability sediment, typically clay, the inhibit the escape of fluid. Excess pressure develops as the weight of newly deposited sediments squeezes the sediment and trapped fluid, however the sediment cannot be compacted since the fluid cannot escape due to a low permeability. With low compressibility, the fluid supports the overburden load instead of the clast. This causes overpressure. This overpressuring process is referred to as undercompaction or compaction disequilibrium. Undercompacted rock will likely to have a higher porosity, and thus lower density, resistivity and velocity. These petrophysical responses from well log or seismic methods can be used to predict to pore pressure (Figure 3.8a) (Tingay, Hillis, Swarbrick, Morley, & Damit, 2011).

Fluid expansion can occur due to fluid expansion mechanisms associated with heating, along with hydrocarbon maturation and expulsion (Bowers, 1995). This method describes overpressure occurring in the reservoir due to an increasing fluid volume in the pore space of the reservoir relative to the compaction of the rock. In this case, overpressure occurs due to the fluid trying to expand while being constrained by the rock volume. Within the rock space that porosity of rock can slightly decrease. Generated hydrocarbon can also cause fractures to occur and so reduce the velocity of the rock. However, these petrophysical responses are typically less pronounce than from disequilibrium compaction. With such low petrophysical responses, it is always a challenge to predict pore pressure in fluid expansion overpressured rocks (Figure 3.8b) (Bowers,
This method is the most likely mechanism that explains the overpressure occurrence within the Niobrara Formation given the self-sourcing nature of the reservoir interval.

In order to differentiate between the undercompaction and the fluid expansion methods, Bower’s plot is used to identify the type of overpressure. The Bower’s plot is a relationship between porosity or velocity and effective stress. In hydrostatic pressure sediment, plotting between two will result in generating a trend called the “loading curve” (Figure 3.8c) (Tingay et al., 2011). Since disequilibrium compaction is caused by the effect of pausing of compaction process, any overpressure data that is plotted along the loading curve will be due to overpressure from disequilibrium compaction. On the other hand, fluid expansion will less likely cause the changing in porosity or velocity and therefore plotted into a shifted trend to the right of the loading curve. This trend is called “unloading curve”. Any overpressure data that is plotted along this trend will be the overpressure from fluid expansion.

Figure 3.8 (a) porosity vs. depth, (b) pressure vs. depth, (c) porosity vs. effective stress (Tingay et al., 2011)
Similar to the Bower’s plot, cross plotting between Vp and density in a hydrostatic rock will result to a normal compaction trend (Figure 3.9). Vp and density from disequilibrium compaction overpressure rock will plotted along this trend. On the other hand, Vp and density from fluid expansion overpressure rock will have a new unloading trend (Swarbrick, 2012).

![Figure 3.9 Determination of overpressure mechanism using the Vp-density cross plot (Swarbrick, 2012)](image)

### 3.7 Estimating reservoir pressures using well log data

In order to assess the Niobrara Shale Reservoir for hydraulic fracturing, it is necessary to obtain or predict the magnitude of the overburden pressure and pore pressure at a given depth within the target reservoir interval to be taken into consideration when calculating the magnitude of minimum horizontal stress. Obtaining the magnitude of minimum horizontal stress is required for planning an efficient hydraulic fracture treatment, and assessing the potential containment within the target reservoir interval. The use of the static Young’s Modulus and Poisson’s Ratio are very important input parameters that go into estimating the magnitude of minimum horizontal stress.

Overburden pressure, overburden stress ($\sigma_v$), is a measure of the overall rock stress exerted onto a specific point in depth. The magnitude of $\sigma_v$ can be derived by integrating the density log
from surface to a certain depth of interest (z) (Zoback, 2007). Equation (3.9) is used to estimate the overburden pressure within this study area. The average overburden pressure gradient calculated at the Niobrara interval is estimated at around 1.05 psi/ft.

\[
\sigma_v = \int_0^z \rho_b(z) g \, dz 
\]  
\text{(Eq. 3.9)}

Pore pressure is defined as a scalar hydraulic potential acting within an interconnected porous rock unit at a certain depth (Zoback, 2007). Normal pressure, or hydrostatic pressure, refers to the pressure associated with a column of water from surface to a certain depth within the reservoir (Zoback, 2007). Typically, hydrostatic pore pressure ranges at a 0.44 psi/ft gradient. When a formation has a gradient above hydrostatic pressure, it is considered to be overpressured. If the formation of interest is below hydrostatic pressure, it is referred to as an underpressured reservoir system.

Eaton’s method (Eaton, 1972) is one of the most used prediction methods. It can be used to predict overpressure both from disequilibrium compaction and from fluid expansion (Eq. 3.10).

\[
P_p = \sigma_v - [\sigma_v - (P_{p_{\text{normal}}})] \times \left[\frac{V_{\text{actual}}}{V_{\text{normal trend}}}\right]^x \quad \text{(Eq. 3.10)}
\]

\[
P_{p_{\text{normal}}} = \text{hydrostatic pressure gradient (psi/ft)} \times Z \text{ depth (ft)} \quad \text{(Eq. 3.11)}
\]

\(V_{\text{actual}}\) refers to the measurements obtained from the sonic log, while \(V_{\text{normal}}\) refers to an extrapolated velocity curve that corresponds to the normal compaction trend observed within a given well. “x” is the Eaton’s exponent, which can be used to calibrate the predicted pressure estimates to direct measurement within the subsurface. In many basins, a value of 3 is appropriate for disequilibrium compaction mechanisms.
In Figure 3.10, an “x” exponent of 1 is used to generate the pore pressure curve using Eaton’s method. The predicted curve using Eaton’s method appears to have generated a good match to the pore-pressure gradient that was observed within the DFIT, although it should be noted that the Vp-measured trend over the Niobrara had to be ignored to produce such a good match.

The example in Figure 3.10 shows the use of density integration to calculate the overburden pressure. Eaton’s pore pressure prediction method is also applied to observe the top of overpressure that occurs within the Lower Pierre interval. Vp readings around the Niobrara required to be altered to produce a pressure match DFIT observed pressure gradients at the Niobrara interval level.

Bowers (1995) is an explicit method that is based on an empirical relationship between pore pressure and sonic velocity logs (V) in (ft/sec). This method requires large amount of pressure
points both from normal and overpressure zones to establish a proper empirical fitting. For
disequilibrium compaction overpressure:

\[ P_p = \sigma_V - \left( \frac{V - 5000}{a} \right)^{1/b} \]  
(Eq. 3.12)

For fluid expansion overpressure:

\[ P_p = \sigma_V - \left[ \frac{U}{\sigma'_{max}} \right] \]  
(Eq. 3.13)

\[ \sigma'_{max} = \left( \frac{V_{max} - 5000}{a} \right)^{1/b} \]  
(Eq. 3.14)

“a” and “b” are fitting parameters that are calibrated with offset velocity versus effective stress
data, “U” is an unloading parameter, \( \sigma'_{max} \) and \( V_{max} \) are the maximum effective stress, and
maximum velocity measured before unloading.

Given that many of these pore pressure estimates are developed for conventional reservoirs,
they do not entirely produce reliable estimates within unconventional shale reservoirs without
adequate calibration to direct pressure measurements from offset wells. Eaton’s method requires
the least amount of calibration to produce an estimate of pore pressure. While Bower’s method
required several pressure points to be directly measured and captured along the vertical length
of a given well to produce a reliable estimate of pore pressure. The use of Eaton’s method was
rather simple to be applied in the RCP study area given the scares amount of direct pressure
measurements obtained from offset wells in the area. Eaton’s “x” exponent was adjusted until the
pressures at the Niobrara matched observations from diagnostic fracture injection tests (DFIT).
The information gathered and analyzed from Diagnostic Fracture Injection Tests (DFIT) from
offset vertical wells is critical for calibrating these pore pressure predictive methods and obtaining a reliable estimate.

For the purposes of this study conducted over the Niobrara, the pore pressure estimates provided by Eaton’s empirical fitting to observed measurements from DFIT analysis showed that the Sharon Springs, Niobrara and Codell Formations are all overpressured (Figure 3.9). The deviation from normal pressure was challenging to produce using either Eaton’s, nor Bower’s methods. To reduce the uncertainty in further calculating the minimum horizontal stress over the Niobrara Formation, as assumption was made that the DFIT acquired measurements will represent the overpressure gradients for the Niobrara, and the overlying and underlying formations that act as stress barriers.

Given that the observed top of overpressure resides several thousand feet above the Niobrara Formation, as observed in Figure 3.10, the effect of overpressure appears to be affecting the Niobrara and the overlying and underlying formation within the study area. Using a direct pore pressure gradient obtained from the DFIT to predict the pore pressure above the Sharon Springs, Niobrara Reservoir and Codell Reservoir intervals is assumed to generate a more consistent analysis of stress over the Niobrara Reservoir interval. Using either the Eaton or Bowers methods to obtain the pore pressures over these formations might increase the level of uncertainty in the analysis.

The effective stress within a fluid saturated rock interval can be expressed as by the relationship between the overburden stress and the pore pressure (Eq. 3.15) (Terzaghi, 1943; Terzaghi, Peck, & Mesri, 1996). The effective stress is a measure of the effective pressure applied on a rock. As pore pressure decreases, the effective stress applied on the rock grains would increase. The increase in pore pressure would also result in the decrease of effective stress, thus reducing the magnitude of effective stress that is supported by the grains within a body of rock.
Effective Stress \[ \sigma_{eff} = \sigma_V - \alpha P_p \] (Terzaghi, 1943) (Eq. 3.15)

Biot’s Poroelastic Coefficient (\(\alpha\)) equals:
\[ \alpha = 1 - \frac{k_b}{k_f} \] (Eq. 3.16)

Typically, \(\alpha\) is neglected and given a value of 1 in most rocks. While in shales, the Biot coefficient can range closer to 0.6 under high stress confinement (Maldonado, Batzle, & Sonnenberg, 2011). \(\alpha\) represents the efficiency with which the internal pore pressure offsets the externally applied vertical total stress (Biot, 1941). As \(\alpha\) declines, the net stress on the intergranular structure of the rock increases and pore pressure variations have less impact on net stress. \(\alpha\) typically ranges between 0.6 – 1. In an attempt to generate a log curve for \(\alpha\), the following equations were used based on a correlation with porosity from (Barree, 2017):

\[ Biot\ V = VBScale \times PHIE^{VBPower} \] (Barree, 2017) (Eq. 3.17)

Assuming, \(VBScale = 1\) \& \(VBPower = 0.1\)

VBScale and VB Power are fitting parameters that can be adjusted to match any core observations in the area. PHIE is the effective porosity. If an effective porosity is not available, an estimate can be derived through the following correlation with Density Porosity (DPHI) or Neutron Porosity (NPHI) (Barree, 2017):

\[ PHIE = Porosity \times (1 - Vshale) \] (Barree, 2017) (Eq. 3.18)

\[ Vshale = 0.5 \times (Shale\ Index)/(1.5 - Shale\ Index) \] (Eq. 3.19)

\[ Shale\ Index = \frac{GR - GR_{min}}{GR_{Max} - GR_{min}} \]; if Shale index < 0.01, then Shale Index = 0.01 (Eq. 3.20)

The effective stress plays a significant role in the calculation of minimum horizontal stress and closure pressure within the reservoir. The closure pressure \(P_c\) is the fluid pressure needed
to initiate the opening of a hydraulically induced fracture by overcoming the minimum horizontal stress ($\sigma_{h\,\text{min}}$) acting a rock unit that is confined by three principal stress directions (Figure 3.11). $P_c$ is equal to the minimum horizontal stress. The magnitude of minimum horizontal stress direction can be determined by a number of log derived methods that are then calibrated to static in-situ reservoir estimates from mini-fracturing tests, diagnostic fracture injection tests (DFIT).

The direction of minimum horizontal stress on the other hand is either estimated by observing the azimuthal direction of Borehole breakout for determining maximum and minimum stress directions (Zoback, Moos, Mastin, & Anderson, 1985). Drilling induced fractures break in the direction of Maximum horizontal stress, while tensile fractures along the wellbore will break in the direction of minimum horizontal stress (Figure 3.14) (Tingay, Reinecker, & Müller, 2008; Zoback et al., 1985). Lineation's in microseismic events due to hydraulic fracturing can also help determine the local stress directions in a given field (Wallace et al., 2016).

![Figure 3.11 Example of variation of magnitude in the three principal stress directions based on the regional tectonic environment (Zoback, 2007)](image-url)

Figure 3.11 Example of variation of magnitude in the three principal stress directions based on the regional tectonic environment (Zoback, 2007)
The simplest method used to calculate the magnitude of minimum horizontal stress was developed by (Hubbert & Willis, 1957). The method is uses the assumption of fracturing in the Mohr-Coulomb plot. If the stress regime is normal, the fracture gradient is obtained through the use of the equation (Eq. 3.21).

\[
\sigma_{h\,min} = \frac{1}{3} (\sigma - P_p) + P_p \quad \text{(Eq. 3.21)}
\]

Matthews and Kelly (1967) continued from the Hubbert and Willis, and instead of using a constant factor of \(\frac{1}{3}\), Matthews and Kelly introduced a variable ratio between horizontal and vertical stress (Eq. 3.22). The stress ratio will generally increase with depth as the rock is compacted (Mathews & Kelly, 1967).

\[
\sigma_{h\,min} = K (\sigma - P_p) + P_p ; \quad \text{(K) refers to the tectonic stress ratio} \quad \text{(Eq. 3.22)}
\]

Eaton’s gulf coast correlation (1969) is similar to the first two methods (Eq. 3.23). Eaton’s method address the factor with the Poisson’s ratio which is based on the data from offshore wells (Eaton, 1969).

\[
\sigma_{h\,min} = \left(\frac{\nu}{1-\nu}\right) (\sigma - P_p) + P_p \quad \text{(Eq. 3.23)}
\]

Daines method (1982) included one additional stress into the equation, a tectonic stress or strain (Daines, 1982). In reality, tectonic stress can only be determined by calibrating the predicted value to an actual observed DFIT test or mini-fracturing test measured at a certain depth corresponding to the formation of interest (Eq. 3.24).

\[
\sigma_{h\,min} = \left(\frac{\nu}{1-\nu}\right) (\sigma - P_p) + P_p + \sigma_t \quad \text{(Eq. 3.24)}
\]
Other modifications to the equation were also depicted to consider the poroelasticity effect of
the rock (Biot’s Poroelastic coefficient), along with considerations with respect to anisotropy. The
minimum horizontal stress determined in isotropic rocks (Eq. 3.25) is shown by (Desroches &
Bratton, 2000). While the minimum horizontal stress determined in anisotropic rocks also took
into account the vertical and horizontal variation in elastic moduli when made available is
represented in (Eq. 3.26) (Desroches & Bratton, 2000).

\[
\sigma_{h\,\text{min}} = \frac{\nu}{(1-\nu)} [\sigma_v - \alpha P_p] + \alpha P_p + \sigma_t \quad \text{(Eq. 3.25)}
\]

\[
\sigma_{h\,\text{min}} = \frac{\nu}{(1-\nu)} [\sigma_v - \alpha P_p] + \alpha P_p + \frac{E}{1-\nu^2} \varepsilon_h + \frac{\nu E}{1-\nu^2} \varepsilon_H \quad \text{(Eq. 3.26)}
\]

The tectonic stress or strain parameter (\(\sigma_{\text{tectonic}}\)) is determined by the amount of calibration
required to match the DFIT information acquired by downhole observation tools. The amount of
stress (\(\sigma_t\)) or strain (\(\varepsilon_h\) or \(\varepsilon_H\)) used to calibrate any of the estimated values for minimum horizontal
stress must be compatible with the geological setting (Desroches & Bratton, 2000). In regions
with tectonic compression, a positive stress can be applied to the \(\sigma_{\text{tectonic}}\) parameter. While in
normal stress regional settings, a negative strain (\(\varepsilon_{\nu}\)) can be applied. As previously discussed in
Chapter 2, the Denver Basin is currently undergoing regional tectonic strain due to the Neogene
Extension. Applying a negative strain to calibrate \(\sigma_{h\,\text{min}}\) to the DFIT measurements might be
required.

Most of the methods discussed earlier in this chapter use empirical fitting to estimate the
formation pressures. Choosing the right prediction method likely depends on the availability of
data. For the purposes of this study, the closure pressures will be estimated using the isotropic
medium equation. If more accessible information was available from core studies on the variability
in anisotropy within the Niobrara, the use of the anisotropic solution might provide us with a more
accurate representation of the reservoir stress distribution within the Niobrara Formation with respect to anisotropy.

The magnitude of minimum horizontal stress in the study area was determined using a modified version of equations (3.25) & (3.26) assuming isotropic elastic rock properties for Young’s and Poisson Ratio values. Calculating closure pressure (minimum horizontal stress) in isotropic medium is conducted using the following equation from (Barree, Gilbert, et al., 2009):

\[
\sigma_{h\ min} = \frac{\nu}{(1-\nu)}\left[\sigma_v - \alpha_v P_p\right] + \alpha_h P_p + \varepsilon_c E + \sigma_t
\]

(Eq. 3.27)

3.8 Pressure calibration to diagnostic fracture injection tests (DFIT)

The DFIT acquired pressure measurements from the following section are vital for calibrating the pressure estimates from these well logs predictive methods and obtaining a reliable pressure estimate (Figure 3.12). By using the DFIT measurements obtained from the direct measurements from the target formation, one can obtain direct physical measurements for fracture gradient (FG or ISIP), closure pressure (P_c or \(\sigma_{h\ min}\)), and process zone stress (PZS or \(\Delta P_{net}\)) determined from the G-Function or Sqrt(t) plots. Other useful reservoir properties such as pore pressure (P_p) and effective reservoir permeability (Perm) are also obtained from pseudolinear or pseudoradial flow analysis (Barree, Barree, & Craig, 2009). All these properties are used to calibrate the log derived predictions of pore pressure and closure pressure that were derived using the equations listed earlier in this chapter.

- **Instantaneous Shut-In Pressure**
  \[
  \text{ISIP (psi)} = \sigma_{h\ min} + \Delta P_{net}
  \]
  (Eq. 3.28)

- **Fracture Gradient Pressure**
  \[
  \text{FG (psi)} = \text{ISIP (psi)}
  \]
  (Eq. 3.29)

- **Fracture Gradient**
  \[
  \text{FG (psi/ft)} = \text{ISIP(psi)}/\text{TVD(ft)}
  \]
  (Eq. 3.30)
Within the RCP study area within Wattenberg Field, pore pressures have been observed within a range from 0.57-0.62 psi/ft based on analyzing 4 offset vertical wells (Table 3.1). Closure pressures are observed in the range of 0.7-0.74 psi/ft. The fracture gradient (ISIP) is approximately at 0.82-0.83 psi/ft. The DFIT analysis was provided by Anadarko Petroleum Company and conducted by Haliburton and Reservoir Development Consulting (RDC).

The pressures obtained from the DFIT analysis are used to confine the calculation of minimum horizontal stress through the following workflow:

1) Estimate pore pressure based on 0.6 psi/ft gradient at the reservoir depth

2) Calculate minimum horizontal stress using (Eq. 3.27) the following parameters:
   a. Static Poisson Ration \( PR_{sta} \)
   b. Static Young’s Modulus \( E_{sta} \) (Mpsi)
   c. Pore Pressure (psi) \( Pp = 0.6 \text{ psi/ft} \times \text{TVD(ft)} \)
   d. Biot Poroelastic Coefficient \( \text{Biot V} \)

3) By assuming “zero” regional stress or strain, an estimate of \( \sigma_{h\ min} \) is obtained within the reservoir interval. The estimated of \( \sigma_{h\ min} \) is then calibrated back to a 0.7-0.74 psi/ft gradient as observed from the DFIT by either adjusting the regional tectonic strain (\( -\varepsilon_x \)) or regional tectonic stress (\( \sigma_{tectonic} \)).

4) \( \sigma_{h\ min} \) calibration required a -100 regional tectonic strain (\( \varepsilon_x \)) to be applied within the study area to adequately match the closure pressure obtained from the DFIT. Applying a negative strain is observed to be consistent with regional Neogene extension within the Denver Basin.

5) The fracture gradient pressure (FG) is obtained through
   a. \( \text{FG(psi)} = \sigma_{h\ min}(\text{psi}) + \text{PZS(psi)} \)
Table 3.1 DFIT analysis provided by Haliburton and RDC from vertical offset wells surrounding the RCP study area

<table>
<thead>
<tr>
<th></th>
<th>Well 1</th>
<th>Well 2</th>
<th>Well 3</th>
<th>Well 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Formation</td>
<td>Codell</td>
<td>Niobrara</td>
<td>Niobrara B Chalk</td>
<td>Niob B Shale</td>
</tr>
<tr>
<td>Depth (ft TVD)</td>
<td>7543 ft TVD</td>
<td>7300 ft TVD</td>
<td>7172 ft TVD</td>
<td>7361 ft TVD</td>
</tr>
<tr>
<td>BH Closure (psi)</td>
<td>5272</td>
<td>5434</td>
<td>4991 psi</td>
<td>5277 psi</td>
</tr>
<tr>
<td>BH Closure Gradient (psi/ft)</td>
<td>0.7 psi/ft</td>
<td>0.74 psi/ft</td>
<td>0.7 psi/ft</td>
<td>0.72 psi/ft</td>
</tr>
<tr>
<td>BH ISIP (psi)</td>
<td>6162</td>
<td>6045</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BH FRAC Gradient - ISIP (psi/ft)</td>
<td>0.82 psi/ft</td>
<td>0.83 psi/ft</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Pressure (psi)</td>
<td>4512 psi</td>
<td>4527 psi</td>
<td>4090 psi</td>
<td>4460 psi</td>
</tr>
<tr>
<td>Reservoir Pressure Gradient (psi/ft)</td>
<td>0.6 psi/ft</td>
<td>0.62 psi/ft</td>
<td>0.57 psi/ft</td>
<td>0.60 psi/ft</td>
</tr>
<tr>
<td>Pore pressure analysis</td>
<td>Pseudolinear flow</td>
<td>Pseudolinear flow</td>
<td>Pseudolinear flow</td>
<td>Pseudolinear flow</td>
</tr>
<tr>
<td>Leakoff Type</td>
<td>Normal Matrix</td>
<td>Transverse Storage</td>
<td>Pressure Dependent</td>
<td></td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>0.0552 mD</td>
<td>0.0183 mD</td>
<td>0.007 mD</td>
<td>0.004 mD</td>
</tr>
<tr>
<td>Flow Capacity kh (md-ft)</td>
<td>0.55 md-ft</td>
<td>0.73 md-ft</td>
<td>0.161 md-ft</td>
<td>0.106 md-ft</td>
</tr>
<tr>
<td>Notes</td>
<td>Haliburton</td>
<td>Haliburton</td>
<td>RDC</td>
<td>RDC</td>
</tr>
<tr>
<td>Process Zone Stress (PZS = iSIP - Pc)</td>
<td>890</td>
<td>611</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The DFIT tests were conducted with the following injection test parameter ranges:

- Injection volume: 100-130 bbl.
- Injection rate: 9-10.5 bbl./min
- Injection Fluid: Water
- Shut-in time: 150 – 339 hours

The DFIT analysis shows variable leakoff methods that illustrate how the natural fracture are affecting the reservoir in the area. The transverse storage and pressure dependent leakoff
indicate the presence of natural fractures. While the normal matrix leakoff indicated that their no leakoff effect caused by natural fractures in the area. As can be observed in Table 3.1, several leakoff mechanisms were observed in the Niobrara and Codell reservoir intervals surrounding the RCP study area. This variability in different leakoff mechanisms observed provides insight into how the natural fractures in the Niobrara and Codell Formations can act as permeability conduits that will enhance the overall permeability of the formation.

An effective permeability is also obtained from the DFIT using pseudolinear flow analysis. The effective permeability represents the matrix and fracture permeability average effect. The effective permeability is what contributes to production from the formation. The permeability values estimated through the DFIT analysis are used to calibrate and predict the permeability values within the Niobrara interval through empirical correlations with porosity in (Eq. 3.31).

\[
Perm = K_{mult} \times PHIE^{K_{exp}} ; \quad C_{ult} = 100, K_{exp} = 3 \quad \text{(Barree, 2017)} \quad \text{(Eq. 3.31)}
\]

\[K_{mult} \text{ and } K_{exp} \text{ are used as fitting parameters to match the DFIT obtained permeability values within the Niobrara and Codell Reservoirs. An example of this estimate of effective permeability is depicted in Figure 3.4.}

3.9 Determining direction of maximum horizontal stress

Determining the magnitude of maximum horizontal stress is difficult, but the direction can be determined by a number of methods. The maximum horizontal stress direction is referred to as \( \sigma_{H_{max}} \), and is commonly observed to be perpendicular (90 degrees aligned) to the minimum stress direction (Zoback, 2007). Depending on the regional stress regime within an area, the three principal stress directions \( \sigma_V, \sigma_H, \sigma_H \) can differ in magnitude, and have a significant effect on hydraulic fracturing (Figure 3.11). Within either normal or thrust regimes, induced fracturing will tend to break in the vertical direction along the direction of maximum horizontal stress. While in
strike-slip regimes, induced fractures will break along the horizontal direction along the direction of maximum horizontal stress (Jaeger, Cook, & Zimmerman, 2007).

For the purposes of shale exploitation, determining the direction maximum horizontal stress is used to drill the wells in the direction of minimum horizontal stress, and generate induced hydraulic fracturing in the direction of maximum horizontal stress. This process effectively generates a larger SRV within the target formation. Making use of these stress directions is essential for generating economic production from tight, low permeability, shale reservoirs (Figure 3.13).

![Figure 3.13 Orientation of hydraulic fracturing relative to wellbore drilling direction and orientation of principal stress direction (Abass, Hedayati, & Meadows, 1996)](image)

As previously discussed in Chapter 1, the regional maximum stress direction within the region trends in the east-west direction (Zoback & Zoback, 1980). The local stress regime can vary with respect to the faulting in each section. The within the Wishbone section appears to be aligned with the regional stress direction as was determined by microseismic lineation’s observed in the
area. An FMI study conducted by Dudley (2015) also provide insight into the direction of maximum stress a select few lateral within the Wishbone section (Figure 3.14). Dudley (2015) shows a number of fracture orientations that were interpreted from the FMI log which also align with the current day principal stress regime. Based on Dudley’s (2015) interpretation of the FMI logs, the faults and fractures oriented parallel to the maximum horizontal stress direction were interpreted to be open (Figure 3.15). These open fractures could potentially enhance permeability within the formation along the maximum stress direction, and potentially cause pressure communication between the wells in the direction of maximum horizontal stress as a result of the preferred stress dependent permeability along fault and fracture planes (fractures parallel to the direction of maximum stress are more likely to be open).

Figure 3.14 Example shown to as a method of obtaining the direction of maximum and minimum horizontal stress using borehole breakout data (Tingay et al., 2008)
Within the Wishbone study area, the microseismic events clearly show a dominant direction for hydraulic fracturing in the area which coincides with the direction of maximum horizontal stress (Figure 3.16). The strike of the events aligns with the maximum horizontal stress direction N70°W (Figure 3.17), while a second dominant direction depicted in Figure 3.17 aligns to the direction in which the lateral wells were drilled (North). The occurrence of these events along the direction in which the lateral wells can be due to either clustering around the wellbore, or potentially due to longitudinal fractures caused by the hydraulic fracturing along the direction of the wellbore.

Figure 3.15 FMI analysis conducted over some of the wells in the Wishbone section to determine the direction of maximum horizontal stress from drilling induced fracturing (red), open fractures (blue), sealed fractures (light blue), and faults (purple), from (Dudley, 2015)
Figure 3.16 Surface microseismic events occurrence within the Wishbone study area

Figure 3.17 Microseismic strike direction from all stages and all wells within the study area
3.10 Conclusions

The intervals within the Niobrara with low Poisson Ratio’s and high Young’s Modulus that are more favorable for hydraulic fracturing also coincide with the chalks within the Niobrara Formation based on their brittleness factor (Figure 3.4). Based the stress vertical stress contrasts within the Niobrara, these chalk intervals might be best suited for fracability given that the marl sections are higher stressed and can act as local stress barriers to the hydraulic fracturing and help contain the hydraulic fracturing within the chalk.

Figure 3.6 shows the vertical variability in in-situ stress conditions within the Niobrara Formation from a 1D perspective. The higher stressed intervals appear to coincide with the marl sections, while the lower stress intervals predominantly reside within the chalk intervals. The Sharon Springs Formation overlying the Niobrara Shale Reservoir is highly stressed and close to approaching overburden pressure. This leads us to believe that the Sharon springs formation will act as a strong upper stress barrier and contain the hydraulic fracturing within the Niobrara Reservoir intervals. Hydraulic fracture simulation conducted over the Niobrara will show more detail in assessing the hydraulic fracture containment within the Niobrara Formation (Chapter 5).
CHAPTER 4
3D GEOMECHANICAL MODELING USING GEOSTATISTICAL METHODS

4.1 Summary

The mapping and distribution of geomechanical properties is a very useful tool for drilling and hydraulic fracture modeling and design. The use of such reservoir models helps develop a better understanding of the stress and pressure changes within the subsurface and allow for better practices to be performed for safer drilling, and better reservoir development. For the purposes of this study, the model will help develop a better representation of the subsurface rock strength parameters to be later utilized for hydraulic fracture stimulation studies in the area. The geologic heterogeneity gained from such 3D geomechanical models allow for a more realistic simulation of the hydraulic fracture treatment to be predicted at a later stage.

This chapter will focus on analyzing the in-situ stress and rock strength properties within the Niobrara (Wattenberg Field) through the generation and distribution of geomechanical properties (Young’s modulus, Poisson ratio), along with pressure data (overburden pressure, pore pressure) within a reservoir model. The product of the geostatistical distributed geomodelling will then be used to calculate a minimum horizontal stress volume. The geomechanical properties are distributed into a reservoir model for in-situ stress modeling (static conditions). The product of this modeling project will be used as an input to hydraulic fracture simulation modeling.

4.2 Introduction

With the move towards horizontal drilling and multistage hydraulic fracturing in tight and unconventional reservoirs, the use of simplistic 1D simulation modeling approaches have become far from realistic due to the level of geological complexity and heterogeneity within such reservoirs. Typical hydraulic fracture simulation models use a simple 1D geomechanical model to
generate a predicted response to hydraulic fracturing. This study proposes a more reasonable approach that allows for better treatments to be designed by incorporating the geological heterogeneity within the simulation models to generate a more realistic reservoir response to the stimulation modeling. The technique uses a geostatistically derived 3D geomechanical model that incorporates faults, lithology changes and lateral variation in reservoir properties and thickness within the horizontal well path as an input to the simulation model. The outcome of this process allows for more reasonable simulation results to be generated when designing hydraulic fracture treatments in complex and heterogeneous reservoirs (Alfataierge, 2017).

The model generated for this study uses a simplistic geostatistical approach that represents the static conditions of the reservoir before hydraulic fracturing takes place. Building the 3D geomechanical model using geostatistical methods allow for a better estimate of lateral heterogeneity throughout the reservoir intervals. Methods such as simple kriging can be used to distribute pore pressure data and overburden pressure data with relative accuracy within a reservoir model. However, closure pressures are more sensitive to the variations of elastic moduli (Young’s modulus and Poisson ratio) within the reservoir (Alfataierge, 2017).

Closure pressure is commonly derived through empirical calculations using log-derived 1D elastic moduli. These elastic moduli are generally assumed to be laterally homogeneous to simplify the simulation modeling process. Using Sequential Gaussian Simulation (SGS), a more appropriate solution is generated that incorporates the reservoir heterogeneity and honors the lateral distribution of the elastic moduli based on the observed well data. Through the use of volumetric calculations, the models generated using SGS are used to calculate the closure pressures within the reservoir intervals. The outcome of the modeling process is calibrated using diagnostic fracture injection test (DFIT) data from surrounding vertical wells in the area and is shown to have a relatively good match (Alfataierge, 2017).
4.3 Geologic structural model

The structural model contained the Sharon Springs formation, Niobrara A Marl, Niobrara B Chalk, Niobrara B Marl, Niobrara C Chalk, Niobrara C Marl, Niobrara D Chalk, Fort Hays, Codell, Carlile formation underlain by the Greenhorn Bridgecreek Limestone (Figure 4.1). All intersecting major faults within the Niobrara and Codell sections were also included within the structural modeling. The structural model has an overall average thickness of 700ft, while the Niobrara interval averages at 300ft in thickness. The model cell size is: X: 50ft, Y: 50ft, Z: 5ft. The structural model was used to distribute the reservoir properties within the model through geostatistical distributions.

Figure 4.1 Complete structural model (left). Niobrara and Codell Structural Model (right). Wishbone section (study area) highlighted by yellow square

The structural model was built by Ning (2017) using seismic derived horizons that were depth converted using the velocities from the wells. Figure 4.2 shows the location of the vertical wells in the area that have synthetic sonic logs that were used for generating this velocity volume for depth conversion. The velocity model was generated by Payson Todd within the RCP study area.
A facies model was also created to help confine the distribution of reservoir properties within the Niobrara Reservoir. The facies distribution was generated using sequential indicator simulation over the study area (Figure 4.3). The facies classification was based on observations made by Mabrey (2016) followed by Brugioni (2017) through different core studies in the area. Based on the core analysis, the GR was used to identify the facies in the area based on the level of chalk to marl content within the Niobrara. Figure 4.4 shows an example of how the GR was used to separate out these facies classifications into chalk, marly chalk, low GR marl, and high GR marl. The Sharon Spring, Codell, Fort Hays, Carlile, and Greenhorn Bridge Creek LS were classified as a shale, sandstone, limestone, shale, and limestone layers.
4.4 Petrophysical analysis & well log upscaling

The reservoir model was generated using 13 vertical wells that were drilled through the Niobrara reservoir interval. The wells were selected on the basis of their log data to be used as an input for geomechanical calculations (Figure 4.2). The model uses a “5ft” vertical cell size to generate an upscaling that would closely resemble the well log data without losing the vertical variability obtained from the well logs. As can be observed, the variability in reservoir properties that are captured in the model cells closely resemble the well logs that were used for the upscaling (Figure 4.4 & Figure 4.5).
Figure 4.4 Example of log signature across the 13 vertical wells compared to upscaled geomodel cells

Figure 4.5 Pore pressure trend, along with overburden stress logs compared to model upscaling for krig interpolation
By taking a close look at the vertical variogram generated for the model as compared with the well logs, we can see that we have a good match between the observed well data and upsampled model (Figure 4.6). Although the well data varies in comparison to the upsampled cells within the model, the distribution is similar enough considering that the well data is sampled at 0.5ft vertical intervals vs. 5ft vertical sampling within the upsampled cells within the model. Using SGS we were successfully capable of matching the reservoir model data distribution to the upsampled cells at the well location.

Figure 4.6 Vertical variograms from upsampled cells compared with well logs
4.5 Geomechanical considerations for 3D modeling

Building a 3D geomechanical model using well properties as an input allows for a better replication of lateral heterogeneity in the field. Methods such as Kriging can be used to distribute pressure data depending on the available observed data. Sequential Gaussian Simulation (SGS) can replicate field heterogeneity more accurately for rock strength related properties (Holland, Brudy, van der Zee, Permallla, & Finkbeiner, 2010).

Young’s modulus is a measurement of stress over strain. Poisson’s ratio measures the radial strain against the axial strain. Both these properties are stress dependent parameters. The change in overburden stress and formation pore pressure (effective stress) directly influences the measurements of Poisson’s and Young’s elastic moduli.

The current model uses a simplistic approach that represents the static predrill conditions of the reservoir. The modeling of pressure, Poisson’s & Young’s moduli are assumed to independent of any later stress changes in the area that occurred due to drilling and hydraulic fracturing. These rock properties can later be used as an input for stress modeling within the Niobrara Reservoir given static conditions (Figure 4.7).

Generally, such 3D geomechanical models are built using numerical simulations with finite element modeling (Fischer & Henk, 2013; Zoback, 2007). For the case of this study, a simpler approach is utilized using geostatistical methods to generate a 3D minimum horizontal stress model that represents the subsurface static conditions prior to hydraulic fracturing and production. The 3D reservoir models are later used as an input to hydraulic fracture simulation in Chapter 5.
4.6 Geostatistical methods

The reservoir model will focus on distributing the pressure related properties using simple kriging to simplify the interpolation of the data between the wells, and allow for a smooth interpolation to occur. The rock strength parameters shown in Figure 4.4 (Young's modulus, Poisson ratio) are modeled using the Sequential Gaussian Simulation (SGS) to generate a more appropriate solution that incorporated reservoir heterogeneity and honors the distribution of the rock strength properties from the observed well data. The SGS reservoir property distribution was confined using the facies classification model that was generated earlier.

The overburden pressure for all 13 wells is observed to increase as a function of depth in a linear trend (Figure 4.5). The observed pressure gradient within the area varies as a function of depth at a rate ranging between 0.8-1.1 psi/ft (higher gradients achieved at higher depths). These pressure measurements vary with depth, but are laterally homogenous at a given depth. Given
the geomechanical characteristics of the pressure data, simple kriging was considered to be the best option for modeling overburden pressure. The simple kriging method is used to allow for smooth interpolation of values to fill in the grid values laterally between the well locations.

Kriging uses a deterministic algorithm to distribute the well log properties into the reservoir model. The kriging results are spatially interpolated between the input well data. The kriging method interpolates values based on the weighted grades of the points surrounding it. The kriging weights are based on the variogram model parameters (nugget, sill, range). The advantage of kriging is that kriging equations minimize the variance of the estimates, kriged estimates are conditionally unbiased, and the kriging process handles clustered data very well (Syrjanen & Loven, 1999). Using Kriging to model the pressure trend within the study area allows for the values to be distributed in the model based on linear interpolation between the wells locations.

The disadvantage of kriging is that the results can be overly smoothed leading to underestimating the larger values within, or over estimating the small values (Figure 4.8). The smoothing using kriging is also driven by the distance away from the input data. The closer the simulated cells are to the wells, the more they will be biased by them. Using kriging to describe reservoir properties such as porosity, permeability or even elastic moduli will yield inaccurate and non-geologically representative results.

Unlike the overburden pressure data, the rock strength properties are much more heterogeneous within the Niobrara. These elastic rock properties typically vary with different facies. Using kriging would yield an inappropriate representation of the reservoir unit. Kriging limitations for rock strength property prediction: results are too smooth, small values are over estimated, large values are under estimates, smoothing is not uniform, the closer the cells are to the wells there is less smoothing, often not representative of subsurface reservoir properties.
The Young’s modulus and Poisson ratio measure the rock strength within the subsurface as a function of stress given static pre-drill conditions. The rock strength variation depends on the mineral content and intrinsic rock properties within the reservoir. These rock properties are geologically variable laterally and vertically within the Niobrara Reservoir. As an alternative to the simple kriging method used to model the pressures, the Sequential Gaussian Simulation (SGS) method is used to honor the property distribution within the reservoir model based on the distribution of the vertical observed data. Using Sequential Gaussian Simulation (SGS) can replicate field heterogeneity more accurately for rock strength related properties (Holland et al., 2010). SGS honors the property distribution observed in the well data to simulate and predict a more accurate representation of the reservoir based on the observed well data.

Sequential Gaussian Simulation (SGS) uses a stochastic algorithm to distribute the reservoir properties within the reservoir model. SGS uses a random seed in addition to the input data. SGS provides a better match to the input data, specifically the variability of the input data. This means that local highs and lows will appear in the results, and won’t be smoothed out as in kriging (Figure 4.8). The results from using SGS provide a better match to the well data distribution, and are much more representative of the geologic heterogeneity within the subsurface.
Although SGS is better at modeling the heterogeneity of the reservoir the simple kriging methods, SGS uses a random seed in addition to the input data. Therefore, each model generated with a different seed will be non-unique. Consecutive runs will give similar results with the same input data, the details of the results will be different. SGS is generally run several times to generate a sense of uncertainty in the prediction of the simulated model.

### 4.7 Geostatistical reservoir modeling

The overburden pressure data were calculated in Chapter 3. The pressure data were distributed into the model using simple kriging (Figure 4.9). The kriging method allowed for pressure to be linearly interpolated between the well locations.

![Overburden pressure model distribution using Interpolated Kriging](image)

Figure 4.9 Overburden pressure model distribution using Interpolated Kriging

The geomechanical properties (PR & $E_{stn}$) were calculated in Chapter 3 and converted to static rock properties. The calculated well log properties were distributed using a Sequential Gaussian Simulation (SGS) to simulate the heterogeneity within the reservoir and honor the distribution of the input data. The use of SGS allowed for the model to honor the data distributions depicted in the histograms within Figure 4.10 & Figure 4.11. The histograms illustrate the variability in the data distribution in the model as a result of the upscaling as compared to the well log property distribution (Figure 4.12).
Figure 4.10 Dynamic Poisson’s ratio model distribution using sequential Gaussian simulation

Figure 4.11 Dynamic Young’s modulus model distribution using sequential Gaussian simulation

Figure 4.12 Histogram of model results compared to the observed well data
Average maps extracted from the 3D reservoir model at the Niobrara B and C chalk intervals show an example of the lateral variability of elastic moduli within the Niobrara Formation (Figure 4.14 & Figure 4.15). This distribution honors and represents the geological heterogeneity within the section as per the facies distribution that was generated and selected using Sequential Indicator Simulation. Using the 3D model distributions of reservoir properties as an input to volumetrically calculating the magnitude of minimum horizontal stress will generate a more representative distribution of stress based on the lithological heterogeneity of the area.

The vertical and horizontal variograms were generated to show the variability of the data in modeling space. High nugget values represent random and short-distance variability factors such as irregular values, and sampling error. Small nugget values indicate good sampling techniques and locally continuous structure (Syrjanen & Loven, 1999). The range is the distance beyond which samples are not correlated with other samples. The sill value is usually equal to the sample variance. The horizontal variogram generated in Figure 4.13 represents the correlation of the data within the simulated reservoir model. The simulated results for Poisson ratio and Young’s modulus show a good correlation within short lag distances, then we lose the correlation with larger lag distances. This illustrates the level of heterogeneity given each rock strength parameter. The model appears to be appropriately simulating the property distribution in lateral space.

Figure 4.13 Horizontal isotropic variograms of the simulated model properties
Figure 4.14 Average map extracted from 3D model showing distribution of Young’s Modulus (Mpsi) within the Niobrara chalk intervals

Figure 4.15 Average map extracted from 3D model showing distribution of Poisson Ratio within the Niobrara chalk intervals
4.8 3D volumetric stress model

The 3D minimum horizontal stress model is calculated in 3D space using the generated volumes required as an input into (Eq. 4.3) to calculate the 3D distribution of minimum horizontal stress with respect to geological heterogeneity within the area. 3D geomechanical modeling using geostatistics is suggested by (Holland et al., 2010) as a method for mapping the distribution of reservoir stress with respect to the change in reservoir properties. The resulting model for minimum horizontal stress considers the lateral variability in young’s modulus and Poisson’s Ratio with respect to facies classifications through sequential Gaussian distribution. While the pore pressure, overburden pressure and tectonic strain are distributed using simple kriging to interpolate the values between the 13 processed observation wells (Figure 4.16).

Calculating closure pressure, minimum horizontal stress, in isotropic medium was conducted using (Eq. 4.1) from Barree, Gilbert, et al. (2009). The 3D volumetric calculation uses the ability to calculate the minimum horizontal stress using 3D volumes for each property that goes into the equation (Eq. 4.1). The outcome of such a calculation is that the properties that go into calculating the minimum horizontal stress over the study area are better represent of the geological heterogeneity within the Niobrara (Figure 4.17).

\[
3D \sigma_{h\ min} = \frac{\nu}{(1-\nu)} [\sigma_v - \alpha_v P_p] + \alpha_h P_p + \varepsilon_E + \sigma_t \quad \text{(Eq. 4.1)}
\]

- Poisson’s Ratio (\(\nu\)) obtained from facies confined SGS distribution
- Overburden Stress (\(\sigma_v\)) obtained from simple kriging
- Biot’s Coefficient (\(\alpha_v = \alpha_h\)) obtained from facies confined SGS distribution
- Pore Pressure (\(P_p\)) volumetrically calculated (3D Pp = 0.6psi/ft*TVD(ft))
- Young’s Modulus (\(E\)) obtained from facies confined SGS distribution
- Regional Horizontal Strain (\(\varepsilon_E\)) obtained from simple kriging between processed wells
- Regional Horizontal Stress (\(\sigma_t\)) obtained from simple kriging between processed wells
The workflow for generating the 3D volumetric stress calculation using 3D geostatistical model distributions can also be described through the following process:

1) Estimate 3D pore pressure based on 0.6 psi/ft gradient (3D \( P_p = 0.6 \text{psi/ft} \times \text{TVD(ft)} \))

2) Calculate minimum horizontal stress using (Eq. 4.1) the following input parameters:
   a. Static Poisson Ratio \( 3D \text{PR}_{\text{sta}} \) (SGS)
   b. Static Young’s Modulus (Mpsi) \( 3D \text{E}_{\text{sta}} \) (SGS)
   c. Pore Pressure (psi) \( 3D \text{Pp} = 0.6 \text{psi/ft} \times \text{TVD(ft)} \)
   d. Biot Poroelastic Coefficient \( 3D \text{Biot V} \) (SGS)

3) By assuming “zero” regional stress or strain, an estimate of \( \sigma_{h_{\text{min}}} \) is obtained within the Niobrara reservoir intervals. The estimated is then calibrated back to a 0.7-0.74 psi/ft gradient, as observed from the DFIT data listed in Table 3.1, by adjusting the regional tectonic strain (-\( \varepsilon_x \)) or regional tectonic stress (\( \sigma_x \)).

![Figure 4.16 Minimum horizontal stress volumes](image)

Figure 4.16 Minimum horizontal stress volumes
Based on the volumetric model calculations and distribution of stress within the Niobrara, average maps were generated within the Niobrara B and C chalk interval to characterize the stress variability and heterogeneity within the formation (Figure 4.18), along with the fracture gradient in the section (Figure 4.19). These maps provide an aerial view of the reservoir heterogeneity, and the control on stress distribution within the reservoir. Histograms were also generated to compare the vertical variation in fracture gradient. The chalk intervals consist of lower ranges of stress and fracture gradients relative to the marl rich intervals (Figure 4.20). This is consistent with the petrophysical observations in Chapter 3, making the chalk intervals more favorable for hydraulic fracturing and containment.
Figure 4.18 Average map extracted from 3D model showing the distribution of minimum horizontal stress (psi) within the Niobrara B and C chalk intervals.

Figure 4.19 Average map extracted from 3D model showing the distribution of fracture gradient (psi/ft) within the Niobrara B and C chalk intervals.
4.9 Volumetric calculations for other reservoir properties

The calculation of other 3D volumetrically property distributions can also utilize the technique that was used in this chapter to distribute the lateral variability of the data with respect to the geological heterogeneity. For example, Biot V and Permeability distributions can be either estimated through SGS, or through the use of equations (Eq. 3.17) & (Eq. 3.31) respectively.

Summary of 3D reservoir model distribution of properties required for hydraulic fracture simulation in Chapter 5:

- 3D Facies distribution: Sequential Indicator Simulation
- Density (RHOB): Sequential Gaussian Simulation
- Gamma Ray (GR): Sequential Gaussian Simulation
- Effective Porosity (PHIE): Sequential Gaussian Simulation
- BIOT V: Sequential Gaussian Simulation
- Resistivity: Sequential Gaussian Simulation
- Poisson Ratio (PR): Sequential Gaussian Simulation
• Static Young’s Modulus \( E_{\text{sta}} \)  
  Sequential Gaussian Simulation
• Water Saturation (Sw)  
  Sequential Gaussian Simulation
• Overburden Pressure  
  Simple Kriging
• Pore Pressure  
  Simple Kriging
• Strain  
  Simple Kriging
• Minimum Horizontal Stress \( 3D \sigma_{h_{\text{min}}} \)  
  3D Volumetric calculation (Eq. 4.1)
• Effective Permeability (Perm)  
  3D Volumetric calculation (Eq. 3.31)

4.10 Discussion

The simulated static rock properties within this study area have been upscaled and modeled to represent the stress conditions affecting the Niobrara reservoir before drilling and hydraulic fracturing. The rock strength properties were generated in a dynamic sense through the use of empirical relationships. The resulting volumes are used to calculate the minimum horizontal stress distribution in 3D with respect to the lateral and vertical facies heterogeneity captured in the reservoir model. The simulated model represents a best approximation for the predicted static in-situ stress conditions within the Niobrara reservoir. As the stresses change due to drilling and hydraulic fracturing, the model will have to be recalibrated and modified to represent the dynamic changes within the reservoir intervals. The results of the simulated model appear to be appropriate for demonstrating the variability of the well data in 3D modeling space.

The results that were used to generate the distribution of Young’s Modulus and Poisson’s ratio depend on a random seed used in the simulation and distribution of the properties. Therefore, each model generated with a different seed will be non-unique. Consecutive runs with different seed numbers will yield non-unique results that would have a similar variogram that matches the input well data. Although a facies model was used to confine the distribution of reservoir properties using SGS, the overall results from SGS are still non-unique. Several runs were processed to
generate a sense of uncertainty in the prediction of the simulated model. The most repetitive and best matching results to the geological understanding of the area were used to carry forward this study.

4.11 Conclusions

3D volumetric calculations using geostatistical methods can be applied to 3D geomechanical model building in areas with multiple wells as input. Such 3D representations of the subsurface are very valuable to drilling and hydraulic fracturing operations. Building a 3D geomechanical model using geostatisticaly populated well properties as an input allows for a better representation of vertical and lateral heterogeneity within the field. Methods such as Kriging have been shown to be best suited for distributing pressure related data from offset well data. Sequential Gaussian Simulation (SGS) is shown to best depict the level of reservoir heterogeneity for rock strength related properties such as Young’s modulus and Poisson ratio. These simulated models can be used for calculating stress related properties that are representative of the lateral and vertical heterogeneity within the reservoir interval.
CHAPTER 5
HYDRAULIC FRACTURE SIMULATION INTEGRATED WITH 4D TIME-LAPSE MULTICOMPONENT SEISMIC AND MICROSEISMIC ANALYSIS

5.1 Summary
Recent advances in geological and geomechanical reservoir characterization, integrated with simulation modeling, has allowed for better optimization and improvement in hydraulic fracture treatment design (Wallace et al., 2016). Within the RCP study area, the use of hydraulic fracture stimulation models integrated with 4D multicomponent time-lapse seismic and micro-seismic analysis show that there is still room for improvement to be made for optimizing well spacing and stage spacing within the Niobrara.

The post treatment analysis conducted using a 3D hydraulic fracture simulation is used to understand the geometry and hydraulic fracturing efficiency of the treatments that were performed on the Wishbone lateral wells. Post treatment analysis will allow for a better understanding of stimulation response to reservoir complexity regarding stress anisotropy and rock strength variability within the Wishbone section. With this information, exploitation and optimization plans can proceed with better efficiency. The simulation model results from post treatment analysis are integrated with 4D seismic and microseismic observations to provide more insight into the effectiveness of the hydraulic fracturing in the section. Recommendations for infill drilling and refracturing are made to increase reserve recovery from the Niobrara Reservoir.

5.2 Introduction
Hydraulic fracturing is a method for accelerating production from a target formation by increasing the effective wellbore connection to the formation (Figure 5.1). This connection between the wellbore and the formation is generated by creating an induced fracture that is filled
with proppant. The fracture is initiated an extended through the use of a clean “pad” fluid, followed by fluid carrying proppant that will help keep the fracture face open and conductive after hydraulic fracture pumping (Barree, 2017). These fracture geometries are controlled by the in-situ reservoir stress conditions and stress state. The ability to initiate the hydraulic fracturing requires overcoming the in-situ stresses within the subsurface to initiate the fracturing.

Predicting fracture geometries is a very valuable tool for understanding the result from a hydraulic fracture treatment. 3D simulation models are best suited for generated fracture geometry that represents the interaction of the hydraulic fracturing with the subsurface stresses. Such representations of the subsurface are typically calibrated and tested for their validity using laboratory and seismic observations. These predictive models are generally calibrated through seismic observations for height, length and overall stimulated reservoir volume (SRV). More information can be extracted from such 3D simulation model representations to understand the effective SRV and provide insight into the fracture face properties. Generating an estimate for the effective fracture conductivity from such simulations models can help guide well spacing and field development. Such 3D representations of the subsurface fracture geometry are essential for
understanding the effect of reservoir heterogeneity on hydraulic fracturing to effectively accelerate recovery and add reserves for unconventional reservoirs.

5.3 Overview of hydraulic fracture simulation theory

Simulation models representing hydraulic fracture treatments are built with three basic equations: the conversion of mass, a fluid-flow equation, and a fracture compliance which relates the fracture width to the net pressure (Ayoub, Brown, Barree, & Elphick, 1992). The net pressure is the pressure above closure that initiates the hydraulic fracturing. Any model starts with a width expansion component as a function of net pressure, Poisson Ratio, and Young’s modulus. The simplest representation of such a width predictive method is depicted in equation (5.1). This equation represents the classical mechanics theory applied on a uniform, isotropic homogeneous, elastic solid (Barree, 2017). Width given from the displacement of the surface of a semi-infinite half-space acted upon a point load is:

$$w = \left(1-v^2\right)\frac{AP_{\text{net}}}{\sigma\theta}$$

(Barree, 1983)  \hspace{1cm} (Eq. 5.1)

The main difference between the models is how they handle the tip effects (Barree, 2017). In Figure 5.2 “a” represents the fracture width opening profile for a plane strain solution. Using a plane-strain solution assumes that the shape of the ellipse cannot change along the entire length of the fracture face (Barree, 2017). That means that fracture width will not vary with length. A simple width solution assumes that the fracture width is a function of only net pressure, rock elastic properties, and the characteristic dimension of the ellipse (Barree, 1983).

Classical “2D” simulation models provide information regarding the width and length of a hydraulic fracture. Fracture height was assumed to be constant. Fracture width was determined by material balance considering the injection fluid volume, leakoff, and fracture volume (Ayoub et
al., 1992). The orientation of the ellipse in Figure 5.2 controlled the overall geometry of the fracture geometry. By using the PKN solution, the increase in pressure drives the increase in fracture width (w) is controlled by the height of the fracture. Increasing width (w) would lead to an increase in overall height in order for pressure to increase. While the KGN model represents the fracture in a horizontal plane. The length is a measure of fracture tip-to-tip length. This method assumes that fracture shear at the target bed boundaries, while fracture length grows as a result of the increase in fracture width (w) (Ayoub et al., 1992).

\[
PKN (w) = \frac{2(1-v^2)H\Delta P_{net}}{E}
\]  
(Eq. 5.2)

\[
KGN (w) = \frac{4(1-v^2)L\Delta P_{net}}{E}
\]  
(Eq. 5.3)

Figure 5.2 Comparison of different 2D models used to control fracture width as a function of pressure increase, and fracture length or height modified from (Barree, 2017)

Using a PKN model, for a given height and internal pressure, the width distribution along the ellipse is determined. This model is typically used to predict the geometry for fractures with short height growth, and longer fracture lengths. This model generally provides a reasonable estimate for fracture width. KGD, predicts fracture width at the wellbore which will grow under constant
pressure with fracture length. The upper and lower boundaries are ignored and assumed to undergo slip motion along the bedding planes. This model is typically used to predict the geometry for fractures with high height growth, and short hydraulic fracturing lengths. For length to height ratios less than one, the KGD model provides a good estimate of fracture width, while at ratios larger than one, this model will generally overestimate fracture width.

Based on the Nolte-Smith log-log plot of net pressure vs. time, hydraulic fractures can be characterized for their geometry as shown in Figure 5.3 (Nolte & Smith, 1981). If the PKN solution for width is assumed, the Nolte-Smith pressure characterization would appear to show that the hydraulic fracturing is occurring with confined height growth, constant compliance, and unrestricted extension (Mode I). If the KGD model was assumed, the hydraulic fracturing would appear to be undergoing rapid height growth (Mode III). These pressure characteristics control the assumptions made by the 2D models (Ayoub et al., 1992).

The 3D hydraulic fracture simulator used for this study was developed by (Barree, 1983) “GOHFER 3D” and is classified as a finite difference model. The numerical simulator can predict fracture geometries in height and length, while handling spatial variation in elastic properties, closure stress, pore pressure, and rock strength. Fracture fluid pressures, fracture widths, and...
net stress are all calculated at uniformly spaced points over the entire fracture face (Barree, 1983). The 3D numerical overcomes the need to assume a height within the classical 2D models (PKN, KGD).

GOHFER uses a decoupled gridding system that allows for shear failure and slip along bedding planes to occur while pressure, fracture width and length increase (Barree, 1983). This mechanism works as a method for controlling height growth in the simulator. The shear-decoupled system to control fracture height growth has been proved to be consistent with field and laboratory observations by (Barree, 2017). This assumption allows for the internal layering within the model to control height growth, much more similar to how the layering within geological bedding planes and shales laminations act as planes of weakness and shear.

5.4 1D simulation modeling for hydraulic fracture containment

As previously discussed within Chapter 3, the chalk intervals within the Niobrara Formation are more favorable for hydraulic fracturing and are bounded by the higher stressed marl intervals. The Niobrara Formation within the RCP study area has two preferred landing intervals that can be observed for favorable hydraulic fracturing. The B chalk and C chalk intervals observed in Figure 5.4 are the main targets for hydraulic fracturing within the Wishbone section. These chalk intervals are bounded by the marls that appear to have a higher hydraulic fracture gradient relative to the chalks, which essentially allows for better containment to occur within the chalk intervals. As we can also see in Figure 5.4, the Niobrara Formation is bounded above by a highly-stressed overlying barrier as observed in Figure 5.4. Simple simulation modeling using the 1D geomechanical model as an input shows that the Niobrara B chalk will respond differently to hydraulic fracturing as compared to the Niobrara C chalk interval (Figure 5.5). The Niobrara B hydraulic fracture appears to be better contained within the upper Niobrara, while the Niobrara C hydraulic fracture results show a downwards growth is more likely to occur. The use of slickwater
versus crosslink is also taken into consideration in the Figure 5.5 example. The use of crosslink fluid is shown to extend in height as compared to the slickwater treatment, and result in a shorter hydraulic fracture length.

The lateral wells drilled within the study area oscillated in and out of the target zone due to the geological complexity and faulting in the section. The intended landing zones are shown in Figure 5.6, while the actual zones that intersect with these 11 lateral wells is shown in Figure 5.7. Using a simple modeling approach based off a 1D geomechanical model to assess the lateral response to hydraulic fracturing will eventually fail and yield incorrect estimates along the entire lateral section. In order to understand the how the hydraulic fracturing was affected by the lateral geologic heterogeneity, the use of a 3D geomechanical model will provide more insight to the response from hydraulic fracturing based on the position of the lateral well section and treatment stage relative to the geological heterogeneities.
Figure 5.5 Simple forward modeling for hydraulic fracture containment comparing the Niobrara-B chalk vs. Niobrara-C chalk response to hydraulic fracturing stimulation (Alfataierge et al., 2018)
5.5 Hydraulic fracturing within the Wishbone section

Within the Wishbone section (RCP study area), 11 lateral wells were drilled. 7 of these wells were drilled targeting the Niobrara, and 4 lateral wells were drilled targeting the Codell (Figure 5.6). These lateral wells were drilled and then hydraulically fracture stimulated from east to west in consecutive order. The wells alternate in targeting intervals between the Niobrara and Codell targets. All the wells were prepared for hydraulic fracture stimulation using sliding sleeve completions, except for the 9N well that was completed using the plug and perf method.

Although the lateral wells landed in the proper targeting zones, the geosteering reports from the lateral length of the wells show that these wells are variable in landing positions relative to the geological heterogeneity. Figure 5.7 shows the variability in landing position relative to the chalk and marl intervals based on the structural model that was generated in Chapter 4. Treating the lateral extent of these wells with the same fluid and treatment design is expected to yield different results from stage to stage based on the variation of geomechanical properties from chalk to marl layers within the Niobrara.

Within each of the lateral sections in this study area, multistage hydraulic fracturing was conducted. 32 stages were treated for each well, with an average stage spacing of 200ft, with the exception of wells 9N and 10C that were treated with 27 and 20 stages. The first 5 stages of almost all the wells were treated with linear gel and cross link fluid, with variable proppant concentration ranging between 0.25-3ppg at an injection rate of 40bbl/min. The entire remaining stages were treated using slickwater with variable proppant concentrations ranging from 0.25-1.25ppg at a rate of 60bbl/min (Table 5.1).

Wells 1N, 2N, 3C, 4N, 5C, 6N, 7N, 8C, 9N, stages 1-5 were treated with crosslink fluid, 0.25-3ppg proppant concentrations alternating concentrations of 40/70 white sand and 30/50 white
sand. Stages treated with slickwater, 0.25-1.25ppg proppant concentrations were treated using 40/70 white sand. Total Fluid per well = 3.5 million gallons and total proppant per well was 2 million lbs. Wells 7N, 8C, and 9N were treated in a zipper fracturing sequence predominantly used to increase the efficiency of the surface operations and reduce the amount of time on location. The zipper fracturing also generated an increase in stress shadow effects within the reservoir and added additional complexity to the hydraulic fracturing geometry.

Wells 10C and 11N were treated differently from the other wells: 10C was treated entirely with slickwater, 0.25-1.25ppg, 60bpm, 3 million gallons, 2 million lbs for 20 stages. While 11N was treated with crosslink fluid (stages 1-5) 0.25-3ppg at 40bpm. While stages 6-32 were treated with slickwater, 0.25-1.25ppg at 60bpm, with a total well fluid of 6 million gallons, and total well proppant equal to 4.6 million lbs. These wells were stimulated using bigger treatment jobs to test whether bigger fracturing jobs can potentially result in better production.

As previously discussed in chapter 4, a 3D geomechanical model was generated as an input to the hydraulic fracture simulation modeling. The modeling in this section will be utilizing the geomechanical model that was established to compare and contrast the results as they compare to the simple modeling. By utilizing the 3D geomechanical, structural and facies model that was generated in Chapter 4, one can better account for the level of heterogeneity that will affect the treatment of every different stage relative to its landing position within the Niobrara. The efficiency of the treatments within this study section can be observed and compared with seismic observations for potential recovery and optimization plans (refracturing and infill drilling) to be put in place for the near future.
Table 5.1 Hydraulic fracturing fluids used per stage: linear gel and crosslink fluid (green), slickwater treatment (blue)

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- **Slick Water**
- **Cross Link**
- **Skipped Stages**
Figure 5.6 Intended target intervals within the study area with arrows showing the sequence of order for hydraulic fracture stimulation between the wells. Modified from (RCP, 2017)

Figure 5.7 Well position relative to geological heterogeneity based off well intersections with structural model. Black dots along the wellbores represent stage locations (Alfataierge et al., 2018)
5.6 3D hydraulic fracture simulation using a 3D geomechanical model

3D hydraulic fracture simulation allows for the variability in treatment efficiency to be assessed and analyzed with respect to the offset wells. By utilizing the 3D geomechanical model as an input to the 3D hydraulic fracture simulation, the overall effectiveness of hydraulic fracture stimulation treatment can be observed with respect to the location of the well and treatment stage relative to the geological heterogeneity (Alfataierge et al., 2018). Figure 5.7 shows how heterogeneous the geology is relative to the lateral wells as previously discussed. These wells had difficulty remaining within the target interval due to the complex faulting and thickness changes within the section. Using a 3D model to understand the hydraulic fracture geometry based on where it landed relative to the geology is important to honor and treat the formation based on where the well intersects with the geology. The 1D simple stress model used in Figure 5.8 is compared to the generated 3D model depicted in Figure 5.9 show how significant the stress can change along the lateral section of the well based on the changes in structural thickness, faulting and lateral lithological variations. A simple model doesn’t capture all this heterogeneity along the extent of the lateral section.

The simple model uses a 1D geomechanical model as an input that assumes homogeneity, constant thickness, no structure, no faults. The 3D volumetric calculated stress model is a heterogeneous model that uses the facies distribution to distribute the reservoir properties that go into calculating the closure stress equation (5.4). The 3D model also uses all available well logs from nearby wells, and takes into account the variable structural thickness and faulting within the section. The minimum horizontal stress in both the 1D and 3D model were estimated and calibrated to the DFIT data using the following equation for Closure Pressure ($P_c$) in isotropic medium within the GOHFER 3D software package (Barree, Gilbert, et al., 2009)

$$
\sigma_{hmin} = \frac{\nu}{(1-\nu)} \left[ \sigma_v - \alpha_v P_p \right] + \alpha_h P_p + \epsilon_x E + \sigma_{tectonic} \quad \text{(Eq. 5.4)}
$$
The results from the running the simulation using the same well, and the same stage to be treated with the exact same treatment that was treated in the section is depicted in Figure 5.10. The 3D volumetric calculated stress model shows potential isolated conductivity established below the wellbore, while the simple model assumes that the proppant was established uniformly around the wellbore. By analyzing the simulation results from the two models generated in Figure 5.10, we can observe that there is a significant difference in the simulation resulting due to the incorporation of geological heterogeneity. Although the simple model results look appealing, it might not necessarily be entirely accurate. Incorporating a higher level of resolution into geological models used in hydraulic fracture simulations can significantly help with better understanding how the reservoir reacts to the hydraulic fracturing at each and every different stage along the lateral (Alfataierge et al., 2018). Along with identifying areas that can potentially result in isolated conductivity being established away from the wellbore. Such isolated conductivity can be avoided through selective stage spacing away from such problematic intervals (avoid sections with high marl content and selectively place stages in chalk rich intervals) (Alfataierge et al., 2018).

Figure 5.8 1D geomechanical model for Well 1N (Alfataierge, 2017)
Figure 5.9 Cross sections through the 3D minimum horizontal stress model used for hydraulic fracture simulation modeling of Well 1N (heterogeneous 3D stress model) (Alfataierge, 2017)

Figure 5.10 Hydraulic fracture simulation results comparing the use of the simple 1D stress model (left) vs. simulation results from using the 3D minimum horizontal stress model (right) from a single stage within the 1N well (Alfataierge, 2017)
5.7 Calibrating the 3D hydraulic fracture simulation results

The 3D hydraulic fracture simulation output from GOHFER shows a wide variability in the effectiveness of the hydraulic fracturing along the lateral wells. Based on the geological heterogeneity of the area, the treatment of each stage is relatively different from the other previous stages due to change in geological and geomechanical properties within the formation. The effect of fault discontinuities and lateral lithological variation strongly influence and control the hydraulic fracture geometry within the simulation. These simulated results were calibrated and pressure matched based on calibrations that were made in chapter 3 & 4 to match the model pressures to the DFIT data. Further calibration was conducted by slightly adjusting the drop in pressure due to friction along the wellbore to generate a popper pressure match between the simulation pressures and actual well treatment pressures.

Using the DFIT pressure data provided in Table 3.1, the closure pressure, process zone stress, pore pressure, and leakoff characteristics are used to calibrate the 3D geomechanical model before hydraulic fracture simulation takes place (Alfataierge et al., 2018). The calibrated 3D geomechanical model is then used for pressure matching the hydraulic fracture simulation model and characterizing the geometry of the hydraulic fracture. An example from the pressure matching process is shown in Figure 5.11. A pressure match is a non-unique solution for fracture geometry. By properly constraining the model to the measured data (DFIT data), the less tuning will be required and the more confidence can be placed into the model. These DFIT measurements are very important for establishing the reliability of the model and simulation results.

The process of calibrating and creating a good pressure match between the simulation and the actual well pressure data requires the adjustment and calibration of the following parameters: the minimum stress calibration, the process zone stress calibration, leakoff calibration, and friction...
calibration. These reservoir properties are calibrated as closely to observed measurements within the area (DFIT) to obtain a close pressure match and obtain reliable fracture geometry results from the simulation.

\[
\text{Initial Shut-in Pressure} \quad \text{ISIP} = \sigma_{h \min} + \Delta P_{\text{net}} \quad \text{(Eq. 5.5)}
\]

\[
\text{Fracture Pressure} \quad P_f = \sigma_{h \min} + \Delta P_{\text{net}} + \Delta P_{\text{friction}} + \Delta P_{\text{tip}} \quad \text{(Eq. 5.6)}
\]

Figure 5.11 Simulation pressure matching to actual well treating pressures after model calibration

5.8 Effective fracture length and fracture conductivity

Although the hydraulic fracture communication (hydraulic fracture length) can extend for several hundred feet away from the treatment stage in each wellbore, the effective fracture length that contributes to production is much smaller (Figure 5.12). The effective fracture length is defined as the propped fracture length that provides communication with the wellbore during the production cycle (Barree et al., 2017). The effective fracture length is typically unobserved by seismic and microseismic analysis. Deriving the effective fracture length is determined internally by the simulator through a relationship between the fracture conductivity, effective fracture half-length and hydraulic fracture length (Figure 5.13).
Estimating effective fracture conductivity is determined by several parameters to account for the effects of stress cycling (Figure 5.14), proppant age degradation, non-uniform stress, gel residue and cleanup, inertial losses, multiphase flow and saturation hysteresis, capillary blockage, reservoir energy for cleanup (Barree, 2017). Figure 5.14 illustrates how the reservoir stress conditions can significantly cause a reduction to the induced fracture conductivity after stimulation.

\[
\frac{X_{\text{eff}}}{X_{\text{flowing}}} = \frac{1}{1 + \left(\frac{\pi}{2F_{\text{CD}}}\right)}
\]

Figure 5.13 Relationship between fracture conductivity and hydraulic fracture length based on data originally published by Pratts and Cinco-Ley (Barree, 2017)
Dimensionless fracture conductivity ($F_{CD}$) is used as a proxy for determining hydraulic fracturing efficiency (Figure 5.15). The goal is to obtain high enough $F_{CD}$ values to make the fracture face much more permeable than the formation. This would allow for hydrocarbons to preferentially flow faster and more freely through the fracture face relative to the effective formation permeability. The numerator ($K_f W_f$) within the equation (Eq. 5.7) refers to the proppant permeability and fracture width. These parameters can be manipulated based on the proppant selection and fluid type used for hydraulic fracturing. The values with the denominator ($K_r X_f$) for calculating $F_{CD}$ take into account the hydraulic fracture length and the effective permeability of the formation. The effective formation permeability considers the overall permeability resulting from the reservoir matrix and fracture network affects.

\[
F_{CD} = \frac{W_f \times K_f}{K_r \times X_f} 
\]  
(Eq. 5.7)

\[ 
\text{Effective Fracture Conductivity} = W_f \times K_f 
\]  
(Eq. 5.8)
Figure 5.15 Definition of effective fracture conductivity

Generating a long narrow fracture using slickwater is typically obtained by designing treatments with low $W_f K_f$. Using crosslink fluid treatments with high proppant conductivity will generate a higher $W_f K_f$, but will typically yield short and wide fracture lengths. During hydraulic fracturing, $F_{CD}$ is usually designed for an $F_{CD} > 2$. Given that the formation permeability of the treatment formation is not usually obtained, and the hydraulic fracture length is usually uncertain, optimum hydraulic fracturing is designed for $F_{CD} >> 2$ to overcome any stress cycling and proppant embedment that would decrease the permeability and width of the induced fracture face after hydraulic pumping.

Hydraulic fracture length within the numerical simulator can be inferred from the distribution of proppant concentrations. Hydraulic fracture length is defined as the pressure communication length caused by the hydraulic fracturing while the hydraulic pumps on surface are actively pumping. The propped fracture length in the length of the fracture containing proppant. Although hydraulic fracturing can result in a couple 1000ft of communication in this section, this length does not necessarily contribute to production. An example showing the variability in proppant
concentrations that was established within the section as a result of hydraulic fracturing within the Niobrara is represented in Figure 5.17. The proppant distribution and hydraulic length is based on the simulation result while the hydraulic pumps on surface are actively pumping. This interwell interference was also observed by Dang (2016) based on the water tracer analysis (Figure 5.16). The tracer results indicate the presence of lateral and vertical communication pathways as between the wells at distances of over 1000ft during hydraulic fracturing. These tracer communication pathways can also have been influenced by the faults and natural fractures within the section that allow for further communication to occur.

Figure 5.16 Amounts of Well 2N tracer that was recovered from offset wells (Dang, 2016)

The effective fracture length is the length of the fracture that ultimately contributes to production, and can be observed from the effective fracture conductivity results within the simulator. The effective fracture length is defined as the propped fracture length that provides communication with the wellbore during the production cycle. The proppant concentration figures depict the hydraulic fracturing length that is generated while the pumps are actively pumping the treatment. This affect due to hydraulic fracture pumping is typically observed by microseismic monitoring. But the effective fracture length is not usually observed using seismic methods, but can be inferred from rate-transient production analysis.
Using the hydraulic fracture simulation, an effective fracture length can be interpreted using the effective fracture conductivity results. The results shown within the bottom half of Figure 5.17 Figure 5.18 represent the effective fracture length of the hydraulic fracture based on an effective fracture conductivity cutoff higher than 0.5 md*ft. The most effective fracture conductivity is assumed to have been generated and established using values over 2md*ft effective fracture conductivity within this study area.

By analyzing the two wells illustrating the difference between hydraulic fracture length and effective fracture length in Figure 5.17, it is observed that the proppant concentrations along the fracture faces are variable from one stage to the other. With the use of crosslink fluid in the toe section of the wells (treatment stages 1-5), it can be observed that higher proppant concentrations are established relative to the rest of the well length. The effective fracture conductivity that is generated from the hydraulic fracture simulation for all the 11 wells in the Wishbone section is depicted in Figure 5.18.

As can be inferred from Figure 5.18, the toe section (treatment stages 1-5) of the lateral wells appear to have generated higher effective fracture conductivity values relative to the rest the well section. The stages with highest fracture conductivities were treated with crosslink fluid that allowed for higher proppant concentrations to be carried out by the fracturing fluid. The 3D simulation results for effective fracture conductivity show a wider range of variability in the established conductivity within the induced fracture network relative to the geology. The variation in reservoir properties, faults, rock strength parameters, and in-situ stress conditions are shown to influence and control the hydraulic fracturing geometry and stimulation efficiency resulting in complex and isolated induced fracture geometries to form within the reservoir. This will consequently impact the effective drainage areas, production performance and recovery rates from these wells.
Figure 5.17 Hydraulic fracture length showing interwell interference while pumping (top), compared with estimated baseline conductivity within the effective fracture length (bottom) (Alfataierge et al., 2018)

Figure 5.18 Niobrara (left), Niobrara-Codell (right) effective fracture length and baseline fracture conductivity post hydraulic fracturing (pre-production) (Alfataierge et al., 2018)
As previously mentioned, the wells are treated in variable spacing ranges from 1200ft – 600ft in lateral separation within the Niobrara interval. The effective fracture lengths generated within the Niobrara appear efficient for a 600ft well spacing based on Figure 5.18. The effective fracture lengths interpreted by using the baseline fracture conductivity show consistent results with rate-transient analysis made by Dang (2016). These effective fracture lengths are variable from stage to stage, and can range from 200-600ft in total effective fracture lengths with variable fracture conductivity values within the induced fracture face (Figure 5.19).

![Figure 5.19 Effective fracture length and baseline fracture conductivity (all wells) (Alfataierge et al., 2018)](image)

As previously mentioned, the 11N was treated with double the fluid and proppant that was placed in the other treatment wells. The simulation results for the 11N well show larger fracture conductivity values relative to the size of the 1N treatment (Figure 5.20). The simulation results also show how the proppant concentrations are distributed in comparison between 1N and 11N. The 11N treatment appears to be influenced by the westward pushing stress shadow in the area. Fracture property results from modeling the 1N and 11N stimulations are shown in Table 5.2.
Simulation results showing the vertical extent and geometry of hydraulically fracturing within the Wishbone section is depicted in Figure 5.21 & Figure 5.22. Figure 5.21 shows the effect of hydraulic fracturing using crosslink versus slickwater within an un-faulted part along the wellbore. The crosslink treated stages appear to develop greater height-growth than the slickwater treatment (Table 5.2). The slickwater treatment is more effective for creating longer fracture lengths.

In most cases the treatment is confined to its target interval, except in the areas affected by fault discontinuities, or around stages that are positioned outside of the chalk intervals (within the Marls). Treating such stages appears most likely results in isolated conductivity away from the wellbore (Figure 5.10). The Faults within the section act as planes of weakness that can significantly influence the geometry of the hydraulic fracturing. Figure 5.22 & Figure 5.23 show how these fault zones can potentially connect to the Codell reservoir and allow for a short lived vertical communication to occur. These fault zones typically influence a larger fracture geometry to occur, that might not necessarily contribute to the effective SRV within the area (Table 5.2).
Figure 5.21 Results from hydraulic fracture simulation showing fracture geometry relative to un-faulted parts within the reservoir. Crosslink treatment observed with larger height, and shorter half-lengths as compared to slickwater treatments.

Figure 5.22 Results from hydraulic fracture simulation showing fracture geometry relative to fault zones affecting the reservoir. Fault zones influence fracture geometry and extend lateral and vertical communication pathways between Niobrara and Codell Formations.
Table 5.2 represents the variability in each hydraulic fracture result from the simulation. Using the 3D geomechanical model that best represents the reservoir heterogeneity within the area, the simulation modeling results consider the effect of variation in reservoir properties on the hydraulic fracture geometry, and fracture face properties (width, proppant concentrations). This variability in hydraulic fracturing efficiency will have a significant effect on the lateral variability in reservoir deliverability to the producing well along the entire length of the wellbore. It is of no surprise that the well lateral length will inevitably perform differently from stage to stage, and from well to well, due to this disparity in hydraulic fracture efficiency that results from the variability in reservoir properties. Production logging tools could potentially capture this variability and help further confine the predictions made from the 3D hydraulic fracture simulation model.
### Table 5.2 Example: Hydraulic fracture simulation results for 1N, 6N and 11N

<table>
<thead>
<tr>
<th>Well 1N</th>
<th>Well 6N</th>
<th>Well 11N</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Stage</strong></td>
<td><strong>Proppant Cutoff Length (ft)</strong></td>
<td><strong>Fracture Height (ft)</strong></td>
</tr>
<tr>
<td>1</td>
<td>320</td>
<td>110</td>
</tr>
<tr>
<td>2</td>
<td>440</td>
<td>90</td>
</tr>
<tr>
<td>3</td>
<td>320</td>
<td>110</td>
</tr>
<tr>
<td>4</td>
<td>400</td>
<td>110</td>
</tr>
<tr>
<td>5</td>
<td>480</td>
<td>110</td>
</tr>
<tr>
<td><strong>Crosslink Average</strong></td>
<td><strong>Crosslink Average</strong></td>
<td><strong>Crosslink Average</strong></td>
</tr>
<tr>
<td>6</td>
<td>680</td>
<td>80</td>
</tr>
<tr>
<td>7</td>
<td>640</td>
<td>110</td>
</tr>
<tr>
<td>8</td>
<td>560</td>
<td>80</td>
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<tr>
<td>9</td>
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<tr>
<td>10</td>
<td>600</td>
<td>50</td>
</tr>
<tr>
<td>11</td>
<td>320</td>
<td>70</td>
</tr>
<tr>
<td>12</td>
<td>440</td>
<td>40</td>
</tr>
<tr>
<td>13</td>
<td>400</td>
<td>50</td>
</tr>
<tr>
<td>14</td>
<td>400</td>
<td>70</td>
</tr>
<tr>
<td><strong>Slickwater Average</strong></td>
<td><strong>Slickwater Average</strong></td>
<td><strong>Slickwater Average</strong></td>
</tr>
<tr>
<td>15</td>
<td>320</td>
<td>200</td>
</tr>
<tr>
<td>16</td>
<td>360</td>
<td>70</td>
</tr>
<tr>
<td>17</td>
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<td>110</td>
</tr>
<tr>
<td>20</td>
<td>320</td>
<td>140</td>
</tr>
<tr>
<td><strong>Fault Zone Average</strong></td>
<td><strong>Fault Zone Average</strong></td>
<td><strong>Fault Zone Average</strong></td>
</tr>
<tr>
<td>420</td>
<td>128</td>
<td>0.11</td>
</tr>
</tbody>
</table>
5.9 Integrating simulation results with seismic observations

The use of seismic observations can further calibrate and help provide better insight into what the simulation results are showing. The microseismic interpretations provided by NanoSeis indicate a strong preference for the events to occur west of the wells. This is a result of the stress shadow effect caused by the sequential well fracturing from east to west, which was also considered in the simulation modeling (Figure 5.24).

Figure 5.24 shows evidence of lateral communication between these treatment wells while hydraulically pumping based on microseismic interpretations that coincide with the simulated results for hydraulic fracture length. This lateral communication between wells due to the hydraulic fracturing is observed within the microseismic events and in the microseismic amplitude maps. This interwell interference is referred to as “frac hits” (Jacobs, 2017). The presence of a west pushing stress shadow, along with the interference between the wells during hydraulic fracturing, is also observed from simulation along with the microseismic (Figure 5.17). But the effective conductivity is only established 200-600ft around the wellbore (variable effective fracture lengths with variable conductivity values) as depicted in Figure 5.19.

Figure 5.25 & Figure 5.26 show the sum of the amplitudes from the surface microseismic events in a cross-sectional view, along with an aerial top view. The amplitude bright spots appear to show a strong correlation with the effective fracture length that was established through the hydraulic fracture simulation. Using the sum of the amplitudes from the surface microseismic events appears to be very useful for mapping the distribution of effective fracture length within the Niobrara and Codell intervals for hydraulic fracture characterization.
Figure 5.24 Sum of all microseismic amplitudes from the Niobrara to Codell showing a strong preference for the events to occur westwards. Possible hydraulic communication with offset wells also circled around 9N. Simulation results below for a slickwater fracturing showing effect of stress shadow and preferential push towards the west.
Figure 5.25 Comparison of simulation conductivity relative to the microseismic amplitude signatures provided by NanoSeis. Niobrara wells (left), Niobrara-Codell (right)

Figure 5.26 Microseismic map view showing the sum of all the amplitudes from the events occurring within the Niobrara and Codell (right), compared with effective fracture length and baseline fracture conductivity from post-hydraulic fracturing (left)

Previous work showing the effect from 4D time-lapse seismic due to hydraulic fracturing was interpreted and analyzed by White (2015). The P-impedance difference response resulting from the hydraulic fracturing is shown in Figure 5.27. As per White (2015), the seismic response appears to be stronger towards the west than towards the east. This is understandable considering that the wells were treated from east to west sequentially with closer well spacing and bigger treatments to the west (Figure 5.6). The P-impedance response is also dominated by the pressure pulse effect caused by hydraulically fracturing these wells with a strong stress shadow pushing towards the west of the section as a result of the sequential fracturing from east to west.
The P-impedance differencing results from Monitor 1 to Baseline surveys reflect the differences in stimulation treatments that were conducted within the section. This is also observed from the hydraulic fracture simulation, where the hydraulic fracturing has a tendency to grow downwards as observed in Figure 5.25 by both the microseismic and simulation modeling results.

The microseismic response depicted in Figure 5.26 also agrees with the observations made by White (2015) illustrating that the western wells within the section appear to be more effectively stimulated relative to the eastern half of the section. This could also be caused due to the closer spacing within the Niobrara wells in the west relative to the east of the section (Figure 5.6).

Based on interpretation from White (2015) the P-wave seismic response from hydraulic fracturing is shown to be affected by the pressure pulse created from stimulating the reservoir. The P-wave response from hydraulic fracturing also shows the presence of pressure compartmentalization caused by fault barriers within the reservoir. The P-wave response from hydraulic fracturing also confirms the results from the 3D hydraulic fracture simulation.
demonstrating an effective stress barrier over the Niobrara Formation which allows for hydraulic fracture containment to occur. The differencing of PP-impedance volumes from in a cross-sectional view along well 1N shows that the Sharon Springs is acting as an effective upper stress barrier (increased impedance) allowing for better containment within the Niobrara from above, while the 4D seismic repose doesn't indicate any effective stress barrier present below the Niobrara and Codell target intervals (Figure 5.28).

Shear (SS) seismic interpretation impedance differencing between Monitor 1 and Baseline surveys over the entire Niobrara and Codell intervals is shown in Figure 5.29. The S-wave signature is insensitive to the pressure and fluid effects caused by hydraulic fracturing. The P-wave response is controlled by compressibility, rigidity and density. While the S-wave response
is only affected by rigidity and density. Seismic shear waves (S-wave) provide a relatively close estimate for the effective fracture lengths that result from hydraulic fracturing based on a successful match to the effective fracture lengths generated from the hydraulic fracture simulation results.

The variability in the S-wave seismic response is believed to show the variability in induced fracturing within the section with regards to the effective stimulated reservoir volume. This does not take into consideration the proppant distribution within the reservoir, but the shear seismic time-lapse response from differencing the monitor 1 to baseline impedance surveys indicates that the reservoir stimulated in the form of isolated pockets within the reservoir. There is a lot of room left unstimulated between the wells based on this shear seismic response that shows a more realistic SRV than that of the PP seismic interpretation (Mueller, 2016). Muller (2016) shows that only 40% of the Niobrara interval is effectively stimulated, while 60% of the Codell formation is stimulated.
A second time-lapse seismic interpretation was conducted on the PP seismic response from the Monitor 2 survey by Utley (2017) to assess the seismic response after 2 years of production. The observations made by Utley (2017) show the effects of production due to a drop in pressure below bubble point within the Niobrara and Codell reservoir intervals that allowed for gas to escape from the hydrocarbon solution (Figure 5.30). The gas effects are very noticeable on the PP production seismic response. The bright spots within the seismic section show the distribution of gas around the wellbore that also coincides with the production from this section (Figure 5.31).

![Figure 5.30 Initial results from production history matching by Ning (2017) using a homogeneous fracture geometry showing the increase in gas saturations around the closely spaced wells (RCP, 2017)](image)

The seismic signatures appear to capture much more heterogeneity than that of the production history matching. The production seismic response also indicates that the northern part of the section appears to be producing more than the southern part of the section. This could be attributed towards the different treatment styles that was treated at the toe of the wells relative to the rest of the lateral well section. The geological heterogeneity also plays a large part in controlling the production. As can be observed from Figure 5.31, the P-impedance response shows how the reservoir production is coming out of different pockets within the reservoir. These productive pockets within the reservoir coincide with the effectively stimulated stages within the
section. Based on the integration, the reservoir appears to be producing out of the effectively stimulated stages where the highest amount of conductivity has been established. The effective fracture length that was generated by the simulation also coincides with the P-impedance bright spots from the 4D seismic production effect. This also confirms that the wells spaced as 600ft from one another appear to be interacting with one another (wells are in pressure communication), while the wells with larger well spacing are not effectively drained. These wells might be suitable for refracturing or down-spacing through infill drilling.

As observed by the simulation results in Figure 5.18 & Figure 5.19, the effective fracture half-length within the Niobrara is estimated at a range of 100-300ft. This basically means that the Niobrara is effectively drained within the section using a 600ft well spacing. This is also apparent from 4D P-impedance production response in Figure 5.31. The wells to the east of the section are widely spaced within he Niobrara, and might require infill drilling or refracturing to increase the effective drainage area around those wells. While the wells on the western part of the section appear to be effectively stimulated and possibly in pressure communication as observed in Figure 5.32.

Production rates from these wells are variable as a result of the differences in effective stimulation treatment (Figure 1.5). The disparity in production performance shows that the closer spaced wells, and larger treatments appear to be performing better than the rest of the wells in the section because of increased natural fracture density as portrayed by the shear wave seismic data. Even though there is no production logging data to indicate the performance of stages within a given lateral well section, the 4D seismic results integrated with the effective fracture conductivity maps in Figure 5.32 show that the more conductive stages are producing better relative to the rest of the fracture stages. Establishing higher conductivity and fracture height through the use of crosslink fluid and higher proppant concentrations appears to be more favorable for better production performance.
The effect of several faults within the study area can also be observed from the 4D seismic and microseismic integration. The east-west faults appear to influence the microseismic events to occur along the direction of the graben (Figure 5.24) which also coincides with the direction of
maximum stress (Figure 3.16). These faults could potentially work as planes of weakness that influence the fracture geometry to grow along its direction. Simulation results around the faults zones show that the Niobrara hydraulic fracture treatment are more likely to grow in height and connect with the Codell around these fault zones.

This hydraulic connection between the Niobrara and Codell is also observed by the water tracer study conducted by Dang (2016). This vertical communication between the Niobrara and Codell could be short lived, it is important to realize that the hydraulic communication might be established while the hydraulic fracturing is being conducted, but as soon as the treatment stage concludes, the formation stresses will seek equilibrium and tend to partially close right after the job is complete. With time, these conductivity path-ways between the Niobrara and Codell can close and potentially reduce or pinch off the vertical communication between the reservoirs.

5.10 Discussion

This study shows that geostatistical methods applied to 3D geomechanical model-building, in areas with relatively good well control, can produce more reasonable simulation results than 1D geomechanical model distributions. Such 3D representations of the subsurface are very valuable for optimizing hydraulic fracture designs in horizontal wells, especially within areas with highly heterogeneous and faulted reservoir interval. Building 3D geomechanical models using geostatistical methods as an input to hydraulic fracture simulation models allow for a better representation of vertical and lateral heterogeneity within the reservoir. Incorporating this level of heterogeneity within stimulation models allows for a more realistic response to be generated within the simulator.

Hydraulic fracture simulations using the 3D geomechanical model shows that the fracturing is more confined to the chalk interval between the marls (Alfataierge et al., 2018). The marls provide weak stress barriers that prevent from the Niobrara C chalk fracture treatment to grow
into the Niobrara B chalk with the use of slickwater. The use of crosslink fluid to establish better fracture height, and larger fracture conductivity is recommended for future fracturing and refracturing. This would allow for a connection between the Niobrara B and C chalks to be better established rather than confining the hydraulic fracture to one of those intervals and bypassing the other.

Some of the observed factors contributing to variation in production within the Wishbone section as a result of well placement, geological heterogeneity, and fracturing efficiency:

- Geologic heterogeneity and well purposing in and out of target interval, leading to the stimulation and treatment of marl sections within the Niobrara Formation that will not perform as well as the chalk intervals.
- Lateral variability in reservoir quality. The hydraulic fracture stimulation of marl vs chalk treatments will respond differently, and also produce differently over time.
- Establishing good connection between wellbore and proppant. Stage intervals that were hydraulically fractured in the marly sections are more likely to exhibit isolated conductivity and proppant pinch-off from the wellbore.
- Overall treatment size and consequential effective fracture conductivity. These higher conductivity stages appear to be performing better as portrayed by the PP production time-lapse results (Figure 5.32).

5.11 Conclusions

The simulation modeling results from hydraulic fracture stimulation appear to be consistent with observations made by seismic methods. The value of validating the 3D hydraulic fracture simulation model results with the dynamic 4D seismic and microseismic observations helps develop more confidence in the results while serving as a guide for further optimizing the development within the Niobrara in Wattenberg Field (Alfataierge et al., 2018). The output of these
3D simulation results can be used to optimize the development of the Niobrara Formation within Wattenberg Field by improving hydraulic fracturing efficiency, and increasing production performance as well as reserve recovery.

By integrating the dynamic 4D/9C PP and SS time-lapse observations and hydraulic fracture simulation modeling, the simulation modeling results can be used with much more confidence and reliability. The modeling results also provide a better understanding of the effects of geological heterogeneity on stimulation and production within the Niobrara. The integration between the microseismic and the simulation modeling results showed that there is a wide variability in hydraulic fracture length, effective fracture length, and geometry of induced fracture matrix relative to the variation in stress distribution within the reservoir.

The results from the modeling show that the hydraulic fracturing is more likely to propagate towards the intervals and areas within the reservoir that are lower stressed. This is also observed through the microseismic response that shows a push of events towards the unstimulated wells as the hydraulic fracturing was being conducted from east to west. The microseismic was able to show the effect of the stress shadow that pushes the events towards a westward direction. This preferential push towards the west of the section is due to the style of and sequence of hydraulic fracturing that took place within the Wishbone section.

Based on the results from the hydraulic fracture simulation, and the microseismic analysis, the stimulation within the Wishbone section appear to have long reach hydraulic fracture lengths. This is also observed through the water tracer analysis provided by Dang (2016) showing vertical and lateral communication pathways being established in the reservoir due to the stimulation. This can also be caused by the natural fractures within the area that were not modeled within the simulation. The natural fracture network within the Niobrara can extend the reach of vertical and
lateral communication pathways during hydraulic fracturing, and effectively increase the size of the stimulated reservoir area (SRV).

Analyzing the PP time-lapse response in comparison to the simulation modeling results from hydraulic fracturing appears to show that the seismic response is predominantly influenced by the pressure pulse caused from hydraulic fracturing. The PP time-lapse response from differencing Monitor 1 to Baseline provides more insight into the style of stimulation, rather than to the calculation of an SRV. The PP seismic response from the production time-lapse seismic (differencing Monitor 2 to Baseline surveys) was very useful for determining the conductivity cutoffs within the simulator to get an understanding for where production is coming out of the reservoir relative to the hydraulic fracture stimulation in the area. Based on this comparison, the reservoir appears to be productive around induced fractures with baseline conductivity values larger than 2md*ft (Alfataierge et al., 2018). This information can be transferred onto nearby sections that do not have time-lapse seismic coverage in-order to predict the effective fracture lengths, and to generate higher fracture conductivity values within the reservoir for better production and recovery to take place.

The SS seismic analysis is surprisingly successful at capturing the variability in effective fracture lengths within the reservoir based on a successful match with the simulated effective fracture lengths; But the SS seismic response cannot predict the amount of proppant or fracture conductivity that was established from the hydraulic fracture stimulations (Alfataierge et al., 2018). The shear seismic response is still very valuable for highlighting the inefficiencies in hydraulic fracture stimulation. The shear seismic response, along with the simulation results, both indicate that the reservoir was stimulated with great variability in effective fracture lengths and fracture face conductivity. Only through the simulation results are we able to observe and identify the effective fracture face conductivities that result from the hydraulic fracture stimulation (Alfataierge et al., 2018). The variability in effective fracture length, and in fracture face conductivity both play
a very important role in identifying the inefficiencies and under-stimulated intervals within the reservoir for further optimization to take place.

Based on the integration between the simulation results with the shear seismic observations and the PP time-lapse response from production, the reservoir does not appear to have been uniformly stimulated due to a number of influencing factors. The hydraulic fracturing appears to have only been successful at stimulating parts of the reservoir in the form of isolated pockets of conductivity. These stimulated pockets within the reservoir appear to be discontinuous, thus allowing for a great amount of reservoirs drainage area to remain inaccessible (Alfataierge et al., 2018).

From the results of the integration between the fracture baseline conductivity, and the seismic derived attributes from hydraulic fracturing and production within the area. The potential areas for enhanced recovery are observed within the southern half of the section, as well as the eastern parts of the section between wells 1N and 2N. Infill drilling between the eastern two wells is recommended, and potential refracturing of the 1N, 2N, 4N is also recommended to increase the conductivity around these wells, and restimulate parts of the reservoir that were ineffectively stimulated.

As an ongoing process of integration within the RCP consortium. The 3D hydraulic fracture simulation output from this study is in the process of being integrated into a fully coupled simulation and production model using CMG to map out the effective drainage area within the section. This integration is being carried forward by Ning (2017), who will be able to further characterize the reservoir within the Wishbone section and provide better insight into the reservoir drainage area through production history matching.
CHAPTER 6
INCREASING RESERVE RECOVERY THROUGH INFILL DRILLING AND REFRACTURING

6.1 Summary

Based on observations made in Chapter 5, recommendations for infill drilling and refracturing are suggested to increase the effective drainage area within the section to improve recovery from the Niobrara. By utilizing the information provided by the hydraulic fracture simulation from the initial job treatments, predictions are made for future jobs in the section. Chapter 6 discusses the effect production and pressure depletion on any potential refracturing or infill drilling within the study area. Forward modeling of hydraulic fracturing effects is taken into consideration to observe the effect of the pore pressure drop and stress changes on refracturing and infill drilling. Interwell communications and possible hydraulic bashing is discussed.

6.2 Introduction

Hydraulic refracturing has become a common process that has been developing recently as a method for increasing reserves and production from low producing wells. Through refracturing, bypassed pay intervals can be restimulated in a more effective manner to help increase the effective SRV surrounding the treatment well yielding better production. Not only does refracturing allow for the restimulation of undrained and previously unstimulated intervals within the reservoir, the process or refracturing can also help restore conductivity loss due to production around the previously stimulated intervals (Figure 5.14).

Based on the 4D seismic integration in Chapter 5 with the hydraulic fracture simulation results, it was observed that the Wishbone section was not uniformly stimulated. Several pockets within the reservoir intervals were deemed to have been ineffectively or inefficiently stimulated.
The production time-lapse seismic showed how the reservoir was producing from isolated pockets within the reservoir, and showed that there was still room for improvement to be made to access the unstimulated intervals within the Niobrara and Codell reservoirs. Recommendations to infill drill between wells 1N and 2N was suggested in Chapter 5. The refracturing of wells 1N, 2N and 4N was also suggested to effectively increase the effective drainage area around those wells.

Refracturing is a very useful method for enhancing the life span of the shale wells in areas where production is declining from previously producing wells. The method of selecting candidate wells for refracturing is described in detail by authors such as (Barree et al., 2017; Vincent, 2010a, 2010b). The selection of wells for refracturing is not an easy step to take, but with the use of simulation model coupled with seismic observations, one can observe areas around lateral producing wells that can be candidates for refracturing or enhanced recovery operations.

Within the Niobrara, vertical wells have been shown to benefit from refracturing. Figure 6.1 shows a vertical well example that was refractured several years after the initial stimulation took place. The production increase due to refracturing appears to have brought new life to the previously low producing well. The successful refracturing of such wells is expected to increase the life span of several shale wells targeting the Niobrara Formation, while increasing reserve recovery from Wattenberg Field.

The most likely causes for refracturing to work can be traced back to the following mechanism: enlarging the fracture geometry, increased induced fracture conductivity compared to initial fracture treatment, restoration of fracture conductivity within the hydraulic fracture face, increase conductivity around inefficient stages from earlier fracture treatment, and the reorientation of local stress field around the wellbores allowing for the hydraulic fracturing to break into “new” rock (Vincent, 2010a, 2010b). These mechanisms primarily focus on enhancing the
connection between the proppant and the wellbore, and extending the connection between the formation and the wellbore.

![Figure 6.1 Refracturing example from vertical well in the Denver Basin (RCP, 2016)](image)

In vertical wells, refracturing has been observed to rotate by 90 degrees from the initial hydraulic fracture orientation (Siebrits et al., 2000). This was also observed by Bratton in a simple model study (RCP, 2016). This reorientation allows for new rock to be stimulated. The effect of stress reorientation due to the 2 years of production as described by Bratton within this study area is also an important factor to consider that would allow for refracturing to break into “new rock”.

Fracture reorientation due to refracturing was observed using tilt-meters by (Siebrits et al., 2000) in the Barnett Shale. Siebrits (2000) shows that refracturing can change the overall geometry from the initial fracture treatment (Figure 6.2), causing the second fracture treatment to break into previously unstimulated parts of the reservoir, and extend further out that the initial fracture treatment into the reservoir. According to Vincent (2010), the stress reorientation around these wellbores can allow for the hydraulic fracturing to break into previously unstimulated parts of the reservoir to enhance to the wellbore communication with the formation and increase the effective drainage area around the well.
6.3 Frac hits and hydraulic bashing

Frac hits are an expensive problem that could lead to significant downtime to prepare for remediation efforts after the fact, and potential loss of productivity in offset producing wells (Jacobs, 2017). Frac hits are defined as the lateral pressure communication between wells due to the hydraulic fracturing. Frac hits can be very destructive should they be strong enough to cause damage to production tubing, casing, and well heads in wells offsetting the treatment well. Due to the ongoing infill drilling and down-spacing between shale wells to further drain the tight reservoirs, frac hits have been observed more often in current shale operations.

Tight well spacing also make the interference between the wells even more obvious, and in some cases more destructive. In some cases, these frac hits can be observed as small pressure pulses in offset wells, these cases can be small enough to go unnoticed and could cause short lived pressure communication between the wells. Production from offset wells can also temporarily fall off before returning back to normal in the offset producers, also termed “parent wells” (Jacobs, 2017).
In other cases, these events can be strong enough to cause serious damage to the offset parent wells. Hydraulic-bashing refers to the case where the offset parent wells take on fluid and proppant from the treatment well thus plugging off production from the parent well (Jacobs, 2017). Hydraulic bashing could also increase water production and the migration of fines and solids into the offsetting wellbores (Bommer, Bayne, Mayerhofer, Machovoe, & Staron, 2017). This would require the parent wells be cleaned out in order to bring them back on production.

Based on the microseismic interpretation in Chapter 5, some frac hits can be observed to have been affected by depletion zones surrounding vertical wells around the Wishbone section. Figure 6.3 shows the how the hydraulic fracturing within the Wishbone section was affected by the depletion zones surround the vertical producing wells around the section. The depleted areas appear to have a strong influence on hydraulic fracture propagation and geometry even at a distance of over 1000ft away from a treatment well.

The process of protecting parent wells from frac hits is a widely expanding and developing process. Prevention techniques are still being assessed and analyzed, but recent examples in the Bakken from Bommer et al. (2017) show how this can be achieved through defending parent wells around infill wells. The process of protecting the offset producers from frac hits and hydraulic bashing was conducted by pumping into the offset producing wells as the hydraulic fracturing is being conducted. Determining the number of wells required to be protected from frac hits is based on experience in the area. For the Bakken example provided by Bommer et al. (2017), wells within 2000ft from the treatment well were protected by injecting treated freshwater into the producing wells, before the hydraulic fracturing took place, with diverters to temporarily seal off entry points along the producing wells. This was followed by continuously pumping into the producing wells (maintaining positive pressure) while the treatment well was being hydraulically fractured (Bommer et al., 2017).
Figure 6.3 Frac hits controlled by depleted zones around producing vertical wells surrounding from the initial hydraulic fracture treatment within the Wishbone section

Other examples of reducing the negative effect caused by hydraulic bashing into producing wells is to refrac the offset producers that might be impacted by the infill well being treated. This expensive solution is currently being marketed by service companies as a process of reducing the impact caused by frac hits (Jacobs, 2017). More practical solutions have been discussed, but not yet tested, by Barree and Jacobs (2017): Barree suggests focusing on improving the stimulation efficiency around the treatment wells rather than pumping large and far reach fractures into infill wells. This would allow for better conductivity to be established around the treatment wells, and reduce the effect of hydraulic bashing into offset wells in the area.

6.4 Effect of pressure depletion on hydraulic fracturing

Reservoir depletion will have a significant effect on the redistribution of stress within the reservoir. Due to the pore pressure dependence in calculating the reservoir stress conditions, these changes in pore pressure will also change the surrounding closure pressure of the reservoir (Mukherjee, Poe, Heidt, Watson, & Barree, 2000).

Being that the Wishbone section has been producing for 3 years out of the Niobrara since the initial hydraulic fracturing, the drop in pore pressure and change in stress conditions must be
taken into account for refracturing or infill drilling in the area. The cause by a 3000psi drop in pore pressure (Figure 6.4) could potentially influence any new hydraulic fracturing in the area. Based on the surface microseismic results from the initial hydraulic fracturing in the area, we are able to observe some interference effects due to hydraulic fracturing into low pressure depletion zones surrounding offset vertical wells in the section (Figure 6.3).

These “frac hits” were observed at the well location while the initial hydraulic fracturing took place, as well as on the microseismic (Figure 6.3). This effect is believed to possibly be stronger around the lateral wells in the Wishbone section given the 3000psi pressure drop in the Niobrara and Codell reservoirs. Infill drilling and/or refracturing must consider this pressure depletion effect to account for the well interference. Any potential refracturing or infill drilling and stimulation will be affected by the surrounding pressure depleted pockets within the reservoir (Figure 6.5). As per Terzaghi’s effective stress relationship depicted in equation (3.15), refracturing into pressure depleted intervals will result in better contained stimulation treatment to take place due to the stress confinement caused by the drop in pore pressure that results in an increase in effective...
stress within the reservoir interval. This confining effect will also allow for refracturing to have longer fracture lengths than the initial treatment (Figure 6.6) (Stegent, 2011).

Figure 6.5 Simple model: Infill drilling scenario (a, b, c), Refracturing scenario (d, e, f)
Using the 3D simulation model, the pressure depletion around the wells was considered to consider the effect of refracturing or infill drilling into a producing section. The pressures were dropped by 1500psi 60ft away from the wellbore, and a 300psi drop in pressure was assumed from 300ft half-length from the wellbore (Figure 6.7). The effect of infill drilling and stimulated a well between wells 1N and 2N is also taken into consideration (Figure 6.8).
The optimum well spacing is observed to be 600ft based on the simulation results in chapter 5, 4D production time-lapse response, and the production rate transient analysis documented and analyzed by Dang (2016). The wells to the east of the Wishbone section that were drilled at a larger well spacing are not effectively stimulated and can make use of infill drilling or down-spacing. Drilling a well in between 1N and 2N would be optimum for reservoir development within the Wishbone section. The interwell interference must be understood and carefully addressed in order to avoid any negative interference between the stimulated well and producing offset well.

Figure 6.5 shows an example of an infill well that was hydraulically fractured in the Niobrara-B chalk interval with crosslink fluid and slickwater. The simple forward model in Figure 6.5 shows that the infill well will strongly be affected by the 1500psi drop in pore pressure around the producing offset wells in the section. This effect must be taken into consideration if infill drilling between these producing wells is to take place. The effect caused by such an interference between the infill and production wells could be destructive and possible lead to a write-off of reserves. This effect is termed “hydraulic bashing”.

Hydraulic bashing into offset producing wells is a commonly observed problem in hydraulic fracturing as observed by Jacobs (2017). The effects of such a large drop in reservoir pore pressure within the Wishbone section might be even more severe on such infill drilling. Figure 6.7 is used to draw in an effective drainage area around the wells with a 1500psi drop 60ft away from the producing wellbores, and a 300psi drop in pore pressure effect 300ft away from the producing wells. Using the modified 3D geomechanical model, this drop-in pore pressure is taken into consideration to observe the effect and change in stress around these depleted pockets within the reservoir intervals.

The forward modeling due to hydraulic fracturing of an infill well between 1N and 2N is depicted in Figure 6.8. Although the simulation shows that these pressure-depleted intervals do
influence the geometry of the hydraulic fracturing the infill well, the effective fracture length and fracture conductivities observed in Figure 6.9 still appears to remain around the treatment well. Hydraulic bashing into the offset producing wells is a serious matter to be concerned when treating an infill well. Even though the infill well is effectively stimulated, the offset wells might be negatively affected by the hydraulic bashing effect and could possibly have a challenging time cleaning up and going back on production.

Figure 6.8 Hydraulic fracturing an infill well between 1N & 2N. (a) showing early fracturing time, (b) showing end of fracturing time

Figure 6.9 Infill drill well fracture conductivity

The effect of refracturing wells 1N, 2N and 6N is shown in Figure 6.10. Refracturing into these produced and pressure-depleted intervals appears to allow for a better conductivity to be established around the wellbore as a result of the increase in confinement that results from the
pore pressure drop and increase in effective stress within the reservoir. This allows for the refracturing to become more effective at establishing better conductivity and potentially breaking into previously unstimulated rock intervals that were affected by the pore pressure depletion.

![Figure 6.10 Refracturing wells 2N (left) and 6N (right) showing interference with pressure depleted zones around the producing lateral wells in the Wishbone section](image)

Even though the fracturing appears to be better contained around the wellbore due to refracturing, the hydraulic fracturing fluid still appears to be affected by the nearby pressure depleted pockets. This issue should be taken into account to avoid hydraulic bashing into an offset producing well that could possibly lead to a right-off of reserves or expensive well clean-up operations (Jacobs, 2017). Several service companies recommend refracturing all the nearby parent wells to avoid this destructive interaction caused by hydraulic bashing into offset producers. While other practitioners of refracturing recommend refracturing with higher proppant concentrations and more viscous fluids (crosslink fluid) to focus on increasing the overall effectiveness of the fracturing around the wellbore and to avoid destructively interacting with the offset producers (Jacobs, 2017).
6.5 Discussion

Candidate selection for refracturing is discussed in detail by Barree et al. (2017). The process of refracturing can be very beneficial if the new treatment can effectively break into new rock that was previously unstimulated or undrained. Determining the need for refracturing requires wellbore diagnostic tools and production analysis (rate-transient) to be used to identify candidate wells for restimulation. Conducting this analysis on some of the wells within the Wishbone section provides insight into the effective drainage area from the well 4N (Figure 6.11).

Based on the type curve analysis in Figure 6.11, the effective fracture length, drainage area, aspect ratio is depicted in a relative scale to the drilled well length. The analysis clearly shows that there is still room for improvement to be made. This is also consistent among all the wells in the section, and is also validated by the 4D seismic and 3D simulation modeling results and observations. The wells in the Wishbone section appear to be clear candidates for refracturing as a method for increasing the effective drainage area around the producing wells.

Although refracturing is recommended for the current wells in the Wishbone section, current technology does not allow for refracturing to efficiently occur along horizontal wells in an effective manner. Diverters are used to divert for over 32 stages, which is not entirely effective. The key to successful refracturing is the ability to re-isolate the stages for re-stimulation to take place. Future technological advances are important for addressing this re-isolation issue before refracturing becomes efficiently performed on horizontal multistage lateral wells.
6.6 Conclusions

In order to access the bypassed pay remaining within the Niobrara shale, infill drilling and refracturing is recommended within the study area. As a method for increasing recovery from the Niobrara Shale reservoir the recommendation to refrac all the Niobrara wells and down space the wells that are spaced at larger spacing than 600ft. Refracturing the entire section would minimize the destructive interference between the wells caused by hydraulic bashing or frac hits.

Refracturing within the Wishbone section would ultimately enlarge the fracture geometry, increase induced fracture conductivity compared to initial fracture treatment, restore fracture conductivity within the hydraulic fracture face, increase conductivity around inefficient stages from earlier fracture treatment, and take advantage of any local stress reorientation around the producing wells allowing for the hydraulic fracturing to break into “new” rock.
Refracturing and infill drilling efforts should make use of a 3D simulation model to help design the treatment of the wells based on their relative location to the geology. Low pressures surrounding the current producing wells offset should be protected from any hydraulic fracturing fluid interaction. Hydraulic refracturing should primarily focus on establishing better near wellbore conductivity around the current wells, and reducing the impact of hydraulic bashing into offset producing wells. With advances in multistage refracturing, the isolation of new stages and refracturing into isolated and previously unstimulated reservoir intervals is also recommended. This would allow for new rock to be stimulated by introducing a much more complex fracture network into the reservoir.

The use of crosslink fluid to establish higher fracture height, along larger effective fracture conductivity values is recommended for refracturing. This would allow for a connection between the Niobrara-B chalk and Niobrara-C chalk to be better established rather than confining the fracture to one of those intervals, and bypassing the other. The use of crosslink fluid with high proppant concentrations would also allow for the fracturing to take place closer to the wellbore, without interfering (bashing) with the offset producers.
CHAPTER 7
CONCLUSIONS & RECOMMENDATIONS

7.1 Conclusions

Hydraulic fracturing is complex and variable. Utilizing multiple diagnostic technologies is key to the success of hydraulic fracturing. Fracture modeling is not sufficient as a stand-alone method for hydraulic fracture characterization (Cipolla, 2005). Fracture models are essential tools, but they have limitations. Validating these models through seismic observations can increase the reliability and accuracy from these predictive modeling results. The value of dynamic 4D/9C PP and SS seismic interpretation is demonstrated in this project as a method for validating hydraulic fracture simulations. Understanding the effect of geological heterogeneity on the complexity of hydraulic fracturing can lead to better wells. Such an understanding allows for better stimulation design, fluid selection, well placement, stage selection and stage spacing.

The integrated analysis shows that the Niobrara reservoir is not uniformly stimulated. The vertical and lateral variability in rock properties control hydraulic fracturing efficiency and geometry (Alfataierge et al., 2018). Better production is correlated to higher fracture conductivity. Dynamic seismic methods essential for validation and calibration hydraulic fracture simulation models. The hydraulic fracture modeling also shows that the Niobrara B chalk has bypassed pay. The initial stimulations treatments in the Niobrara C chalk intervals were not effective in communicating the Niobrara B and C chalks together. Alternating drilling and stimulation into these separate chalk intervals would be more efficient for stimulating and draining the entire Niobrara reservoir (Alfataierge et al., 2018). Forward modeling of stimulated infill drilled wells is shown to be influenced by low pressure intervals surrounding production wells in the Niobrara.
Based on the simulation modeling results from using the 3D geomechanical model as an input to hydraulic fracture simulation and characterization, hydraulic fracturing efficiency appears to be controlled by the distribution of stress within the reservoir, and fault planes of weakness. The hydraulic fracturing fluid preferentially moves towards the lower stress intervals, and will tend to channel along the fault planes. This movement towards the lower stressed and easier to break intervals within the formation has a significant effect on the overall hydraulic fracture geometry, fracturing efficiency and proppant distribution within the induced fracture network. The use of 3D simulation models for hydraulic fracture stimulation design and planning can help control the size and geometry of the hydraulic fracture by understanding the 3D distribution of stress within the reservoir as influenced by the geological heterogeneity in the reservoir. By understanding the effect of geological heterogeneity on the elastic rock properties and stress distribution within the reservoir, plans can be made for optimizing treatment design for better containment, establishing better fracture conductivities around the wellbore, and selectively planning stage treatments based on well landing position. This optimization process would allow for stimulation treatments to improve recovery.

The integration between the 3D simulation result and dynamic seismic interpretations both reveal that the variation in reservoir properties (faults, rock strength parameters, and in-situ stress conditions) influence and control the hydraulic fracturing geometry and stimulation efficiency. The observed microseismic data is indicative of hydraulic fracture lengths up to 1000 ft (300m) and initial interwell communication during the pressure-up phase was confirmed using tracer analysis (Dang, 2016). The P-wave seismic response from hydraulic fracturing is shown to be affected by the pressure pulse created from stimulating the reservoir. The P-wave response from hydraulic fracturing also shows the presence of pressure compartmentalization caused by fault barriers within the reservoir (White, 2015). The P-wave response from hydraulic fracturing also confirms the results from the 3D hydraulic fracture simulation demonstrating an effective stress barrier over
the Niobrara Formation which allows for hydraulic fracture containment to occur (Alfataierge et al., 2018). Seismic shear waves (S-wave) provide a relatively close estimate for the effective fracture lengths that result from hydraulic fracturing based on a successful match to the simulation results. The effective fracture length is defined as the propped fracture length that provides communication with the wellbore during the production cycle. This effective fracture length is confirmed through the production time-lapse seismic using the P-wave data that is capable of identifying production from the Niobrara out of isolated pockets within the reservoir (Alfataierge et al., 2018). This production effect is only observed on the PP seismic once the reservoir pressures drop below bubble point and gas starts coming out of solution within the more extensive natural fracture systems (Utley, 2017).

Through the integration between the 3D hydraulic fracture simulation model results with the dynamic 4D seismic and microseismic observations, more confidence is placed on results from the modeling as a guide for further optimizing the development of the Niobrara Formation within Wattenberg Field (Alfataierge et al., 2018). Seismic methods are shown to be capable of capturing the effect of geological heterogeneity on hydraulic fracture completion efficiency. This integrated analysis in reservoir characterization provides valuable insight into optimizing well spacing, increasing recovery and improving production performance in the Niobrara as well as highlighting areas with bypassed potential within the reservoir. Subsequent to any mechanical issues that affect production from lateral wells, the variability in production performance and reserve recovery along multistage lateral shale wells is controlled by the reservoir heterogeneity and its consequent effect on hydraulic fracture stimulation efficiency (Alfataierge et al., 2018). Production performance observed from the horizontal multi-stage hydraulically fractured wells within the study area is attributed, but not limited, to the following observations:

- Geologic heterogeneity and well purposing in and out of target interval
- Lateral variability in reservoir quality (chalk vs. marl stimulated intervals)
• Poor initial completion efficiency: inefficient connection between proppant pack and wellbore, also termed as “isolated conductivity” (Figure 5.10)

7.2 Recommendations

Infill drilling and refracturing the Niobrara Formation is recommended to increase reserve recovery from such tight shale reservoir intervals. The initial hydraulic fracture stimulation in the Niobrara was only capable of stimulating some isolated pockets within the reservoir. Refracturing the Niobrara Formation after several years of production and pressure depletion would allow for a more complex and contained fracture geometry to be generated, break into previously unstimulated and undrained sections within the reservoir, and replace near-well conductivity losses that resulted from several years of stress cycling and production. The process of hydraulic fracturing and refracturing around producing wells should be analyzed properly with caution not to damage or bash into pressure depleted intervals surrounding the offset producing wells. Remediating the wells after damage has been incurred due to hydraulic bashing could be an expensive and time-consuming problem.

Hydraulically fracturing the Niobrara reservoir intervals (chalks) by alternating between the different chalk intervals is also highly recommended to insure breaking into both the Niobrara B chalk and the Niobrara C chalk. This would be more efficient than stimulating the Niobrara-C the chalk interval with hope of breaking into the overlying Niobrara B chalk. Simulation results in Figure 5.5 show that the marls could act as stress barriers within the formation resulting in bypassed pay to occur in the Niobrara B chalk when targeting the Niobrara C. Landing the wells in the Fort Hays formation overlying the Codell is also preferred to allow for more efficient proppant distributions to be generated around the well and for better containment to occur as a result of the fracture stimulation (Figure 3.6).
Based on the simulation results from the initial hydraulic fracture treatment, it has been observed that establishing effective fracture conductivity around the wellbore is more important than stimulating a large part of the reservoir. Future hydraulic fracturing and refracturing should focus on establishing a proper connection between the wellbore and the proppant pack to avoid wasting energy on over stimulating the reservoir and eventually pinching off the proppant from the wellbore (isolated conductivity). Selective stage spacing in lower stress and higher reservoir quality intervals is preferred when designing for hydraulic fracture stimulation treatments in horizontal multi-stage wells. The use of a 3D geomechanical models as an input to hydraulic fracture simulation can help with designing better treatments that focus on generating a good connection between the stimulated reservoir volume, the proppant pack, and the wellbore. Without this established connection, inefficient stages will not produce up to their expected potential, leading to an inefficient well performance and incomplete drainage areas.

7.3 Recommendations for future work

- No core data was used to calibrate the geomechanical properties (static measurements are calculated from empirical relationships). If dynamic to static core measurements are made available for the Niobrara, such relationships should be used to generate a better estimate for static elastic moduli. Horizontal core is recommended to obtain mechanical rock strength measurements from within the Niobrara and observe the level of reservoir heterogeneity in a lateral perspective on the mechanical rock properties.

- Natural fracture effects could potentially result in longer hydraulic fracture communication, and increase the effective drainage areas around the wells. The effect of natural fractures was not taken into considerations in the modeling. The natural fracture effects could be taken into consideration by using a DFN model integrated with a production simulation to assess how much effect the natural fractures can have on production and reserve recovery.
• Hydraulic fracture simulation results are based on a planar fracture solution that is oriented in the direction of principal, maximum, horizontal stress. Future advancements in the simulation software capabilities might allow for a more representative fracture network to be simulated to take into account the effect of natural fracture (DFN) influence on simulated fracture geometries.

• Bentonite beds can seal off hydraulic fracture communication pathways after being established. Bentonite beds will eventually seal and close communication pathways in the reservoir due to their ductile and swelling nature. Many bentonite layers are present in the Lower Niobrara intervals. No attempt at modeling the effects of bentonite were taken into consideration in this analysis. Addressing the bentonite upscaling within the modeling and observing its effect on the hydraulic fracturing through the simulation could be very beneficial.

• An isotropic solution was assumed for stress state calculation. Although the Niobrara in this study area is assessed to be weakly anisotropic, using an anisotropic stress state solution might yield different results in reservoir stress bounding conditions and hydraulic fracture geometry predictions within the 3D numerical simulator.

• The sequential Gaussian simulation results for 3D geomechanical modeling are non-unique. Several iterations were generated, and a best fitting geological model was selected for this study. The use of seismic guided co-kriging algorithms could have helped constrain the model predictions to observations made from seismic inversion for geomechanical property prediction.

• DFIT analysis providing pressure calibrations and permeability values from offset wells are used to calibrate and predict reservoir pressure and stress related properties. Any changes to the DFIT information within the study area from the offset wells will strongly have an effect on the simulation results.

• Baseline conductivity represents the post-pumping case for effective fracture conductivity. This conductivity is expected to drop with production and could possibly pinch-off after several years. Recommendations for refracturing are suggested here when conductivity diminishes.
around these wells. Modeling of this conductivity loss given the reservoir confining pressures is recommended to get a sense for when refracturing might be recommended.

- The decision to infill drill between the wells or refracture the wells will require further economic analysis before being conducted. Choosing the right time to conduct such developmental practices requires thorough economic analysis and assessment for potential return on investment. The price of oil and gas relative to the operational costs of infill drilling and refracturing must be assessed before these recommendations can be brought forward.

- Refracturing in horizontal multistage wells is a relatively new and challenging process. The process of re-isolating the stages that are suggested for refracturing needs to be mechanically established before recommendations for refracturing can be pushed forward and conducted on horizontal wells.

- Integrate the effective fracture conductivity results from hydraulic fracture simulation into CMG for dynamic conductivity loss over time, and to map the effective drainage area using a fully coupled production simulation model. Such an analysis will highlight areas that are less productive for infill drilling or refracturing in a 3-dimensional perspective.

- Utilize the seismic generated elastic moduli as a co-kriging trend volume for the geostatistical distribution of Young’s modulus and Poisson ratio using sequential Gaussian simulation. Such a seismic driven geomechanical model has been generated by (Grazulis, 2016), and can help guide the sequential Gaussian simulation to a solution that mimics trends observed from seismic inversion results.

- Utilize 4D SS time-lapse seismic response to observe the unstimulated intervals in the Niobrara B chalk that were bypassed by the drilling and targeting of the Niobrara-C chalk interval.

- Interpret the 4D SS time-lapse seismic response to observe the effect of fractures opening and closing within the reservoir due to hydraulic fracturing and production.
- Interpret the 4D SS time-lapse seismic response to observe the effect of local stress rotations around the wells as a result of the hydraulic fracturing and production.

- Acquire production logs (PLT) and distributed acoustic sensing (DAS) in future wells along wellbore length as a method for monitoring hydraulic fracture inefficiencies locally surrounding the wellbore while production is ongoing. This can help narrow down the potential intervals along the wells that are candidates for re-isolation and re-fracturing.

- Utilize 3D geomechanical model for hydraulic fracture stimulation design for better stage selection and more optimum fracture placement. This would allow for better predicting the efficiency of each fracture stage relative to the intersecting heterogeneities within the reservoir.
REFERENCES


