MULTICOMPONENT SEISMIC MONITORING
OF STRAIN DUE TO CO₂ INJECTION AT
DELHI FIELD, LOUISIANA

by

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

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ABSTRACT

Time-lapse, multicomponent seismic data are used in this thesis to monitor geomechanical changes within the reservoir and in the overburden layers at Delhi Field, Louisiana. Multicomponent seismic data are important for monitoring gas saturation and pressure changes associated with CO$_2$ flooding. A seismic survey acquired before CO$_2$ injection operations began serves as a baseline survey and a pair of multicomponent monitor surveys acquired during first two years of injection allow time-lapse analysis of amplitude differences and time-shifts between seismic surveys.

Time-lapse seismic data are used for mapping fluid and pressure changes within the reservoir interval. Reservoir pressure increases at Delhi Field cause overburden compaction and time-shifts between seismic monitor surveys. Vertical strain in the overburden is calculated from compressional and converted wave time-shifts and provide quantitative insight into how injection operations affect overburden layers. Strain estimated from converted wave seismic data shows both a different pattern and magnitude than strain estimated from compressional seismic data. Monitoring these geomechanical changes enables the calibration of geomechanical models to understand the influence of reservoir dynamics on the overburden and the underburden.
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CHAPTER 1
INTRODUCTION

The research in this thesis is being conducted as Phases XIII and XIV of the Reservoir Characterization Project at the Colorado School of Mines. The goal of these phases is to study a CO$_2$ enhanced oil recovery and sequestration project at Delhi Field, Louisiana using multicomponent, time-lapse seismic data. The goal of this thesis is to investigate geomechanical changes in the reservoir and overburden with multicomponent, time-lapse seismic data.

1.1 Thesis content

This thesis contains six chapters, including this introduction. This chapter, Chapter 1, contains an overview of CO$_2$ flooding, a description of Delhi Field, and an introduction to the seismic data used in this thesis.

Chapter 2 contains rock physics modeling results for expected fluid and pressure changes within the Delhi Field reservoir. Also, the parameter $\alpha$ is introduced and derived from well log data.

Chapter 3 overviews the cross-equalization process applied multicomponent seismic data at Delhi Field. In all cases post stack cross-equalization improves time-lapse repeatability. Time-lapse time-shifts are calculated and applied to Delhi Field seismic data to improve repeatability. In Chapter 5, time-lapse time-shifts are analyzed for strain.

In Chapter 4, time-lapse amplitude changes are calculated and analyzed for CO$_2$ fluid movement in the Delhi Field reservoir. PP seismic data are analyzed for fluid saturation changes while converted wave data are analyzed for reservoir pressure changes.

Chapter 5 gives an introduction to the seismic attribute time-strain and overviews the methodology for calculating strain from time-lapse time-shifts. A method to calculate SS time-shifts at a single horizon from PP and PS seismic data is discussed. Finally, strain is
estimated from both PP and reconstructed SS time-shifts for a horizon in the overburden. The

Chapter 6 gives conclusions from the work performed in this thesis. Furthermore, recom-

mendations for future work are made.

1.2 Overview of CO₂ flooding

During a typical improved oil recovery (IOR) project water is injected into a hydrocarbon
reservoir to displace oil toward producers. However, when oil saturation in the reservoir
reaches the residual oil saturation water can no longer displace oil. In these cases CO₂ can
be injected into the reservoir to continue oil production. This process is known as CO₂
flooding and commonly follows or is coupled with water flooding (Dake, 1978). CO₂ is a
good candidate for enhanced oil recovery due to its high solubility in crude oil. Above certain
reservoir pressures CO₂ expands oil remaining in the pore space and reduces its viscosity
up to 10 times (Holm, 1982). In other cases, CO₂ may be more effective at mechanically
displacing oil due to high solubility of oil in CO₂. These techniques are known as miscible
and immiscible CO₂ flooding. A comprehensive treatment of the behaviors of fluids in
hydrocarbon reservoirs can be found in McCain (1990). Figure 1.1 shows a typical example
of a CO₂ flood in a hydrocarbon reservoir. Tertiary CO₂ flooding can lead to increased oil
recovery while storing large volumes of CO₂. In Delhi Field, Denbury Resources estimates
that an additional 15 percent of oil can be recovered and 30 percent of injected CO₂ can be
sequestered (Richards, 2011).

1.3 Delhi Field background

This section provides a brief overview of Delhi Field geology, production history, and
available data. A detailed description of tectonic history, structure, stratigraphy, and the
petroleum system at Delhi Field can be found in previous theses (Klepacki, 2012; Robinson,
2012; Shahid, 2011; Silvis, 2011; Torsch, 2012).
Figure 1.1: An illustration of a typical miscible CO₂ flood in a hydrocarbon reservoir (DOE, 2010). The Delhi Field flood is immiscible and monitoring pressure changes due to CO₂ injection are particularly important.
Delhi Field is a producing oilfield located in northeast Louisiana approximately 30 miles east of Monroe, LA and 40 miles from the Louisiana-Mississippi state line. Delhi Field was discovered in December 1944 by C. H. Murphy Jr., and Sun Oil Company (Powell, 1968). In 2006, Delhi Field was purchased by Denbury Resources and placed under CO₂ flood in 2009 (Richards, 2011).

Delhi Field sits on the southern flank of the Monroe Uplift and the western edge of the Mississippi Interior Salt Basin (Klepacki, 2012). The wedge-shaped reservoir at Delhi Field was created through mid-Cretaceous uplift and subsequent erosion. Work by Johnson (1958), Robinson (2012) and Klepacki (2012) shows that the Monroe structure was actively uplifting during Tuscaloosa deposition. The reservoir interval at Delhi Field is made up of the Cretaceous Tuscaloosa and Paluxy sandstone units. The lower Cretaceous Paluxy sandstones were deposited in a prograding fluvial/deltaic depositional environment and are overlain by the upper Cretaceous Tuscaloosa sandstones, which were deposited in a transgressive near-shore marine and fluvial depositional environment (Klepacki, 2012; Robinson, 2012; Shahid, 2011; Silvis, 2011). Paluxy sandstones have an average porosity of 30 percent and an average permeability of 1,000 mD. Tuscaloosa sandstones have an average porosity of 29 percent and average permeability of 2,700 mD. The reservoir interval is overlain by 500 feet of Midway Shale. The Midway Shale is a Paleocene marine shale deposited in the Mississippi embayment (Klepacki, 2012; Silvis, 2011). Well log measurements show that the Midway Shale above Delhi Field has a porosity of 25 percent. The Midway Shale seals the dipping reservoir layers and provides a trap for oil accumulation in the Paluxy and Tuscaloosa sandstones. The Eocene Wilcox Formation lies above the Midway Shale and is a thick deltaic to submarine fan. Above the Wilcox Formation lies the Claiborne Group that contains the Cane River, Sparta, and Cook Mountain Formations (Silvis, 2011). The Glen Rose Group lies below the reservoir interval. Injected CO₂ at Delhi Field is produced from the Jackson Dome, which is a 40 km volcanic structure near the town of Jackson, Mississippi. CO₂ is piped from Jackson Dome to Delhi Field and injected into the reservoir.
Delhi Field was placed on primary production shortly after discovery in 1944. Water flooding began in 1953 and continued until the field was shut in. 129 MMBO were recovered through primary and secondary production. Figure 1.3 gives the production history of Delhi Field from 1944 to 2009 when tertiary CO₂ flooding commenced. Figure 1.4 shows oil production increase due to CO₂ injection beginning in 2009 through 2011. CO₂ injection at Delhi Field has increased oil production from 0 to 5000 barrels of oil per day as of the end of 2012.

Figure 1.2: Delhi Field stratigraphic column and schematic showing reservoir sands and overlying Midway Shale. Red arrows point to unconformities and the blue box represents the stratigraphic layers present in Delhi Field. Figure courtesy of Silvis (2011)

A number of different datasets are used to perform research on CO₂ injection at Delhi Field. To distinguish between different types of seismic data a two index notation is used where the first index represents the down-going wave and the second index represents the
Figure 1.3: Delhi Field production history before CO₂ flooding. Figure courtesy of White (2012). Production data provided by Denbury Resources.

Figure 1.4: Delhi Field production history after CO₂ flooding. Figure courtesy of Carvajal (2013). Production data provided by Denbury Resources.
up-going wave. For example, a survey with down-going P-waves and reflected S-waves is noted as “PS”. Seismic data available for this research are baseline (M0) PP 3D survey, a first monitor (M1) PP and PS 3D surveys, and a second monitor (M2) PP and PS 3D surveys. All PS data volumes analyzed in this thesis are rotated to the radial direction. Radial data was chosen over transverse due to higher time-lapse repeatability.

There are 18 wells within the RCP area with modern well logs. These wells have a variety of well logs available for analysis of the subsurface before CO₂ injection, such as gamma ray, resistivity, spontaneous potential, neutron, caliper, and photoelectric potential. Two wells have both P-wave sonic and S-wave sonic logs.

1.4 Seismic data acquisition and processing

In this section, the seismic data acquisition parameters and processing workflows are tabulated and presented for the baseline, first monitor and second monitor surveys. Tables 1.1 and 1.2 give the acquisition parameters of each seismic survey. The acquisition of the M0 survey performed by CGG Veritas for Denbury Resources is significantly different than the monitor surveys acquired by Tesla Exploration for the Reservoir Characterization Project. Table 1.3 gives the processing workflow between the M0 and M1 seismic surveys performed by Geotrace. The processing sequence performed by Geotrace was not specifically designed for time-lapse processing and repeatability values between M0 and M1 reflect this. Processing performed by Geotrace was intended to bring commonality between bin geometries, offset, and azimuth between surveys. Table 1.4 gives the 3C 4D processing workflow between M1 and M2 performed by Sensor Geophysical. A detailed overview of converted wave processing at Delhi Field can be found in O’Brien (2012). A time-lapse processing sequence was applied to the M1 and M2 surveys. As a result, time-lapse repeatability between first and second monitor survey is high. No processing sequence took into account all three seismic surveys (baseline, first monitor, and second monitor) and analysis between M2 and M0 is difficult due to issues with seismic repeatability. However, analysis can be performed between M0 and M1 and M1 and M2.
Table 1.1: 2008 3D survey acquisition parameters by CGG Veritas.

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<tr>
<td>Bin size</td>
<td>82.5 by 82.5 ft</td>
</tr>
<tr>
<td>Azimuth angle</td>
<td>18.43 degrees</td>
</tr>
<tr>
<td>CDP bins</td>
<td>55577</td>
</tr>
<tr>
<td>E-W line (inlines)</td>
<td>1-251</td>
</tr>
<tr>
<td>N-S line (crosslines)</td>
<td>1-303</td>
</tr>
</tbody>
</table>

Table 1.2: June 2010 and August 2011 3D survey acquisition parameters by Tesla Exploration.

<table>
<thead>
<tr>
<th><strong>M1 Acquisition</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Source line</td>
<td>NW-SE, 300 ft separation</td>
</tr>
<tr>
<td>Total source points</td>
<td>1053</td>
</tr>
<tr>
<td>Source interval</td>
<td>165 ft</td>
</tr>
<tr>
<td>Source line interval</td>
<td>495 ft</td>
</tr>
<tr>
<td>Source type</td>
<td>Dynamite, single hole, 1.1 lb at 30 ft</td>
</tr>
<tr>
<td>Amplifier</td>
<td>FireFly, 6327 channels max, 3(12)-.75 nyq. min phase</td>
</tr>
<tr>
<td>Receiver line</td>
<td>SW-NE, 300 ft separation</td>
</tr>
<tr>
<td>Total receiver points</td>
<td>2093</td>
</tr>
<tr>
<td>Receiver interval</td>
<td>82.5 ft</td>
</tr>
<tr>
<td>Receiver line interval</td>
<td>495 ft</td>
</tr>
<tr>
<td>Sensors</td>
<td>Vectorseis, single 3 component 270 degree orientation</td>
</tr>
<tr>
<td>Record length</td>
<td>6 seconds, 2 ms sample interval (2010), 1 ms sample interval (2011)</td>
</tr>
<tr>
<td>Bin size</td>
<td>41.25 by 82.5 ft</td>
</tr>
<tr>
<td>Azimuth angle</td>
<td>196.01 degrees</td>
</tr>
<tr>
<td>CDP bins</td>
<td>39102</td>
</tr>
<tr>
<td>E-W line (inlines)</td>
<td>1-133</td>
</tr>
<tr>
<td>N-S line (crosslines)</td>
<td>1-294</td>
</tr>
</tbody>
</table>
Table 1.3: Processing workflow for M0 and M1 performed by Geotrace.

<table>
<thead>
<tr>
<th>M0 and M1 3D Processing Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reformat</td>
</tr>
<tr>
<td>Geometry Definition and QC</td>
</tr>
<tr>
<td>Edit bad traces</td>
</tr>
<tr>
<td>Wavelet transform filter- space, time, frequency</td>
</tr>
<tr>
<td>Time-frequency domain noise attenuation-Discrete wavelet transform</td>
</tr>
<tr>
<td>Spherical Divergence</td>
</tr>
<tr>
<td>Surface consistent gain</td>
</tr>
<tr>
<td>Refraction statics application, datum: sea level, 6000 ft/s correction velocity</td>
</tr>
<tr>
<td>Surface consistent wavelet deconvolution</td>
</tr>
<tr>
<td>Initial velocity analysis</td>
</tr>
<tr>
<td>Normal moveout correction</td>
</tr>
<tr>
<td>Front end mute NMO stretch removal</td>
</tr>
<tr>
<td>Surface consistent autostatics</td>
</tr>
<tr>
<td>Velocity analysis every 0.5 sq mile</td>
</tr>
<tr>
<td>Surface consistent autostatics</td>
</tr>
<tr>
<td>Premigration offset binning and noise attenuation</td>
</tr>
<tr>
<td>KMIG velocity analysis every 0.5 sq mile</td>
</tr>
<tr>
<td>Curved ray Kirchoff prestack time migration</td>
</tr>
<tr>
<td>Common depth point stack</td>
</tr>
<tr>
<td>Tv bandpass filter 2/4-50/60 Hz Ormbsby applied to 3.5-4.5 s</td>
</tr>
<tr>
<td>1000 ms AGC</td>
</tr>
</tbody>
</table>
Table 1.4: Processing workflow for M1 and M2 performed by Sensor Geophysical Ltd.

<table>
<thead>
<tr>
<th>M1 and M2 3C 4D Survey Processing Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reformat: Record length 6.0 seconds, sample interval 2 ms</td>
</tr>
<tr>
<td>Geometry assignment: 3D Asymptotic binning</td>
</tr>
<tr>
<td>Tilt angle correction</td>
</tr>
<tr>
<td>Rotate H1/H2 to radial/transverse; Trace kills; Sinusoidal noise removal</td>
</tr>
<tr>
<td>Amplitude recovery: Spherical divergence correction +6 dB/sec gain</td>
</tr>
<tr>
<td>Instrument compensation; Surface consistent scaling</td>
</tr>
<tr>
<td>PP refraction statics: Datum elev. 0 ft, replacement vel. 6000 ft/s, 2 layers</td>
</tr>
<tr>
<td>Additional PS receiver statics from common receiver stacks</td>
</tr>
<tr>
<td>F-K filter to attenuate source generated noise</td>
</tr>
<tr>
<td>Adaptive eigenimage filtering (via SVD) to attenuate source generated noise</td>
</tr>
<tr>
<td>Surface-consistent devconvolution: Spiking, 100ms, pre whitening 0.01 percent</td>
</tr>
<tr>
<td>Components: Resolved: Source, receiver, offset; applied: Source, Receiver</td>
</tr>
<tr>
<td>Design window: 250-450ms at 0 ft offset, 1455-2500ms at 4579 ft offset</td>
</tr>
<tr>
<td>Offsets used in design 1000-5000 ft</td>
</tr>
<tr>
<td>Surface-consistent statics: Max shift 20 ms, correlation window: 300-1750 ms</td>
</tr>
<tr>
<td>T-F adaptive noise suppression applied to common source and receiver gathers</td>
</tr>
<tr>
<td>Analyze 350-850, 950-1600, 1600-2400 ms for PS1/PS2 and rotate</td>
</tr>
<tr>
<td>Time-variant spectral whitening: 0/5-80/100 Hz, 7 panels, 750 ms operator</td>
</tr>
<tr>
<td>NMO correction: eta=0.2; Mute: 0, 500, 3500 ms at 660, 1402.5, 10230 ft offsets</td>
</tr>
<tr>
<td>Maximum power autostatic; AGC; Operator length 750 ms, 5/10-40/50 Hz band</td>
</tr>
<tr>
<td>Fold match 2010 and 2011 surveys; Common conversion point stack: +100 ms bulk</td>
</tr>
<tr>
<td>Time-variant spectral whitening: 0/5-80/100 Hz, 7 panels, 750 ms operator</td>
</tr>
<tr>
<td>F-XY filtering: 3x3 point operator, 150 ms window, 75 ms overlap</td>
</tr>
<tr>
<td>Anisotropic diffusion filter, 1 step, 0.25 rate, 7x11 trace x 50 ms window</td>
</tr>
<tr>
<td>TE: 350-1600 ms; 3D implicit FD time migration: 95 percent of stacking velocities</td>
</tr>
<tr>
<td>Bandpass filtering: 5/10-70/80 Hz at 800 ms, 5/10-50/60 Hz at 2200 ms</td>
</tr>
</tbody>
</table>
CHAPTER 2
ROCK PHYSICS

Rock physics relationships must be applied to understand how fluid and pressure changes in a reservoir affect seismic data. CO$_2$ flooding operations at Delhi Field change fluid saturations and reservoir pressures. Several rock physics models are examined in this chapter to calculate velocity changes due to CO$_2$ flooding. An empirical rock physics relationship is developed to relate time-lapse time-shifts to compaction in the reservoir and overburden layers.

2.1 Overview of seismic geomechanics

Petroleum reservoirs can be modeled as packs of sediment grains filled with fluid. Effective stress ($\sigma$) on a petroleum reservoir can be calculated from fluid and overburden pressures. Fluid pressure, also known as hydrostatic pressure, increases with depth and can be calculated as

$$p_{\text{fluid}} = \int_0^z g z \rho_f(z) dz + p_{\text{atm}}$$

(2.1)

where $g$ is the acceleration due to gravity, $z$ is depth, $\rho_f(z)$ is the density of fluid as a function of depth, and $p_{\text{atm}}$ is atmospheric pressure. Overburden pressure, the pressure due to the overlying geologic layers, also increases with depth and can be calculated as

$$p_{\text{overburden}} = \int_0^z g z \rho(z) dz$$

(2.2)

where $\rho(z)$ is the combined density of both fluid and sediment as a function of depth. Effective stress can then be calculated as Equation 2.3

$$\sigma = p_{\text{overburden}} - \alpha p_{\text{fluid}}$$

(2.3)

where $\alpha$ is Biot’s coefficient (the $\alpha$ considered in this section is not representative of the parameter used to relate velocity and strain later in this thesis) (Mavko et al., 2009).
Hooke’s law states that for small volume changes to a material strain ($\epsilon$) is related to stress ($\sigma$) as

$$\sigma = C\epsilon$$  \hfill (2.4)\

where $C$ is the stiffness tensor. For isotropic media stress and strain can be related with Equation 2.5 (Tsvankin, 2005). $\lambda$ and $\mu$ are the Lame’s parameters and denote elastic stiffness and shear modulus.

\[
\begin{pmatrix}
\sigma_{xx} \\
\sigma_{yy} \\
\sigma_{zz} \\
\sigma_{xy} \\
\sigma_{yz} \\
\sigma_{zx}
\end{pmatrix} =
\begin{bmatrix}
\lambda + 2\mu & \lambda & \lambda & 0 & 0 & 0 \\
\lambda & \lambda + 2\mu & \lambda & 0 & 0 & 0 \\
\lambda & \lambda & \lambda + 2\mu & 0 & 0 & 0 \\
0 & 0 & 0 & \mu & 0 & 0 \\
0 & 0 & 0 & 0 & \mu & 0 \\
0 & 0 & 0 & 0 & 0 & \mu
\end{bmatrix}
\begin{pmatrix}
\epsilon_{xx} \\
\epsilon_{yy} \\
\epsilon_{zz} \\
\epsilon_{xy} \\
\epsilon_{yz} \\
\epsilon_{zx}
\end{pmatrix}
\]  \hfill (2.5)

Stress coefficients $\sigma_{xx}$, $\sigma_{yy}$, and $\sigma_{zz}$ are normal stresses and represent maximum horizontal stress, minimum horizontal stress and vertical stress, respectively. $\sigma_{xy}$, $\sigma_{yz}$, and $\sigma_{zx}$ represent shear stresses. Stiffness tensors with higher orders of symmetry, such as those for anisotropic rocks, also exist. An overview of anisotropic symmetry systems can be found in Tsvankin (2005).

Combining Hooke’s law with the wave equation gives wave velocities for compressional (Equation 2.6) and shear (Equation 2.7) waves where $K$ is bulk modulus, $\mu$ is shear modulus, and $\rho$ is density (Ikelle and Amundsen, 2005). It is important to note that P-waves are sensitive to changes in both bulk and shear modulus while S-waves are sensitive only to the shear modulus.

$$v_p = \sqrt{\frac{K + \frac{4}{3}\mu}{\rho}}$$  \hfill (2.6)\

$$v_s = \sqrt{\frac{\mu}{\rho}}$$  \hfill (2.7)

Field operations such as production or injection of fluids into the reservoir change effective stress on the reservoir over time. As a result, field operations can change seismic wave velocities. The remainder of this chapter uses rock physics models to predict how changing
reservoir conditions, such as CO₂ saturation increase and pressure increase, cause changes to seismic wave velocities in sedimentary rocks. Finally, a parameter to relate velocity changes to strain is derived.

### 2.2 Fluid substitution modeling

Several previous researchers have investigated the effect of fluid substitution on seismic velocities in Delhi Field (Klepacki, 2012; Mustafayev, 2010; Ramdani, 2012; Robinson, 2012; Shahid, 2011). The results of previous fluid substitution work will be summarized here, and analyzed for travel time changes related to CO₂ injection in Delhi Field.

Calculating changes in seismic velocity due to changes in fluids is typically done using Gassman fluid substitution models (Mavko et al., 2009). The Gassman equation for fluid substitution is written as

\[
K_{\text{sat}} = K_{\text{dry}} + \frac{1 - K_{\text{dry}}}{K_0} \frac{\phi}{K_{\text{fl}}} + \frac{1 - \phi}{K_0} \frac{K_{\text{dry}}}{K_0^2} + \frac{1 - \phi}{K_0} \frac{K_{\text{dry}}}{K_0^2}
\]  

(2.8)

where \(K_{\text{sat}}\) is fluid saturated bulk modulus, \(K_{\text{dry}}\) is effective bulk modulus, \(K_0\) is mineral bulk modulus, \(K_{\text{fl}}\) is pore fluid bulk modulus, and \(\phi\) is porosity. Seismic velocity can then be determined using Equation 2.6.

Ramdani (2012) provides a thorough analysis of CO₂ fluid substitution in Delhi Field based on rock property work of previous authors (Mustafayev, 2010; Shahid, 2011). Fluid substitution analysis calculates P and S-wave velocity changes in the Tuscaloosa and Paluxy Formations for cases of CO₂ replacing brine and CO₂ replacing oil. Final results of fluid substitution modeling is shown in Figure 2.1, Figure 2.2, Figure 2.3, and Figure 2.4. Gassman modeling predicts that in the Tuscaloosa Formation CO₂ replacing brine will decrease P-wave velocity from 9400 ft/s to 8700 ft/s and increase S-wave velocity from 5000 ft/s to 5100 ft/s. In the Paluxy Formation modeling predicts CO₂ replacing brine will decrease P-wave velocity from 9300 ft/s to 8000 ft/s and increase S-wave velocity from 5275 ft/s to 5452 ft/s. Assuming zero offset seismic data and reservoir thicknesses of 40 ft for the Tuscaloosa and 70 ft for the Paluxy two way travel-time changes through the reservoir can be calculated.
using the equation
\[ \Delta t = 2h \left( \frac{1}{v_1} - \frac{1}{v_2} \right) \]
where \( \Delta t \) is the two way travel-time change through the reservoir, \( h \) is reservoir thickness, \( v_1 \) is interval velocity before fluid substitution and \( v_2 \) is interval velocity after fluid substitution.

Modeling predicts PP travel-time changes through the Tuscaloosa and Paluxy Formation due to \( \text{CO}_2 \) replacing brine are -0.6 ms and -2.5 ms, respectively. Modeling predicts SS travel-time changes through the Tuscaloosa and Paluxy Formation due to \( \text{CO}_2 \) replacing brine are 0.3 ms and 0.8 ms, respectively. Calculations assume that \( \text{CO}_2 \) has remained within the reservoir interval. Fluid replacing brine is not the only effect that causes travel-time changes. Travel-time changes are also caused by changes in reservoir pressure and are modeled in Section 2.3.

### 2.3 Velocity-pressure relationship

In this section, a modeled relationship between velocity and pressure is analyzed for time-lapse changes in clean, high porosity sandstones. Pressure changes related to \( \text{CO}_2 \) injection in Delhi Field affect seismic wave velocities and are important for quantitative interpretation of PP and PS time-lapse seismic data.

A soft sand rock physics model relating pressure to seismic velocity is used to model pressure changes in Delhi Field. Hertz-Mindlin theory (Mindlin, 1949) gives a model for effective bulk \( (K_{HM}) \) and shear \( (\mu_{HM}) \) moduli for a random pack of dry, spherical grains at an effective pressure as

\[
K_{HM} = \left[ \frac{C^2(1 - \phi_0)^2 \mu^2}{18\pi^2(1 - \nu)^2} P \right]^{1/3}
\]

\[
\mu_{HM} = \frac{5 - 4\nu}{5(2 - \nu)} \left[ \frac{3C^2(1 - \phi_0)^2 \mu^2}{2\pi^2(1 - \nu)^2} P \right]^{1/3}
\]

where \( \phi_0 \) is critical porosity, \( C \) is coordination number, \( \nu \) is Poisson’s ratio, and \( P \) is effective pressure (Mavko et al., 2009). Coordination number is defined as the number of contacts
Figure 2.1: P wave velocity changes with fluid substitution results for Tuscaloosa Formation. Oil saturation in the Tuscaloosa Formation is assumed to be 30 percent. After Ramdani (2012).
Figure 2.2: S wave velocity changes with fluid substitution results for Tuscaloosa Formation. Oil saturation in the Tuscaloosa Formation is assumed to be 30 percent. After Ramdani (2012).
Figure 2.3: P wave velocity changes with fluid substitution results for Paluxy Formation.
After Ramdani (2012).
Figure 2.4: S wave velocity changes with fluid substitution results for Paluxy Formation. After Ramdani (2012).
each grain has with the surrounding grains (typical values are 5-12). To calculate a model with intermediate stiffness, high values of coordination number can be inserted. Critical porosity is defined as the porosity at which grains are no longer load-bearing and become a suspension (Nur et al., 1995). Geologically, critical porosity can be thought of as the porosity when sediment was first deposited and before compaction has occurred. To calculate the effective bulk modulus and shear modulus at a porosity different from the critical porosity a Hashin-Shtrikman lower bound is used

\[ K_{\text{eff}} = \left[ \frac{\phi/\phi_0}{K_{\text{HM}} + \frac{4}{3} \mu_{\text{HM}}} + \frac{1 - \phi/\phi_0}{K + \frac{4}{3} \mu_{\text{HM}}} \right]^{-1} - \frac{4}{3} \mu_{\text{HM}} \]  

(2.12)

\[ \mu_{\text{eff}} = \left[ \frac{\phi/\phi_0}{\mu_{\text{HM}} + \frac{\mu_{\text{HM}}}{6}\left(\frac{9K_{\text{HM}} + 8\mu_{\text{HM}}}{K_{\text{HM}} + 2\mu_{\text{HM}}}\right)} + \frac{1 - \phi/\phi_0}{\mu + \frac{\mu_{\text{HM}}}{6}\left(\frac{9K_{\text{HM}} + 8\mu_{\text{HM}}}{K_{\text{HM}} + 2\mu_{\text{HM}}}\right)} \right]^{-1} - \frac{\mu_{\text{HM}}}{6}\left(\frac{9K_{\text{HM}} + 8\mu_{\text{HM}}}{K_{\text{HM}} + 2\mu_{\text{HM}}}\right) \]  

(2.13)

where \( K \) is the mineral bulk modulus (Mavko et al., 2009). Parameters for Delhi Field used in Equations 2.10-2.13 are for typical Paluxy sandstones. Figure 2.5 shows a thin section through the Paluxy sandstone from core data at Delhi Field. The thin section shows a typical unconsolidated sandstone with low coordination number. Parameters used to model the velocity-pressure response in Delhi Field can be found in Table 2.1 below. The model is calculated for brine-saturated sandstones.

Table 2.1: Parameters used in velocity-pressure modeling for Delhi Field.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poisson’s ratio</td>
<td>0.3</td>
</tr>
<tr>
<td>Bulk modulus</td>
<td>36.5 GPa</td>
</tr>
<tr>
<td>Coordination number</td>
<td>9</td>
</tr>
<tr>
<td>Shear modulus</td>
<td>40 GPa</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.3</td>
</tr>
<tr>
<td>Critical porosity</td>
<td>0.36</td>
</tr>
</tbody>
</table>

Figure 2.6 shows modeled pressure increases at Delhi Field causes P-wave velocity to drop from 8230 ft/s to 7583 ft/s and S-wave velocity to drop from 4798 ft/s to 4058 ft/s. Assuming
Figure 2.5: Thin section through the Paluxy reservoir. The thin section shows a typical unconsolidated sandstone with low coordination number. Image courtesy of Denbury Resources.

The Tuscaloosa and Paluxy Formations are in pressure communication; these pressure drops correspond to time-shifts of -2.3ms for P-waves and -8.3ms for S-waves. These predictions are valid for clean, un-cemented sandstones. To determine how changes in pressure affect rocks of varying porosity empirical velocity-porosity relationships must be developed.

2.4 Dilation factor

In this section, an empirical relationship for velocity-porosity is developed from well log data. Dilation factor, $\alpha$, is calculated to quantify the relationship between strain and velocity changes in shale and reservoir layers in Delhi Field. The pressure-velocity relationship modeled in Section 2.3 gives the velocity change with effective pressure for a clean sandstone with dry, spherical grains. It is necessary to understand how layers with different porosities, such as shales, respond to changes in reservoir pressure in Delhi Field. Shale layers violate the assumption of a rock with spherical grains (Xu and White, 1995). Therefore, an empirical relationship is derived from well log data to understand how sand and shale layers respond to pressure change.
Figure 2.6: P and S wave velocity with change in effective pressure. Before CO$_2$ injection Delhi Field was at an effective pressure of approximately 1400 psi. After CO$_2$ injection the effective pressure in Delhi Field is approximately 500 psi.
Figure 2.7: Change in bulk and shear moduli with effective pressure. Before CO$_2$ injection Delhi Field was at an effective pressure of approximately 1400 psi. During CO$_2$ injection the effective pressure in Delhi Field is approximately 500 psi.
Roste (2007) proposed a dilation parameter, $\alpha$, to describe how changes in pressure affect different lithologies for P and S-waves. Other authors use the parameter, known as “R-factor”, to describe how changes in pressure affects rock of different porosities for P-waves (Hatchell and Bourne, 2005). Herwanger and Koutsabeloulis (2011) present an overview of R-factor.

To understand how porosity affects dilation and compaction in Delhi Field, the workflow proposed by Roste (2007) will be followed and dilation factor, $\alpha$, will be calculated for the entire logged interval. Theory for calculation of $\alpha$ will be summarized below followed by calculation of $\alpha$ for P and S-waves from log data at Delhi Field. $\alpha$ is defined as relative change in velocity divided by relative change in thickness. Empirical relationships give velocity as a function of porosity. Coupled with the assumption that stress changes in a porous medium are uniaxial, approximate thickness changes in an interval can be given as changes in porosity (Guilbot and Smith, 2002). Equation 2.14 gives the relationship between thickness and porosity as

$$\frac{\Delta z}{z} \approx \frac{\Delta \phi}{1 - \phi} \quad (2.14)$$

where $z$ is thickness, and $\phi$ is porosity. Hatchell and Bourne (2005) and Roste (2007) give relative change in velocity as

$$\frac{\Delta v}{v} = (1 - \phi) \frac{v'(\phi)}{v(\phi)} \frac{\Delta z}{z} \quad (2.15)$$

where $v$ is velocity, $z$ is thickness and $\phi$ is porosity. Solving for change in velocity over relative change in thickness gives $\alpha$ (Equation 2.16).

$$\alpha = (1 - \phi) \frac{v'(\phi)}{v(\phi)} \quad (2.16)$$

Previous researchers (Hatchell and Bourne, 2005; Roste, 2007) have used Han’s linear velocity-porosity relationship to calculate seismic velocity and $\alpha$ ($C$ denotes fractional clay content).

$$v_p[km/s] = (5.8 - 2.4C) - 8.6\phi \quad (2.17)$$
\[ v_s[km/s] = (3.7 - 2.1C) - 6.3\phi \quad (2.18) \]

\[ v'_p(\phi) = -8.6 \quad (2.19) \]

\[ v'_s(\phi) = -6.3 \quad (2.20) \]

Equations 2.17-2.20 represent P and S-wave velocity and the derivative of P and S-wave velocity with respect to porosity. Inserting Han’s velocity relations into equation 2.16 gives dilation factor for P and S-waves, \( \alpha_p \) and \( \alpha_s \), respectively.

\[ \alpha_p = (1 - \phi) \frac{-8.6}{(5.8 - 2.4C) - 8.6\phi} \quad (2.21) \]

\[ \alpha_s = (1 - \phi) \frac{-6.3}{(3.7 - 2.1C) - 6.3\phi} \quad (2.22) \]

To analyze how lithology impacts dilation factor two cases will be examined. The first is for a clean sandstone with no clay content \( (C=0) \) and the second for high clay content \( (C = 0.55) \) over a range of porosities for P and S-waves. Figure 2.8 shows dilation factor calculated for P and S-waves in clean and shaly sands. Modeling shows that rocks with high clay content are more sensitive to uniaxial pressure changes than clean sands. S-waves are also more sensitive to uniaxial stress changes than P-waves due to their pore shape (Xu and White, 1995).

An empirical velocity-porosity relationship is derived from well log data to determine \( \alpha_p \) in Delhi Field for varying porosities. P-wave velocity and porosity logs from well 140-1 were used. A quality control check on velocity logs in Delhi Field was performed by Klepacki (2012). P-wave velocity and porosity are cross-plotted and linear velocity-porosity trends for rocks with different porosities are calculated. Figure 2.9 shows the P-wave velocity-porosity cross-plot used to calculate a linear velocity-porosity relationship for rocks with different porosities. A linear velocity-porosity relationships for rocks with variable porosity is given in Equation 2.23.

\[ v_p(\phi) = 3.72 - 0.04\phi \quad (2.23) \]
Figure 2.8: Dilation factor calculated for P and S waves from Han’s velocity-porosity relationship. Rocks with high clay content or more sensitive to uniaxial stress changes than clean sands. Shear waves are also more sensitive to uniaxial pressure changes than compressional waves. Rocks with high clay content are more sensitive to compaction due to their pore shape (Xu and White, 1995).
P-wave dilation factor as a function of porosity can then be given as Equation 2.24 (where \( \phi \) is percent porosity).

\[
\alpha_p(\phi) = (100 - \phi) \frac{-0.04}{3.72 - 0.04\phi}
\]  

(2.24)

Figure 2.9: Linear regression analysis performed on P-wave velocities versus porosities for the entire logged interval of well 140-1. The linear best-fit line gives an empirically derived velocity-porosity relationship with a normalize standard error of 0.03 km/s. A linear velocity-porosity relationship is used for simplicity when finding \( v_p'(\phi) \).

An empirical velocity-porosity relationship is also derived from well log data to determine \( \alpha_s \) in Delhi Field for varying lithologies. S-wave velocity and porosity logs from well 140-1
were used. A quality control check on velocity logs in Delhi Field was performed by Klepacki (2012). S-wave velocity and porosity are cross-plotted and linear velocity-porosity trends for rocks with variable porosity are calculated. Figure 2.10 shows the S-wave velocity-porosity cross-plot used to calculate a linear velocity-porosity relationship. A linear velocity-porosity relationship for low and high porosity rocks is given in Equation 2.25.

\[ v_s(\phi) = 1.7 - 0.02\phi \]  

(2.25)

S-wave dilation factor as a function of porosity can then be given as Equation 2.26 (where \( \phi \) is percent porosity).

\[ \alpha_s(\phi) = (100 - \phi) \left[ \frac{-0.02}{1.7 - 0.02\phi} \right] \]  

(2.26)

Using the empirical relationship developed for dilation factor, \( \alpha \) is calculated for a range of porosities for both P and S-waves. Figure 2.11 gives the empirically derived dilation factor for P and S-waves in Delhi Field. Dilation factor was derived for a large portion of the rocks at Delhi Field and given a porosity of a certain formation a relationship between velocity change and strain can be calculated using the definition of \( \alpha \) given in Equation 2.27.

\[ \Delta v = \alpha \frac{\Delta z}{z} \]  

(2.27)

Hatchell and Bourne (2005) and Roste (2007) give the relationship between relative travel-time changes and strain as Equation 2.28.

\[ \frac{\Delta t}{t} = (1 + \alpha) \frac{\Delta z}{z} \]  

(2.28)

This relationship between time-lapse time-shifts and \( \alpha \) will be exploited in Chapter 4 to understand how pressure increases in Delhi Field cause strain in the reservoir interval and the overburden.
Figure 2.10: Linear regression analysis performed on S-wave velocities versus porosities for well 140-1. The linear best-fit line gives an empirically derived velocity-porosity relationship with a normalized standard error of 0.16 km/s. A linear velocity-porosity relationship is used for simplicity when finding $v'_s(\phi)$. 
Figure 2.11: Dilation factor, $\alpha$, calculated for a range of porosities using Equations 2.18 and 2.20. As expected S-waves have $|\alpha|$ greater than P-waves. Scenarios were also calculated to examine how error in the regression analysis changes $\alpha$ ($\alpha_+$ and $\alpha_-$).
CHAPTER 3
CROSS-EQUALIZATION

A process known as cross-equalization is used to improve the quality of time-lapse seismic
difference volumes. The goal of cross-equalization is to reduce the effect of acquisition and
processing related changes between two vintages of seismic surveys so that physical changes
in the subsurface can be analyzed. Helgerud et al. (2011) shows the importance of cross-
equalization and gives a benchmark NRMS value of 0.2-0.3 for highly repeatable seismic
surveys. Moderately repeatable seismic surveys have NRMS values of 0.3-0.6. An NRMS
value of 1.4 is equivalent to two datasets of random noise. Validity of time-lapse seismic
amplitude data are typically evaluated using NRMS statistics. NRMS is defined in Equation
3.1 and is the RMS of the difference divided by the RMS of the average of input traces from
two vintages of seismic data. Equation 3.2 defines RMS operator for a time window $t_1$ to $t_2$
where $N$ is the number of samples in the time interval (Kragh and Christie, 2002).

$$NRMS = \frac{2 \ast RMS(a - b)}{RMS(a) + RMS(b)} \quad (3.1)$$

$$RMS = \sqrt{\frac{\sum_{t_1}^{t_2} x_t^2}{N}} \quad (3.2)$$

NRMS statistics give confidence that interpreted time-lapse anomalies are real and not
caused by differences in acquisition and processing. NRMS can also be used to validate
time-lapse time-shifts between two vintages of seismic surveys. After time-shifts are ap-
plied to the monitor survey the NRMS must decrease for time-shifts to be considered valid.
The magnitude of NRMS decrease after application of time-shifts varies depending on the
repeatability before time-shifts are applied. Coupled with modeled time-lapse amplitude
changes a confident interpretation of fluid movement within the reservoir interval can then
be performed. A custom workflow is developed for each pair of seismic surveys to obtain
the lowest possible NRMS value. Sections 3.2-3.4 give the workflow and results for PP and
PS surveys over Delhi Field. Interpretation of time-lapse amplitude difference volumes and
time-lapse time-shift volumes is performed in Chapters 4 and 5.

3.1 Cross-equalization of monitor 0 and monitor 1 PP data

In this section, the M0 (2008 baseline survey) and M1 (2010 monitor survey) cross-
equalization workflow and results are reported. M0 and M1 surveys are determined to
have moderate repeatability. Figure 3.1 shows an initial time-lapse difference section. The
reservoir interval is visible below 900ms, however, much of the section has coherent reflections
where no difference should be visible. To determine initial repeatability NRMS is calculated
in a sliding 200ms window for the whole volume. Figure 3.2 shows initial NRMS for M0 and
M1. Repeatability in most of the section is very poor and cross-equalization is necessary to
interpret any time-lapse changes due to CO$_2$ injection. Repeatability values just above the
reservoir level have a mean of 1.21 with a standard deviation of 0.17.

M1 was re-binned and re-gridded to match the geometry of M0. During this process,
the M0 survey was cropped to 3.5 mi$^2$ that overlaps M1. A window of 400ms to 800ms
was chosen for cross-equalization. To begin, a global average amplitude gain was applied to
the monitor survey to normalize amplitudes in the overburden. A global scalar of 3.659e-07
was applied to M1 to match the overburden amplitudes to M0. Next, a global phase shift
of 3.84 was calculated allowing a 40ms correlation shift and a correlation threshold of 0.5.
Traces with a correlation less than 0.5 in the design window were not included in the global
phase shift calculation. Next, a global average match filter combined with a zero-phase
frequency matching filter was applied. Again, a correlation threshold of 0.5 was required for
traces to be included in the global filter design. According to the Hampson-Russell Pro4D
manual the first shaping filter attempts to make a full phase, frequency, and amplitude
match between the datasets, while the second filter attempts to make a zero-phase match
from wavelets extracted from the design window. An overview of least-squares match filters
can be found in Claerbout (1985). Finally, the two volumes were cross correlated with
a 200ms sliding window allowing each trace to move up to 20ms to calculate time-varying
time-shifts throughout the volume. Next, the cross correlation volume and time-shift volume were cross-plotted. A density map for the cross plot was produced and a filter was designed to include time-shifts with high cross correlation coefficients in high density areas. This filter included most time-shifts between -5ms and 5ms and correlation coefficients greater than 0.5. Finally, these time-shifts were applied to M1. Previous RCP researchers continued cross equalization beyond this step with trace by trace amplitude gains and shaping filters. These steps were skipped for this work, as they do not appear to preserve amplitudes within the reservoir interval, even though they improve repeatability in the design window.

After cross-equalization a final time-lapse difference section was calculated to determine time-lapse repeatability. Figure 3.3 shows the final time-lapse difference section after the cross-equalization workflow. A negative time-lapse anomaly is visible around well 148-2. The final difference section is a considerable improvement over Figure 3.1. To quantify the improvement an NRMS volume is calculated using a sliding 200ms window for the whole volume. Figure 3.4 shows the final NRMS for M0 to M1. Repeatability in most of the section is improved from the initial section. To further quantify the improvement in repeatability NRMS values are extracted at the overburden horizon and a histogram of NRMS values is calculated. Figure 3.5 and Figure 3.6 show the time-slice and NRMS histogram. Repeatability values at the overburden horizon after cross-equalization have improved to a mean of 0.54 with a standard deviation of 0.16. Previous RCP researchers reported mean NRMS values of 0.21 (Frigerio, 2011) and 0.27 (Robinson, 2012). Higher repeatability was achieved in both cases by the use of trace by trace shaping filters, which was not employed here.

Cross-equalization has improved repeatability between M0 and M1. Even with improvement the final difference section still has only moderate repeatability. Time-lapse changes can be interpreted, however, some care must be used to ensure time-lapse differences are not caused by errors in acquisition and processing during the interpretation workflow.
Figure 3.1: Initial time-lapse difference section. Although the reservoir interval is clearly visible below 900ms the rest of the section has coherent reflectors where no difference should be visible.
Figure 3.2: Initial NRMS section. Repeatability through most of the section is very poor. Cross-equalization is necessary to interpret any time-lapse changes.
Figure 3.3: Final time-lapse difference section. A negative time-lapse anomaly is visible around well 148-2. The final difference section is a considerable improvement over Figure 3.1. Shallow time-lapse differences are due to low fold in the near surface. These will have no effect on time-lapse analysis in the reservoir.
Figure 3.4: Final NRMS section. Repeatability through most of the section is improved, however, there are still some areas of moderate to poor repeatability. High NRMS values in the near surface are due to low fold. Low repeatability in the near surface will have no effect on time-lapse analysis in the reservoir.
Figure 3.5: Final NRMS values at the overburden horizon. Repeatability in the cross-equalization window is improved.
Figure 3.6: Final NRMS histogram. Repeatability values have a mean of 0.54 and standard deviation of 0.12.
3.2 Cross-equalization of monitor 1 and monitor 2 PP data

In this section the M1 and M2 cross-equalization workflow and results are reported. M1 and M2 surveys are determined to have excellent repeatability. Figure 3.7 shows an initial time-lapse difference section. The reservoir interval is visible below 900ms. The rest of the section is mostly devoid of time-lapse differences. To determine initial repeatability NRMS is calculated in a sliding 200ms window for the whole volume. Figure 3.8 shows initial NRMS for M1 and M2. Repeatability in most of the section is very good. Repeatability values just above the reservoir level have a mean of 0.24 with a standard deviation of 0.12.

A window of 400ms to 800ms was chosen for cross-equalization. To begin, a global average amplitude gain was applied to the monitor survey to normalize amplitudes in the overburden. A 200ms running average amplitude gain was applied to M2 to match the overburden amplitudes to M1. Next, a global phase shift of -0.976 was calculated allowing a 40ms correlation shift and a correlation threshold of 0.5. Traces with a correlation less than 0.5 in the design window were not included in the global phase shift calculation. Next, a global average match filter combined with a zero-phase frequency matching filter were applied. An overview of least-squares match filters can be found in Claerbout (1985). Again, a correlation threshold of 0.5 was required for traces to be included in the global filter design. Finally, the two volumes were cross correlated with a 200ms sliding window allowing each trace to move up to 20ms to calculate time-varying time-shifts throughout the volume. Next, the cross correlation volume and time-shift volumes were cross-plotted. A density map for the cross-plot was produced and a filter was designed to include time-shifts with high cross correlation coefficients in high density areas. This filter included most time-shifts between -3ms and 3ms and correlation coefficients greater than 0.5. Finally, these time-shifts were applied to M2.

After cross-equalization a final time-lapse difference section was calculated to determine time-lapse repeatability. Figure 3.9 shows the final time-lapse difference section after the cross-equalization workflow. A time-lapse anomaly is visible around well 158-2. The final
difference section is a considerable improvement over Figure 3.7. To quantify the improvement an NRMS volume is calculated using a sliding 200ms window for the whole volume. Figure 3.10 shows the final NRMS for M1 to M2. Repeatability in most of the section is improved from the initial section. To further quantify the improvement in repeatability NRMS values are extracted at the overburden horizon and a histogram of NRMS values is calculated. Figure 3.11 and Figure 3.12 show the time-slice and NRMS histogram. Repeatability values after cross-equalization have improved to a mean of 0.19 with a standard deviation of 0.09.

Cross-equalization has improved repeatability between M1 and M2. After cross-equalization time-lapse repeatability is excellent. Time-lapse changes can be confidently interpreted.

Figure 3.7: Initial time-lapse difference section. The reservoir interval is visible below 900ms.
Figure 3.8: Initial NRMS section. Repeatability through most of the section can be considered moderately repeatable.
Figure 3.9: Final time-lapse difference section. Time-lapse anomalies are visible within the reservoir section below 900ms. The final difference section is an improvement over Figure 3.7. Shallow time-lapse differences are due to low fold in the near surface. These will have no effect on time-lapse analysis in the reservoir.
Figure 3.10: Final NRMS section. Repeatability through most of the section is improved, and can be considered excellent after cross-equalization. Low fold causes high NRMS values in the near surface. Low repeatability in the near surface will not effect interpretation at the reservoir.
Figure 3.11: Final NRMS slice at the overburden horizon. Repeatability in the cross-equalization window is improved.
Figure 3.12: Final NRMS histogram. Repeatability values have a mean of 0.19 and standard deviation of 0.09.
3.3 Cross-equalization of monitor 1 and monitor 2 PS data

In this section the M1 and M2 cross-equalization workflow and results are reported. M1 and M2 surveys are determined to have excellent repeatability for PS radial surveys. An initial time-lapse difference section was calculated to determine time-lapse repeatability. Figure 3.13 shows the initial time-lapse difference section. The reservoir interval is below 1800ms. The section has some time-lapse differences, but other than below the reservoir the section is relatively quiet. To determine initial repeatability NRMS is calculated in a sliding 400ms window for the whole volume. Figure 3.14 shows initial NRMS for M1 and M2. Repeatability in most of the section is good. Repeatability values just above the reservoir have a mean of 0.27 with a standard deviation of 0.07.

Cross-equalization of the PS data follows a similar workflow as PP data, but with different choices in parameters. A window of 1000ms to 1600ms was chosen for cross-equalization. To reduce noise a 5-10-30-35 Hz band pass filter was applied to both M1 and M2. Next, a global phase shift of 0.60 was applied. Traces with a correlation coefficient less than 0.5 in the design were not included in design of the phase shift operator. Next, a global average match filter combined with a zero phase frequency matching filter were applied. An overview of least-squares match filters can be found in Claerbout (1985). Again, the correlation threshold of 0.5 was required for traces to be included in the global filter design. Finally, the two volumes were cross correlated with a 400ms sliding window allowing each trace to move up to 40ms to calculate time-varying time-shifts throughout the volume. Next, the cross correlation volume and time-shift volumes were cross-plotted. A density map for the cross plot was produced and a filter was designed to include time-shifts with high cross correlation coefficients in high density areas. This filter included most time-shifts between -10ms and 10ms and correlation coefficients greater than 0.5. Finally, these time-shifts were applied to M2.

After cross-equalization a final time-lapse difference section was calculated to determine time-lapse repeatability. Figure 3.15 shows the final time-lapse difference section after the
cross-equalization workflow. The final difference section is an improvement over Figure 3.13. To quantify the improvement, an NRMS volume is calculated using a sliding 400ms window for the whole volume. Figure 3.16 shows the final NRMS for M1 to M2. Repeatability in most of the section is improved from the initial section. To further quantify the improvement in repeatability NRMS values are extracted at the overburden horizon and a histogram of NRMS values is calculated. Figure 3.17 and Figure 3.18 show the time-slice and NRMS histogram. Repeatability values after cross-equalization have improved to a mean of 0.23 with a standard deviation of 0.08.

Cross-equalization has improved repeatability between M1 and M2 for PS radial data. After cross-equalization time-lapse repeatability is excellent. Time-lapse changes can be interpreted.

Figure 3.13: Initial time-lapse difference section. The reservoir interval is visible below 1700ms.
Figure 3.14: Initial NRMS section. Repeatability through most of the section can be considered good.
Figure 3.15: Final time-lapse difference section. The final difference section is an improvement over Figure 3.13. Time alignment and NRMS have both improved significantly.
Figure 3.16: Final NRMS section. Repeatability through most of the section is improved, and can be considered good after cross-equalization.
Figure 3.17: Final NRMS slice at the overburden horizon. Repeatability in the cross-equalization window is improved.
Figure 3.18: Final NRMS histogram. Repeatability values have a mean of 0.23 and standard deviation of 0.08.
In this chapter time-lapse changes in seismic amplitude are evaluated and interpreted. Well logs are tied to seismic data, and interpretations of CO$_2$ anomalies are made for PP and PS seismic data. The following section uses the sign convention that impedance decreases are indicated by troughs (colored red) and impedance increases are indicated by peaks (colored blue). All time-lapse amplitude difference volumes are viewed as quadrature phase, a 90 degree phase rotation from zero phase data, so that anomalies caused by fluid movement are occurring within the reservoir interval rather than at reservoir boundaries. Negative amplitude anomalies indicate CO$_2$ saturation in PP data and reservoir pressure increase in PS data.

### 4.1 Seismic to well log tie

In this section methodology for well to seismic ties is reviewed. Wells are tied to seismic data using two wells in Delhi Field with P-wave and S-wave velocity logs. An example well tie for each pair of surveys analyzed is given below. Well to seismic ties are performed by creating synthetic PP and PS seismograms from P-wave velocity, S-wave velocity, and density well logs. Synthetic seismograms are calculated by convolving a wavelet extracted from the seismic data with a reflectivity series calculated from well logs. Equation 4.1 gives the formula to calculate a synthetic seismogram (S) from a wavelet (W) and a reflectivity series (R). For PS data Hampson-Russell software was used to create an elastic synthetic seismogram. The software assumes a 1D isotropic earth model and solves the elastic wave equation to generate full P, S, and converted wave fields.

\[
S = W \ast R
\] (4.1)
Next, synthetic seismograms are tied to actual seismic data. The quality of the well to seismic tie is evaluated using cross-correlation. Finally, top reservoir, base reservoir, and a horizon above the reservoir, henceforth indicated as the “overburden” horizon located above the Midway Shale, are interpreted on PP and PS seismic data.

A PP synthetic seismogram was calculated and a well to seismic tie was performed at well 140-1 for M0. After performing a well to seismic tie the synthetic seismogram was correlated to the actual seismic data, and a value of 0.63 was calculated for a window the length of the well log. A correlation value of 0.63 between synthetic and actual seismic data allows interpretation of top reservoir, base reservoir, and overburden horizons. Figure 4.1 shows the well to seismic tie at well 140-1.

![Figure 4.1: PP synthetic seismogram and well to seismic tie for M0. The blue traces are the generated synthetic seismogram, the red traces are an extracted trace at the well location and the black traces are seismic data near the well.](image)

Next, a PP synthetic seismogram was calculated and a well to seismic tie was performed at well 140-1 for M1. After performing a well to seismic tie the synthetic seismogram was
correlated to the actual seismic data and a value of 0.73 was calculated for a window the length of the well log. A correlation value of 0.73 between synthetic and actual seismic data allows interpretation of top reservoir, base reservoir, and overburden horizons. Figure 4.2 shows the well to seismic tie at well 140-1.

![Figure 4.2: PP synthetic seismogram and well to seismic tie for M1. The blue traces are the generated synthetic seismogram, the red traces are an extracted trace at the well location and the black traces are seismic data near the well.](image)

Finally, a PS synthetic seismogram was calculated and a well to seismic tie was performed at well 140-1 for M1. After performing a well to seismic tie the synthetic seismogram was correlated to the actual seismic data and a value of 0.80 was calculated for a window the length of the well log. A correlation value of 0.80 between synthetic and actual seismic data allows interpretation of top reservoir, base reservoir, and overburden horizons. Figure 4.3 shows the well to seismic tie at well 140-1. Comparisons of Figure 4.2 and Figure 4.3 illustrate differences in expressions of PP and PS seismic data on synthetic sections due to fundamentally different impedances.
Figure 4.3: PS synthetic seismogram and well to seismic tie for M1. The blue traces are the generated synthetic seismogram, the red traces are an extracted trace at the well location and the black traces are seismic data near the well.
4.2 Analysis of monitor 0 and monitor 1 PP data

In this section a time-lapse interpretation between M0 and M1 is made. The horizons “top reservoir” and “overburden” shown in all figures correspond to geologic horizons picked in Section 4.1. Robinson (2012) performed a similar analysis on the same data. Figure 4.4 shows a typical time-lapse amplitude difference through CO$_2$ injector well 140-1. The overburden and top reservoir horizons are displayed for reference. The negative anomalies below the top of the reservoir show areas where CO$_2$ injection has caused impedance decrease. A map view of negative anomalies shows CO$_2$ near injection wells (Figure 4.5). Robinson (2012) also interpreted CO$_2$ injection anomalies near Tuscaloosa injector 149-1. An inline section through injector 149-1 is shown in Figure 4.6. A CO$_2$ anomaly can be interpreted near injector 149-1 indicating that some CO$_2$ sweep has occurred in the Tuscaloosa Formation, however, the lateral extent of reservoir sweep in the Tuscaloosa is much smaller than the Paluxy Formation. No amplitude anomaly near injector 123-1 was observed in this work (previously reported by Robinson (2012)).

4.3 Analysis of monitor 1 and monitor 2 PP data

In this section a time-lapse interpretation is made between M1 and M2. The horizons “top reservoir” and “overburden” shown in all figures correspond to geologic horizons picked in Section 4.1. CO$_2$ movement is analyzed using injection data and cross-equalized seismic difference volumes. Figure 4.7 shows a typical inline through CO$_2$ injector well 140-1. The overburden and top reservoir horizons are displayed for reference. The negative anomalies below the top of the reservoir show areas where CO$_2$ injection has caused impedance decrease. Up-dip of injector 140-1 there is a gap between the injector and the negative anomaly caused by CO$_2$. This gap in amplitude difference between the injector and CO$_2$ anomaly is due to low sensitivity to seismic velocity after initial injection of CO$_2$. Figure 2.3 shows that P-wave velocity is sensitive to CO$_2$ saturation until 20 percent of the pore space has been saturated. Velocity changes are negligible after 20 percent saturation has been reached.
Figure 4.4: Example of the time-lapse amplitude difference section around CO₂ injector 140-1. The black arrow shows an impedance decrease anomaly within the reservoir interval around the CO₂ injector.
Figure 4.5: Time-lapse difference amplitudes extracted along Base Paluxy. Impedance decreases are evident near CO$_2$ injectors marked by red triangles.
Figure 4.6: Time-lapse amplitude difference at Tuscaloosa injector well 149-1. The solid black arrow marks the amplitude difference caused by CO$_2$ injection into the Tuscaloosa Formation. The dashed arrow marks CO$_2$ injected into the Paluxy Formation accumulating near the pinch out.
M2-M1 amplitude anomalies will only show areas where CO₂ saturation has increased from 0 to 20 percent. Zones that reached CO₂ saturations of 20 percent before M1 was acquired will appear as if no CO₂ has swept that portion of the reservoir when interpreting M2-M1 differences. However, these areas correspond to time-lapse amplitude differences that were present between M0 and M1.

Figure 4.8 shows a map view of extracted amplitudes for the Paluxy Formation. Map view of amplitudes in the Paluxy Formation shows CO₂ is moving away from injector wells and into un-swept rock volume. Black arrows in Figure 4.8 represent areas where CO₂ has swept between M1 and M2. In general, CO₂ injected into the Paluxy Formation appears to be effectively sweeping the reservoir interval, however, CO₂ is not staying in the reservoir interval at injector 160-1. An inline view of injector 160-1 shown in Figure 4.9. Amplitude differences can be seen from base reservoir to top reservoir horizons. CO₂ is leaking out of the Paluxy and into the Tuscaloosa Formation above. Ideally, CO₂ would stay in the Paluxy Formation. However, at injector 160-1 CO₂ is leaking out of zone and traveling upwards toward the top of the reservoir. CO₂ could be escaping due to interconnected reservoir sands near injector 160-1 or a poor casing cement job.

Injector wells into the Tuscaloosa Formation also appear to be operating inefficiently. Robinson (2012) interpreted time-lapse anomalies near injector wells 123-1 and 149-1 between M0 and M1. However, between M1 and M2 no amplitude anomalies are present near injectors 123-1 and 149-1 indicating that CO₂ has not continued to sweep the Tuscaloosa Formation. An arbitrary line through injectors 123-1 and 149-1 (Figure 4.10) show no amplitude anomalies near the injection wells indicating additional CO₂ sweep has not occurred in the Tuscaloosa Formation since M1 was acquired.

4.4 Analysis of monitor 1 and monitor 2 PS data

In this section a time-lapse interpretation of PS amplitudes is made. The horizons “top reservoir” and “overburden” shown in all figures correspond to geologic horizons picked in Section 4.1. Modeling in Chapter 2 showed that P-wave seismic data are mostly sensitive
Figure 4.7: M2-M1 time-lapse amplitude difference near injector 140-1. Solid black arrows point to areas of new CO$_2$ saturation. The dashed arrow points to an area previously swept by CO$_2$. Green horizons mark the overburden and top reservoir horizons.
Figure 4.8: M2-M1 time-lapse amplitude difference map view. The dashed arrows point to examples of an areas previously swept by CO$_2$. Solid black arrows point to areas of new CO$_2$ saturation.
Figure 4.9: M2-M1 time-lapse amplitude difference near injector 160-1. CO₂ can be seen leaking out of the Paluxy Formation. The black arrow points toward CO₂ escaping toward the top of the reservoir interval.
Figure 4.10: An arbitrary line for M2-M1 time-lapse amplitude through injector wells 123-1 and 149-1. No CO$_2$ anomalies are present in the Tuscaloosa Formation near the injector wells indicating no new CO$_2$ sweep has occurred since M1 was acquired.
to saturation changes while S-wave seismic data are mostly sensitive to pressure changes. Carvajal (2013) presents a rock physics model to analyze PS time-lapse anomalies for fluid saturation and pressure changes. In this thesis, time-lapse PS amplitude differences are interpreted to give support to overburden time-lapse time-shift observations for PS data in Chapter 5. Areas in the reservoir zone that contain amplitude changes are likely to correlate to changes in pressure and fluid saturation which will give insight into where changes in PS time-shifts may occur in the overburden. Troughs in the difference amplitudes show pressure increases.

Figure 4.11 shows an amplitude difference section through injector well 160-1. The PS amplitude difference begins away from injector 160-1 near the pinch out indicating that pressure is increasing in the reservoir interval, but away from injector well 160-1. Pressure data at injector 160-1 shows no pressure increase near the injection well. Amplitude differences are also observed near injector 160-1 very near the injector (Figure 4.9) for PP data, however they do not travel up toward the pinch out. Rather, PP differences show CO₂ escaping upward into the Tuscaloosa Formation. Combining interpretations of both PP and PS amplitude difference shows areas where pressure change is likely occurring. Figure 4.12 shows a map view of PS amplitude changes below the top reservoir horizon. Areas with strong negative anomalies are indicated by dashed circles and correspond to increases in reservoir pressure. Injection wells near the reservoir pinch out show negative amplitude anomalies. These wells have corresponding increases in pressure of 10 percent. Robinson (2012) and Ramdani (2012) indicated a potential baffle to flow just north of injector 160-1. Unexpected CO₂ and pressure changes near injector 160-1 are likely due to facies changes just north of the injection well.

Positive time-shifts near injectors (Chapter 5) should be observed in the overburden for both PP and PS time-lapse seismic data in areas where Figure 4.12 shows increase in reservoir pressure. Specifically, time-shifts should be observed in the overburden near all injectors, but particularly near the reservoir pinch out.
Figure 4.11: PS amplitude difference section through injector well 160-1. The black arrow indicates amplitude differences caused by pressure increases. Amplitude differences start away from the injector near the pinch out indicating that reservoir pressure is increasing away from injector 160-1. Reference Figure 4.9 for changes due to CO$_2$ saturation increase near injector 160-1.
Figure 4.12: Map view of mean PS amplitude changes in a window 300 ms below the top reservoir horizon. A large window is used to ensure amplitude changes in the thickest portion of the reservoir interval are captured. Negative amplitude anomalies are indicated by dashed circles and correspond to CO\textsubscript{2} saturation and reservoir pressure changes. Reference Figure 4.8 for comparison to PP seismic data. The black arrow indicates a zone of low quality reservoir identified by Robinson (2012) and Ramdani (2012). Pressure increase anomalies occur near the pinch out due to pressure build up.
CHAPTER 5
TIME-LAPSE TIME-SHIFT ANALYSIS

In this chapter time-lapse time-shifts are analyzed and interpreted for PP and PS seismic data. PP and PS travel-times are converted into SS travel-times using a horizon based approximation for stacked data of the PP+PS=SS method (Grechka and Tsvankin, 2002). The dilation factor calculated in Chapter 2 is applied to time-shift data to quantify strain in the overburden for PP and reconstructed SS travel-time changes. In this thesis positive time-shifts, which are colored blue, represent compaction and velocity increase.

5.1 Overview of time-lapse time-shifts

Time-lapse time-shifts are valuable attributes for mapping fluid and pressure changes within reservoirs. A number of authors have also related time-lapse time-shifts to dilation and compaction of reservoir and overburden layers (Hatchell and Bourne, 2005; Herwanger and Horne, 2005; Herwanger and Koutsabeloulis, 2011; Landro and Stammeijer, 2004; Rickett et al., 2007; Roste, 2007; Zwartjes et al., 2008). Landro and Stammeijer (2004) proposed the relation between time-lapse time-shifts calculated from zero offset seismic data to velocity and thickness changes of a layer (Equation 5.1). Equation 5.1 has been modified from its original form derived by Landro and Stammeijer (2004) due to the fact that time-shifts computed in this thesis are the correction applied to the monitor survey. Fuck et al. (2009) describes the theory for prestack travel-time shifts around compacting layers.

\[
\frac{\Delta t}{t} = \frac{\Delta z}{z} + \frac{\Delta v}{v} \tag{5.1}
\]

Hatchell and Bourne (2005) and Roste (2007) extended Equation 5.1 to relate travel-time changes of pure modes (PP or SS seismic data) to vertical strain (\(\epsilon_{zz}\)) through Equation 5.2.

\[
\frac{\Delta t}{t} = (1 + \alpha)\epsilon_{zz} \tag{5.2}
\]
In Delhi Field, two way travel-times are known for PP and PS seismic data \((t_{pp1}, t_{pp2}, t_{ps1}, \text{ and } t_{ps2})\) for a horizon in the overburden. Relative change in PP travel-time, also known as time-strain \((\Delta t)\), can be given as Equation 5.3 (Hatchell and Bourne, 2005; Landro and Stammeijer, 2004; Rickett et al., 2007; Roste, 2007). PS data are difficult to work with due to asymmetric moveout, low amplitude near zero offset, and reflection point dispersal (Tsvankin and Grechka, 2011). Time-shifts for PS data need to be converted to SS travel-time to avoid difficulties associated with PS seismic data. SS travel-time for zero offset seismic data can be calculated using a horizon based approximation of the PP + PS = SS method (Grechka and Tsvankin, 2002). The horizon based approximation for SS travel-time changes is given in Equation 5.4. Relative change in SS travel-time can then be approximated as Equation 5.5 where \(\Delta t_{ps}\) and \(\Delta t_{pp}\) are calculated time-shifts at a known horizon.

\[
\frac{\Delta t_{pp}}{t_{pp1}} = \frac{t_{pp2} - t_{pp1}}{t_{pp1}} \tag{5.3}
\]

\[
t_{ss} = 2t_{ps} - t_{pp} \tag{5.4}
\]

\[
\frac{\Delta t_{ss}}{t_{ss1}} = \frac{2\Delta t_{ps} - \Delta t_{pp}}{t_{ss1}} \tag{5.5}
\]

Vertical strain \((\epsilon_{zz})\) can be estimated from PP and reconstructed SS seismic travel-times using Equations 5.6 and 5.7.

\[
\epsilon_{zz,p} = \frac{\Delta t_{pp}}{t_{pp1}} \frac{1}{1 + \alpha_p} \tag{5.6}
\]

\[
\epsilon_{zz,s} = \frac{\Delta t_{ss}}{t_{ss1}} \frac{1}{1 + \alpha_s} \tag{5.7}
\]

Values of vertical strain calculated from time-lapse seismic data can be directly compared to strain values calculated using geomechanical reservoir simulation modeling currently in progress for Delhi Field.

5.2 Analysis of monitor 0 and monitor 1 PP data

In this section, time-lapse time-shifts are analyzed and time-strain \((\Delta t [\text{unitless}])\) is calculated and interpreted for M0 and M1. The horizons “top reservoir” and “overburden” shown
in all figures correspond to geologic horizons picked in Section 4.1. As part of the cross-
equalization of M0 and M1 datasets, time-varying time-shifts were calculated and applied
to M1 using a 1D cross-correlation method. Horizon based time-strain above the reser-
voir is calculated by extracting the time-shifts along the overburden horizon divided by the
travel-time of the overburden horizon (see Equation 5.3).

Figure 5.1 shows a vertical section through calculated time-shifts near injector well 140-1.
Due to injection related pressure increases within the reservoir time-shifts are positive in the
shale interval above the reservoir and increasing in magnitude toward the top of the reservoir
as a result of compaction. Modeling work in Chapter 2 showed time-shifts are expected to
decrease 5ms due to pressure and CO$_2$ saturation changes within the reservoir. A 4.7ms
time-shift decrease from the top of the reservoir to below the Paluxy is observed.

Figure 5.2 shows a map view of time-shifts in the overburden. CO$_2$ injection wells are
marked by red triangles. Reservoir pressures in the eastern portion of the seismic survey
increase approximately 40 percent (700-1000 psi) between M0 and M1. Positive time-shifts
in the eastern portion of the seismic survey are larger in magnitude due to the large change
in reservoir pressure. Injection in the western portion of the survey was not ramped up until
after M1 was acquired. Time-strain is calculated by dividing time-shifts at the overburden
horizon by two way travel-time of the overburden horizon. A map view of time-strain for
the overburden horizon is shown in Figure 5.3. Time-strain changes up to 1.5 percent in
the overburden correspond to areas with 40 percent increase in reservoir pressure. Vertical
strain is calculated and analyzed in Section 5.5.

5.3 Analysis of monitor 1 and monitor 2 PP data

In this section time-lapse time-shifts are analyzed and time-strain ($\Delta t$) is calculated and
interpreted for M1 and M2. The horizons “top reservoir” and “overburden” shown in all
figures correspond to geologic horizons picked in Section 4.1. As part of the cross-equalization
of M1 and M2 data time-varying time-shifts were calculated and applied to M2 using a 1D
cross-correlation method. Horizon based time-strain above the reservoir is calculated by
Figure 5.1: A vertical crossline section through time-shifts near injector well 140-1 marked by the red triangle. Reservoir pressure increase due to CO$_2$ injection cause positive time-shifts in the overburden which increase in magnitude near the top of the reservoir. Time-shifts within the reservoir and below the injector decrease due to pressure and CO$_2$ saturation changes. Modeled values of time-shifts in Chapter 2 match observed values.
Figure 5.2: Map view of overburden time-shifts. Red triangles mark locations of CO$_2$ injection wells. Time-shifts in the overburden correspond to 40 percent (700-1000 psi) increase in reservoir pressure in the eastern portion of the survey. Injection in the western portion of the survey was not ramped up until after M1 was acquired.
Figure 5.3: Map view of overburden time-strain. Red triangles mark locations of CO$_2$ injection wells. Time-strain in the overburden correspond to 40 percent (700-1000 psi) increase in reservoir pressure in the eastern portion of the survey. Values are computed using Equation 5.3
extracting the time-shifts along the overburden horizon divided by the travel-time of the overburden horizon (see Equation 5.3).

Figure 5.4 shows a vertical section through calculated time-shifts near injector well 140-1. Due to injection related pressure increases within the reservoir time-shifts are positive in the shale interval above the reservoir. Shales are chosen for this analysis because the lithology is constant and they are more likely to compact. A 2ms time-shift decrease from the top of the reservoir to below the Paluxy is observed.

Figure 5.5 shows a map view of time-shifts in the overburden. CO₂ injection wells are marked by red triangles. Reservoir pressure in the western portion of the seismic survey increased between 0 and 10 percent (200-250 psi) between M1 and M2. Positive time-shifts are observed near injection wells, but are relatively small in magnitude compared to M1-M0 time-shifts. Time-strain is calculated by dividing time-shifts at the overburden horizon by two way travel-time of the overburden horizon. A map view of time-strain for the overburden horizon is shown in Figure 5.6. Black arrows indicate positive time-strain between M2 and M1. Reservoir pressure increase near injection wells between M1 and M2 is small compared to reservoir pressure changes between M0 and M1. At injection well 164-3, where the largest time-strain values for M2-M1 occur, reservoir pressure increased 10 percent (200-250 psi). Corresponding time-strain is 0.1 percent, which is 15 times smaller than the maximum strain between M0 and M1.

5.4 Analysis of monitor 1 and monitor 2 PS data

In this section time-lapse time-shifts are analyzed and time-strain (\(\Delta t_t\)) is calculated and interpreted for PS data. The horizons “top reservoir” and “overburden” shown in all figures correspond to geologic horizons picked in Section 4.1. A previous case study by Zwartjes et al. (2008) also analyzes PS time-shifts and compares them to PP time-shifts at Valhall Field. As part of the cross-equalization of M1 and M2 datasets time-varying time-shifts were calculated and applied to M1 using a 1D cross-correlation method. Horizon based SS time-strain above the reservoir is calculated by applying Equation 5.6.
Figure 5.4: A vertical section through M2-M1 PP time-shifts near injector well 140-1 marked by the red triangle. Reservoir pressure increase due to CO$_2$ injection cause positive time-shifts in the overburden which increase in magnitude near the top of the reservoir. Time-shifts decrease below the injection well due to pressure and CO$_2$ saturation increases. Modeled values of time-shifts in Chapter 2 match observed values.
Figure 5.5: Map view of the overburden horizon M2-M1 PP time-shifts. Red triangles mark locations of CO$_2$ injection wells. Black arrows point toward areas of positive time-shifts at the overburden horizon. The dashed circle corresponds to a zone of low quality reservoir (Ramdani, 2012; Robinson, 2012). Time-shifts above 0.25 ms are within the detectable range.
Figure 5.6: Map view of the overburden horizon M2-M1 PP time-strain. Red triangles mark locations of CO₂ injection wells. Black arrows point to areas with compaction and velocity increase at the overburden horizon. The dashed circle corresponds to a zone of low quality reservoir (Ramdani, 2012; Robinson, 2012).
Figure 5.7 shows an inline section through the calculated time-shifts near injector 160-1. Due to injection related pressure increases within the reservoir time-shifts are positive in the Midway Shale and increase toward the top of the reservoir as a result of compaction. Shear velocity is sensitive to shear modulus and time-shifts in converted wave data indicate areas of potential shear strain near injection wells. Modeling work in Chapter 2 showed time-shifts are expected to decrease at most 8 ms due to pressure and CO$_2$ saturation changes within the reservoir. A time-shift decrease of less than 6 ms from the top of the reservoir to below the Paluxy is observed.

Figure 5.8 shows a map view of PS time-shifts in the overburden. CO$_2$ injection wells are marked by red triangles. Reservoir pressure in the western portion of the seismic survey increased approximately 10 percent (200-250 psi) between M1 and M2. Time-strain for reconstructed SS data was calculated using Equation 5.5. Figure 5.9 shows a map view of time-strain at the overburden horizon. Time-strain for reconstructed SS data between M1 and M2 is twice as large as time-strain calculated from PP data.

5.5 Quantification of strain change

Time-strain is a valuable attribute to interpret where reservoirs or overburden layers compact. Vertical strain data are required to constrain geomechanical reservoir simulation results and to understand how pressure increases at Delhi Field affect overburden layers. Time-strain attributes couple velocity and strain together. Strain and velocity are related through the parameter $\alpha$. Strain is derived from PP and reconstructed SS time-strain attributes using Equations 5.6 and 5.7. Possible values of $\alpha$ are given in Table 5.1 by evaluating $\alpha$ for the normalized standard error range of the best fit regression of Delhi velocity-porosity data. The porosity of the overburden horizon is determined through well log analysis.

Time-strain for M0 to M1 is converted to the best estimate of vertical strain using $\alpha_p$. Figure 5.10 gives a map view of vertical strain for the overburden horizon. Values in the eastern portion of the field, where reservoir pressure increased 40 percent, reach a maximum of 0.8 percent vertical strain change. Strain is calculated for $\alpha_p$, $\alpha_p-$, and $\alpha_p+$ to give a
Figure 5.7: An inline section through PS time-shifts near injector well 160-1 marked by the red triangle. Reservoir pressure increase due to CO$_2$ injection cause positive time-shifts in the overburden which increase in magnitude near the top of the reservoir. Work by Guan (2012) showed changes to formation strength should be expected near injection wells. Black arrows point to areas of potential shear strain near injection well 160-1. Time-shifts within the reservoir and below the injector decrease due to pressure and CO$_2$ saturation changes. Modeled values of time-shifts in chapter 2 match observed values.
Figure 5.8: Map view of the overburden horizon M2-M1 PS time-shifts. Red triangles mark locations of CO$_2$ injection wells. Time-shifts in the overburden correspond to 10 percent (200-250 psi) increase in reservoir pressure in the western portion of the survey. Injection in the western portion of the survey area was not ramped up until after M1 was acquired.

Table 5.1: Range of $\alpha$ for P and S-waves. Plus and minus indicate the ends of reasonable values of $\alpha$.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
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<tbody>
<tr>
<td>$\alpha_{p,-}$</td>
<td>1</td>
</tr>
<tr>
<td>$\alpha_p$</td>
<td>1.1</td>
</tr>
<tr>
<td>$\alpha_{p,+}$</td>
<td>1.25</td>
</tr>
<tr>
<td>$\alpha_{s,-}$</td>
<td>1.2</td>
</tr>
<tr>
<td>$\alpha_s$</td>
<td>1.4</td>
</tr>
<tr>
<td>$\alpha_{s,+}$</td>
<td>1.7</td>
</tr>
</tbody>
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Figure 5.9: Map view of overburden M2-M1 reconstructed SS time-strain. Red triangles mark locations of CO$_2$ injection wells. Black arrows point to areas with compaction and velocity increase at the overburden horizon.
range of possibility to strain estimates. Maximum strain change between M0 and M1 could range between 0.74-0.84 percent. Strain values measured in the laboratory for similar rocks by Plona and Cook (1995) show a match to strain estimates derived from Delhi seismic data for similar pressure changes.

Figure 5.10: Map view of the overburden horizon M1-M0 vertical strain from PP data. Strain values were determined using the best fit $\alpha$. Strain values on the eastern portion of the field reach 0.8 percent. Strain values must be interpreted using caution due to the lower than ideal repeatability between M0 and M1. Black arrows point to strain values where repeatability is low (Figure 3.5) and should be interpreted with caution.

Time-strains from M1 to M2 for PP and reconstructed SS data are converted to the best estimate of vertical strain using $\alpha_p$ and $\alpha_s$. Figure 5.11 gives a map view of vertical strain
estimated from PP and reconstructed SS data at the overburden horizon.

PP data shows vertical strain near the injection wells and in between injection wells in the western portion of the field where reservoir pressure increased by 10 percent. The magnitude of vertical strain for the best fit value of \( \alpha_p \) reach 0.047 percent. Strain is calculated using a range of \( \alpha \) given in Table 5.1. Maximum estimated vertical strain between M1 and M2 for PP data could range between 0.045 and 0.05 percent. No strain is calculated in the eastern portion of the reservoir between injection wells. This area underwent considerable change between M0 and M1. Also, Ramdani (2012) and Robinson (2012) indicated that the area missing a compaction response on PP data corresponds to a zone of poor reservoir quality in the Paluxy. This area is not expected to be swept with CO\(_2\) and is considered a barrier to flow in Delhi Field. Finally, strain above reservoir stop just north of injection wells where the reservoir pinches out. No significant compaction response is seen between M1 and M2 north of the reservoir pinch out.

Reconstructed SS data shows strain between injection wells in the western portion of the reservoir. However, the magnitude of reconstructed SS estimated strain as well as the pattern of strain is different than PP strain estimates. The magnitude of strain for the best fit values of \( \alpha_s \) reach 0.075 percent. Maximum estimated vertical strain between M1 and M2 for reconstructed SS data could range between 0.065 and 0.081 percent. Maximum strain ranges for PP and reconstructed SS data do not overlap. However, analysis of time-shifts show that a 0.25 ms error in time-shift estimation in PS data could lead to differences of 0.015 percent in vertical strain estimation for reconstructed SS data. An error in well to seismic tie or the lower repeatability of PS time-lapse data could lead to 0.25 ms errors in time-shifts at the overburden horizon. Although the maximum values of vertical strain do not overlap most of the vertical strain values predicted by reconstructed SS data fall within the maximum range predicted by PP data. Figure 5.12 shows a histogram comparison of strain values in PP and reconstructed SS data for the best fit \( \alpha \).
Although the magnitude differences of strain estimated from PP and reconstructed SS data can be explained by errors in time-shift estimation and $\alpha$, this does not explain the difference in time-shift distribution. Reconstructed SS data show strain in between injection wells, while PP data show strain directly above injection wells. Comparison of time-shifts from PP and PS radial data by one other author shows a similar response (Zwartjes et al., 2008). Future work is needed to determine why the time-shift responses of PP and PS radial data are different.

Figure 5.13 gives a comparison of reconstructed SS strain to time-lapse PS amplitudes in the reservoir and time-shifts below the reservoir interval. Both the PS time-lapse amplitudes and PS time-lapse time-shifts are representative of areas of pressure change within the reservoir.

Overall time-lapse time-shifts calculated from PP seismic data prove to be robust attribute to monitor reservoir pressure increases at Delhi Field and the resulting overburden compaction. Strain estimated from PP and reconstructed SS time-shifts show different a different pattern of strain in the overburden layers. Future work is necessary to determine why PS radial data does not predict the same vertical strain pattern as PP data.
Figure 5.11: Map view of overburden M2-M1 vertical strain. The top figure is PP strain estimates while the bottom figure is SS strain estimates. Maps were generated using the best fit $\alpha$. The magnitude of predicted strain from PP data is different that that of SS data.
Figure 5.12: Histograms of overburden M2-M1 vertical strain. The top figure is PP strain estimates while the bottom figure is reconstructed SS strain estimates. The difference in magnitude of strain estimated from PP and reconstructed SS data is evident when comparing histograms of vertical strain calculated at the overburden horizon.
Figure 5.13: A comparison of A) PS time-lapse amplitudes within the reservoir, B) PS time-shifts below the reservoir, and C) vertical strain above the reservoir from reconstructed SS data. Negative amplitude anomalies within the reservoir and negative time-shifts below the reservoir are both indicative of pressure increase. Strain above the reservoir agrees with expected locations of reservoir pressure increase in PS data. Strain at the overburden horizon and time-shifts below the reservoir correspond to ramp up of CO$_2$ injection in the western portion of the field after M1 was acquired. The proximity to the reservoir and lithology of the layer both contribute to the response to reservoir pressure increases.
CHAPTER 6
CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

From this study the following conclusions are drawn:

- Reservoir pressure increases at Delhi Field during the first two years of CO$_2$ injection cause overburden compaction.

- Maximum vertical strain between M0 and M1 is calculated to be 0.8 percent with a possible range of 0.74 to 0.84 percent. Maximum vertical strain between M1 and M2 for PP data is calculated to be 0.047 percent with a possible range of 0.045 to 0.05 percent. Maximum vertical strain between M1 and M2 for reconstructed SS data is calculated to be 0.075 percent with a possible range of 0.065 and 0.081 percent.

- Strain estimated from PP and PS seismic data shows a different pattern and magnitude of strain in the overburden interval. The differences in magnitude of strain estimated from PP and PS data can be accounted for through errors in time-shift estimation and $\alpha$. However, the differences in the pattern of strain estimated from PP and PS seismic data can not be accounted for.

- A combined interpretation of PS amplitude analysis within the reservoir, PS time-shift analysis below the reservoir, and strain analysis in the overburden are consistent with one another.

- PS amplitude differences show pressure increase near the reservoir pinch out.

- Gassmann fluid substitution predicted -2.5 ms time-shifts through the reservoir interval due to CO$_2$ replacing brine for PP seismic data. Time-shifts due to pressure increase from CO$_2$ injection in the reservoir interval for PP data are predicted to be -2.3 ms.
Measured time-shifts between M0 and M1 decrease 4.7 ms and are consistent with model predictions of pressure increase and \( CO_2 \) replacing brine.

- SS time-shifts are predicted to increase 0.8 ms due to \( CO_2 \) replacing brine and decrease 8.3 ms due to pressure increase from \( CO_2 \) injection. PS time-shifts decrease by as much as 6 ms below the reservoir, which is consistent with modeling.

- Fluid substitution modeling predicts little change in velocity after 20 percent \( CO_2 \) has been injected into the reservoir. Field observations of time-lapse amplitude changes between M1 and M2 in Chapter 4 show little to no change in amplitude where \( CO_2 \) was observed between M0 and M1.

- Cross-equalization improves time-lapse repeatability in all surveys. Repeatability between M0 and M1 is moderate and repeatability between M1 and M2 is excellent for PP seismic data and good for PS seismic data. Time-lapse acquisition and processing significantly improved repeatability between M1 and M2.

- PP seismic amplitude differences show \( CO_2 \) near injection wells between M0 and M1.

- Between M1 and M2 \( CO_2 \) moves farther into the reservoir and continues to sweep the Paluxy Formation. PP amplitudes are also reduced where \( CO_2 \) was observed between M0 and M1.

- Tuscaloosa injectors 123-1 and 149-1 have not continued to sweep the Tuscaloosa Formation.

- PP amplitude analysis at Paluxy injector 160-1 shows \( CO_2 \) escaping the Paluxy Formation and traveling upward toward the reservoir seal.

- Modeled time-shifts below the reservoir for both PP and PS seismic data are consistent with measured data.
6.2 Recommendations

Time-lapse amplitude analysis shows CO\textsubscript{2} escaping at injection well 160-1. I recommend that Denbury Resources temporarily halt injection and check the cement job through the reservoir interval using a cement bond log. If the CO\textsubscript{2} leak at injector 160-1 is not due to faulty cement the injection well may need to be moved in order to effectively sweep the Paluxy Formation. Another alternative is to produce from both Paluxy and Tuscaloosa reservoirs near injector well 160-1. CO\textsubscript{2} injection should continue to be monitored in all parts of Delhi Field to optimize sweep and identify problems in injection patterns. Furthermore, areas with faulting near injection wells should be monitored carefully due to strain above the reservoir. Roste (2007) showed faults can reactivate due to changes in strain. Pressure increases at Delhi Field show compaction and shear anomalies in the overburden. These changes could reactivate faults above injection wells and provide a pathway for CO\textsubscript{2} to leak into the overburden.

I also recommend six paths of further study beyond the work completed in this thesis: (1) 3D estimation of shifts in seismic images, (2) shear wave splitting analysis to understand overburden strain, (3) study of offset dependent strain estimated from PP and PS seismic data, (4) application of the exact PP+PS = SS method to estimate SS strain, (5) spatial calculation of $\alpha$, and (6) development of a geomechanical reservoir simulation model. The remainder of this section details the previous six recommendations.

Recent publications have presented methods to estimate shifts not only in the vertical direction, but also in the horizontal planes (Hale, 2009, 2012). Horizontal displacement from these methods should be studied to potentially characterize three dimensions of strain (and velocity) changes rather than just vertical strain change.

I recommend the use of shear wave splitting analysis to better understand overburden strain at Delhi Field. Shear wave splitting is a tool used to measure the degree of anisotropy within a geologic layer. Anisotropy can be caused by preferred orientation of mineral grains, thin bedding of isotropic layers, fractures, or nonhydrostatic stress (Tsvankin, 2005). Recent
case studies have shown that shear wave splitting can occur due to stress changes related to compaction (Bale et al., 2013; Davis et al., 2013; Herwanger and Horne, 2005; Herwanger and Koutsabeloulis, 2011; O’Brien, 2012). In particular, Herwanger and Horne (2005) and Herwanger and Koutsabeloulis (2011) show that shear wave splitting correlates to compaction related stress changes. Their analysis at Valhall Field shows that shear wave splitting should be expected near the edges of compaction bowls where vertical strain is minimal. Previous Delhi Field researchers have performed shear wave splitting analysis on overburden layers above CO₂ injectors (Couzens, 2012; Davis et al., 2013; O’Brien, 2012). Figure 6.1 shows a comparison of shear wave splitting magnitude and vertical strain. Areas where shear wave splitting magnitude is large correspond to areas of computed vertical strain. Future works may be able to use shear wave splitting and vertical strain estimated from PP data to understand shear strain present above reservoir. A study should be undertaken to understand how stress induced shear wave splitting can further our knowledge of compaction near reservoirs. The use of both three-dimensional time-shifts and shear wave splitting has the potential to lead to an understanding of not only vertical strain, but also shear strain.

I also recommend that the offset dependence of time-shifts for PP and PS data be studied further. One difference between the travel-times from PP seismic data and reconstructed SS travel-times is that reconstructed SS travel-times do not cover the same offset range as PP travel-times. Tsvankin and Grechka (2011) show that reconstructed SS travel-times from PP and PS data are limited by the critical angle of the mode converted shear wave ($\theta_{S,\text{critical}}$). Equation 6.1 gives the critical angle of the mode converted S wave in terms of Vp/Vs ratio. An example of PP offset range and PS offset range for a single horizontal layer is shown in Figure 6.2. In Delhi Field, converted reflections from top reservoir are limited to angles of 22 degrees or less. Reconstructed SS time-strain values do not contain time-shift information from offset angles greater than $\theta_{S,\text{critical}}$. Studies on offset dependence of time-shifts (Chu et al., 2011; Fuck et al., 2009; Herwanger and Koutsabeloulis, 2011) show time-shifts decrease with offset. Therefore, reconstructed SS data could be more sensitive to compaction than
Figure 6.1: Shear wave splitting magnitude (PS1/PS2) above the reservoir at Delhi Field (Couzens, 2012) compared to vertical strain above the reservoir. The black arrows point to areas where shear wave splitting magnitudes are large and the corresponding areas of strain estimated from PS data. In future works shear wave splitting in the overburden may help delineate vertical strain from shear strain.
full offset PP data. I recommend that angle stacks for near and far offsets are created. Then, the workflow presented in this thesis can be followed to study offset dependence of vertical strain estimation. Comparisons of near offset PP data strain estimates to reconstructed SS strain estimates should be made.

\[
\Theta_{S,\text{critical}} = \sin^{-1} \frac{V_s}{V_p}
\]  

(6.1)

In this thesis a poststack approximation of the PP+PS = SS method was used to reconstruct SS time-lapse time-shifts. Further work should be done using the exact PP+PS = SS
method.

I consider $\alpha$ to be constant in the overburden due to limited measurements of velocity and porosity in wellbores. To estimate $\alpha$ with spatial confidence from well logs would require extensive velocity-porosity logging. I propose that further work be done to calculate $\alpha$ spatially to give a better estimate of strain. An inversion for porosity in the overburden should be converted into a cube of $\alpha$.

I recommend that a reservoir simulation study of strain at Delhi Field be completed. A simple wedge model could be used to study the strains that occur due to pressure increase at Delhi Field. A representative model could give important insight into three dimensional strain in the overburden and could also give insight into how the underburden should change due to CO$_2$ injection. Strain in the overburden could be used to calibrate geomechanical models and evaluate the risks of fault slipping and wellbore damage due to CO$_2$ injection. Drilling and injection operations could then be altered to avoid areas with high risk for CO$_2$ escaping or wellbore damage.

Finally, multicomponent seismic opens up a new direction for monitoring changes related to hydraulic fracturing of unconventional resources. Steinhoff (2013) showed shear wave splitting analysis could effectively monitor hydraulic fractures. Understanding the distribution of induced fractures, and the geomechanical changes related to hydraulic fracturing provide a future direction of research in unconventional reservoir characterization.
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