VELOCITY, ATTENUATION, AND MICROSEISMIC
UNCERTAINTY ANALYSIS OF THE NIOPRARA
AND MONTNEY RESERVOIRS

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

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ABSTRACT

Time-lapse reservoir characterization with surface seismic provides greater spatial information about reservoir physical properties, and delineates reservoir scale changes. Identification of reservoir deformation due to hydraulic fracturing and production improve reservoir models by mapping non-stimulated and non-producing zones. Monitoring these time-variant changes improves the prediction capability of reservoir models, which in turn should lead to improved well and stage placement.

In Wattenberg Field, the Reservoir Characterization Project (RCP) at the Colorado School of Mines (CSM) and Anadarko Petroleum Corporation (APC) collected time-lapse, multicomponent seismic data in order to characterize the reservoir fracture changes caused by hydraulic fracturing and production in the Niobrara Formation and Codell Sandstone member of the Carlile Formation. Three seismic surveys help understand the dynamic reservoir changes caused by hydraulic fracturing and production of eleven horizontal wells within a one-square mile section (Wishbone Section). A baseline survey was recorded immediately after the wells were drilled, another survey after stimulation, and a third survey after two years of production. A robust layer stripping method is used to quantify 4D velocity and attenuation from pre-stack seismic data. Processing of the data before attenuation analysis includes noise reduction, regularization of amplitudes, and statics. Data show that time-lapse, pre-stack velocity and attenuation estimates are sensitive to hydraulic stimulation and production.

Time-lapse velocity and attenuation results are integrated with image logs, surface microseismic, tracer data, and production information to analyze how faults, joint sets, and well spacing, affect stimulation, early term production, and late term production of the eleven horizontal wells in the Wishbone Section. Data demonstrate that faults in the reservoir limit lateral stimulation and allow hydraulic fracture fluids to move to other reservoir facies ver-
tically within the Wishbone Section. Attenuation and velocity changes are observed in the western portion of the survey. Higher producing wells are also located in the western portion of the study area.

Borehole microseismic is a common tool used to evaluate hydraulic stimulation. A challenge in microseismic monitoring is quantification of survey acquisition and processing error, and how these errors jointly affect estimated locations. Quantifying error and uncertainty has multiple benefits, such as more accurate and precise estimation of locations, anisotropy, moment tensor inversion, and, potentially, allowing for detection of 4D reservoir changes.

Processing steps are applied to a downhole microseismic dataset from Pouce Coupe, Alberta, Canada. A probabilistic location approach is implemented to identify the optimal bottom well location based upon known source locations. Probability density functions (PDF) are utilized to quantify uncertainty and propagate it through processing, including in source location inversion to describe the 3D event location likelihood. Event locations are calculated and an amplitude stacking approach is used to reduce the error associated with first break picking and the minimization with modeled travel-times. Changes in the early processing steps have allowed for understanding of location uncertainty and improved the mapping of the microseismic events.

The overall research illustrates that reservoir heterogeneity significantly affects hydraulic stimulation and production. Integration of multi-disciplinary data is vital for reservoir characterization in shale reservoirs. Additionally, this work shows how the assessment of data uncertainty is necessary for future development of reservoir characterization tools in anisotropic reservoirs. The developed workflows provide new approaches for appraising shale reservoirs, and quantifying uncertainty associated with geophysical data.
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LIST OF SYMBOLS

Complex stiffness tensor $C_{ij}$

$Q$–factor matrix $Q_{ij}$

Maximum Horizontal Stress $\sigma_H$

Minimum Horizontal Stress $\sigma_h$

Vertical Stress $\sigma_V$

Pore pressure $P_P$

Fluid viscosity $\eta$

Fracture radius $a$

Grain size $\varsigma$

Permeability $\Gamma$

Average number of pores or fractures $c_2$

Normal stress applied on crack face $\sigma$

Fluid bulk modulus $\kappa_f$

Volume of individual fracture $f_v$

Fluid relaxation time $\tau$

Fracture aspect ratio $\alpha$

Eshelby compliance tensor $S^0$

Second rank identity tensor $I_2$

Forth rank identity tensor $I_4$

Applied stress to fluid pressure $\Psi^{(n)}$
Poisson’s ratio \(v\)

Shear modulus \(\mu\)

Frequency \(\omega\)

Source and receiver directivity \(G\)

P-wave normal moveout velocity \(V_{NMO}\)

Vertical attenuation coefficient \(A_{P0}\)

Thomsen velocity anisotropy parameters \(\epsilon, \delta, \text{ and } \gamma\)

Thomsen-style attenuation anisotropy parameters \(\epsilon_Q, \delta_Q, \text{ and } \gamma_Q\)
LIST OF ABBREVIATIONS

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<tr>
<td>APC</td>
<td>Anadarko Petroleum Corporation</td>
</tr>
<tr>
<td>RHOB</td>
<td>Bulk Density</td>
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<tr>
<td>CSM</td>
<td>Colorado School of Mines</td>
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<tr>
<td>4D</td>
<td>Four-Dimensional</td>
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<td>GR</td>
<td>Gamma Ray</td>
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<td>GOR</td>
<td>Gas Oil Ratio</td>
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<td>Horizontal Transverse Isotropy</td>
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<td>RCP</td>
<td>Reservoir Characterization Project</td>
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<td>Vertical Transverse Isotropy</td>
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<td>Colorado</td>
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Normal root mean square .............................. NRMS
Formation microimage ................................ FMI
Western Interior Seaway .............................. WIS
Foot ...................................................... ft
Northwest ............................................... NW
milisecond .............................................. ms
Neutron Porosity ...................................... NPHI
millisecond .............................................. ms
centipoise .............................................. cP
pound per square inch ............................... psi
boundary dominated flow ............................. BDF
power spectral density ............................... PSD
signal-to-noise ratio ................................ S/N
self-organizing feature map ........................ SOFM
Receiver operating characteristic curve ........ ROC
Probability density function ........................ PDF
signal noise ratio ..................................... S/N
Velocity independent layer stripping .............. VILS
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For my family
CHAPTER 1
INTRODUCTION

Improved mapping of shale reservoir heterogeneity can lead to better completion designs, more accurate reservoir models, and better understanding of how stimulation and production are influenced by reservoir heterogeneity. Mapping reservoir deformation with microseismic, and time-lapse seismic data can identify non-stimulated and non-producing zones.

The Reservoir Characterization Project (RCP) collaborated with Anadarko Petroleum Corporation (APC) and Talisman Energy Inc. (now Repsol), in order to perform multidisciplinary studies in the Wattenberg Field and Pouce Coupe Field, respectively. In Wattenberg Field, APC and the RCP collected time-lapse multicomponent (9C) seismic data in order to understand how the Niobrara Formation and Codell Sandstone member of the Carlile Formation respond to deformation caused by hydraulic fracturing and production. Three seismic surveys help understand the dynamic reservoir changes caused by hydraulic fracturing and production of eleven horizontal wells within a one-square mile section. A baseline survey was recorded immediately after the wells were drilled, another survey after stimulation, and a third survey after two years of production.

In Pouce Coupe Field, a downhole microseismic array was deployed during the stimulation of three horizontal wells. Two of the wells target the Montney C, and one well targets the Montney D. The main objective of both studies is to quantify how geology and completion parameters influence hydraulic fracturing and production.

1.1 Motivation

Horizontal well development in shale reservoirs has drastically increased over the past ten years. Identification of geologic and completion factors that affect the economic success of an unconventional well is vital in a low oil price environment, and remains an important problem.
Hydraulic stimulation is the process of injecting proppant and hydraulic fracture fluid into a reservoir in order to increase reservoir permeability. Tracer, completion, production, and microseismic are typical data collected to evaluate a stimulated reservoir volume and well connectivity. However, geologic variances are difficult to explain all production variation with these data alone. Time-lapse seismic is a powerful tool that can improve the understanding of spatial variability between stages and wells. Assessment of proppant and hydraulic fracture fluid after stimulation, and identification of producing zones can provide valuable information that can improve reservoir models and completion designs.

Application of time-lapse seismic velocity and attenuation analysis can provide improved understanding of fractures, permeability, and fluid viscosity (Behura et al., 2012; Blanchard & Delommot, 2015; Dinh et al., 2015; Puasa et al., 2014; Reine et al., 2012a). In conventional reservoirs time-lapse attenuation has shown 4D changes that correlate to the oil/water contact (Blanchard & Delommot, 2015). Gas break out in reservoirs has also been identified with time-lapse attenuation (Dinh et al., 2015; Puasa et al., 2014). Furthermore, various studies have shown that joint quantification of velocity and attenuation anisotropy provides more information about the distribution of fractures, and fluid content. Maultzsch et al. (2007) argue that azimuthal attenuation anisotropy correlates with open fluid-filled fractures.

Shale reservoirs are also monitored with borehole microseismic. Microseismic events are commonly utilized to assess the induced and productive fracture sets (Blias & Grechka, 2013; Coffin et al., 2012; Grechka & Heigl, 2017; Jechumtálová et al., 2016; Su et al., 2018). Understanding error associated with survey limitations and processing steps is needed in order to avoid over-interpretation or misinterpretation of results (Bulant et al., 2007). Moreover, accounting for error due to acquisition and processing can improve assessment of reservoir anisotropy, and potentially identify time-lapse changes due to hydraulic stimulation. Overall, this research examines the applicability of joint time-lapse velocity and attenuation analysis in a shale reservoir, and examines the error associated with acquisition and processing of downhole microseismic.
1.2 Objectives

The purpose of this work is to evaluate the applicability of joint time-lapse velocity and attenuation anisotropy in the Niobrara reservoir, CO., and to quantify how acquisition and processing errors affect locatable microseismic events within the Montney Formation, Alberta, Canada. In order to accomplish these research goals, the following objectives have been set:

1. Perform rock physics modeling in order to understand what reservoir properties will affect the time-lapse attenuation signature in a shale reservoir
2. Implement velocity independent layer-stripping for velocity and attenuation dynamically
3. Assess the applicability of joint velocity and attenuation analysis for time-lapse shale reservoir characterization
4. Integrate multidisciplinary data in order to access how geologic heterogeneity within the Niobrara reservoir affects hydraulic stimulation and production
5. Determine how acquisition and processing uncertainty propagates into estimated locations of microseismic events recorded in a borehole environment

The value of this study is to develop new technologies and processing workflows to improve shale reservoir characterization.

1.3 Thesis Overview

The first part of this thesis focuses upon 4D viscoelastic responses of fractured reservoirs. Chapter 2 focuses upon modeling 4D velocity and attenuation changes due to stimulation and production. I show the effects of increased fracture permeability and fluid changes upon velocity and attenuation anisotropy. Time-lapse modeling of attenuation shows that joint
4D anisotropic velocity and attenuation changes are a reservoir attribute that can map fluid and fracture changes within a reservoir.

**Chapter 3** focuses upon joint time-lapse anisotropic velocity and attenuation processing and inversion of a time-lapse P-wave dataset. The 4D seismic survey monitors the reservoir deformation caused by hydraulic fracturing and production in the Niobrara Formation and Codell Sandstone. Three seismic surveys were collected by the RCP and APC, in order to understand the how reservoir heterogeneity and well spacing influence the stimulation and production of eleven horizontal wells within a one-square mile section. I utilize a robust layer stripping method to invert for time-lapse velocity and attenuation.

**Chapter 4** integrates multiple data types in order to identify how faults and well spacing affects stimulation and production. I analyze time-lapse changes within the Niobrara Reservoir in the Wishbone Section, located in Wattenberg Field, Colorado (CO). Results estimate reservoir scale deformation caused by stimulated and producing reservoir zones. I integrate the 4D measurements with surface microseismic, tracer information, production data, completion data, and reservoir models to evaluate completion effectiveness and production.

The second part of this thesis is a collaborative research effort with fellow PhD student Isabel White. Our collaboration is auxiliary to my main PhD research on 4D viscoelastic response of the Niobrara Reservoir. The resulting research from our collaboration appears in both of our theses, and at the time of this publication has been submitted to Geophysical Prospecting. In **Chapter 5** I present our work that focuses upon the uncertainty associated with a downhole survey in Pouce Coupe Field, Alberta, Canada. We implement a probabilistic approach to account for the acquisition error associated with the downhole geophones. Additionally, we use known sources to reduce error associated with not having a deviation survey, improve detection of weak microseismic events, and implement a robust amplitude ratio methodology to estimate hodograms in noisy borehole environments. We also illustrate how early processing improvements reduce azimuth and depth uncertainty in estimated microseismic source locations. These improvements are necessary in order to
accurately recover anisotropy parameters and potentially 4D changes within the reservoir. In Chapter 6 I present my conclusions and recommendations based upon my modeling and field data for Wattenberg Field, and my joint microseismic work in Pouce Coupe Field, Alberta, Canada.
CHAPTER 2
VISCOELASTIC ROCK-PHYSICS AND 4D MODELING

Identification of reservoir properties such as fluid mobility (the ratio of permeability and fluid viscosity) are important characteristics for stimulation and production of shale reservoirs (Adam et al., 2009; Blanchard & Edgar, 2015; Chapman, 2003; Guo & McMechan, 2017; Jakobsen & Chapman, 2009). Attenuation is an under utilized reservoir characterization parameter, which is sensitive to reservoir fluid properties. During stimulation, hydraulic fracture fluid is injected into the reservoir to drastically increase permeability. As the reservoir is produced, fractures lacking proppant close, the reservoir compacts, and gas comes out of solution. Application of joint velocity and attenuation analysis in shale reservoirs can identify where stimulation fluid has been placed, and which zones contribute to production.

Attenuation is a physical parameter that is typically not estimated in the characterization of unconventional reservoirs. Effective attenuation \( Q_e^{-1} \) is the sum of apparent and intrinsic quality factors:

\[
Q_e^{-1} = Q_i^{-1} + Q_a^{-1},
\]

(2.1)

where \( Q_i^{-1} \) is intrinsic attenuation, and \( Q_a^{-1} \) is apparent attenuation (Blanchard & Edgar, 2015; Spencer et al., 1982). Intrinsic attenuation is the loss of seismic energy as a wave propagates through a medium, which is caused by fluid flow and scattering (Blanchard & Edgar, 2015; Liner, 2012; Spencer et al., 1982; Stephen, 1992). Historically, evaluation of attenuation is performed with vertical seismic profiles (VSP). For example, attenuation in VSP studies is calculated for an isotropic value of Q as a function of depth (Hackert et al., 2001; Hauge, 1981; Pujol & Smithson, 1991; Raikes & White, 1984; Reid et al., 2001; Stainsby & Worthington, 1985; Tonn, 1991). In-situ isotropic attenuation derived from VSP measurements correlate to lithology, formation boundaries, and fractures/faults (Hamilton, 1972, 1976; Hauge, 1981; McDonal et al., 1958; Newman & Worthington, 1982;
Pujol & Smithson, 1991; Raikes & White, 1984; Ricker, 1953; Spencer et al., 1982; Stainsby & Worthington, 1985; Tonn, 1991). Hackert et al. (2001) note that higher attenuation corresponds to thicker beds of carbonate and sands, which are assumed to correspond to fracturing or higher variations in permeability.

The main cause of intrinsic attenuation is fluid flow (Behura et al., 2012; Blanchard & Edgar, 2015; Chapman, 2003; Guo & McMechan, 2017; Jakobsen & Chapman, 2009). Biot or global flow, squirt flow, and mesoscale flow are considered the main mechanisms that describe attenuation mechanisms at ultrasonic, sonic, and seismic frequencies, respectively (Biot, 1956; Chapman, 2003; Chapman et al., 2002; Collet & Gurevich, 2016; Dvorkin et al., 1994; Germán Rubino et al., 2013; Guo & McMechan, 2017; Gurevich et al., 2010; Jakobsen & Chapman, 2009; Jakobsen et al., 2003; Müller et al., 2010; Rubino & Holliger, 2013). These mechanisms are created when seismic waves cause local pressure gradients, which cause local fluid flow at grain and mesoscale heterogeneities (Chapman, 2003; Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Rubino & Holliger, 2013). Strong seismic attenuation occurs due to aligned reservoir scale fractures in a porous rock, and patchy saturation (Dvorkin & Mavko, 2006; Guo & McMechan, 2017; Johnson, 2001).

Various studies have shown that joint quantification of velocity and attenuation anisotropy provides more information about the distribution of fractures, and fluid content. Maultzsch et al. (2007) argue that azimuthal attenuation anisotropy correlates with open fluid-filled fractures. Liu et al. (2007) demonstrate that velocity and attenuation anisotropy may provide different information about a reservoir’s fracture sets (Liu, 2005).

Rock physics measurements indicate the importance of joint velocity and attenuation anisotropy analysis. Frequency-dependent measurements of velocity and attenuation show that increasing the fluid mobility causes the peak attenuation to move to higher frequencies for seismic and sonic frequencies (Batzle et al., 2006). Chichinina et al. (2009) measure P, SH, and SV attenuation in unsaturated and saturated transversely isotropic rock. Calculations show how attenuation anisotropy (114-153%) is significantly higher than velocity anisotropy.
(10-38%). The authors emphasize that velocity and attenuation anisotropy are linked and reservoir characterization should integrate both P- and S-wave velocity and attenuation anisotropy (Chichinina et al., 2009).

Multiple seismic modeling algorithms illustrate how to incorporate attenuation (Bai & Tsvankin, 2016; Guo & McMechan, 2017). However, few papers illustrate how reservoir parameters affect attenuation values, and synthetic seismograms (Agersborg et al., 2007; Dupuy & Stovas, 2013; Guo & McMechan, 2017; Maultzsch et al., 2007). Guo and McMechan (2017) implement the T-matrix method for calculating velocity and attenuation for horizontal transverse isotropy (HTI), and reservoir properties such as fluid type affect attenuation and synthetic seismograms. Results show that attenuation is strongest perpendicular to the fracture orientation. Synthetic seismograms also illustrate that reservoir parameters potentially can be inferred with attenuation measurements (Guo & McMechan, 2017).

I utilize the viscoelastic T-matrix approach to evaluate the sensitivity of the attenuation relaxation mechanisms to dynamic changes within the Niobrara reservoir properties such as permeability and fluid viscosity. Additionally, I utilize reflectivity modeling to show the sensitivity of the Niobrara reservoir to dynamic changes associated with velocity and attenuation.

### 2.1 Velocity and attenuation anisotropy

Velocity and attenuation anisotropy are described by stiffness coefficients. For seismic processing the application of Thomsen, or Thomsen-style, parameters is more suitable for seismic velocity and attenuation analysis. The Thomsen velocity parameters are defined as:

\[
V_{P0} = \sqrt{\frac{c_{33}}{\rho}}, \quad (2.2)
\]

\[
V_{S0} = \sqrt{\frac{c_{55}}{\rho}}, \quad (2.3)
\]
where $\rho$ is density, $C_{ij}$ are elastic stiffnesses, and the P- and S-wave velocities are $V_{P0}$ and $V_{S0}$, respectively. The dimensionless Thomsen parameters are:

$$\epsilon = \frac{c_{11} - c_{33}}{2c_{33}},$$

$$\delta = \frac{(c_{13} + c_{55})^2 - (c_{33} - c_{55})^2}{2c_{33}(c_{33} - c_{55})},$$

$$\gamma = \frac{c_{66} - c_{55}}{2c_{55}},$$

where $\epsilon$ and $\delta$ influence P- and SV-waves, and $\gamma$ controls SH-waves (Tsvankin & Grechka, 2011). For orthorhombic media, Tsvankin (1997) derived Thomsen-style velocity anisotropy parameters $\epsilon_{1,2}, \delta_{1,2,3},$ and $\gamma_{1,2}$.

In order to quantify attenuation anisotropy, Zhu and Tsvankin (2006) derived attenuation anisotropy parameters to approximate phase attenuation coefficients of P- and S-waves in homogeneous TI media. Attenuation anisotropy is calculated from the $Q$-factor

$$Q_{ij} = \frac{Re(C_{ij})}{Im(C_{ij})},$$

where $C_{ij}$ is the complex stiffness tensor. The Thomsen style attenuation TI parameters are defined as:

$$A_{P0} \equiv \frac{1}{2Q_{33}},$$

$$A_{S0} \equiv \frac{1}{2Q_{55}},$$

$$\epsilon_{Q} \equiv \frac{Q_{33} - Q_{11}}{Q_{11}},$$

$$\delta_{Q} \equiv \frac{Q_{33} - Q_{55}}{Q_{55}} \frac{c_{55}(c_{13} + c_{33})^2 + 2Q_{33} - Q_{13}c_{13}(c_{13} + c_{55})}{c_{33}(c_{33} - c_{55})}$$

$$\approx 4 \frac{Q_{33} - Q_{55}}{Q_{55}} g + 2 \frac{Q_{33} - Q_{13}}{Q_{13}} (1 + 2\delta - 2g),$$

$$\gamma_{Q} \equiv \frac{Q_{55} - Q_{66}}{Q_{66}},$$

where $c_{ij}$ are elastic stiffnesses, and the P- and S-wave velocities are $V_{P0}$ and $V_{S0}$, respectively.
where $Q_{ij}$ are the quality factor coefficients, $A_{P0}$ and $A_{S0}$ are the attenuation coefficients for P- and S-waves, $\delta_Q$ “governs the variation of $A_{P0}$ with the phase angle $\theta$ near the symmetry axis”, and $\epsilon_Q$ is the “fractional difference between the P-wave attenuation coefficients in the isotropy plane and along the symmetry axis” (Zhu & Tsvankin, 2006). Additionally, $\gamma_Q$ controls SH-wave attenuation anisotropy (Zhu & Tsvankin, 2006). For attenuative orthorhombic media, Zhu and Tsvankin (2007) employed notation similar to Tsvankin’s Thomsen style velocity anisotropy parameters where P- and S-waves attenuation anisotropy are described by $\epsilon_{Q1,2}$, $\delta_{Q1,2,3}$, and $\gamma_{Q1,2}$ (Zhu & Tsvankin, 2007).

2.2 Methodology

Modeling the sensitivity of a shale reservoir to time-lapse velocity and attenuation changes can help indicate the offset and azimuth coverage needed to observe changes in fracture properties. Additionally, sensitivity analysis of relaxation mechanisms is vital for 4D analysis of attenuation. During stimulation and production of a shale reservoir permeability, fracture aperture, fracture density, and fluid viscosity are changing. Sensitivity analysis can help illustrate, which time-lapse effect is dominate. The workflow integrates sensitivity analysis utilizing the T-matrix modeling of viscoelastic rocks, orthorhombic velocity and fluid substitution, and synthetic modeling of the Niobrara reservoir (Figure 4.3).

2.3 T-Matrix approach to fractures and attenuation

The T-matrix utilizes a large number of parameters in order to estimate a frequency-dependent, complex valued stiffness tensor for fractured media (Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Jakobsen et al., 2003). Many of these parameters such as fluid viscosity ($\eta$), fracture radius ($a$), grain size ($\varsigma$), permeability ($\Gamma$) and the average number of pores or fractures ($c_2$) connected to each fracture cannot be estimated from seismic data. Using other data such as Pressure Volume Temperature (PVT) tests can help reduce the number of free variables.
The advantage of the T-matrix approach is the ability to input reservoir parameters such as fluid viscosity, fracture aperture, and permeability. The T-matrix is an effective medium theory that incorporates fluid flow in rocks (Jakobsen & Chapman, 2009; Jakobsen et al., 2003). The formulation unifies three attenuation mechanisms: global, squirt, and mesoscale flow mechanisms (Jakobsen & Chapman, 2009). Additionally, the approach includes the interactions between inclusions.

Jakobsen et al. (2003b) and Jakobsen and Chapman (2009) developed the frequency-dependent T-matrix approach for complex stiffness. The formulation unifies three attenuation mechanisms: global, squirt, and mesoscale flow mechanisms (Jakobsen & Chapman, 2009). Additionally, the approach includes the interactions between inclusions.

\[
C^* = C^0 + C_1 \left( I_4 + C_1^{-1} C_2 \right)^{-1},
\]

where \( C^0 \) is a combination of the elastic response of a solid matrix. The response of interactions between inclusions is

\[
C_1 = \sum_{r=1}^{N} \phi^{(r)} l^{(r)},
\]

where \( \phi^{(r)} = 4/3\pi \alpha^{(r)} \epsilon^{(r)} \) is \( r \)-type inclusion porosity, \( \alpha^{(r)} \) is the fracture aspect ratio, and \( \epsilon^{(r)} \) is the fracture density (Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Jakobsen et al., 2003). Additionally, the interactions between inclusions is

\[
C_2 = \sum_{r=1}^{N} \sum_{s=1}^{N} \phi^{(r)} t^{(r)} G_{d}^{(rs)} l^{(s)} \phi^{(s)}
\]

where the dry cavity type \( r \) T-matrix is

\[
t_d^{(n)} = -C^{(0)} : \left( I_4 + G^n : C^{(0)} \right)^{-1},
\]

and the fully saturated T-matrix of inclusion \( r \) is

\[
t^{(n)} = t_d^{(n)} + t_s^{(n)} : S^{(0)} : \left( I_2 \otimes \Psi^{(n)} \right) : C^{(0)},
\]

where \( G^n \) is the fourth-rank tensor dependent upon \( C^0 \), the fracture aspect ratio and orientation. \( S^{(0)} \) is a compliance tensor of the medium which is estimated from the Eshelby matrix (Jakobsen & Chapman, 2009; Jakobsen et al., 2003). \( I_2 \) and \( I_4 \) are the second and four rank identity tensors, respectively (Guo & McMechan, 2017; Jakobsen & Chapman,
\[
\Psi^{(n)} = -\frac{\tilde{\Theta} \sum_r \frac{\phi^{(r)} I_2 K_d^{(r)}}{1 + i \omega \gamma^{(r)} \tau} + i \omega \tau \kappa_f I_2 : K_d^{(n)}}{1 + i \omega \gamma^{(n)} \tau},
\]
(2.18)

and

\[
\tilde{\Theta} \equiv \Theta (1 - \Delta) = \kappa_f \left[ \sum_{r=1}^{N} \frac{\phi^{(r)} \gamma^{(r)}}{1 + i \omega \gamma^{(r)} \tau} + \frac{i \kappa_f \Gamma_{ij} k_i k_j}{\eta_f \omega (1 - \Delta)} \right]^{-1},
\]
(2.19)

where

\[
\gamma^{(n)} = 1 + \kappa_f I_2 : (K^n - S^{(0)}) : I_2.
\]
(2.20)

In order to couple squirt flow and global flow

\[
\Delta \equiv \frac{\kappa_f \tau}{\phi \eta_f} \Gamma_{ij} k_i k_j
\]
(2.21)

where \(\tau\) is the fluid relaxation time and \(\Gamma_{ij}\) is the anisotropic permeability (Jakobsen & Chapman, 2009; Jakobsen et al., 2003).

The mechanism for attenuation in the T-matrix is the interaction of fluids to aligned fracture sets, and randomly oriented pores. The interactions generate local fluid localized pressure gradients, which causes attenuation at seismic frequencies (Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Jakobsen et al., 2003). The T-matrix formulation also accounts for global Darcy’s law, which describes global flow within a medium. This links attenuation to total fluid mass in a saturated rock, fluid viscosity and density, and anisotropic permeability (Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Jakobsen et al., 2003).

The previous parameters all influence the fluid relaxation time

\[
\tau_f = \left[ \frac{f_v \eta_f (1 + K)}{c_2 \sigma \varsigma} \right] \Gamma^{-1}
\]
(2.22)

where \(\sigma\) is the normal stress applied on the crack face, where

\[
\sigma = \frac{\pi \mu \alpha_f}{2 (1 - v)}.
\]
(2.23)
The ratio of $\sigma$ and the fluid bulk modulus ($\kappa_f$) is $K$, and Poisson’s ratio is $\nu$. The volume of an individual fracture is

$$f_v = \frac{4}{3\pi} a^3 \alpha_f$$  \hspace{1cm} (2.24)

where $\alpha_f$ and $a$ are the fracture aspect ratio and fracture radius, respectively (Guo & McMechan, 2017; Jakobsen & Chapman, 2009; Jakobsen et al., 2003). Average number of connected pores, $c_2$, is set to be equal to a square of the fracture radius, $a^2$ (Jakobsen et al., 2003). Decreasing the fluid relaxation time moves the apex attenuation to higher frequencies. The relationship between fluid relaxation time and apex attenuation is also observed in laboratory measurements for fully saturated rocks, and partially saturated models (Adam et al., 2009; Batzle et al., 2006; Carcione & Picotti, 2006; Guo & McMechan, 2017; Rubino et al., 2012). Additionally, Guo and McMechan (2017) utilizes the T-matrix modeling to illustrate the sensitivity of anisotropic attenuation to fracture aperture and density, permeability, fluid viscosity. The authors utilize a synthetic seismograms and demonstrate the sensitivity of seismograms to anisotropic attenuation (Guo & McMechan, 2017).

In order to understand 4D attenuation measurements it is important to model how changes within fractures and fluids may affect the time-lapse signature of a shale reservoir due to hydraulic stimulation and production. During stimulation, proppant and hydraulic fracture fluid are injected into the reservoir in order to greatly increase fracture permeability. As the reservoir is produced, reservoir pressure decreases, gas comes out of solution, and fractures lacking proppant close.

Understanding fluid mobility is important in reservoir models, and overall production of oil and gas. Fluid mobility is the ratio of permeability to fluid viscosity. In the T-matrix formulation, fluid relaxation time is directly proportional to fluid mobility and fracture properties. Guo and McMechan (2017) demonstrate how increasing the relaxation time shifts the apex attenuation to higher frequencies. Modeling shows that fluid relaxation times between $5^{-5}s - 5^{-4}s$ produce measurable amounts of attenuation within the seismic bandwidth (Figure 2.1) (Guo & McMechan, 2017). The fluid relaxation time is an intermediate value in the
T-matrix approach that links attenuation to the fluid properties of the reservoir. However, these parameters cannot be estimated without PVT data, core analysis, and estimates of fracture properties.

![Fluid relaxation time (s)](image)

Figure 2.1: Attenuation modeling from Guo and McMechan (2017). The results show how seismic attenuation (mesoscale attenuation) occurs within relaxation times that vary between $5^{-5}s - 5^{-4}s$ (Guo & McMechan, 2017).

I utilize known reservoir properties to estimate the relation time of the Niobrara reservoir and how it changes with time. In order to understand how the Niobrara reservoir’s attenuation response may change due to fluid and fracture properties, PVT analysis, rock and fracture properties are used to model the sensitivity of fluid relaxation time to specific parameters (Table 2.1) (Dudley, 2015; Kamruzzaman, 2015; Ning, 2017).

### 2.3.1 Sensitivity of attenuation to changes in reservoir parameters

Three different stages are modeled to illustrate the variability of the fluid relaxation and the vertical attenuation under different reservoir conditions. The first stage represents non-stimulated reservoir rock that has microDarcy permeability and small fracture aperture (Figure 2.2) (Table 2.1). The second model has larger fracture properties and permeabil-
Table 2.1: Parameters used in sensitivity tests for velocity and attenuation changes

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Pre-stimulation</th>
<th>Post-stimulation</th>
<th>Post 2 yrs. production</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture aspect ratio $\alpha_f$</td>
<td>0.01</td>
<td>0.1</td>
<td>0.025</td>
</tr>
<tr>
<td>$V_{P0}$ (m/s)</td>
<td>3657</td>
<td>3657</td>
<td>3657</td>
</tr>
<tr>
<td>$V_{S0}$ (m/s)</td>
<td>2106</td>
<td>2106</td>
<td>2106</td>
</tr>
<tr>
<td>Density ($kg/m^3$)</td>
<td>2640</td>
<td>2640</td>
<td>2640</td>
</tr>
<tr>
<td>Fluid bulk modulus ($\kappa_f$) (Mpsi)</td>
<td>0.030</td>
<td>0.030</td>
<td>0.038</td>
</tr>
<tr>
<td>Gas bulk modulus (Methane) ($\kappa_f$) (Mpsi)</td>
<td>N/A</td>
<td>N/A</td>
<td>0.002457</td>
</tr>
<tr>
<td>Grain size ($\varsigma$) (m)</td>
<td>$1 \times 10^{-6}$</td>
<td>$1 \times 10^{-6}$</td>
<td>$1 \times 10^{-6}$</td>
</tr>
<tr>
<td>Condensate viscosity ($\eta$) (cP)</td>
<td>0.11</td>
<td>0.11</td>
<td>0.175</td>
</tr>
<tr>
<td>Gas viscosity ($\eta$) (cP)</td>
<td>N/A</td>
<td>N/A</td>
<td>0.0175</td>
</tr>
</tbody>
</table>

ity due to hydraulic stimulation (Table 2.1). During hydraulic stimulation, some fractures contain condensate and other fractures are filled with water. The third reservoir condition is representative of two years of production when fracture aperture has decreased due to compaction, and gas has come out of solution (Table 2.1) (Eker, 2018).

Figure 2.2: Potential relaxation times for the Niobrara. Permeability and fracture radius are varied. Pre-stimulation reservoir conditions have microDarcy permeability and condensate filled fractures.

Figure 2.2: Potential relaxation times for the Niobrara. Permeability and fracture radius are varied. Pre-stimulation reservoir conditions have microDarcy permeability and condensate filled fractures.

Stimulation drastically alters the fracture properties and permeability of the reservoir. Stimulation also introduces water into the reservoir, which has a higher bulk modulus and viscosity than the condensate (Table 2.1). Reservoir simulation work from the Niobrara indicates that fracture permeability can range between $10^{-4}D - 10^{-3}D$ after stimulation. The
introduction of fracture permeability will generate anisotropic permeability within the reservoir. Previous work has shown that anisotropic permeability will appear isotropic at seismic frequencies in the T-matrix formulation due to global Darcy’s law (Ali & Jakobsen, 2014; Guo & McMechan, 2017). Therefore, seismic will only be sensitive to fracture permeability. The introduction of water into the reservoir has the potential to decrease the relaxation time in comparison to condensate filled fractures (Figure 2.3).

After hydraulic stimulation of a shale reservoir, the reservoir permeability decreases as small amounts of compaction occur due to production of hydrocarbons (Eker, 2018). Additionally, reservoir pressure decreases and gas comes out of solution. Gas has lower compressibility and viscosity (Table 2.1). Previous work illustrates that introduction of gas into a formation can shift the apex attenuation to higher frequencies (Guo & McMechan, 2017). This occurs because the fluid relaxation time shifts away from the ranges that affect the seismic bandwidth (Figure 2.4).

The T-matrix formulation has multiple parameters that are difficult to parameterize without downhole calibration data such as repeat formation microimage logs, fluid measurements, and vertical seismic profiles. These data could help narrow the range of parameters needed for input to the relaxation time and attenuation calculation. Fracture radius is the most difficult parameter to constrain because fracture lengths cannot be estimated from any borehole information.

In order to understand what may occur due to stimulation, arbitrarily permeability measurements are selected from known ranges (Kamruzzaman, 2015; Ning, 2017). The baseline, monitor 1, and monitor 2 surveys are modeled with $10^{-6}$ D., $6^{-4}$ D., and $2^{-4}$ D. The baseline permeability is selected from core measurement ranges (Kamruzzaman, 2015). Permeability values for monitor 1 and monitor 2 are selected from the ranges estimated from reservoir simulation, and decreased for monitor 2 in order to account for reservoir compaction (Eker, 2018; Ning, 2017). Fracture radius is arbitrarily selected as 1/100 m. for baseline, and 2 m. for monitor 1 and 2. No calibration data can refine these estimations.
Figure 2.3: Potential relaxation times for the Niobrara. Permeability and fracture radius are varied. Post-stimulation reservoir conditions have fracture permeability can range between $10^{-4} \text{ D} - 10^{-3} \text{ D}$. a) The fluid relaxation time of condensate is slightly higher than water. b) The fluid relaxation time of water is lower than condensate.
Figure 2.4: Potential relaxation times for the Niobrara. Permeability and fracture radius are varied. Post-stimulation reservoir conditions have fracture permeability can range between $10^{-4}$ D - $10^{-3}$ D. a) The fluid relaxation time of gas is higher due to the low compressibility and viscosity of gas. b) The fluid relaxation time of condensate.
The modeled attenuation response shows the vertical attenuation may increase due to stimulation, and decrease due to production (Figure 2.5). Smaller sizes of the fracture radius can cause the apex attenuation to shift towards higher frequencies. Due to this attribute, hydraulic stimulation and production may cause the apex attenuation to shift away from the baseline case, and cause an apparent decrease of the vertical attenuation over the seismic bandwidth (Figure 2.6).

![Modeled attenuation for baseline, monitor 1, and monitor 2. Permeability and fracture properties are arbitrarily chosen since no calibration data is available for the monitor surveys.](image)

2.3.2 Sensitivity of velocity to changes in reservoir parameters

Core measurements and sonic scanner estimates of VTI anisotropy indicate that the Niobrara reservoir has strong anisotropy (Bratton, 2018; Kamruzzaman, 2015). The T-matrix formulation is not able to incorporate VTI anisotropy in the current formulation. Schoenberg and Helbig (1997) fracture modeling for orthorhombic media, and anisotropic Gassmann fluid substitution are implemented in order to understand the potential velocity time-lapse change due to stimulation and production (Collet & Gurevich, 2016; Gassmann, 1951). Modeling fractures in a VTI media is calculated with the background stiffnesses ($C_{ij}$),
Figure 2.6: Modeled $Q_{33}$ for baseline, monitor 1, and monitor 2. Smaller fracture radius shift the apex attenuation to higher frequencies. a) Fracture radius is varied for Monitor 1. b) Fracture radius is varied for Monitor 2.
and the normal ($\delta_N$), vertical ($\delta_V$), and horizontal ($\delta_H$) tangential compliance (Schoenberg & Helbig, 1997). The resulting orthorhombic effective compliances are,

$$C^{nf}_{ij} = \begin{bmatrix}
C_{11b}(1 - \delta_N) & C_{12b}(1 - \delta_N) & C_{13b}(1 - \delta_N) & 0 & 0 & 0 \\
C_{12b}(1 - \delta_N) & C_{11b}(1 - \delta_N) & C_{13b}(1 - \delta_N) & 0 & 0 & 0 \\
C_{13b}(1 - \delta_N) & C_{13b}(1 - \delta_N) & C_{33b}(1 - \delta_N) & 0 & 0 & 0 \\
0 & 0 & 0 & C_{44b}(1 - \delta_V) & 0 & 0 \\
0 & 0 & 0 & 0 & C_{66b}(1 - \delta_H) & 0 \\
0 & 0 & 0 & 0 & 0 & 0 
\end{bmatrix}.$$  \hspace{1cm} (2.25)

The normal compliance is

$$\delta_N = \frac{4\epsilon_f}{3g(1 - g)},$$ \hspace{1cm} (2.26)

where $g \equiv \frac{V_S^2}{V_P^2}$ and $\epsilon_f$ is the crack density (Schoenberg & Helbig, 1997). The vertical compliance is

$$\delta_V = \frac{16\epsilon_f}{3(3 - 2g)},$$ \hspace{1cm} (2.27)

If the fractures are rotationally invariant then $\delta_V = \delta_H$ (Schoenberg & Helbig, 1997). Fluid effects within the reservoir are accounted for by calculating the modified normal compliance, and anisotropic fluid substitution (Collet & Gurevich, 2016; Gassmann, 1951). The modified normal compliance for anisotropic fluid substitution is

$$\delta_{Nmf} = \frac{C_{11b}\delta_N}{C_{11b} + \frac{\delta_N}{\phi_c(1/K_f - 1/K_g)}},$$ \hspace{1cm} (2.28)

where $K_f$ and $K_g$ are the fluid and grain bulk modulus (Collet & Gurevich, 2016; Gassmann, 1951). The compliant porosity for spheroidal crack is a product of fracture density and fracture aspect ratio where

$$\phi_c = \frac{4\pi \alpha_f \epsilon_f}{3}.$$ \hspace{1cm} (2.29)

The compliant porosity assumes small crack density and aspect ratios (Thomsen, 1995). Fully saturated, anisotropic Gassmann fluid substitution calculates,

$$C_{ij}^{sat} = C_{ij}^{mf} + \alpha_i \alpha_j M,$$ \hspace{1cm} (2.30)
where $C_{mf}^{ij}$ are the effective stiffnesses calculated using the modified normal compliance (Collet & Gurevich, 2016; Gassmann, 1951). Additionally, $\alpha_i$ is

$$\alpha_i = 1 - \frac{\sum_{j=1}^{3} C_{mj}^{ij}}{3K_{tg}}, \quad (2.31)$$

for $i = 1, 2, 3$ and $\alpha_4 = \alpha_5 = \alpha_6 = 0$ (Collet & Gurevich, 2016; Gassmann, 1951). The pore space modulus is

$$M = \frac{K_{tg}}{(1 - K^{*}/K_{tg}) - \phi(1 - K^{*}/K_{mf})}, \quad (2.32)$$

and the generalized drain bulk modulus is

$$K^{*} = \frac{1}{9} \sum_{i=1}^{3} \sum_{j=1}^{3} C_{mj}^{ij}. \quad (2.33)$$

Time-lapse downhole calibration data is not available for estimates of fracture density or fracture aperture. Formation microimage logs indicate the presence of sealed and open natural fractures (Dudley, 2015; Grechishnikova, 2017). Small fracture apertures approximately equal to 0.01 are typical for unconventional shale reservoirs (Nelson, 2009). During hydraulic stimulation, proppant is injected into the formation in order to keep fractures from closing. For a fracture to be wide enough for three course sand particles (20/40 mesh), the fracture aperture should increase to approximately 0.1 (Nelson, 2009). As the reservoir produces hydrocarbon, the fractures will compress (Bratton, 2018; Eker, 2018). An arbitrary fracture aperture of 0.025 is selected for fracture apertures after two years of production. Fracture density estimates are utilized from discreet fracture modeling (0.03), and are arbitrarily increased in order to simulate the effect of hydraulic fracturing (0.05), and the reservoir compaction caused by production (0.04) (Grechishnikova, 2017). The difference between $\delta_V$ and $\delta_H$ is set equal to the fracture density. Background VTI parameters are from core measurements from a Niobrara core plug (Table 2.2) (Kamruzzaman, 2015).

Equation 2.30 is utilized to calculate fully saturated orthorhombic stiffnesses for the potential velocity changes due fracture and fluid changes in the Niobrara reservoir. P-waves are calculated at 30° incidence using the Christoffel equation (Tsvankin, 2012; Walker...
The variation with azimuth (VVAZ) between the saturated and non-saturated cases shows that fluids will cause a maximum of \( \sim 1\% \) change in the P-wave velocity (Figure 2.7). The largest velocity change is due to fracture aperture and fracture density changes (Figure 2.7). The normal moveout velocities are calculated for orthorhombic \((V_{NMO_1}, V_{NMO_2})\) and VTI media using the values in Table 2.1. VTI media does not describe a fractured reservoir, therefore \( \delta_1 \) and \( \delta_2 \) are averaged together to illustrate how the VTI \( V_{NMO} \) will change due an increase in reservoir fracture properties (Grechka & Mateeva, 2007).

The modeled effect of hydraulic stimulation causes the two orthorhombic \( V_{NMO} \) velocities to separate furthest due to the larger fracture aperture and fracture density (Figure 2.8). The estimated VTI \( V_{NMO} \) velocity also decreases from the baseline case. Due to production and reservoir compaction, fracture properties are reduced. The average VTI \( V_{NMO} \) velocity will increase after hydraulic stimulation, but will remain less than the baseline case. Thus, areas with greatest change in \( V_{NMO} \) velocity will indicate areas of increased fracturing due to hydraulic stimulation.

### 2.4 Sensitivity of P-wave seismic to time-lapse changes within the Niobrara Reservoir

To illustrate the Niobrara reservoir’s sensitivity to time-lapse velocity and attenuation changes, a reflectivity model is built with estimations of anisotropy from sonic scanner data, core, and discrete fracture models (Behura et al., 2016; Fryer & Frazer, 1984, 1987; Grechishnikova, 2017; Kamruzzaman, 2015). Core anisotropy results indicate that the Niobrara marl matrix has strong vertical transverse isotropy (VTI) (Kamruzzaman, 2015; Ou & Prasad, 2017). Additionally, sonic scanner estimates of anisotropy also corroborate the strong VTI
Figure 2.7: The modeled VVAZ for one fracture set aligned with N70°W, and fracture properties from Table 2.1. a) Fractures and matrix with no fluids. b) Fractures and matrix with condensate in baseline and monitor 1. Gas and condensate are used for fluid substitution in monitor 2.
anisotropy observed the core measurements. Model parameters are built with upscaled sonic scanner estimates of anisotropy (Bratton, 2018). Assuming a delta of 0.15, the epsilon values range from 0.006 to 0.47, based upon the ANNIE approach for estimating anisotropy from sonic scanner data (Figure 2.9) (Bratton, 2018; Schoenberg, 1996; Suarez-Rivera & Bratton, 2012). Fracture aperture and density estimates for pre-stimulation and post-stimulation are calculated from FMI logs, completion data, and reservoir discrete fracture models (Grechishnikova, 2017; Ning, 2017). Completion modeling from the Wishbone Section calculates a range for fracture height growth and half lengths of 20-190 ft. and 260-480 ft., respectfully (Ning, 2017). Additionally, attenuation information for the overburden is estimated from a vertical seismic profile north of the Wishbone Section (Tamimi, 2015). Isotropic attenuation is arbitrarily chosen within the reservoir interval ($A_{P0} = 0.0116$). Fracture parameters for pre-stimulation and post-stimulation are in Table 2.3.

Estimation of orthorhombic anisotropic parameters with only P-wave data requires offset to depth ratios greater than two (Vasconcelos & Tsvankin, 2006). This is due to the polarization of the P-wave to the orientation of the fractures within the reservoir. In order
Figure 2.9: Velocity and density values for model in reservoir interval. Model courtesy of Payson Todd.

Table 2.3: Fracture parameters used in modeling in order to simulate before and after stimulation.

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Pre-stimulation</th>
<th>Post stimulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture aspect ratio $\alpha_f$</td>
<td>0.01</td>
<td>0.1</td>
</tr>
<tr>
<td>Fracture density $\epsilon_f$</td>
<td>0.03</td>
<td>0.05</td>
</tr>
</tbody>
</table>
to illustrate the seismic signature of only the Niobrara and underlying geologic formations, the overburden is separately modeled and subtracted from models that contain the reservoir interval. Common offset and common azimuth plots are generated to illustrate the velocity variation with azimuth for P-wave.

Both models have the same background VTI properties based upon sonic scanner results. Due to the strong polar anisotropy non-hyperbolic moveout is observed on the P-wave data at offsets greater than 16,000 ft. In order to flatten the synthetic gathers an $\eta$ of 0.2 is used. The low crack density P-wave model of the Niobara shows little VVAZ at offsets of 11,000 ft. Offsets greater than 13,000 ft. are required in order to observe the velocity anisotropy. The model with larger fracture properties has observable VVAZ on the P-wave data at approximately 10,000 ft. (Figure 2.10).

In order to illustrate the sensitivity of the Niobrara Reservoir to changes in attenuation, four synthetic seismograms are generated. The first two synthetic seismograms have the same velocity structure, a constant overburden $A_{P_0}$ of 0.005, and the Niobrara reservoir $A_{P_0}$ is varied from 0.0116 to 0.0147. The change in vertical attenuation is approximately 20%, and occurs over the reservoir interval (225 ft.). The last two synthetic seismograms vary $A_{P_0}$ within the overburden between 0.01 - 0.083, and again change $A_{P_0}$ within the Niobrara reservoir by 20%. The synthetic seismograms show a frequency change with offset in both seismograms (Figure 2.13). When the overburden has a constant $A_{P_0}$ of 0.005, the farther offset difference between the two seismograms are visible (Figure 2.11). However when the overburden $A_{P_0}$ varies between 0.01 - 0.083, the change within the reservoir is greatest before an offset of 9,000 ft (Figure 2.12). Farther offsets have longer ray-paths through the overburden, and higher frequencies attenuate more before reaching the reservoir (Figure 2.13). This causes the near-offsets to be affected more by the dynamic change in attenuation.
Figure 2.10: Modeled reservoir response of the Niobrara with pre- and post-stimulation values of fracture properties (Table 2.3). a) Model of the Niobrara reservoir with small fracture properties. VVAZ response is observed on offsets greater than 13,000 ft. b) Model of the Niobrara reservoir with large fracture properties. VVAZ response is observed on offsets greater than 10,000 ft.
Figure 2.11: The left and middle panels of the figure are the P-wave COCA images with the same velocity model, and different attenuation within the reservoir. The overburden attenuation is constant and set to an $A_{P0}$ of 0.005. The second model has attenuation decreased by 20% within the reservoir from 0.0116 to 0.0147. The right panel shows the time-lapse change due to isotropic attenuation. Near offset data have higher frequency content than far offset data.

Figure 2.12: The left and middle panels of the figure are the P-wave COCA images with the same velocity model, and different attenuation within the reservoir. The overburden attenuation is varied between 0.01 - 0.083. The second model has attenuation decreased by 20% within the reservoir from 0.0116 to 0.0147. The right panel shows the time-lapse change due to isotropic attenuation. The degree of change is greater in the near offsets due to the presence of higher frequency data. Far offset data observes smaller changes since the main frequency content is below 40 Hz.
Figure 2.13: The frequency spectra extracted over the reservoir interval from the model with a constant overburden $A_{P0}$ of 0.005, or a variable overburden $A_{P0}$ between 0.01 - 0.083. Near offset spectra are extracted over the reservoir interval from 0 - 3500 ft. Far offset spectra are extracted from 21,000 - 24,500 ft. a) Near offset frequency spectra from constant overburden model. b) The far offset frequency spectra from the constant overburden model. c) The near offset frequency spectra from the variable overburden model. d) The far offset frequency spectra from the variable overburden model.
2.5 Conclusions

The T-matrix approach to modeling complex, stiffness properties of a rock can help inform how changing reservoir parameters such as fluid viscosity and permeability may effect the fluid relaxation time and attenuation. The fluid relaxation mechanism is an intermediate value that influences the potential attenuation signature of a reservoir. For dynamic reservoir characterization of shale reservoirs, multiple properties such as fluid viscosity, permeability, and fracture aperture change due to stimulation and production. Time-lapse changes due to hydraulic stimulation may decrease the fluid relaxation time due to hydraulic fracture water, the increase in reservoir permeability, and fracture properties. Additionally when the reservoir drops below bubble point and gas is introduced into the system, the apex frequency may move outside of the seismic bandwidth, and cause an apparent decrease in the attenuation.

Parameters used in the T-matrix modeling are difficult to constrain without downhole calibration data. Fluid viscosity and bulk density are the only data that can be constrained. In order to constrain forward model estimations of attenuation, time-lapse FMI logs, pressure readings, and vertical seismic profiles are needed. Additionally, the T-matrix is not able to incorporate VTI anisotropy in the background rock properties. Further development of viscoelastic rock models is needed to account for lower symmetry rocks. These models also need to reduce the number of free variables in the T-matrix approach. Reservoirs over time experience changes in fracture properties, porosity, permeability, and fluid properties. Changes in all of these parameters limits the applicability of time-lapse attenuation analysis.

Fracture modeling and anisotropic fluid substitution is performed in a VTI background to illustrate how changing fracture and fluid properties affect P-wave velocities. Fluid substitution shows less than 1% change in velocities due to fluids. Fractures cause the largest time-lapse change associated with hydraulic stimulation and production. Furthermore, measurements with VTI $V_{NMO}$ will detect changes caused by increased fracture properties. Modeling shows that monitor 1 and monitor 2 surveys will observe a decrease in $V_{NMO}$ velocity.
from the baseline survey. P-wave $V_{NMO}$ will also show a slight increase between monitor 1 and monitor 2 surveys due to reservoir compaction, and the production of hydrocarbon.

Synthetic seismograms are generated with estimations of velocity and VTI anisotropy from sonic scanner. Models vary both the degree of fracturing within the reservoir, and attenuation in order to show the sensitivity of the Niobrara reservoir to time-lapse velocity and attenuation. VVAZ within the Niobrara is observed at offsets greater than 10,000 ft. and 13,000 ft. for the models with varying fracture properties.

Time-lapse attenuation shows sensitivity to offset. Though the modeled change in attenuation is isotropic, the far-offsets are have longer ray-paths through the overburden and attenuate more before reaching the reservoir. The near offset traces have the largest observable change in attenuation, because of the higher frequency content of near offset traces. This may limit the effectiveness of time-lapse anisotropic attenuation in thin reservoirs such as the Niobrara since far-offset data is not as sensitive to dynamic changes in attenuation as near offset traces.
Dynamic (4D) fracture characterization in unconventional reservoirs provides spatial information about a reservoir’s response to hydraulic fracturing and production. Identification of dynamic properties improves reservoir models, and illustrates how reservoir heterogeneity effects well stimulation and production. Joint quantification of velocity and attenuation provides more information about the distribution of fractures, and distinguishes between fluid-filled and open/cemented fracture sets (Liu et al., 2007; Maultzsch et al., 2005, 2007; Varela et al., 2006). Identification of open fluid filled fractures, fluid content, permeability contrasts, and mesoscale fracture geometries is key towards improved assessment of well spacing, and identification of producing and non-producing zones in shale reservoirs.

Time-lapse seismic is a powerful tool for assessing changing reservoir properties. Velocity and amplitude changes are commonly observed with reservoir compaction (Bertrand et al., 2014; Landro et al., 1999; Lumley et al., 2003; Lumley, 2001; Watts et al., 1996). As a reservoir is produced, pressure reduction causes compaction within the reservoir and thus velocity changes within the rock (Landro & Stammeijer, 2004; Tura et al., 2006). Velocity changes are also observed during CO₂ or gas injection. As the reservoir is flooded, the rock properties change causing a slowing of the velocity. Additionally, velocity changes due to hydraulic fracturing are observed due to fracturing and stress changes (Toomey et al., 2017; Vinal & Davis, 2015).

Attenuation is typically estimated post migration as a seismic attribute (Blanchard & Edgar, 2015; Blanchard & Delommot, 2015; Dinh et al., 2015). This is not desirable for true estimations of attenuation since deconvolution, NMO correction, and pre-stack migration alter the seismic spectrum. However, many time-lapse surveys have successfully used fre-
frequency attributes to estimate changes in attenuation. Attenuation measurements from post-stack data also correlate to changes in the oil/water contact caused by production (Blanchard & Delommet, 2015). Similar implementations also show that attenuation correlates to gas break out (Dinh et al., 2015; Puasa et al., 2014). Overall, these implementations illustrate that time-lapse attenuation identifies changes in fluid concentrations within the reservoir.

Pre-stack seismic attenuation measurements are less commonly applied for reservoir characterization. Behura et al. (2012) examine the interval velocity and interval attenuation anisotropy of the Mannville Group at Coronation Field, Canada. The authors found that high levels of attenuation correspond to existing gas-production. The vertical attenuation coefficient $A_0$ is not sensitive to vertical fractures, but is sensitive to gas within the formation. The authors do not find any correlation to the azimuthal attenuation anisotropy, and note that the entire interval includes lithologies other than the Rex member, which may affect the interval attenuation measurement (Behura et al., 2012).

Reine et al. (2012a,b) also implements pre-stack Q estimation in the $\tau-p$ domain. Attenuation measurements correspond to the top of gas within the reservoir. Additionally, the authors compare attenuation measurements from a VSP in the same geologic formation and found similar attenuation measurements as the surface seismic (Reine et al., 2012a,b).

I demonstrate the application and results from pre-stack time-lapse attenuation and velocity measurements that characterize the reservoir deformation caused by hydraulic fracturing, and production in the Niobrara Formation and Codell Sandstone, Wattenberg Field, Colorado. Three seismic surveys help us understand the dynamic reservoir changes caused by hydraulic fracturing and production of eleven horizontal wells within a one-square mile section. A baseline survey was recorded immediately after the wells were drilled, another survey after stimulation, and a third survey after two years of production. I utilize a robust layer stripping method to quantify 4D velocity and attenuation from pre-stack seismic data (Behura & Tsvankin, 2009a). Finally, results are discussed, and the limitations of the PP time-lapse survey are identified. In this chapter I discuss the 4D processing, layer stripping,
and inversion on the Turkey Shoot PP time-lapse seismic survey.

3.1 Geologic Background

The time-lapse survey focuses upon the hydraulic fracturing and production effects of eleven horizontal wells in the Niobara Formation, and the Codell Sandstone member of the Carlile Formation (Figure 3.1). The wells are located within a one sq. mi. section called the Wishbone Section. The Niobrara deposition occurred in a foreland basin during multiple transgressions and regressions. These sea-level undulations resulted in the deposition of chalks and marls. Chalks were deposited in higher sea level. The Codell Sandstone member has two dominant facies (Sonnenberg, 2012). The first is a laminated bioturbated sandstone with hummocky cross stratification. The second facies is a well sorted extremely bioturbated sandstone with multiple carbonate clasts and burrows (Mabrey, 2016). The Niobrara reservoir is an unconventional reservoir with microdarcy permeability and porosity that ranges between 6-12% (Kamruzzaman, 2015). The Codell Sandstone has slightly higher porosity ranging between 7-15%. The Niobrara and Codell Sandstone are approximately 200 and 25 ft thick, respectively. Underlying the Carlile Formation is the Greenhorn Formation, which is approximately 230 ft. thick (Sonnenberg, 2012, 2013).

The Wishbone Section is located within the volatile oil portion of Wattenberg Field, Colorado. Fluid sampling from the reservoir shows the viscosity at in-situ pressure at 4500 psi. is 0.1651 cPa with an API gravity of 44.7 (Figure 3.2). As the reservoir is produced and pressure is drawn down, the viscosity of the oil decreases, and gas comes out of solution. Variations in reservoir permeability and fluid viscosity have a significant influence upon the attenuation response of the reservoir. Permeability estimates from reservoir simulation and fluid viscosity values from PVT analysis demonstrate how fluid mobility (mD/cP) changes between monitor 1 and monitor 2 (Figure 3.3). As fluid mobility increases, so too does $A_{P_0}$. During monitor 1 the reservoir is dominated by the oil viscosity, hydraulic fracture fluid viscosity, and reservoir fracture permeability. Monitor 2 is dominated by gas permeability and reservoir permeability. Joint attenuation and velocity analysis is useful for the discrimi-
Figure 3.1: Left side of image are the relevant geologic formations in Wattenberg Field. The land zones for the eleven horizontal wells within the Wishbone are shown on the right image. The lower map shows the orientation of the wells, and the major faults at the top of the Niobrara within the section (Pitcher, 2015; Sonnenberg, 2013; Utley, 2017).
inating between areas that have been more heavily fractured, and identifying zones with varying gas oil ratios (GOR).

![Liquid and Vapor Viscosities](image)

Figure 3.2: Pressure-volume-temperature (PVT) analysis from a well located southwest of the Wishbone Section.

### 3.2 Acquisition Parameters

The three surveys were intended to measure the effects of hydraulic fracturing and production. The surveys cover 4 sq. mi. and were designed to image the Niobrara reservoir in the Wishbone Section of Wattenberg Field (Table 3.1). The focus of the survey is the 1 sq. mi. Wishbone Section. Outside of the high fold areas, the survey is unevenly sampled and affects recovered velocity and attenuation values (Figure 3.5). For velocity and attenuation analysis, data are put in 275 ft. x 275 ft. supergathers (Figure 3.4). The central portion of the survey is uniformly sampled to 11,000 ft.

### 3.3 Velocity Independent Layer Stripping

To perform the time-lapse analysis, I implement a kinematic velocity-independent layer-stripping algorithm for interval velocity and interval attenuation anisotropy (Behura &
Figure 3.3: Fluid mobility at different pressures, viscosities, and reservoir permeability. a) Fluid mobility permeability ranges for monitor 1, b) Fluid mobility permeability ranges for monitor 2. Gas will dominate the attenuation signal.
Table 3.1: Acquisition parameters of time-lapse surveys

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Survey type</td>
<td>4D 9-C</td>
</tr>
<tr>
<td>Receiver spacing</td>
<td>110 ft.</td>
</tr>
<tr>
<td>Receiver line spacing</td>
<td>660 ft.</td>
</tr>
<tr>
<td>Shot spacing</td>
<td>110 ft.</td>
</tr>
<tr>
<td>Shot line spacing</td>
<td>880 ft.</td>
</tr>
<tr>
<td>Repeatable receivers</td>
<td>2,410</td>
</tr>
<tr>
<td>Repeatable shots</td>
<td>1,099</td>
</tr>
<tr>
<td>Nominal fold (55x55 ft.)</td>
<td>180</td>
</tr>
<tr>
<td>Sample Rate</td>
<td>2 ms.</td>
</tr>
<tr>
<td>Source</td>
<td>Vib. 3 sweeps 8-96 Hz.</td>
</tr>
</tbody>
</table>

Figure 3.4: CDP bin size and locations. Data are placed in 275 ft. x 275 ft. supergathers.
Figure 3.5: CDP offset and azimuthal coverage up to 12,000 ft. at 55 ft. bins. Each image displays the fold count in offset/azimuth bins from 0-360°, a histogram of offset and azimuth bin coverage, and the CDP location on the survey fold map. a) CMP with best coverage in the center of Wishbone Section b) CDP at edge of Wishbone Section, c) CDP with poor azimuthal and offset coverage
The attenuation analysis extends the kinematic velocity-independent layer-stripping algorithm of Dewangan and Tsvankin (2006), where the interval travel-time in a target layer is described by the ray path,

$$t_{BCE} = t_{ABCEG} - \frac{t_{ABD} + t_{GEF}}{2}. \quad (3.1)$$

The travel-times $t_{ABCEG}$, $t_{ABD}$, and $t_{GEF}$ describe the raypaths along ABCEG, ABD, and GEF (Figure 3.6) (Behura & Tsvankin, 2009a). The authors assume a laterally homogeneous overburden with horizontal symmetry plane, that has a horizontal symmetry plane. The spectral-ratio method is applied to estimate the normalized phase attenuation coefficient, $A$, from,

$$\ln \left( \left| \frac{U_{ABCEG}(\omega)^2}{|U_{ABD}(\omega)||U_{FEF}(\omega)|} \right| \right) = \ln G - 2\omega At_{BCE}, \quad (3.2)$$

where $\omega$ is the frequency, and $G$ is the source and receiver directivity, scattering coefficients, and geometrical spreading. $U_{ABCEG}(\omega)$, $U_{ABD}(\omega)$, and $U_{FEF}(\omega)$ are frequency-domain amplitudes of target and overburden reflections (Behura & Tsvankin, 2009a).

VILS improves estimation of interval velocity parameters from traditional Dix-type estimation of anisotropy. Previous synthetic tests illustrate that VILS maintains accuracy even with dips of up to 10° in the overburden (Wang & Tsvankin, 2009). Additionally it is important to note that faults and lateral velocity gradients will cause inaccuracy in the recovered travel-times.
Travel-times to the top and bottom of the target layer are calculated with the 3D non-hyperbolic semblance algorithm for VTI media,

\[ t^2(x) = t_0^2 + \frac{x^2}{V_{nmo}^2} - \frac{2\eta x^4}{V_{nmo}^2[t_0^2 V_{nmo}^2 + (1 + 2\eta)x^2]}, \]  

(3.3)

where \( \alpha \) is the source and receiver azimuth, \( V_{nmo} \) is the normal-moveout velocity, \( t_0 \) is the two-way zero-offset reflection travel-time, \( x \) is the offset, and \( \eta \) is the anellipticity parameter (Behura & Tsvankin, 2009a).

3D non-hyperbolic velocity analysis is performed on shot and receiver gathers to calculate moveout parameters for the reservoir interval. The reservoir and overburden are assumed to be locally laterally homogeneous in order to apply Equation 3.3, and estimate optimum moveout parameters for shot and receiver gathers. The top of the Niobrara and the top of the Lincoln Limestone member of the Greenhorn Formation define the interval of interest for velocity and attenuation analysis (Figure 3.7). The travel-times for the Niobrara and Lincoln Limestone are inputs for the velocity and attenuation layer stripping.
3.4 Time-lapse Seismic Processing

Processing for attenuation and velocity analysis is designed to preserve amplitude information (Figure 3.8). Processes that can alter the spectrum of the data such as deconvolution are not applied. The time-lapse processing utilizes a simultaneous processing approach in order to preserve time-lapse effects (Lumley et al., 2003; Lumley, 2001). The data were received from the contract processor with geometry and static corrections applied. The contractor utilized a three layer refraction static model built from the software GeoTomo GLI (Zhang & Toksöz, 1998). Statics are calculated from all three seismic surveys.

Trace regularization is performed by removing all sources and receivers that are not present in all surveys. During the acquisition of baseline and monitor 1 survey, approximately one fifth of receivers are not continuously recording (Figure 3.9). The intermittent recording causes non-uniform trace counts, if triplications are not calculated from source, receivers, and dead traces for each survey (Table 3.2). Noisy traces are also removed from all three surveys.
Figure 3.8: Processing flow for velocity independent layer stripping for interval velocity and interval attenuation.

Figure 3.9: Source and receiver locations for the 9C Turkey Shoot Survey. The black circles and black asterisks are sources and receivers kept in all surveys, respectfully. The red circles and red asterisks are the sources and receivers removed in all surveys, respectfully. Green asterisks are receivers that have partial coverage. Partial coverage means the receiver recorded a limited number of shots.
Table 3.2: Number of traces in each Turkey Shoot Survey and number of traces kept for 4D analysis.

<table>
<thead>
<tr>
<th></th>
<th>Baseline</th>
<th>Monitor 1</th>
<th>Monitor 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raw Survey</td>
<td>2,720,410</td>
<td>2,716,572</td>
<td>2,907,950</td>
</tr>
<tr>
<td>General S/R Removal</td>
<td>2,401,019</td>
<td>2,397,981</td>
<td>2,608,594</td>
</tr>
<tr>
<td>True 4D Trace Count</td>
<td>2,365,889</td>
<td>2,365,889</td>
<td>2,365,889</td>
</tr>
</tbody>
</table>

After trace regularization, filtering is performed to remove ground roll and random noise. A time frequency domain filter is utilized to remove outlier traces (Allinson et al., 2013; Stein & Langston, 2007). Additionally, surface consistent amplitude corrections are applied to shot, receiver, and channels to account for variations in amplitude caused by sources (Figure 3.10) (Taner & Koehler, 1981). Ground roll is removed by a $3Df − kk$ filter and a $f − xy$ median noise burst removal filter (Stein & Langston, 2007). $F − k$ filtering can potentially introduce artifacts into the spectrum of the data (Reine et al., 2012a,b), however bandpass filtering is not able to remove ground roll without affecting reservoir signal. The $f − xy$ filter is applied after the $3Df − kk$ filter in order to remove remaining noise at the near offsets.

3.5 Velocity Independent Layer Stripping Analysis

The interval of interest is the Niobrara reservoir. Velocity and attenuation analysis are performed from the top of the Niobrara Formation to the top of the Greenhorn Lincoln Limestone (∼400 ft thick). The interval is selected because of the strong reflectivity of the Niobrara and Greenhorn Lincoln Limestone on shot and receiver gathers. The resulting velocity and attenuation is an effective measurement of the entire interval.

Attenuation anisotropy parameters of the reservoir layers are estimated with the spectral-ratio method and the previous travel-time values. Velocity anisotropy information is needed to estimate the phase direction from the group direction (Behura & Tsvankin, 2009a,b; Behura et al., 2012).
Figure 3.10: a) Shot 5 with statics applied.  b) Shot 5 with statics, surface consistent amplitude compensation, and filtering applied.
Instantaneous $Q$ values are estimated with a $\pm 16$ms window centered around the top and base horizons of the target layer. Larger windows result in interference from other reflections. Spectra are estimated from 14-35 Hz. and 14-55 Hz (Figure 3.11). Spectra are smoothed with a median filter in order to remove notches (Figure 3.12).

Figure 3.11: Extracted spectra from 14 - 55 Hz. from each leg of the layer stripping.

Though the Niobrara reservoir interval is likely orthorhombic or monoclinic, the 4D survey is limited to an offset to depth ratio of 1.6. Therefore, the interval velocity and attenuation values are inverted for VTI parameters. P-wave phase attenuation for VTI media is calculated:

$$A_P(\theta) = A_{P0} \left[ 1 + \delta_Q \sin^2 \theta \cos^2 \theta + \epsilon_Q \sin^4 \theta \right],$$

(3.4)

where $A_{P0}$ is the vertical attenuation coefficient, which is equivalent to the group attenuation coefficient (Zhu et al., 2006). $\delta_Q$ and $\epsilon_Q$ are the Thomsen-style attenuation anisotropy parameters for vertical and horizontal wave propagation, respectfully (Zhu et al., 2006). Layer
stripped values are sorted into supergather CMP locations, and a grid search inversion approach is implemented to estimate interval values. Accuracy of the algorithm has previously been confirmed with synthetic seismic (Behura & Tsvankin, 2009a).

3.6 Survey Limitations

Estimation of anisotropic parameters with only P-wave data requires large offset to depth ratios. As mentioned previously, consistent azimuthal and offset sampling is only to 11,000 ft, which is approximately an offset to depth ratio of 1.6. Vasconcelos and Tsvankin (2006) illustrate larger offset to depth ratios are necessary in order to estimate \( \eta_1 \) and \( \eta_3 \), which contribute only to non-hyperbolic moveout at long spreads. Additionally, \( \eta_3 \) estimation is the least constrained because it is only influential on travel-times away from the symmetry planes (Vasconcelos & Tsvankin, 2006). The symmetry plane orientation \( \phi \) is highly constrained since the symmetry plane is influenced by the azimuthally varying non-hyperbolic moveout, and the NMO ellipse. These restrictions also hold true when estimating the anisotropic
attenuation parameters (Zhu & Tsvankin, 2006).

The Niobrara matrix is a shale carbonate reservoir, and core samples from near the Wishbone Section illustrate VTI velocity and attenuation anisotropy (Kamruzzaman, 2015; Ou & Prasad, 2017). Fractures are also present within the reservoir before hydraulic fracturing. Formation microimage logs and microseismic moment tensors measure the orientation of the dominant natural and induced fractures that are oriented N70°W (Grechishnikova, 2017). It is important to note that three other minor fracture orientations are present within the Wishbone Section. The other fracture sets would cause the reservoir to have monoclinic symmetry. However, due to the limitations of the 4D P-wave survey, the effect of fractures is not present, or barely observed within the offset limitation of 11,000 ft (Figure 3.13). Additionally, estimation for VTI parameters cause instability within the inversion process. Therefore, core estimates of velocity and attenuation anisotropy are used to fix velocity and attenuation anisotropy values during the inversion. Fixing the results to known core estimates of anisotropy stabilize the inversion. Thus, the inversion estimates relative velocity and attenuation parameters dynamically (Table 3.3) (Kamruzzaman, 2015; Ou & Prasad, 2017).

<table>
<thead>
<tr>
<th>Velocity</th>
<th>Attenuation</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\epsilon$: 0.28</td>
<td>$\epsilon_Q$: -0.275</td>
</tr>
<tr>
<td>$\delta$: 0.07</td>
<td>$\delta_Q$: 1.115</td>
</tr>
</tbody>
</table>

Modeling illustrates the VVAZ response of the Niobrara is limited due to the size of the hydraulic fractures and the thickness of the reservoir interval Figure 2.10. Due to this restriction, assessment of azimuthal time-lapse changes requires longer offsets, or multicomponent data.
Figure 3.13: The travel-time variability shows minimal VVAZ on the far-offset traces. The far offset travel-time variability is only half a cycle within one offset plane. Therefore, velocity variability does not resemble HTI or orthorhombic velocity anisotropy. a) Example COCA from baseline survey. b) Monitor 1 COCA example
3.7 Results

Due to the limited offset of the time-lapse surveys, recovery of both $V_{NMO}$, $\eta$, $\epsilon_Q$, and $\delta_Q$ are not possible. Core estimates of anisotropy are used to stabilize the inversion. Due to this assumption any geologic variance in $\epsilon$, $\delta$, $\epsilon_Q$, and $\delta_Q$ will cause an inaccurate estimation in $V_{NMO}$ and $A_{P0}$ in the surveys. However, any time-lapse changes will illustrate how the reservoir is changing qualitatively.

Velocity results for all surveys are consistent laterally, and have similar ranges based on well log estimates from the Wishbone Section. Attenuation ranges are similar to other reported values of the Niobrara reservoir (Behura et al., 2016). Different bandwidth selections show minimal influence upon recovered attenuation. Two bandwidths of 14-35 Hz and 14-55 Hz. show similar interval attenuation values (Figure 3.14). The similarity of the two bandwidths indicates that frequency independent Q is an appropriate assumption. Typical attenuation shifts range between 0.001-0.0015 $A_{P0}$. The window size around the top and base horizons has a large effect upon recovered attenuation parameters, and the stability of the results. Too large of a window introduces other reflections. Increasing the window size by 6 ms. causes the recovered interval attenuation to drastically shift $A_{P0}$ by 0.0114.

The section of the time window is not a robust approach due to the sensitivity of various window sizes to interference effects. Optimum parameters are found with a window size of 16 ms. Between each survey, changes in the distribution of layer stripped attenuation values are observed (Figure 3.15).

Laterally model parameters are coherent for baseline velocity and attenuation results, and the assumed VTI background values give stability to the inversions. The VTI parameters allow global minimums to be reached for both the velocity and attenuation inversions (Figure 3.16). Uncertainty maps are generated by calculating the average error between velocity and attenuation data with the estimated model. Uncertainty and threshold maps are generated for each survey to illustrate the model fit, the spatial variance of the inverted parameters, and how the uncertainty changes with time (Figure 3.17).
Figure 3.14: Example attenuation shifts caused by different bandwidths a) Typical bandwidth differences observed b) Largest bandwidth differences observed.

Figure 3.15: Example attenuation shifts between surveys at an example CDP in Wishbone Section a) Baseline and monitor 1 attenuation distribution b) Monitor 1 and monitor 2 attenuation distribution.
The velocity error maps show lower error associated with the baseline survey. The higher travel-time errors are observed on the edges of the survey area. Higher travel-time error maybe due to the lower fold at the edges of the survey area, or the recovered parameters may deviate more significantly from a VTI model. The baseline attenuation misfit illustrates higher uncertainty in the northeast portion of the survey area. Monitor 1 attenuation misfit decreases from the baseline parameters.Monitor 2 attenuation misfit has the lowest misfit over the entire survey area (Figure 3.17).

Threshold maps are also generated to illustrate the variance of the global minimum for the recovered model parameters. In order to calculate potential variance of the models, travel-time and attenuation misfits are scaled between 0 and 1, where the lowest misfit is 1. The variance of the global minimum is estimated at 0.98 or the 98%, which correlates to the flat portion of the objective functions for both the attenuation and velocity (Figure 3.16). The velocity variance is highest around the boundaries of major faults in all three surveys (Figure 3.18). This may be attributed to the approximations of the VILS method, or higher amounts of anisotropy within the reservoir interval near faults. In the monitor surveys the variance of the models spatially remain consistent.

The baseline attenuation threshold map illustrates greater variance between the recovered model parameters in the southwestern part of the survey. These areas also have the best misfit between the interval values and the recovered model. The larger values are also observed over wells that were previously producing for a year west of the Wishbone Section. Overall, the attenuation results show the lowest error in the monitor 2 survey. The area with larger variance in $A_{P0}$ coincides with microseismic activity that is discussed further in Chapter 4. Monitor 2 variance in attenuation parameters is greatest over the western portion of the survey area, which coincides with the smallest model misfit. Additionally, this are correlates with the larger changes in attenuation observed between monitor 2 and the baseline surveys.
Recovered interval values show laterally consistent $V_{NMO}$ velocities. The faults within the section appear to have a significant effect upon the velocities. For example, interval $V_{NMO}$ velocities decrease $\sim2,000$ ft/s on the northern side of the north-east trending graben. Attenuation is also influenced by the northwest trending fault (Figure 3.19).

It is important to note that the wells west of the Wishbone Section have been on production for approximately one year before the baseline survey. The wells east of the Wishbone section (not shown) were stimulated three months before the baseline. Vertical wells within the section stimulated the Niobrara and Codell approximately eight years before the baseline survey.

Monitor 1 results show an overall decrease in interval $V_{NMO}$ velocity, which is attributed to the hydraulic stimulation that occurs before the survey (Figure 3.20). The highest velocity decrease is observed in the western portion of the survey along the north-east trending graben where well spacing is tighter (Figure 3.20). Additionally, the main time-lapse change (11-13%) is observed over the horizontal wells that are stimulated, and the producing wells west of the Wishbone Section. Other time-lapse surveys of fluid injection have observed smaller changes in velocity of $\pm5\%$ change in velocity (Rivet et al., 2016).

The higher percent changes are likely due to $\epsilon$ and $\delta$ remaining constant during the inversion, thus any time-lapse or spatial change in anisotropy causes an increase in monitor 1 $V_{NMO}$. Additionally, the assumption of VTI limits the accurate recovery of parameters since the Niobrara is a fractured reservoir. The inverted maps estimate an average decrease in $\delta$, which is caused by a increase in fracturing.

The attenuation results show mostly negative changes in the western portion of the survey near tightly spaced wells, and along the northwest trending fault. The decrease in negative attenuation maybe attributed to the higher viscosity of the hydraulic fracture fluid than the hydrocarbon in the reservoir, and the drastic increase in fracture permeability (Figure 3.19).

Monitor 2 results show moderate changes from Monitor 1 in velocity due to the production of wells within the survey area (Figure 3.19). As the reservoir is produced, pressure decreases,
Figure 3.16: Example error plot from baseline survey for a) $V_{NMO}$ B) $A_{P0}$. 
Figure 3.17: Error maps of travel-time misfit and attenuation misfit for baseline survey for a) Baseline $V_{NMO}$ Error, b) Monitor 1 $V_{NMO}$ Error, c) Monitor 2 $V_{NMO}$ Error, d) Baseline $A_{P0}$ Error, e) Monitor 1 $A_{P0}$ Error, f) Monitor 2 $A_{P0}$ Error.

Figure 3.18: Data misfit range at 0.98% a) Baseline $V_{NMO}$ Threshold, b) Monitor 1 $V_{NMO}$ Threshold, c) Monitor 2 $V_{NMO}$ Threshold, d) Baseline $A_{P0}$ Threshold, e) Monitor 1 $A_{P0}$ Threshold, f) Monitor 2 $A_{P0}$ Threshold.
Figure 3.19: Baseline, Monitor 1, and Monitor 2 velocity and attenuation results. a) Baseline $V_{NMO}$, b) Monitor 1 $V_{NMO}$, c) Monitor 2 $V_{NMO}$, d) Baseline $A_{P0}$, e) Monitor 1 $A_{P0}$, f) Monitor 2 $A_{P0}$.

Figure 3.20: Time-lapse velocity and attenuation results, a) Monitor 1 - Baseline $\%\Delta V_{NMO}$, b) Monitor 2 - Monitor 1 $\%\Delta V_{NMO}$, c) Monitor 2 - Baseline $\%\Delta V_{NMO}$, d) Monitor 1 - Baseline $\%\Delta A_{P0}$, e) Monitor 2 - Monitor 1 $\%\Delta A_{P0}$, f) Monitor 2 - Baseline $\%\Delta A_{P0}$.
fractures lacking proppant close, and gas comes out of solution. The reservoir shows both increases and decreases of $V_{NMO}$ within the section. The decrease in $V_{NMO}$ is generally near major faults within the survey, whereas the larger increases in velocity are generally south of the main graben (Figure 3.20). The observed changes in velocity are smaller than the stimulation response, and range between -4 - 8%.

As stated previously, the increase in the reservoir is probably less dramatic since $\epsilon$ and $\delta$ are kept constant during all three inversions, and VTI parameters cannot describe a fractured reservoir. Time-lapse changes between monitor 2 and baseline show a decrease in velocities. Larger velocity changes are observed around wells with tighter well spacing, which is caused by larger changes in reservoir fracture properties.

The attenuation results show an overall decrease in $A_{P0}$ after two years of production between monitor 2 and baseline (Figure 3.19). Zones with highest decreases of attenuation are in the western portion of the survey area (Figure 3.20). Previous attenuation studies typically observe an increase in attenuation associated with gas in a reservoir (Dinh et al., 2015; Puasa et al., 2014; Reine et al., 2012a). These results do not agree with previously observed correlations with gas and P-wave seismic attenuation. Previous reservoir are conventional reservoir that only experience fluid changes. In an unconventional reservoir, hydraulic fracturing and production cause drastic changes in permeability, fluid properties, and fracture properties. These changes may cause an apparent decrease in attenuation by shifting the apex attenuation to higher frequencies outside of the P-wave seismic bandwidth.

3.7.1 Comparison to post-stack attributes

In order to illustrate the applicability of time-lapse interval velocity and attenuation, post-stack amplitude and frequency attributes are compared. Frequency and amplitude changes are calculated from cross equalized post-stack data, that had an average NRMS error of 0.25 (Utley, 2017). The RMS amplitude and average frequency of the interval of interest are calculated over the same interval as the velocity and attenuation analysis (Chopra & Marfurt, 2007). Both amplitude and frequency attributes show decreases over
the stimulated wells, and an increase is observed in monitor 2 (Figure 3.21).

Time-lapse anomalies are greatest in the western portion of the survey area (Figure 3.22). Monitor 1 to baseline shows both average frequency and RMS amplitudes show little change in the eastern portion of the survey. The anomalies also do not trend along the wells or the structural features within the survey area. Monitor 2 to monitor 1 shows the largest changes in the western portion of the survey area. Large amplitude ranges are observed between monitor 2 and monitor 1. Frequency changes show more coherent spatial anomalies between the surveys that are bounded by faults. Monitor 2 to baseline show larger changes in the western and northeast portion of the survey. Anomalies have less of a dynamic range than comparisons to monitor 1.

![Figure 3.21: Baseline, Monitor 1, and Monitor 2 RMS amplitude and average frequency results. a) Baseline RMS amplitude, b) Monitor 1 RMS amplitude, c) Monitor 2 RMS amplitude, d) Baseline Avg. Freq., e) Monitor 1 Avg. Freq., f) Monitor 2 Avg. Freq.](image)

Time-lapse velocity and attenuation show similar dynamic ranges as the post-stack attribute results, and similar spatial distributions. Overall, interval velocity and attenuation parameters show spatially coherent parameters, which is significant if the changes are due to
Figure 3.22: Time-lapse amplitude and average frequency results, a) Monitor 1 - Baseline % RMS amplitude, b) Monitor 2 - Monitor 1 % RMS amplitude, c) Monitor 2 - Baseline % RMS amplitude, d) Monitor 1 - Baseline % Avg. Freq., e) Monitor 2 - Monitor 1 % Avg. Freq., f) Monitor 2 - Baseline % Avg. Freq. 

3.8 Discussion

Time-lapse processing of the surveys is designed to match the number of sources and receivers present in all three surveys. Due to irregular trace recording present in baseline and monitor 1, \( \sim 13\% \) of the data are removed for time-lapse analysis. Additionally, consistent offset azimuth information is limited to 11,000 ft. These survey restrictions limit the observable VVAZ on recorded data.

Frequency-independent Q is an appropriate assumption for the time-lapse surveys. Varying bandwidths show similar repeatable measurements for each survey. Window selection
for the selected horizons has a significant effect upon recovered parameters. Larger windows begin to incorporate interference effects, which corrupt the spectral ratio estimate. Selection of the window size is arbitrary.

Synthetic models are generated with the entire reservoir fractured, in order to demonstrate the limitations of small offset to depth ratios. Observable P-wave VVAZ in the Niobrara reservoir is between 10,000 ft. to 13,000 ft. offset. Increases in fracture density and aperture cause observable VVAZ at farther offsets, but are minor within the limits of the acquired surveys. These results agree with previous anisotropic P-wave moveout analysis, and the need for far offset P-wave data in order to recover fractured media properties (Vasconcelos & Tsvankin, 2006).

Due to acquisition limitations, velocity and attenuation analysis is restricted to VTI, and anisotropy parameters are fixed during the inversion to add stability. The spectral ratio method is very sensitive to the window selection. Without using full-waveform or tomography approaches, attenuation window size has the potential to be impacted by interference effects. Results show observable velocity changes due to both stimulation and production. The observable changes range from -13% - 12% $V_{NMO}$ velocity. The larger velocity changes are due to the VTI assumption, and not allowing $\eta$ to vary spatially and dynamically. Though these changes are high, 4D anomalies correlate with the stimulated and producing wells. Inverted velocity results for both monitor surveys show decreases in the $V_{NMO}$ velocity from the baseline survey. Travel-time differences between monitor 2 and monitor 1 generally show positive changes due to reservoir compaction and smaller fracture properties (Eker, 2018). These time-lapse changes agree with the rock physics modeling in Chapter 2.

Time-lapse attenuation shows detectable changes in $A_{P0}$. However, without a vertical seismic profile, it is difficult to confirm actual time-lapse velocity or attenuation changes within the reservoir. Time-lapse results also show that the dynamic change in attenuation is more significant than the velocity response of the reservoir. $A_{P0}$ changes range from -20% - 8%, which is a similar range as post-stack amplitude changes within the reservoir.
3.9 Conclusions

In this chapter, I utilize a robust velocity and attenuation layer stripping method, and apply it on time-lapse P-wave seismic data (Behura & Tsvankin, 2009a; Dewangan & Tsvankin, 2006; Wang & Tsvankin, 2009). Previous synthetic tests show the methodology is stable when geologic dip is less than 10° (Dewangan & Tsvankin, 2006; Wang & Tsvankin, 2009). The dip at the survey area is approximately 1°. Faults within the overburden may limit the accuracy of the layer stripping methodology due to the assumption of lateral homogeneity. Velocity and attenuation anomalies spatially correlate with horizontal wells that are stimulated and producing. Anomalies cannot be matched to variations in well lithology, because the measurements are calculated from the top of the Niobrara Formation to the base of the Lincoln Limestone member of the Greenhorn Formation. Calibration data is not available to confirm the time-lapse anomalies. Future work must include downhole pressure measurements, repeat logs, and vertical seismic profiles in order verify the degree of change observed by the P-wave seismic.

The velocity and attenuation inversion methodology suffers from lack of longer offset P-wave seismic data. Therefore, dynamic fracture properties cannot be estimated with the P-wave data alone. Previous rock physics modeling indicates that the VTI $V_{NMO}$ velocity will decrease due to increased fracturing caused by hydraulic stimulation. The time-lapse data agrees with the modeling work. The time-lapse velocity changes from baseline to monitor 1, and baseline to monitor 2 both show a decrease in the P-wave $V_{NMO}$ velocity. Additionally, the $V_{NMO}$ velocity increases between the monitor 1 and monitor 2 surveys due to reservoir compaction, which matches the rock physics modeling (Eker, 2018). Overall, travel-time changes show non-uniform variances in $V_{NMO}$ velocity over the Wishbone Section. The largest changes in $V_{NMO}$ velocity are observed over the western wells in the survey.

Baseline attenuation shows coherent spatial patterns, and the ranges of $A_{P0}$ agree with other published vertical attenuation values from the Niobrara reservoir (Behura et al., 2016). Previous rock physics modeling indicates that the fracture radius has a large impact upon
the potential time-lapse attenuation response of the reservoir. The T-matrix modeling shows that a decrease in the vertical attenuation from the baseline case is possible over the seismic bandwidth. The decrease in attenuation is due to the apex frequency shifting outside of the seismic bandwidth due to changes in the reservoir permeability, fracture properties, and reservoir fluids. The seismic data shows a decrease in the vertical attenuation from the baseline survey. Seismic data also do not show frequency dependent attenuation. Based upon the T-matrix modeling in Chapter 2, a decrease in $A_{P0}$ during monitor 1 may indicate zones with open fluid filled fractures. The decrease in $A_{P0}$ during monitor 2 may indicate zones with higher gas concentration. The decrease in vertical attenuation over the seismic bandwidth is contrary to previous attenuation measurements made in reservoirs with gas coming out of solution (Dinh et al., 2015; Puasa et al., 2014; Reine et al., 2012a). Those observations however are made in conventional reservoirs where all other rock properties are constant, whereas the observations in this chapter are made in a tight shale reservoir that is experiencing fracture, permeability, and fluid changes.

Overall, pre-stack estimates of interval velocity and interval attenuation are sensitive to hydraulic fracturing and production in the Niobrara Reservoir. Rock physics modeling in Chapter 2 agrees with the decrease in observed P-wave $V_{NMO}$ due to increased fracturing. Additionally, T-matrix modeling indicates that a decrease in vertical attenuation is possible due to the apex attenuation shifting outside of the seismic bandwidth. Future work must acquire downhole calibration data, and vertical seismic profiles in order to verify the observed changes.
CHAPTER 4
INTEGRATED RESERVOIR CHARACTERIZATION DUE TO HYDRAULIC FRACTURING AND PRODUCTION EFFECTS AT WISHBONE SECTION, WATTENBERG FIELD, COLORADO

Improved estimation of spatial variability in unconventional reservoirs can lead to improved completion designs, reservoir models, and understanding of how reservoir heterogeneity affects stimulation and production. Seismic is typically used for static characterization of unconventional reservoirs. For example, estimation of geomechanical properties with isotropic inversions, and identification of faults (Goodway et al., 2010; Refayee et al., 2016).

During hydraulic stimulation, proppant and frac fluid are injected into the reservoir in order to increase reservoir permeability. During the completion of wells, tracer and microseismic data may be collected, and connections are drawn between these data to estimate a stimulated reservoir volume and well connectivity. However, without time-lapse seismic, spatial variations within the reservoir cannot be mapped, and stage variances are difficult to explain. For example, a particular stage may have large amounts of microseismicity, but may be a poor producer. Time-lapse seismic has helped understand areas of reservoirs affected by hydraulic stimulation and production (Duliman et al., 2013; Johri & Zoback, 2013; Lambert et al., 2017; Landro & Stammeijer, 2004; Tura et al., 2006; Wang et al., 2017; White & Davis, 2016). Incorporation of 4D seismic can improve reservoir models, and enhance understanding of how fractures and faults affect stimulation, early term production, and long term production.

In Wattenberg Field, APC and the RCP collected time-lapse multicomponent (9C) seismic data to understand how the Niobrara Formation and Codell Sandstone respond to deformation caused by hydraulic fracturing and production. Three seismic surveys help us understand the dynamic reservoir changes caused by hydraulic fracturing and production.
of eleven horizontal wells within a one-square mile section. A baseline survey was recorded immediately after the wells were drilled, another survey after stimulation, and a third survey after two years of production.

Understanding how the Niobrara reservoir responds to stimulation and production can illustrate how the geology influences well spacing, and how faults and fractures affect completions and the production response of the reservoir. In conjunction with image logs, surface microseismic, tracer data, and production information I use time-lapse velocity and attenuation to analyze how faults, joint sets, and well spacing affect stimulation, early term production, and late term production from eleven horizontal wells, Wattenberg Field, Colorado.

4.1 Data Availability

Time-lapse seismic, surface microseismic, tracer data, and completion data for my study are from the monitoring of eleven horizontal multistage wells in the Niobrara Formation and Codell Sandstone, Wattenberg Field, Colorado (Butler et al., 2016; Motamedi & Davis, 2015; Nurhasan & Davis, 2016; Paskvich, 2016; Pitcher & Davis, 2016; White & Davis, 2016). Six of the wells target the Niobrara C Chalk, one well targets the Niobrara B chalk, and the remaining four wells target the Codell Sandstone member of the Carlile Formation. Table 4.1 provides a summary of seismic data acquired to study the hydraulic fracturing and production effect in the Wishbone section. The 4D multicomponent seismic survey is the Turkey Shoot. The seismic surveys are highly repeatable with an average NRMS error of 0.25 (Utley, 2017). Surface microseismic data were acquired during the completion of all eleven horizontal wells. The survey was collected at the surface using a Microseismic Inc. FracStar array (Pitcher, 2015). Well logs, tracer data, FMI logs, and production information are also available for the Wishbone Section.
Table 4.1: Timeline of Wishbone Section drilling, completion, production, and seismic surveys.

<table>
<thead>
<tr>
<th>Timeline</th>
<th>Event</th>
</tr>
</thead>
<tbody>
<tr>
<td>1\textsuperscript{st} Month</td>
<td>Wishbone Wells Drilled</td>
</tr>
<tr>
<td>2\textsuperscript{nd} Month</td>
<td>Baseline 9C Survey</td>
</tr>
<tr>
<td>4\textsuperscript{th} Month</td>
<td>Wishbone Wells Completed</td>
</tr>
<tr>
<td>4\textsuperscript{th} Month</td>
<td>Surface Microseismic Survey</td>
</tr>
<tr>
<td>6\textsuperscript{th} Month</td>
<td>Monitor 1 9C Survey</td>
</tr>
<tr>
<td>2 Years</td>
<td>2 Years Production</td>
</tr>
<tr>
<td>2 Years</td>
<td>Monitor 2 9C Survey</td>
</tr>
</tbody>
</table>

4.2 Data Limitations and Uncertainty

The Turkey Shoot time-lapse survey is a four sq. mi. survey that focuses upon the Wishbone Section. Offset and full azimuthal coverage is limited to 11,000 ft, which restricts the potential recovery of anisotropic parameters with only P-wave data. Due to these limitations, velocity and attenuation data are estimated with a VTI model, and core estimations of anisotropy (Kamruzzaman, 2015; Ou & Prasad, 2017). VTI models cannot describe changes in fracture properties. Before and after stimulation the velocity variation with azimuth is not present throughout most of the survey before 11,000 ft. In order to accurately describe the Niobrara reservoir, at least orthorhombic parameters are required. Due to the survey limitations, relative changes in $V_{NMO}$, and $A_{P0}$ are analyzed dynamically to understand the reservoir deformation caused by stimulation and production.

The Wishbone Section was monitored by a surface microseismic array, and processed by a vendor (Pitcher & Davis, 2016). The majority of surface microseismic events have an X and Y, and Z sensitivity of less than 30 ft. and 50 ft., respectfully. The largest density of events is within the reservoir, however the total range of events is from the Morrison Formation to the Lower Pierre Formation (Figure 4.1). Events near the Morrison Formation have large depth uncertainty, whereas the shallower events in the Lower Pierre Formation have high confidence.
Figure 4.1: Microseismic events recorded from the stimulation of the eleven wells in the Wishbone Section. a) Map view of microseismic events, which mainly trend with the maximum horizontal stress. The events are colored by relative depth. The background is the fault likelihood attribute. b) Depth view of the microseismic events, which are colored by elevation sensitivity. Main horizons from the surface seismic are also displayed.

Event magnitudes range from -2.2 to -0.5. Few of the events are above -1, and the mean magnitude is $\sim$-1.7. The majority of fault plane solutions are oriented with the maximum
horizontal stress (N70°W), have high dips, and are dip slip events (Figure 4.2). A smaller subset of events are strike-slip or oblique-slip events, and the moment tensor strike directions are aligned with three fracture sets found within the Wishbone Section (Grechishnikova, 2017). The auxiliary planes are more variant in strike direction.

Figure 4.2: a) Rose diagrams of moment tensor orientations separated by tensor type. The majority of events trend N70°W b) Histogram of microseismic dips of fault plane, and auxiliary plane.

4.3 Methodology

Integration of multiple data types with time-lapse velocity and attenuation data is performed in order to access the effects of faults, and well spacing due to stimulation and production. I investigate how geologic heterogeneity influences operational variances within the Wishbone Section. The workflow integrates multiple data types in order to understand reservoir deformation due to stimulation and production (Figure 4.3).
4.4 Geologic setting

Wattenberg Field is approximately 2,000 mi² located 35 miles northeast of Denver, CO. Time-lapse seismic were collected to understand the dynamic response of hydraulic stimulation and production of eleven horizontal wells in the Niobrara Formation and Codell Sandstone, Wishbone section, Wattenberg Field. Seven of the wells target the Niobrara Formation, and the remaining wells target the Codell Sandstone Member of the Carlile Formation (Figure 3.1). The Niobrara Formation and Carlile Formation are overlain by the Pierre Shale, and underlain by the Greenhorn Formation. Due to faulting within the section, wells are not consistently in the same bench within the Niobrara Formation. Gamma ray and resistivity logs were acquired in the horizontal wells and used to determine the location of a stage within the formation.

The Niobrara Formation was deposited in the Western Interior Seaway (WIS). The WIS is divided into multiple basins such as the Denver, Piceance, and Uinta Basin (Underwood, 2013). The Denver Basin formed during the Laramide Orogeny. The Laramide Orogeny

Figure 4.3: Interpretation workflow. Two stages of data integration are performed in order to understand reservoir deformation caused by stimulation and production.
uplifted the Rocky Mountains, and created the asymmetrical foreland Denver Basin. The western part of the Denver Basin is steeply dipping, whereas the eastern flank has a shallow dip of less than one degree (Sonnenberg, 2015). During the Cretaceous, Precambrian shear zones experienced recurrent movement, which provided a tectonic control on sedimentation by influencing topography and bathymetry (Sonnenberg & Weimer, 1981; Weimer, 1978, 1980, 1983, 1984).

The Niobrara Formation was deposited during the Late Cretaceous. Deposition occurred in a foreland basin during multiple transgressions and regressions. These sea-level undulations resulted in the deposition of chalks and marls. Marls were deposited in higher sea level. Coccolith-rich carbonates dominated the deposition because of the mixing of the cold Boreal and warm Tethyan water (Locklair & Sageman, 2008). The marl units were generally deposited in an anoxic environment when sea level was lower. The shallower sea-levels allowed for the preservation of organic carbon, and higher deposition rates (Kauffman, 1977).

Across Wattenberg Field the Niobrara Formation’s thickness ranges from 200 to 400 ft. (Sonnenberg, 2015). The Niobrara Formation is composed of two separate members: the Smoky Hill Member and Fort Hays Member. The Smoky Hill Member represents interbedded chalks and marls (A, B, and C benches) (Figure 4.4). Individual chalk and marl layers’ thicknesses range from 30 - 50 ft. The Fort Hays Member is a highly bioturbated limestone that is approximately 20 ft thick. Within the RCP study section, the A chalk is not present due to an erosional unconformity on the Wattenberg High (Mabrey, 2016).

The Codell Sandstone member is approximately 89 Ma. Previous core analysis in the RCP study area documented two dominant facies. The first facies is a laminated bioturbated sandstone with hummocky cross stratification. The second facies is a well sorted extremely bioturbated sandstone with multiple carbonate clasts and burrows (Mabrey, 2016).
4.4.1 Faults and fractures

Multiple faulting systems are present within Wattenberg Field. Stone (1969) and Weimer (1996) identified and mapped regional northeast trending wrench fault systems. The RCP study area is located between two wrench faults, the Lafeyette and Longmont faults. In the Cretaceous interval, Davis (1985) identified three distinct stratigraphic units that exhibit
listric normal faults: the Laramie-Fox Hills to Upper Pierre, the Middle Pierre Hygiene zone, and the Niobrara-Carlie-Greenhorn interval. The previous intervals represent periods of movement along basement-controlled faults (Davis, 2011). After the Laramide Orogeny, the Denver Basin experienced extensional tectonism during the Tertiary. Vincelette and Foster (1992) indicated that the extensional phase may have reactivated older fracture sets and caused mineralization. Formation image log analysis and surface microseismic moment tensor analysis within the RCP study area illustrates four fracture sets, which contain mineralization and open fractures (Figure 4.6) (Dudley, 2015; Grechishnikova, 2017). This indicates post-Laramide reactivation of paleo-fracture sets.

The complex fault system within the RCP study area is influenced by both the de-watering of the Niobrara Formation after deposition, and low-angle listric faults that form an en-echelon graben system (Figure 4.5) (Davis, 2011; Pitcher, 2015; Shelton, 1984; Sonnenberg & Underwood, 2012; Weimer & Davis, 1977). Two graben structures are present in the Wishbone section and extend into the Carlile and Greenhorn Formation. At the C Chalk interval, the de-watering (polygonal fault system) is present within the Turkey Shoot Survey (Pitcher, 2015). Recent discrete fracture analysis shows that four major fracture sets are present within the Wishbone Section. $J_1$ compressional joints, $J_2$ extensional joints, and $S_3$ and $S_4$ conjugate shear fracture sets are observed from FMI logs, moment tensor analysis, and outcrop analysis (Grechishnikova, 2017). Additionally, higher fracture intensity is observed within chalks than the marls, and higher fracture density is measured near faults (Dudley, 2015; Grechishnikova, 2016).

4.4.2 Fault Stability Modeling

Natural fractures, reservoir stresses, and faults have shown to influence hydraulic fracturing effectiveness within shale reservoirs (Dahi-Taleghani et al., 2011; Rogers et al., 2010; Vermylen et al., 2011; Zoback et al., 2012). In order to understand how faults may respond to hydraulic fracturing, stability modeling is performed to understand the in-situ fault conditions (Bratton, 2018; Priest, 1993). Stability modeling can illustrate when a fault
Figure 4.5: The stage location for each of the horizontal wells, and the red outline is the Wishbone Section. Colored circles are stage locations for each well. Faults within the section cause wells to undulate between different benches of the Niobrara Formation. Lumina’s fault likelihood attribute at top Niobrara Formation. The larger displacement in ms the more probable the fault exists.

Theoretically becomes unstable. The normal and shear stresses aligned with a fault are computed using a stress transformation that rotates the stresses from a Cartesian coordinate system aligned with the far-field principal stresses. Inputs from the study area include the principal stresses, and the strike and dip angles for faults (Table 4.2).

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th>Friction angle</th>
<th>Cohesion coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_P$</td>
<td>$\sigma_h$</td>
<td>$\sigma_H$</td>
<td>$\sigma_V$</td>
<td>25</td>
<td>20</td>
</tr>
</tbody>
</table>

Stability modeling highlights the strikes and dips of faults under this stress regime that are under the most stress (Figure 4.7). Faults under higher levels of stress are more prone to higher fracture density and may have higher permeability (Bratton, 2018; Priest, 1993). These fault zone characteristics influence completion effectiveness. The western portion of
the main graben lies within the fault instability zone, which is orientated at approximately 115° NW. It is key to note that no microseismic events were recorded above a magnitude of 0. Thus, there is no evidence of actual full fault slip in the area.

4.4.3 Baseline Velocity and Attenuation

Interval measurements illustrate how the reservoir is affected by the faults. Stability modeling shows that north-east trending faults are the most stable, whereas faults aligned with the maximum horizontal stress (N70°W) are the most stressed. Baseline velocity results show significantly higher interval velocities over parts of the Wishbone Section (Figure 4.8). Baseline attenuation results also appear to be influenced by the northwest trending fault (Figure 4.8). Overall, the two grabens and the northwest trending fault are the main structural features that bound the baseline velocity and attenuation results, which may indicate reservoir compartmentalization due to faulting.
4.5 Hydraulic fracturing effects

The Wishbone Section is a pilot well spacing and completion program conducted by APC. The eleven horizontal wells in the Wishbone Section are fractured from east to west, and
Figure 4.8: Baseline interval velocity and attenuation a) $V_{NMO}$ is laterally confined by the northeast trending graben and northwest trending fault, b) $A_{P0}$ shows the northwest trending fault affects the interval attenuation distribution.

Wells 7N, 8C, and 9N were zipper frac’ed (Figure 3.1). Wells were drilled in June, 2013 and completed between August and September, 2013. Additionally, the wells have tighter well spacing in the western portion of the survey. The well spacing ranges from 600 ft. to 1200 ft. across the section. The number of stages per well also vary between 20-32. Relative fluid and proppant injected, and relative stimulation dates are in Table 4.3.

Though wells target a specific zone of the reservoir such as the C Chalk, faults cause wells to deviate into bounding beds (Figure 4.9). Besides the eleven horizontal wells within the Wishbone Section, multiple older vertical wells are present within the survey area that previously produced from the Niobrara reservoir. Sections that surround the Wishbone Section also have horizontal wells that were previously stimulated and producing before the baseline survey (Nurhasan, 2017).

In order to understand how the Niobrara reservoir is affected by stimulation, I integrate time-lapse velocity and attenuation analysis with microseismic and completion data. Additionally, I utilize 4D time-shifts and microseismic to illustrate how hydraulic stimulation affects the overburden.
4.5.1 Time-lapse velocity and attenuation changes due to stimulation

Dynamic measurements illustrate how reservoir heterogeneity and well spacing affect the stimulation of the eleven horizontal wells. In the Wishbone Section, time-lapse velocity changes show a velocity decrease up to 13% over the wells. These changes are relative because the inversion holds $\eta$ constant. Highest changes are associated with closer well spacing in the southwestern part of the section where the wells do not cross the a graben (Figure 4.10). The toe portion of wells 7N - 11N has an overall change of $\sim$5%.

Time-lapse attenuation shows a decrease in attenuation within the reservoir after stimulation. $A_{P0}$ is sensitive to fluid content within the reservoir. During stimulation, significant amounts of frac fluid are injected into the reservoir, which has a viscosity of $\sim$1 cP. This
Table 4.3: Summary of Well Completions

<table>
<thead>
<tr>
<th>Well</th>
<th>Stimulation</th>
<th>Flowback</th>
<th>Method</th>
<th>Stages</th>
<th>Fluid Injected (Ratio of Well to Average)</th>
<th>Proppant Injected (Ratio of Well to Average)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1N</td>
<td>Day 1</td>
<td>Day 12</td>
<td>Method 1</td>
<td>32</td>
<td>0.87</td>
<td>0.88</td>
</tr>
<tr>
<td>2N</td>
<td>Day 3</td>
<td>Day 15</td>
<td>Method 1</td>
<td>32</td>
<td>0.87</td>
<td>0.88</td>
</tr>
<tr>
<td>3C</td>
<td>Day 5</td>
<td>Day 15</td>
<td>Method 1</td>
<td>32</td>
<td>0.98</td>
<td>0.88</td>
</tr>
<tr>
<td>4N</td>
<td>Day 8</td>
<td>Day 21</td>
<td>Method 1</td>
<td>32</td>
<td>0.91</td>
<td>0.88</td>
</tr>
<tr>
<td>5C</td>
<td>Day 10</td>
<td>Day 22</td>
<td>Method 1</td>
<td>32</td>
<td>0.93</td>
<td>0.92</td>
</tr>
<tr>
<td>6N</td>
<td>Day 13</td>
<td>Day 21</td>
<td>Method 1</td>
<td>32</td>
<td>0.92</td>
<td>0.97</td>
</tr>
<tr>
<td>7N</td>
<td>Day 14</td>
<td>Day 33</td>
<td>Method 1 zip-</td>
<td>32</td>
<td>0.96</td>
<td>0.92</td>
</tr>
<tr>
<td>8C</td>
<td>Day 14</td>
<td>Day 34</td>
<td>Method 1 zip-</td>
<td>32</td>
<td>0.97</td>
<td>0.92</td>
</tr>
<tr>
<td>9N</td>
<td>Day 14</td>
<td>Day 30</td>
<td>Method 2 zip-</td>
<td>27</td>
<td>1.03</td>
<td>0.85</td>
</tr>
<tr>
<td>10C</td>
<td>Day 22</td>
<td>Day 45</td>
<td>Method 1</td>
<td>20</td>
<td>0.81</td>
<td>0.92</td>
</tr>
<tr>
<td>11N</td>
<td>Day 23</td>
<td>Day 45</td>
<td>Method 1</td>
<td>32</td>
<td>1.75</td>
<td>2.01</td>
</tr>
</tbody>
</table>

An increase in viscosity is approximately six times greater than the oil within the reservoir. The lower values of attenuation indicate areas potentially affected by frac fluid (Figure 4.10). Additionally, anomalies show the potential for interaction with other horizontal wells west of the Wishbone Section. Overall, changes in time-lapse velocity and attenuation show the reservoir is not uniformly stimulated.

4.5.2 Microseismic and completion data

Microseismic and completion data further illustrate how the faults within the reservoir affect stimulation. The western portion of the Wishbone Section has the largest number of events. These wells have tighter well spacing and were stimulated last. The majority of microseismic events trend with the current maximum horizontal stress direction of N70°W. Linear events and smaller cloud like groupings are two common geometries observed during stimulation of the Niobrara and Codell Sandstone. Linear geometries are interpreted to represent stimulation of a type 1 proximal event (Dohmen et al., 2014; Maxwell et al., 2015). Cloud like microseismic groupings correspond to effective stress changes near faults.
or fractures and are type II distal events (Dohmen et al., 2014; Maxwell et al., 2015). Type I events mainly correspond to dip slip moment tensor events, which are oriented towards N70°W. Type II events correspond to strike slip and oblique slip moment tensors. These events have a greater range of orientations than the dip slip events, and have large populations aligned with other identified fracture sets (Grechishnikova, 2017). Events that are considered distal must meet the following criteria:

1. “Are there natural fractures favorably oriented to shear failure?”
2. “Is the reservoir critically stressed or over-pressurized?”
3. “Do any microseismic events appear away from the injection points at early time?”
4. “Do any microseismic events appear disconnected from microseismicity concentrated around the injection points?”
5. “Do any microseismic events correspond to optimally oriented shear orientation, based on either lineations in the microseismic locations or from the source mechanisms?” (Maxwell et al., 2015).

For example, in Figure 4.11 the blue stage shows type II events and a pressure increase. As the frac continues, pressure decreases and microseismic events trend deeper into the
formation. These trends are similar to the stages in Well 6N where the pressure builds over time and cloud like microseismic trends occur. Afterwards, a pressure drop occurs and microseismic events trend deeper into the formation along the fault plane Figure 4.11. When plotted in time, the yellow and red events coincide with a pressure decrease, which indicates that frac fluid is flowing through the fault plane.

Stability modeling shows that faults oriented along N70°W are more stressed. Faults along this strike range coincide with higher magnitude events that follow the fault strike orientation. In Well 2N, a series of events over three stages follow a curved fault. The event mechanisms trend with the fault strike and rotate as the fault strike changes (Figure 4.12). Events located during the stimulation of Well 6N and Well 11N also illustrate how fault orientations control the orientation of moment tensors, and the trend of microseismic events (Figure 4.13). Overall, these examples illustrate how faults act as lateral barriers that bound the stimulation. The barriers occur because the stimulation overcomes vertical stress and frac fluid propagates along the fault plane which has higher porosity, permeability, and fracture density (Grechishnikova, 2017).

4.5.3 Vertical well depletion zones

The vertical wells in the survey area had previously produced from the Niobrara and Codell, and production data show higher GOR at the time of the baseline survey. During the hydraulic stimulation, pseduo-isotropic microseismic events are recorded near older vertical wells in the western portion of the survey. Pseudo-isotropic events are estimated moment tensors that can be a mixed double-couple and explosive event, or non-vertical dip-slip. Many of the microseismic events occur early in the stimulation and are interpreted to be stress related.

Both attenuation and velocity changes are observed near three older vertical wells (Figure 4.14). Time-lapse results show a decrease in velocity between the three vertical wells, which corresponds to the microseismic event locations. The attenuation change is offset from the microseismic events and velocity anomaly. During hydraulic stimulation, the highly vis-
Figure 4.11: a) Relative depth of microseismic events from 6N. As the hydraulic stimulation progresses, events move deeper in depth. b) Relative depth of microseismic events from 11N. c) Pump rates from 11N and microseismic events. Events move deeper in depth after the dark blue stage.

cous oil and gas are dominated by the frac fluid, which causes the attenuation to decreases. Thus, the microseismic events and velocity anomaly may be associated with a stress change, whereas the attenuation observes a fluid change near the older vertical wells.
4.6 Time-lapse production effect

Time-lapse seismic is a useful tool for mapping lateral changes due to production (Johnston, 2013). After stimulation of horizontal wells, wells are flowed back and production begins. As a reservoir is produced, fractures lacking proppant close, compaction occurs, and reservoir fluids change. 4D surveys are typically utilized for conventional reservoirs where porosity and permeability are high (Landro & Stammeijer, 2004; Tura et al., 2006). Incorporation of time-lapse seismic, tracer and production data, and reservoir models can help illustrate how joint sets and faults, and well spacing influence initial and long-term production.

Production data illustrate variances between the wells within the Wishbone Section (Figure 4.15 - Figure 4.16). Based upon production data alone, closer well spacing influences gas oil ratios over time. Tighter well spacing draws down reservoir pressure faster over time and increases gas oil ratios (GOR). This is because more fractures per area are created during stimulation. In the section, the GOR trend increases from east to west (1N to 11N) (Figure 4.15).
Figure 4.13: a) Microseismic events from well 6N. Events correlate with fault locations. b) Microseismic events from well 11N.
Figure 4.14: Black and red lines are Niobrara Formation and Codell Sandstone wells, respectively. The black faults are calculated from Transforms fault probability attribute. a) Time-lapse $V_{\text{NMO}}$ from monitor 1 to baseline. Velocity anomaly related to vertical wells is by red arrow, b) Time-lapse $A_{P0}$ from monitor 1 to baseline. Attenuation anomaly potentially related to vertical well depletion zone, c) Pseudo-isotropic microseismic events occur either along horizontal wells, or near older vertical wells. Red circles highlight the events related to vertical wells.

4.6.1 Initial flowback and tracer data

Production and tracer data are correlated to understand how the reservoir’s faults affect initial production and fluid communication between wells in the section. Production data show two different flow regimes in the Niobrara and Codell reservoirs, transient flow, and
boundary dominated flow (BDF) (Eker, 2018). Longer time periods of transient flow indicate better initial production and overall well performance. Without geologic or completion differences all of the wells should reach BDF at approximately the same time. Well 3C is one of the best producers within the Wishbone section and reaches BDF after 250 days. Well 4N is one of the worst producers and reaches BDF after 200 days.

Ning (2017) and Dang (2016) both examined tracer data from the Wishbone Section. Tracer results show extensive communication between the Niobrara and Codell wells. Dang (2016) utilizes a communication index to quantify the inter-well connectivity. Tracer data confirms flow communication during flowback and initial production between 3C and 4N Dang (2016). Specifically, tracers from 4N are recovered in 3C.

Microseismic also shows downward growth along faults that wells 3C and 4N cross. Therefore, 3C causes early time production interference, causes 4N to reach BDF earlier, and degrades 4N overall production (Figure 4.17) (Dang, 2016; Eker, 2018).

4.6.2 Reservoir Models

Reservoir models are utilized to predict future well performance, understand how well and stage spacing, and geology affect production within the Wishbone Section. Ning (2017) uti-
Figure 4.16: Relative gross BOE normalized by number of stages a) Niobrara wells, which have a 55% difference from 4N to 9N. b) Codell wells, which have a 34% difference between 8C to 10C (Utley, 2017).

This utilizes an integrated workflow in order to account for the tight well spacing, extensive faulting, and light hydrocarbon content in the Wishbone Section (Ning, 2017). Current modeling of the completion and production data utilize structural data such as horizons, faults from seis-
Figure 4.17: Schematic of the fluid interaction between 3C and 4N caused by faults within the reservoir during stimulation and flow-back (Team, 2015).

mic, and is populated with well logs properties. Hydraulic fracturing results from GOHFER are integrated with flow simulation modeling (Alfataierje, 2017; Ning, 2017). Results show higher GOR on the western portion of the Wishbone Section, and the simulation matches production data. Incorporation of heterogeneous fractures improves the history match from reservoir simulations that used uniform fractures (Figure 4.18). Simulated gas saturation in macro/micro fractures show large concentrations of gas near or along fault boundaries. Previous interpretations have correlated high microseismic intensity with simulated gas saturations within the reservoir (Figure 4.19) (Ning, 2017).
4.6.3 Time-lapse velocity and attenuation changes due to production

Time-lapse seismic velocity and attenuation measurements help illustrate how faults and well spacing affect the long term production within the Wishbone Section. 4D velocity changes ($\%\Delta V_{NMO}$) between monitor 2 and monitor 1 show a range of changes between ±10% over the survey area. The majority of the changes are in the range of ±5%. Its important to note that these changes are relative because $\eta$ is held constant spatially and dynamically. Negative changes are observed around the northeast trending graben and the northwest trending fault. Away from these faults, positive changes are observed, which indicates fractures closing (Figure 4.20). Time-lapse changes between monitor 2 and baseline show a change of $V_{NMO}$ velocity between -9 - 4%. The largest changes are over the western wells and at the edges of the survey. Overall changes show a decrease in $V_{NMO}$ velocity, which indicates an increase in fractures (Figure 4.20).

Monitor 2 attenuation results show a decrease in $A_{P0}$ between both monitor 1 and baseline. Though gas comes out of solution as the wells are produced, attenuation does not increase between surveys. The decrease in attenuation is attributed to gas coming out of solution, which has an overall lower bulk density and viscosity. Rock physics modeling with
the T-matrix method, shows that a decrease in attenuation can be caused by a shift in the apex attenuation to outside of the seismic bandwidth (Guo & McMechan, 2017). The shift outside of the seismic bandwidth would cause an apparent decrease in attenuation. Thus, zones with less change in $A_{P0}$ may indicate areas with smaller GOR. It is important to note that these are inferences based upon rock physics modeling, and can only be accurately confirmed with downhole calibration data. 4D attenuation changes between monitor 2 and monitor 1 show similar time-lapse changes as monitor 2 to baseline. However, the time-lapse change in $A_{P0}$ does not add interpretive value, because the time-lapse changes are a mix between stimulated fractures and areas with higher amounts of gas.

4.7 Discussion

The faults within the reservoir have a significant effect upon the lateral variability of time-lapse anomalies within the reservoir. Before stimulation, lateral velocity changes are bounded by the grabens within the section and the northwest trending fault. These faults influence the stimulation by acting as vertical conduits within the Niobrara Reservoir based upon completion, microseismic, and tracer data (Dang, 2016). Time-lapse seismic anomalies are bounded spatially by the reservoir faults. Anomalies also indicate the potential for communication with wells west of the Wishbone Section.

Stimulation causes an overall decrease in $V_{NMO}$ and $A_{P0}$ within the reservoir. Hydraulic fracturing causes increased fracture aperture, radius, and permeability. Additionally, significant amounts of fracture fluid is injected into the reservoir, which has a lower fluid viscosity. Combined these changes cause a decrease in the reservoir vertical attenuation (over the seismic bandwidth), and P-wave $V_{NMO}$ velocity.

Fault stability modeling also shows that faults aligned along maximum horizontal stress are critically stressed (Bratton, 2018). Stages that initiate near faults aligned with max stress, control the orientation of stimulation, and cause microseismic events to follow the fault strike trends. Microseismic events that occur near faults occur in cloud like geometries, and have either strike-slip or oblique slip moment tensors, which are aligned with the $S_4$
conjugate shear fracture set (Grechishnikova, 2017). Faults that are oriented along the maximum horizontal stress are lateral barriers to stimulation. Microseismic and pump rates illustrate that when stages are near faults, less reservoir is stimulated due to fluid loss along the fault plane.

Time-lapse changes in $V_{NMO}$ and $A_{P0}$, due to production, are irregular and are influenced by both well spacing and faults within the reservoir interval. Velocity and attenuation anomalies show the northeast trending graben and the northwest trending fault are major drivers towards reservoir compartmentalization. Additionally, the northeast trending graben and northwest trending fault are barriers to both stimulation and production based upon microseismic, tracer data, and time-lapse seismic anomalies.

Time-lapse velocity and attenuation anomalies show similarities to the reservoir simulation results such as the larger time-lapse anomalies over the western part of the Wishbone Section. For example, wells with closer spacing correlate with larger time-lapse anomalies and better producing wells.

The integration of seismic, microseismic, and tracer data indicate that faults and neighboring wells play a significant role in the distribution of anomalies. For example, in the simulation model the highest gas saturation is near or along faults. At the juncture of the two grabens, the simulation results show high concentrations of gas saturation, whereas the time-lapse anomalies are larger south of the graben. At the juncture of the grabens, microseismic events trend deeper into the reservoir along fault planes, completion pressures decrease, and tracer data shows connectivity between the Niobrara and Codell wells (Dang, 2016; Ning, 2017). This indicates fluid loss along the fault plane, which reduces the amount of reservoir stimulated. Previous interpretations use reservoir simulation models and microseismic events to interpret that fault zones are effectively stimulated (Ning, 2017). The reservoir models indicate these zones to have high gas concentration and significant amount of microseismic activity. However, though the number of microseismic events is high, a microseismic event does not imply stimulation has produced an open fluid filled fracture that
will contribute to production.

4.8 Conclusion

Integrated reservoir characterization with seismic, microseismic, tracer, reservoir simulation, and production data consistently demonstrate the reservoir’s faults limit lateral reservoir stimulation and allow fluids to move to other facies vertically within the Wishbone Section (Dang, 2016). Seismic also shows hydraulic fracturing did not uniformly stimulate the reservoir. Areas with closer well spacing show larger time-lapse changes, which correlate with higher GOR rates and rock physics modeling. Results also show that reservoir modeling should incorporate time-lapse anomalies to refine high stimulation and producing zones. Additionally, inclusion of surrounding wells and older vertical wells is important for reservoir modeling in unconventional reservoirs. The eleven vertical wells and horizontal wells near the Wishbone Section potentially interact with the horizontal wells in the Wishbone Section. Overall, data demonstrate geologic heterogeneity significantly influences stimulation effectiveness and production.
Figure 4.19: a) Simulated gas saturation from heterogeneously fracture simulation model, b) Microseismic recorded from eleven horizontal wells. Events are colored by the time of the event (Ning, 2017).
Figure 4.20: White and red lines are Niobrara and Codell wells, respectively. The faults are in black. a) Time-lapse percent difference of $V_{NMO}$ between Monitor 2 - Monitor 1 b) Time-lapse percent difference of $V_{NMO}$ between Monitor 2 - Baseline a) Time-lapse percent difference of $A_{P0}$ between Monitor 2 - Monitor 1 b) Time-lapse percent difference of $A_{P0}$ between Monitor 2 - Baseline
CHAPTER 5
MICROSEISMIC REPROCESSING AND UNCERTAINTY ANALYSIS

Determination of induced hydraulic fracture planes and existing discontinuities in unconventional reservoirs remains an important problem. One of the primary ways to monitor hydraulic stimulation of wells is microseismic. Downhole microseismic monitoring offers the benefit of in-reservoir seismic recording of the rock reacting to injection. Over the last decade, development of new reservoir characterization and imaging tools improved the estimation of hydraulic stimulation effects, and the interpreter’s ability to estimate fracture properties (Blias & Grechka, 2013; Coffin et al., 2012; Grechka & Heigl, 2017; Jechumtálová et al., 2016; Liu et al., 2011; Su et al., 2018; Zhang et al., 2018).

In order to use microseismic information for reservoir characterization, it is essential to develop and apply robust processing techniques, and to understand and quantify the uncertainty throughout processing. Failure to account for uncertainty and the limitations of a survey can lead to over-interpretation or misinterpretation of results (Bulant et al., 2007). Without properly understanding the data and the errors associated with particular processing steps, advanced velocity analysis or inversion for geomechanical properties cannot be performed with confidence. Integration of total error, deriving from microseismic acquisition and processing is necessary in order to accurately estimate reservoir anisotropy and potentially detect dynamic reservoir changes due to hydraulic stimulation. Moreover, understanding the survey error and receiver orientation error is vital towards recovery of accurate and precise reservoir parameters.

In this chapter, we reprocess a legacy downhole microseismic survey from Pouce Coupe Field, Alberta, Canada, and quantify the error associated with each stage of processing (Figure 5.1). The improved early processing workflow incorporates survey and processing uncertainty into the event location error using PDFs. We focus, primarily, on the processing
steps that have the greatest impact on uncertainty and, specifically contribute to the final location error PDF.

![Processing Steps and Uncertainty Workflow](image)

Figure 5.1: Processing and uncertainty workflow. The uncertainty flow shows each processing step that has uncertainty in azimuth, radial, and depth directions. The PDFs are convolved to create a final 3D PDF for each event.

5.1 Dataset

The microseismic dataset for our study is from the monitoring of three horizontal multi-stage wells (102/2-7, 102/7-7 and 102/8-7) in the Montney Formation, Pouce Coupe Field, Alberta, Canada (Andersen et al., 2013; Andrews, 2016; Atkinson & Davis, 2011; Dueñas & Davis, 2014; Lee et al., 2014) (Table 5.1). Two of the wells target the Montney C, and
one well targets the Montney D (Figure 5.2). The wells are hydraulically fractured from December 2008 to January 2009.

Table 5.1: An overview of the fracturing and microseismic monitoring operation. Modified from (Andrews, 2016).

<table>
<thead>
<tr>
<th>Date</th>
<th>Treatment Well</th>
<th>Observation Well(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12/12/2008</td>
<td>102/2-7 (Montney C)</td>
<td>Horizontal 102/8-7 (10 rec.)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vertical 9-7 (50 rec.)</td>
</tr>
<tr>
<td>12/17/2008</td>
<td>102/7-7 (Montney D)</td>
<td>Horizontal 102/8-7 (10 rec.)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Vertical 9-7 (50 rec.)</td>
</tr>
<tr>
<td>01/09/2009</td>
<td>102/8-7 (Montney C)</td>
<td>Vertical 9-7 (12 rec.)</td>
</tr>
</tbody>
</table>

The three horizontal wells are drilled in the northwest-southeast direction, roughly perpendicular to the regional maximum horizontal stress (Davey, 2012). Wells 102/2-7 and 102/7-7 each have five stages. Well 102/8-7 originally had six stages, however, due to completion issues Stages 1 and Stage 3 were each fractured twice instead of Stages 2 and 4 (Figure 5.2).

The acquisition geometry for microseismic recording was modified a number of times during completion. Wells 102/2-7 and 102/7-7 are recorded by a longer vertical array in Well 100/9-7, with the deepest receiver at the top of the Montney D, and by a short horizontal array in the heel of Well 102/8-7. Well 102/8-7 is monitored by a shorter vertical 12 receiver array, straddling the Montney C and D (Table 5.1). The receivers are all three component geophones. The data is sampled at 0.25 ms.

A number of sources with known locations are used for velocity modeling and receiver orientations, although it should be noted that none of the original times for these events are known. In Well 102/8-7, the perforations for Stages 3 and 4 are recorded. Wells 102/2-7 and 102/7-7 are sliding sleeve completions. The response of the mechanical sleeve closing are found in the recordings for Well 102/7-7 Stages 1 and 2. Additionally, three stringshots are recorded, two in the heel of Well 102/7-7 and one in the heel of Well 102/2-7 (Figure 5.2). For this paper we only focus our analysis on the monitoring of wells with the vertical arrays.
Figure 5.2: Well and receiver geometry. The red markers are the stage locations, and the green markers are the horizontal and vertical array locations.

in Well 100/9-7.

5.2 Methodology

The microseismic data are processed from raw continuous data in order to access uncertainty with probability density functions. We investigate four aspects of processing to understand the uncertainty and error:

1. Acquisition and well geometry

2. Event detection

3. Hodogram analysis

4. Event location

The overall workflow performs Monte Carlo importance sampling with probability density functions (PDFs) in order to statistically estimate likely error from survey design, data
limitations, event polarizations, and waveform stacking (Ghahramani & Rasmussen, 2003). The resulting estimates of location uncertainty represent the azimuthal, radial, and depth uncertainties due to receiver orientation, event polarization, velocity model, and geometrical error.

5.2.1 Acquisition Uncertainty

A primary step in the processing of microseismic data is a quality control check of the acquisition geometry and completions set up. Multiple studies identify the sources of error associated with microseismic surveys (Bulant et al., 2007; Eisner et al., 2011; Jechuntálová et al., 2016; Kidney et al., 2010; Maxwell, 2009). As discussed in the previous section, there were a number of completions and acquisition variances that impacted the recording of microseismic. The main acquisition challenge for this survey is the lack of a deviation survey for the vertical 100/9-7 receiver well. Not accounting for deviation surveys in vertical wells effects the observed azimuth of event orientations, and can cause more than 20° uncertainty on inverted fracture properties. Combined with uncertainty in horizontal well location, the cumulative effect upon fractures is nonlinear, and may produce several millisecond error between the SH-P wave travel-times (Bulant et al., 2007). Thus, before continuing processing it was key to understand the impact of the Well 100/9-7 location uncertainty on the recordings of the vertical geophones in that well and refine the bottomhole location if necessary.

An inclination survey is available for Well 100/9-7, however, the survey only narrows the possible location of the receivers to a cone with a radius of up to 30m. A basic finite difference model is implemented to investigate the impact of tens of meters of receiver location uncertainty on the microseismic recording. By modeling the perforation recording for Stage 3 in Well 102/8-7 (Figure 5.3 (a)), a 10m shift in the well location results in a significant shift in the P-wave arrival time (Figure 5.3 (b)). The time shift with vertical error is less noticeable, the wavelet is slightly different (Figure 5.3 (c)), however due to the acquisition geometry we expect the most significant error to be horizontal. At the distances and frequencies in this microseismic survey the 30m of uncertainty in the location of the receiver will have a large
impact on processing and the modeling shows it is necessary to reduce the well location error before further processing.

Figure 5.3: Receiver 4 of the vertical array monitoring Well 100/9-7. a) Recorded perforation at stage 3 on Receiver 4, b) and c) Models of the x-component and y-component of the perforation shot. The blue lines are the modeled synthetic when the well location is the same as the kelly bushing. The red lines are the modeled synthetic when the bottom hole location is 10 m east of the kelly bushing.

Three types of data are used to refine location of the bottom hole of Well 100/9-7. The location is refined with the following steps:

1. Well 100/9-7 Inclination Survey - The provided inclination survey shows a maximum drift of 30m. This creates a cone of uncertainty for the well location and a circle at the bottom hole (Black circle in Figure 5.4). The location of the bottom hole is restricted to this radius.

2. Deviation Surveys - Analysis of the vertical sections of the available deviation surveys showed a consistent drift to N40°E, which is structurally up dip. The vertical sections are shown to drift within the range of 4 to 15 meters. In order to account for the well drift, a background linear dip is added to the probability map, making the northeast
3. Location of Known Sources - Seven known sources are identified in the data: three stringshots (One in the heel of Well 102/2-7, two in the heel of Well 102/7-7), two perforations (Well 102/8-7 Stages 3 and 4), and two mechanical sleeve openings (Well 102/7-7 Stages 1 and 2) (Figure 5.4). P-wave and fast S-wave arrivals are picked for each known source. The optimal horizontal velocities were estimated using the results of tomography and refined with the arrival times from the stringshots to the horizontal array. With the arrival times and the velocities, an arc is created for each known source and a normal distribution from 0 to 10% anisotropy with a $[x_1, x_3]$ symmetry plane oriented N40°E (Andrews, 2016; Davey, 2012). Figure 5.5 shows that the arcs overlap on the eastern side of the well inclination zone.

Figure 5.4: Steps for input into well probability analysis. Each inset also includes Step 1, the refinement within 30m from the inclination survey. Step 2 is the background trend based on deviation surveys a), Step 3 is the probability from the known sources, perforations b), sliding sleeve mechanisms c), and stringshots d).

The result of this analysis is highlighted in the inset of Figure 5.5. The colors in the circle indicate the probability of the bottomhole of the well being at that location with yellow being the most probable and blue the least. The new bottomhole location for Well 100/9-7 is estimated to be at the spot with the highest probability (Open triangle in the inset of Figure 5.5). The new location is 19.6m east and 2.7m south of the surface location. The 95% error ellipsoid of this estimate has a radius of 1.5m in the NW and 0.43m in NE.
A new Well 100/9-7 deviation survey is created using this bottomhole location and the well location probability is propagated through to the next steps of processing using PDFs.

Figure 5.5: Results of the well location probability analysis. The inset shows the mapped probability with yellow being the higher likelihood and the open triangle the most likely bottomhole location.

5.3 Event detection

Event detection from continuous microseismic records is an initial step in processing microseismic (Maxwell, 2014). Improved detection of weak locatable microseismic events is important for spatial and temporal correlation to understand the effects of hydraulic stimulation. Recordings from microseismic surveys span significant time periods (multiple hours/days), and automatic detection of events is required to make processing tractable and economically viable. The goal of automated detection is to minimize the amount false
positives (noise identified as an event), and maximize the number of locatable events. Noise caused by poor receiver coupling and hydraulic pumping can mask weaker events (Maxwell, 2014). Accurate parameterization of detection algorithms is vital for distinguishing between noise and weak events.

Acquisition geometry also impacts the ability to detect microseismic data due to signal attenuation. This study focuses on processing of the microseismic recorded on the vertical arrays in Well 100/9-7 (Figure 5.2). We expect the number of detected events to be highest at Stages 1 and 3 in Well 102/8-7, and Stages 1 and 2 of Well 102/7-7. Each of those locations are only a few hundred meters from the receiver well. As completion moves toward the heel of those wells, we expect a significant decrease in recorded signal amplitude due to attenuation (Maxwell, 2014). Furthermore, the distance to Well 102/2-7 means there is likely to be much fewer detectable events at all stages.

The performance of the power spectral density (PSD) is analyzed (Vaezi & van der Baan, 2015). Additionally, a random forest detection algorithm is performed only on Well 102/8-7 Stages 1-4 to demonstrate the potential applicability of machine learning detection algorithms.

5.3.1 PSD

The PSD detection algorithm operates in the frequency domain ((Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015)). Previous work illustrates how the PSD methodology increases the detection of events and produces smaller numbers of false positives in comparison to STA/LTA (Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015). PSD identifies microseismic events with stronger spectral content over a specific band than background noise. The Welch method estimates the spectral information (McNamara & Buland, 2004; Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015; Welch, 1967).

The original implementation averages the background seismic noise, $\overline{PSD}$, after events and noise bursts have been removed. The continuous data that we utilize is approximately 21 hours long between the two well stimulations. Therefore, we approximate $\overline{PSD}$ with
the spectral estimate of the entire seismic record. \( \text{PSD} \) will contain the spectral content of microseismic events, but will be dominated by the background noise.

The microseismic record is divided into \( N \) overlapping segments of length \( L \) to calculate \( \text{PSD}_{k,c,n,t}(f) \) for each segment, where \( t \) is the time sample at the middle point of every \( n \)th segment for each receiver component \( e \)th, and for each \( k \)th receiver in the tool array (Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015). A 50% overlap Hamming taper is applied to reduce side-lope spectral leakage (Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015). The normalized PSDs are calculated with the misfit at each segment, and standard deviation of each frequency (\( \text{std}(f) \)) where,

\[
misfit_{k,c,n,t}(f) = \text{PSD}_{k,c,n,t}(f) - \overline{\text{PSD}}(f),
\]

\[
u_{k,c,n,t}(f) = \frac{misfit_{k,c,n,t}(f)}{\text{std}(f)}.
\]

Similar to Vaezi and van der Baan (2015), we set anomalous \( u_{k,c,n,t}(f) \) ratios above 1 to zero, and an averaged criteria for triggering is calculated,

\[
\Lambda_{\text{PSD}}(t) = \frac{\sum_{f=0}^{f_{\text{Nyq}}} \sum_{c=1}^{c} u_{k,c,n,t}(f)}{N_f},
\]

where \( \Lambda_{\text{PSD}}(t) \) is a detection criteria for the tool array of 3-component receivers as a function of time, \( f_{\text{Nyq}} \) is the Nyquist frequency, and \( N_f \) is the frequency range. An event is triggered when \( \Lambda_{\text{PSD}}(t) \) passes a predetermined threshold (Vaezi & Van der Baan, 2014; Vaezi & van der Baan, 2015).

### 5.3.2 Detection Results

The PSD parameters are shown in (Table 5.2). Parameters are selected to produce the largest possible number of events with the fewest false positives. The PSD algorithm is applied to the continuous seismic recording with limited filtering (Table 5.2). Half of the detected events have only S-wave energy and lower S/N ratio (Table 5.3). On Well 102/2-7, few events are detected due to signal attenuation. Additionally, we are unable to visually identify P-waves on the detected events from Well 102/2-7 (Table 5.3). One disadvantage of
the PSD algorithm is the larger computational expense when computing multiple frequency spectra.

Table 5.2: Optimum PSD parameters for wells 102/2-7, 102/7-7, and 102/8-7

<table>
<thead>
<tr>
<th>PSD parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Min. event separation</td>
<td>0.5 s</td>
</tr>
<tr>
<td>Well 102/8-7 Stage 1-2 PSD Λ</td>
<td>0.45</td>
</tr>
<tr>
<td>Well 102/8-7 Stage 3-4 PSD Λ</td>
<td>0.80</td>
</tr>
<tr>
<td>Well 102/7-7 PSD Λ</td>
<td>0.99</td>
</tr>
<tr>
<td>Well 102/2-7 PSD Λ</td>
<td>2.00</td>
</tr>
<tr>
<td>Bandpass filter</td>
<td>30 - 1100 Hz</td>
</tr>
</tbody>
</table>

Table 5.3: Detected microseismic events on wells 102/2-7, 102/7-7, and 102/8-7.

<table>
<thead>
<tr>
<th>Method</th>
<th>All Events</th>
<th>Events with P &amp; S waves</th>
<th>False Pos.</th>
</tr>
</thead>
<tbody>
<tr>
<td>102/8-7 PSD</td>
<td>4488</td>
<td>2292</td>
<td>373</td>
</tr>
<tr>
<td>102/7-7 PSD</td>
<td>6211</td>
<td>2992</td>
<td>537</td>
</tr>
<tr>
<td>102/2-7 PSD</td>
<td>310</td>
<td>0</td>
<td>62</td>
</tr>
</tbody>
</table>

5.3.3 Random Forest

Any trigger method requires manual quality control of detected events. For Well 102/8-7, 373 false alarms are identified over four stages with the PSD method. Modern completions stage counts range from 20 - 50 stages. Detection of weak and strong events could result in thousands of false positives (based upon Well 102/8-7), and would add to processing time. In order to increase detection performance, we implement a random forest supervised machine learning approach. Supervised learning machines are common tools for nonlinear pattern recognition (Beran & Oldenburg, 2008; Dorrington & Link, 2004; Masotti et al., 2006; Provost et al., 2017; Van der Baan & Jutten, 2000). Supervised approaches utilize training data \( (x_i) \) to calculate a decision rule that maps selected model parameters from the feature space to the desired output \( (y_i) \) (Beran et al., 2011; Bray & Link, 2015). In order to test the decision
rule, a subset of the training data is withheld from training for validation and testing. A main goal of supervised training is to obtain a decision rule with low-bias and high-variance. For validation, random subsampling 10 fold nested loop cross-validation is implemented (Rokach & Maimon, 2005; Varma & Simon, 2006). Cross-validation is important during training in order to determine if the resultant learning machine has low bias and high variance.

Random forests are classification or regression methods that utilizes bootstrap aggregation, and random variable selection to generate an ensemble of decision trees (Breiman, 2001). Grid search methodology is used during cross validation to find optimum parameters. Random forest adjustable parameters are the number of trees in the forest, the percentage of variables used at a split, and the minimum size for a terminal node for a tree. The best-performing configuration of parameters is selected as the optimum parameters.

A challenge for microseismic event detection is the significant overlap between weak events and strong noise signals. The standard deviation of $\Lambda_{PSD}(k, t)$ across the array is plotted against the average 3-component $\Lambda_{PSD}(t)$ for events and triggered noise (Figure 5.6). Many weak events have a similar signature as strong noise within the dataset. In order to build a representative training set that captures the variances within noise and events, self organizing feature maps (SOFM), or unsupervised neural networks are implemented (Kohonen, 1998, 2013). SOFMs are an objective way to build a multi-classification training set, by splitting microseismic events and noise into four and three classes, respectfully. The events and noise are classified separately in order to avoid misclassification.

Training sets are built from spectral information calculated with the PSD methodology. Normalized PSDs ($u_{k,c,n,t}(f)$), are calculated from $[40\ 1000]$ Hz for each receiver. Due to the number of receivers and large frequency range, principal component analysis is performed on each normalized PSD for each receiver. The first seven principal components are selected for training since they describe approximately 95% of the variance within each spectrum (Figure 5.7). Thirty events of each SOFM class are randomly generated to build a training set of 120 microseismic events. To ensure a large test set, 80% of the noise training set is
composed of weak background noise, and the remaining 20% are composed equally of the higher background noise that was initially triggered as an event.

After training and validation, the test set results are merged to generate binary labels from multiclass labels (Figure 5.7). The random forest PSD method reduces the false alarm rates from the PSD methodologies. Though the 100% confidence interval is 53%, all events with P- and S-waves are detectable at a 51% confidence interval. Due to the close proximity of Well 100/9-7, many weak events are detected and compose the misidentified events above 90% confidence.

5.4 Hodogram analysis

Borehole geophone orientations must be computed from controlled sources in order to properly orient the geophones that are oriented orthogonal to the monitor well. The traditional eigenvector type hodogram analysis performs poorly on this dataset (Maxwell, 2014; Moriya, 2008). This poor performance is due to noise and other wave modes present that mix in the rotation window. For example, there is often a head wave that arrives very close in time with the P-wave direct arrival, and these are impossible to separate. The mixing of
amplitudes of different modes causes highly variant results.

Hodogram analysis introduces difficulties with noisy data. The eigenvector approach suffers from vector fidelity issues. Attempts at noise reduction, filtering, and hodogram window size did not reduce hodogram errors. A different hodogram algorithm, using energy ratios and a grid search method, is more robust with the presence of noise and other wave modes. Over a range of azimuths (0 to 180°) and inclinations (-90 to 90°), the amplitude ratio method calculates

$$Hodo_{azi} = \max \left( \frac{C_V}{C_{H1} + C_{H2}} \right)_{P_{win}},$$

where $C_V$, $C_{H1}$ and $C_{H2}$ are the RMS amplitudes over the P-wave arrival on the z-, x- and y-components, respectively. The p-window is calculated from the minimum dominant frequency across the receiver array. Hodogram error was estimated by normalizing $Hodo_{azi}$ by the maximum value, and taking the 95th percentile azimuths as an error estimate.

The amplitude hodogram methodology requires approximate first breaks for ratios to accurately determine event azimuth and inclination. Interpolation is implemented to reduce processing time and decrease manual picking. Seed picks for both P- and S- waves are picked.
to represent the normal move-out of events across the receiver array. Interpolation selects
the remaining event picks.

Figure 5.8 shows a comparison between the two types of hodogram analysis using the
perforation from Well 102/8-7 Stage 3. The perforation before and after rotation to north,
east, and vertical (NEV) is compared for the eigenvector method used by the contractor and
the amplitude ratio method used in this study. Using the improved NEV rotations and the
new hodogram method the perforation locations from well 102/2-7 and 102/7-7 are located
with ±1.5° azimuthal uncertainty. The estimated 95% error estimated ±2.0° azimuthal
uncertainty. The amplitude ratio hodogram method shows events more clearly and provides
improved interpretation, reduces error estimates, and exemplifies shear wave splitting.

5.5 Event Location

Microseismic event locations are typically estimated with arrival-time inversion, stack-
ing, or full waveform methods (Maxwell, 2014). Arrival time inversion is manually intensive
and subjective to waveform interpretation. Stacking methods are inherently data driven and
provide increased automation, which is advantageous when thousands of events are detected.
The events for this study are located using a combination of arrival time inversion and amplitu-
de stacking. Events are located in cylindrical coordinates and the uncertainty is determine
for each azimuth, distance, and depth. The isotropic velocity model for the location is cal-
culated by performing tomography with seven known events (Perforations, stringshots, and
sleeve openings). Tomography is performed with GeoPRO by Sigma3. An S-wave velocity
model is then constructed with $\frac{V_P}{V_S}$ from logs near the survey and P-wave tomography results.

To capture the 3D location uncertainty, 10,000 azimuth orientations are selected from the
hododgram PDF results using likelihood sampling (Devore et al., 2013). First-break times
are also varied based upon the travel-time residual average and standard deviations (Kidney
et al., 2010). The events then are rotated into P-wave (P), radial (R), and transverse (T)
for each selection from the hodogram PDF.
Figure 5.8: Receiver orientations in example for the perforation for Well 102/8-7 Stage 3 a) Unrotated near vertical and two horizontal components, b) Eigenvalue rotations to vertical (Z), east (X), and north (Y), c) Amplitude ratio rotation to vertical (Z), east (X), and north (Y).
The location was performed using a combination of travel-time minimization and amplitude stacking. The general equation used for travel-time minimization is

\[ t_{\text{image}}(k, t) = \min(t_{\text{data}}(k, t)) + t_{\text{eikonal}}(k, t), \]

where, \( t_{\text{data}}(k, t) \) are the event arrival picks, \( t_{\text{eikonal}}(k, t) \) is the travel-times calculated with isotropic 2D eikonal solver, and \( t_{\text{image}}(k, t) \) is the travel-times for each potential image point (Faria & Stoffa, 1994; Schneider Jr et al., 1992). For this equation the travel-times and picks can be for P-wave arrivals, S-wave arrivals, or the S- to P- arrival difference. For the amplitude stacking methodology a stacked value is

\[ S(r, z, t) = \frac{A_P^2(t)}{A_R^2(t) + A_T^2(t)}, \]

where \( S(r, z, t) \) is the stacked value, \( A_P, A_R, A_T \) are the amplitudes on the vertical, radial, and transverse component over the either the P- or S-window (Rentsch et al., 2007). Amplitude windows for stacking are selected from the minimum dominate frequency \( \lambda_{\text{min}} \) of P- or S-waves across the receiver array.

To determine the optimum objective function for location, four combinations of the travel-times and amplitudes were analyzed,

1. S-travel-times only (Figure 5.9)
2. S- to P-travel-times difference only (Figure 5.9)
3. S-travel-times and S- to P-travel-time difference (Figure 5.9)
4. S-travel-times, S- to P-travel-time difference, P-wave amplitudes, and S-wave amplitudes (Figure 5.9 d and h)

Due to the acquisition geometry the S-travel-times constrained location in depth (Figure Figure 5.9e) and the S- to P-travel-times differences constrained the locations radially (Figure Figure 5.9b). The combination of the two provides optimum uncertainty reduction
in depth and radius while the amplitude stacking of P- and S-waves adds additional focusing (Figure 5.9d).

Figure 5.9: Four types of location for events from Well 102/87 Stage 3-4 in map view (a-d) and depth view (e-h).

The largest stacked value is selected as the source location \((S(r, z, t))\) for each azimuth iteration, which in turn generate the PDFs for an event in azimuth, radius, and depth. The resulting PDFs only describe the location error from receiver orientations, hodogram analysis, and the travel-times calculated from the 2D isotropic velocity model. Error from well geometry is incorporated by convolving the well error PDF with the location PDF. The location and error are then converted to Cartesian coordinates, \(X, Y,\) and \(Z\). The final PDF describes the location probability of a microseismic event in \(X, Y,\) and \(Z\).
An example of the results of location and Monte Carlo analysis is shown in Figure 5.10 for an event from Well 102/8-7 Stage 3-4. The rotated event waveforms are displayed in Figure 5.10 a); the event has relatively high signal to noise and shows clear P- and S-wave arrivals. Figure 5.10 b) and c) show depth view and map view, respectively, results for the initial event location (red star) and the Monte Carlo probability.

Figure 5.10: 3D PDF for an event from Well 102/8-7 Stage 3-4. a) Event rotated into P, Radial, and Transverse components. b) Depth view of the 3D PDF likelihood from the Monte Carlo approach. The red star is the event location without Monte Carlo. c) Map view of event location and probability.

Figure 5.10 shows how the error tapers off in a particular direction. The location method improves upon first break minimization by using a data driven approach, where am-
Amplitudes are stacked to provide the optimum location. Our current location and errors also use the travel-times estimated with an isotropic velocity model. Future work will account for velocity anisotropy with tomography or full waveform inversion.

Our workflow focuses upon the inclusion of total survey error, and how that propagates into location estimates. The lack of deviation surveys can drastically increase location uncertainty. With previous estimates of reservoir anisotropy, we reduce the acquisition error. The bottomhole location error for Well 102/8-7 is reduced from an area uncertainty of 2,800 m$^2$ to 2 m$^2$. Additionally, we use known source locations and measure hodogram directions to better estimate receiver positions. We capture this spatial uncertainty with PDFs, which are combined with hodogram and location estimates. Our final 3D PDF for an event shows the likelihood an event occurred within a particular location.

The signal loss with distance for the vertical array in Well 100/9-7 is evident with the low number of events in the stages located closer to the heel in Well 102/7-7, and in all stages from Well 102/2-7. For example, roughly 80% of events in Well 102/7-7 are located at Stage 1 with the other 20% located near the remaining four stages. Due to distance of Well 102/2-7 from the receiver Well 100/9-7, no events are detect with P- and S-wave energy.

The amplitude ratio hodogram helps overcome issues caused by mixing of wave modes (direct and head waves) and low signal to noise ratio. The reduction of error azimuthally improves amplitude alignment for location based stacking. An improvement of this methodology would be to utilize the shear-waves within the hodogram analysis. Yuan and Aibing (2017) implemented shear-wave splitting analysis into a grid search methodology, and illustrated a significant azimuthal error reduction.
The results of event location are shown in Figure 5.11 for Well 102/8-7 Stages 1-4, and Well 102/7-7. The event locations show a greater spacial extent and more interaction between wells than previous results indicated. Additionally, the depth view shows the events are contained within the Montney D Facies.

Locations for Well 102/8-7 are also shown in Figure 5.11. As previously mentioned, completion complications caused Stage 1 and Stage 3 to be re-fractured, instead of fracturing Stage 2 and Stage 4. Additionally, a number of the events from Stage 1-2 (blue) are located around Well 7-7 Stage 1. Previous fault interpretations of surface seismic identify fault lineaments that trend N40°E near the toe of Well 102/7-7 and Well 102/8-7, which in conjunction with the microseismic locations indicate communication between the two stages (Steinhoff, 2013). Also, the previous processing resulted in events located passed Stage 3, but before Stage 1. Placement of events before a stage would require a negative epsilon, which does not make sense. The new locations are both slightly farther than their stage, indicating a small, positive epsilon, in agreement with the environment. Overall, the new microseismic locations provide new insights into the effects of the hydraulic fracturing for Well 102/7-7 and Well 102/8-7.

5.6 Conclusions

Quantifying uncertainty and error due to microseismic processing is vital for accurate and precise location of microseismic events. This chapter focuses upon the inclusion of acquisition and processing error with probability density functions. Estimation of early processing steps and acquisition is vital before inversion for anisotropy or moment tensors. Detecting smaller events at a greater distance from borehole receivers improves an interpreters ability to make decisions about well and stage spacing. Overall, incorporation of event location error into the microseismic location inversion reduces the uncertainty associated with results, and shows how the error can be propagated into future analysis.
Figure 5.11: Event locations for wells 102/7-7, and 102/8-7 in map view a) and depth view with relevant horizons b). Events are colored by stage and well number.
Pre-stack time-lapse estimation of attenuation is an applicable seismic attribute for reservoir characterization. The layer stripping assumption of lateral homogeneity can be overcome with the application of tomography or full-waveform approaches. Integration of velocity and attenuation with microseismic, tracer data, and production data can improve understanding of how faults and fractures affect the stimulation and production of horizontal wells.

Viscoelastic modeling with the T-matrix approach requires multiple input parameters that are difficult to constrain without downhole calibration data. Some parameters, such as fracture radius, cannot be estimated even with downhole calibration data. These numerous input parameters limit the applicability of modeling the time-lapse response of shale reservoirs when permeability, fluid viscosity, and fracture properties are all varying due to hydraulic stimulation. I utilize estimates of fluid properties, seismic log velocities, grain size, fracture properties, and permeability to model the potential time-lapse response of the vertical attenuation in a fractured reservoir (Bratton, 2018; Dudley, 2015; Kamruzzaman, 2015; Nelson, 2009; Ning, 2017). Modeling shows that the fracture radius has a significant impact upon the potential time-lapse attenuation response of a reservoir. Depending upon the fracture radius, the time-lapse attenuation may show either an increase or decrease in the vertical attenuation. Rock physics models for attenuation must decrease the number of input parameters in order to make more objective analysis of time-lapse attenuation responses.

The T-matrix approach cannot handle a VTI background, therefore velocity values are modeled separately in order to understand the potential velocity time-lapse change due to stimulation and production (Collet & Gurevich, 2016; Gassmann, 1951; Schoenberg & Helbig, 1997). Anisotropic fluid substitution shows fluids cause less than 1% change in the velocity response of the reservoir. The major effect upon the velocity is the fracture
properties. Calculations with VTI $V_{NMO}$ velocity can detect changes caused by increased fracture properties. Modeling shows that the surveys will observe a decrease in the VTI $V_{NMO}$ velocity from the baseline survey. Additionally, between monitor 1 and monitor 2 surveys, the VTI $V_{NMO}$ velocity will increase due to reservoir compaction (Eker, 2018). The VTI $V_{NMO}$ velocity detects the changes in fractures because of the larger separation between $V_{NMO1}$ and $V_{NMO2}$ (Figure 2.8).

Synthetic reflectivity modeling utilized upscaled log velocity and anisotropy estimates in order to model the potential VVAZ and attenuation signature of the Niobrara Reservoir. Modeling assumed orthorhombic velocity and isotropic attenuation within the reservoir. The models illustrate that P-wave VVAZ is only detectable at offsets greater than 13,000 ft. for smaller amounts fracturing within the Niobrara Reservoir (Figure 2.10) (Omar, 2018). 4D attenuation changes are more apparent in the near offset traces. This is due to the overburden attenuating higher frequencies at far offset traces (Figure 2.13).

Simultaneous processing and layer stripping with a 1D approximation of the P-wave seismic shows that the Wishbone Survey does not have large enough offsets to accurately characterize a fractured reservoir with only P-wave seismic. The Turkey Shoot survey has consistent 4D azimuthal and offset sampling to 11,000 ft. Without the inclusion of S-wave data, fractures within the reservoir cannot be estimated. Due to this limitation, data are inverted with a VTI assumption using core estimations of velocity and attenuation anisotropy (Kamruzzaman, 2015; Ou & Prasad, 2017).

Anisotropy parameters could not be recovered during the inversion process because of the offset restrictions. Time-lapse anomalies show relative changes in $V_{NMO}$ and $A_{P0}$, because anisotropy parameters are held constant spatially and dynamically. The window size in the spectral ratio approach has a large effect upon recovered attenuation parameters, and the stability of the results. Larger window sizes can incorporate interference effects, which cause the spectral ratio estimates to become highly variable. For example, a change of the window size by 6 ms can drastically shift $A_{P0}$ by 0.0114. Faults within the overburden may reduce the
reliability of the layer stripping methodology due to the assumption of lateral homogeneity. Previous synthetic tests show the methodology is stable when geologic dip is less than 10° (Dewangan & Tsvankin, 2006; Wang & Tsvankin, 2009).

Inversion results of \( V_{NMO} \) and \( A_P \) show detectable and spatially coherent changes in both velocity and attenuation. In order to validate the spatial patterns of \( V_{NMO} \) and \( A_P \), post stack RMS amplitude and average frequency attributes are calculated over the reservoir interval. Time-lapse anomalies show similar spatial patterns to the velocity and attenuation anomalies. Though similarities are observed, the layer stripping removes the effect of the overburden. Estimation of velocity and attenuation changes, in conjunction with rock physics modeling, can be used to make inferences about the changes in the reservoir due to fracturing and reservoir fluids. For example, modeling shows that a decrease in the \( V_{NMO} \) velocity is due to greater amounts of fracturing within the reservoir.

Time-lapse velocity results show an overall decrease in the \( V_{NMO} \) velocity, which is attributed to increased fracturing within the reservoir. The main time-lapse anomaly ranges between 11-13% over the horizontal wells that were stimulated and the producing wells west of the Wishbone Section. The larger percent change is due to the VTI assumption, and fixing \( \eta \) spatially and dynamically during the inversion. Time-lapse attenuation results show a decrease over the reservoir due to stimulation. The T-matrix rock physics modeling indicates that hydraulic stimulation may decrease the fluid relaxation time due to hydraulic fracture water, the increase in reservoir permeability, and fracture properties.

The second monitor survey occurred after two years of production. Velocity results indicate compaction and withdrawal of hydrocarbon may cause moderate changes from monitor 1 (Bratton, 2018; Eker, 2018). As the reservoir is produced, fractures lacking proppant close, gas comes out of solution, and reservoir pressure decreases. The velocity changes due to production are smaller than the stimulation response, and range between -4 - 8%. Time-lapse velocity changes between monitor 2 and baseline decrease, which is interpreted to indicate larger fractures properties based upon rock physics modeling in Chapter 2. The larger
velocity anomalies are located over the wells with tighter well spacing (Figure 3.20). Future reservoir simulation results should integrate the lateral boundaries of the anomalies into the reservoir model in order to more accurately estimate optimum well spacing.

Time-lapse attenuation shows a decrease in $A_{P0}$ after two years of production between monitor 2 and baseline (Figure 3.19). Larger decreases in attenuation are associated with higher producing wells in the western part of the survey, which have closer wells spacing. Though gas is coming out of solution, increases in attenuation are not observed due to the higher viscosity of gas (Figure 3.20). This observation is contrary to other attenuation measurements where gas is coming out of solution (Dinh et al., 2015; Puasa et al., 2014; Reine et al., 2012a). Those observations are made in conventional reservoirs where all other rock properties are constant, whereas the observations in this field are from a tight shale reservoir that is experiencing fracture, permeability, and fluid changes. Thus, the decrease in attenuation maybe due to a shift of the apex attenuation to higher frequencies outside of the seismic bandwidth (Guo & McMechan, 2017).

For each of the monitor surveys it is difficult to confirm the exact change in reservoir properties without downhole calibration data. The T-matrix formulation has multiple parameters that are difficult to constrain without downhole calibration data such as repeat formation microimage logs, fluid measurements, and vertical seismic profiles. These data could help narrow the range of parameters needed for modeling. Additionally, the limited offset data restrict the amount of velocity and attenuation parameters that can be recovered. Therefore only inferences can be made into the exact meaning of the anomalies.

The time-lapse velocity and attenuation data are integrated with image logs, surface microseismic, tracer data, reservoir simulation, and production information to analyze how faults, joint sets, and well spacing affect stimulation, and production of the eleven horizontal wells in the Wishbone Section. The integrated interpretation illustrates that faults in the reservoir cause compartmentalization during stimulation and production. Faults limit lateral stimulation and allow hydraulic fracture fluids to move to other reservoir facies vertically
within the Wishbone Section. Both attenuation and velocity changes illustrate that closer well spacing causes greater spatial anomalies, which correlate to higher producing wells.

The key results and takeaways for this project are:

- Current reservoir models of the Wishbone Section indicate the juncture of the two grabens has the largest simulated gas concentration. However, the main time-lapse seismic anomalies are south of the main graben.

- Time-lapse acquisition should ensure that receivers are completely functioning throughout all surveys. In this study the baseline and monitor surveys have \(~13\%\) less data than the monitor 2 acquisition. This limited the amount of data available for analysis. Additionally, far offset data past 11,000 ft. was not fully sampled azimuthally. Modeling shows that P-wave data must have offset coverage twice the depth of the reservoir in order to accurately characterize a fractured shale reservoir.

- Microseismic, tracer, and production data indicate that the faults cause fluid loss, which indicates an area was not effectively stimulated.

- Inclusion of time-lapse seismic anomalies will improve reservoir model estimations of producing zones.

- Closer well spacing and stages placed away from faults allow for improved stimulation of the reservoir, and recovery of hydrocarbon based upon time-lapse changes in $V_{NMO}$ and $A_P$.

6.1 Pouce Coupe Field Microseismic Conclusions

Understanding uncertainty and error at every level of microseismic processing is key towards accurate and precise characterization of hydraulic fracturing. Our study focuses on inclusion of acquisition and processing error with probability density functions. The key results and takeaways for the microseismic are:
• Uncertainty in acquisition geometry can have significant impact on downhole microseismic event location. In this study, the most probable vertical receiver locations were found to be over 10 m. from the original survey locations. Not accounting for such receiver error causes a significant location bias in estimated event locations.

• The PSD or machine learning detection methodologies provide accurate temporal and spatial representation of hydraulic fracture effects.

• Amplitude ratio hodogram analysis methods can reduce azimuthal uncertainty in the presence of high noise and interference with other wave modes.

• Probabilistic location combines amplitude stacking and travel-time minimization methods to create a 3D PDF that incorporates the error associated with acquisition, hodogram analysis, and location analysis.

Integration of survey and processing uncertainty increases accuracy and precision when interpreting microseismic results. Quantification of error from early processing steps and acquisition is vital before higher levels of processing or analysis such as anisotropy inversion. Furthermore, the improvements in detection and location of events show a greater extent of fracturing than previous results. Detecting smaller events at a greater distance from borehole receivers enables interpreters and operators to understand how they are stimulating the reservoir and to improve future decisions about well and stage spacing. Additionally, incorporating the event location error into interpretation can enable quantification of risk associated with microseismic interpretation and the error can be propagated into future analysis.

6.2 Recommendations

Below are recommendations for improved reservoir characterization:

1. The characterization of the Niobrara reservoir utilized velocity independent layer stripping, which assumes lateral homogeneity. The methodology utilizes the spectral ratio
method, which is sensitive to interference effects. Future work should pursue tomography or full-waveform methods in order to reduce the effects of faults in the overburden and avoid interference effects. This is needed for future application in basins where the assumption of lateral homogeneity will not hold, such as the Delaware Basin.

2. The current T-matrix approach has too many parameters for time-lapse rock physics attenuation modeling of a shale reservoir. Information such as the fracture radius and grain size can change the forward model response of a reservoir. Additionally, the T-matrix approach cannot account for a VTI background. This limits anisotropic modeling in shale reservoirs that have strong VTI background.

3. Future velocity and attenuation studies must incorporate downhole calibration data such as pressure data, repeat FMI logs, fluid samples, and vertical seismic profiles. Downhole fiber data can also assist in quantifying the amount of reservoir velocity changes observed. These data could be used as spatial and dynamic constraints in the velocity and attenuation inversions.

4. The velocity and attenuation inversion methodology for this work utilized core VTI estimations from rock measurements (Kamruzzaman, 2015; Ou & Prasad, 2017). This was required due to full offset azimuth coverage being limited to 11,000 ft. The Niobrara reservoir has at least orthorhombic anisotropy, which means that P-wave offsets must be at least twice the depth of the reservoir (Vasconcelos & Tsvankin, 2006). Additionally, incorporation of the shear wave data from the Turkey Shoot Survey could help constrain the anisotropy parameters. The inclusion of shear wave information could also improve the interpretation of the time-lapse effects by mapping changes in fractures with velocity and attenuation.

5. This work indicates high attenuation within the reservoir (Figure 3.20). Larger amounts of attenuation can reduce the effectiveness of amplitude verses offset analysis (Blanchard & Delommot, 2015). If surveys have longer offset data, full-waveform techniques
or tomography can be extended for Q compensation in order to increase the accuracy of amplitude analysis in shale reservoirs.

6. The integrated interpretation of the Wattenberg data shows that faults within the reservoir limit the effectiveness of lateral stimulation. Future work should collect downhole fiber data and integrate with tracer, microseismic, surface seismic, and production data in order to improve the understanding of how faults behave dynamically within a shale reservoir due to hydraulic stimulation and production. Studying the effects of faults within a shale reservoir could lead to improved stage and well placement.

7. The final integrated interpretation at Wattenberg indicates that wells outside of the Wishbone Section may interact with the wells in the western part of the section. Additionally, fault zones are not areas with high production, which is based upon microseismic, tracer, and production data. Future reservoir modeling of the Wishbone Section must incorporate wells west of the study area, and incorporate the time-lapse velocity and attenuation data into the reservoir models. This will improve estimations of well and stage spacing, and the drainage area.

8. The microseismic uncertainty analysis has improved rotation of waveforms, and generated PDFs that account for the depth, azimuth, and radial uncertainty. Future work should extend these estimates from the Pouce Coupe microseismic survey for shear-wave splitting analysis. Past shear-wave splitting analysis illustrated that limited amounts of reliable shear-wave splitting results could be estimated with the Pouce Coupe data (Andrews & Davis, 2016). This was attributed to the poor rotations of the P- and S-waves. If shear-wave splitting results are greatly improved, 3D orthorhombic tomography could be implemented to estimate anisotropy within the Montney reservoir.

9. The improved uncertainty analysis of the Pouce Coupe dataset also has the potential for attenuation analysis. This could greatly improve the understanding of both fractures
and fluids within the Montney Reservoir. The T-matrix rock physics modeling, and the time-lapse results from Wattenberg indicate that the attenuation is sensitive to the fluid change caused by the hydraulic fracture fluid in the stimulated fractures. The application of attenuation may help identify areas with hydraulic fracture fluid.
REFERENCES CITED


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