SEISMIC CHARACTERIZATION OF NIOBRARA FLUID AND ROCK PROPERTIES: A 4D STUDY AND MULTICOMPONENT (3C) ANALYSIS

by

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Unconventional plays in tight porosity, low permeability formations have found large success by stimulating hydraulic fractures to increase hydrocarbon production. Strategies to improve and optimize recovery can be aided by the use of multi-component, time-lapse seismic data for well placement, geologic understanding, monitoring production and identifying zones which have been under-stimulated, or by-passed entirely.

Within the Wattenberg Field in the Denver-Julesburg (DJ) Basin, in a collaborative research project between the Reservoir Characterization Project (RCP) and field sponsor Anadarko Petroleum Corporation (APC), three time-lapse (4D) multicomponent (9C) seismic surveys were acquired within the Wishbone Section to analyze performance of the horizontal wells (seven horizontal wells were drilled in the Niobrara and four in the Codell): Baseline seismic survey, acquired just after the wells were drilled; Monitor 1, acquired after stimulating induced fractures; Monitor 2, acquired after two years of production.

In order to determine the value added by incorporating multicomponent data in the inversion process, two inversions were performed and examined: first, a single vertical component pre-stack PP inversion and second, a joint pre-stack PP-PS inversion, using three-component (3C) converted shear reflection (PS) seismic. Inverted volumes of P-impedance ($Z_P$), S-impedance ($Z_S$) and density ($\rho$) derived from joint pre-stack PP-PS simultaneous inversion were compared to those of pre-stack PP simultaneous inversion. The PS seismic incorporated into the joint inversion improved correlation of $Z_P$, $Z_S$ and $\rho$ of inverted volumes with well log derived values by 8%, 19% and 45%, respectively. Improved correlation of fluid and rock properties of incompressibility ($\lambda \rho$) and rigidity ($\mu \rho$), components of $\lambda \mu \rho$ analysis, resulted from the increased accuracy of inverted volumes ($Z_P$, $Z_S$ and $\rho$). Incompressibility served as a fluid indicator which differentiated between oil and gas, while rigidity served as lithology indicator and differentiated between chalks and marls.
in the Niobrara. By incorporating PS seismic, the joint inversion increased correlation of $\lambda \rho$ and $\mu \rho$ volumes with well log values by 22% and 24%, respectively. Including PS seismic data in the joint inversion created a more precise image of the subsurface which could allow for better well placement by more precisely landing wells within the targeted lithology.

While 4D cross equalization of PP seismic showed excellent repeatability, poor repeatability of PS seismic showed an inability to use 4D PS seismic data. This led to 4D $\lambda \mu \rho$ analysis using only cross equalized PP seismic surveys, though inclusion of PS seismic would have undoubtedly shown improved results. Visualized in cross section, $\Delta \lambda \rho$ and $\Delta \mu \rho$ showed presence of gas ($\Delta \lambda \rho < 0$) and reservoir compaction ($\Delta \mu \rho > 0$) in zones immediately surrounding producing wells. Crossplots of $\Delta \lambda \rho$ and cumulative gas production showed correlation of 0.84 with Niobrara wells and 0.71 with Codell wells, indicating strong correlation of $\Delta \lambda \rho$ with gas production. 4D $\lambda \mu \rho$ analysis aided in identification of gas producing zones ($\Delta \lambda \rho < 0$), absence of gas and zones of understimulation ($\Delta \lambda \rho \geq 0$), and areas which had been effectively drained and compacted ($\Delta \mu \rho > 0$). Providing knowledge of productive zones and the ability to differentiate between areas of effective stimulation and understimulation, time-lapse $\lambda \mu \rho$ analysis could establish potential locations for infill drilling or re-stimulation.
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“... for if I have seen further, it is by standing on the shoulders of giants.”

- Sir Isaac Newton

In an allusion to a dwarf gaining the ability to see further not by possessing taller stature, but by gaining the support of a giant’s shoulder, Newton credited his predecessors upon whose discoveries he had built his own. So, in that spirit, I would like to thank the giants in my life who allowed me to stand on their shoulders.

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For those that shall follow after.
1.1 Preface: Literature Review

To preface the work done in this thesis, the following literature review summarizes studies which used similar methods to those used in this research and also gives context to the 4D-3C interpretation done in this body of work.

Wattenberg Project

Within the Wattenberg Project in the collaborative RCP research group, previous studies used 4D inversion of pre-stack PP (1C) data to identify time-lapse changes in P-impedance ($Z_P$) within the Niobrara reservoir (Utley, 2017). As this work focused only on changes in $Z_P$, and not S-impedance ($Z_S$) or density ($\rho$), derivation of fluid and rock properties incompressibility ($\lambda_\rho$) and rigidity ($\mu_\rho$) were not possible. In this research, the previous time-lapse changes in $Z_P$ were furthered by using 4D inversion of pre-stack PP data to find changes in $Z_P$, $Z_S$ and $\rho$. These time-lapse elastic properties were then used to calculate differences of $\lambda_\rho$ and $\mu_\rho$ to identify changes in fluid content and lithology.

Forward Modeling

As the joint PP-PS inversion in Hampson-RussellTMimplemented isotropic inversion equations and as anisotropy, such as that known to exist within the Wattenberg Field, caused amplitude variations in seismic data, a synthetic joint PP-PS inversion was performed using synthetic models with known anisotropy. Synthetic models were created using velocity and density values upscaled from Wattenberg well logs (Omar, 2018). Anisotropy was then added to these models using penny-shaped cracks with specified orientation, crack density, fracture aperture and fluid fill (Omar (2018); Hudson (1980)). The four synthetic models represented
anisotropy during time-lapse seismic survey conditions: isotropic (control); HTI, fluid filled (Baseline); monoclinic, fluid filled (Monitor 1); HTI, gas filled (Monitor 2).

Analysis using these four synthetic models was furthered by extracting single PP and PS shot gathers from the four models which was used as input to the joint PP-PS inversion workflow in Hampson-Russell™. Quantified differences between inverted isotropic and anisotropic models identified variations of amplitude with incident angle in output PP and PS shot gathers, proving the effect of anisotropy on seismic amplitudes and the need to correct for anisotropy when implementing isotropic inversion equations.

**Multicomponent (3C) Comparison**

Prior research on joint PP-PS inversions focused on visual comparisons of joint inverted elastic parameter volumes ($Z_P$, $Z_S$ and $\rho$) to their counterparts produced from PP inversions in either cross sections with tied well logs (Chaveste et al. (2013); Gaiser (2016)) or comparisons of elastic parameters derived from inverted synthetic gathers with 1D logs (Khare et al. (2007); Zhi et al. (2013); Veire and Landro (2006); Lu et al. (2015)).

Though the work in this thesis also included qualitative visual comparisons of cross sections with well ties, correlations were also evaluated via quantitative comparison in the form of crossplots of inverted ($Z_P$, $Z_S$ and $\rho$) and calculated ($\lambda\rho$ and $\mu\rho$) volumes with values measured from well logs. Correlation coefficients of these crossplots quantitatively evaluated the accuracy of elastic parameters derived from both joint PP-PS and PP inversions.

In this research, assessment of inversion accuracy was further strengthened by using quantitative comparison, to provide numerical values evaluating the correlation of inverted volumes with well logs, in addition to qualitative comparison, which provided a visual match of cross sections with tied well logs.

**Time-Lapse (4D) Analysis**

Previous time-lapse studies were used to identify a threshold value of NRMS difference during the cross equalization of the Monitor 2 seismic survey to Baseline (Helgerud et al.
Using these 4D studies, an NRMS value of 0.3 was established as the target for all angle stacks of the Monitor 2 survey.

In terms of Lambda-Mu-Rho (LMR; \( \lambda \mu \rho \)) for rock physics analysis, previous studies focused on the use of incompressibility (\( \lambda \rho \)) and rigidity (\( \mu \rho \)) to evaluate the fluid content and lithology of reservoir rocks (Gray et al. (1999); Anderson and Gray (2001); Goodway and Limited (1990); Goodway et al. (1996a); Goodway et al. (1996b); Goodway (2001)). With the focus of 4D analysis in this thesis, rock physics analysis was furthered by focusing on the evaluation of change in fluid content (\( \Delta \lambda \rho \)) and rigidity (\( \Delta \mu \rho \)), where negative \( \Delta \lambda \rho \) indicated increased gas content, negative \( \Delta \mu \rho \) indicated open fractures and positive \( \Delta \mu \rho \) indicated compaction and closing of fractures.

The previously mentioned 4D inversion which focused on changes in \( Z_P \) saw strong correlation (correlation coefficient of 0.865) of negative \( \Delta Z_P \) with cumulative gas production from Niobrara and Codell wells (Utley, 2017). This correlation with gas production was further evaluated in this thesis by finding high correlation (correlation coefficient of 0.84) between negative \( \Delta \lambda \rho \) with cumulative production. Furthermore, in an investigation whether time-shifts between Monitor 2 and Baseline seismic surveys were caused by production, this study found negative time-shifts to correlate even higher with cumulative gas production (correlation coefficient of 0.93)

1.2 Wattenberg Project Background

In partnership with field sponsor Anadarko Petroleum Company (APC), the Wattenberg Project began in the Fall of 2013 as Phase XV and XVI of the Reservoir Characterization Project (RCP). In the world of low porosity, tight permeability unconventional reservoirs, the Wattenberg Project focuses on the optimization and exploitation of production in the Niobrara and Codell formations within the Denver-Julesburg (DJ) Basin, Colorado.

The main objectives of the Wattenberg Project are to implement multicomponent, time-lapse seismic data for the purpose of investigating dynamic changes in reservoir properties
and incorporate leading-edge technologies to aid in the interpretation of these properties.

Principle objectives specific to RCP’s Wattenberg Project include:

- Using time-lapse multicomponent seismic to enhance ultimate recovery
- Characterization of natural faults and induced fractures as drivers of well performance
- Analysis of stress changes within the reservoir to evaluate fracture efficiency
- Interpretation of production through iterative, integrated multi-scale reservoir models

Time-lapse (4D), multicomponent seismic data were collected in the form of three seismic surveys (Baseline, Monitor 1 and Monitor 2) using three component (3C) geophones and three component sources in order to measure three different modes of seismic propagation: P-wave (PP), PS-wave (PS) and S-wave (SS) reflections. This PS-wave, or “converted shear” wave, defined as an incident P-wave and reflected S-wave served as the focal point of this research.

These modes of seismic data were measured in order to assess changes occurring within the targeted Niobrara and Codell reservoirs. In terms of time-lapse changes, the three seismic surveys observe the reservoir under in-situ (pre-stimulation; Baseline), after induced hydraulic fracturing (post-stimulation; Monitor 1), and after two years of production from the reservoir (after production; Monitor 2).

1.3 Objectives and Added Value of Research

Overarching objectives specific to this research project include: using PS seismic to supplement traditional PP seismic in a joint PP-PS simultaneous inversion to produce volumes of acoustic and elastic impedance ($Z_P$ and $Z_S$, respectively) and density ($\rho$); using fluid and rock property analysis (Lambda-Mu-Rho; $\lambda\mu\rho$; LMR) to identify reservoir zones which have undergone stimulated fracturing to evaluate areas of effective and ineffective stimulation; and quantify the effect of reservoir stimulation and production in terms of bulk and shear moduli.
The principle objective of this study was to analyze changes in fluid content and lithology, specifically changes in rock matrix strength, within the Niobrara reservoir through the use of time-lapse (4D), multicomponent (3C) seismic data. For the purposes of this study, PP and PS seismic surveys were used in a joint PP-PS simultaneous inversion in order to produce volumes of P-impedance \( Z_P \), S-impedance \( Z_S \) and density \( \rho \). These impedance and density volumes were then used to calculate fluid and rock properties of incompressibility \( \lambda \) and rigidity \( \mu \) where \( \lambda \) can indicate the fluid content of the reservoir and \( \mu \), equal to the shear modulus, can differentiate between lithologies (Goodway, 2001). Generated for each time-lapse seismic survey, these elastic property volumes \( Z_P, Z_S, \rho \), and therefore \( \lambda \) and \( \mu \) were used to analyze 4D changes in reservoir properties due to stimulation and production.

The secondary objective of this study was to demonstrate the value added through the incorporation of multicomponent seismic data to reservoir characterization. In a seismic survey using a vertically oriented source and vertically oriented receivers, mainly PP seismic reflections are recorded, whereas the same survey with a vertically oriented source and multi-component (3C) receivers records both PP and PS reflections. The elastic inversion volumes \( Z_P, Z_S, \rho \) produced from pre-stack PP simultaneous inversion and joint pre-stack PP-PS simultaneous inversion of the same survey area were compared, where the only difference between the two sets of elastic inversion volumes came from the inclusion or omission of PS seismic.

Inversion volumes produced from both joint pre-stack PP-PS simultaneous inversion and pre-stack PP simultaneous inversion were compared to assess the value of incorporating multi-component (PS) seismic to the inversion process. Crossplotting inverted parameters against well log data was used to gauge the accuracy of the inversion process, where the correlation coefficient of the linear regression measured the degree to which data from logs had been replicated throughout the elastic inversion volumes.

Incorporation of PS seismic was expected to better identify brittle, more easily fractured lithology to pinpoint ideal locations to induce fracture stimulation and enhance ultimate
recovery through $\lambda\mu\rho$ analysis. $\lambda\mu\rho$ analysis can be utilized in reservoir engineering by using $\lambda\rho$ and $\mu\rho$ to calculate bulk ($K$) and shear ($\mu$) moduli, Poisson’s ratio and potentially other petrophysical properties such as Young’s modulus ($E$), porosity and fluid saturation (Anderson and Gray, 2001). Additionally, improved vertical resolution can aid horizontal well placement and geosteering such that wells are properly landed in zone to improve efficiency of stimulated fractures and production.

The value in adding multicomponent (PS) data to the inversion process through the joint PP-PS inversion is demonstrated to improve elastic inversion versus using pre-stack PP data alone. This added value can not only be visualized as increased vertical resolution, but also as higher correlation coefficients in cross plots of inverted elastic properties versus well logs. With this information, a better, more accurate knowledge of subsurface structure can be obtained and used to steer and land wells more precisely within formations, and with 4D analysis, identify bypassed pay, target understimulated zones for restimulation and gain an understanding of dynamic changes in rock and fluid properties within the reservoir.

1.4 Study Area

The study area within the Wattenberg Field, Colorado, located in the Denver-Julesburg Basin, focuses on a four-square mile section of time-lapse (4D), multicomponent (9C) seismic data: the Turkey Shoot Survey. More specifically, the area of investigation of this study, called the Wishbone Section, consists of a one-square mile section centered within the Turkey Shoot and contains eleven horizontal wells. Of the eleven horizontal wells, seven landed within the Niobrara formation and four within the Codell Sandstone (Figure 1.1).

The acquisition of the time-lapse multicomponent seismic in the Turkey Shoot Survey took place over two years (Figure 1.2). During May of 2013, the horizontal wells within the Wishbone Section were drilled. The Turkey Shoot 9C Baseline (BL) survey was shot during June 2013. In August 2013, the eleven horizontal wells in the Wishbone Section were completed, where induced fractures were stimulated via hydraulic fracturing, while surface microseismic was acquired. The first 9C monitor seismic survey (Monitor 1; M1)
was shot following well completion in October 2013. After two years of production from the Niobrara and Codell reservoirs, the second 9C monitor seismic survey (Monitor 2; M2) was acquired (January 2016) and delivered to RCP for analysis (September 2016). These three multicomponent seismic surveys (BL, M1, M2) comprised the time-lapse (4D) seismic surveys for analysis of stimulation (M1) and production (M2) effects within the Niobrara and Codell reservoirs.

Figure 1.1: East-West schematic cross section across the Turkey Shoot Survey illustrating the location and variable spacing of the eleven horizontal wells. Note that Niobrara wells are more closely spaced towards the West, and that wells 4N and 11N landed in the C-Marl and B-Marl, respectively (Johnson, 2018).

Figure 1.2: Timeline of data acquisition in the Turkey Shoot Survey.

1.5 Available Data

Data delivered to RCP from field sponsor Anadarko Petroleum Corporation include a wealth of well logs, seismic data, microseismic data and production data.
1.5.1 Well Data

Well logs provided by APC include Gamma Ray (GR), neutron porosity (NPHI), resistivity (ILD) and bulk density (RHOB). Sonic logs, both compressional (DTC) and dipole shear (DTS), within the Turkey Shoot section were derived from a neural-network (NN) system developed by previous RCP students (Pitcher, 2015). One issue that arose when incorporating these NN-derived sonic logs as active wells in the inversion was a strong correlation of $V_p/V_s \approx 2$ which introduced suspicious bias into inversion-derived $Z_P$ and $Z_S$, and therefore $V_P$ and $V_S$.

In order to mitigate the influence of the NN-derived sonic, a well with real sonic logs was shifted from just outside of the Turkey Shoot Survey into the survey area (distance of 2130 ft at a bearing of N 56° E) (Utley, 2017) (“Shifted Well”, Figure 1.3).

Given the consistent geology, meaning isopachous lithologies with no faults between the two locations (Figure 1.4), and the small distance of 2130 ft between the original well location and shifted location, basing the inversion off of a single well with real sonic logs and using the real density logs for QC was the optimal strategy.

Figure 1.3: Schematic showing available wells in the Turkey Shoot Survey Area, Wishbone Section. Note the well labeled Shifted has been shifted 2130 ft from its original position (labeled Original) at a bearing of N 56° E from just South of the Turkey Shoot Survey bounds to its location shown above.
Figure 1.4: Cross section from A - A’ along the path (2130 ft, oriented N 56° E) from the Original Well location to its Shifted location. Left: PP seismic cross section; Right: PS seismic cross section. Note the lack of faulting along the cross section, and continuous thickness of isochron between interpreted horizons.

In addition to the logs themselves, production data from all eleven wells and deviation surveys within the Turkey Shoot were provided. This helped in constraining subsurface locations of horizontal wells and determining where, lithologically, the wells were located and from which formation they produced. Of the seven wells landed in the Niobrara formation and subsequently fractured, six (1N, 2N, 4N, 6N, 7N and 9N) were landed within the C-Chalk, while the last well (11N) landed within the B-Chalk (Figure 1.1).

Additional data which was provided by APC included Formation Micro Image (FMI) logs, which were used to determine fracture orientation (strike, dip) and fracture density (Dudley, 2015), and surface microseismic, which has been used to evaluate effectiveness of individual frac stages by analyzing moment tensors and event clustering by prior RCP students (Grechishnikova (2017); Alfataierge (2017)).

1.5.2 Seismic Data

Compressional (vertical source) and two shear (inline and crossline horizontal sources) vibroseis sources were used in all three surveys (Baseline, Monitor 1 and Monitor 2). The
compressional (vertical) vibroseis was shot in a linear sweep from 8-96 Hz, indicating the frequency range expected within the seismic volume. Similarly, the shear (horizontal) vibroseis were shot in a linear sweep from 4-45 Hz. Retaining the same geometry between surveys (Baseline, Monitor 1 and Monitor 2), source lines were placed W - E with separation of 880 ft while receiver lines were placed S - N and spaced 660 ft. Traces for the PP and SS surveys were then binned into 55 ft x 55 ft CDP grids. PP and PS seismic were both sourced by the compressional vibroseis, but the PP seismic was measured from the vertical component of the 3C geophone receivers, while the PS seismic was measured from the horizontal receiver component. Processing of the PP and PS seismic datasets mostly followed similar steps, with additional steps applied to the PS data (Figure 1.5).

Figure 1.5: Processing workflows performed on the PP (left) and PS (right) seismic datasets. For refraction statics of the PS seismic, the pure shear wave data (TT; transverse component) was used to derive the S-wave refraction statics, then applied to the source-side refraction statics obtained from the pure P-wave (PP) refraction statics.
1.5.3 Considerations for PS Seismic

Refraction Statics: Varying Surface Conditions

For the processing of the Turkey Shoot PS seismic, the PP and SS refraction statics were both used in combination to solve for the PS refraction statics. The concern with refraction statics, however, lies in the varying near surface conditions to which the refraction statics were applied, not the calculation of PS refraction statics themselves.

As previously mentioned, the three seismic surveys (Baseline, Monitor 1 and Monitor 2) were acquired not only during different years but also under different near surface conditions: Baseline, acquired during August 2013, had dry surface conditions; Monitor 1, acquired in October 2013, had saturated near surface conditions due to heavy flooding across Colorado; Monitor 2, acquired January 2016, had frozen surface conditions due to Colorado winter.

The seismic processing report did not detail whether a single refraction statics solution was applied to all three (Baseline, Monitor 1 and Monitor 2) surveys, or whether individual refraction statics solutions were calculated for each survey, accounting for differing surface conditions between the three surveys. If a single solution for refraction statics was applied to the three surveys, this could prevent appropriate 4D analysis in PS seismic cross equalization.

Source-Receiver Orientation and Rotation to Radial-Transverse Coordinates

The horizontal receivers used for acquisition of the seismic surveys were oriented North (0° Azimuth). In Figure 1.6, the relevant coordinate systems are shown where the seismic data are rotated from the acquisition source-receiver (H1-H2) orientation into radial-transverse (R-T) orientations. For a given source-receiver pair, the radial direction points from the source to the receiver, while the transverse direction lies orthogonal to the radial direction.

Source-receiver orientation has been shown to be variable between the Baseline, Monitor 1 and Monitor 2 surveys (Daves, 2018). Recent insight to receiver orientation shows that the Baseline and Monitor 2 surveys were placed in agreement with how they were processed: receivers oriented due North (0° azimuth). However, the Monitor 1 survey showed
a distribution of receiver orientations centered about 10° azimuth. As the seismic data was processed and rotated assuming receiver orientation due North (0° azimuth), this 10° declination from North affected the amplitudes of rotated seismic data (PS, SS). The Monitor 1 PS seismic data was unusable for AVA inversion analysis due to degradation of amplitudes resulting directly from these mis-oriented geophones and the manner in which they were processed. Fortunately, the PP data remained unaffected by the radial receiver orientation as the PP seismic, only measuring the vertical component of the seismic signal, did not undergo rotation.

![Figure 1.6: Schematic depicting rotation from H1-H2 (shown as X-Y) acquisition coordinates into radial-transverse (shown as R-T) coordinates. α represents the angle of rotation to change from X-Y into R-T.](image)

**PS Seismic Binning**

Due to the asymmetric ray path taken by PS seismic, composed of a longer but faster incident P-wave ray path on the shot side and a shorter but slower reflected S-wave ray path on the receiver side, the PS survey was binned using Asymptotic Conversion Point (ACP) binning which does not vary conversion point location with depth and is calculated using a global $V_P/V_S$. The ideal method to bin PS seismic would be with the Common Conversion Point (CCP) which does vary conversion point with depth, and therefore necessitates interval-specific $V_P/V_S$ values to properly bin to the PS reflection point (Figure 1.7). CCP binning sorts PS data to its true reflection point, rather than an estimated location as in ACP binning used by the processor.
1.6 Geologic Background

As the purpose of this study revolves around monitoring reservoir conditions during stimulation of fractures and production, understanding the geologic history of the DJ Basin and specifically the Wattenberg Field in the context of depositional environment, tectonic environment and petroleum system is key to proper application of geophysical inversion techniques.
1.6.1 Depositional Environment

The Niobrara Formation was deposited during the Upper Cretaceous in the shallow marine setting present in the Western Interior Seaway (WIS) (Figure 1.8). The WIS Basin, an asymmetric foreland basin, shows stratigraphic thickening towards the West. Deposited in the fluctuating sea levels of the Upper Cretaceous, carbonate-rich sediments and detrital clays compose the primary lithologic constituents of the Niobrara Formation in the form of interbedded chalks, marls and calcareous shales (Sonnenberg, 2011). Within the Wattenberg Field, the Niobrara Formation ranges from 240-330 ft and has four productive chalk members which range from 20-30 ft in thickness and have porosity $< 10\%$ and permeabilities $< 0.1 \text{ mD}$ (Higley and Cox, 2005). The Codell sandstone underlying the Niobrara formation serves as a secondary petroleum reservoir which contributes significantly to production in the Wattenberg Field. The Codell sandstone reservoir thickness averages between 22-35 ft, has an average porosity of 14% and permeability of about 0.1 mD (Higley and Cox, 2005). The low porosity and permeability exhibited by the Niobrara and Codell formations illustrate the importance of using hydraulic fracturing to induce stimulated fractures and reopen natural fractures in order to increase flow rates of oil and gas out of these tight formations.

Niobrara source rock contains Type-II, oil-prone kerogen, where oil accumulations are found within the oil-generation window and thermogenic gas accumulations where the source rock lies in the gas-generation window (Sonnenberg, 2011). The oil-rich carbonate (interbedded chalks and marls) Niobrara Formation, overlain by calcareous shales, gives a strong increase in impedance whose expected amplitude-versus-offset (AVO) response would be classified as a Class 1 AVO, characterized by a large positive zero-offset amplitude contrast which decreases with increasing offset and incidence angle (Castagna and Swan, 1997).

As fractures were induced outwards from horizontal wells landed within the C-chalk, these fractures were expected to propagate throughout the more brittle chalk and marl sections composing the Niobrara Formation. The Pierre Formation, composed of calcareous shales, is less susceptible to vertical fracture propagation due to its ductility. Therefore, due to
the difference between brittle and ductile lithology, fractures induced in the C-Chalk of the upper Niobrara Formation are expected to terminate at the Lower Pierre Formation in their vertical propagation.

Figure 1.8: Left: Depositional environment of the Wattenberg Field within the Cretaceous Western Interior Seaway, located in the center and denoted by black arrow. Right: Location of the Wattenberg Field (red box). Maps are modified from Blakey (2014).

1.6.2 Tectonic Environment

The Wattenberg Field lies in an asymmetric foreland basin (DJ Basin) which features steep dips and stratigraphic thickening to the West towards the Front Range of the Rocky Mountains and gentle dip and thinner stratigraphy towards the East (Figure 1.9; Sonnenberg (2011)). The tectonic environment of the Wattenberg Field results from the complex combination of multiple faulting styles and stress regimes. The interaction of listric normal faults, anticlinal folds and extensional flexure create stress fields conducive to multiple fracture sets given local and regional structural setting (Sonnenberg, 2011). Though fractures open roughly parallel to the direction of maximum horizontal stress ($S_{HMax}$), in the absence of a dominant $S_{HMax}$ where $S_{HMax} \simeq S_{HMin}$, fractures open in the polygonal fault systems (PFS). PFS, a combination of shear fractures and normal faults, are typically restricted to
intervals composed of fine-grained sediments, such as carbonates and clays, and bounded by undeformed intervals (Sonnenberg et al., 2016). The DJ Basin, whose tectonic setting consists of extensional normal faulting and shear stress fractures, contains the preferred environment of PFS which create horst-graben structures within the Niobrara Formation.

Specifically within the Wattenberg Field, previous studies have shown the dominant fracture strike orientation to be N 70° W (Dudley, 2015). Thus, N 70° W has been presumed to be roughly the orientation of $S_{HMax}$ within the Turkey Shoot survey and the expected direction into which stimulated fractures open.

Figure 1.9: West to East cross section schematic illustrating the asymmetric foreland basin comprising the Wattenberg Field. Note the Niobrara formation produces biogenic gas towards the shallow, eastern section but the burial history of the Wattenberg Field places the reservoir at depths within the thermogenic window (Sonnenberg, 2011).

1.6.3 Petroleum System and Stratigraphic Column

Overlain by the Upper and Lower Pierre Shale Formations and the Sharon Springs Member, the primary reservoir target of the Niobrara Formation consists of interbedded, four alternating chalk and marl sequences, though only three chalk sequences are present in the Wattenberg Field with the A Chalk removed due to erosion (Figure 1.10). The Niobrara Formation overlies the Fort Hays Limestone and the secondary reservoir target of the Codell Sandstone. Below the Codell Sandstone lies the Greenhorn Limestone whose increased impedance relative to the Codell served as a strong reflector which was used to correlate PP and PS seismic volumes.
Deposition of the Greenhorn, Codell and Niobrara during the Late Cretaceous in the dysoxic to anoxic environment of the WIS allowed for preservation of organic content within these lithologies. Compaction of these fine-grained, siliceous grains created low porosity and permeability rocks, trapping and confining organic content within each formation. Given the tight porosity and permeability of the Niobrara and Codell formations, the two serve as their own source, reservoir and seal, creating two self-contained petroleum systems (Figure 1.11). Deposition of overburden rock and consequential subsidence shifted the Niobrara and Codell formations to depths of higher temperature and pressure within the oil window, allowing for hydrocarbon generation during the Paleocene through Miocene. These observations of the depositional environment and petroleum system of the DJ Basin and Wattenberg Field correlate with well logs from the Turkey Shoot survey area. Resistivity readings show intervals of high resistivity indicating presence of hydrocarbons within the Niobrara and Codell intervals (Figure 1.12).
Figure 1.11: Petroleum system chart showing depositional timing within the DJ Basin. Note the Niobrara and Codell formations both act as a self-contained play, serving as their own source, reservoir and seal. After overburden deposition subsided the reservoir into the oil window, hydrocarbon generation began during the late Paleocene. Modified from Higley and Cox (2005).

Figure 1.12: Typical typelog for the Wattenberg Field. From left to right, tracks show: Gamma Ray; Bulk Density; Resistivity (red fill denotes Resistivity over 10 ohm-m); P-wave Slowness; S-wave Slowness. The margin on the right side shows interval tops of which can be correlated with Figure 1.10. The margin on the left side denotes the targeted interval of interest, where the horizontal wells in the Niobrara have been landed in the B-Chalk and B-Marl, as per Figure 1.1. The higher resistivity seen within the Fort Hays compared to the Codell formation is common for the DJ Basin (Sonnenberg (2011); Higley and Cox (2005)).
CHAPTER 2
THEORY OF CONVERTED SHEAR, LAMBDA-MU-RHO ANALYSIS AND JOINT INVERSION

Conventional seismic surveys use only a vertical geophone, and thus record only the vertical component of particle motion. P-waves, in general, have particle motion in the vertical and horizontal planes, the distribution of which depends on the emergent angle at the receiver.

Multicomponent sources and receivers must be used to detect shear waves - pure shear (SS) or converted shear (PS) - whose particle motion travels orthogonal to the direction of propagation. Seismic surveys implementing multicomponent (3C) receivers can detect both vertical ($S_V$ waves) and horizontal ($S_H$ waves) shear waves. Vertical receivers, however, can only detect $S_V$ waves (P - $S_V$ reflection) traveling in the vertical, radial plane, in the absence of anisotropy and shear-wave splitting. These $S_V$ waves compose the upgoing raypath of converted shear (PS) waves, which are the focus of this study.

PS-waves can be detected by 3C receivers using a vertical vibrator, or explosive source, and do not necessitate a source of shear energy. Using a single vertical source to generate both PP- and PS-waves for multicomponent seismic analysis proves to be more cost efficient than shooting the same survey twice, using both vertical and horizontal vibrators.

2.1 Converted Wave Theory

S-waves can be generated by a horizontal vibrator source, or through mode conversion, where a P-wave incident on a lithologic boundary reflects as an S-wave, referred to as a converted or PS-wave. Mode conversion, an angle-dependent phenomenon, depends upon on the angle of P-wave incidence ($\theta$) and contrast in rock properties of P-wave velocity ($V_P; \alpha$), S-wave velocity ($V_S; \beta$) and density ($\rho$) at the layer boundary (Aki and Richards, 1980). The angle of reflection of seismic waves obey relationships dictated by Snell’s Law (Figure
Definitions of symbols used in this thesis can be found in Table 2.1.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\alpha$</td>
<td>(P-wave velocity); $V_P$</td>
</tr>
<tr>
<td>$\beta$</td>
<td>(S-wave velocity); $V_S$</td>
</tr>
<tr>
<td>$Z_P$</td>
<td>P- (acoustic) Impedance</td>
</tr>
<tr>
<td>$Z_S$</td>
<td>S- (elastic) Impedance</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Density</td>
</tr>
<tr>
<td>$\theta$</td>
<td>Angle of P-Wave Incidence</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Angle of $S_V$-Wave Reflection</td>
</tr>
<tr>
<td>$p$</td>
<td>Ray Parameter $\frac{\sin\theta}{\alpha} = \frac{\sin\phi}{\beta}$ $= p$</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Lamé Parameter: Incompressibility</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Shear Modulus and Lamé Parameter: Rigidity</td>
</tr>
<tr>
<td>$K$</td>
<td>Bulk Modulus</td>
</tr>
<tr>
<td>$\nu$</td>
<td>Poisson’s Ratio</td>
</tr>
</tbody>
</table>

Table 2.1: Symbols used in equations and their definitions.

\[
\frac{\sin\theta}{\alpha} = \frac{\sin\phi}{\beta} = p \tag{2.1}
\]

\[
\theta_{PPIIncident} = \theta_{PPReflected} \tag{2.2}
\]

Figure 2.1: Schematic diagram illustrating mode conversion. $\theta$ represents the angle of P-wave incidence and reflection, while $\phi$ represents the angle of S-wave reflection. Note the PS-wave conversion point lies asymmetrically closer to the receiver. Modified from Stewart et al. (2002).
Governed by the Zoeppritz equations, the amplitude of PP reflections depend on contrast of three properties across the interface: $\Delta \alpha = \alpha_2 - \alpha_1$, $\Delta \beta = \beta_2 - \beta_1$ and $\Delta \rho = \rho_2 - \rho_1$, where subscripts 1 and 2 represent the properties above and below the interface (Aki and Richards, 1980) (Equation 2.3). The Zoeppritz reflectivity equations use $\bar{\alpha}$, $\bar{\beta}$ and $\bar{\rho}$ to represent average background parameters (i.e.: $\bar{\alpha} = (\alpha_1 + \alpha_2)/2$).

The amplitudes of PS reflections, however, only depend upon the contrast of two rock properties: $\beta$ and $\rho$ (Equation 2.4). The coefficients of each term in Equation 2.3 are weighted depending on incidence angle ($\theta$) while terms in Equation 2.4 depend on both incidence angle ($\theta$) and PS reflection angle ($\phi$), though both $\theta$ and $\phi$ can be represented as a single variable related by the ray parameter: $p$. The angles $\theta$ and $\phi$ are determined from the medium parameters. The fractional changes ($\Delta \alpha$, $\Delta \beta$, $\Delta \rho$) are the unknowns to be inverted for from the Zoeppritz equations, where $\Psi = 4 \left( \frac{\beta}{\alpha} \right)^2$ (Equations 2.3 and 2.4).

$$R_{PP}(\theta) = \frac{1}{2} \left( \frac{\Delta \alpha}{\alpha} + \frac{\Delta \rho}{\rho} \right) + \frac{1}{2} \left( \frac{\Delta \alpha}{\bar{\alpha}} - \Psi \frac{\Delta \rho}{\bar{\rho}} - 2\Psi \frac{\Delta \beta}{\bar{\beta}} \right) \cdot \sin^2 \theta$$

$$+ \frac{1}{2} \left( \frac{\Delta \alpha}{\bar{\alpha}} \right) \cdot \sin^2 \theta \tan^2 \theta$$

(2.3)

$$R_{PS}(\theta, \phi) = \left( \frac{-p\bar{\rho}}{2 \cos \phi} \right) \left[ \left( 1 - 2\bar{\beta}^2 p^2 + 2\bar{\beta}^2 \frac{\cos \theta \cos \phi}{\bar{\alpha}} \right) \frac{\Delta \rho}{\bar{\rho}} - 4\bar{\beta} \left( p^2 - \frac{\cos \theta \cos \phi}{\bar{\alpha}} \right) \frac{\Delta \beta}{\bar{\beta}} \right]$$

(2.4)

2.1.1 Added Value of Converted Shear: PP vs PP + PS

P- and S-wave velocities, as well as P- and S-impedance, can be calculated using relationships between density ($\rho$) and the first two Lamé parameters: $\lambda$, incompressibility, and $\mu$, rigidity (Equations 2.5 and 2.6). As S-wave velocity depends only upon the rigidity ($\mu$), or shear modulus, of the rock matrix and the density of the rock, $V_S$ does not vary with fluid fill unless the fluid drastically affects the rock’s density. P-wave velocity depends on the incompressibility of a rock in addition to its rigidity and density. The incompressibility ($\lambda$) of a rock is most sensitive to fluid fill, and thereby sensitive to porosity (Goodway et al., 1996a). This sensitivity of $V_P$ to fluid fill, due to $\lambda$, can create bright spots or Direct Hydrocarbon
Indicators (DHI) in P-wave seismic images when imaging gas and oil filled reservoirs. As the shear component of the PS wave is unaffected by fluids within a reservoir, the same DHI would not appear on PS seismic, providing an undistorted image of hydrocarbon reservoirs.

By incorporating the two-term reflectivity equation of the PS-wave alongside that of the P-wave, the solution for variables of \( V_S(\beta) \) and density \( (\rho) \) is potentially further constrained compared to using the PP reflectivity equation alone.

\[
V_P = \sqrt{\frac{\lambda + 2\mu}{\rho}} \quad V_S = \sqrt{\frac{\mu}{\rho}} \quad (2.5)
\]

\[
Z_P = V_P \cdot \rho \quad Z_S = V_S \cdot \rho \quad (2.6)
\]

### 2.2 Rock Physics and Lambda-Mu-Rho Theory

Behind the mechanics of the fundamental wave equation, it has been shown that seismic wave propagation depends on density \( (\rho) \) and rock modulus \( (M) \), where \( M \) is calculated from Lamé parameters \( \lambda \) and \( \mu \): \( M = \lambda + 2\mu \) (Goodway et al., 1996a).

With this direct dependence on rock properties of \( \rho \) and \( M \), the most effective method of distinguishing rock type and fluid fill comes from analysis of Lamé parameters of incompressibility, \( \lambda \), rigidity, \( \mu \), and density, \( \rho \), rather than the seismic velocities \( V_P \) and \( V_S \) which depend on combinations of \( \lambda \) and \( \mu \) (Equation 2.5). Given their dependence on \( \rho \), more accurate estimates of \( \lambda \) and \( \mu \) can be obtained with the aid of PS seismic and the additional constraint in solving for \( \rho \) that it provides.

As rigidity \( (\mu) \), equivalent to the shear modulus, depends only on the matrix of the rock fabric, its value remains constant between both dry and saturated conditions for a given lithology (Equation 2.7). High values of \( \mu \) indicate very rigid rocks, such as cemented sandstones, whereas more ductile rocks, such as shales, tend to have lower values of \( \mu \) (Goodway, 2001). \( \mu \) and \( \mu \rho \), therefore, can be used to differentiate between matrix lithologies.
\( \mu = \mu_{\text{Dry}} = \mu_{\text{Sat}} \) (2.7)

\[
\lambda \rho = Z_P^2 - 2Z_S^2 \\
\mu \rho = Z_S^2
\] (2.8)

Conversely, incompressibility (\( \lambda \)), changes between dry and saturated conditions, thereby indicating the fluid content of the rock. Low values of \( \lambda \) and \( \lambda \rho \) likely indicate gas due to its highly compressible nature, whereas higher values of \( \lambda \) and \( \lambda \rho \) indicate very tight porosity rocks with little volume for fluid fill (Equation 2.8) (Goodway et al., 1996a)).

Figure 2.2: Comparison between crossplots of \( Z_P \) and \( Z_S \) (left) and \( \lambda \rho \) vs \( \mu \rho \) (right). Note better spread and distinction between lithologies and fluid content on the \( \lambda \rho-\mu \rho \) cross plot on the right. Modified from Goodway (2001).

Figure 2.3: Rock physics template based on lithology and fluid/porosity attributes in \( \lambda \rho \) and \( \mu \rho \) crossplots. Modified from Goodway (2001).
As \( V_P \) and \( V_S \), and therefore \( Z_P \) and \( Z_S \) (Equations 2.5 and 2.6), depend on \( \lambda \) and \( \mu \), \( \lambda \rho \) and \( \mu \rho \) serve as better metrics to differentiate between fluid and rock properties. By utilizing \( \lambda \rho \)-\( \mu \rho \) crossplots, better separation between lithologies and different fluid properties can be identified (Figure 2.2). The use of \( \lambda \rho \)-\( \mu \rho \) crossplot hinges on the assumption of an accurate \( \rho \) volume from which \( \lambda \rho \) and \( \mu \rho \) can be derived. The issue that arises is \( \rho \) cannot be inverted for accurately given the angle range in conventional acquisition of surface seismic PP data alone, hence the emphasis on incorporation of PS seismic alongside PP seismic in the inversion process. Calculated directly from both well logs and elastic inversion volumes, \( \lambda \rho \) and \( \mu \rho \) are compared and analyzed in crossplots with \( \lambda \rho \) on the x-axis and \( \mu \rho \) on the y-axis (Figure 2.2). Gas sands cluster towards areas with low \( \lambda \rho \) and high \( \mu \rho \) due to their highly compressible and rigid nature, while shales tend to appear towards the high \( \lambda \rho \) and low \( \mu \rho \) zones due to their low porosity, ductile tendencies.

Given the depositional environment of the DJ Basin and the petroleum system local to the Wattenberg Field, the calcareous shales and marls within the Niobrara reservoir are expected to plot at values of low rigidity along the vertical axis, while higher rigidity within the carbonate-rich Niobrara chalks would be clustered higher along the vertical axis (Figure 2.3). With all other things being equal, notably no change in porosity, the horizontal axis of incompressibility indicates fluid content, where lithologies with compressible gases and low values of \( \lambda \rho \) plot towards the left and lithologies with less compressible fluids (oil or brine) with high values of \( \lambda \rho \) plot further to the right (Figure 2.3).

Previous time-lapse pre-stack PP inversion from RCP within the Wattenberg Project have found lower \( Z_P \) measured between Baseline and Monitor 2 to correlate positively with gas production within the Wishbone section (Utley, 2017). 4D seismic data can be applied to time-lapse LMR crossplots where time-lapse differences in \( \lambda \rho \) and \( \mu \rho \) are plotted against each other (time-lapse \( \lambda \rho \) on the x-axis; time-lapse \( \mu \rho \) on the y-axis) to identify how incompressibility and rigidity change between seismic surveys. Using time-lapse \( \Delta \lambda \rho - \Delta \mu \rho \) crossplots calculated from the Baseline and Monitor 2 seismic surveys within the Wattenberg Field,
the previously identified gas effect will be studied (Utley, 2017).

2.3 Inversion Theory

This study focuses on the inversion of conventional PP seismic alongside converted PS seismic, where an incident P-wave undergoes mode conversion and reflects as an upgoing $S_V$ wave (Figure 2.1), to solve for elastic parameters $Z_P$, $Z_S$ and $\rho$ and then calculate fluid and rock properties $\lambda \rho$ and $\mu \rho$.

In a pre-stack PP simultaneous inversion, P-wave reflection angles are used in the three-term PP reflectivity equation to solve for fractional changes in rock properties of $V_P (\Delta \alpha/\alpha)$, $V_S (\Delta \beta/\beta)$ and density ($\Delta \rho/\rho$). From the angle-dependent coefficients of the PP reflectivity equation, the solution of $\Delta \alpha/\alpha$ depends on the near angles while the density term $\Delta \rho/\rho$ depends on the far angles (Equation 2.3), implying that in order for a pre-stack PP inversion to properly derive density, the input PP seismic must have data in the far angle stacks. In contrast, the PS reflectivity equation resolves changes in $\Delta \rho/\rho$ at smaller angles, made possible due to the angle-dependent coefficients of the $\Delta \rho/\rho$ term (Equation 2.4), representing a benefit of utilizing PS seismic in the joint PP-PS simultaneous inversion.

In the absence of shear seismic (PS or SS), Hampson-Russell™ uses an empirically calibrated linear relationship between $\alpha$ and $\beta$ known as the Castagna mudrock equation to estimate background $\bar{\beta}$ from $\alpha$ using input slope ($a$) and intercept ($b$) terms (Equation 2.9); (Castagna et al., 1985)). Though Castagna et al. (1985) obtained coefficients from lab measurements, Hampson-Russell™ uses crossplots of well logs to solve for $a$ and $b$. As the Turkey Shoot data provided by APC included interval and RMS velocities for the pure shear (SS) seismic data, background $\bar{\beta}$ was derived using these delivered SS velocities in lieu of using Equation 2.9.

$$\beta = a \cdot \alpha + b \tag{2.9}$$

To add further constraint to the density ($\rho$) term, Gardner’s equation is implemented to create a low frequency background $\rho$ trend to be perturbed by the fractional changes $\rho$. 

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These fractional changes are calculated by the linearized Gardner equation between $\alpha$ and $\rho$ (Equation 2.10; Gardner et al. (1974)). As with Equation 2.9, the background trend in $\rho$ could have been created using Equation 2.10 but instead the background model was created using $\rho$ logs from wells within the Turkey Shoot survey area.

$$0.25 \frac{\Delta \alpha}{\alpha} = \frac{\Delta \rho}{\rho} \quad (2.10)$$

### 2.3.1 Joint Pre-Stack PP-PS Simultaneous Inversion Theory

The overall goal of the inversion process is to minimize the difference between observed and predicted data. The difference between observed data ($d$) and the forward modeling operator ($g$) applied to the model parameters ($m$) while accounting for noise ($n$) is calculated by Equation 2.11.

$$d = g(m) + n \quad (2.11)$$

The joint pre-stack PP-PS simultaneous inversion is performed in the amplitude vs incident-angle (AVA) domain. In the case of PP reflectivity, $d$ represents angle-dependent reflection amplitudes ($R_{PP}$) at each two-way vertical traveltime sample, $g$ represents the angle-dependent coefficients and $m$ represents the fractional changes in model parameters ($\Delta \alpha/\alpha$, $\Delta \beta/\beta$, $\Delta \rho/\rho$) (Equation 2.12). Likewise for PS reflectivity, $d$ and $g$ both represent angle-dependent reflection amplitudes, ($R_{PS}$) and angle-dependent coefficients, respectively, while $m$ represents the fractional change of only two parameters: $\Delta \beta/\beta$ and $\Delta \rho/\rho$ (Equation 2.13). Equations 2.12 and 2.13 follow the form of Equation 2.11: $d$ on the left; $g$ in the center; $m$ on the right. While the PP reflectivity equation contains three linearized fractional parameters ($\Delta \alpha/\alpha$, $\Delta \beta/\beta$, $\Delta \rho/\rho$), the two linearized fractional parameters ($\Delta \beta/\beta$, $\Delta \rho/\rho$) in the PS reflectivity equation provide additional constraint in determination of $\beta$ and $\rho$.

Least squares differences iteratively minimize differences between $d$ and $g(m)$ while solving for the fractional changes in model properties with respect to incidence angle $\theta$ (Equation 2.14). Generally, the solution to a linear problem can be solved in a single iteration; in prac-
tice, additional iterations may be required depending on values of the covariance matrix (Equations 2.15 and 2.16).

\[
\begin{bmatrix}
R_{PP}(\theta_1) \\
\vdots \\
R_{PP}(\theta_N)
\end{bmatrix} = 
\begin{bmatrix}
\frac{1}{2\cos^2 \theta_1} - 4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_1 \left( 1 - 4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_1 \right) \\
\vdots \\
\frac{1}{2\cos^2 \theta_N} - 4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_N \left( 1 - 4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_N \right)
\end{bmatrix}
\begin{bmatrix}
\Delta \alpha \\
\Delta \beta \\
\Delta \rho
\end{bmatrix}
\] (2.12)

\[
\begin{bmatrix}
R_{PS}(\theta_1) \\
\vdots \\
R_{PS}(\theta_N)
\end{bmatrix} = 
\begin{bmatrix}
2 \sin \theta_1 \left( \frac{\sin^2 \phi_1}{\cos \phi_1} - \cos \theta_1 \right) \\
\vdots \\
2 \sin \theta_N \left( \frac{\sin^2 \phi_N}{\cos \phi_N} - \cos \theta_N \right)
\end{bmatrix}
\begin{bmatrix}
\Delta \beta \\
\Delta \rho
\end{bmatrix}
\] (2.13)

\[
\Delta m = [G^T G + C_m^{-1}]^{-1} G^T d
\] (2.14)

In terms of model covariance \(C_m\); Equation 2.14), the use of PP reflectivity terms \(\alpha, \beta\) and \(\rho\) in \(d\) creates a 3x3 model covariance matrix (Equation 2.15), where \(\sigma_{2m_i}^2\) represents the variance in parameter \(m_i\) when compared to the model and \(\sigma_{mimj}^2\) represents the covariance of parameter \(m_i\) with parameter \(m_j\) (Simmons and Backus, 1996). Similarly, the PS reflectivity equation uses a 2x2 covariance matrix with reflectivity terms \(\beta\) and \(\rho\) (Equation 2.16).

\[
C_{PPm} = \begin{bmatrix}
\sigma_{\alpha}^2 & \sigma_{\alpha\beta} & \sigma_{\alpha\rho} \\
\sigma_{\beta\alpha} & \sigma_{\beta}^2 & \sigma_{\beta\rho} \\
\sigma_{\rho\alpha} & \sigma_{\rho\beta} & \sigma_{\rho}^2
\end{bmatrix}
\] (2.15)

\[
C_{PSm} = \begin{bmatrix}
\sigma_{\beta}^2 & \sigma_{\beta\rho} \\
\sigma_{\rho\beta} & \sigma_{\rho}^2
\end{bmatrix}
\] (2.16)

The least squares solution for model parameters and observed data depends very closely on the relationship between model covariance, \(C_m^{-1}\), and the \(G\) matrix \((G^T G)\), an indicator of how much the data will change due to perturbation of a model parameter. In inverse
theory, these terms are referred to as the “fractional derivatives”. The magnitude of values
in $\mathbf{C}_m$ basically control the amount a given parameter can change from its prior background
value. If there exists no model covariance (i.e. $\mathbf{C}_m^{-1} = 0$), then the least squares solution
difference between model parameters ($\mathbf{m}$) and observed data ($\mathbf{d}$) only requires a single
iteration as without a perturbation of model parameters, $\mathbf{m} = \mathbf{d}$. For a covariance matrix
$\mathbf{C}_m^{-1} > \mathbf{G}^T \mathbf{G}$, the $\mathbf{G}$ matrix contributes negligibly, and the least squares solution is controlled
by the $\mathbf{C}_m^{-1}$ term. For model covariance values $0 < \mathbf{C}_m^{-1} < \mathbf{G}^T \mathbf{G}$, the least squares solution
effectively minimizes differences between observed data and model parameters within a given
number of iterations. For a $\mathbf{G}$ matrix containing columns of non-independent data, the least
squares solution does not minimize differences between observed data and model parameters,
indicating that the model parameters associated with these columns cannot be resolved. This
illustrates the effectiveness of using linearized relationships in the absence of measured data
to infer unknown data from known data: $\alpha$ and $\beta$ (Equation 2.9) or $\alpha$ and $\rho$ (Equation 2.10).
In order to ensure a damped least squares solution, a diagonalized model covariance matrix
can be implemented to minimize differences between $\mathbf{m}$ and $\mathbf{d}$: a 3x3 matrix for the three
parameter PP reflectivity equation or a 2x2 matrix for the two parameter PS reflectivity
equation (Equation 2.17).

$$\mathbf{C}_m = \begin{bmatrix}
\sigma^2_\alpha & 0 & 0 \\
0 & \sigma^2_\beta & 0 \\
0 & 0 & \sigma^2_\rho
\end{bmatrix}$$

(2.17)

In the joint inversion process, Hampson-Russell™ must use a combination of the two
forms of $\mathbf{d} = g(\mathbf{m})$, using both Equations 2.12 and 2.13 (Equation 2.18). This combined
$\mathbf{d}_{PP-PS} = g(\mathbf{m}_{PP-PS})$ would use a single 3x3 $\mathbf{C}_m$ (Equations 2.15 and 2.16) where values of
$\sigma^2_\beta$, $\sigma_\beta \rho$, $\sigma_\rho \beta$, and $\sigma^2_\rho$ from $\mathbf{C}_{PPm}$ provide constraint to the same variance ($\sigma$) terms in $\mathbf{C}_{PPm}$.

By using the two-term PS reflectivity equation and PS seismic data to supplement the
three-term PP reflectivity equation and PP data, the inversion process becomes better con-
strained and overdetermined which better minimizes the differences between real data (PP and PS) and modeled parameters. Thus, by using PS seismic together with PP seismic, more accurate and realistic shear impedance ($Z_S$) and density volumes can be created in the joint inversion process.

$$
\begin{bmatrix}
    d_{PP} \\
    d_{PS}
\end{bmatrix} =
\begin{bmatrix}
    g_{PP} \\
    g_{PS}
\end{bmatrix}
\begin{bmatrix}
    \frac{\Delta \alpha}{\alpha} \\
    \frac{\Delta \beta}{\beta} \\
    \frac{\Delta \rho}{\rho}
\end{bmatrix}
\begin{bmatrix}
    \frac{1}{2 \cos^2 \theta_{PP}} \\
    -4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_{PP} \\
    0
\end{bmatrix}
\begin{bmatrix}
    1 - 4 \left( \frac{\beta}{\alpha} \right)^2 \sin^2 \theta_{PP} \\
    \sin \theta_{PS} \left( \frac{\sin^2 \phi_{PS}}{\cos \phi_{PS}} - \cos \theta_{PS} \right) \\
    2 \sin \theta_{PS} \left( \frac{\sin^2 \phi_{PS}}{\cos \phi_{PS}} - \frac{1}{2 \cos \phi_{PS}} - \cos \theta_{PS} \right)
\end{bmatrix}
\begin{bmatrix}
    \frac{\Delta \alpha}{\alpha} \\
    \frac{\Delta \beta}{\beta} \\
    \frac{\Delta \rho}{\rho}
\end{bmatrix}
$$

(2.18)

### 2.4 Assumptions: Anisotropy and Implications for Isotropic Inversion

The reflectivity equations used in Hampson-Russell joint PP-PS simultaneous inversion assume isotropic conditions, where there exist no azimuthal variations in P- or S-wave velocities. Within the Wattenberg Field, the presence of not only natural in-situ fractures and vertical transverse isotropy (VTI), but also induced hydraulic fractures, may create complex, anisotropic variation in seismic velocities.

With the known horizontal layering created by deposition of shale lithologies, VTI is created. A single vertical fracture set within an isotropic background creates horizontal transverse isotropy (HTI) (Bakulin et al., 2000a). Two orthogonal vertical fracture sets interact to create orthorhombic anisotropic media, while the combined effect of two non-orthogonal vertical fracture sets is known as monoclinic anisotropy (Tsvankin (1997); Bakulin et al. (2000b)). The complexity of the fracture sets present in the Wattenberg Field is unclear.
but the fact remains that the seismic recorded from the Turkey Shoot survey has been affected by anisotropic media, though there remains the question of whether the seismic is sensitive to this anisotropy. Thus, the effect of applying isotropic inversion equations to an inherently anisotropic media was compared to the application of isotropic equations to an isotropic media.

Induced fractures within the Turkey Shoot survey area have been found to strike N 70° W, while natural fractures have been found to strike at N 50° E and N 70° W (Figure 2.4) (Dudley, 2015). Natural fractures open parallel to maximum horizontal stress ($\sigma_{HMax}$) and perpendicular to minimum horizontal stress ($\sigma_{hmin}$). This combination of natural, in-situ fractures and induced hydraulic fractures oriented at non-orthogonal orientations (120° between the two fracture sets) characterize the anisotropic conditions in the Wattenberg Field to indicate monoclinic anisotropy.

Figure 2.4: Rose diagrams showing azimuth distribution of open and sealed natural fractures (blue), fault azimuths (purple) and induced fracture orientations (red) (Dudley, 2015).
For a single set of vertical fractures (HTI), the fast shear (S1) travels parallel to the fracture plane while the slow shear (S2) travels perpendicular to the fracture planes. Principal directions determined by P-wave azimuthal AVO in HTI media differ from S1 and S2 orientations in the presence of multiple fracture sets. For two or more non-orthogonal fracture sets, S1 and S2 lie not parallel or perpendicular to the fracture planes, but along the principal axes determined by the fracture compliance tensor, $s_{ij}$ (Sayers and Dean, 2001).

Using azimuthal AVO to model non-orthogonal (monoclinic) anisotropic media involves adding fracture sets to an isotropic background rock by combining the excess compliance tensor created by fractures to the compliance tensor of the isotropic background rock to create the effective elastic compliance tensor ($s_{ij} = s_0 + \Delta s_{ij}$) (Sayers and Dean (2001); Sayers (2009)). These compliance tensors ($s_{ij}$) are then divided into isotropic and anisotropic compliance, converted to isotropic and anisotropic stiffness tensors ($c_{ij} = 1/s_{ij}$) and finally converted to reflection coefficients for incident P-waves ($R_{PP}^{iso}$ and $R_{PP}^{Aniso}$, respectively) (Equation 2.19) (Bachrach et al., 2013). The azimuthally-dependent coefficients ($b_n$) of $R_{PP}^{Aniso}$ are calculated from Thomsen parameters of $\delta$, $\epsilon$ and $\gamma$ which vary in the $x$, $y$ and $z$ directions (Thomsen, 1986).

Though the isotropic reflection coefficient depends only upon P-wave angle of incidence (Equation 2.20), the anisotropic reflection coefficient also depends on azimuth angle ($\Phi$) (Equation 2.21). In the presence of two fracture sets, $\Phi$ represents the angle between the azimuths of each fracture set ($\Phi = \Phi_1 - \Phi_2$) (Equation 2.21). These equations for amplitude versus azimuth (AVAz) variations were derived for PP seismic, using altered PP reflectivity equations. For PS and SS, AVAz is restricted to the principal fracture directions as the same equations used for PP seismic above do not yet exist (Ruger, 1995).

These concepts and equations of non-orthogonal fracture sets were incorporated in modeling the synthetic response of the anisotropic, time-lapse Wattenberg field seismic data. Amplitudes at a reservoir horizon in two synthetic models, one with a single fracture set at N 70° W and a second with two non-orthogonal fracture sets (N 70° W and N 50° E), were
compared with amplitudes of isotropic model in order to determine the effect of anisotropy on seismic amplitudes. The same synthetic models (single fracture set and two non-orthogonal fracture sets) were used to simulate seismic surveys with differing fluid conditions, wet and dry, to estimate time-lapse changes from water-filled to gas-filled fractures.

\[ R_{PP}(\Phi, \theta) = R_{PP}^{iso} + R_{PP}^{aniso} \]  

\[ R_{PP}^{iso}(\theta) = A + b_1 \sin^2 \theta + b_2 \sin^2 \theta \tan^2 \theta; \]
\[ A = \frac{1}{2} \Delta Z_P; b_1 = \frac{1}{2} \left( \frac{\Delta \alpha}{\alpha} - 4 \left( \frac{\beta}{\alpha} \right)^2 \frac{\Delta G}{G} \right); b_2 = \frac{1}{2} \frac{\Delta \alpha}{\alpha}; Z_P = \alpha \rho; G = \rho \beta^2 \]  

\[ R_{PP}^{aniso} = \left[ b_3 \cos^2 \Phi + b_4 \sin^2 \Phi \right] \sin^2 \theta + \left[ b_5 \cos^4 \Phi + b_6 \sin^4 \Phi + b_7 \cos^2 \Phi \sin^2 \Phi \right] \sin^2 \theta \tan^2 \theta; \]
\[ b_3 \equiv \Gamma_x = \left( \Delta \delta_x - 8 \left( \frac{\beta^2}{\alpha^2} \right) \Delta \gamma_x \right); b_4 \equiv \Gamma_y = \left( \Delta \delta_y - 8 \left( \frac{\beta^2}{\alpha^2} \right) \Delta \gamma_y \right); \]
\[ b_5 = \frac{\Delta \epsilon_x}{2}; b_6 = \frac{\Delta \epsilon_y}{2}; b_7 = \frac{\Delta \delta_z}{2}; \Phi = \Phi_1 - \Phi_2 \]  

(2.21)
CHAPTER 3
FORWARD MODELING

Synthetic models were utilized to validate observations seen in the seismic data. By designing synthetic models with known background parameters and changing variables in a reasonable, controlled manner, seismic observations can be validated.

3.1 Source-Receiver Orientations and Rotation to Radial-Transverse Coordinate System

When designing and processing of multicomponent surveys, careful scrutiny must be utilized to properly convert seismic data from the field acquisition coordinates, in which the data was recorded, into the radial-transverse coordinate system, in which the data will be interpreted. For the seismic surveys in the Wattenberg Field, nominal direction of horizontal receiver $H_1$ was presumed to be North, $H_1 = 0^\circ$, with $H_2 = 90^\circ$.

The PS data was then rotated from field acquisition coordinates into radial-transverse coordinates assuming $H_1 = 0^\circ$. The radial-transverse coordinate system, designed to account for polarization of multicomponent particle motion, defines the radial direction as parallel to the source-receiver orientation while the transverse direction lies orthogonal to the radial direction (Figure 3.1) (Gaiser, 1999).

Due to anomalous signal ("leakage"), attributed to the wet surface conditions by the processing contractor, seen in Limited-Angle-Stacks (LAS) of the SS seismic data in Monitor 1, the Monitor 1 surveys for both SS and PS seismic were considered unusable. Using Common-Offset-Common-Azimuth (Hons et al., 2007) gathers of PS data, the source of this leakage was determined to be a global error in $H_1$ orientation where optimal $H_1 \approx 10^\circ$ as opposed to the $H_1 = 0^\circ$ orientation assumed and used during rotation to radial-transverse coordinates (Daves, 2018). The Baseline and Monitor 2 surveys were properly rotated to radial-transverse, using the correct $H_1 = 0^\circ$, while the Monitor 1 survey with nominal $H_1 =$
8 – 10° (Figure 3.2), later identified to be the magnetic declination in the field area, was improperly rotated to radial-transverse coordinates using $H_1 = 0°$. Due to this improper rotation of the Monitor 1 survey of the PS seismic was omitted from time-lapse analysis in this study.

Figure 3.1: Schematic illustrating radial-transverse coordinate vectors for shot-receiver pairs with the same P- to S- conversion point for PS seismic (Gaiser, 1999).

Figure 3.2: Histogram distribution of optimal $H_1$ azimuth to minimize reflection energy on PS transverse component, and maximize reflection energy on PS radial component. This method used P-wave first arrivals to drive the analysis (Daves, 2018).
3.2 Time-Lapse Anisotropic Modeling

By performing an inversion using isotropic reflection equations on an inherently anisotropic dataset, there existed potential for unrealistic anomalies in the resulting inversion volume. Therefore, synthetic models with both isotropic and anisotropic conditions were created in order to constrain the observations seen in the Wattenberg dataset, and quantify differences in amplitudes between isotropic and anisotropic conditions.

With the known presence of VTI due to lithology and two fracture non-orthogonal fracture sets (natural fractures at N 70° W and induced fractures at N 50° E), anisotropic modeling was performed assuming the following:

- Baseline: HTI anisotropy with fractures oriented as the natural fractures at N 70° W
- Monitor 1: Monoclinic anisotropy, featuring both natural fractures at N 70° W and induced fractures at N 50° E
- Monitor 2: HTI with natural fractures at N 70° W, as induced fractures were presumed to have closed after two years of production

<table>
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<th>Formation</th>
<th>V_P (m/s)</th>
<th>V_S (m/s)</th>
<th>Density (g/cc)</th>
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<th>Baseline</th>
<th>Monitor 1</th>
<th>Monitor 2</th>
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<td></td>
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<td></td>
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<tr>
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<tr>
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<td>1864.7</td>
<td>2.57</td>
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Figure 3.3: Input parameters for modeling of anisotropic reflectivity in the Wattenberg Field using a 11-layer model. Parameters include V_P, V_S, density. The orange boxes in each survey detail the anisotropic parameters (fracture orientation and fluid fill) per survey. For each anisotropic model, Hudson parameters of fracture density (e) and fracture aperture (f) were held constant (“Baseline”, “Monitor 1” and “Monitor 2”) using Hudson cracks oriented at N70°W for HTI models and at N70°W and N50°E for the monoclinic model.
An eleven-layer model was created based on the stratigraphy in the Wattenberg Field using realistic $V_p$, $V_S$, and $\rho$ and approximate layer thicknesses (Figure 3.3) (Omar, 2018). Within this eleven layer model, four intervals comprised the reservoir: the combined Niobrara A/B, Niobrara C, Niobrara D and the combined Fort Hays-Codell intervals. In order to isolate anisotropic effects on seismic amplitudes within the reservoir for all models, the elastic properties within each of the four overburden intervals remained isotropic. Meanwhile, the four reservoir intervals underwent varied anisotropic conditions reflecting known changes between seismic surveys.

The initial model, designed to mimic the in-situ conditions of the Baseline survey, was shot with a single fracture set in the reservoir interval, creating HTI oriented at N 50° E to simulate natural fractures. The second model, accounting for the induced hydraulic fractures seen in Monitor 1, had an added second, non-orthogonal, fluid-filled fracture set oriented N 70° W, which represented the induced fractures. For the third model, modeling the Monitor 2 survey where previous RCP studies have encountered a gas-saturation effect, the fluid fill of the fractures changed from fluid-filled to gas-filled cracks (Utley, 2017). These models were shot with a vertical source (z-direction) which were then received by multicomponent (3C) geophones as PP-wave and a converted shear PS-wave recorded in field (x, y) coordinates, then rotated into radial-transverse (R-T) coordinates.

Fractures in these synthetic seismograms were modeled using Hudson’s penny-shaped cracks and a defined crack density, Thomsen anisotropic parameters ($\varepsilon; \delta; \gamma$) as well as normal ($\Delta_N$) and tangential ($\Delta_T$) compliance from linear slip theory (Hudson (1980); Thomsen (1986); Schoenberg and Helbig (1997); Omar (2018)). Though Thomsen’s anisotropic $\varepsilon$, $\delta$ and $\gamma$ were not explicitly used in modeling, the Hudson parameterization defined $\Delta s_{ij}$ which, combined with the isotropic background ($s_{bij}$), created the compliance tensor $s_{ij}$ (where $s_{ij} = s_{bij} + \Delta s_{ij}$) from which the anisotropic stiffness tensor was calculated ($c_{ij} = 1/s_{ij}$) and converted to reflection coefficients (Equation 2.19; Section 2.4).
Fractures were populated into the models based on their fracture aperture \((f)\) and fracture density \((e)\). Fracture aperture, the aspect ratio of fractures, was calculated as the ratio between semimajor \((a)\) and semiminor \((c)\) axes, where \(f \equiv c/a = 0.01\), while fracture density was calculated as \(e = \xi \langle a^3 \rangle = 0.04\), where \(\xi\) equals the number of fractures per volume and \(\langle \rangle\) represents the volume average (Hudson (1980); Bakulin et al. (2000a)). Values of \(f = 0.01\) and \(e = 0.04\) were based on geologic fault models of the Turkey Shoot survey area (Grechishnikova, 2017). Cracks were modeled as fluid-filled (wet) for the Monitor 1 synthetic model and changed to gas-filled (dry) cracks for the Monitor 2 synthetic, representing the gas-saturation effect. These models (isotropic, wet HTI, wet monoclinic and dry HTI) were modeled using prestack anisotropic modeling code shot with a vertical source and received vertical \((zz; PP\text{-}wave)\) and radial \((zr; PS\text{-}wave)\) components (Simmons (2009); Omar (2018)).

All three models (HTI, wet monoclinic and dry monoclinic) were compared to the isotropic model in order to assess amplitude variations between isotropic and anisotropic models. In order to assess how isotropic joint PP-PS simultaneous inversion equations used in Hampson-Russell™ affect amplitudes within anisotropic seismic volumes, single CDP shot gathers of PP and PS seismic were generated for each of the four synthetic models: Isotropic, Baseline, Monitor 1 and Monitor 2. These PP and PS angle gathers were corrected for moveout using using exact velocities from the model in the NMO process (Figure 3.4).

Following the joint PP-PS inversion workflow (detailed in Section 4.3.1), these PP and PS angle gathers were inverted simultaneously and compared to the output synthetic gather created by Hampson-Russell™. If the joint PP-PS inversion process perfectly replicated the the output synthetic gathers would perfectly match the input anisotropic gathers and the difference between the two would equal zero. However, this was not the case, as using the aforementioned isotropic equations to invert anisotropic data resulted in lower overall magnitude of amplitudes in the resulting output gathers (Figure 3.5).
Figure 3.4: Anisotropic angle gathers which were input to the Hampson-Russell™ joint pre-stack PP-PS simultaneous inversion process. The gathers were flattened and corrected for moveout (NMO). Left: PP angle gathers; Right: PS angle gathers. From top to bottom: Isotropic, Baseline (Wet HTI), Monitor 1 (Wet Monoclinic), Monitor 2 (Dry HTI).

For the isotropic model (Figure 3.5, top row), low negative differences were seen from 10° – 40° along the Niobrara in the PP angle gathers. At the far angles (> 40°) of both PP and PS in all models, differences change to high positive values indicating an overestimation by the isotropic inversion equations affecting the far angles. While the PP HTI anisotropic models (Baseline and Monitor 2), show high negative differences at the near incidence angles and low differences at the mid angles, the monoclinic anisotropic model (Monitor 1) shows the opposite: low differences in the near angles and higher negative differences at mid angles (Figure 3.5, left column). Differences between input and output PS synthetic angle gathers had more consistency between models, showing lower positive and negative differences at the same incident angles (Figure 3.5, right column). When comparing the PS isotropic model against PS HTI anisotropic models, the HTI models (Baseline, Monitor 2) showed negative
and positive differences at the same angle locations, but anisotropic models showed higher values of difference. Synthetic gathers replicated by isotropic inversion equations showed lower overall differences within the PS seismic and higher differences (both high negative and high positive) within the PP synthetic gathers. This indicated that isotropic equations used in the joint inversion process would affect seismic amplitudes differently at the near, mid and far incident angles.

All three models (Baseline: HTI, wet cracks; Monitor 1: Monoclinic, wet cracks; Monitor 2: HTI, dry cracks) were compared to the isotropic control model in order to assess amplitude differences on the synthetic gathers input to and output from the joint inversion process (Figures 3.6 and 3.7). By comparing the input PP and PS angle gathers to their output counterparts, the effect of inverting anisotropic datasets using isotropic inversion equations was visualized as lower overall differences seen in the output gathers. For all three anisotropic models, when comparing amplitudes difference at the same location along the Niobrara reflector between the synthetics input to and output from the joint inversion process, differences from the output synthetics contained values closer to zero.

Figure 3.5: Residual (differences between synthetic gathers input to the joint inversion and synthetic gathers output from the joint inversion) from the joint PP-PS inversion process for PP gathers (left) and PS gathers (right).
This decreased difference indicated that the joint inversion process damped amplitudes of the anisotropic models, indicating that using anisotropic inversion equations may restore these higher amplitudes and produce larger differences which may be more realistic. Therefore, the use of isotropic inversion on anisotropic datasets reproduced seismic gathers showing amplitudes which were lower than their true values (Figures 3.6 and 3.7). Despite these illustrated differences, the joint PP-PS inversion proceeded using isotropic inversion equations but with consideration of the implication that true amplitudes may have higher values than the output volumes show. We recommend that this topic of anisotropic synthetic modeling be tested in greater detail in future studies.

Figure 3.6: Differences between anisotropic and isotropic PP angle gathers, such that negative difference indicates higher values in the isotropic gather. Left column: Differences between anisotropic and isotropic PP angle gathers input to the joint PP-PS inversion process for all three anisotropic models (described in Figure 3.3). Right column: Differences between anisotropic and isotropic PP angle gathers output by the joint PP-PS inversion process.
Figure 3.7: Differences between anisotropic and isotropic PS angle gathers, such that negative difference indicates higher values in the isotropic gather. Left column: Differences between anisotropic and isotropic PS angle gathers input to the joint PP-PS inversion process for all three anisotropic models (described in Figure 3.3). Right column: Differences between anisotropic and isotropic PS angle gathers output by the joint PP-PS inversion process.
CHAPTER 4
BASELINE SURVEY: PRE-STACK PP INVERSION VS JOINT PRE-STACK PP-PS INVERSION

4.1 Pre-Conditioning Workflow for Input to Inversion

In preparation for pre-stack PP and joint pre-stack PP-PS simultaneous inversions, the input PP and PS seismic data was pre-conditioned in order to remove inconsistencies and variations within the data. For consistency in output elastic property volumes and interpretation, the same parameters were used in the following pre-conditioning workflow and applied to both time-lapse, multicomponent seismic surveys used in the joint inversion: Baseline and Monitor 2 surveys for both PP and PS.

PP and PS seismic data volumes delivered from the processor underwent analysis of geophone orientation, rotation into radial and transverse orientation, P- and S- refraction static solutions for sources and receivers, respectively, surface consistent deconvolution and residual statics and 3D noise removal.

The preconditioning workflow for PP seismic volumes began with application of trim statics to a window which encompassed both the overburden and reservoir interval and second sorted to angle gathers (Figure 4.1). After applying trim statics, PP offset gathers were sorted to incidence angle. PS seismic offset gathers were first sorted to angle gathers and second had trim statics applied, using the same window which encompassed the overburden and reservoir. The trim statics operation applied time-shifts to adjacent traces in order to align horizons for interpretation (Figure 4.2 and 4.3). Once in the angle domain with trim statics applied, amplitudes of the angle gathers were analyzed in terms of amplitude vs incidence angle (AVA). Similar to amplitude vs offset (AVO) analysis, AVA analysis of the reservoir interval identified Class 1 behavior in the PP seismic where amplitude decreased with increasing angle (Castagna and Swan, 1997). Next, angle stacks were created by stacking the angle...
gathers in intervals of 10°: 10-20° (Near); 20-30° (Near-Mid); 30-40° (Far-Mid); 40-50° (Far) (Figure 4.4).

Figure 4.1: Preconditioning workflow applied to the raw gathers prior to input to inversion workflow. Note that PS data was first sorted to angle gathers and then had trim statics applied as this improved alignment.

Figure 4.2: PP gathers before (left) and after (center) the application of Trim Statics, and the difference between the two (right). Note the Greenhorn horizon was not completely flat-as the Greenhorn represented the base of the reservoir interval of interest, this did not affect the inversion process.
Figure 4.3: PS angle gathers before (left) and after (center) the application of Trim Statics, and the difference between the two (right).

Figure 4.4: Angle gathers of PP (left) and PS (right) seismic. Gathers are colored by incidence angle.
After the angle stacks were created from the Baseline survey for the PP and PS seismic, amplitudes were extracted at the Niobrara horizon for each of the eight angle stacks (four each from the PP and PS: Near, Near-Mid, Far-Mid, Far) (Figure 4.5). Examining the Niobrara amplitudes from the PP seismic (Figure 4.5, top), the AVA behavior acts as expected for Class 1: high amplitudes in the Near stack which decreased with increasing angle.

Amplitudes of the PS survey showed a trend opposite to that of the PP survey: Low near stack amplitudes which increased with increasing angle, and high amplitude in the Far stack (Figure 4.5, bottom). As near-zero-incidence P-waves do not undergo mode conversion to generate converted S-waves (Equation 2.4), the PS Near Stack shows expected low amplitudes.

Further, the Near-Mid, Near-Far and Far angle stacks all show higher amplitudes towards the central portion of the survey and anomalously low amplitudes towards the fringes of the survey, mirroring the acquisition fold map (Figure 4.6). As fold directly affects seismic amplitudes, the acquisition fold map of the Turkey Shoot survey and more specifically the areas of full fold, which is smaller for PS data, must be separately taken into account during interpretation of the PP and PS data.

Figure 4.5: Horizon slices colored by maximum amplitude extracted from the Niobrara horizon in the PP and PS Baseline surveys angle stacks. Top row: PP survey; Bottom row: PS survey; Left to right: Near Stack (5-15°), Near-Mid Stack (15-25°), Far-Mid Stack (25-35°), Far Stack (35-45°). The black box denotes the location of the Wishbone Section.
4.1.1 Considerations for PP and PS Data

Throughout the pre-conditioning workflow, amplitude slices were extracted along the Niobrara horizon. A close examination of amplitude slices from both PP and PS seismic revealed imperfections which could create inaccuracies in the final elastic property volumes if perpetuated throughout the joint PP-PS inversion workflow.

Acquisition Footprint

Though the PP and PS seismic resolve geologic features with relative clarity, a closer inspection of the Niobrara amplitude slices in both seismic volumes revealed amplitude striping in the inline and crossline directions (vertically and horizontally) known as acquisition footprint, which arise from issues in acquisition geometry (Chopra and Larsen, 2000). The principal concern with acquisition footprint is its imprint on the seismic amplitudes which in turn affect the inversion results.

Further processing steps could be performed to correct this footprint including 5D interpolation, filtering in the frequency-wavenumber domain ($f-k$ filtering) or forming super
gathers. Alternatively, AVA analysis could be performed on the unmigrated seismic data: the PS seismic would be rotated from field coordinates ($H_1$, $H_2$) to radial-transverse coordinates, NMO would be applied to flatten shot gathers using RMS or interval velocities obtained from processing, trim statics would be applied to time-shift adjacent traces to align horizons of interest, then the data would be sorted from offset gathers to angle gathers using the RMS or interval velocities and stacked by angle for AVA analysis. However, this shortcoming would ideally be avoided through improved acquisition in order to mitigate footprint in the seismic data in the first place.

Amplitude Anomalies

A secondary concern can be seen with inspection of the PS seismic amplitudes decreasing toward the edges of the survey area. The Niobrara amplitude slices from the PS seismic closely resemble the fold map of the Wishbone Section (Figure 4.6). The processing report, which detailed corrections applied to both PP and PS data, stated that PS seismic was binned using the Asymptotic Conversion Point (ACP), a depth-invariant approximation of the location at which an incident P-wave undergoes mode conversion and is reflected as an S-wave, using a single $V_P/V_S$ ratio (from Contractor Processing Report). The PS data was binned into Common Offset Vector (COV) tiles and migrated using a prototypical, proprietary anisotropic Kirchhoff PS Pre-stack Time Migration algorithm (from Contractor Processing Report). Due to the proprietary nature of this PS migration algorithm, direct understanding of how the PS data migration was unclear.

A possible correction to the issue of decreasing amplitude towards the survey edges would be binning PS data not by ACP, but instead by Common Conversion Point (CCP) (Figure 1.7) (Stewart et al., 2002). For deeper reflections, ACP provide an adequate approximated location of the conversion points but at shallow depths, ACP location can differ significantly from the more accurate CCP (Figure 1.7).
Considerations for Monitor 1 Survey

As outlined in the Section 3.1, the Monitor 1 PS data was rotated from field coordinate system into radial-transverse coordinates under the assumption that all receivers were oriented North when in reality, receiver orientations for Monitor 1 varied from N40°W to N40°E with a majority of receivers oriented at $H_1 = 10^\circ$E (Figure 3.2). As such, the Monitor 1 survey was omitted from time-lapse analysis of the joint PP-PS inversion.

4.2 Pre-Stack PP Inversion

Prior to including multicomponent PS seismic in the inversion process, pre-stack PP inversion was performed on the Baseline survey in order to establish a basis for comparison.

4.2.1 Pre-Stack PP Inversion Workflow

After preconditioning the PP and PS seismic data (Section 4.1), the four angle stacks ($10$-20°, ..., 40-50°) from the PP Basline survey was used for input to the pre-stack PP simultaneous inversion process. The pre-stack PP simultaneous inversion used the PP Baseline survey and wells within the Turkey Shoot survey area, following the workflow included in Hampson-Russell™ProMC package (Figure 4.7).

After pre-conditioning the PP Baseline stacks (Figure 4.8; Section 4.1), PP angle stacks were correlated to five wells central to the pre-stack PP simultaneous inversion: one well input to the inversion (Well Shifted) and four wells omitted from the inversion used as blind test wells (Blind 1; Blind 2; Blind 3; Blind 4) (Figure 4.9).

As previously elaborated (Section 1.5.1), neural-network derived sonic logs inserted an artificial bias to the sonics ($V_P/V_S \approx 2$). This prompted the use of a well with real sonic logs by shifting its location 2130 ft, at a bearing of N 56°E, from just outside the Turkey Shoot survey area to just within the survey area (Figures 1.3 and 1.4). Though the shear-sonic logs of this Shifted Well were derived from neural-network, the P-sonic logs were actual measured logs.
Figure 4.7: Workflow for pre-stack PP simultaneous inversion. Input data (PP seismic; Well Logs) shown in dark blue at top.
Figure 4.8: Preconditioned PP seismic used for input to pre-stack PP simultaneous inversion.

Figure 4.9: Turkey Shoot survey (blue outline) and Wishbone Section (yellow outline) locations shown with available wells (colored circles) and an arbitrary line used for well tie QC (A - A’).
The PP Baseline survey was divided into angle stacks (10-20°, ..., 40-50°). Once these PP angle stacks were correlated with wells, angle-dependent statistical wavelets were extracted from each angle stack and input to the inversion process (Figures 4.10). Four horizons were used in the inversion process: Lower Pierre, Niobrara, Codell and Greenhorn (Figure 4.11).

Figure 4.10: Statistical wavelets extracted from the Angle Stacks created from the PP Baseline survey. All wavelets were extracted as zero-phase and 200ms in length in a depth interval from +150ms above the Niobrara to -150ms below the Greenhorn. Wavelets are colored by the following: Near Stack (10-20°) Blue; Near-Mid Stack (20-30°) Green; Far-Mid Stack (30-40°) Yellow; Far Stack (40-50°) Pink.

Figure 4.11: Left: Well ties between PP seismic at Shifted Well. Right: Correlation coefficients between PP seismic and wells (Blind wells A - D and Shifted).

Pre-conditioned PP angle stacks were used as input to the inversion and the four interpreted horizons (Lower Pierre, Niobrara, Codell and Greenhorn) were used for the pre-stack PP simultaneous inversion (Figure 4.11, left). Though only the Shifted Well was active for
the pre-stack PP simultaneous inversion, horizons were tied to all well logs used as Blind Wells to evaluate the inversion results (Figure 4.11, right). Pre-stack PP simultaneous inversion utilized P-sonic, S-sonic and density well logs filtered to frequencies of 6-8 Hz to compensate for the lack of low frequency in the seismic data to create the low frequency background model (Figure 4.12).

![Figure 4.12: Low frequency background model used as input to the pre-stack PP simultaneous inversion. The above LFM shows the background model of $Z_P$, though background models for $Z_S$ and $\rho$ also were used. All three background models ($Z_P$, $Z_S$ and $\rho$) visually resemble each other, showing good lateral continuity and high values within the reservoir.](image)

After correlation of PP angle stacks with wells, extraction of angle-dependent wavelets and building the low frequency background model, the Baseline PP seismic was inverted at the trace location of the Shifted Well. This gather analysis quantitatively evaluated the effectiveness of the pre-stack PP inversion through correlation of inverted volumes ($Z_P$, $Z_S$ and $\rho$) with $Z_P$, $Z_S$ and $\rho$ calculated from logs of the Shifted Well. Correlation between inverted and log values were evaluated through crossplots and with filtered well logs.

After evaluating the correlation of inverted properties with well logs through single point analysis at the Shifted Well location, pre-stack PP inversion parameters were applied to the entire volume, but confined to a window starting 150ms above the Niobrara and extending 150ms below the Greenhorn. The elastic properties ($Z_P$, $Z_S$ and $\rho$) resulting from the pre-stack PP simultaneous inversion were transformed into lambda-rho ($\lambda\rho$; incompressibility)
and mu-rho (\(\mu\rho\); rigidity) for rock and fluid property analysis.

### 4.2.2 PP Baseline Survey

After performing the pre-stack PP inversion on the Baseline survey, cross sections from A - A’ (Figure 4.13) through the producing area of the Wishbone Section were taken from the elastic parameters resulting from the joint inversion, shown in Figures 4.14 through 4.18.

![Figure 4.13](image)

Figure 4.13: Illustration showing the location of cross section A - A’ through the producing wells in the Wishbone Section. Cross section A - A’ was used to show inverted volumes from the pre-stack PP simultaneous inversion (Figures 4.14 through 4.18) and the joint PP-PS simultaneous inversion (Figures 4.25 through 4.29).

Examining the cross sections for elastic parameters \(Z_P\), \(Z_S\) and \(\rho\) (Figures 4.14, 4.15 and 4.16), alternating high and low P- and S- impedance and density values resolved the interbedded nature of the Niobrara formation. Likewise, the increase in impedance and density at the Codell seen in the filtered logs at Wells A, B, C and D appeared in the \(Z_P\), \(Z_S\) and \(\rho\) volumes. The byproduct of \(Z_P\), \(Z_S\) and \(\rho\) (Equation 2.8), \(\lambda\rho\) and \(\mu\rho\) both followed trends similar to the impedance and density volumes from which they were derived (Figures 4.17 and 4.18).
Figure 4.14: Arbitrary line (A - A') through the Wishbone Section showing $Z_P$ derived from pre-stack PP simultaneous inversion.

Figure 4.15: Arbitrary line (A - A') through the Wishbone Section showing $Z_S$ derived from pre-stack PP simultaneous inversion.
Figure 4.16: Arbitrary line (A - A’) through the Wishbone Section showing $\rho$ derived from pre-stack PP simultaneous inversion.

Figure 4.17: Arbitrary line (A - A’) through the Wishbone Section showing $\lambda\rho$ calculated from $Z_P$ and $\rho$ derived from pre-stack PP simultaneous inversion.
4.2.3 Qualitative and Quantitative Analysis

In order to assess the validity and accuracy of the elastic parameters, each \(Z_P\), \(Z_S\), \(\rho\), \(\lambda\rho\) and \(\mu \rho\) from the pre-stack PP simultaneous inversion volumes were crossplotted against values from well logs, with well logs on the x-axis and inverted values on the y-axis (Figures 4.19 and 4.20). As expected from the Zoeppritz equation (Equation 2.3), \(Z_P\) from the pre-stack PP simultaneous inversion correlated best with well log values (\(Z_P\) correlation: 0.732), while \(\rho\) correlated relatively poorly (\(\rho\) correlation: 0.351).

Figure 4.19: Crossplots of \(Z_P\) (left), \(Z_S\) (center) and \(\rho\) (right) showing correlation between pre-stack PP simultaneous inversion-derived volumes (y-axis) and well log values (x-axis).
4.3 Joint Pre-Stack PP-PS Inversion

To determine the added value of multicomponent pre-stack PS data to the inversion process and a direct comparison between the Baseline pre-stack PP simultaneous inversion and the Baseline joint pre-stack PP-PS simultaneous inversion, identical parameters were used for the pre-stack PP inversion as for the joint pre-stack PP-PS inversion. Thus, the joint pre-stack PP-PS inversion followed a very similar workflow to that of the pre-stack PP simultaneous inversion, except with the inclusion of the pre-stack PS dataset.

4.3.1 Joint Pre-Stack PP-PS Simultaneous Inversion Workflow

After preconditioning both the PP and PS pre-stack seismic data (Section 4.1), the four angle stacks (10-20°, ..., 40-50°) from both PP and PS seismic surveys were used for input to the joint inversion process. The joint pre-stack PP-PS simultaneous inversion used both PP and PS Baseline surveys and wells within the Turkey Shoot survey area and followed the workflow included in Hampson-Russell™ProMC package (Figure 4.21).
Figure 4.21: Workflow for joint PP-PS simultaneous inversion. Input data (PP, PS seismic; well Logs) shown in dark blue at top.
After pre-conditioning the PP and PS Baseline stacks (Section 4.1), as with the PP seismic in the pre-stack PP inversion, PS seismic stacks were correlated to the same five wells: one well input to the inversion (Well Shifted) and four blind test wells (Blind 1; Blind 2; Blind 3; Blind 4) (Figure 4.9).

PP and PS Baseline surveys were divided into angle stacks (10-20°, ... , 40-50°). Once these PP and PS angle stacks were correlated with wells, angle-dependent statistical wavelets were extracted from each angle stack and input to the inversion process (Figures 4.10 and 4.22). The same four horizons interpreted in the PP angle stacks were also interpreted in the PS angle stacks: Lower Pierre, Niobrara, Codell and Greenhorn (Figure 4.23).

Figure 4.22: Statistical wavelets extracted from the Angle Stacks created from the PS Baseline survey. All wavelets were extracted as zero-phase and 300ms in length. Wavelets are colored by the following: Near Stack (10-20°) Blue; Near-Mid Stack (20-30°) Green; Far-Mid Stack (30-40°) Yellow; Far Stack (40-50°) Pink.
Figure 4.23: Well ties between PP seismic (left) and PS seismic (right) at Shifted Well. Note that PS seismic wavelength acts as a limiting factor in horizon interpretation, which led to the use of four horizons: Lower Pierre, Niobrara, Codell and Greenhorn.

After interpretation of these four horizons (Lower Pierre; Niobrara; Codell; Greenhorn) in the PP and PS surveys, volume registration was performed by registering the PS horizons to the PP horizons. The horizon registration process used measured PS travel time \( t_{PS} \) to a given PS horizon and PP travel time \( t_{PP} \) to the same given PP horizon as input for calculation of interval-specific \( V_P/V_S \) used to compress PS travel times \( t_{PS} \) to match PP travel times \( t_{PP} \) (Equation 4.1) (Stewart et al., 2002). By matching Lower Pierre PS to Lower Pierre PP, Niobrara PS to Niobrara PP, Codell PS to Codell PP and Greenhorn PS to Greenhorn PP, the horizon registration process was used for domain conversion by compressing PS travel times to match PP travel times.

\[
V_P/V_S = 2(t_{PS}/t_{PP}) - 1
\]  

(4.1)

The same Low Frequency Model (LFM) used in the pre-stack PP simultaneous inversion was used as the background model in the joint pre-stack PP-PS inversion, created from P-wave sonic, S-wave sonic and density curves correlated with the PP and PS angle gathers (Figures 4.23 and 4.24). After correlation of well logs with PP and PS seismic volumes, P-sonic, S-sonic and density logs were filtered to frequencies of 6-8 Hz and used to create
the low frequency background model which compensated the low frequency content missing from the seismic data.

<table>
<thead>
<tr>
<th>Well</th>
<th>PP Well Tie Correlation Coeff.</th>
<th>PS Well Tie Correlation Coeff.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well A</td>
<td>0.675</td>
<td>0.610</td>
</tr>
<tr>
<td>Well B</td>
<td>0.564</td>
<td>0.651</td>
</tr>
<tr>
<td>Well C</td>
<td>0.766</td>
<td>0.733</td>
</tr>
<tr>
<td>Well D</td>
<td>0.662</td>
<td>0.802</td>
</tr>
<tr>
<td>Shifted</td>
<td>0.820</td>
<td>0.668</td>
</tr>
</tbody>
</table>

Figure 4.24: Correlation coefficients of well ties between both PP and PS seismic volumes. Blind wells were labeled following notation in Figure 4.9, while the well active in the joint inversion was the Shifted Well.

After domain conversion of the PS seismic travel time to PP seismic travel time, correlation of PP and PS angle gathers with P-wave sonic, S-wave sonic and density logs from the Shifted Well, creation of the low frequency background model using correlated well logs and extraction of angle-dependent PP and PS wavelets, all necessary components for the joint pre-stack PP-PS simultaneous inversion were prepared and ready for the inversion.

In order to QC the joint inversion, a single gather at the Shifted Well location was inverted where well logs were used to calculate values of $Z_P$, $Z_S$, $\rho$ which were used to create synthetic PP and PS seismic angle gather responses. These synthetic seismic gathers and calculated logs were compared to real PP and PS seismic angle gathers and inverted logs, calculated using PP and PS angle gathers and Zoeppritz equations for PP and PS reflectivity (Equations 2.3 and 2.4). Differences between real and inverted logs, as well as crossplots between real and inverted data, were used to quantitatively define how well the inverted elastic property volumes represent the real data.
The joint inversion process was confined to a window which encompassed the whole reservoir interval, extending from 150ms above the Niobrara to 150ms below the Greenhorn. After ensuring that inverted $Z_P$, $Z_S$ and $\rho$ volumes correlated visually with blind wells along the arbitrary well tie line and quantitatively with well log values via crossplots, volumes of lambda-rho ($\lambda\rho$) and mu-rho ($\mu\rho$) were generated using known relationships with $Z_P$, $Z_S$ and $\rho$ (Equation 2.6).

4.3.2 Joint Pre-Stack PP-PS Baseline Survey

For visual comparison, the same A - A’ cross sections (Figure 4.13) through the Wishbone Section were taken from the elastic parameters resulting from the joint pre-stack PP-PS inversion and are shown in Figures 4.25 through 4.29.

Figure 4.25: Arbitrary line (A - A’) through the Wishbone Section showing $Z_P$ derived from joint pre-stack PP-PS inversion.
Figure 4.26: Arbitrary line (A - A’) through the Wishbone Section showing $Z_s$ derived from joint pre-stack PP-PS inversion.

Figure 4.27: Arbitrary line (A - A’) through the Wishbone Section showing $\rho$ derived from joint pre-stack PP-PS inversion.
Figure 4.28: Arbitrary line (A - A’) through the Wishbone Section showing $\lambda \rho$ calculated from $Z_P$ and $\rho$ derived from pre-stack joint PP-PS inversion.

Figure 4.29: Arbitrary line (A - A’) through the Wishbone Section showing $\mu \rho$ calculated from $Z_S$ and $\rho$ derived from joint pre-stack PP-PS inversion.

4.3.3 Qualitative and Quantitative Analysis

In order to assess the accuracy of the elastic parameters, each $Z_P$, $Z_S$, $\rho$, $\lambda \rho$ and $\mu \rho$ from the inverted volumes were crossplotted against values derived from well logs, with well
logs on the x-axis and inverted values on the y-axis (Figures 4.30 and 4.31). The most stark improvement in correlation came in the $\rho$ volume, which translated into significant improvement of correlation in both $\lambda \rho$ and $\mu \rho$ with well logs. Inverted volumes resultant from both pre-stack PP and joint pre-stack PP-PS inversion were crossplotted against well logs, directly showing the improvement in correlation from incorporation of pre-stack PS seismic (Figures 4.32 through 4.36).

Though the correlation of inverted $\rho$ with well log $\rho$ drastically increased relative to that from the pre-stack PP simultaneous inversion (Figure 4.34), this higher correlation was expected based on the inclusion of PS seismic and therefore increase of constraint on the $\rho$ variable based on the linearized Zoeppritz equations (Equations 2.3 and 2.4). Similarly, from the linearized Zoeppritz equations, the correlation of $Z_S$ with well logs improved with the inclusion of pre-stack PS seismic (Figure 4.33). The further constraint on $Z_S$ and $\rho$ from addition of pre-stack PS seismic directly resulted in improvement of not just $\lambda \rho$ but $\mu \rho$. This increase in correlation coefficients was quantified in terms of percent-difference for each elastic parameter ($Z_P$, $Z_S$, $\rho$, $\lambda \rho$ and $\mu \rho$) (Figure 4.37).

Figure 4.30: Crossplots of $Z_P$ (left), $Z_S$ (center) and $\rho$ (right) showing correlation between joint PP-PS simultaneous inversion-derived volumes (y-axis) and well log values (x-axis).
Figure 4.31: Crossplots of $\lambda_\rho$ (left) and $\mu_\rho$ (right) showing correlation between joint PP-PS simultaneous inversion-derived volumes (y-axis) and well log values (x-axis).

Figure 4.32: Crossplot correlation between $Z_P$ from well logs (x-axis) and inverted $Z_P$ (y-axis) from the pre-stack PP simultaneous inversion (left) and the joint pre-stack PP-PS simultaneous inversion (right).
Figure 4.33: Crossplot correlation between $Z_s$ from well logs (x-axis) and inverted $Z_s$ (y-axis) from the pre-stack PP simultaneous inversion (left) and the joint pre-stack PP-PS simultaneous inversion (right).

Figure 4.34: Crossplot correlation between $\rho$ from well logs (x-axis) and inverted $\rho$ (y-axis) from the pre-stack PP simultaneous inversion (left) and the joint pre-stack PP-PS simultaneous inversion (right).
Figure 4.35: Crossplot correlation between $\lambda \rho$ from well logs (x-axis) and inverted $\lambda \rho$ (y-axis) from the pre-stack PP simultaneous inversion (left) and the joint pre-stack PP-PS simultaneous inversion (right).

Figure 4.36: Crossplot correlation between $\mu \rho$ from well logs (x-axis) and inverted $\mu \rho$ (y-axis) from the pre-stack PP simultaneous inversion (left) and the joint pre-stack PP-PS simultaneous inversion (right).
Figure 4.37: Summarized percent difference in correlation coefficients between pre-stack PP inversion and joint pre-stack PP-PS inversions with well logs, directly illustrating added value of PS seismic.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>PP-Only Correlation Coeff.</th>
<th>PP-PS Correlation Coeff.</th>
<th>% Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>$Z_P$</td>
<td>0.7323</td>
<td>0.7944</td>
<td>+8%</td>
</tr>
<tr>
<td>$Z_S$</td>
<td>0.5904</td>
<td>0.7160</td>
<td>+19%</td>
</tr>
<tr>
<td>$\rho$</td>
<td>0.3512</td>
<td>0.5555</td>
<td>+45%</td>
</tr>
<tr>
<td>$\lambda \rho$</td>
<td>0.7101</td>
<td>0.8868</td>
<td>+22%</td>
</tr>
<tr>
<td>$\mu \rho$</td>
<td>0.5882</td>
<td>0.7530</td>
<td>+24%</td>
</tr>
</tbody>
</table>

By plotting $\lambda \rho$ vs $\mu \rho$ in crossplot, distribution of lithology and fluid content can be differentiated (Goodway et al. (1996a); Goodway (2001)). Similar distribution of values were seen when comparing joint pre-stack PP-PS inversion derived values of $\lambda \rho$ vs $\mu \rho$ to those derived from pre-stack PP inversion (Figure 4.38). It should be noted that values of $\lambda \rho$ for the joint pre-stack PP-PS inversion (Figure 4.38; left) ranged from 15 to 75 (GPa*g/cc), whereas the pre-stack PP simultaneous inversion (Figure 4.38; right) ranged from -5 to 85 (GPa*g/cc). These negative $\lambda \rho$ values, arising from the $\lambda \rho$ calculation (Equation 2.8), suggested that $(2Z_S^2 > Z_P^2)$. While the joint pre-stack PP-PS inverted $\lambda \rho$ showed only positive values, the negative $\lambda \rho$ values from the pre-stack PP inversion were presumed to have originated from the lower accuracy of the $Z_S$ and $\rho$ volumes generated in the pre-stack PP inversion (Figure 4.37).
Figure 4.38: $\lambda_\rho$ vs $\mu_\rho$ crossplot using volumes derived from pre-stack PP inversion (left) and joint pre-stack PP-PS inversion (right). Note larger spread of $\lambda_\rho$ values for the PP inversion, where points from the Greenhorn have negative $\lambda_\rho$ values.

4.4 Conclusion: Added Value of Pre-Stack PS Seismic

All crossplots of well log values against inverted volumes show higher correlation of joint pre-stack PP-PS volumes over pre-stack PP volumes. The improvement, directly illustrating the added value of incorporating pre-stack PS seismic in the joint pre-stack PP-PS inversion process, was seen in percent difference between correlation coefficients of the joint pre-stack PP-PS and pre-stack PP inverted volumes with well log values (Figure 4.37). In $\lambda_\rho$-$\mu_\rho$ crossplots, $\lambda_\rho$ calculated from pre-stack PP inversion elastic volumes showed negative values which indicated poor accuracy of $Z_S$ and therefore $\rho$ of the pre-stack PP inversion. The same $\lambda_\rho$-$\mu_\rho$ crossplot for the joint pre-stack PP-PS inversion showed only positive values of $\lambda_\rho$, indicating the additional constraint in calculation of $Z_S$ and $\rho$ resulted in physically meaningful values of $\lambda_\rho$ stemming from the inclusion of pre-stack PS seismic in the joint inversion process. By incorporating PS seismic, better resolution of $Z_S$ and $\rho$ volumes directly impacted calculation of $\lambda_\rho$ and $\mu_\rho$. With increased accuracy of $\lambda_\rho$ and $\mu_\rho$, fluid and rock characterization can be improved to develop a more definite, meaningful portrayal of the reservoir.
CHAPTER 5
CROSS EQUALIZATION AND TIME-LAPSE (4D) PRE-STACK PP INVERSION

5.1 Time-Lapse (4D) Cross Equalization Workflow

Time-lapse cross equalization between vintages of seismic surveys attempts to minimize differences in the overburden interval, where no change was assumed to have occurred, and preserve the normalized RMS error (NRMS) within the reservoir interval. In order to compare the two seismic volumes for time-lapse analysis, the Baseline survey was designated as the reference survey to which the Monitor 2 survey was matched. Cross equalization was performed using the steps illustrated in Figure 5.1. These steps were applied to the Monitor 2 survey only, leaving the reference Baseline survey unchanged. By normalizing differences in the overburden between the two datasets, all changes could be seen to occur within the reservoir interval.

![Cross equalization workflow](image)

Figure 5.1: Cross equalization workflow consisted of matching amplitudes, frequencies and phase-time shifts from the Monitor 2 survey to the Baseline survey. This workflow was followed for both the PP and PS seismic separately, where the PP Monitor 2 survey was cross equalized to the PP Baseline survey, and the same process for the PS seismic. After each step (1 - 5), NRMS repeatability was measured between the two volumes. The final step (6) did not involve altering the seismic volumes, but instead was a QC check to make sure frequency spectrum of the Baseline and cross equalized Monitor 2 volumes matched well.
The Lower Pierre horizon was picked as a datum to align the Monitor 2 survey to the Baseline survey, as its location in the overburden indicated it had remained unaffected by the induced fracture stimulation within the reservoir interval. With the Lower Pierre chosen as the reference datum, cross equalization was performed in a 520ms window extending from 200ms above the Lower Pierre down to just above, but excluding, the Niobrara (reservoir) (Figure 5.2, ”Overburden Window”). This window encompassing the overburden and Lower Pierre will henceforth be referred to as the ”Overburden Window”.

Baseline and Monitor 2 pre-stack seismic volumes for both PP and PS seismic were split into 10° intervals and stacked (i.e. the 10-20° angle gathers produced an angle stack centered at 15°, etc.) for each angle range: 10-20°, ..., 40-50°. Due to anomalously low signal potentially caused by overly harsh surface-wave attenuation in processing, the 0-10° angle range was omitted from the inversion (Utley, 2017). The resulting Monitor 2 angle stacks were then cross equalized to their respective angle stacks in the Baseline survey.
The effectiveness of cross equalization was quantitatively assessed using the repeatability metric of NRMS (Kragh and Christie (2002); Helgerud et al. (2011)):

\[
NRMS = \frac{2 \cdot RMS(Monitor_2 - Baseline)}{RMS(Monitor_2) + RMS(Baseline)}
\] (5.1)

NRMS was measured in the same Overburden Window as the cross equalization to ensure minimized NRMS. NRMS was also calculated within the reservoir interval, from the Niobrara to Greenhorn (Figure 5.2, ”Reservoir Window”), to keep track of NRMS differences in the reservoir. This window encompassing the Niobrara and Greenhorn will henceforth be referred to as the ”Reservoir Window”.

Previous time-lapse studies were compiled in order to establish an acceptable value of NRMS for cross equalization of the Monitor 2 survey to the Baseline survey (Table 5.1). Though acceptable NRMS varied slightly depending whether the survey was shot as land or marine seismic, a threshold of ”Good” NRMS was chosen to be 0.3 and ”Excellent” NRMS was chosen as 0.2 for the Turkey Shoot seismic surveys. NRMS difference of 0.3 and 0.2 indicated the ability to reproduce seismic amplitudes in the monitor survey to within 30% and 20%, respectively, of the reference survey (Helgerud et al., 2011).

<table>
<thead>
<tr>
<th>Reference</th>
<th>Onshore / Offshore</th>
<th>Acceptable NRMS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Helgerud et al. (2011)</td>
<td>Offshore (Marine)</td>
<td>Good: NRMS &lt; 0.35; Excellent: NRMS &lt; 0.15</td>
</tr>
<tr>
<td>Koster et al. (2000)</td>
<td>Offshore (Marine)</td>
<td>Good: NRMS &lt; 0.35</td>
</tr>
<tr>
<td>Lumley (2010)</td>
<td>Offshore (Land)</td>
<td>Good: NRMS &lt; 0.4; Excellent: NRMS &lt; 0.2</td>
</tr>
<tr>
<td>Pevzner et al. (2011)</td>
<td>Onshore (Land)</td>
<td>Good: NRMS &lt; 0.3; Excellent: NRMS &lt; 0.2</td>
</tr>
<tr>
<td>Urosevic et al. (2011)</td>
<td>Onshore (Land)</td>
<td>Excellent: NRMS &lt; 0.2</td>
</tr>
</tbody>
</table>

Table 5.1: Compilation of acceptable ranges in NRMS and the survey environment (Onshore (land seismic) or offshore (marine seismic)) from various time-lapse studies.

The cross equalization workflow (Figure 5.1) first applied global adjustments, where a single scalar value was estimated between the Monitor 2 and Baseline surveys then applied to the Monitor 2 survey. Trace-by-trace adjustments were applied second, where individual scalar values were estimated and applied to each trace. Adjustments in the cross equalization workflow consisted of matching amplitudes, frequency and phase-time shifts of the Monitor
2 survey to those of the Baseline survey.

### 5.1.1 Global Amplitude Correction

The first step of the cross equalization workflow was to scale the amplitudes of the Monitor 2 survey to better match those of the Baseline survey. This amplitude scaling, known as a global amplitude scaling factor, estimated the amplitudes of traces within the Overburden Window, measured the RMS average of all traces in the Baseline and Monitor 2 survey and applied a single global scalar value to the amplitudes of the Monitor 2 survey to better match the Baseline survey. For PP cross equalization, values of global amplitude scaling factors varied with each angle range: 10-20° angles: 0.949; 20-30°: 1.039; 30-40°: 1.017; 40-50°: 1.033. For PS cross equalization, global amplitude scaling factors values were slightly higher, indicating more poorly matched amplitudes between surveys: 10-20° angles: 1.139; 20-30°: 1.099; 30-40°: 1.071; 40-50°: 1.054.

### 5.1.2 Frequency Shaping Filter

In order to account for differences in frequency content between Baseline and Monitor 2 wavelets, a shaping filter was designed to match the frequency spectrum of the Monitor 2 survey to that of the Baseline survey (Figures 5.3 and 5.4).

### 5.1.3 Global Phase-Time Shifts

Variations in phase and time-shifts between the Monitor 2 and Baseline surveys were addressed by applying a global phase and time-shift to the Monitor 2 data in Step 3 of the cross equalization workflow (Figure 5.1). This global scalar value was estimated by cross-correlating traces between the Baseline and Monitor 2 surveys in the Overburden Window, then values of every trace within the surveys were averaged to produce single values of phase-shift and time-shift. For PP and PS cross equalization, values of global phase-time shifts varied with each angle range (Table 5.2).
<table>
<thead>
<tr>
<th>PP Angle Stack</th>
<th>Phase Shift</th>
<th>Time Shift</th>
<th>PS Angle Stack</th>
<th>Phase Shift</th>
<th>Time Shift</th>
</tr>
</thead>
<tbody>
<tr>
<td>10-20°</td>
<td>-2.57°</td>
<td>-0.139ms</td>
<td>10-20°</td>
<td>-5.04°</td>
<td>-0.388ms</td>
</tr>
<tr>
<td>20-30°</td>
<td>-3.01°</td>
<td>-0.172ms</td>
<td>20-30°</td>
<td>-6.49°</td>
<td>-0.534ms</td>
</tr>
<tr>
<td>30-40°</td>
<td>-2.19°</td>
<td>-0.164ms</td>
<td>30-40°</td>
<td>-5.21°</td>
<td>-0.351ms</td>
</tr>
<tr>
<td>40-50°</td>
<td>-1.83°</td>
<td>-0.173ms</td>
<td>40-50°</td>
<td>-5.50°</td>
<td>-0.363ms</td>
</tr>
</tbody>
</table>

Table 5.2: Values of global phase-time shifts applied to PP (left) and PS (right) angle stacks during cross equalization.

Figure 5.3: Frequency spectrum of the two raw surveys (Baseline, pink; Raw Monitor 2, green) and shaped survey (Shaped Monitor 2, blue) for all PP angle stacks: 10-20° (top left); 20-30° (top right); 30-40° (bottom left); 40-50° (bottom right). The goal of matching the frequency spectrum of the Monitor 2 (green) survey to that of the Baseline (pink) was achieved by applying a shaping filter to the raw Monitor 2 survey, resulting in the shaped Monitor 2 (blue) frequency spectrum.
Figure 5.4: Frequency spectrum of the two raw surveys (Baseline, pink; Raw Monitor 2, green) and shaped survey (Shaped Monitor 2, blue) for all PS angle stacks: 10-20° (top left); 20-30° (top right); 30-40° (bottom left); 40-50° (bottom right). The goal of matching the frequency spectrum of the Monitor 2 (green) survey to that of the Baseline (pink) was achieved by applying a shaping filter to the raw Monitor 2 survey, resulting in the shaped Monitor 2 (blue) frequency spectrum.

5.1.4 Trace-by-Trace Amplitude Scaling Factor

After global scaling of parameters (amplitude, frequency, phase and time-shifts), cross equalization of Baseline and Monitor 2 volumes was performed on a trace-by-trace basis. Similar to their global estimation and application, traces within the Monitor 2 volume were compared with their respective traces in the Baseline surveys where RMS scaling factors were applied to individual traces in the Monitor 2 survey. RMS scaling factors applied to individual traces ranged from 0.9 to 1.1.
5.1.5 Trace-by-Trace Phase-Time Shifts

Following the trace-by-trace application of amplitude scaling factors, trace-by-trace phase-time shifts between the Monitor 2 and Baseline surveys were estimated and applied to the Monitor 2 survey. Values of phase shifts ranged from $+16^\circ$ to $-16^\circ$, while time shifts ranged from $+2$ms to $-2$ms.

5.2 Findings from PP Cross Equalization

The effectiveness of cross equalizing the PP surveys was evaluated through estimates of NRMS repeatability (represented graphically in Figure 5.5), time-variant (4D) time-shifts (Figure 5.6) and differences between both PP surveys for each angle stack (Figure 5.7).

PP NRMS Analysis

Aided by the graphical representation of change in NRMS throughout the cross equalization process, the most effective step in minimizing NRMS within the overburden was application of the frequency shaping filter. When applied to the Monitor 2 survey, the frequency shaping filter damped high frequency content of the Monitor 2 survey to match that of the Baseline survey, and accounted for the largest decrease in NRMS for the cross equalization of the PP seismic data, decreasing NRMS by an average of 6.5% with a maximum decrease of 7.7% (Figure 5.5). This large drop in NRMS indicated frequency content difference to be the most inconsistent parameter between the Baseline and Monitor 2 surveys.

All four angle stacks of the PP seismic fall well below the previously established target threshold for NRMS repeatability of 0.3 (PP 10-20\(^\circ\): 0.222; PP 20-30\(^\circ\): 0.188; PP 30-40\(^\circ\): 0.149; PP 40-50\(^\circ\): 0.201). This led to the decision to include all four angle stacks in the time-lapse (4D) pre-stack PP simultaneous inversion.
Figure 5.5: Table and graph of NRMS difference measured between PP Baseline and PP Monitor 2 surveys prior to cross equalization ("Raw") and after each step in the cross equalization workflow (Figure 5.1). Top rows represent NRMS estimates within the Overburden Window of each angle stack range (10-20°, ... , 40-50°), while the bottom rows refer to the Reservoir Window NRMS difference for each angle stack range. Naming scheme used “P-T Shifts” for “Phase and Time Shifts” and “TbT” for “Trace-by-Trace”. NRMS values after the final step (Step 5: Trace-by-Trace Phase-Time Shifts) were colored relative to the threshold NRMS value of 0.3 (bold black line in the graph) where values < 0.3 were colored green, values ≈ 0.3 were colored yellow and values > 0.3 were colored red. The graph plots NRMS vs cross equalization step, where solid lines show overburden NRMS while dashed lines show the reservoir NRMS; both sets of lines are color-coded with their respective angle stack in the table.
PP Time-Shifts

After cross equalizing the four Monitor 2 angle stacks to their Baseline counterparts, time-variant time-shifts were extracted from all four angle stacks, based on travel time variations within the Niobrara reservoir between surveys. Physically related to changes in reservoir properties (such as stress, compaction, pressure and fluid saturation), time-shift analysis served as an indicator of changes in reservoir conditions.

The dominance of negative time-shifts and minimal amounts of positive time-shifts within the Turkey Shoot survey area indicated decreasing seismic velocities between the Baseline and Monitor 2 surveys (Figure 5.6). The near 10-20°, mid-near (20-30°) and mid-far (30-40°) angle stacks showed time-shifts ranging from +0.5 to -2ms and most frequently occurring time-shift of -1ms. The far (40-50°) angle stack, however, showed overall higher time-shifts, ranging from +0.5 to -4ms and most frequently occurring time-shifts of -3ms.

PP Angle Stack Amplitude Differences

For a qualitative visual QC of the cross equalization process, amplitude differences were calculated between each angle stack range by subtracting the Baseline from the Monitor 2, such that negative values indicated higher amplitudes in the Baseline survey. These differences were calculated for each angle stack (10-20°, ..., 40-50°) of the PP seismic (Figure 5.7). Differences for the near 10-20°, mid-near (20-30°) and mid-far (30-40°) stack showed minimal amplitude difference in the Overburden Window and larger differences apparent within the Reservoir Window. The largest negative amplitude difference, however, were seen within the reservoir interval of the far (40-50°) angle stack.
Figure 5.6: Time variant time-shifts within the Niobrara reservoir between Monitor 2 and Baseline surveys of the PP seismic data. Time-shifts were calculated after cross equalization of the Monitor 2 survey to the Baseline survey. Negative time-shifts, associated with reservoir softening, appeared near producing wells in the Wishbone Section and were most prevalent to the closest spaced wells in the West (see Figures 5.10 and 5.11).

Observations made from the amplitude differences concurred with time-shift observations: angle stacks 10-20°, 20-30° and 30-40° contained consistent values for both amplitude difference and time-shifts, while the 40-50° featured the most anomalous signatures (larger negative time shifts (Figure 5.6); larger amplitude differences (Figure 5.7, bottom row)). As negative time-shifts and negative angle stack differences in the reservoir, like those seen in the far 40-50° angle range, indicative of softening from gas out of solution, further examination was done to ascertain whether these time-shifts and amplitude differences originated from time-lapse production effects (Sections 5.4.1 and 5.5.3).
Figure 5.7: Differences between Baseline and cross equalized Monitor 2 PP seismic surveys. Negative differences (green or orange) indicate higher amplitudes in the Baseline survey. Niobrara shown as blue horizon, Codell shown as green horizon and Greenhorn shown as cyan horizon. Cross sections shown run West-East across the producing horizontal wells (Niobrara wells shown as blue circles; Codell wells shown as orange circles) within the Wishbone section (Basemap shown top left).

5.3 Findings from PS Cross Equalization

Cross equalization of the PS data proved significantly less effective than that of the PP data. The same quantitative and qualitative evaluation used in assessment of the cross equalization process for the PP data was applied to the PS data using graphed NRMS values and PS angle stack differences (Figures 5.8 and 5.9).
PS NRMS Analysis

Values of NRMS for the PS surveys are shown in tables and graphs to analyze which step in the cross equalization process had the greatest effect in minimizing NRMS in the overburden (Figure 5.8). Though the frequency shaping filter proved most effective step for minimizing overburden NRMS during cross equalization of the PP seismic surveys, application of the frequency shaping filter proved less effective in the PS data: average NRMS decrease = 2.7%, maximum NRMS decrease = 3.3%. For the PS data, application of the trace-by-trace phase-time shifts proved to be the step most effective in minimizing NRMS: average NRMS decrease = 7.6%; maximum NRMS decrease = 8.7% (Figure 5.8). The largest change in NRMS of the PS seismic surveys attributed to the trace-by-trace phase-time shifts indicated that, unlike the PP seismic, the PS seismic surveys were out of phase and misaligned in time, despite careful application of trim statics to better align adjacent traces.

PS Angle Stack Differences

The phase-time discrepancies appeared most evidently in the angle stack difference cross sections (Figure 5.9). Not only did differences between the PS angle stacks have higher magnitude than differences in the PP angle stacks (PP differences < ±1%; PS differences < ±2%), but also showed spatial inconsistency: traces with high differences adjacent to traces with little to no differences.

Unfortunately for the PS time-lapse seismic data, after undergoing the cross equalization workflow, not a single resulting angle stack had NRMS reduced below 0.3. Though the far angles nearly reached this NRMS value (PS 30-40°: 0.336; PS 40-50°: 0.380), the near angles never reached the proximity of 0.3 (PS 10-20°: 0.700; PS 20-30°: 0.480). High values of NRMS served as the limiting factor in time-lapse analysis of PS seismic, and deemed the PS surveys unusable for use in time-lapse analysis of the 4D joint PP-PS inversion.
Figure 5.8: Table and graph of NRMS difference measured between PS Baseline and PS Monitor 2 surveys prior to cross equalization (“Raw”) and after each step in the cross equalization workflow (Figure 5.1). Top rows represent NRMS estimates within the Overburden Window of each angle stack range (10-20°, ..., 40-50°), while the bottom rows refer to the Reservoir Window NRMS difference for each angle stack range. Naming scheme used “P-T Shifts” for “Phase and Time Shifts” and “TbT” for “Trace-by-Trace”. NRMS values after the final step (Step 5: Trace-by-Trace Phase-Time Shifts) were colored relative to the threshold NRMS value of 0.3 (bold black line in the graph) where values < 0.3 were colored green, values ≈ 0.3 were colored yellow and values > 0.3 were colored red. The graph plots NRMS vs cross equalization step, where solid lines show overburden NRMS while dashed lines show the reservoir NRMS; both sets of lines are color-coded with their respective angle stack in the table.
Figure 5.9: Differences between Baseline and cross equalized Monitor 2 PS seismic surveys. Calculated as (Difference = Monitor 2 - Baseline), where a negative difference (green or orange) indicates larger values in the Baseline survey. Niobrara shown as blue horizon, Codell shown as green horizon and Greenhorn shown as cyan horizon. Cross sections shown run West-East across the producing horizontal wells (shown as red lines in cross section) within the Wishbone section (Basemap shown top left). Purple ovals were used to highlight vertical features of high difference (both positive and negative) which striped across the cross section, possibly indicative of static differences between PS Baseline and PS Monitor 2.
5.3.1 Potential Sources of Error in 4D PS Seismic Data

With the unfavorably high values of NRMS after cross equalization of the PS seismic surveys came questions regarding the origin of time-lapse discrepancies between the PS Baseline and Monitor 2 surveys. All questions centered around the same pivotal subject: “Why was the PS data so different between Baseline and Monitor 2?” Answers to this key question revolved around themes of acquisition and processing.

As previously detailed (Section 1.5.3), known issues were present in acquisition and processing of the PS seismic which likely affected the resulting PS data: in acquisition, varying near surface conditions and inconsistent receiver orientations existed; in processing, the COV binning (ACP vs CCP) and migration likely created artifacts in PS seismic data. These issues were then propagated through the processing workflow, where they manifested as large differences between Baseline and Monitor 2 PS seismic surveys.

Near Surface Conditions

Despite three different near surface conditions (dry during Baseline; wet during Monitor 1; frozen during Monitor 2), only a single solution for refraction statics was calculated and applied to the Baseline, Monitor 1 and Monitor 2 surveys. Using inappropriate refraction statics when processing seismic data would affect each subsequent step in the processing workflow, including migration (Figure 5.9; purple ovals highlighting vertical stripes of high difference). From this impact, refraction statics must be calculated and applied individually for each seismic survey to account for differing near surface conditions during acquisition.

Receiver H1 Orientations

Though receiver orientations in the Baseline and Monitor 2 data did not have the global skew present in Monitor 1 survey, distribution of H1 orientations from P-wave first arrival method for Baseline and Monitor 2 receivers ranged from $-40^\circ$ to $+40^\circ$ (Figure 3.2; Daves (2018)). Rotating from field coordinates to radial-transverse coordinates with incorrect $H_1$
orientations produce amplitude anomalies in the resulting rotated volumes. Thus, rotation of the Baseline and Monitor 2 surveys whose $H_1$ orientations varied by up to $\pm 40^\circ$ undoubtedly produced anomalous amplitudes which affected the PS cross equalization.

**COV Binning: ACP vs CCP**

COV binning of the PS seismic data used Asymptotic Conversion Point (ACP) which approximated the conversion point of the PS asymmetric raypath. While ACP binning estimated the PS conversion point, the true conversion point location could be calculated more accurately by using the Common Conversion Point (CCP) (Sections 1.5.3 and 4.1.1). By using CCP and binning PS reflections at their proper reflection location, the fold of the Turkey Shoot PS seismic surveys would increase (Figure 4.6).

**Anisotropic Kirchoff PS Pre-Stack Time Migration**

From the processing report of the Turkey Shoot survey, the PS seismic data was migrated using an anisotropic Kirchoff pre-stack time migration designed to account for vertical transverse isotropy (VTI) using COV binned seismic data. The first issue with this migration algorithm came from its proprietary nature, where little documentation was available to understand the process. Secondly, this anisotropic migration accounted only for VTI anisotropy. The simplest anisotropy present in the Wattenberg Field would be horizontal transverse isotropy (HTI) but likely more complex monoclinic anisotropy. By using the migration algorithm which only accounted for simple VTI anisotropy, the migrated PS seismic may contain residual artifacts due to complex nature of anisotropy in the study area. The more likely source of error within the PS seismic comes from a combination of COV binning together with the pre-stack time migration algorithm.

**5.4 4D Analysis of PP Seismic**

As discussed, only the PP seismic data will be considered further. For the PP seismic surveys, each cross equalized angle stack was analyzed in terms of time-variant time shifts and amplitude differences between Baseline and Monitor 2.
5.4.1 Time-Shifts

Physically related to changes in numerous reservoir properties such as stress, reservoir compaction, pressure and fluid saturation, negative time-shifts due to slowing of seismic velocities occurred predominantly near producing wells. Most apparent in the far 40-50° angle stack, large negative time-shifts also appeared on the western margin of the survey, a considerable distance from wells within the Wishbone Section. This zone of large negative time-shifts, however, directly aligns with wells in the adjacent section which have had more production than those in the Wishbone Section (Figure 5.10). This observation of spatial correlation with producing wells gave confidence in moving forward with the 4D results using the far 40-50° angle range.

Figure 5.10: Time variant time-shifts from the 40-50° angle range with the Wishbone Section outlined in black. Note large negative time-shifts West of the Wishbone Section directly aligned with producing horizontal wells in the adjacent section. These wells started production three months before the wells in the Wishbone Section.
Figure 5.11: Cross section from A - A’ across the Wishbone Section showing time variant time-shifts from the 40-50° angle range. Note large negative time-shifts within the Wishbone Section directly aligned with producing wells in the Niobrara (light blue) and Codell (orange) towards the Western portion of the Wishbone Section. Note that wells from the adjacent section West of the Wishbone also show large negative time-shift.

From this direct spatial correlation between negative time-shifts and producing wells, origin of negative time-shifts were presumed to be due to production-related effects rather than 4D seismic artifacts due to processing or cross-equalization. Given the proximity to wells that produced gas during Monitor 2, the origin of negative time-shifts was interpreted as fluid saturation changes and the effect of gas coming out of solution causing slowdown of seismic velocities.

Larger negative time-shifts were seen in the far angle stack as opposed to the near, mid- near or mid-far angle ranges because with increasing angle, the seismic ray path spends more traveltime within the slow interval. By increasing the amount of time spent in the slow interval, seismic propagation would be affected by increased slowdown which would decrease propagation velocity and increase traveltime difference ($\Delta t$), leading to larger negative time-shifts.
Estimations of 4D velocity changes and time-shifts using methods which account for non-vertical seismic ray paths via ray-based tomography have been shown to calculate time-shifts more accurately than those calculated assuming vertical, zero-offset seismic propagation (Edgar and Mastio, 2017). Though Edgar and Mastio (2017) used zero-offset raypaths in their modeling, the time-shifts seen in the near (10-20°), mid-near (20-30°) and mid-far (30-40°) angle stacks showed significantly lower time-shifts when compared to the far (40-50°) angle stacks. Though further investigation would be recommended, the largest time-shifts in the far angle stack could be interpreted as showing that the 40-50° incidence angle more accurately estimating time-shifts than the other angle stacks.

5.4.2 Amplitude Differences

Reflection amplitude differences from the Niobrara horizon were calculated by taking the difference between Monitor 2 and Baseline surveys (Difference = Monitor 2 - Baseline) for each angle stack (10-20°, ... , 40-50°), as well as the “full” angle stacks of 10-40° and 10-50° PP angle stacks (Figure 5.12). In these amplitude difference slices (Figure 5.12), negative values indicated softening and higher amplitudes in the Baseline survey, while positive values indicated hardening and higher amplitudes in the Monitor 2 survey. When examining the amplitude differences for individual angle stacks from the Near Stack (10-20°) to the Far Stack (40-50°), differences increased from largely negative differences (near angles) to slightly negative to positive differences (far angles). The highest prevalence of positive amplitude differences were seen in the Far Stack (40-50°). The presence of the most negative time-shifts (Figures 5.6 and 5.10) as well as the highest amplitude differences (Figure 5.7) in the Far Stack pointed to the 40-50° angle range being most affected by 4D changes within the reservoir.
Figure 5.12: Amplitude differences between angle stacks (10-20°, ... , 40-50°) and the full 10-40° and 10-50° angle stacks of the Monitor 2 and Baseline survey within the Niobrara reservoir. Differences were calculated such that negative differences indicated softening and higher amplitudes in the Baseline survey, while positive differences indicated hardening and higher amplitudes in the Monitor 2 survey. Amplitude differences were calculated after cross equalization of the Monitor 2 survey to the Baseline survey.

5.5 4D Pre-Stack PP Inversion

Following a successful inversion of the Baseline survey (Section 4.2), the exact same parameters of the pre-stack PP simultaneous inversion used for the PP Baseline survey were used for the PP Monitor 2 survey. The only difference between the two inversions were the input data: the PP Monitor 2 angle stacks (10-20°, ... , 40-50°) and angle-dependent wavelets extracted from these Monitor 2 angle stacks (Figure 5.13).
Figure 5.13: Statistical wavelets extracted from the Angle Stacks created from the PP Monitor 2 survey. All wavelets were extracted as zero-phase and 200ms in length. Wavelets are colored by the following: Near Stack (10-20°) Blue; Near-Mid Stack (20-30°) Green; Far-Mid Stack (30-40°) Yellow; Far Stack (40-50°) Pink.

After inverting the cross equalized PP seismic volumes (Baseline and Monitor 2), the inverted volumes (Z_P, Z_S, \rho, and therefore \lambda \rho and \mu \rho) were subtracted and divided by their average (Equation 5.2), such that a positive difference indicates a larger value of impedance or density in Monitor 2, and a negative difference indicates Baseline having the larger value.

\[
\text{Difference} = \frac{2(Monitor2 - Baseline)}{(Monitor2 + Baseline)} \tag{5.2}
\]

Time-lapse (4D) inversion analysis of the PP seismic data mainly focused on differences in Z_P and \lambda \rho between Baseline and Monitor 2 surveys where large negative changes in \lambda \rho correlate spatially with 4D time-shift analysis and gas production.

5.5.1 4D PP Inversion: Angle Range from 10-50°

Cross sections from A - A’ through the Wishbone Section were used to visualize time-lapse (4D) differences in elastic parameters (Z_P, Z_S, \rho, \lambda \rho and \mu \rho) from Baseline to Monitor 2 (Figures 5.14 through 5.18). These 4D differences show layer-bound changes, in that both positive and negative differences were seen within the Niobrara to Codell interval.
Figure 5.14: West-East crossline (A - A’) through the Wishbone Section showing $\Delta Z_P$ percent difference from Baseline to Monitor 2. Differences shown were calculated from the 4D PP inversion using the full 10-50° angle range.

Figure 5.15: West-East crossline (A - A’) through the Wishbone Section showing $\Delta Z_S$ percent difference from Baseline to Monitor 2. Differences shown were calculated from the 4D PP inversion using the full 10-50° angle range.
Figure 5.16: West-East crossline (A - A’) through the Wishbone Section showing $\Delta \rho$ percent difference from Baseline to Monitor 2. Differences shown were calculated from the 4D PP inversion using the full 10-50° angle range.

Figure 5.17: West-East crossline (A - A’) through the Wishbone Section showing $\Delta \lambda \rho$ percent difference from Baseline to Monitor 2. Differences shown were calculated from the 4D PP inversion using the full 10-50° angle range. Note large decrease in $\Delta \lambda \rho$ surrounding Niobrara wells and smaller decrease in $\Delta \lambda \rho$ surrounding Codell Wells.
5.5.2 Qualitative and Quantitative Analysis

Analysis of the 4D pre-stack PP simultaneous inversion was done in the form of crossplots and correlation with production data. As percent differences cannot be crossplotted against actual well logs, crossplots of the change in $\lambda/\rho$ ($\Delta\lambda/\rho$) and change in $\mu/\rho$ ($\Delta\mu/\rho$) were instead compared to determine the effect of stimulation and production on the lithology and fluid content of the reservoir.

4D $\lambda/\rho-\mu/\rho$ Crossplots

As was done with the pre-stack PP inversion on the Baseline survey, $\lambda/\rho-\mu/\rho$ crossplots were generated for the Monitor 2 survey (Figure 5.19). The primary difference between the Baseline and Monitor 2 $\lambda/\rho-\mu/\rho$ crossplots was seen in the Niobrara interval (orange points) decreasing not only in $\lambda/\rho$ (incompressibility), but also $\mu/\rho$ (rigidity).
Time-lapse differences in $\lambda\rho$ and $\mu\rho$ were plotted to illustrate changes in rock and fluid properties by creating $\Delta\lambda\rho$ vs $\Delta\mu\rho$ (Figure 5.20). From the $\Delta\lambda\rho$-$\Delta\mu\rho$ crossplot of points within the reservoir interval (Niobrara to Greenhorn):

1. The primary change within the Niobrara interval (orange points) occurred as a decrease in both $\lambda\rho$ and $\mu\rho$. The negative change in $\lambda\rho$ can indicate an increase in compressible fluid within the reservoir, implying softening due to the presence of gas. The negative change in $\mu\rho$ can indicate a weakening of the rock matrix, implying an increased presence of open fractures within the reservoir. These open fractures would increase void space, increasing porosity where the induced change in porosity intrinsically affects $\lambda\delta\rho$.

2. Though there could exist alternate explanations for the positive $\lambda\rho$ change, this could potentially indicate a reduction in porosity and imply decreased presence of pore fluid (oil or gas).
3. Positive changes in $\mu_\rho$ could indicate strengthening of the rock matrix, implying hardening due to compaction.

From these positive and negative changes in $\lambda_\rho$ and $\mu_\rho$, and their implications for dynamic changes in reservoir properties, four distinct trends were identified from the $\Delta \lambda_\rho$-$\Delta \mu_\rho$ crossplot: Trend A, B, C and D (Figure 5.20).

![Figure 5.20: Crossplot showing time-lapse $\Delta \lambda_\rho$ (x-axis) vs $\Delta \mu_\rho$ (y-axis) illustrating 4D changes in rock properties between Baseline and Monitor 2. Following convention from Equation 5.2, negative values indicate overall decrease in a given property from Baseline to Monitor 2, while positive values indicate overall increase. Three separate trends of $\Delta \lambda_\rho$ and $\Delta \mu_\rho$ were identified from this time-lapse crossplot: A (green): Negative $\Delta \lambda_\rho$ and negative $\Delta \mu_\rho$; B (blue): Negative $\Delta \lambda_\rho$ and positive $\Delta \mu_\rho$; C (orange): Positive $\Delta \lambda_\rho$ and positive $\Delta \mu_\rho$; D (grey): No distinct trend. Points in this crossplot were colored by depth.](image)

After identifying trends A, B, C and D from the $\Delta \lambda_\rho$-$\Delta \mu_\rho$ crossplot, fluid and fracture effects were modeled from well log data in the Niobrara interval. In order to determine how a pure fluid change and a pure fracture change affected $\Delta \lambda_\rho$ and $\Delta \mu_\rho$, the two changes were modeled separately: a fracture compliance model increased the amount of fractures from $Z_t = 0.0$ to $Z_t = 0.20$ and changes in fluid fill, from oil to gas, were modeled using Gassmann fluid substitution at $Z_t = 0.20$ (Bratton, 2018).
Though fracture and fluid effect models (Figure 5.21) showed much higher percent difference than did the field data (Figure 5.20), this difference in values originated from the scale of the data. While modeled data had log scale resolution on the order of inches, the field data had seismic wavelength resolution on the order of hundreds of feet. The scale of seismic resolution averaged intervals of high percent difference in $\Delta \lambda \rho$ and $\Delta \mu \rho$ with intervals of no difference, which decreased the amount of difference observed in the field data. This indicates that absolute values between model and field data would differ, though the trends of $\Delta \lambda \rho$ and $\Delta \mu \rho$ provided grounds for comparison.

Though the fluid and fracture models both showed decrease in $\lambda \rho$ and $\mu \rho$, the slope or rate of change for fluid and fracture effects provided the most insight to changes in rock properties (Figure 5.21). Replacement of oil with gas primarily showed $\lambda \rho$ to decrease roughly 8x more than the decrease in $\mu \rho$, where the slope of fluid effect = $\Delta \mu \rho / \Delta \lambda \rho = 1/8$. The fracture effect showed nearly twice the decrease in $\mu \rho$ than did the fluid effect, where the slope of the fracture effect = $\Delta \mu \rho / \Delta \lambda \rho = 1/4$. The addition of fractures to a background model significantly decreased the strength of the rock matrix and had a much larger negative change in $\mu \rho$ than did the fluid effect. The effect of fractures closing would follow the same slope as that of fractures opening but have the opposite sign, indicating an increase in both $\Delta \mu \rho$ and $\Delta \lambda \rho$.

The main takeaway from these models was that the fracture effect decreased the strength of the rock matrix much more than did the fluid effect, indicating that changes in $\Delta \lambda \rho$-$\Delta \mu \rho$ crossplot due to fractures would have more of a vertical ($\Delta \mu \rho$) component than would the $\Delta \mu \rho$ resulting from a fluid change. For the fracture effect of $\Delta \lambda \rho$-$\Delta \mu \rho$, the vertical ($\Delta \mu \rho$) component changes significantly more than the horizontal ($\Delta \lambda \rho$) component. Conversely, the fluid effect in $\Delta \lambda \rho$-$\Delta \mu \rho$ crossplot would show larger horizontal ($\Delta \lambda \rho$) component than vertical ($\Delta \mu \rho$) component.
Figure 5.21: Left: Modeled change in $\lambda_\rho$ and $\mu_\rho$ due to fluid and fracture effects. Fluid effect (blue) consisted of changing fluid content from oil to gas at $Z_t = 0.20$, while the fracture effect (orange) consisted of increasing fracture compliance from no fractures initially to fracture compliance of $Z_t = 0.20$. Right: Arrows indicate qualitative effect of fluid and fracture effects on $\Delta\lambda_\rho$ and $\Delta\mu_\rho$. Modified from Bratton (2018).

Trends A, B, C and D were further broken down using the slopes of the fluid and fracture effects on $\Delta\lambda_\rho$-$\Delta\mu_\rho$ (Figure 5.22). Rocks that underwent pure fluid change or gas effect, composed primarily of large negative $\Delta\lambda_\rho$ and small negative $\Delta\mu_\rho$, would plot in the bottom left quadrant of the $\Delta\lambda_\rho$-$\Delta\mu_\rho$ crossplot (Figure 5.22, “Gas effect”). Both Trend A and B demonstrated the negative $\Delta\lambda_\rho$ components resultant from this fluid change and gas effect. The effect of opening and closing of fractures from the fracture modeling showed larger change in $\Delta\mu_\rho$ than did the effect of fluid change. Further, closing of fractures (“Hardening”) would lead to positive $\Delta\lambda_\rho$ and positive $\Delta\mu_\rho$, while an opening of fractures would be indicated by negative $\Delta\lambda_\rho$ and negative $\Delta\mu_\rho$. Hardening, a measure of increased effective stress, would originate from either an increase in overburden stress or decrease in pore pressure ($\sigma_{eff} = \sigma_{Ob} - P_P$, where $\sigma_{Ob}$ represents the overburden stress and $P_P$ represents pore pressure). Formations undergoing an opening of fractures would plot in the bottom left quadrant,
while formations experiencing a closing of fractures would plot in the top right quadrant. Trend A and Trend C exhibited this opposite behavior from opening or closing of fractures, though modeled effects show smaller values of $\Delta \mu \rho$. Trend B showed negative values of $\Delta \lambda \rho$, attributed to a change in fluid content from oil to gas, the positive $\Delta \mu \rho$ was attributed to the effect of closing fractures.

![Crossplot showing $\Delta \lambda \rho$ vs $\Delta \mu \rho$ (as in Figure 5.20) with included interpretation of Trends A, B and C, in terms of gas, fracture and hardening effects.](image)

Figure 5.22: Crossplot showing $\Delta \lambda \rho$ vs $\Delta \mu \rho$ (as in Figure 5.20) with included interpretation of Trends A, B and C, in terms of gas, fracture and hardening effects.

Trend A showed components of negative $\Delta \lambda \rho$ and $\Delta \mu \rho$, indicating softening of the reservoir from the presence of gas and fracturing, indicating that the induced fractures present in Niobrara interval during the Monitor 1 survey had not fully closed at the time of the Monitor 2 survey.

Trend B showed components of negative $\Delta \lambda \rho$, again implying softening due to gas, but positive $\Delta \mu \rho$, which implied closing of the induced fractures from Monitor 1 and hardening due to reservoir compaction.

Trend C showed components of positive $\Delta \lambda \rho$, which could be attributed to decreased presence of pore fluid and reduction in porosity, and positive $\Delta \mu \rho$, which would be attributed to hardening of the reservoir due to compaction.
Region D, comprised of very small changes in $\Delta \lambda \rho$ and $\Delta \mu \rho$, showed differences that did not categorize within any of the three trends. Points encompassed by Region D were presumed to be areas of low signal-to-noise (S/N) changes. With improved 4D repeatability and lower NRMS, these low signal-to-noise events may separate from background noise.

Though colored by depth interval in Figures 5.20 and 5.22, interpretation was further developed by observing specific subsurface locations of these four trends within the reservoir interval (Figure 5.23). From this $\Delta \lambda \rho$-$\Delta \mu \rho$ trend cross section (Figure 5.23), Trends A, B, C and D were seen to have fairly consistent lateral presence, but showed variance with depth.

Within the upper Niobrara, for instance, Trend A (negative $\Delta \lambda \rho$; negative $\Delta \mu \rho$) was seen above above and below the Top Niobrara, but transitioned to Trend B (negative $\Delta \lambda \rho$; positive $\Delta \mu \rho$) close to the Niobrara wells. The change from Trend A (green) to Trend B (blue) implies a transition from weaker rock matrix and possible open fractures to a strengthened rock matrix, indicating hardening due to reservoir compaction with increased proximity to the Niobrara wells.
Within the lower Niobrara and upper Codell, Trend B and Trend C showed higher presence, with very little Trend A. The positive $\Delta \mu \rho$ of Trends B and C indicate further hardening due to reservoir compaction throughout the lower Niobrara and upper Codell intervals. Within this interval, $\Delta \lambda \rho$ showed considerable lateral variation, shifting from negative values (Trends A and B) to positive values (Trend C) in localized pockets. Trends B and C dominate the middle Codell interval, showing positive $\Delta \mu \rho$ throughout, but $\Delta \lambda \rho$ changing from positive to negative with increased proximity to the Codell wells.

This indicated the presence of hardening due to reservoir compaction throughout the Codell interval but a change from a possible decreased presence of pore fluid (oil and gas) in the upper Codell but increased presence of gas surrounding the Codell wells. By visualizing trends of positive and negative $\Delta \lambda \rho$ and $\Delta \mu \rho$ within the reservoir, zones of negative $\Delta \lambda \rho$, indicative of softening and change of pore fluid from oil to gas, and positive $\Delta \mu \rho$, indicative of hardening and reservoir compaction, were seen to surround producing wells in both Niobrara and Codell intervals.

5.5.3 Time-Lapse Correlation with Gas Production

$\Delta \lambda \rho$ vs Gas Production

In order to calibrate the 4D response, $\Delta \lambda \rho$ was extracted in two windows: from a 30ms window in the lower Niobrara and in a separate 10ms window for the Codell, each encompassing the interval of negative $\Delta \lambda \rho$ values (Figure 5.24). $\Delta \lambda \rho$ was then summed and averaged along the path of horizontal wellbores in the Wishbone Section and plotted against cumulative gas production for each well in the section: Niobrara wells (Figure 5.25, left) and Codell wells (Figure 5.25, right).

Landing within the C-Marl instead of the C-Chalk, the 4N well (Figure 5.25: grey point, left graph) was omitted as an outlier. The resulting correlation between $\Delta \lambda \rho$ and cumulative gas production within the Niobrara was 0.84. As the 8C well (Figure 5.25: grey point, right graph) was the only Codell well incorporated in the zipper frac, it also was omitted as
an outlier. Correlation of $\Delta \lambda \rho$ and cumulative gas production within the Codell formation between the remaining three wells was 0.71. It should be noted that a linear trend of three points can typically be approximated fairly easily, resulting in very high correlation coefficients (Figure 5.25, right), thus increasing the probability of spurious correlation (Kalkomey, 1997). Despite the probability of increased random correlation between $\Delta \lambda \rho$ and gas production in the three Codell wells used, a higher correlation was established using more data points with the six Niobrara wells which quelled concern of spurious correlation of $\Delta \lambda \rho$ and gas production.

Figure 5.24: $\Delta \lambda \rho$ extracted from a 30ms interval within the Niobrara formation shown in map view of the Wishbone section, overlain by horizontal producing wells.
Figure 5.25: Crossplot of $\Delta \lambda$ ("dLR\%") (x-axis) and cumulative gas production (y-axis) for all wells in the Wishbone section: 7 Niobrara wells (left) and 4 Codell wells (right).

Negative Time-Shifts vs Gas Production

Values of negative time-shifts in the Wishbone Section (Figure 5.10) were extracted along Niobrara and Codell wellbores, summed then averaged and plotted versus cumulative gas production of Niobrara wells (Figure 5.26, left) and Codell wells (Figure 5.26, right). Both crossplots show correlation coefficients between time-shifts and cumulative gas production for including all Niobrara and Codell wells, as well as correlation coefficients when excluding certain wells with anomalously high (9N and 11N) or low (10C) values. Note that all three wells omitted (9N, 10C and 11N) all resided on the western margin of the Wishbone Section where the highest time-shifts were observed (Figure 5.10). The 9N, 10C and 11N wells represent the highest producers of gas in the Wishbone Section when normalizing for number of stages. This could be the result of the order in which wells were stimulated, from East to West, where the 11N, 10C and 9N would be the last three wells to be stimulated. Due to this, the 9N, 10C and 11N were omitted from correlation coefficients. Correlation between time-shifts and cumulative gas production for Niobrara wells increased from 0.51 to 0.93 with the omission of the 9N and 11N wells, while correlation for Codell wells increased from 0.31
to 0.98. As previously noted, high correlation coefficients from linear trends of three points (Figure 5.26, right) have increased probability of spurious correlation. However, a correlation $> 0.9$ from five or fewer data points has an associated probability of spurious correlation of only 4% (Kalkomey, 1997). Given this low probability, a correlation coefficient greater than 0.9 for Codell wells (0.91) and a similarly high correlation using more data points for Niobrara wells (0.93), a strong correlation between negative time-shifts and cumulative gas production was observed within the Wishbone Section.

Figure 5.26: Crossplot of negative time-shifts (x-axis) and cumulative gas production (y-axis) for all wells in the Wishbone section: 7 Niobrara wells (left) and 4 Codell wells (right). Data labels, left: ”40-50 TS all Nio” refers to time-shifts extracted from the 40-50° angle range, with all Niobrara wells plotted; ”40-50 TS Nio No 9N/11N” refers to time-shifts extracted from the 40-50° angle range, with the 9N and 11N wells omitted from the plot. Data labels, right: ”40-50 TS all Codell” refers to time-shifts extracted from the 40-50° angle range, with all Codell wells plotted; ”40-50 TS Nio No 10C” refers to time-shifts extracted from the 40-50° angle range, with the 10C well omitted from the plot.

As cumulative gas production can be biased by gas produced in solution with oil with reservoir pressure above bubble point, gas-oil-ratio (“GOR”) served as a more telling indicator of gas presence. In order to further confirm reservoir pressure dropped below bubble point and gas came out of solution, $\Delta \lambda \rho$ and negative 4D time-shifts were compared to GOR of three wells in different areas of the Wishbone Survey area: the West, the center and the

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East (Figure 5.27). With areas of largest negative $\Delta \lambda \rho$ and time-shifts located on the Western edge of the Wishbone Section, and the established correlation of $\Delta \lambda \rho$ with cumulative gas production, GOR trends of the 1N (located on the Eastern portion of the Turkey Shoot), 6N (center of the Turkey Shoot) and 11N (Western portion of the Turkey Shoot) showed highest GOR in the 11N in the Western portion of the Wishbone Section.

![Figure 5.27: Gas-Oil-Ratio (“GOR”) of three wells in the Wishbone Section: 11N on the West; 6N in the center; 1N on the East. Increased GOR and gas trends were seen towards the West.](image)

5.6 Conclusions

By incorporating PS seismic in the joint PP-PS inversion, an improved correlation was seen between all elastic parameters ($Z_P$, $Z_S$, $\rho$, $\lambda \rho$ and $\mu \rho$) and well logs values, when compared to the pre-stack PP inversion alone (Figure 4.37). Though the NRMS 4D repeatability of the PS seismic cross equalization proved problematic (Figure 5.8), with better care in acquisition and processing, 4D joint PP-PS inversion analysis should be considered. With good NRMS 4D repeatability of the PP seismic (Figure 5.5), 4D $\lambda \rho$-$\mu \rho$ analysis indicated increased gas content within the reservoir in the Monitor 2 survey (Figure 5.20). Visualiz-
ing spatial locations of positive and negative trends in $\Delta \lambda \rho$ and $\Delta \mu \rho$ through cross section aided in characterization of the reservoir interval by illustrating discernible changes in fluid and rock properties (Figure 5.23). Trends of negative $\Delta \lambda \rho$ and positive $\Delta \mu \rho$ were seen to surround both Niobrara and Codell wells, indicating that both softening, due to pore fluid changing from oil to gas, and hardening, due to reservoir compaction, occur with increased proximity to producing wells. 4D time-shifts (Figure 5.10) and negative $\Delta \lambda \rho$ (Figure 5.24) showed spatial correlation and consistency within the Western Turkey Shoot and North-West Wishbone Section areas. Correlation between $\Delta \lambda \rho$ and cumulative gas production was seen to support the increase in gas content (Figure 5.25). Similarly, cumulative gas production and negative time-shifts were seen to have strong correlation. With improved repeatability in the PS seismic surveys, extracted $\lambda \rho-\mu \rho$ from 4D joint PP-PS inversion would be expected to improve upon the 4D correlation results shown with the pre-stack PP inversion.
6.1 Added Value of Multicomponent: Pre-Stack PP Inversion vs Joint Pre-Stack PP-PS Inversion

Through both qualitative and quantitative assessment, the incorporation of pre-stack PS seismic into the inversion process produced improved vertical resolution in inverted volumes (Figures 4.14 through 4.16 for PP; Figures 4.25 through 4.27 for PP-PS), as well as higher correlation between every inverted property and calculated well log properties than did the pre-stack PP seismic alone (Figure 4.37). This visual and numerical improvement in accuracy of inverted volumes ($Z_P$, $Z_S$, $\rho$, $\lambda\rho$ and $\mu\rho$) can be translated into increased certainty of subsurface reservoir characterization, more exact well placement, and be used as input to static and dynamic geologic and geomechanical models.

6.2 4D PS Considerations and Recommendations

Unfortunately, due to differences in acquisition and processing of the PS seismic between Baseline and Monitor 2, 4D joint PP-PS inversion analysis was not possible. The overburden NRMS values were too large for any 4D signal detection. From this, greater care must be taken in planning PS seismic survey acquisition and processing for 4D purposes. This involves more careful geophone orientation and rotation into radial-transverse coordinates, proper binning of PS seismic data using ACP binning, calculation of near surface conditions individual to each time-lapse survey and further insight to PS pre-stack time migration algorithms.

6.3 4D PP Inversion

Analysis of the 4D time-shifts in the PP seismic showed higher negative time-shifts evident in the far 40-50° angle stack compared to the near (10-20°), mid-near (20-30°) or mid-far (30-40°) angle stacks. Time-shifts from the far angle stack were presumed to better approximate
reservoir time-shifts due to the non-vertical seismic raypath spending more traveltime within the slow interval. These time-shifts from the 40-50° angle range correlated spatially with producing wells in both the Wishbone Section and the adjacent section (Figure 5.10).

4D PP inversion showed clear decrease in $Z_P$ and $\lambda_P$ between Monitor 2 and Baseline. These time-lapse differences were translated into 4D $\Delta\lambda_P-\Delta\mu_P$ crossplots which showed trends of Niobrara lithologies decreasing in both $\lambda_P$ and $\mu_P$ (Figure 5.22). Representing a decreasing incompressibility and decreasing rigidity or rock strength, these negative differences in $\lambda_P$ were attributed to gas out of solution and open fractures within the Niobrara reservoir, while negative differences in $\mu_P$ were associated with opening of fractures within the reservoir, which lowered the strength of the rock fabric and $\mu_P$, and positive differences in $\mu_P$ were attributed to closing of fractures and compaction, or hardening.

When the trends identified in $\Delta\lambda_P-\Delta\mu_P$ crossplot (Figure 5.20; Trends A, B, C and Region D) were visualized in cross section through the Wishbone Section (Figure 5.23), presence of negative $\Delta\lambda_P$ and positive $\Delta\mu_P$ were seen to surround the subsurface locations of both Niobrara and Codell wells. These changes were interpreted as both softening due to increased presence of gas (negative $\Delta\lambda_P$) and hardening due to reservoir compaction and closing of fractures (positive $\Delta\mu_P$).

6.4 Integrated Results:

6.4.1 $\Delta\lambda_P$ and Traveltime Results

Both $\Delta\lambda_P$ (Figure 5.24) and 4D time-shifts (Figure 5.10) were seen to correlate spatially. Regions of highest change in $\Delta\lambda_P$ and largest negative time-shifts both occurred in the Western portion of the Turkey Shoot survey area and the Northwest corner of the Wishbone section. The Western Turkey Shoot survey contained wells that started production three months prior to the those in the Wishbone Section, while the Northwest portion of the Wishbone Section contained the highest producing wells. With spatial correlation of highest changes in $\Delta\lambda_P$ and negative time-shifts with producing wells, correlation with gas production was investigated.
6.4.2 Correlation of $\Delta \lambda \rho$ with Gas Production

In order to constrain the premise of $\Delta \lambda \rho$ pointing to gas out of solution, gas production from the eleven horizontal wells within the Wishbone Section was plotted against negative differences of $\Delta \lambda \rho$ along each horizontal wellbore. When removing two outlier wells (Well 4N: anomalously low production because it landed in the C-Marl instead of the productive C-Chalk; Well 8C: anomalously high production because it was part of the zipper frac), strong correlation was seen between gas production in Niobrara and Codell wells and negative $\Delta \lambda \rho$.

6.4.3 Correlation of 4D Time-Shifts with Gas Production

4D time-shifts were extracted from the 40-50º angle stack along the horizontal wellbores of Niobrara and Codell wells in the Wishbone Section and crossplotted against cumulative gas production (Figure 5.26). Negative time-shifts and cumulative gas production for Niobrara and Codell wells showed correlation coefficients of 0.91 and 0.93, respectively. From these strong correlations, presence of gas in the reservoir was presumed to be responsible for the slowdown of seismic velocities and the resulting negative time-shifts seen in the Wishbone Section.
REFERENCES CITED


