4D SIMULTANEOUS PP-PS PRESTACK INVERSION: THE EDVARD GRIEG FIELD, NORWEGIAN NORTH SEA

by

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ABSTRACT

The Edvard Grieg oil field was discovered in 2007 in the Norwegian North Sea and is operated by Lundin Energy Norway. The field is in the production stage. Production began in November 2015, and water injection began in July 2016. The oil bearing reservoir lies in a half graben in Haugaland High, composed of multi-source sediment accumulation bounded by unconformities as most of deposition occurred subareally. The early Cretaceous to late Triassic reservoir is composed of aeolian sands, fluvial sands, alluvial conglomerates, and shallow marine sands, all capped by a regionally extensive unit of chalk. Reservoir characterization challenges arise from the depositional complexity of the field and detailed analysis must be done to plan for future production. In the oil and gas industry, detailed analysis and inversion is typically done using PP seismic data. In this project, I work to evaluate the benefits of PS data to better characterize the reservoir heterogeneity and understand the effects of production and injection by performing simultaneous PP-PS prestack time-lapse inversion.

My analysis begins with theoretical expectations of the PS dataset from a rock physics approach and analysis of the raw seismic and well data. The input PS data has significant signal loss from sand injectites directly above the reservoir, where PP data showed no signal loss, resulting in the PS reservoir interval to contain a 9Hz peak frequency when registered to PP time. Given this information, the expectation of the PS data was to only marginally improve model estimates.

Synthetic work was done to assess inversion performance and controlling parameters. Findings show if only PP waves were used for inversion, large offsets would be needed for a partially successful S-impedance inversion, which is not available in the Edvard Grieg survey, due to a maximum 34° incidence angle. This idea is reflected in the prestack PP inversion results for the field data. The prestack PP inversion produces the best estimate
for P-impedance, a large improvement from post-stack inversion, however, the resulting S-impedance estimate simply follows the background relationship with the P-impedance term. By performing joint PP-PS inversion, we greatly improve the S-impedance estimates to further characterize the reservoir heterogeneity using $V_P/V_S$.

The seismic data is shot in two vintages, 2016 and 2018, with time-lapse purposes in mind, leading to excellent repeatability (11% NRMS for PP data, 24% NRMS for PS data). Theoretically, the P-impedance estimate is influenced by fluid and pressure changes, while the S-impedance estimate is chiefly influenced by pressure. This discrepancy can be used to separate these two effects in locations where overlap and interference occurs. The inversion results showed that with limited offsets, the PP prestack inversion derived S-impedance change estimate provides no time-lapse interpretation benefits and simply mimics the changes in P-impedance. With PP-PS 4D inversion the S-impedance was able to capture geomechanical changes in the field and aid in the separation of the effects of saturation and pressure.

The optimal P-impedance estimate is derived from PP prestack inversion while the optimal S-impedance estimate is derived from PP-PS prestack inversion. This S-impedance is noisier due to the PS data, but is far more accurate and allowed for better identification of reservoir quality heterogeneities from impedance extractions and the generation of facies volumes. Baffles and barriers were identified in the large sand bodies and alluvial section that correlate to the 4D response.

S-impedance change is used in conjunction with P-impedance change to create saturation and pressure change maps in the reservoir. The maps are used to determine reservoir compartmentalization, monitor injected fluids, understand water drive, and identify bypass zones. The work in this thesis demonstrates the benefits of 4D joint PP-PS prestack inversion on maximizing the understanding of reservoir quality, heterogeneity, and fluid flow pathways. This information proves invaluable to industry asset teams in making drilling and reservoir management decisions.
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CHAPTER 1
INTRODUCTION

The Reservoir Characterization Project (RCP) is well known for research in multicomponent data, exploring its benefits in onshore fields from the Eagle Ford to the Vaca Muerta. This thesis applies the knowledge base from previous RCP studies to a challenging offshore environment in the North Sea. Thus far, inversion has been performed only on the PP seismic data in the Edvard Grieg field by the operator, Lundin Norway. The objective of this project is to investigate the potential benefits of utilizing time-lapse multicomponent ocean bottom cable 4-D 4-C data for improved inversion results in Edvard Grieg, compared to the conventional pre-stack PP inversion. Improved inversion results can allow for a better understanding of the static and dynamic model of the subsurface. This chapter gives an introduction to inversion theory and an overview of the North Sea Project data and geology.

1.1 Seismic Inversion

The overall goal of a geophysicist is to best represent the geology of the subsurface using data. It is important to recognize not only the geologic features associated with hydrocarbon migration and entrapment, but also the static and dynamic characteristics of the reservoir (Chopra & Marfurt, 2005). Parameters used to identify the structure and architecture of the reservoir include, but are not limited to, depth, thickness, faults, facies heterogeneity, porosity, permeability, and fluid flow. Well logs provide this information but in a very sparse 1D sampling. Therefore, we use various attributes derived from seismic to estimate the reservoir properties of interest. Seismic data shows us the interface property of reflectivity, the contrast between rock properties of velocity and density. In order to gather more information from reflectivity, geophysicists have leaned to the seismic process of inversion.
Inversion is the technique of extracting, from seismic data, the underlying physical earth parameters which gave rise to that seismic. This process utilizes the interface property of reflectivity to produce an interface property of the rock units. In order to perform the model based inversion discussed in this thesis, there must be three inputs, the initial model, the wavelet, and the seismic data. Ultimately, the result from inversion is a nonunique solution for certain rock properties, which is why much care and analysis needs to be done in the process. The following section gives the theory behind this process and the parameters at play.

1.1.1 Convolutional Model and Poststack Acoustic Impedance Inversion

The backbone of seismic inversion is based on the convolutional model. The convolutional model is forward modeling, meaning the inputs are the earth model and wavelet, the output is the seismic data. In this model, the seismic trace time series equals the convolution of the seismic wavelet with the reflectivity series of the earth plus noise. Written as

\[ s(t) = r(t) \ast w(t) + n(t), \]  

(1.1)

where \( s(t) \) is the seismic trace, \( r(t) \) is the reflectivity series, \( w(t) \) is the equivalent wavelet, \( n(t) \) is noise, and \( \ast \) represents convolution. The assumption of the wavelet in this case is that there is a single time-invariant stationary wavelet, however, in reality wavelets are both time-varying and complex in shape (Russell, 1988). The noise component is a combination of random noise and coherent noise, where coherent noise is the culprit of many processing steps. Reflectivity is the interface property of the layering of the earth, determined by the contrast in velocity and density. In the simplest case, for pure-mode zero-offset reflections, the reflection coefficient is

\[ r(t) = \frac{V_2 \rho_2 - V_1 \rho_1}{V_2 \rho_2 + V_1 \rho_1}, \]  

(1.2)

where \( V \) is velocity, \( \rho \) is density and the subscript represents the layer, where for a simple downgoing wave, layer 2 is below layer 1. The product of velocity and density is impedance
(Z), thus, reflectivity is the impedance contrast between beds. Figure 1.1 provides a visual representation of the convolutional model.

![Figure 1.1 Steps in convolutional model to create noise-free synthetic seismic. Impedance equally sampled in depth is converted to reflectivity equally sampled in time. The reflection coefficient time series is then convolved with the seismic wavelet estimate to produce the synthetic seismic trace (Image courtesy of Arcis Seismic Solutions, TGS, Calgary).]

From the convolutional model, we establish the relationship that is used in post-stack recursive or direct inversion. Theoretically, we see that given a wavelet and the seismic data we can extract a model of the reflectivity, and thus a model of the relative acoustic impedance. However, direct inversion assumes noise-free data and that the seismic wavelet is known and exact (Goupillaud, 1961; Robinson, 1975). The wavelet is deconvolved from the data and the deconvolved data are time integrated to produce relative impedance estimates. Because of these assumptions, the recursive inversion technique can be severely affected by noise, poor amplitude recovery, and the band limited nature of the seismic data. Any problems in the data itself will be in the final inversion result (Lindseth, 1979; Russell, 1988). This is why for my studies I will be performing model-based inversion.

In model-based inversion, the process begins with building a geologic model and using a forward-modeling operator to iteratively adjust the initial impedance model to achieve the best fit between observed and predicted data (Cooke & Schneider, 1983). The basic workflow for this inversion technique is shown in Figure 1.2. Here we start with the seismic
data, a wavelet, and an initial impedance estimate from a low frequency background model. The low frequency background model is built from log data to give absolute values for the inversion’s initial guess and final estimate, this is necessary because the inversion is relative and therefore needs a starting point. Each iteration updates the impedance model using a Generalized Linear Inversion (GLI) framework with a minimization criterion (Keys & Weglein, 1983). The user can selectively weight the data misfit (Least-Mean-Squared-Error (LMSE) $l_2$ norm), and the model reasonableness (Daves, 2018). Model reasonableness is a manual user input and an interpretive judgement. It is implemented through the use of the model-covariance matrix (Tarantola, 2005). This model-covariance matrix constrains deviations from the current model at each iteration, but can also incorporate relative weights between each model parameter.

In model-based inversion for post-stack data we are inverting for acoustic impedance, as we don’t have a relationship with angle or offset. Moving from post-stack data to pre-stack data we introduce more noise, but we are also able to estimate more parameters. This is simultaneous amplitude versus angle (AVA) pre-stack inversion, a form of inversion that inverts for multiple rock parameters simultaneously. In the case of the Hampson Russell model-based pre-stack inversion used for this analysis, the outputs are absolute P-impedance, S-impedance, and density. The actual parameters inverted for, and the implications thereof, are discussed in detail in Chapter 3. These parameters open the door to estimate a number of other valuable rock properties.

1.1.2 AVO/AVA Prestack Inversion

Till now we have discussed the inversion of normal incidence seismic traces, but for prestack data we are dealing with reflections recorded over a range of incident (reflected) angles. These additional data cause the inversion to be more complex, but also results in more information about the subsurface. When a seismic wave is initiated at a given point, it propagates through the medium and at each interface generates reflected and transmitted P- and S-waves. The conversion between the compressional and shear wave is called a mode
Figure 1.2 Model-based inversion workflow in Hampson Russell. This simplified flow demonstrates the iterative process in the model-based inversion. Given a low-frequency background impedance model and a seismic wavelet estimate, the impedance model is then iteratively updated such that the observed seismic data are reproduced. Note the low-frequency model convolved with the wavelet produces no reflections. Therefore, the first iteration of data is actually the data misfit. Modified from Russell (1988).

There are four potential derived waves shown in Figure 1.3, the reflected P-wave, transmitted/refracted P-wave, reflected S-wave, and transmitted/refracted S-wave.

The reflected and transmitted angles for an incident wave striking at angle $\theta$ are described by the generalized Snells law,

$$ p = \frac{\sin \theta_i}{V_i} = \frac{\sin \theta_R}{V_i} = \frac{\sin \theta_T}{V_i}, $$

(1.3)

with variable $p$ as the ray parameter or horizontal slowness term. In this case, the velocity, $V_i$ can be P-velocity or S-velocity, and $\theta$ can be P-wave angle or S-wave angle. This term is conserved throughout the ray path through reflection, refraction, and mode conversion. For reflections at a given depth, rays are bent away from the vertical with increasing source-
receiver offset. Additionally, the larger the velocity contrast between layers, the more the transmitted ray path bends away from the vertical. If the velocity contrast is large enough the incident angle will become critical, meaning the refracted wave travels along the interface between the two media. Important assumptions break down at post-critical angles, therefore, these angle ranges should not be used for reflection seismic analysis (Chopra & Castagna, 2007).

With pre-stack data we can observe amplitude variation with angle (AVA) that provides valuable information on lithology and fluid. A fundamental principal of fluid and facies detection using AVA analysis is the concept that anomalous contrasts in Vp/Vs or the Poissons ratio on either side of the surface, result in anomalous partitioning of energy as a
function of angle of incidence (Chopra & Castagna, 2007). Therefore variation of AVA can be correlated to rock properties like Poissons ratio, described in the isotropic case by the formula,

\[
\sigma = \frac{(V_p/V_s)^2 - 2}{2[(V_p/V_s)^2 - 1]}.
\]

(1.4)

Poisson’s ratio is a measure of transverse strain to axial strain, which is related to Vp/Vs. The larger the contrast between the Vp/Vs ratio between mediums, the larger the AVA response (Koefoed, 1955). Accurate Vp/Vs is of great interest to exploration geoscientists as it is can indicate fluid presence, rock type, and underlying rock properties (Nanda, 2016; Tatham, 1982).

AVA information for inversion purposes is very useful as it allows for the estimation of additional model parameters beyond just P-impedance. With increasing angle, S-impedance and density begin to contribute to the amplitude of seismic reflections. Amplitudes of reflected and transmitted plane waves at planar boundaries of two elastic media are defined for all incident angles by the Zoeppritz equations (Zoeppritz, 1919). These equations govern the partitioning of energy in the various wave modes seen in Figure 1.3. Due to the difficulty in solving the equations, many linearized approximations have been made (Fatti et al., 1994; Shuey, 1985; Smith & Gidlow, 1987; Wiggins et al., 1983), the Aki and Richards approximation being most popular (Aki & Richards, 1980). This approximation defines that the PP reflection coefficients (R) in seismic data can be generated by a combination of the fractional changes in elastic properties across an interface shown in Equation 1.5. These inverted properties are \(\Delta V_p\), change in P-wave velocity; \(\Delta V_s\), change in S-wave velocity; and \(\Delta \rho\), change in density.

\[
R_{PP}(\theta) \approx \frac{1}{2} \left(1 - 4\left(\frac{V_s}{V_p}\right)^2 \sin^2 \theta \right) \frac{\Delta \rho}{\rho} + \frac{1}{2 \cos^2 \theta} \frac{\Delta V_p}{V_p} - 4\left(\frac{V_s}{V_p}\right)^2 \sin^2 \theta \frac{\Delta V_s}{V_s}
\]

(1.5)

Because the impact of each parameter changes with angle, \(\theta\), we can use pre-stack data to estimate the combination of parameters that best fits the angle-dependent reflection coefficients. At smaller incident angles, such as the zero offset reflection, the contribution of
P-wave dominates the approximation and there is no influence from S-wave. At larger angles around $\theta=30^\circ$ we begin to get impact from the S-wave term. Farther angles are needed for recovery of the density term, at $\theta=45^\circ$ the estimation is still not robust (Castagna & Backus, 1993; Rosa, 1976). Because the S-wave and density terms do not contribute to the amplitude of the plane wave till far angles, estimating these parameters from limited angle range is difficult when looking at one mode PP data. Density is the most unreliable parameter in PP AVA inversion. PS AVA is advocated to better constrain density since the PS AVA linearized approximation involves only S-wave and density.

1.1.3 Multicomponent Joint Prestack Inversion

In order to improve inversion model parameter estimates, multiple modes can be inverted. Body waves have three modes, consisting of compressional P-waves, and two polarizations of shear waves, SV-waves, and SH-waves. These waves have different propagation directions and particle motion. Compressional wave particle motion direction is parallel to the propagation direction, while SV-wave particle motion is in the vertical-radial plane as shown in Figure 1.3. Seismic reflection data can be a combination of these, PP, PS, SS, and SP, the first letter denoting the downgoing wave, the second letter denoting the upgoing wave. In our study, we are working with PP and PS data, shown in Figure 1.4.

![Figure 1.4 Schematic diagram of P-wave reflection (PP) data. Propagation direction noted in blue, particle motion noted in red. Source marked by *, receiver marked by v. Modified from Spikes (2017).](image-url)
Conventional quantitative interpretation is done using single component PP data. This is for multiple reasons. PP data typically has the highest resolution and signal to noise. Using PP data we are able to adequately invert for P-Impedance which is the rock property focused on by many interpreters. However, the relationship between the rock properties and fluids in P-wave seismic data is nonunique (Veire & Landrø, 2006). Consequently, there can be large uncertainties in the inversion results from P-wave data alone.

Acquiring multicomponent data in offshore settings can be costly compared to PP streamer acquisition. Even processing multicomponent data poses a huge challenge, particularly related to the S-wave velocity estimation and shear wave statics, which is why S-wave interpretation is not common (Veire & Landrø, 2006). In many of the cases that PS data is recorded, it is not considered for processing or interpretation due to the challenges mentioned above. However, recent improvements in S-impedance inversion and analysis (Duffaut et al., 2000), have shown that the benefits of improved reservoir characterization may outweigh the costs of acquisition and processing of S-wave data. PP data and PS data have different propagation directions as shown in Figure 1.4, and highlight different features in the data (Aki & Richards, 1980). Because S-waves do not propagate in fluids, the combined use of P-wave data and S-wave data might improve our ability to characterize fluid response from lithology effects. This can be used to our advantage in quantitative interpretation to improve the 3D static model and the dynamic reservoir model.

This project looks into simultaneous inversion of PP and PS pre-stack seismic data. In this inversion, the PS data must be registered to PP time using a workflow described in Chapter 5, then a modified version of Fatti’s linearized approximation is used to invert for P-impedance, and deviations in S-impedance and density (Fatti et al., 1994; Hampson et al., 2005). This is described in more detail in Chapter 3. RCP Phase XVI work showed the improvement in inversion results using simultaneous inversion including PS field data for S-impedance in an unconventional reservoir (Copley, 2018). My work aims to analyze the benefit of utilizing PS data in joint 4D inversion on a complex offshore dataset for better
understanding reservoir geometry, heterogeneity, and response to production and injection.

1.2 Time Lapse

Time lapse seismic data can illuminate pore pressure and saturation changes. This information can allow the identification of permeability pathways, flow barriers and baffles, bypassed reservoir, overpressure zones, compaction, and expansion in the field. In order to understand how changes in elastic properties correspond to rock physics parameters, we establish a rock physics model based on well data.

There are multiple requirements in the seismic data to allow for interpretation and correlation to our rock physics model. For the 4D seismic surveys, adequate time between seismic surveys must be allotted to allow for dispersion of the fluid. Along with time being an important component for observing a time lapse response, so is repeatability. Repeatability is simply a measure of the similarity between the baseline and monitor survey. This is vital as we are focusing on differences with time from baseline to monitor, thus the interpretable differences should only be caused by the development of the field, not due to differences in the seismic acquisition or processing. Perfect repeatability is unattainable, a level of noise will exist between surveys due to multiple factors including but not limited to seismic interference, tidal effects, shot generated noise, and ambient noise (Johnston, 2013). The level of repeatability is measured in NRMS, which measures the noise level between surveys and sets an expectation of what amplitude 4D changes we can resolve in the seismic. With this analysis we can begin to understand how the reservoir is behaving dynamically.

1.2.1 Dynamic Effects

As fields undergo production and injection, there are a magnitude of changes in that occur both in the reservoir and the overburden. In general, pressure and saturation are both changing in areas of production and injection, this is why it is important to understand what part of the change is due to pressure versus saturation. In the case of hydrocarbon production, there are changes in pressure, saturation, and temperature. As the reservoir is
being depleted, the pore pressure in the reservoir decreases and over time there is often a saturation change from hydrocarbon to water. If the pore pressure drops to bubble point then the process of gas exsolution begins. Pressure depletion in the reservoir increases the load on the rock matrix resulting in compaction. In most cases the level of compaction is negligible, but with large enough pressure drop or in highly compressible reservoir rock compaction may be significant (Toomey et al., 2017). As the reservoir pulls away from the surface of the earth, the overburden expands in response, causing stress arching, notable in the North Sea and the Gulf of Mexico (Keszthelyi et al., 2016; Toomey et al., 2017).

In the case of water injection, we see the opposite set of responses. The injector causes saturation change, pore pressure increase, and expansion of the reservoir, and potentially a responding compaction or compression in the overburden. In this scenario again we have a combination of effects. These are just two of the many potential scenarios in a developing field, but in both scenarios the pressure changes and saturation changes destructively interfere. Meaning if there was solely a pressure or saturation change, we would see a stronger change in amplitude than when there is a combination of pressure and saturation change. This is why it is necessary to recognize and distinguish the changes as a response to pressure versus saturation change to accurately characterize our dynamic reservoir model.

1.2.2 4D Joint PP/PS Inversion

Joint 4D PP-PS inversion has been proven to be a robust tool for characterizing effects of field development. Acoustic impedance from PP data captures pressure changes and saturation changes, while an improved shear impedance from the PS data captures only pressure changes, since S-waves are considered insensitive to changes in pore fluid. Formulas for computation of pressure and saturation changes from 4D PP and PS seismic data have been derived and tested on synthetic data (Landrø et al., 2003). From synthetic tests, it is clear that PS data actually shows more sensitivity to pressure (Shahin et al., 2008). In these synthetics, pressure and saturation changes were distinguished best in amplitude and travel times, however within the impedance domain we can better understand the separation.
Using our rock physics template derived from log and core data, we can relate the elastic differences to rock properties like porosity and permeability and improve our understanding of reservoir heterogeneity. By utilizing the benefits of PS and PP data with simultaneous inversion, and highly repeatable seismic surveys, we can better characterize the reservoir statically and dynamically.

1.3 North Sea: Edvard Grieg Field

RCP introduced The North Sea project in Spring 2019 with Lundin Norway as the sponsor, providing multicomponent seismic data from 2016 and 2018 over the Edvard Grieg Field in the Norwegian North Sea. This project involves the analysis of multicomponent data in a complex field that is currently undergoing production and further development.

Figure 1.5 Edvard Grieg field study area (Halland et al., 2013; Ronnevik et al., 2017).
1.3.1 Field Background

The Edvard Grieg oil field lies in the Norwegian North Sea, about 180 km west of Stavanger in PL338 with an average water depth of 110 meters. The operator, Lundin Norway, is targeting a variable facies reservoir in a regional inverted high, the Haugaland High, which is located at the southern part of Utsira High Figure 1.5. The reservoir is situated at a depth of approximately 1,900 meters in a Triassic Age half graben. The field consists of undersaturated light oil with a GOR of around 702 scf/bbl (Runnevik et al., 2017). Today there are 10 exploration wells, 10 production/observation development wells, and 4 injection wells, totaling 24 wells seen in Figure 1.6. The exploration well penetrating the thickest reservoir, well E, hits a thick aeolian package with a 40 meter oil column. The project area was discovered in 2007 by well A, production started in November 2015, and water injection started in July 2016. In injector W-2, gas has also been injected for limited periods due to gas capacity issues. The field is estimated to have 300 MMBOE recoverable reserves with 160 MMBOE remaining reserves (Directorate, 2020). Ocean bottom cable (OBC) multicomponent surveys were shot in 2008, 2016, and 2018 for time-lapse (4D) seismic analysis. Edvard Grieg is in an active development phase as Lundin and partners in the field, OMV and Wintershall, plan to reshoot a seismic survey in 2020 to monitor the production and injection while drilling 4 more wells as injectors.

1.3.2 Data

For the project the following data are available from Lundin Norway:

- 2016 and 2018 4C Seismic Surveys
- Post-Stack and Pre-Stack PP and PS data
- 10 Exploration Well Logs
- 14 Production/Injection Wells with very limited log data
Figure 1.6 Development of Edvard Grieg showing injectors in blue and producers in green. Edvard Grieg field polygon is limited in the East, North, and South by the extent of the half graben and in the West by the oil water contact. The updip edge of the trap lies in the South-East.

- Modeling from Core Analysis

- Velocity Models for PP and PS data

Ocean bottom cable full azimuth seismic surveys were acquired by WesternGeco in 2016 and in 2018 to obtain a 4D dataset with high repeatability to use for reservoir evaluation. In this project, we will be focusing on the 2016 and 2018 surveys as the original 4C 2008 survey was acquired using orthogonal shots instead of parallel, and the majority of 4D effects from production and development began in 2016. The surveys were acquired in around 110m of water using Q-seabed OBC cable receivers with a source vessel towing two matched source arrays (Figure 1.7). Acquisition parameters are shown in Table 1.1. The
survey source-receiver geometry is shown in Figure 1.8. Overall data quality is very good. The predominate external noise type for both surveys were surface currents and seismic interference from an OBN survey in the north-west, the Grane field towards the northeast, and the Johan Sverdup platform activity in the East, however none of the lines were discarded for this seismic interference.

![Figure 1.7 2016 and 2018 seismic survey acquisition](image)

Figure 1.7 2016 and 2018 seismic survey acquisition (from Lundin Norway processing report).

<table>
<thead>
<tr>
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<th>Baseline September/October 2016</th>
<th>Monitor September/October 2018</th>
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<tr>
<td>Receiver Line Spacing (m)</td>
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<td>Source Line Spacing (m)</td>
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Table 1.1 OBC 4C seismic acquisition parameters

Both 2016 and 2018 surveys were then processed by WesternGeco, using the same workflow to permit time lapse interpretations. The processing workflow consisted of Up-/Down Deconvolution pre-processing for multiples and deghosting instead of conventional pre-processing (Ford et al., 2019). The data were split into 1248 Offset Vector Tiles (OVT) and after Kirchoff Prestack Depth Migration (KPSDM) the number of OVT was reduced to 621, the maximum fold of the data. Inline spacing is 12.5m and crossline spacing is 25m,
providing substantial data density. The 2018 monitor gathers were matched to the 2016 baseline gathers with a global scalar and frequency filtering operator derived from the stacked volumes. The PS dataset went through a similar processing workflow but is smaller in area, approximately 2km smaller in the inline direction. Using the velocity model from KPSDM, the PS is partially registered to the PP data and of high quality as seen in Figure 1.9, however, further registration steps will be taken in this project.

In addition to the geophysical datasets we have well logs and core analysis for various wells in the study. There are 9 wells with sufficient log to accurately tie to seismic time, 6 exploration, 1 production, and 2 injection wells, all containing variable quantity of sonic (P and S-wave) and density log. Core data was taken at well A, E, and F, and provide information on rock physics properties that can be used for modeling.

Figure 1.8 2016 and 2018 seismic survey geometry (from Lundin Norway)
Figure 1.9 Comparison of 2016 PP and PS seismic data. PP and PS reflections are sensitive to different factors, and by using both we may obtain more information on the fracturing and fluids. Acquisition footprint is much larger in PS. Frequency content drops significantly with depth for PS data. Shallow high amplitude anomalies are prevalent in both sections.

1.3.3 Geology

The Edvard Grieg field geology is complex both depositionally and structurally. The field is located on Haugland High, the southern part of the Utsira high which is a large basement high flanked by the Viking Graben to the West. The reservoir was deposited from the late Triassic to early Cretaceous in a half graben with an active basement fault seen in Figure 1.10 (Directorate, 2018). The reservoir is composed of multi-source sediment, bounded by unconformities as most of the deposition occurred subareally. It consists of aeolian sands, fluvial sands, alluvial sandy matrix conglomerate, alluvial silty matrix conglomerate, and shelfal sand facies (Figure 1.11). Additionally, multiple wells in the North of the field at the basement high have proven oil shows in the underlying altered/fractured granitic basement as this bedrock was subareally exposed for an extended period of time (Riber et al., 2015).
Figure 1.10 Regional seismic line running W-E through the Viking Graben and Haugaland High (Ronnevik et al., 2017). Neighboring Johan Sverdup field has similar reservoir depth but the reservoir is composed of younger Jurassic shoreface sheet sands and fan-delta deposits.

This area is heavily influenced by tectonics, particularly due to three rifting events. Firstly, in the Devonian, gravitational collapse of thickened crust and shear driven pull-apart triggered the start of an extensional regime (Coward, 1993). The tectonic stresses of this early extension are NE-SW oriented. The second and largest important tectonic event occurred in the late Permian to early Triassic rift phase. This rift system stress regime is oriented approximately perpendicular to the previous extension, reactivating Devonian age structures and creating new fault systems that cross-cut pre-existing systems (Ziegler, 1992). The Edvard Grieg field Triassic reservoir was deposited in the accommodation space created by this Early Triassic rift stage that lasted regionally in the North Sea till late Jurassic. Rapid rates of infill and subsidence ultimately decreased in the early Cretaceous as a major transgression swept through the North Sea (Ziegler, 1992). This transgression is marked in the field as the transition from Triassic sands to the Cretaceous marine sands and the Cretaceous Shetland chalk caprock. Tectonics not only influence the Edvard Grieg field deposition, but also with regards to the generation and migration of hydrocarbon. The
third major tectonic influence to the field is the Pliocene to Pleistocene tectonic inversion that formed the Haugaland high and shifted the basin axis southwest. This caused renewed petroleum migration from the late Jurassic Volgian-Valanginian Draupne source rock, migrating from the Viking graben through vertical leakage along faults and fractures in the basement to the inverted high and sealed by the Cretaceous chalk (Riber et al., 2015; Ronnevik et al., 2017). The low-maturity undersaturated oils were generated and migrated late. The filling of the inverted high traps depended on this major tectonic event (Riber et al., 2015; Ronnevik et al., 2017).

Figure 1.11 Seismic interpretation of the Edvard Grieg Field. Reservoir in the half graben includes alluvial sediment, aeolian sands, and thin seismically unresolvable marine sands capped by the Shetland Chalk unit. Note that the aeolian unit contains interbedded fluvial sediment and is interbedded in the alluvial sediment throughout the field. Alluvial packages contain fluvial sediment and high amounts of lacustrine deposits particularly at greater depths. Relatively flat reflectors can be seen beneath the chalk. These reflectors are parallel to the chalk and are peg-leg multiples, not lithology.

The alluvial fan intervals were deposited by several major floods that carried large volumes of sediment down to the paleovalley. The sandstone-dominated alluvial fan reservoir has good sorting and intergranular porosity. The predominate sandy matrix conglomerate
or pebbly sandstone has poor sorting with variable matrix lithology and is most abundant in the southern and eastern areas of the field. Alluvial sediments make up the bulk of the reservoir in Edvard Grieg but are the most variable in facies. Sediment can change from sands to sandy matrix conglomerate to tight conglomerates in close proximity, and differentiating the changes in this conglomerate reservoir quality is a challenge. The high spatial variability of this unit is shown from the well section in Figure 1.12. In certain areas of the South of the field, the alluvial sediment has high quality sands while towards the North of the graben the reservoir quality of the alluvial silty matrix sediment is actually worse than the fractured basement. Within this alluvial package there is large presence of interbedded lacustrine and fluvial sediment. The lacustrine sediment is most prevalent at greater depths in the half graben.

![Figure 1.12 Cross-section running through wells in the survey highlighting the reservoir. Velocity logs increase to the right, log area filled with color noted by colorbar. Basement rock only penetrated in well C and well G.](image)

The aeolian sandstone is approximately 6-40 meters thick, sourced from the northeast and holds approximately 50% of the Edvard Grieg oil reserves. This Triassic age aeolian sand comes from a wet system with high feldspar content from the reworking of the alluvial section. There are baffles in this clean sand formed by interdune sediment and wind ripple surfaces with relatively higher clay content identified in core. The reservoir quality is the highest in the aeolian sandstone, containing multi-Darcy permeability, 100% net to gross, and a minimum
porosity of 24% (Ronnevik et al., 2017). Overall in this unit, we observe the strongest seismic amplitude and time-lapse response. The PP amplitude response of the reservoir interval is shown in Figure 1.13, where the thin finger like east-west oriented structures are bodies of high porosity oil-bearing aeolian sand. The amplitude drop towards the downdip western side is the oil-water contact, but even past the oil water contact relatively bright amplitudes remain. This indicates very porous sands exist farther downdip, but are water bearing. The time-lapse response in areas of production and injection are much stronger in these sands because the unit is very permeable, as shown in Figure 1.14. However, the log response to the oil bearing aeolian unit is remarkably minimal with regards to gamma ray and resistivity. This is because the aeolian unit mineralogy contains a percentage of potassium feldspar which is a conductive mineral and shows high gamma ray values from the potassium measurement. The low velocity, low resistivity, high gamma ray signature of this oil bearing aeolian unit indicates a typical shale. Spectral gamma ray could be used to show the high potassium content, but log signature still did not indicate high porosity clean sands. Therefore, without the core analysis of this aeolian sediment, it was unlikely that this reservoir was to be identified as a clean sand.

Good quality fluvial sands are interbedded in the aeolian unit. These meandering streams move through the aeolian sands and rework the aeolian and alluvial sediment. The sands are spatially variable and seismically undetectable. They are observed in log and core often interbedded on the top and base of this aeolian unit, observed most abundantly in well logs B and L.

Asgard bioclastic shelfal sandstones of excellent reservoir quality are the final chief reservoir. This unit contains 28% porosity and multi Darcy permeability, but is relatively thin at 3-5 meters thickness, well below seismic resolution (Ndingwan et al., 2018). Production wells in the North of the field have targeted this thin sand unit and have extracted large amounts of oil from both the sands and the underlying fractured basement. This unit marks the start of the major transgression in the Cretaceous shifting from subaerial alluvial and
Figure 1.13 PP RMS amplitude extraction ranging from 10 ms above to 10 ms below the reservoir. Southeast being updip in the chalk caprock structure. Faults are normal faults at the reservoir interval, black box indicates hanging wall side.

Although the reservoir is our primary area of interest, it is important to understand the variations in the overburden as they may hinder the data quality in our target. The field is sealed by the Paleocene shale and the late Cretaceous Shetland chalk. The thin high velocity Shetland chalk directly overlies the reservoir and attenuates half of the energy and frequencies below. Additionally, critical reflection at the high velocity chalk occurs at 34° incidence for the downgoing P-wave. This limits the offset and angle range for velocity analysis and degrades the seismic image over the reservoir interval (Whitebread, 2018). Further definition of the spatial architecture needs to be studied to better characterize and
Thick units of Cretaceous shale interbedded with blocky sandstones overly the Shetland chalk. The Hordaland group, shown in Figure 1.11, contains two levels of very strong polygonal faulting, the shallowest level shown in Figure 1.15. This section also contains unconsolidated sands such as the Grid sands and other interbedded marine sands. When these sands experience pressure, in the presence of pathways of least resistance (along dilated polygonal faults), and with fluids flowing, sand injectites will most likely form (Cartwright et al., 2008). In the overburden of Edvard Grieg, this is very common. The most notable injectites seen in this unit are the conical cemented sands that appear as positive anomalies in the seismic for both PP seismic and PS seismic data, noted in Figure 1.11. These high velocity sands are heavily cemented due to high pressures and fluids that come from underlying units, potentially even spilloff from the reservoir at an earlier geologic time. In this same process, hydraulic elevation creates forced folds directly overlying the cemented sand bodies. These features are commonly associated with polygonal faulting as seen in the area, prevalent in the Eocene shale units of the North Sea (Hurst & Cartwright, 2007). In the deeper Horda section directly overlying the chalk there is another unit of injectites, the Grid.
sands, these are uncemented sands very prominent in the PS seismic data. It is important to identify these bodies as they act as transmission path obstacles that cause azimuthal variation, pull-up, and amplitude loss in the reservoir unit directly beneath, particularly the shallower injectites.

Figure 1.15 Time slice of variance attribute in PP data showing polygonal faulting in shallower units. Time indicated by the arrow in cross section view. Variance is a calculation of discontinuity between adjacent seismic locations. High variance can be a key indicator of faulting.

With analysis of the reservoir and overburden, it is clear that the Edvard Grieg field is highly heterogeneous and structurally complex. In order to perform the geophysical analysis on this field it is vital we have a good understanding of variations in the reservoir and potential challenges that may arise from the overburden.

1.3.4 Project Goal

In this project, we plan to use the time-lapse PS component data, in conjunction with the PP data, to better understand reservoir heterogeneity and response to production and injection. Time-lapse seismic is of strategic importance to many operators due to the value
added in extending base production, adjusting depletion plans, rejuvenating the field by targeting un-swept areas, and most importantly managing the life-of-field more effectively. After processing, PS seismic data is usually not utilized for interpretataion purposes. By using PS data directly we can get more accurate rock properties to better characterize the reservoir and how it is responding to development. Overall, the goal of this project is to evaluate the potential benefits of PS data in improving static and dynamic reservoir models by performing joint 4D PP-PS pre-stack inversion.
CHAPTER 2
DATA OBSERVATIONS

In the past, seismic surveys have utilized one component (1C) vertical geophones/hydrophones to record seismic waves. However, even in the case of compressional P-waves, the wave propagates both in the vertical and horizontal plane, so multicomponent receivers are needed to capture vertical and horizontal components of particle motion. In this project, the data is 4 component, one vertical, two orthogonal horizontal receivers, and one hydrophone. 3C geophones allows for full acquisition of PP data and PS data. This multicomponent data can prove useful in obtaining better estimates for inverted properties compared to utilizing solely PP data. Before diving into the inversion, it is important to first investigate the potential value of joint PP-PS inversion by analyzing simple PS reflectivity theory, rock physics, and seismic data quality and character.

2.1 Data Types

The reflection data we have in this project are PP data and PS data. As mentioned in Chapter 1, PP data denotes single mode P-waves, compressional downgoing and upgoing waves with particle motion parallel to propagation direction. PS data involves a P-wave, which converts to an upgoing SV-wave upon reflection. The shear upgoing wave consists of particle motion orthogonal to the propagation direction shown in Figure 2.1. Particle motion of PP and PS waves is both in the vertical and horizontal planes. Even though this occurs, the vertical receiver is used for PP seismic data and horizontal receivers are used for PS data. In the isotropic case, the shear waves are SV waves, while in the anisotropic case, shear wave splitting will occur and create SH-waves with particle motion in the horizontal plane. These S-wave modes both exhibit orthogonal propagation directions (in the isotropic media case), but with significantly different AVO behavior. In the processing for the PS dataset, the X and Y components were rotated about the Z axis to radial (SV-waves) and
transverse (SH-waves). After rotation analysis and vector fidelity applications, only radial components were carried through for final processing. Therefore, we will be focusing on SV-waves.

Figure 2.1 Schematic diagram of PP and PS reflection data. Common conversion point noting the location at depth of the reflection or mode conversion. It is important to note that if we want PP and PS data for the same offset, the PS incident P angle is larger than for PP reflection (Copley, 2018).

An important property of PS data is that there is asymmetry in the ray path. At the same common image point, the PS data has smaller offset than PP data seen in Figure 2.1. To account for this in PS surveys, acquisition is done with a conventional source but several times more recording channels. In the North Sea surveys, the same recording channels for PP data are for PS data and we can observe the gaps in data caused by sparse receiver spacing in the PS seismic data. These gaps from undersampling cause significant migration noise or “swing ups,” principally due to edge effects seen in the crossline direction. Fortunately, these data gaps do not continue into the target interval and are isolated in the shallow units. This would only be a large concern if the target was in the shallow units.
Processing PS data is typically more difficult than PP data for a magnitude of reasons, but in order to invert the data it must be properly processed for best signal to noise and resolution. The process started with a merged dataset for X and Y and the resampled output from overlapping shot removal of P and Z to generate the downgoing wavefield required for radial up/down deconvolution (Watts et al., 2016). The PS data underwent this similar up/down deconvolution (UDD) processing because it was found that UDD produced an uplift in the 4D signal along with benefits in deghosting compared to the conventional workflow (Ford et al., 2019). However, UDD produced a result with lower frequency and slightly higher signal to noise when compared to the conventional preprocessing result. Like the PP data, the PS vintages were co-processed through the same workflows to maintain 4D capabilities.

2.2 Value for Inversion

In chapter 1, we explored the Aki and Richards approximation for PP data reflectivity. The equation for PS reflectivity may allow us to better constrain the inverted properties other than P-impedance, when used in conjunction with PP data. Inverting PP data alone with a limited angle range gives a reliable estimate for P-impedance, however, S-impedance and density can potentially be improved through the use of PS data. For converted P-SV waves, the reflection coefficient variation with angle at an interface can be described by the Aki & Richards (1980) approximation,

\[ R_{PS}(\theta, \phi) \approx \frac{p V_P}{2 \cos \phi} \left[ (1 - 2 V_S^2 p^2 - 2 V_S^2 \frac{\cos \theta \cos \phi}{V_P V_S} \frac{\Delta \rho}{\rho} - 4 \frac{\Delta \rho}{\rho} - 4 V_S^2 \frac{\Delta \rho}{\rho} - 4 V_S^2 \frac{\Delta \rho}{\rho} \Delta V_S \right]. \quad (2.1) \]

Here the reflectivity is a function of two angles, \( \theta \) and \( \phi \), the incident and reflected angles respectively, corresponding to Figure 2.1. The variable \( p \) is the ray parameter defined in the previous chapter which can be written as,

\[ p = \frac{\sin \theta}{V_P} = \frac{\sin \phi}{V_S}. \quad (2.2) \]
Substituting the ray parameter and redistributing variables, equation 2.1 can be written as,

\[ R_{PS}(\theta, \phi) \approx \left( 2 \frac{V_P}{V_S} \sin^2 \phi \tan \phi - 2 \cos \theta \sin \phi \right) \frac{\Delta V_S}{V_S} + \left( -\frac{1}{2} \frac{V_P}{V_S} \tan \phi + \frac{V_P}{V_S} \sin^2 \phi \tan \phi + \cos \theta \sin \phi \right) \frac{\Delta \rho}{\rho}. \]  

(2.3)

Here we can better understand the contribution of the S-wave and density terms (\( \frac{\Delta V_S}{V_S} \), and \( \frac{\Delta \rho}{\rho} \)) to the PS reflectivity with varying angle. \( \frac{\Delta V_P}{V_P} \) does not contribute to the PS reflectivity. We can compare this equation with equation 1.5, to see at which angles we get the largest contribution of each term for both PP and PS reflectivity. Previous work has been done in this subject by RCP student Adam Tuppen and shown in Figure 2.2, where these contributions, or \( \Delta \) terms are plotted. These terms vary with \( \frac{V_P}{V_S} \) which is defined in the Aki Richards equations as the average \( \frac{V_P}{V_S} \) between the two medium at each interface (Aki & Richards, 1980). For the PP data, the zero-offset reflectivity is controlled by the P-velocity and density contrasts. At larger offsets the density term deviates from the P-velocity while the S-velocity begins to have more of an effect.

For the PS data, the S-velocity has a larger contribution to the reflectivity particularly at mid-angles compared to the S-velocity in the PP data. This suggests utilizing the PS data can provide more accurate estimations of S-velocity. The density term requires even larger angles to show significant contribution, so the PS data in inversion will most likely not improve the accuracy of this term. The larger the effect of each of these variables, the more potential there is to get an accurate estimate through inversion. However, it is important to note that the project data only includes angles up to 34°, because of the overlying high velocity Shetland chalk. Additionally, the Aki-Richards linearized approximations can become inaccurate at far angles for certain parameters. For P-waves, the Aki Richards equations are very close to the exact Zoeppritz below about 40 degrees, however for converted waves the approximation begins to deviate from the exact Zoeppritz at around 20 degrees (Haase, 2004). Another challenge we face in these estimations, particularly with the density term, is separating the
effects of each term. In many cases of PP seismic data inversion, the density term follows the trend of the P-velocity. These are all factors we must keep in mind moving forward with our expectations in the inversion process.

### 2.2.1 Rock Physics Value

Another way to test the potential benefits of utilizing PS data jointly with PP data in inversion, is to look at the well logs for rock physics analysis. This allows us to identify if an improved value for shear velocity or impedance from the incorporation of PS data, will actually help us understand the reservoir heterogeneity. For reference, the locations of the logs are shown in Figure 1.6 with the field outline.

The wells used for the majority of analysis are exploration wells A, E, and F. These wells were chosen because they show the 3 major facies of the reservoir, aeolian sands (well E), good quality alluvial sands and conglomerates (well A), and poor quality alluvial (well F). In Figure 2.3, we can observe the facies separability in the crossplot domain. The separation
between good and bad quality conglomerate is complex in that it depends on multiple variables. The conglomerate reservoir quality is dependent on both matrix composition, (sandy or silty), the presence of clays in the matrix, and the size and contacts of the clasts. The big challenge is that elastically, it is difficult to differentiate the effects of the clast size and matrix mineralogy because the clasts are often composed of the same mineralogy as the matrix. In these three wells, we can identify “good” quality versus “bad” quality based on core photos but there is still a simplification in the plot by grouping in matrix and clast size variables together. Nevertheless, by grouping the conglomerates into “good” and “bad” quality we can see that the facies are separable in the log domain using both S-impedance and P-impedance. Having an improved S-impedance can be used in conjunction with P-impedance to better constrain facies identification in the reservoir.

Figure 2.3 Crossplot of S-impedance and P-impedance using the data from wells A, E, and F. Three grey boxes denote the three main facies categories seen in Edvard Grieg. These being, (a) aeolian sands, (b) alluvial sands and good quality conglomerate, (c) poor quality conglomerate.

The rock property that is often related to reservoir quality and type is $V_P/V_S$. This can be particularly useful in separating “good” quality conglomerates from “bad” quality conglomerates, specifically from the clast size more so than the matrix mineralogy. Labo-
ratory studies suggest that pore geometry has a stronger effect on observed $V_P/V_S$ values than the elastic constants of the mineral comprising the matrix (Tatham, 1982). Using this logic, we can use variations in $V_P/V_S$ to potentially separate the variable of matrix mineralogy from clast size. By having an accurate $V_P/V_S$ estimate, we can better understand the quality of conglomerate with regards to the clast size and narrow down the distribution in the impedance domain in crossplots like Figure 2.3. There is clear separability in the impedance domains but in the $V_P/V_S$ domain for log data points, shown in Figure 2.4, the $V_P/V_S$ overlaps with facies. However, the conglomerate shows separability in $V_P/V_S$. Where we have better reservoir quality conglomerate, there is higher $V_P/V_S$. A combination of these rock properties can be used in 3D to better constrain reservoir facies spatially, and uncover mineralogy vs clast size contributions to reservoir quality in the alluvial section.

![Figure 2.4 Crossplot of Vp/Vs versus P-Impedance and Vp/Vs vs S-Impedance respectively using the data from wells A, E, and F. Circles denote the three main facies categories seen in Edvard Grieg. These being (a) aeolian sands, (b) alluvial sands and good quality conglomerate, (c) poor quality conglomerate.](image)

To establish a basis for interpretation of future inversion results, I have created a rock physics template for the Edvard Grieg field. The concept of rock physics templates was proposed by Dvorkin & Nur (1996) and Odegaard & Avseth (2003) to relate the fluid and mineralogical composition of the reservoir to $V_P/V_S$ using a crossplot. The rock physics template utilized for our purposes will be P-impedance versus $V_P/V_S$ with modeled lithology-porosity-saturation trends superimposed. Like Odegaard & Avseth (2003), Hertz-Mindlin
contact theory was applied to calculate the pressure-dependency at the high porosity and low porosity end members modified by a critical porosity reference. Gassmann’s equations were used for fluid substitution.

![Figure 2.5 Fluid substitution done on Well E for the aeolian sand. Overlain trends are various types of dry bulk modulus and cementation trends. Fluid substitution is done with in situ fluid conditions calculated using methods from FLAG in Rokdoc.](image)

To understand the effects of changing pore fluids, dry rock properties were calculated at well E and fluid substituted to calculate brine filled, oil filled, and gas filled cases in the aeolian sediment. This trend is shown in Figure 2.5. With decreasing density of the pore fluid, the $V_P/V_S$ drops, as does the P-impedance. This is the fluid trend for aeolian sands. Additionally, $V_P/V_S$ can highlight lithology. With increasing porosity, $V_P/V_S$ increases, however, a more dramatic increase in $V_P/V_S$ is caused by clay content. Pressure is also a factor as increasing pressure drops $V_P/V_S$. Clearly, this parameter can be influenced by a magnitude of factors, this is why formulating a rock physics template from the well logs and known data can help differentiate influences.

Rock physics templates used for Edvard Grieg are calculated for the aeolian sands and the alluvial sediment, shown in Figure 2.6. Each of these templates show fluid and porosity trends expected given the in situ pressure, temperature, fluid properties, and mineralogy. Two trends needed to be identified due to the large differences in mineralogy of the aeolian...
sands and conglomerates. These templates provide a "tool-box" for lithology and pore fluid interpretation of inversion results and can help reduce uncertainty in interpretation Odegaard & Avseth (2003). However, the templates are created using equations that contain many assumptions. The assumptions include, but are not limited to, matrix homogeneity, well connected pore space, pressure equilibrium, and spherical grains. Large variation lies in the geology of the Edvard Grieg reservoir, therefore, these templates should be used for guidance but not firm quantitative assessment.

Figure 2.6 Crossplot of $V_P/V_S$ versus P-impedance using well data and overlying rock physics templates for (a) aeolian sands and (b) alluvial sediment. In situ case includes 40% oil saturation. Trend nearing horizontal marks the porosity trend. Trends closer to vertical are the fluid trends for varying porosity, moving from brine to oil to gas at constant porosity with decreasing $V_P/V_S$. Points above the porosity trend are more likely to be brine filled.

We have shown that obtaining an accurate S-impedance and $V_P/V_S$ can be used to better constrain the reservoir heterogeneity when used in conjunction with P-impedance and established tools to aid inversion interpretation. The next step is to see if S-impedance can actually help more than P-impedance in separating reservoir facies. Previous work in the North Sea has established fields coined “stealth” reservoirs, meaning that the reservoir has low P-impedance but high S-impedance contrast (Rape et al., 2005). In these fields, the reservoir often appears more clearly in the PS seismic data than the PP. The Alba Field in the UK North Sea is the most prominent, and earliest example of this phenomena. In this field, there were many features that the PS data highlighted better than PP, such as the
reservoir base and top, sand discontinuities, and sand injectites (MacLeod et al., 1999). Also in the North Sea, the Balder field OBC survey showed that the S-impedance from the PS volume provided better illumination of the deeper target reservoir than the S-impedance or P-impedance derived from the PP data (Jenkinson & Bucki, 2013). In this field, a Paleocene deep water gravity flow reservoir that was best imaged in the PS seismic data, and an Eocene sand injectite reservoir best imaged in the PP seismic data. Similar findings were discovered in the Grane field in the UK North Sea, where using only one PS stack for inversion actually best characterized the reservoir as shear impedance alone could be used to discriminate the sand body (Jenkinson et al., 2010).

If the Edvard Grieg field shares comparable qualities, the PS data may actually provide more information than the PP data. To test this, we look at the log data and see if at the reservoir, the S-impedance contrast is higher than the P-impedance contrast. This would suggest that the PS data would illuminate the reservoir. In Figure 2.7 we can see that there are areas with higher contrasts in shear, but they lie above the reservoir in the Grid sands and the Shetland Chalk.

The Grid sands are Eocene age uncemented injectites formed from the marine sands prevalent in this shallow unit throughout the survey. These sands lie directly above the reservoir. They have a much stronger response in S-impedance than P-impedance, and are very high amplitude features in the PS seismic data, particularly when compared to the PP data in Figure 2.8. The Vp/Vs at this interface drops from 3 in the shales to 2 in the injectites. This shear-velocity contrast results in a larger PS reflection coefficient, due to the larger shear weight in the PS data. Because most energy is reflected at this interface, less energy is transmitted. These features attenuate the seismic energy before it hits the reservoir causing a dimmer chalk and reservoir response. According to this same theory, the logs show that the chalk should also have a stronger amplitude, neglecting noise and attenuation, in the PS data than the PP data. However, because of the large velocity contrast at the Grid sands, the chalk and reservoir reflectors are lower amplitude relative to the respective reflectors on
Figure 2.7 P and S-impedance logs from multiple wells in the field overlain with different scales to match the background shale trend of the log. Note P-impedance is not equal to S-impedance in any location, this differential scaling is a display tool to highlight where S-impedance contrast is higher than P-impedance contrast.

the PP seismic data.

Figure 2.8 Crossline 1969 running through PP and PS seismic data, highlighting the Grid sands and the aeolian reservoir unit.
2.2.2 AVA Analysis

Another component to analyze from the log and seismic data is amplitude variation with offset. The pre-stack seismic data contains AVO which can provide more information for inversion purposes but also be used for interpretation. The background AVO trend of PP seismic data is a decreasing amplitude with offset, while the trend for PS seismic data is increasing amplitude with offset. Deviations from the background trend come from the AVO characteristics of the lithology or fluids which can be shown and modeled with log data.

AVO is dependent on elastic reflectivity and the Poisson’s ratio. The larger the contrast in Poisson’s ratio between units at an interface, the more AVO we should observe. Poisson’s ratio is a function of $V_P/V_S$, so we can look at contrasts in $V_P/V_S$ from log data to understand the effect expected in AVO. In the log shown in Figure 2.9, there is no apparent jump in $V_P/V_S$ at the top of the reservoir, the oil water contact, or the base of the aeolian section.

Figure 2.9 Well log E, showing the thickest aeolian unit drilled by an exploration well in Edvard Grieg.
The lower part of the Shetland group chalk is the Tor chalk with very high velocity. This chalk has an average $V_P/V_S$ of about 1.8 as does the reservoir and the conglomerate section below. This is why the AVO at the reservoir is actually class 4, meaning a low impedance event with slightly decreasing AVO for PP seismic data (Castagna & Swan, 1997). For PS seismic data we see a low impedance event with increasing AVO similar to the background trend. There is not enough change in $V_P/V_S$ to cause an anomalous AVO. This is confirmed with synthetic modeling on multiple wells in Chapter 3. Because the AVO is not strong in this reservoir, in depth AVO analysis will most likely prove insignificant for interpretation purposes.

From this well log scale analysis, we have observed potential benefits and shortcomings of the seismic data caused by the particular geology of the Edvard Grieg field. We can expect that an improved shear impedance from the PS data will aid in understanding reservoir heterogeneity when used in conjunction with P-impedance. We have also identified some potential pitfalls of the PS seismic data. The amplitudes of the reservoir and caprock, the Shetland group chalk, are both diminished due to the large shear impedance response in the overlying Grid sands. Moving forward, we recognize this energy loss as a challenge in 3D reservoir characterization using the PS data and gather conditioning may be a step towards better imaging of the chalk and reservoir.

### 2.2.3 4D effects

The PP and PS seismic data vintages are from August-October 2016 and August-October 2018. Production began November 2015 and injection started July 2016. Therefore we cover almost 3 years of production and 2 years of seawater injection with intermittent gas in injector W-2. Information on the gas injection was not provided.

Thus far we have shown how shear impedance may help characterize 3D reservoir heterogeneity, now we can look to see how shear impedance can help characterize 4D reservoir response to development. To do this various scenarios expected in the Edvard Grieg field were modeled in the oil bearing aeolian reservoir at Well E, assuming an the average poros-
ity of 27%. Figure 2.10 shows four one variable changes and 4 potential scenarios seen in this field. This plot will allow us to understand how much change we would expect in the impedance domain for certain development scenarios, and which of these changes the seismic can resolve.

The center of the axis indicates virgin conditions; a temperature of 80.2 °C, pore pressure of 19.3 MPa, 24% water saturation, and 76% oil saturation. The salinity, mineralogy, GOR, API, and gas gravity were taken into account for the modeling. The matrix mineralogy bulk modulus and shear modulus were calculated using the Voight-Reuss-Hill approximation (Hill, 1952; Reuss, 1929; Voigt et al., 1928). Fluid substitution was done using Gassmann’s equations. For gas saturation, the points move from 0%, 10%, 30%, and 80% deviating from the origin. For water saturation, the points move from 0%, 40%, 70%, and 83%. The values were chosen taking into account the irreducible water saturation and clay bound water. For pore pressure variations, the values are equal magnitude opposite signs, meaning decreasing pore pressure is negative increasing pore pressure is positive. The magnitudes move from 0MPa, 2.5MPa, 5MPa, and 14MPa pore pressure change. The relationship with pressure and impedance was derived from core data, however core data was not available for shear velocity. Therefore, an approximation was made in which half of the P-velocity change associated with pressure was applied to S-velocity. Based on historical core measurements in other fields, this assumption grants a reliable approximation for pressure changes over 1 MPa (Dutta et al., 2010; Zimmer et al., 2002).

Based on this modeling, we can better understand each scenarios response in P-impedance and S-impedance. As expected, saturation change influences P-impedance more so than S-impedance, as shear modulus does not depend on fluids. The slight change in S-impedance is due to the density term. Pressure changes affect P-impedance and S-impedance equivalently. Because S-impedance has a stronger response to pressure change than saturation change, a more accurate estimation of this model parameter may allow separation between pressure and saturation changes.
Figure 2.10 Modeling done on well log E. Origin shows virgin pressure and saturation in an oil bearing aeolian section. Moving outward from the origin on each line increases pressure change and saturation change. Field scenarios shown are squares.

The modeled scenarios shown as squares in Figure 2.10 are gas exsolution, water injection, production maintaining pressure, and pressure depletion without saturation change. In the gas exsolution case, there is a conservative estimate of 5% gas coming out of solution, still dissolved in the oil, not yet free gas. In this case the gas saturation increases by 5% and the pore pressure drops by 5.5 MPa. Because this pressure drop and saturation change oppositely affect impedance, this scenario actually results in smaller changes in impedance than each one variable change occurring alone. The S-impedance change is stronger than the P-impedance change. In the water injection case, the water flood contains an 83% change in water saturation as the rest of the pore space is irreducible and 5.5MPa drop in pressure. Again the change in saturation and pressure work destructively and the resulting change
in the impedances is lower, particularly in P-impedance. The S-impedance actually moves from a positive change to a negative change with the influence of pressure. The two final scenarios are one variable changes. Production while maintaining pressure suggests that water is replacing oil but the pressure is not dropping due to pressure support. Pressure depletion without saturation change is the case that a producer remains in the oil leg but is dropping the pore pressure from extraction.

From this analysis, we can estimate the 4D impedance response in the reservoir unit. In the case of noise free seismic, all of these changes would be seen in the seismic. However, seismic data is inherently noisy and repeatability between surveys is never perfect. The measure of repeatability we use is NRMS, normalized root mean square (Kragh & Christie, 2002). In the areas of interest, the NRMS value is about 12% in the PP seismic data, decreasing with increasing angle. The near angle for PP data contains the worse signal to noise because in near angles multiples are most difficult to remove. An NRMS value of 12% indicates excellent repeatability even for a marine survey, but the lower the NRMS, the better. The far stacks have slightly lower values of NRMS and therefore the polygon was made reflecting the NRMS values in the far stack.

In order to relate the NRMS to impedance, we have to model each scenario in 4D reflectivity at a simple interface. The reflectivity of the top reservoir is calculated before and after each scenario in four angle stacks using Fatti’s approximation (Fatti et al., 1994). The RMS of one value is simply the value itself, so the equation for NRMS becomes the normalization equation for two values, the reflectivity before and after each scenario. This is done at each location of the crossplot for each angle stack, to find in what areas the calculated value of NRMS is greater than that of the seismic, suggesting that it can be seen in the difference volume. The polygon drawn is a result of this analysis, scenarios inside the polygon should not be seen in seismic difference and those outside the polygon should be clear.

Water injection and production maintaining pressure are visible in the seismic, but 5% gas exsolution and pressure depletion without saturation change are not distinguishable due
to the level of noise. It is important to note that this method of analysis has been previously stated as often underestimating the visibility of scenarios in the seismic (Johnston, 2013). This underestimation is commonly seen and may be due to discrepancies in the datasets used such as in the PVT, which can be highly uncertain (Johnston, 2013). This is most likely the case in the Edvard Grieg field, as the water injection shows a very bright 4D response but according to the NRMS polygon should be barely visible. Additionally, indications of gas exsolution are faint but detectable in the seismic difference, suggesting that this method is an underestimate of the seismic or that a higher saturation of gas is coming out of solution than previously thought by Lundin Norway.

With this 4D modeling, it is clear that an improved shear-impedance from joint inversion will be a very useful parameter in distinguishing the interplay between pressure change and saturation change. Additionally, water injection and production without pressure change should be clear in the difference seismic for the aeolian unit. 4D responses are much smaller in amplitude in the alluvial section due to the porosity decrease. Nonetheless, this is a conservative method of analysis and does not negate signs of gas coming out of solution in the difference seismic. Any signs of this or production without saturation change may suggest a different saturation change or pressure change is occurring than expected by the operator, or that the method was too conservative.

2.3 Field Data

Lundin Norway provided PP and PS gathers in their native time with 2016 and 2018 vintages. The data underwent up down deconvolution preprocessing, Kirchoff pre-stack depth migration, and were matched for 4D purposes. More details on processing and acquisition are in Chapter 1.

Viewing the PP full stack seismic data crossline (Figure 2.11) and inline (Figure 2.12), we can better understand the character and geometry of the seismic data. The PP dataset has no visible waterbottom as the water is only 110m in depth. There is a slight acquisition footprint from the receiver cables visible in the crossline direction (Figure 2.11) and a gap
in the data due to the platform along with shallow gas hydrates. However, most of these features do not affect the reservoir unit as it is much deeper.

![Figure 2.11 Full stack PP crossline 1729. Shallow parabolic feature near acquisition footprint shows the edge of the platform effect. Signal perturbation is much larger underneath platform.]

The geologic features are nicely imaged in this PP dataset. The steep faults in the basement are resolved in most areas of the survey, potentially due to the tilted transverse isotropy (TTI) migration in processing. The fluid effect in the reservoir is clear in the strong trough (red) underneath the chalk.

There are three main seismic aspects of thin-bed tuning prevalent throughout the survey (Widess, 1973). Firstly, there is a brightening of amplitudes nearing the pinchout of the graben in the South visible in Figure 2.11. This should be noted for all amplitude maps taken around the reservoir as this bright amplitude in corner of the graben can be misleading. Second, according to wedge modeling the tuning thickness of the aeolian reservoir in the PP data is 17 meters. The aeolian reservoir varies from 6-40m in thickness, thus much of the reservoir is under tuning causing a deceptively large amplitude. Thirdly, the Shetland group chalk which acts as the seal of the reservoir, has a peak tuning of 22 meters, however, there is more complexity in this group. The chalk is composed of two limestones, the upper unit
Figure 2.12 Full stack PP inline 1475. Strong trough reservoir response may continue under injectite, but injectite footprint destroys signal.

is the Ekofisk chalky limestone, and the lower unit is the Tor chalk. The tops of both units are marked by a sharp increase in velocity, clear in Figure 2.9. Because there are actually two thin units of chalk in this one package, tuning overall begins at 50m from the interfering internal carbonate units. This suggests that in the majority of the Edvard Grieg field, the Shetland Group chalk is within tuning.

Pre-stack AVA information can be seen in Figure 2.13. The overall background trend shows decreasing AVA as expected. With increasing incident angle, PP particle motion becomes more horizontal and less vertical. There are some features that are best illuminated at certain angles. The progradational reflectors in the shallower alluvial section in the half graben are the most clear in the near stack. The ultra far stack best retains the amplitudes of the reservoir area under cemented sands. This is most likely due the raypath undershooting the cemented sand anomalies which is particularly noticeable on the larger shallow cemented injectites.

In order to understand the spatial energy loss we have in the PP seismic data, we analyze RMS extractions over the survey in Figure 2.14. In the first 500ms there is a clear acquisition footprint of the receiver lines which we can observe in 2D in crosslines like Figure 2.11. We can
Figure 2.13 Near (0-17°), Mid (17-25°), Far (25-30°), and Ultra-far (30-34°) stacks of PP seismic data showing cemented sands and reservoir.

Also see the gap in the lines from the platform and a signature of the pipeline moving North, refer to Figure 1.6 for exact locations. Moving to the 500ms-1000ms window, faint receiver line and platform footprints remain. In the 1000ms-1500ms window, the platform footprint continues and we see a large response to the locations of the cemented sand injectites. These high amplitude sands attenuate much of the seismic energy before it hits the reservoir. In window 1500ms-2000ms lies the reservoir. There are amplitude gaps in the locations directly beneath the cemented sands. Additionally, there still remains a footprint from the platform. It is important to recognize the areas of amplitude loss to better understand what results from the inversion are reliable.

The PS data is much lower resolution with a peak frequency of around 5 Hz at the reservoir (in native time), compared to the peak frequency of 25 Hz in the PP data as shown in Figure 2.15. When the PS data is registered to PP time, the peak frequency increases to 9 Hz at the reservoir, which is still very low for seismic interpretation purposes. The ray-path experiences a significant amount of energy loss from the Grid sands (for PS data) and the chalk unit as mentioned in the previous section.
Figure 2.14 RMS extractions in 500 ms windows throughout the PP survey.

Figure 2.15 Amplitude spectra of PP and PS full-stack seismic data in their native time domain for (a) the reservoir and (b) the entirety of the survey.

The inlines and crosslines in PS seismic data show that resolution drop (Figure 2.12). The PS dataset has a stronger acquisition footprint than the PP seismic seen in the crossline direction in Figure 2.11. This is due to the asymmetry in the PS ray path requiring denser receiver spacing than PP in the crossline direction. Without dense receiver spacing, there will be gaps in the data that cause migration swings. The reservoir now lies around 3800ms in PS time as the S-velocity is slower than P-velocity but we may still be getting an acquisition footprint at the reservoir.
The geologic features can still be seen in this dataset but not to the clarity of the PP dataset. The steep basement faults are not observable in most areas of the survey. The chalk is more variable in amplitude. Additionally, the reservoir does not stand out as strongly in amplitude as in the PP seismic data. This is because the PS data does not show fluids and the fluid response causes amplitude to increase in magnitude in the PP seismic. However, the PS data shows clear lithology changes at the reservoir, shown in Figure 2.8. Moving in the reservoir from PP to PS data, the bright red amplitude in PP data turns into a clear top and base aeolian section in the PS data, which in PP data was dominated by fluid response. Understanding lithology distribution and spatial extent is particularly useful in Edvard Grieg as the reservoir geology is complex and heterogeneous.

There are the same components of tuning in the PS data but the tuning thicknesses are all larger. There are bright spots near the pinchout of the graben just as in the PP seismic data. The resolution of the chalk is now 66 meters and the resolution at the reservoir is 53 meters due to the lower frequency content of the PS data. This varies slightly throughout the survey depending on velocity and frequency content. However, it is important to note

Figure 2.16 PS full stack crossline 1729. No fluid response at reservoir capped by chalk. Only a response to lithology.
that this is a measure of resolvability, not detectability. The reservoir below this tuning thickness is still detectable but top and base are not separable and accurate correlations with amplitude to reservoir quality cannot be made.

The PS dataset contains AVA information which can be seen in Figure 2.18. The overall background trend is an amplitude increase with offset till the mid to far angles, described by Zoeppritz (1919) and shown in Figure 2.2. Shear wave particle motion is perpendicular to the propagation direction. At an interface, at normal incidence, there cannot be a mode conversion from P-wave to S-wave (Zoeppritz, 1919). Physically, one needs incident angle to increase to produce a mode conversion from P to S. In the near stack there seems to be much more noise, less signal, and a footprint from the platform in the center of the survey. The mid, far, and ultra-far stacks look very similar in amplitude and each stack highlights the reservoir geometry where the top and base sand can be distinguished. An interesting feature to note is that the amplitude for the far stack in the chalk is actually slightly higher than the ultra-far stack. This suggests that the amplitude rises and falls in the chalk with offset, confirmed by simple modeling in Chapter 3.
Figure 2.18 Near, Mid, Far, and Ultra-far stacks of PS seismic data showing cemented sands and reservoir.

As was done in the PP data, RMS amplitude extractions over the PS survey were taken every 500ms of PP time for comparison purposes, shown in Figure 2.19. In the shallow window, there is a strong acquisition footprint which we can observe in the crosslines like Figure 2.16. There remains a platform and pipeline footprint. Moving to the 500ms-1000ms window, there is still a very strong acquisition footprint from receiver lines, the platform, and the pipeline. This footprint goes much deeper in the PS data than the PP data. In the next window (1000-1500ms), the platform footprint remains and we see a large response from the cemented sand injectites, as we saw in the PP data. In the reservoir window (1500-2000ms), there are the same amplitude gaps as in the PP seismic data. The PS extraction in the reservoir unit looks much more noisy and discontinuous than the PP seismic data. This may cause difficulty in interpretation.

Both PP and PS datasets contain areas in the reservoir that cannot be used for quantitative interpretive purposes. These areas are caused by the shallow cemented sands and the platform in the center of the survey. Steps in processing have been taken to reduce the footprint of the cemented sands. These features were inserted in the migration velocity model as geobodies, however there is still significant pull up and amplitude loss in the area.
Figure 2.19 RMS extractions in 500 ms windows in PP time throughout the PS survey. Beneath them. Using the RMS amplitude maps and the seismic, the areas of unreliability can be marked as in Figure 2.20 to avoid interpretation mistakes moving forward. These data are sufficient for the scope of this project, but future work may be done on recovering the signal under the cemented sands.

Figure 2.20 RMS Extraction at the reservoir interval of the PP data. Polygons are created to highlight regions of signal loss due to the platform and shallow cemented sands. PS contains similar regions of data loss but larger noise.
2.4 Data Conditioning

In order to give the inversion the best chance to succeed, it is important to prepare the data and improve signal to noise. This can increase accuracy and resolution in the reservoir property estimates that result from our analysis. WesternGeco has performed a variety of post-migration processing methods, including two radon demultiple rounds, minor trim statics, and residual moveout correction. This dataset was delivered to RCP with relatively strong signal to noise. However, upon further investigation we identified various features that could be improved.

![Figure 2.21 Raw offset PP and PS gathers at inline 1759 crossline 1887.](image)

From looking at the gathers in Figure 2.21, it is apparent that there is “jitter” or mismatch in the reflectors in our reservoir with significant residual move-out. Inversion assumes that the data has been successfully flattened and there is no residual move-out, so this must be fixed before moving forward. Without fixing this, we obtain large misfit in the prestack inversion particularly in the reservoir where we have the strongest amplitudes as shown in Figure 2.22.

To tackle this problem, trim statics were applied to the PP and PS offset gathers. Trim statics is a form of static correction that attempts to determine the optimal time shift needed to align events on prestack data. This is done by cross-correlating a model trace to a windowed trace of input data. There are multiple techniques of applying trim statics. This flattening method can be applied before or after stacking. Applying the method after
Figure 2.22 Here we can observe the effect of inverting data with residual moveout in the angle stacks by looking at the (a) 2016 PP baseline prestack seismic data, (b) synthetic created from the prestack inversion, and (c) misfit or difference between volumes. The location around Well E is a known reservoir interval and area of interest. The chalk is labeled in each figure with the blue dashed line.

stacking lessens the chance of aligning noise and of having residual moveout in the area of interest. However, because the stacking is done with the “jitter” in the gathers, mismatched reflectors are stacked, decreasing the signal to noise and resolution in each of the angle stacks. The process of stacking assumes that the reflection data is aligned and the amplitude will increase proportional to the fold, giving way to the theory that larger fold results in better signal to noise. If the data is misaligned the amplitude will not stack constructively with fold, and may actually result in a low signal to noise. Applying trim statics before stacking works to insure that the “jitter” is removed before stacking, theoretically improving the signal. The downside is that if the correlation window is large enough, or time variant, there is a possibility of aligning random noise. To moderate this negative effect, constraining parameters can be applied that control window length and the maximum time shift. This minimizes the chance of aligning random noise in the gathers. There are pros and cons to both applications, but given the constraints we are able to apply, we chose to apply trim statics to the gathers before stacking.
With Hampson Russell’s software capabilities, trim statics can be applied in three methods, shown in Figure 2.23. The trim statics application can be done with (1) time variant shifts throughout the volume, (2) constant time shifts from one interval, or (3) constrained window time shifts from two intervals.

The time variant method uses multiple model traces and multiple windows for correlation, iteratively stepping through time. This method will create very flat gathers, but has the highest chance of aligning, and ultimately stacking random noise because there are a large amount of correlation windows. By comparing the data output with the synthetics from the log data, areas where the time variant trim statics aligned noise were clearly identified. This is a quick quality control technique as the synthetics do not contain noise. Additionally, the focus of the project is to best analyze the reservoir interval, and with the time variant method there is no control to prioritizing or weighting a specific target depth more heavily than others. In Figure 2.23 (a), we have run 100ms correlation windows every 1ms.

![Figure 2.23 Gathers after application of trim statics using (a) time variant trim statics, (b) constant time shifts calculated from the chalk, and (c) time shift calculated from two intervals. Colors overlain represent the time shifts calculated at each window. Constant time shift (b), shows one correlated window and surrounding times as a constant large negative shift, however, this time shift is a display issue in Hampson Russell, the time shift in the correlation window is applied as a bulk shift to each trace.](image)

The other two methods utilize specific zones for cross correlation. Figure 2.23 (b) shows the result of using one correlation window around the reservoir. In this, the model trace
is acquired from stacking traces with 100m to 2000m offset, then cross correlated with the traces in a 300ms window around the chalk. The time shift computed is applied to the entire trace. This creates more alignment in the reflectors around the target, but in the shallow units the shifts create discontinuities. This is clear in Figure 2.24, after the constant time shift is applied, the shallow continuous reflectors now appear heavily faulted.

![Figure 2.24](image)

Figure 2.24 The shallow section of the PP seismic data before and after one window of trim statics was applied.

In order to solve this issue, two zones were used for cross correlation, one around the reservoir, and one in the shallow units. With these trim statics windows, the shallow areas are not distorted, the reservoir reflectors are aligned, there are lower chances of stacking noise, and time shifts are better interpolated with depth. Using two windows for trim statics resulted in the best signal to noise when stacking, for both the shallow units and deep units in PP and PS datasets.

The methodology and window lengths were similar for both datasets but the maximum time shift was different. In order to assign a maximum time shift, the data was scanned in the offset range that would be eventually stacked. This being up to 2000m for PP data and 1300m for PS data. The maximum time shifts needed for the chalk to align in that range was assigned as the maximum time shift for each dataset. It is important to identify the necessary maximum time shift to constrain the trim statics. With a large maximum time shift, the trim statics are capable aligning random noise traces to reproduce any given
reference trace (Bancroft et al., 2000). For the PP data, a maximum time shift of 12ms was used, while for the PS data, a maximum time shift of 35ms was used. The PS data needs a larger maximum time shift as the gathers for the PS data show larger misalignment.

The PP seismic data was successfully flattened and aligned using trim statics as shown in Figure 2.25, however, the application on the PS data was not as effective. The gather shown in Figure 2.26 is representative of an average quality gather in the PS seismic data, some gathers have more time shift and some have less. Nonetheless, time-shifts remained in the PS seismic data that could not be fixed with a larger maximum time shift trim statics. Increasing the maximum time shift for trim statics would actually increase the mismatch. Other methods of gather conditioning would have to be utilized.

Figure 2.25 PP gather before and after the two window method of trim statics was applied.

Figure 2.26 PS gather before and after the two window method of trim statics was applied.
In both the PP seismic data and the PS seismic data, the jitter or time shifts appeared to be somewhat cyclical in nature (Figure 2.21). The mismatch of the chalk reflector would rise and fall with offset in a pattern. This observation suggested that there could be an azimuthal component to the mismatch. The PS data was sorted into 18 azimuth bins, 20 degrees each bin, shown in Figure 2.27. The gathers sorted into their individual azimuth sector showed well behaved AVA and minimal jitter in the chalk reflector. Our goal in sectoring is to make trim statics application simpler and to identify if there are azimuth bins that are noisier and have more error that is negatively impacting the stacked data.

![Figure 2.27 The PS seismic data sorted into 18 azimuth sectors (upper right) shown at inline 1943 and crossline 1807 with offset muted to 1400 meters.](image)

The criteria for analyzing the azimuth sectors were fold, residual moveout, signal-to-noise, and image quality in and around the reservoir. Initially when looking at these azimuths, we found that the highest fold was around bin 4 and 15 and the lowest fold was around bin 9. Most likely due to the acquisition geometry of the OBC dataset, but exact source receiver geometries were not available to confirm this hypothesis. Although variation in fold was common in each location, upon muting we found that the increased fold in certain azimuths were in offsets not included in our stacks. The next criteria is residual moveout. This was solved by applying individual trim statics on each of the 18 azimuth sectors. Because the
individual azimuth stack reflectors were more aligned, a smaller maximum time shift of 20ms was sufficient to flatten the chalk and reservoir in comparison to the previous 35 ms shift. The final criteria was signal-to-noise and image quality in and around the reservoir. This was analyzed by stacking each sector individually and viewing every 32 crosslines with a chalk horizon interpreted on the full stack as a reference. This allowed us to simultaneously compare all azimuths with each other and the interpretation from the full azimuth stack as shown in Figure 2.28.

![Figure 2.28 PS crossline through aeolian reservoir in 18 azimuth sectors. Blue horizon noting chalk picked on full stack full azimuth PS seismic data.](image)

With this analysis, we found that no azimuths could be deemed as noisy in every location. Azimuth sector 13 is consistently better image quality however, lacks the detail that other azimuth sectors contain in certain locations. There is no justification from this analysis to remove any azimuths.

There are observations for future work. Azimuths 11-17 contain higher signal to noise than their counterparts. There is also a minor time shift in the data varying from sector 1-10 that changes magnitude with location. The statics seen in the chalk and reservoir reflectors are most likely associated with the Grid sand injectites and polygonal faulting directly overlying the chalk in the overburden. These discontinuities also cause lateral velocity variations most likely not captured by the S-wave velocity model, contributing to the complex azimuthal effect that we found to be the strongest in the PS seismic data. The acquisition
geometry used in conjunction with the azimuth sectoring could potentially provide useful information on this time shift but the source receiver geometry information is not available. Even with this information, given the level of polygonal faulting in both the Grid sands and the shallower section in the Hordaland unit, it would very challenging to identify azimuths that have ray paths which produce the best image. Future work can be done in picking individual time shifts with azimuth and removing them in their individual sectors. For our work, we have utilized the dataset with individual trim statics on each sector to remove the residual moveout that varies with sector, then combined sectors to common image point offset gathers. The azimuthal time shifts became clear in these offset gathers as the residual moveout was fixed individually. To fix the time shift from the azimuthal effect, we applied another round of trim statics that greatly improved the gather quality and sufficiently flattened the gathers.

2.5 Stacking Methods

After conditioning the gathers for optimal alignment, we stack the data into angle stacks. This is to increase signal to noise of the data. The more angle stacks you create, the better sampling of amplitude variation with offset. This becomes particularly important if the reservoir is class 2P and flips polarity with offset as many fields in the North Sea are, but this is not the case for the Edvard Grieg field (Jenkinson et al., 2010). Additionally, the amount of traces or fold in each of those stacks decrease with increased number of angle stacks, therefore, you obtain lower signal to noise with increased number of angle stacks. The optimal number of stacks for this dataset was set as 4, with the largest angle being 34 degrees. This angle is where the cap-rock, the Shetland chalk goes critical.

Conventionally, gathers are stacked into equal angle. This often causes the near stacks to have minimal fold as seen in Figure 2.29. In our dataset, with equal angle stacks, the near stack will have very few traces. The near offsets are more prone to noise because many demultiple techniques rely on residual moveout and identifying reflectors that are not properly flattened by the velocity model. There is more moveout in the fars than the nears,
in fact, often in the nears the multiples appear flat, which is why the nears contain more residual multiple energy as they are harder for processors to remove. With equal angle, the near stack would contain less fold of noisier data. Ultimately, we decided to move from equal angle stacks to equal fold stacks as shown in Figure 2.29.

To do this we equate each location to the center of a circle as shown in Figure 2.30 (Todd & Backus, 1985). The area of that circle is the total fold and the radius is the offset at the farthest angle. In this case, the chalks critical angle of 34 degrees is the largest angle we want to include in our stacks. At this gather, 34 degrees corresponds to 1950m offset at the reservoir which becomes radius. With this value for radius, R, we can estimate what values of offset needed to create equal fold angle stacks proportional to $R^2$ or offset squared, schematically shown in Figure 2.30. The respective offsets are converted to angle in Hampson Russell using the velocity model.

Sorting by offset squared for equal fold is advantageous in multiple facets. According to Shuey’s two-term AVO equation, amplitude variation with offset varies with $\sin^2 \theta$ (Shuey, 1985). Offset squared is roughly proportional to $\sin^2 \theta$, thus even sampling in offset squared results in even sampling of the reflectivity. Additionally, residual moveout is also proportional.
to offset squared, so effective residual moveout is evenly sampled. Based on this foundation, the chosen equal fold angle stacks are 0-17°, 17-25°, 25-30°, and 30-34°. The same angles are used for PP and PS datasets. This final dataset was shown in the previous section.

2.6 Wavelet Phase

According to processing reports of the PP and PS data, the seismic data has been effectively zero-phased. However, even with this done in the processing there could be some minor phase remaining in the data. A thorough analysis of wavelet phase was performed using well ties and inversion analysis iterations to test what phase best fit the seismic data.

Initially, a statistical wavelet was calculated from a 500ms window around the reservoir with a 180ms wavelet length for the PP seismic data, and a 750ms window with a 270ms wavelet for the PS seismic data. This algorithm extracts the wavelet amplitude spectrum by analyzing the autocorrelation of a set of assigned high fold traces over a time window. Here, the reflectivity is assumed to be white. According to the convolutional model equation, if the reflectivity is white, then the autocorrelation of the data is the autocorrelation of the
wavelet. The phase of the data cannot be determined in this method, the wavelet is assumed zero phase or assigned a phase. The challenge with this extraction is the lack of statistics or reflectors in the wavelet extraction window around the reservoir, shown in Figure 2.31. This window in the seismic data contains the Grid sands, the chalk, and the reservoir. The chalk is the only strong consistent reflector in the interval for the PP seismic data, therefore a statistical wavelet extraction from this window may potentially just replicate the chalk reflector. Even with this issue, forward modeling with the statistical wavelet from PP data matched the seismic dataset nicely but the wavelet shape was not captured in the PS data with statistical extraction. To tackle the data statistics challenge in the reservoir window, we extracted a wavelet in the shallow section with many clear reflectors to get wavelet shape and bandpass filtered the wavelet to match the frequency content at the reservoir. However, the wavelet is assumed to be zero phase. Another disadvantage in this extraction is that whiteness-based deconvolution criteria boost the noise level outside the bandpass of the wavelet because they enforce whiteness over the entire frequency range (Edgar & Van der Baan, 2011).

Figure 2.31 PP full stack seismic data with extraction window outlined.

Next, a deterministic wavelet was calculated from the datasets. This was done by tying each well with a Ricker wavelet, then a statistical wavelet, and finally iterating through
deterministic wavelets using the well data and the same window of seismic as the statistical 
extration. The deterministic wavelet or “wavelet using wells” extraction in Hampson Russell 
extracts the wavelet by finding an operator that when convolved with the reflectivity from 
the well, approximates the seismic traces near the well. This extraction is extremely sensitive 
to the quality of the correlation between the well logs and the seismic data which is why 
multiple iterations of well ties had to be done. After each individual tie was made an overall 
wavelet was extracted using six reliable wells, well A, B, C, D, E, and G. This wavelet 
had a minor phase of -8° suggesting the data at the reservoir had residual phase as shown 
in Figure 2.32. From this analysis we moved forward with a deterministic wavelet that 
cluded information on the phase. More about wavelet extraction and the PS wavelet will 
be discussed in Chapter 4.

![Figure 2.32 Extracted PP wavelets, from (a) statistical methods and (b) deterministic meth- 
ods.](image)

**2.7 Summary**

Using the analysis done in this chapter, we have established a scope of the possible uses 
of an improved S-impedance with rock physics work. Theoretical work on the reflectivity 
equations set expectations for which model estimates are attainable from inversion, given 
limited angle range. The potential challenges the PS data were identified as well and data 
quality in both the PP and PS datasets were assessed. Gather conditioning and stacking 
was done to provide the PS data the best chance to improve model estimates. Overall, 
advantages with more accurate S-impedance were analyzed, potential bottlenecks of PS data
were discussed, and the inputs and tools to aid inversion work were refined. Now we will move to testing inversion methods on synthetic data to evaluate the inversion parameters and potential improvement from incorporating PS seismic data.
CHAPTER 3
SYNTHETIC DATA TESTS

Real data contains noise, multiples, changing geology, and a magnitude of other obstacles for an inversion algorithm to tackle, as discussed in Chapter 2. Before inverting challenging real data, we want to understand what value joint PP-PS inversion can add by inverting synthetic data. The synthetic data is forward modeled using the Edvard Grieg exploration wells. By inverting for these known properties, the level of precision and potential shortcomings of model based inversion can be discerned and optimal inversion parameters can be selected. In this chapter we explore the data further with comparisons to noise free full elastic synthetics, forward modeling, and inversion of synthetic data.

3.1 Elastic Waveform Modeling

Synthetic seismograms act as a noise free comparison to the seismic data to study the noise level and potential presence of multiples. The primary synthetic analysis was done on wells A, B, C, D, E, and G as these were all vertical exploration wells. These wells contain generally full suites of logs but occasional gaps particularly in $V_S$ and density, pseudo logs were created using the relationships derived from other wells in the interval of interest. For example, the relationship from Figure 3.1 was utilized to convert $V_P$ to pseudo $V_S$ logs. A similar crossplot was derived for pseudo density. Following the pseudo-log estimation, all essential logs underwent a mild 10 ft median filter and were checked for washout zones using the caliper log. After this log editing, we are able to use all exploration wells but Well F, as it only contains 150m of log, which is insufficient for use in synthetic modeling, ties, and background models.

There are many methods of quality control of seismic data using well log synthetics. A vital first step is to check the seismic data for multiples and noise with well ties. Figure 3.2 shows a well tie in the reservoir area on Well A, the discovery well. The synthetic is modeling
the central angle, 21°, using the deterministic wavelet in Figure 2.32, and the seismic data for comparison is the full stack PP data (0-34°). The chalk and reservoir area are replicated in the synthetic. The shale unit above the chalk has fluctuating density but the resulting synthetic shows low frequency fluctuations just as seen in the field data. The shallowest reflector in the window shows mismatch but is not within the inversion window. The correlation coefficient refined to this 400ms interval is 0.92 indicating a reliable well to seismic tie, with a correlation of 1 being a perfect match. The well ties for other exploration wells in PP time have similar correlation coefficients in the reservoir ranging from 0.85 to 0.96, often depending on chalk thickness. There is no clear mismatch in the reservoir area for any of the logs that would suggest multiple energy. A notable feature is that the grid sands typically appear much brighter in the synthetic than they do in the PP seismic data. This could be from some interference and noise in the seismic data that is not reflected in the synthetic.
Figure 3.2 PP seismic well tie around reservoir at Well A. Synthetic and real data show the same trace repeated 4 times. Shallow high velocity bed noted by the grid sands. Synthetic is lower frequency than real data in this area due to the use of a time constant wavelet and preferential extraction from the deeper reservoir unit.

Figure 3.3 shows a PS well tie in the reservoir area on Well A. The synthetic is modeling the central angle, 21°, using a deterministic wavelet, and the seismic data for comparison is the full stack PS data (0-34°). This PS data is far lower frequency than the PP seismic data. The time-depth of the positive reflectors match nicely but there are minor differences above and below the chalk reflector. In the synthetic, the shale unit above the chalk has fluctuations that the real data does not. The Grid sands also appear much stronger in the synthetic than in the real data, potentially the same interference and noise issue that the PP seismic data undergoes in the heavily faulted Grid sands. However, the trough that marks the reservoir response is stronger in the real data than in the synthetic. The correlation coefficient refined to this interval is 0.74, indicating a relatively good PS well to seismic tie. The other PS well ties have similar correlation coefficients in the reservoir ranging from 0.62 to 0.77.

From this introductory analysis, it is clear that the data has been processed well and that large noise features like multiples are not very prevalent in the data within the range of the logs. This analysis can be made because multiples are not included in the synthetics.
Figure 3.3 PS seismic well tie around reservoir at Well A. Synthetic and real data show the same trace repeated 4 times. Shallow high velocity bed noted by the grid sands. Synthetic is lower frequency than real data in shallow section due to the use of a time constant wavelet and preferential extraction from the lower frequency reservoir unit.

The next step is to analyze the modeled prestack gathers. This is done by comparing the synthetic gathers with the real seismic gathers to catch any discrepancies that need to be addressed in the gather conditioning, or if not fixable, that need to be noted moving forward. For this comparison, I will be showing a synthetic gather at wells A, E, and B for the PP data (Figure 3.4) and the PS data (Figure 3.5).

The PP and PS synthetics were created using Hampson Russell’s elastic wave algorithm. This method was utilized instead of the Zoeppritz algorithm because the exact Zoeppritz equations models primary energy only. Because of this, the algorithm may be inaccurate for thin layer models with large impedance contrasts as demonstrated by Simmons & Backus (1994). In Edvard Grieg, the Shetland chalk cap-rock is within tuning thickness (50m) and marked by a high impedance layer relative to the shale above and reservoir below, so the Zoeppritz equations may result in imprecise synthetic results. The elastic wave algorithm models all wave modes simultaneously to solve this problem. This reflectivity modeling method is designed to simulate the AVO effect of P-wave reflectivity for a 1D model with complex reflection layering in the target interval. The synthetics were moveout corrected.
using the exact log velocities and taking into account nonhyperbolic moveout. This is particularly important in the converted waves as they display nonhyperbolic moveout and conventional NMO methods do not flatten reflections accurately. Finally, the synthetics are stacked for inversion analysis in the same angle range as the field data, 0-17°, 17-25°, 25-30°, and 30-34°.

Ideally, the synthetic and field data would show the same general trend across multiple wells. For the inversion flow, there are angle-dependent scalars applied to the PP and PS angle gathers. This scalar should adjust the inversion to account for any variations between the AVO from the synthetic and the seismic data. In Hampson Russell, the scalar is calculated based on the 10 strongest peaks or troughs in a chosen window around the reservoir for the wells used in the low frequency background model. However, this is a global scalar, meaning one value is applied per stack in each mode. There is an assumption that the AVO trend difference between seismic and synthetic should be consistent throughout the wells and seismic. The main concern is identifying if the AVO trend difference is variable between wells, so I have analyzed the AVO at the wells in the survey used in the initial model.

Figure 3.4 shows the PP synthetic gathers alongside the field seismic gathers for three well locations. The PP gathers match fairly well to the synthetic with a minor time shift, and both show decreasing AVO trend. However, the amplitude seems to decay much faster in the real data than the synthetic gathers, particularly in the overburden. The synthetic does not account for complicated wave propagation effects that are expected in the faulted region of the overburden. This may be the reason for why the amplitude decays faster in the real data. The chalk begins to go critical at around 2100 meters offset in the synthetic, which is the case for the field data, but residual moveout was corrected for in the trim statics process as discussed in Chapter 2. The 34° critical angle at the chalk forces us to omit offsets past 1900m.
Figure 3.4 PP synthetic gathers (left) compared to the real gather (right) at the respective well locations.

The PS synthetic gathers and real data at the same location, in Figure 3.5, match well in time and show a general increasing AVO trend. A notable feature is the consistently high amplitude reflectors with a decreasing AVO in the field data about 500 ms above the chalk, these are the Grid sands. In the real data, the chalk and reservoir have lower relative amplitude due to the attenuation from these injectites. The synthetics don’t incorporate transmission path complexities. The chalk begins to go critical at around 1400 meters offset in the PS synthetic, which is the case for the field data, but residual moveout was corrected for in the trim statics process as discussed in Chapter 2. The $34^\circ$ critical angle at the chalk forces us to omit offsets past 1300m in the PS data. Another notable feature is that the synthetic wavelet looks lower frequency. This could be due to the low frequency chalk dominating the wavelet extraction. In regions of thicker chalk towards the East of the field,
Figure 3.5 PS synthetic gathers (left) corrected for non hyperbolic moveout compared to the real gather (right) at the respective well location. The chalk at wells A and E shows residual moveout.

like in wells G, D, and C, the chalk reflector may appear lower frequency and the wavelet extraction included these wells. Potentially, excluding these wells in the wavelet extraction could provide a better match for the synthetics in well A, E, and B, but would be less representative of the Eastern portion of the field. Overall, both the conditioned PP and PS gathers match with the synthetic gathers in AVO trend sufficiently for inversion purposes.
3.2 Poststack Inversion

The first and simplest method of inversion tested is post-stack inversion of the PP seismic data. Here, we want to understand the parameters that go into the inversion using the synthetic data to have a basis of which parameters to choose for the field data inversion. The package used is the Hampson Russell model-based inversion software which is a generalized linear inversion (Cooke & Schneider, 1983). I will discuss the post-stack inversion method and main parameters such as the weighting terms, prewhitening, number of iterations, and block size.

All inversions attempt to solve the linearized model of seismic inversion, written as,

\[ d = g(m) + n, \]

where \( d \) is a vector containing the data time series, \( g \) is the forward modeling operator, \( m \) is the model parameter, and \( n \) represents the noise in the data. In post stack inversion, the model \( m \) contains the logarithm of P-impedance and the operator \( g \) contains the wavelets and derivatives. The pre-stack model and operator include more variables but will be discussed in the next section.

The post-stack inversion attempts to minimize the objective function to find acoustic impedance, \( m \), values that when converted to reflectivity and convolved with the wavelet, \( g \), best match the observed seismic volume, \( d \). Like most inversion techniques, this method is non-unique. To manage this non-uniqueness, particular weighting parameters can be applied in the objective function.

The objective function of the Hampson Russell post-stack inversion is,

\[ J = w_1 \times (d - W \ast r) + w_2 \times (M - H \ast r), \]

where \( J \) is the objective function, \( w_1 \) and \( w_2 \) are weighting terms, \( d \) is the seismic trace, \( W \) is the wavelet, \( M \) is the initial impedance model, \( H \) is the integration operator that produces impedance from reflectivity, and \( r \) is the reflectivity of the current model.
This objective function is a combination of the seismic data misfit and allowed model variation (how far can the model deviate in each iteration from the initial model), ultimately controlled by the weighting terms. Note that the two weighting terms add up to 1. A larger value for $w_1$ would force a solution that minimizes data misfit, and a larger value of $w_2$ forces a solution that remains close to the initial impedance model. In Hampson Russell, there is a “soft” and “hard” constraint option for the weighting terms. The “hard” constraint sets $w_2$ to zero and the final impedance values are limited to range of upper and lower values for maximum impedance change and if the value exceeds this range, it is clipped. This is actually recommended by Hampson Russell, because the constraint may prevent small amounts of noise in the data or model errors to drive the algorithm to an incorrect result. The “soft” constraint option is “stochastic” model inversion and allows the model to deviate from the initial model and allows the user to assign the model constraint, $w_2$, consequently setting $w_1$. This requires multiple iterations and updates to the initial model to converge to a close match to the seismic.

I used the “soft” constraint option moving forward to allow for deviations from the initial model as the initial model may have error especially in this highly heterogeneous field. The starting model, or the low frequency model, is derived from constraining horizons picked on the PP data and the well data. The inversion then iteratively solves for reflectivity by identifying and minimizing misfit between the seismic data and the synthetic seismic data. Consequently, the more iterations done in the inversion, the lower the seismic misfit. However, typically after 2-3 iterations, while the seismic misfit decreases, the model error between control points (wells) and inversion results increases. There is always a trade-off in inversion between model parameter accuracy and predicted seismic misfit. I will be focusing on minimizing model misfit more so than seismic misfit as the purpose of the inversion is to get accurate rock properties. The number of iterations and the prewhitening is set by the user. These parameters have an important interplay as well. The prewhitening is a constraining term in the solution for the model update, used to dampen the seismic misfit.
influence on each inversion iteration. The larger the prewhitening, the closer the model remains in each update to the previous model, and the more iterations it takes for the seismic misfit to diverge. This parameter becomes much more important in the pre-stack inversion and will be discussed further in the following section.

Finally, the post stack method allows for specification of “block size,” which is the thickness in time of each model parameter grid block. A smaller block size results in a smoother result which can better fit the seismic data, while a larger block size will result in a more sparse subsurface representation. Large block sizes may oversimplify the geology but in cases with little knowledge of the geologic setting or in complex geology, this method may be preferred. Small block size gives denser, or a larger number of model parameter estimates. Denser model estimations can fit the data better, but this may not necessarily be ideal. After experimentation in the Edvard Grieg field, I found a block size of 4 ms was best able to capture the gradational changes in the reservoir, while the larger block size was best able to replicate the sharp change at the chalk. The time sampling of the data is also 4 ms. With the reservoir being the primary interest of the field, 4 ms block size was chosen for the post-stack inversions.

After better understanding the parameters going into the objective function and creating the necessary synthetics, we go forward with the inversion of the synthetic from well A. The model based inversion requires a wavelet, a low frequency model, and the seismic data. For the low frequency model for the synthetic tests, I used the exact values of the input model parameter, the P-impedance from the well, and applied a 6 Hz low pass and 9 Hz high cut filter. This frequency range was applied to fill the frequency band below that of the seismic frequency spectrum. This inversion was done on a full stack PP synthetic seismic dataset using angles 0-34 degrees. The wavelet used is the deterministic wavelet in Figure 2.32.

The synthetic post-stack inversion parameters were $w_2$, model constraint, of 0.1, $w_1$ of 0.9, 8% prewhitening, and 9 iterations. To determine the accuracy of the inversion methods, I will be showing the inversion on the most representative well, Well A. Figure 3.6 shows the
Figure 3.6 The inversion analysis window for post-stack PP inversion on synthetic data generated at Well A. This method of inversion only outputs acoustic impedance and utilizes a full angle stack, the seismic shown is one trace repeated five times. The correlation coefficient (CC) of the seismic data and seismic data misfit is noted on the bottom of the synthetics.

Inversion analysis window at Well A for post stack inversion. In this window, the inverted P-impedance is compared to the well logs filtered to the seismic frequency band to represent attainable frequencies. The seismic data shown is the seismic data created from the inverted model parameters, the input seismic data, and the misfit which is the difference between the input and output seismic. The inversion result for P-impedance closely matches the well data in all areas but overshoots very slightly in the Grid sandstone. Nonetheless, the acoustic inversion on the synthetic is very accurate. There is minimal misfit in the data as the synthetic data is noise free. The seismic in the area of interest, from 1500ms to 2050ms, has a correlation coefficient of 0.989 suggesting an excellent match, expected in a synthetic test. The P-impedance model parameter match shown in Figure 3.7 has a correlation of 0.98 within a given error bar. This same window and error bar will be used for estimating the correlation coefficients of the model parameters and the seismic data in every inversion for consistent comparison purposes.
Figure 3.7 Crossplot showing variation between P-impedance derived from the post-stack PP synthetic inversion and the P-impedance from the log at well A. The red line shows the linear fit line, a one to one relationship for reference. The correlation between the inverted and log P-impedance is shown in red, this correlation coefficient is based solely on the model parameter estimate versus log values.

Next we can test accuracy by looking at the model parameters in the crossplot domain, in Figure 3.7. In a perfect match, all points would be on the red line representing a one to one relationship. There are slight deviations particularly in the reservoir interval but the inversion is very close to exact according to this crossplot. The deviations in the reservoir are likely due to hydrocarbon presence in the conglomerate section and may be improved with the addition of AVA information. By performing an inversion on the full stack synthetic data, we see best case scenario of the post-stack inversion.

3.3 Prestack Inversion

After testing post-stack inversion, I moved on to the prestack domain to see if model parameters would be improved using AVA information. Prestack inversion uses angle stacks and is a simultaneous inversion, meaning the inversion solves for multiple parameters at the
same time, solving for P-impedance, S-impedance, and density.

Post-stack inversion ignores the relationship between S-impedance and P-impedance. However, from the post-stack inversion P-impedance estimate, the user can predict S-impedance from established relationships between S-wave and P-wave velocity. According to Castagna’s equation, $V_P$ and $V_S$ should be linearly related for water saturated siliciclastic rocks (Castagna et al., 1985). Gardner’s equation shows $V_P$ and density should be linearly related in clastic rocks (Gardner et al., 1974). Simultaneous pre-stack inversion includes coupling between these variables to add stability to the non-unique and noise sensitive nature of inversion.

The pre-stack inversion algorithm is under three assumptions, (1) linearized approximation for reflectivity holds, (2) PP and PS reflectivity as a function of angle can be given by the Aki-Richards equations, and (3) there is a linear relationship between the logarithm of P-impedance and both S-impedance and density, which should hold for background wet lithologies (Hampson et al., 2005). Simmons Jr & Backus (1996) used a similar approach in building relationships between $V_P$, $V_S$, and density to invert for linearized P-reflectivity($R_P$), variations in S-reflectivity($\Delta R_S$), and variations in density reflectivity($\Delta R_D$). Buland & Omre (2003) used comparable methods but solved for three different terms $\Delta V_P/V_P$, $\Delta V_S/V_S$, $\Delta \rho/\rho$. This study used the Aki Richards approximation as well, but then used a small reflectivity assumption to relate changes in the parameter to the original parameter itself with a logarithmic approximation. The Hampson Russell technique combines these approaches with the three assumptions and the small reflection coefficient assumption of 0.1 or less magnitude (Russell, 2014). Note that the small reflection assumption is not optimal for the Edvard Grieg field as the chalk reflector at normal incidence has a reflectivity of 0.25, while top reservoir reflectivity is 0.2. But based on an analysis of the tools in various software, this method is the most tested and proven technique in the consortia. With these assumptions, the reflectivity approximations can be given by,

$$R_{P_i} \approx \frac{1}{2} \Delta L_{P_i} = \frac{1}{2}(L_{P_i+1} - L_{P_i}),$$

(3.3)
Here, $i$ represents the interface between layers $i$ and $i+1$, and $L_P = \ln(Z_P)$, $L_S = \ln(Z_S)$, and $L_D = \ln(\rho_P)$. In matrix notation this becomes,

$$ R_P = \frac{1}{2} DL_P, $$ (3.6)

$$ R_S = \frac{1}{2} DL_S, $$ (3.7)

$$ R_D = DL_D, $$ (3.8)

where $R$ is the reflectivity vector, $D$ is the derivative matrix, and $L$ is the log of the impedance or density vector. For post-stack inversion, substituting the reflectivity vector into the convolutional model from equation 1.1, the equation becomes,

$$ d = \frac{1}{2} WD L_P. $$ (3.9)

where $d$ is the seismic trace vector, and $W$ is the wavelet convolutional matrix in which each column contains $n$-sample wavelet shifted by one sample from the previous column. This is not solved using full matrix inversion, as it is costly and potentially unstable. The strategy chosen is to start with an initial guess impedance for $DL_P$ and iterate towards a solution using the conjugate gradient method. For pre-stack inversion, Hampson Russell uses the Fatti et al. (1994) re-expression of Aki-Richards linearized approximation,

$$ R_{PPg} = c_1 R_P + c_2 R_S + c_3 R_D. $$ (3.10)

where, $c_1 = 1 + \tan^2(\theta)$, $c_2 = -8 \left( \frac{V_S}{V_P} \right)^2 \tan^2(\theta)$, $c_3 = 0.5 \tan^2(\theta) - 2 \left( \frac{V_S}{V_P} \right)^2 \sin^2(\theta)$.

Substituting the reflectivity vectors from equation 3.6, 3.7, and 3.8, and using the convolutional model from equation 1.1, this equation can be used for inversion. However, it ignores the relationship between $L_P$ and $L_S$ and between $L_P$ and $L_D$. Simmons Jr & Backus (1996) used delta terms to account for deviations away from a linear fit of Castagna’s equation and
Gardner’s equation. In Hampson Russell, the algorithm actually inverts for deviations away from a linear fit in logarithmic space using the equations,

\[
L_S = k_L P + k_c + \Delta L_S, \tag{3.11}
\]

\[
L_D = m_L P + m_c + \Delta L_D, \tag{3.12}
\]

where constants \(k\) and \(m\) are slope and \(k_c\) and \(m_c\) are intercept derived from well logs. These values are determined in the crossplot domain using the wells included in the low frequency background model as in Figure 3.8. The delta parameters in Figure 3.8 are independent variables and makes the system more stable. In Hampson Russell model-based inversion, the three inverted model estimates are \(L_P\), \(\Delta L_S\), and \(\Delta L_D\).

Figure 3.8 Crossplots of \(\ln(Z_S)\) vs. \(\ln(Z_P)\) (left) and \(\ln(Z_D)\) vs. \(\ln(Z_P)\) (right) from well log A used in the synthetic pre-stack inversion as this is the only log included in the background model. A best fit line has been added according to the assumptions listed above. The deviations away from the line are the delta terms which do not fit the background trend and can be indicators of fluid anomalies.

Given these assumptions and relationships, Fatti et al. (1994) linearized equation can be re-expressed as,

\[
d_\theta = c_1 W(\theta) D L_P + c_2 W(\theta) D \Delta L_S + c_3 W(\theta) D \Delta L_D \tag{3.13}
\]

where \(\tilde{c}_1 = \frac{1}{2} c_1 + \frac{1}{2} k c_2 + m c_3\) and \(\tilde{c}_2 = \frac{1}{2} c_2\) and \(d\) is the seismic trace. This equation is not solved by full matrix inversion methods because the low frequency content cannot
be resolved and the process would be costly and unstable as in the post-stack case. The practical approach taken is to initialize the solution to \([LP \Delta LS \Delta LD]^T = [LP_0 0 0]^T\) where \(LP_0\) is derived from the initial impedance model and used to iterate towards a solution using the conjugate gradient method.

Referring back to equation 3.1 for pre-stack inversion, the data, \(d\), is a vector containing the data time series for each angle of incidence, the model parameter, \(m\), is a vector that contains the natural logarithms of \(Z_p\), \(ΔZ_s\), and \(Δρ\), and the operator, \(g\), contains the wavelets, derivatives, and coefficients of the AVA linearized approximation. This operator describes the function that calculates seismic data amplitudes from model parameters as a matrix of coefficients, obtained from equation 3.13 for the corresponding angles in \(d\). Because \(g\) and \(d\) are known, \(m\) can be solved for using the standard least squares inversion approach (Russell, 2014),

\[
m = (G^TG + \sigma_d^2C_m^{-1})^{-1}G^Td,
\]

where \(\sigma_d^2\) is the prewhitening (damping) factor and \(C_m\) is the model covariance matrix. The incorporated factor is the prewhitening assigned to the inversion. This parameter is a noise level added to stabilize the operation and should reflect the variance of the noise in the input data. In the inversion, a larger the prewhitening requires more iterations for the predicted data to match the observed, since the model update at any iteration is small. Large prewhitening means the seismic misfit has less weight on inversion updates, and restricts the inversion from forcing large changes in the model within an iteration. The model updates are small and close to the pre-established coupling relationships. This can be useful to constrain the inversion in noisy seismic data. The method of choosing prewhitening is to test various magnitudes and select a value that minimizes the data misfit while avoiding model error, as with increasing iterations past 2, the seismic misfit drops while the model error relative to log values increases.

The covariance matrix \(C_m\) uses the expected ranges for the natural logarithms of \(Z_p\), \(ΔZ_s\), and \(Δρ\) to derive prewhitening parameters based on the amount of prewhitening set.
These values are calculated from the crossplots of the log data like Figure 3.8, based on the average scatter around each regression line. The matrix is given by

\[
C_m = \begin{bmatrix}
\sigma_1^2 & \sigma_{12} & \sigma_{13} \\
\sigma_{21} & \sigma_2^2 & \sigma_{23} \\
\sigma_{31} & \sigma_{32} & \sigma_3^2
\end{bmatrix}
\]  

(3.15)

where \(\sigma_{i,j}\) represents the covariance and the subscripts indicate the model parameter.

The diagonal terms are the variance of each model parameter from the initial low frequency model. Because a modified Fatti’s approximation is used, where a single parameter \(L_P\) describes the majority of the data with two delta terms \((\Delta L_S\) and \(\Delta L_D\)), the terms vary independently of each other. This allows a reasonable assumption of zero covariance, meaning all off-diagonal terms in the covariance matrix go to zero. A larger value of covariance in the matrix means the inverse value will be smaller, thus less damping is applied to that term. Presumably, this term will be \(L_P\). This covariance matrix constrains the inverted estimate to only vary within a specific range around the value predicted by the established coupling relationship.

Other parameters involved in the prestack inversion include the background ratio \((V_S/V_P)\), the global scalar (briefly discussed in the elastic modeling section), and the scalar adjustment factor. The background ratio starts from the initial model and may be updated with iterations or can be kept constant at 0.5. In equation 3.13, \(V_S/V_P\) or gamma is assumed to be constant and accurately chosen. Another assumption in this Hampson Russell implementation is that the angle, \(\theta\), is taken as the incident angle, when according to the Aki Richards equation the angle should be the average between the incident and the refracted angle (Hampson & Russell, 2013). The motivation for these assumptions is to allow the coefficients in equation 3.13 to be constant with time, speeding up and stabilizing the calculation (Hampson & Russell, 2013). To address these assumptions, the gamma can be automatically updated with a chosen iteration count starting from the initial model. This causes (1) a time-variant gamma, (2) a gamma that is updated from the inversion values, lessening the non-linear problem from one of the “unknowns” being in the coefficients, (3)
the correct average angle is used for calculations, using the time-variant velocity, and (4) a longer operation runtime (Hampson & Russell, 2013). This updated gamma can give a higher resolution than the default constant gamma but can also be unstable and result in noise. This parameter is analyzed on a case by case basis to identify the preferred method.

The global scalar is a scalar applied to each angle stack to account for any variations in amplitude with offset between synthetic generation and the seismic data. Two values are used, the model scalar, which is the RMS of the model amplitude in the inversion window, and the seismic scalar, which is the RMS of the 10 largest amplitudes in the inversion window divided by the model scalar. The calculated values are preferred to manual changes. Finally, the scalar adjustment factor is an input to scale the average reflectivity, the default is set at 1 but minor changes have shown improvements in the inversion results.

After understanding parameters going into prestack inversion, we can test the inversion on prestack synthetics from Well A. This inversion requires an angle dependent wavelet, a low frequency model, and pre-stack seismic data. A deterministic wavelet was calculated for each angle stack to reflect the changing frequency content (moveout-stretch) and phase with angle. This is important as the nears include high frequencies and the fars are lower frequency. The same low frequency model is used as in the post-stack seismic for only well A, but now includes S-impedance and density as well as P-impedance, with the same 6-9 Hz low pass filter applied.

Figure 3.9 shows the optimal inversion result on the synthetic dataset at Well A. Here the optimal model parameters were calculated using a prewhitening of 6% and 7 iterations. These values were chosen to get the best model parameter fit which is clear in the logs for P-impedance and S-impedance. The density term closely follows the P-impedance as expected because very large angles are not included in this dataset. However, there is some amount of deviation in the chalk density. The correlation coefficient of the synthetic in the inversion window is 98.0% which is very high but slightly lower than the post-stack inversion. This is due to my chosen values for prewhitening and iteration number, as with higher iterations or
Figure 3.9 The inversion analysis window for pre-stack PP inversion on synthetic data generated at Well A. This method of inversion outputs P-impedance, S-impedance, and density (from the inverted estimates of $L_P$, $\Delta L_S$, and $\Delta L_D$) and utilizes four angle stacks. The $V_P/V_S$ is updated one time with the inversion result. The seismic is a trace for each angle stack for the inverted synthetic, original synthetic, and misfit.

lower prewhitening the seismic correlation would increase, but my goal is obtaining the best model parameters for rock property analysis. There is consistently a concession between seismic misfit and model error, but better model parameters are the goal of the project, so model error will be preferentially lowered. The seismic misfit in this inversion is larger than the post-stack inversion because of this preferential weighting of model parameters. In real data, the seismic misfit will be even larger in the prestack compared to post-stack due to the presence of increased noise in prestack data. Because there is less fold in each angle stack relative to the full stack, there is inherently more noise in the prestack information which can cause more misfit between the observed and predicted seismic data. However, in this case, we are testing on noise-free synthetic data. The variance determined for each term was $L_P = .332$ $\Delta L_S = .125$ $\Delta L_D = .027$. These relative magnitudes are reasonable, the majority of variations should be described by the first term, and the S-impedance variations are expected
to be larger than that of density, so the second term should be larger than the third. An automatic gamma value with one update allowed for the best fit of $V_p/V_s$ without arbitrary fluctuations from noise.

Figure 3.10 Crossplot comparing P-impedance, S-impedance, $V_p/V_s$, and density from the pre-stack PP synthetic inversion versus the log values at well A. The red line shows the linear fit line, a one to one relationship for reference. The correlation between the inverted and log parameter is shown in red. Note $V_p/V_s$ is a derivative product of the inversion estimates.

The model parameter misfit can be seen in crossplot form in Figure 3.10. There are minor variations between the log values and the inverted values for P-impedance and S-impedance. The $V_p/V_s$, even with a moderate match in Figure 3.9, has a large amount of misfit in the units directly above the chalk but near the reservoir the estimates converge to the log values.
This is most likely due to the geology of the chalk and reservoir and a lack of large changes in $V_P/V_S$ as discussed in Chapter 2.

The prestack PP simultaneous inversion of the synthetic at Well A has multiple benefits over the post-stack inversion. Prestack data allows for estimations of additional valuable model estimates and a marginally improved estimate of P-impedance. The P-impedance model parameter improved by 0.01 in the pre-stack inversion, but the seismic misfit increased. With more data, there is more information to obtain a better model parameter estimate. This is clear in the synthetic case, however, with real data there is more noise and variations in geology. P-impedance estimates can be improved using prestack data but if the signal to noise of the data is too low the model parameter may contain more error than the post-stack derivation. Additionally, the added model parameters of S-impedance and density from PP prestack inversion are heavily dependent on angle range, if the data does not contain sufficient angle range, an independent derivation of shear and density is unlikely as discussed in Chapter 2. This synthetic analysis shown was done on well A, similar work was done on other wells that supported the conclusion that PP prestack inversion slightly improved the estimate of P-impedance compared to solely using full stack data.

3.4 Prestack Joint PP-PS Inversion

The next method of simultaneous prestack inversion we test incorporates the PS multicomponent data. The benefit of multicomponent data is disputed in the literature because its addition does not always reap enough benefits in inversion to justify its costly acquisition and processing (Garotta et al., 2002; Jenkinson et al., 2010; Roure & Russell, 2019). PS data contains lower signal to noise relative to PP data. Potential benefits depend largely on the accurate processing of the data and the geology of the field. As discussed in Chapter 2, the term “stealth” reservoir has been coined as reservoirs with geology that is better highlighted with shear impedance, but from the geology of the Edvard Grieg field it seems the shear impedance contrasts are the largest in the overburden (Jenkinson et al., 2010). This effect actually works against our PS data, showing that PS data alone is not able to better charac-
terize the reservoir than PP data alone. Utilizing PS data in joint prestack PP-PS inversion may still provide benefits in the S-impedance because the term is a larger component in the PS reflectivity, shown in Figure 2.2.

For joint inversion, the modified Fatti’s equation 3.13 is extended to include prestack PS data. The reflectivity of PS data is written in terms of shear reflectivity and density reflectivity as,

\[ R_{PS}(\theta, \phi) = c_4 R_S + c_5 R_D, \]  

(3.16)

where 

\[ c_4 = \frac{\tan(\phi)}{\gamma} \left[ 4 \sin^2(\phi) - 4\gamma \cos(\theta) \cos(\phi) \right], \]

\[ c_5 = -\frac{\tan(\phi)}{2\gamma} \left[ 1 + 2 \sin^2(\phi) - 2\gamma \cos(\theta) \cos(\phi) \right], \]

and \( \gamma = V_S/V_P \). The SV reflection angle, \( \phi \), is a function of the P-wave incident angle, \( \theta \), as in Snell’s law, \( \phi = \sin^{-1}(\gamma \sin(\theta)) \). \( R_S \) and \( R_D \) are the same as in Fatti’s approximation in equation 3.10. With the same small reflectivity assumption, the equation can be written as,

\[ d_{PS}(\theta, \phi) = c_4 W(\phi) D\Delta L_S + c_5 W(\phi) D\Delta L_D. \]  

(3.17)

Finally, because of the established relationships between the parameters, the variables are coupled again and the equation becomes

\[ T_{PS}(\theta, \phi) = \tilde{c}_4 W(\phi) DL_P + +c_4 W(\phi) D\Delta L_S + c_5 W(\phi) D\Delta L_D, \]  

(3.18)

where \( \tilde{c}_4 = kc_4 + mc_5 \). This equation in Hampson Russell results in the same three parameters as the prestack PP inversion. The PS reflectivity is not dependent on P-impedance, but it is one of the parameters in the final equation used in the inversion process. This means that the PS data can actually interfere or leak into the P-impedance estimate when performing joint inversion. PS data should not theoretically add value to the P-impedance, so any leakage may potentially damage the P-impedance estimate. Therefore, the preferred method of interpretation should use the P-impedance estimate from prestack PP inversion and the S-impedance estimate from prestack PP-PS inversion.
3.4.1 PP-PS Inversion Parameters

Testing the inversion on the synthetic from well A allows clear understanding of the parameters involved in the inversion in a noise free dataset with no registration mismatch, as this is often one of the main difficulties of PP-PS inversion. In joint PP-PS pre-stack inversion, two datasets are required with at least three fold each to provide the same number of data as unknowns in the data operator matrix, $g$. We utilize four fold PP and PS angle gathers with the equivalent angle ranges of 0-17°, 17-25°, 25-30°, 30-34°. Then four PP deterministic angle dependent wavelets and four PS angle dependent wavelets are extracted from the data to represent the phase and frequency content at each angle stack. More about this extraction is discussed in Chapter 4 on the field data. The same low frequency background model should be used as the previous inversions.

The major preparation step for this method is registration. This is the method of converting PS seismic data to PP time which can be challenging because even a minor mismatch can cause significant inversion result errors (Jenkinson et al., 2010; Khare et al., 2009). Registration can be accomplished through numerous approaches such as horizon picking, KPSDM velocity models, synthetic matching, and attribute matching. More on this will be discussed in Chapter 4 as registration on synthetic data is not required. A precise registration of the synthetics is possible by using the log velocities at the well originally used to create the synthetic gathers.

A larger prewhitening is typically applied for joint inversion as the PS dataset contains more noise and the inversion should be more constrained from quickly changing the model estimates to fit the seismic. If adding multicomponent data improves shear impedance, updates in gamma should be more accurate so this value is set to update twice. The same scalars apply, however, different scalars are applied for each angle stack for PP and PS, as well as a different parameter for global scaling factor for each dataset. This can cause either PP or PS to be weighted more. If the global scaling factor of PP is higher than PS, the reflections at the PP traces would be scaled to a higher value and have an increased influence
on the model parameters.

The main weighting factor in the joint inversion is the PS/PP ratio. The larger this value, the more influence PS data has on the seismic misfit, therefore, the larger the PP data misfit particularly in field data. Respectively, the smaller the PS/PP ratio, the more influence PP data has and the larger the PS data misfit in the field data. Changing the PS/PP ratio from 0.5 to 1.5 for the synthetic inversion makes minor differences in the seismic misfit. Because the data is synthetic, noise free, and forward modeled from the compared log data, changing the PS/PP ratio does not result in a significant change in seismic misfit. The inversion is non-unique and the seismic misfit will be diverge if allowed enough iterations, but the errors become very significant in the model parameters.

![Figure 3.11](image_url)

Figure 3.11 The inversion analysis window for pre-stack PP-PS inversion on synthetic data generated at Well A using a large PS/PP ratio of 100,000, most influenced by the PS data. This method of inversion outputs P-impedance, S-impedance, and density and utilizes four angle stacks from PP and PS data. The $V_P/V_S$ is updated two times with the inversion result. The seismic is a trace from each four angle stacks for the PP and PS inverted synthetic, original synthetic, and misfit.

To better understand the weighting parameter PS/PP and the influence of each mode of data, we test an exceptionally large and small ratio. Figure 3.11 shows the inversion analysis window using a very large PS/PP ratio of 100,000. The PS is driving the inversion almost completely and has a very high seismic correlation and low seismic error. Even though PP
is weighted minimally, the seismic correlation is over 0.9, and the P-impedance is matching in most areas. This $L_P$ term must be coming from the PP data, suggesting the PS/PP ratio does not stop the PP data from having influence. The most noticeable area of error is at the chalk where seismic error increased in PP seismic data and in all model parameters. The inversion is not able to capture the sharp impedance contrast at the top chalk from relying on PS data, suggesting the chalk is not a relatively strong reflector in the PS. This is because the wavelet is low frequency, therefore seismic misfit is low but the model parameters show error and the PP data shows coherent seismic misfit. The PS pre-stack seismic data in Figure 3.11 shows that the chalk is a large reflector but much lower frequency than the overlying reflectors. This is potentially softening the chalk impedance contrast in the model parameters. The Grid sands overlying the chalk are much stronger impedance contrasts in the S-impedance than the P-impedance, as discussed in Chapter 2. This causes attenuation of seismic energy above the PS chalk reflector in the field data which may increase the model parameter error at the chalk.

Figure 3.12 The inversion analysis window for pre-stack PP-PS inversion on synthetic data generated at Well A using a small PS/PP ratio of .00001, most influenced by the PP data. This method of inversion outputs P-impedance, S-Impedance, and density and utilizes four angle stacks from PP and PS data. The $V_P/V_S$ is updated two times with the inversion result. The seismic is a trace from each four angle stacks for the PP and PS inverted synthetic, original synthetic, and misfit.
The next test is using a PS/PP value of 0.00001. Theoretically, the result should be very similar to the PP prestack inversion since minimal weight is given to the PS data. The result is shown in Figure 3.12. The PS seismic correlation has dropped to 0.71 and the error has increased to 0.76, significantly higher error and lower correlation than the PP seismic data contained when increasing the PS/PP ratio to 100000. This indicates that inversion iterations are able to obtain a match to the PP seismic data much more effectively than PS seismic data, even with very clean synthetic data. The PP seismic correlation has decreased by performing joint inversion with the large PS/PP when compared to the PP prestack inversion by about 0.001, which is a negligible difference. The model parameters of this inversion look similar to those of the PP prestack inversion but contain more deviations from the log values particularly noticeable in the decrease in impedance at the reservoir. The joint inversion estimates lower impedance values than the well values for the chalk and the reservoir which is the area of interest. The S-impedance estimate is worse than the PP prestack inversion alone most likely because previously, the S-impedance was dominated by the relationship with P-impedance and at this well the relationship holds. By adding PS data even with a very small PS/PP ratio, there is still leakage of PS data into the PP seismic data causing the differences we see between this inversion and the PP pre-stack inversion.

Tuppen (2019) found that although PS seismic data can help improve S-impedance estimates, they can diminish the accuracy of P-impedance estimates. There is a significant difference in $V_p/V_S$ between the large and small test values for PS/PP. The large PS/PP inversion generates a $V_p/V_S$ that more closely matches the well logs while the small PS/PP actually deviates from the low frequency model in the opposite direction in one body of shale. However, the $V_p/V_S$ in the PP prestack inversion looks much better than the high PP weighted joint inversion and is comparable to the low PS/PP joint inversion. From this we can conclude that in order to allow the PS to provide benefits to the joint inversion, a significant PS/PP ratio should be applied. Often this ratio is lowered to 0.1-0.3, but this simply provides a less accurate version of the PP prestack inversion.
Figure 3.13 The inversion analysis window for pre-stack PP-PS inversion on synthetic data generated at Well A using all final parameters, influenced strongly by both PP and PS data. This method of inversion outputs P-impedance, S-impedance, and density and utilizes four angle stacks from PP and PS data. The $V_P/V_S$ is updated two times with the inversion result. The seismic is a trace from each four angle stacks for the PP and PS inverted synthetic, original synthetic, and misfit.

The PP-PS joint inversion result that contained the most optimal weighting of PP and PS seismic data is applying a 0.7 PS/PP ratio as shown in Figure 3.13. The PP and the PS correlation are within 0.005 of the best correlation coefficients from the small PS/PP ratio and large PS/PP ratio application respectively. The PP seismic misfit is slightly higher at the chalk than the PP pre-stack data inversion alone, but generally has very small error in seismic data. The model parameters of the PP-PS inversion and the PP inversion are where the chief differences are shown. The PS seismic data does not reflect that the chalk amplitude is drastically larger than that of the Grid sands above, therefore the PS data pushes for a smaller impedance contrast at the chalk that is akin to the contrast at the Grid sands. This may be from error in the wavelet extracted from the seismic data. In the PP data, the chalk is the overwhelmingly strong reflector so the inversion using this dataset is able to recognize a sharp large change in impedance and deviate farther from the low frequency model. Incorporation of the PS data can help in certain areas, but because the chalk is not a relatively high amplitude reflector, the inversion does not recognize the need
to deviate anomalously far from the model to the chalk. Here it is important to recognize the limits of our chosen inversion. A major assumption made in the modified version of Fatti’s used in the model-based inversion is the small reflectivity assumption. The area that our inversion is failing in the PS data is in the very strong chalk reflector that has a normal incidence reflection coefficient of 0.25, well over the acceptable reflectivity (0.1) from the assumption.

An improvement from the joint PP-PS inversion is the $V_P/V_S$ estimate. This is most clear in the inversion analysis window because the crossplots in Figure 3.14 suggest the joint inversion drops the $V_P/V_S$ correlation value. In the inversion analysis window, it is clear the PP-PS derived estimates are able to deviate farther from the initial model closer to the well log values because the joint inversion is able to obtain more accurate updates in the $V_P/V_S$ from utilizing the multicomponent dataset.

Figure 3.14 shows the variation of the inverted model parameters from the log values. The joint PP-PS prestack and PP prestack inversion parameters have nearly equivalent model correlation coefficients. Neither PP prestack nor PP-PS prestack inversion provided improvement in the density parameter, as expected given the limited angle range. The PP prestack derived correlations are very slightly higher on all parameters other than S-impedance which marginally improved using the PS seismic data. This study on synthetic data reveals that where the subsurface follows the low frequency background model and the geology follows the coupling relationships between $V_P$ and $V_S$, and $V_P$ and density, accurate model parameters can be estimated from PP data alone. For synthetic inversion this suffices, but in real data the background model is limited to the sampling of wells, most of the background model is interpolation between wells. In the case that the geology will be different than the well locations, the background model will be inaccurate. This is when the inversion depends on the coupling relationships between $V_P$ and $V_S$, and $V_P$ and density, and the covariance matrix derived from the log data.
3.5 Discussion

For pre-stack PP inversion, the inversion result depends highly on the variations of the natural log of P-impedance. The changes in P-impedance drive any changes in S-impedance and density. With simple modeling in Figure 2.2, we know that S-impedance contributes to the PP reflectivity at far angles. Where there is no direct contribution, the background trend with P-impedance from the well logs is utilized. Both PP and PP-PS inversions solve for $L_P$, $\Delta L_S$, and $\Delta L_D$, so if the background model relationship holds, only the $L_P$ is needed to predict the data, whether the seismic data is PP or PS. In areas where the linear relationship
between $V_P$ and $V_S$ is not suitable and a model change in S-impedance is not included in the background model, the change in S-impedance will not be detected. In this case an independent estimation of $\Delta L_S$ is not possible with limited angle PP data. For example, in a unit with anomalously large changes in S-impedance compared to P-impedance, the PP prestack inversion will be unable to estimate the correct S-impedance.

For pre-stack PP-PS inversion, the result depends on both the variations in S- and P-impedance. The changes in P-impedance still have the largest covariance value but the PS/PP ratio adds weight to the S-impedance. This bimodal weighting causes an averaging effect. In areas where the background relationship between $V_P$ and $V_S$ is not suitable and the background model does not contain the correct low frequency absolute values, the model estimate will effectively average the true S-impedance and P-impedance. For example, in a unit with anomalously large increase in S-impedance, the S-impedance will become closer to the true impedance increase and the P-impedance will overshoot its impedance estimate and become less accurate. Whereas PP prestack inversion will simply fit P-impedance model parameters and replicate that onto S-impedance, instead of estimating a truly independent $\Delta L_S$.

The PP-PS inversions can yield the most significant benefits where the the background model does not fit the geology, and the linear relationship between $V_P$ and $V_S$ is not suitable. This assumption fails in real data where all geology is not simple brine-filled sedimentary rock, particularly for the oil bearing Edvard Grieg field which is capped by a carbonate. This averaging effect in the PP-PS inversion for P-impedance and S-impedance can decrease the accuracy of the P-impedance result and increase the accuracy of the S-impedance result. Therefore, the model parameter for P-impedance is best derived by PP pre-stack inversion while S-impedance is best derived by PP-PS pre-stack inversion.

The seismic misfit of the two inversion methods can be used jointly to find deviations from the background model and the coupling relationship. Areas that have the most seismic misfit indicate that the background model is not representative of the geology or that the
linear relationship between $V_P$ and $V_S$ is not suitable. This is clear particularly in the PP-PS prestack inversion. If seismic misfit is observed in the PS seismic data, this can potentially confirm a variance from the linear relationship between $V_P$ and $V_S$, and be a indicator of the averaging effect between P-impedance and S-impedance. The inaccuracy of the P-impedance can be observed in the PP seismic misfit derived from the joint inversion. The area with the most overlap in misfit between PS and PP can suggest that the P-impedance estimate is most inaccurate. In the same sense, we can look to the misfit in the far stack where S-impedance begins to take an effect in the PP seismic data derived from the PP prestack inversion. If the far stack contains more misfit than at well control points, the linear relationship between $V_P$ and $V_S$ may not suffice and the estimated S-impedance may be inaccurate.

3.6 Summary

In this chapter, we have further assessed the field data quality and established AVA integrity with elastic modeling. The theoretical importance of the parameters going into each inversion has been discussed and the assumptions given with this mode-based inversion are noted. In the synthetic noise free domain, the different techniques of inversion are compared to see that PP prestack inversion provides the most accurate model estimates other than S-impedance which is improved marginally with the PP-PS inversion. Therefore, the model parameter estimates chosen for interpretation purposes should include P-impedance from PP pre-stack inversion and S-impedance from PP-PS pre-stack inversion. Neither inversion method was able to estimate density independently due to limited angle range.

Moving forward with the field data, areas where the seismic misfit is strongest especially in the joint PP-PS inversion can suggest that the coupling relationship between $V_P$ and $V_S$ is not suitable or the background model does not fit the variation of S-impedance from P-impedance. If at the same location misfit is observed in the far angle stacks in the from the PP prestack inversion, this can potentially confirm there is a variation in S-impedance not resolved by the PP prestack inversion. Both prestack inversions provide added value and can be used collectively to distinguish error in model parameter estimates.
CHAPTER 4
BASELINE FIELD DATA APPLICATION

The previous chapters have shown the potential benefits of utilizing multicomponent data and introduced the theory and parameters going into the inversion algorithms. Working with synthetic seismic data allows us to see the idealistic inversion result. With real data, many more challenges arise from noise, variations in geology, and data uncertainty. Both well logs and seismic data have a degree of error which must be reflected in the inversion parameters. In this chapter, the methods established in previous chapters will be applied to the Edvard Grieg Field data.

4.1 Low Frequency Background Model

The inversion inputs are the wavelet, seismic data, and the low frequency background model. Although the wavelet and the seismic data conditioning are crucial to the inversion, in model-based inversion particularly, the low frequency background model is often the bottleneck to accurate model parameter estimates.

The low frequency background model is the initial guess for the absolute rock properties and supplies the low frequencies missing in the seismic data. The inversion starts with the reflection-free low frequency background model and with each iteration the model updates to predict the seismic response. Without the initial model, the inversion can only output relative changes in properties. There can be a number of models that match the seismic data due to the non-uniqueness of inverting band-limited data. This is why providing a reliable background model is very important. It allows the inversion algorithm to move from relative changes to geologic terms and rock properties like velocity, impedance, and $V_P/V_S$.

The workflow for creating this initial model, requires two main inputs, (1) low frequency sampling of rock properties, and (2) bounding horizons. The rock properties can come from the well logs or the seismic velocity model. The smooth velocity model is used in cases
with limited or unreliable well logs because the model often lacks representation of the range of geology in the field. In the case of Edvard Grieg, there is sufficient well information to construct the low frequency background model. Six vertical well logs within the OBC volume were selected as inputs to the initial model. All 6 (wells A,B,C,D,E,G) contain a large depth range of \( V_p \), \( V_s \), and density and could be accurately tied to the PP seismic time and the PS seismic time. In some wells where the \( V_s \) and density logs had gaps, pseudo logs were created using relationships derived with \( V_p \). Because the Edvard Grieg field is laterally heterogeneous, all 6 wells were used to capture the variations in geology. The initial model needs to capture this lateral heterogeneity to supply the inversion with an accurate starting point. Because of this, unconventional fields like in the Vaca Muerta and Eagle Ford are sufficiently represented by one well as done previously in the RCP consortia, but as this field contains complex geology, more wells are necessary. Tests were done with variable number and different well logs but we found that these six wells provided the best representation of the heterogeneity of the field. Including more wells would overly fit the background model to the specific wells. Five horizons were picked on the PP seismic data and used as the bounding surfaces, including the Hordaland, Horda, Rogaland, Shetland Chalk, and the Basement. These bounding horizons/surfaces are used to guide the interpolation. No horizons were used inside the half graben to avoid biasing the inversion result in the reservoir.

The next challenge is the interpolation method between the wells constrained by the horizons. Hampson Russell contains various interpolation methods shown as in Figure 4.1, such as inverse distance power, triangulation, and kriging. Theoretically, the application of these methods should mitigate wells from producing “bullseyes”, or local highs and lows of model parameters in the low frequency model. These “bullseyes” will bias the inversion result, and most likely be replicated in the inverted model parameters. In application, all these methods fail to extrapolate the logs in a way that avoids local highs and lows in model parameters. Steps to include the velocity model as an interpolation method for the
wells produced the cokringing result in Figure 4.1. The velocity model contains much lower velocity values than the log values, therefore, to incorporate the velocity model in the initial model, the velocity model needs to be arbitrarily calibrated to the well logs.

![Figure 4.1 P-impedance low frequency models for various interpolation methods through an arbitrary line in the survey seen in the top right. Well logs overlain with P-impedance values filtered to seismic frequency.](image)

Ultimately, the chosen initial model was created in the Petrel software by PhD student Charles Todd shown in Figure 4.2 (Todd, n.d.). The method used was the kriging method applied with different parameters. This method is known as the best linear unbiased estimator based on the fundamental statistical properties of the data mean and variance. The algorithm uses a spherical variogram to express the spatial variability of the data. In Petrel, the user is able to set more parameters for the interpolation method as the software is more robust in property modeling. Therefore, the kriging method in Petrel was best able to interpolate between logs without causing “bullseyes”. After the interpolation, the model was low pass filtered to 6-9Hz to account for gap in the seismic frequency content. One obstacle in using an externally created model in Hampson Russell is the method the software uses to calculate global model and seismic scalars. These are calculated using the well logs included in the low frequency background model, but in an externally derived model the software is unable identify these wells. Therefore, in order to use an external model, the inversion
analysis is first run using a model that is created using the same wells in Hampson Russell to calculate scalars. With these scalars set, the updated Petrel model can be used.

Figure 4.2 The chosen low frequency model, P-impedance shown, for the Petrel kriging interpolation methods through an arbitrary line in the survey. Well logs overlain with P-impedance values filtered to seismic frequency, white space indicates lack of log data. Confining horizons in blue. Low impedance feature towards the West is a mix of sand and lacustrine sediment. The low impedance event extending from this well in the bottom of the half graben may be lacustrine sediment infill in the alluvial sediment or an artifact from interpolation.

4.2 Wavelet

After seismic conditioning and log calibration is completed, an accurate wavelet can be extracted from the dataset. Chapter 2 briefly discussed the statistical and deterministic methods of wavelet extraction and concluded that deterministic produced the best model parameter estimates from the seismic data. Now we will discuss how using a deterministic wavelet in inversion produces the more accurate model estimates than using a statistical wavelet.

Statistical extraction is the less complex technique and only depends on the seismic data. As discussed in Chapter 2, this extraction was taken in a 500ms window around the reservoir and outputs a zero phase wavelet, which according to processing reports, is the phase of the data. The deterministic extraction utilizes the same seismic window along with the well tie to create a wavelet that captures the phase of the data. After refining well ties, we found
that the PP seismic data contained a very minor negative phase ranging from -14° to -3°, decreasing phase with each angle stack. To determine which wavelet was best suited for inversion, I inverted the datasets using both statistical and deterministic methods. This analysis was done for every inversion method, but for simplicity, the post-stack inversion result will be discussed to compare the deterministic wavelet and the statistical zero phase wavelet.

Figure 4.3 shows the PP post-stack inversion analysis window on Well K. This inversion analysis window is the same as described in the previous chapter, where the model estimates and generated seismic data are compared with the well data and field data. This well is a blind well since it is highly deviated, blind meaning not used in the initial model. The inversion using either wavelet matches the seismic data with minimal misfit. The statistical and deterministic inversions actually have the almost exact same correlation coefficients in the seismic data, the only difference is that the deterministic wavelet produces a match to the seismic with 0.001 less error. The seismic misfit difference is negligible, but the major difference is in the estimated P-impedance. Neither post-stack inversion derived P-impedance estimates is very accurate, but there are improvements from using the deterministic wavelet. The deterministic wavelet is able to capture larger changes in impedance, particularly noticeable in the chalk and the reservoir. The statistical wavelet has more difficulty with large variations away from the background model. This observation holds through all other wells.

Typically the deterministic wavelet is always preferred, but an argument in favor of statistical wavelets is that deterministic wavelets may be potentially overfitting the logs and result in inaccuracies away from the wells. Therefore to address this concern, the inverted volumes are examined in 3D to discern if the misfit and model parameters deviate away from the wells. The seismic misfit for the statistical and deterministic wavelets is shown in Figure 4.4. The difference in seismic misfit is minimal and does not vary largely away from the well locations in either case. The misfit in the deterministic wavelet has higher frequency content which is expected when looking at the input wavelets in Figure 2.32, as it
Figure 4.3 The inversion analysis window for post-stack PP inversion on synthetic data generated at Well K using a (a) statistical wavelet and (b) deterministic wavelet. The seismic shown is one trace repeated five times. The correlation coefficient (CC) and misfit is noted on the bottom of the synthetics. In neither case is the P-impedance estimate from the post-stack inversion very accurate.

has a stronger side lobe than the statistical wavelet. The area with best reservoir lies around Well E, which contains similar error in both inversions but very slightly lower using the deterministic wavelet. Whereas in the area with higher slope towards well B, the statistical wavelet performs better at the chalk. The seismic misfit shows marginal variations but as mentioned previously, I set the inversion parameters to give the model parameters the least error which is done in lieu of decreasing the seismic misfit.

Figure 4.4 The inversion misfit for post-stack PP inversion using a (a) statistical wavelet and (b) deterministic wavelet, compared to the (c) original Baseline PP seismic data. The seismic misfit is the synthetic generated by the inversion subtracted by the original data.
According to the inversion analysis window control points, the model parameters show more change with varying wavelet than the seismic misfit. Figure 4.5 shows the P-impedance derived from post-stack inversion using the statistical wavelet (a) and the deterministic wavelet (b). The deterministic wavelet shows a better match to the well log values and can capture sharp vertical changes in impedance. The most notable difference is the lateral continuity of the chalk using the deterministic wavelet versus the statistical. The unit of interest lies in the 50ms below the chalk, depending chalk depth and the oil water contact. The oil bearing reservoir is the thickest at well E, and at well B there is the thickest body of sand. Both are clearly identified with around 7000 (m/s)*(g/cc) P-impedance. The statistical wavelet inversion accurately identifies the body, but the deterministic wavelet inversion is able to capture the large and abrupt changes in impedance at the top and base of the sands. Additionally, the reservoir is lower impedance in the deterministic inversion, closer to the known well log values. The statistical wavelet inversion looks overall smoother but the deterministic is sharper and more accurate. This holds for PP pre-stack inversion as well as PP-PS pre-stack inversion.

Figure 4.5 The P-impedance estimate derived from post-stack PP inversion using a (a) statistical wavelet and (b) deterministic wavelet. Well logs overlain with P-impedance values filtered to seismic frequency. Sand body is expected to vary in quality/impedance throughout the field. Arrows indicate clear areas of improvement using a deterministic wavelet.
Based on this analysis, we find that the deterministic wavelet produces the most accurate inversion results. The deterministic wavelets shown in Figure 4.6 will be used for analysis. The seismic extraction window for the PP wavelets is 1500-2000ms as described previously, while the extraction window in the PS seismic is 3400-4200ms. The window of extraction should be approximately 2-3 times the size of the wavelet length. With this in mind, we found that a wavelet length of 180ms and taper of 40ms produces the best PP wavelet, while a wavelet length of 270ms and taper of 60ms produced the best PS wavelet. It is recommended that the taper is 10-25% of the wavelet length. For a larger taper, the wavelet signal is lost and the low frequencies in the wavelet are increased. This variation in window length is due to the difference in frequency content of the PP and PS data. The reliable frequency content in the data is where the amplitude spectrum lies above -15dB in Figure 4.6. The PP wavelet contains low frequency content in the PP dataset with up/down deconvolution pre-processing (our dataset), but not in the data with the conventional pre-processing flow. This is also seen in the statistical wavelet extraction. The low frequencies in the wavelet can be reduced by increasing the wavelet length, but this causes notches in the frequency spectrum that would be replicated in the inversion result. The wavelet length was increased till notches appeared in the frequency spectrum which resulted in the lengths listed. The PP amplitude spectrum at the reservoir contains frequencies from 2 Hz to 60 Hz, with a peak frequency of 25 Hz. The PS data has much lower frequency content but not the same DC signature as in the PP data. The PS seismic amplitude spectrum at the reservoir contains frequencies from 2 Hz to 10 Hz in native time but compression to PP time effectively increases these values to a peak frequency of 10 Hz in the reservoir.

Both extracted wavelets show that with increasing angle, the high frequencies decay and the low frequencies moderately increase. The near stacks have the highest phase and highest level of noise. The PP wavelets shows a consistently small negative phase and the PS wavelets have a smaller magnitude phase per stack. According to the processing report, the zero-phase designature operator applied to the dataset was derived from shaping the ghost-free target
calibrated marine source (CMS) far-field signature to a zero-phase equivalent. Zero-phasing operators derived solely from seismic without well log quality control, as typically done by processors, may have error in the result (Simm & White, 2002). Additionally, it is unlikely that the far-field signature recorded was angle-dependent. This is most likely what the cause of the slight phase in the data at the reservoir interval.

4.3 Post-stack Inversion

After conditioning the field data, obtaining an accurate low frequency background model and representative wavelets, I inverted the PP post-stack volume with the same processes used for the synthetic data. The inputs to the inversion will be the full stack PP seismic dataset with angles from 0° to 34°, a single deterministic wavelet, and a P-impedance initial model. Various parameters were tested by comparing the well logs to the inverted model parameters and observing variations in seismic misfit. The chosen post-stack inversion parameters are given in Table 4.1. The “soft” constraint option was chosen to allow for deviations from the initial model because the geology in the Edvard Grieg field is heterogeneous and variability from the initial model is inevitable. The model constraint, $w_2$ in equation
3.2, is set to 0.1 which forces the seismic misfit to heavily influence the inversion updates. This low model weight is set because higher values constrain the updated models from deviating from the initial model sufficiently to match the well logs. Additionally, the post-stack seismic contains higher signal to noise as it is stacked over a large angle range and should be less prone to error, therefore, the data is given a higher weight than the model. The prewhitening is set as 8% to counteract the amount of weight given to the seismic data by constraining how far the initial model may change to match the seismic with each iteration. In the post-stack case, the model constraint and prewhitening perform similar functions. A larger model constraint works to keep the model parameter update close to the starting model, while a larger prewhitening works to dampen the influence of the seismic misfit on each inversion iteration. The iterations were limited to 9 because the seismic misfit leveled at this iteration so with more updates the seismic misfit would be minorly improved but the model parameters significantly suffered. This may imply that the inversion begins to fit noise or that the model parameters update in a null space but have no influence on data misfit. Finally, the block size was set to 4ms as done in the synthetic example to capture gradational and sharp changes in geology because important features in the field like the chalk and reservoir show both types of impedance change with spatial variability.

Table 4.1 Post-Stack Inversion Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Model Constraint</td>
<td>0.1</td>
</tr>
<tr>
<td>Prewhitening</td>
<td>8</td>
</tr>
<tr>
<td>Iterations</td>
<td>9</td>
</tr>
<tr>
<td>Average Block Size</td>
<td>4</td>
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</table>

Given these parameters, we move forward with the post-stack inversion of the PP seismic data. To demonstrate the success and changes within each inversion, four windows will be shown; (1) the inversion analysis window, (2) the model parameter crossplot, (3) the seismic misfit in 3D, and (4) the model parameters in 3D. The inversion analysis window allows the user to measure the accuracy of the inversion at the well locations by comparing the estimated
model parameters to true log values and the inversion generated synthetic seismic data to the real data at that location. The parameters selected for each inversion were chosen as the most optimal parameters to obtain the lowest model misfit at all well locations. These parameters were fine tuned using the inversion analysis window for quality control. The model parameter crossplot as shown in the previous chapter compares the inverted model parameters and the log values in the same window of 300 ms around the chalk. This allows us to see improvements in model parameters on a larger scale with all logs included. Finally, the seismic misfit (synthetic minus field data) and model parameters in 3D can demonstrate how the inversion performed spatially in between the control point wells.

Figure 4.7 The inversion analysis window for post-stack PP inversion, showing inversion results generated at (a) well A, (b) well E, and (c) well K. This method of inversion only outputs acoustic impedance and utilizes a full angle stack, the seismic shown is one trace repeated five times. The correlation coefficient (CC) and misfit is noted on the bottom of the generated synthetic and misfit respectively.

Figure 4.7 shows the inversion analysis window for the post-stack inversion at three control points, Well A (discussed in the synthetic chapter), Well E, and Well K. Well A and E were used in the low frequency background model, but well K is a blind producing well and is deviated, containing a limited log suite. The distribution of wells is shown in Figure 4.9. The areas of focus are the chalk and the underlying reservoir. The chalk at well K is captured in the inversion P-impedance estimate, the estimate is slightly low for well E, and very high for well A. The chalk at well A is thinner and within tuning, causing an amplified response in the seismic data. Inversion does not fix tuning issues, instead it uses
the higher seismic amplitude at the thin chalk in Well A, and estimates a larger impedance chalk. The reservoir and underlying units for all wells is underestimated in P-impedance. This post-stack inversion is estimating the P-impedance of the reservoir to be higher than the true value. Seismic misfit is minimal at all wells as this is done on one stack with high signal to noise. Well K has the most seismic misfit and model error (compared to log values) in the reservoir. This well had been producing for 9 months before the baseline (2016) survey, causing the impedance in the reservoir to increase. The inversion model estimate shows a higher impedance estimation using the baseline survey. Therefore the misfit may be due to production in the reservoir, not accounted for in the log values.

Figure 4.8 Crossplot showing variation between P-impedance derived from the post-stack PP inversion of the field data and the P-impedance from the log at well A. The red line shows the linear fit line, a one to one relationship for reference. The correlation between the inverted and log P-impedance is shown in red.

The model parameters can be further compared in the crossplot domain as seen in Figure 4.8. This crossplot uses log values from all exploration wells and three producers (wells H, Q, and K), and compares them with the inverted estimate at each well. The post-stack inversion obtains a P-impedance estimate with a high correlation of 0.9487. It is important to note that none of the inversions are able to capture Well F. This exploration well encounters tight alluvial sediment and contains minimal reservoir but is located nearest to
the well that drilled the thickest aeolian reservoir, well E. Unfortunately, well F cannot be included in the low frequency background model as it only contains 150m of log which is not sufficient for an accurate well tie. Without this well in the background model, the inversion is unable to recognize a sharp change in lithology with the proximity of 1km from well E to F. Therefore, in all inversion results, the high impedance true values at Well F are estimated to be much lower impedance, and can be seen in each P- and S-impedance crossplot as the points deviating the farthest from the log values. The cluster of points seen in each crossplot with log impedance values between 37000 and 42000 (ft/s)*(g/cc) and with inverted values between 28000 and 34000 (ft/s)*(g/cc) are the well F deviations. This shows the importance of representing the heterogeneity in the field with the low frequency background model. However, due to the lack of log at well F, it is not included in the model, causing error at that location.

The logs used for the background model are shown in Figure 4.9. For optimal display and to compare known well logs model parameters with the estimated parameters, two arbitrary lines through the wells are chosen as X-X’ and Y-Y’. These lines will be used for all baseline inversion analysis.

The misfit of the post-stack inversion of the PP seismic data for the two cross-sections is shown in Figure 4.10. The error of the deterministic wavelet as described in the previous section can be seen in the high frequency fluctuations near the chalk particularly in line Y-Y’. The misfit is the greatest in areas with higher slope changes in the chalk. Additionally, in areas where the reservoir is the thinnest, the misfit consistently becomes negative which could be caused by tuning occurring in the real data but not replicated accurately in the synthetic dataset. It is important to keep in mind that the parameters for all inversions were chosen specifically to obtain the lowest model error, thereby allowing more seismic misfit in the inversion that could have been decreased with more iterations. This seismic analysis also shows that underneath the chalk the data quality significantly decreases and the reflectors become less reliable. This noise and multiple energy will impact the inversion
Figure 4.9 Map of wells in the survey, noting blind wells and those used in the background model. Cross sections shown are used for analysis.

Figure 4.10 The input seismic data, predicted data, and misfit from the PP poststack inversion for (a) line X-X’ and (b) line Y-Y’. Note different time scales are used, figures actually contain the same frequency content.
model parameter estimates.

The P-impedance model derived from the inversion in Figure 4.11 shows a good correlation with the log values other than well F, for reasons described previously. The clean sands are the low impedance events with values between 4500 to 7000 m/s*g/cc. The oil water contact for scale is approximately at the base of the sand at well E shown in both sections. This contact can vary with location, particularly at well B, where the contact lies 16 meters lower than expected, clear in the green low impedance values at well B in Figure 4.11. The target for our analysis is roughly the 50-70ms below the chalk. The largest oil column sampled is at well E, about 40 meters, which is approximately the thickness of the aeolian sand at that well. Well K samples the area of the reservoir that is interfingerling aeolian and alluvial sediments, visible in the seismic, but made very clear in this inversion result. The lower impedance values are the aeolian fingers while the higher impedance fingers are the alluvial sediment. Although these features are captured in the inversion, they are smoothed over so the extremes of lows and highs in impedance are not distinguished, clear in the very

Figure 4.11 Cross sections X-X’ and Y-Y’ of the PP post-stack inverted P-impedance estimate. Well logs overlain filtered to the same frequency content.
low impedance events of the reservoir in well K.

Looking mainly at the reservoir interval, there are also features not captured in the acoustic impedance estimates, besides well F. The inversion recognizes the thinning of the sand moving from well E and F without a bounding horizon but cannot recognize the high impedances of the conglomerates at the base of the reservoir (blue color). In the conglomerate unit in well F, the inversion result actually deviates to a lower impedance value due to a reflector in the seismic data that is most likely noise. The chalk is highly and erroneously variable in impedance, as expected from the inversion analysis windows in Figure 4.7. When the reservoir is the thickest at well E, the chalk unit becomes less clear. The full stack may not provide enough information to understand the spatial variation in the chalk unit as the chalk is typically within tuning and is a very large impedance contrast. The low impedance values in wells K, E, and B around 4,500 m/s*g/cc in the reservoir are not identified by the inversion, which is the most crucial area of the survey. This is because the PP AVA is decreasing and the full stack dataset used in post-stack inversion is not the same as the normal-incidence synthetic. The full stack amplitude will be weaker than that of a normal incidence synthetic, which is why the post-stack inversion is underestimating the impedance.

Acoustic inversion is able to obtain a relatively accurate P-impedance model but fails in certain areas of the chalk and reservoir. Including additional information from AVA may be able to extract the correct P-impedance in our area of interest.

4.4 Prestack PP Inversion

With the inclusion of PP seismic data AVA behavior, the inversion is able to simultaneously estimate S-impedance and density in addition to P-impedance. According to Figure 2.2 from Chapter 2, AVA information can even improve the estimate for P-impedance when full-stack data is not representative of normal incidence. In the prestack PP inversion, I used the same low frequency background model as in the acoustic inversion, but used angle dependent deterministic PP wavelets shown in Figure 4.6. Four equal fold angle stacks were used with angle ranges 0-17°, 17-25°, 25-30°, and 30-34°, as discussed in Chapter 2. Again various
parameter combinations were tested to ultimately produce the best model estimates. The parameters chosen are shown in Table 4.2.

Table 4.2 Pre-Stack Inversion Parameters

<table>
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</thead>
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<td>Prewhitening</td>
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</tr>
<tr>
<td>Iterations</td>
<td>7</td>
</tr>
<tr>
<td>Gamma</td>
<td>Update Once</td>
</tr>
<tr>
<td>Scalar Adjustment</td>
<td>0.85</td>
</tr>
<tr>
<td>Angle Range</td>
<td>0-34°</td>
</tr>
</tbody>
</table>

The prewhitening is set to 3% to allow the inversion to deviate from the initial model with more influence from the seismic misfit for 7 iterations. Gamma, $V_S/V_P$, is the parameter in equation 3.13 that affects the contribution of S-wave and density terms to the reflectivity equation. This term is time variant and set to update once on iteration 5 from the background trend. It is limited to one iteration to allow the inversion to use the seismic AVA information to improve the $V_S/V_P$ but prevent introducing additional error into the results from poor estimates of P-impedance and S-impedance. The scalar adjustment factor was chosen as 0.85 as this produced the best match to the model estimates at the wells. This factor is a constant scalar manually chosen to match the observed and predicted data. The full range of PP seismic data was utilized to attempt capturing accurate S-impedance and density estimates, but as our angle range is limited to 34°, the results show that the S-impedance and density closely follow the background trend set by the well logs and are not independently estimated. This trend is utilized in all prestack inversions, meaning the same covariance values for prestack inversion and joint PP-PS inversion. The variance determined for each term was $L_P = .35$, $\Delta L_S = .12$, and $\Delta L_D = .03$. This indicates that the majority of variations in model parameters are driven by $L_P$, then the $\Delta L_S$, and finally $\Delta L_D$ influence will be minimal.

The inversion analysis windows in Figure 4.12, Figure 4.13, and Figure 4.14, show the difference of adding AVA information into the inversion. At well A the inverted P-impedance
at the chalk remains too high but is closer to the log data than in the PP post-stack inversion. This is because the PP AVA is decreasing, utilizing the full stack dataset to represent normal incidence will underestimate the reservoir amplitude as we have seen. Incorporating AVA information allows better estimation of the normal incidence property. The S-impedance has more error than the P-impedance and appears to be following the P-impedance trend as is the density estimate, which is inaccurate when the trend does not hold as in the deeper sections below the reservoir. There is a 1% increase in seismic misfit but that is to be expected as each angle stack contains more noise than the full stack because the fold in each stack is lower.

![Figure 4.12](image1.png) Figure 4.12 The inversion analysis window for pre-stack PP inversion showing inversion results generated at well A.

![Figure 4.13](image2.png) Figure 4.13 The inversion analysis window for pre-stack PP inversion showing inversion results generated at well E. The reservoir is a low impedance body but in the middle of the reservoir there is a slight increased impedance ”notch” associated with a side lobe most prominent in the near stack seismic data.
At well E, both the high impedance chalk and low impedance reservoir are aligned with the log data for P-impedance, but the S-impedance is slightly overestimated. This well contains the cleanest reservoir but with the addition of angle stacks, a notch in the clean reservoir response is introduced. This notch is a higher impedance bed within the clean sand in Figure 4.13. This could be interpreted as a siltier section of potentially interdune if this log comparison step was not taken. The notch is correlated with the side lobe interference seen in the near stack of the field data. The notch becomes stronger using a statistical wavelet. Parameters were tested to attempt to alleviate this problem, but the notch remained in the inversion result. Future work could be done in data processing to remove this sidelobe from the reservoir and mitigate this problem.

Finally in well K, the blind well, the inversion estimates match the well data in the chalk but are unable to capture the low impedances of the reservoir. Nonetheless, the P-impedance deviates farther from the initial model, closer to the log values in the prestack inversion than in the post-stack inversion. In all logs in the field, the the addition of PP AVA data improved the normal incident estimate of the P-impedance, but contained error in the S-impedance and density where the relationship with P-impedance did not hold. The $V_P/V_S$ remained close to the background model potentially because minor S-impedance and density information could be extracted from the limited angle range in the prestack data.
Figure 4.15 Cross plot comparing P-impedance, S-impedance, calculated $V_P/V_S$, and density estimates from the prestack PP inversion versus the well log data in 300ms window around the chalk. The red line shows the linear fit line, a one to one relationship for reference. The correlation between the inverted estimate and log data is shown in red.

The model parameters in the crossplot domain (Figure 4.15), show high correlation for P-impedance and S-impedance. The P-impedance improved 1% from the acoustic inversion but is still unable to capture the deviations at well F. The $V_P/V_S$ correlation shows two distinct packages. The deeper package at the chalk to underlying reservoir shows minimal variation in $V_P/V_S$ as discussed in Chapter 2, and has an excellent correlation. The second package is above the chalk shallower than 1800ms. Here there is a much lower correlation due to the variability in $V_P/V_S$ in the Grid sands and shales. The density estimate shows a high correlation from following the P-impedance trend. The analysis of control points in
the PP prestack inversion show that the P-impedance coupling relationships are generally sufficient for obtaining S-impedance and density in the Edvard Grieg Field but deviations from the relationships exist particularly in the chalk and deeper alluvial section.

Figure 4.16 The input seismic data, predicted data, and misfit from the PP pre-stack inversion for (a) line X-X' and (b) line Y-Y'.

Figure 4.17 Misfit variation with angle from the prestack PP inversion in line Y-Y'.

Looking at the seismic misfit at a broader scale (Figure 4.16), shows that greatest misfit occurs at the chalk reflector, which is also by far the highest amplitude reflector in the survey. This may be from a combination of the tuning at the chalk, particularly where it is the thinnest in the western part of the survey. Additionally, there may be shortcomings in our result due to the assumptions of small reflectivity in the inversion algorithm. The low
frequency misfit and thickness correlation seen in the post-stack misfit is not as apparent in the prestack misfit. The seismic misfit of the prestack inversion clearly exposes the peg leg multiples of the chalk particularly in line Y-Y'. These multiples are most prominent in the near angle stack in Figure 4.17 because it is the most difficult to remove multiples in the near offsets. There are high slope features around the basement horizon most clear in the mid-stacks. These features correlate to reflectors in the angle gathers with strong residual moveout, indicative of multiples. The seismic misfit in this PP data decreases with offset as expected from the inversion analysis windows. Generally, relative to the amplitude of the data, the seismic misfit is minimal.

Figure 4.18 Estimated P-impedance and S-impedance from PP pre-stack inversion in lines X-X' and Y-Y'.

The prestack PP inversion results are shown in Figure 4.18 and Figure 4.19. In the post-stack P-impedance estimate, the chalk was heavily variable and erroneous, at well A the impedance was over 12,000 m/s*g/cc while towards well B and E the chalk became indistinguishable from the sands. By including AVA information, the P-impedance at the chalk becomes much more consistent with the well locations and drastic spatial variations in impedance decrease significantly. The low impedance at the reservoir is much better captured in all locations but the top sand at Well B, which neither inversion was able to estimate.
The changes at the base and top of the reservoir are sharper in the prestack estimate without causing unrealistic fluctuations in the model parameters or smoothing through changes as in the post-stack inversion.

The improvement is clear in the interbedded aeolian and alluvial fingers around well K. The prestack P-impedance better separates the individual aeolian packages and illuminates the fact that these packages actually extend farther down in depth. The S-impedance closely follows the P-impedance spatially, but is less continuous in the sand bodies. For example, in the large sand body at well B, the estimated S-impedance shows bedding and stratification that according to the log is nonexistent. Any discontinuities in the sand body like these in the P-impedance estimation are amplified in the S-impedance. The internal geometry of the sand at well B consists of aeolian and fluvial sands, and these interval variations are much better distinguished in the prestack derived model estimates.

Figure 4.19 Estimated density and calculated Vp/Vs from PP pre-stack inversion in lines X-X’ and Y-Y’.

The final estimated model parameter, density, is the most difficult parameter to obtain and differentiate from the trend of P-impedance, particularly without far angles as Figure 2.2 demonstrates. Khare & Rape (2007) suggests that to obtain an accurate density inversion from PP data alone angles to 60° are needed, varying with Vp/Vs ratio of the specific
field. Unfortunately, with angles limited to $34^\circ$, accurate density values are most likely not attainable. The density estimates derived from prestack inversion, shown in Figure 4.19, replicate the pattern of P-impedance. This actually results in a match with most well logs but fails in areas where the density term deviates from the P-impedance trend as in Well A, H, K, G, and B. The Vp/Vs is computed based on estimated values of P- and S-impedance. As discussed in Chapter 2, the Vp/Vs should not show significant changes in the reservoir. There is a low correlation of the Vp/Vs values and the log values in the reservoir interval, most likely due to the S-impedance estimation simply being driven by the background trend created from the well logs.

Prestack PP inversion produced a P-impedance that captures heterogeneities in the reservoir and is more accurate than the post-stack inversion estimate according to control points. The AVA information in the field data is not constant, so the full stack is not equal to normal incidence as assumed in post-stack inversion. Thus, adding this AVA data significantly improved the P-impedance estimate. The shear impedance and density are not independently estimated in this inversion due to the limited angle range. The estimated S-impedance has a strong correlation with the P-impedance trend causing an inaccurate Vp/Vs. The derived density is also correlated with the P-impedance. Inclusion of direct multicomponent data may allow for a improved estimation of S-impedance in areas where the rock properties vary from the established background trend, thereby improving the calculated Vp/Vs.

4.5 PS Seismic Data Incorporation

4.5.1 Registration

Thus far, we have discussed PP seismic data in PP time. To incorporate multicomponent PS data into the inversion the PS time must be registered to PP time. This registration process is crucial to the inversion, as any mismatches in time can cause considerable error in the inversion. Because of its importance, many different methods of registration have been tested, such as attribute matching, horizon matching, and synthetic matching. Previous work in RCP has used horizon matching, but this method applies brute force stretching
and squeezing in time and is heavily dependent on how accurate the horizons are picked. Even with utmost interpretation accuracy, horizon matching registration generally leaves residual errors and may distort the PS wavelet from squeezing in time and interpolation between horizons (Ursenbach et al., 2013). This is why for the registration of the PS survey to PP time, we performed two stages of registration (1) using the Kirchoff Pre-stack Depth Migration Velocity Model and (2) horizon registration.

The most reliable method of registration is inversion in the native time domain to create Vp/Vs models, and register the PP and PS times using the Vp/Vs estimates that theoretically are the equivalent in both inversions (Jenkinson et al., 2010). However, this step can be skipped if the data were pre-stack depth migrated, as done in the Edvard Grieg surveys. Previous studies indicate that this method is preferred because using the correct velocity model from depth migration of PP and PS data, the position of the reflectors will coincide on both types of data (Vanzeler et al., 2014). Using the velocity models, the PS data can be converted to approximate PP time, with minor fluctuations. To correct for the minor fluctuations, a second pass of registration was performed. This was horizon registration using 2 horizons in PP time and PS time. The horizons were the Hordaland and the Shetland chalks shown in Figure 4.20. These horizons were the sole continuous reflectors that could be mapped reliably throughout the PS survey. Because the velocity model converts the PS data to PP time within an error of approximately ±25ms, the horizon picking was done as a refinement process. The calculated $V_p/V_s$ used to convert PS to PP time is shown in Figure 4.20. These values were cross checked for accuracy by looking at the log values. This quality control check confirmed that the calculated $V_p/V_s$ roughly approximated to smoothed low frequency log values.

A final step of registration was tested to see if any further refinement could be done. This test was registration with synthetic matching (Ming et al., 2013). In this process, the data is jointly inverted, creating a synthetic PS seismic dataset from the estimated model parameters. Because a higher weight is manually set onto the PP data than the PS, roughly
Figure 4.20 Registration window with (a) PP data and (b) PS data showing the result of the velocity model application and horizon matching to convert PS data to PP time.

60% weight, the PP seismic data will drive the model estimates. When these parameters are forward modeled, the resulting synthetic in PS seismic time should be better matched with the PP seismic time given the application of the same registration technique (velocity model and horizons). This inversion generated PS synthetic can be used to update the PS seismic data. Each angle stack in the synthetic data was cross correlated with original PS seismic data. The time variant time shifts produced were preconditioned with cross correlation values to assure moderate shifts were to be applied. Each stack was then individually shifted to better match the synthetic PS with the preconditioned angle stack dependent time shifts. Then a new wavelet was generated with this third pass registration. The approach appeared to slightly improve model parameters but significantly damaged repeatability, therefore, the synthetic matching step was omitted.

It is also important to check for lateral shifts in the PP vs PS data as this can be a bottleneck for registration. Lateral misalignment of the PP and PS seismic data can be caused by imaging issues related to inaccurate migration velocities in the overburden.
This has been a problem in the Grane field seismic data which underwent prestack time-migration (Jenkinson et al., 2010). The Edvard Grieg dataset was imaged with a prestack depth algorithm which better preserves amplitudes and handles lateral velocity variations, so the dataset is less likely to have lateral misalignment (Jenkinson et al., 2010). It is still an important issue to check because if there are lateral shifts in the datasets, the registration process may be in error and the joint inversion will suffer. The quality control step applied to check this was to pick major faults on both PP and PS datasets. Then view the faults in map view and see if there is any lateral offset in the features. Another method was to look at the variance attribute at the same depth and see if the faults or discontinuities illuminated with the attribute align on PP and PS datasets. With this analysis, we found that there were no lateral misalignment issues from the velocity models used for prestack depth migration, and we could proceed with the joint inversion.

4.5.2 Prestack Joint PP-PS Inversion

According to the Aki and Richards linearized approximation equation, the addition of PS data in seismic inversion should result in a more accurate S-impedance estimate, particularly with a large angle range. In the synthetic tests done in Chapter 3, the incorporation of the PS data did not greatly improve the model estimate but this was due to the estimated S-impedance values following the established background trend from the well logs. If the rock property trend varies from this background trend, then the S-impedance would not be accurately estimated from PP inversion alone. This is where PP-PS inversion can add value.

The PP-PS inversion inputs are the same low frequency model as the previous inversions, 4 angle dependent PP wavelets, 4 angle dependent PS wavelets, and 8 equal fold angle stacks. The four PS angle stacks were stacked with the same angle range as the PP angle stacks. Khare & Rape (2007) suggest that it is important to probe different angle ranges for PP and PS for PP-PS inversion because noise and acquisition geometries produce different usable ranges for PP and PS data. PS seismic data at the same incident angle as the PP data is associated with a smaller offset. However, in the area of interest both PP and PS contained
usable data till the critical angle of the caprock, the Shetland Chalk, which is 34° incidence. Even though the PS data has smaller offsets associated with this angle, the critical angle is 34° incidence for both PP and PS data.

<table>
<thead>
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<tbody>
<tr>
<td>Prewhitening</td>
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</tr>
<tr>
<td>Iterations</td>
<td>13</td>
</tr>
<tr>
<td>Gamma</td>
<td>Update Twice</td>
</tr>
<tr>
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<td>0.95</td>
</tr>
<tr>
<td>PS/PP Contribution Ratio</td>
<td>0.7</td>
</tr>
<tr>
<td>Angle Range</td>
<td>0-34°</td>
</tr>
</tbody>
</table>

Inclusion of the multicomponent data requires additional inversion parameters as discussed in Chapter 3. The optimal PP-PS inversion parameters are shown in Table 4.3. Higher prewhitening is given to dampen the influence of the seismic misfit on each inversion iteration because the inclusion of PS data adds more noise. Given the shear component in PS data, the gamma was updated twice in the inversion to allow for improvement. The scalar adjustment factor of 0.95 was found to produce the best match with the logs. Finally, a PS/PP contribution ratio of 0.7 was chosen to allow the PS data to adjust the inversion results while maintaining the high resolution of the PP data. This means the PP data has approximately 60% weight and PS has 40% weight.

Figure 4.21 The inversion analysis window for prestack joint PP-PS inversion showing inversion results generated at well A.
Figure 4.22 The inversion analysis window for prestack joint PP-PS inversion showing inversion results generated at well E.

Figure 4.23 The inversion analysis window for prestack joint PP-PS inversion showing inversion results generated at well K.

The inversion analysis windows in Figure 4.21, Figure 4.22, and Figure 4.23 show the impact of adding multicomponent information into the inversion. The expectation is that P-impedance remains similar to the PP prestack derived estimate while S-impedance improves. At well A, the estimated P-impedance at the chalk shows the same match as PP prestack inversion but the S-impedance is now closer to the well log values particularly in the chalk and the deeper alluvial section. The density remains the same as in the previous inversion. The seismic misfit of the PP seismic has increased due to the added influence of the PS data. The misfit in the PP data at the chalk is negative in the nears and positive in the mid, far, and ultra far. This suggests that at this location the synthetic AVA is smaller than in the real data, potentially due to chalk tuning at well A. Tuning effects amplify AVA in the real
data, which are not reflected in the synthetic. The PP seismic misfit has the most error in the near stack and at the chalk, while the PS misfit is minimal at the chalk for well A.

In well E, we see a similar improvement in the S-impedance at the chalk. However, the high impedance notch in the clean reservoir caused by the near PP stack is augmented with the inclusion of PS data. This sidelobe is only in the PP data, showing how heavily the inversion leans to the influence of PP misfit rather than PS misfit. The inversion may be combining the information from the sidelobe in the PP data with the low frequency reflector at the base of the reservoir in the PS data to create an amplified error. The PS misfit is higher at the chalk in this location because the high impedance notch is derived from the PP data and then used to create the PS synthetic.

Finally, at blind well K, there is minor variation from the PP prestack inversion. The low impedance shale section above the chalk is more accurately captured, as is the chalk, but the parameters deviate from the reservoir response. This could be from the difficulty of obtaining a well tie in the PS data with this horizontal short log, thus, the PS data comparison window may not be exact. In the case that the seismic traces shown in the PS are correct, the PS data shows the reservoir, the small trough under the chalk, that is not well captured in the PS synthetic data. At this control point the PS addition may not have provided value.

The model parameters from the joint inversion in the crossplot domain (Figure 4.24) show high correlation for P-impedance and S-impedance. In this domain, the P-impedance and S-impedance are slightly improved while Vp/Vs and density correlations are slightly reduced. Although this may suggest the PS data added little value, we know from the inversion analysis windows that the joint inversion is actually improving the S-impedance in our target zones. This crossplot domain, although conventionally shown, can mask the actual result of the inversion in the area of interest, particularly when there is error in the low frequency model.
Figure 4.24 Cross plot comparing P-impedance, S-impedance, $V_P/V_S$, and density derived from the prestack PP-PS inversion versus the well log data. The red line shows the linear fit line, a one to one relationship for reference. The correlation between the inverted and log P-impedance is shown in red.

The most interesting control point in this domain is Well F. As mentioned previously, this well is a blind well due to the limited log depth coverage and an inability to tie the log to seismic time. This well consists of tight conglomerates and is the most proximal to Well E which penetrates the thickest oil bearing reservoir. The low frequency model is unable to capture the sharp change from clean reservoir to tight conglomerate without this sample point. This makes blind well F particularly useful in observing the change in model parameters by incorporating PS data. The prestack PP P-impedance correlation at this well is 0.775 and S-impedance is 0.802. The joint PP-PS inversion decreases the P-impedance correlation to 0.759 but increases the S-impedance correlation to 0.832. This suggests that the joint PP-PS inversion has slightly reduced the accuracy of the P-impedance
model estimate with leakage from the PS data but improves the S-impedance estimate.

Figure 4.25 The input seismic data, predicted data, and misfit from the synthetic PP data generated from the PP-PS prestack inversion for (a) line X-X’ and (b) line Y-Y’. Chalk multiples can be seen most clearly at the left side of Y-Y’.

The joint inversion outputs a PP synthetic and a PS synthetic. The misfit calculated is shown in Figure 4.25 and Figure 4.26. The PP misfit from the joint inversion resembles the misfit from the prestack PP inversion but contains more fluctuations in the chalk. These fluctuations correlate to the multiples of the chalk that are the most clear in Figure 4.25b towards the left side of the seismic line. In Figure 4.27, we see that the near stack PP misfit contains much stronger chalk reverberations than in the PP prestack misfit. Overall, the seismic misfit follows the same decreasing amplitude with angle trend as the prestack PP inversion result, but contains more error.

In the PS seismic data, misfit appears to be less correlated to particular horizons or multiples and is more random. Figure 4.26b highlights the amount of random noise present in the data. The clean synthetic created from forward modeling the inversion result is unable to capture the noise level, and the resulting misfit is dominated by this random noise. The
Figure 4.26 The input PS seismic data, PS predicted data, and misfit from the synthetic PS data generated from the PP-PS prestack inversion for (a) line X-X’ and (b) line Y-Y’.

Figure 4.27 Seismic misfit variation with angle from the joint PP-PS prestack inversion for PP and PS synthetic seismic data for line Y-Y’. Chalk multiples are most clear at the left side Y-Y’ in the near stack PP data.

only unit with laterally continuous misfit is the chalk which is a strong reflector and again with the assumptions of the inversion algorithm of small reflectivity may not be captured accurately. The PS misfit follows the opposite trend of the PP, as the misfit increases
with offset (Figure 4.27). This can also be due to relative amplitude because in the PP data, the nears have the largest amplitude, while in the PS data, the fars have the largest amplitude. Potentially, the inversion seismic scalars are incorrect and underestimating the high amplitude in the nears for PP and the high amplitudes in the fars for PS. These scalars are automatically set by the AVO relationship between synthetics from the wells in the initial model and the seismic data. If this relationship varies spatially in the field, seismic misfit may be larger in the areas with most divergent AVO trends. This was analyzed further to see if the misfit was consistently high in the chalk for all well locations. The findings showed that there was variable misfit, some control points contained misfit at the chalk that increased with offset, some decreased with offset, and some contained minimal misfit. Because of this analysis, no change in scalars for nears or fars could be justified and the angle dependent scalars were not changed.

The prestack PP-PS inversion results for P-impedance and S-impedance are shown in Figure 4.28. The P-impedance estimate aligns with that from the PP prestack inversion. The joint inversion increases the impedance at the reservoir slightly compared to the PP inversion. No large changes should be expected in the P-impedance estimate. The changes

Figure 4.28 Estimated P-impedance and S-impedance from joint PP-PS pre-stack inversion for lines X-X’ and Y-Y’.
should be seen in S-impedance. In the prestack PP inversion, the S-impedance followed
the P-impedance according to the background trend set by the well logs, but in PP-PS
inversion, we begin to see deviations from the background trend. This S-impedance includes
more heterogeneities that may be real, or may be a result of the addition of the PS dataset
which contains lower signal to noise. At the well locations, the S-impedance match does not
seem to have improved, many of the deviations of the inversion result are not seen in the
log information. It is important to recognize that these logs are filtered to the frequency of
the seismic so heterogeneities and sharper changes in impedance do occur. Overall, the joint
inversion shear impedance shows deviations from the background trend and heterogeneities
that may not be reliable. However, the sands are a mixture of aeolian, fluvial, and alluvial
sands so these variations could very well be feasible for the geology of the field.

Figure 4.29 Estimated density and Vp/Vs from PP-PS pre-stack inversion for lines X-X’ and
Y-Y’.

The PP-PS inversion estimated density and calculated Vp/Vs are shown in Figure 4.29.
This density estimate equates to the density estimate from the PP prestack inversion. The
density term was not expected to improve based on the limited angle range of both the PP
and PS seismic datasets according to the analysis in Chapter 2. Khare & Rape (2007) suggest
PS angles of 55° are necessary in PS data to provide added value in the density component.
Next, the Vp/Vs results actually show significant improvement that the crossplots were unable to capture. The trend of Vp/Vs in the reservoir from the PP prestack inversion was highly inaccurate, high Vp/Vs zones were estimated where low were measured, and vice versa. The Vp/Vs derived from the joint inversion appears noisier and contains less obvious interpretable units, however, the general Vp/Vs trend is improved from the PP inversion at all well control points. This improvement is most obvious at wells K, E, A, D, and C. All these wells target the reservoir which is undergoing production. The Vp/Vs calculation from PP prestack inversion in the reservoir interval of these wells often estimated high Vp/Vs where low Vp/Vs should be shown. This may be due to the fluid effect in the reservoir. Hydrocarbon causes P-impedance to drop. The PP prestack inversion calculates an accurate P-impedance with this fluid effect and uses a relationship for brine filled siliciclastics to estimate S-impedance from P-impedance. This results in a S-impedance that is too low due to the erroneous fluid influence, which in turn causes the calculated Vp/Vs to be larger than the true value.

The joint PP-PS inversion is able to slightly improve the S-impedance in areas where the background trend is not sufficient. This is particularly clear in the calculated Vp/Vs. The S-impedance estimate shows increased heterogeneity in the reservoir which may not be reliable according to log data, but is feasible according to the geologic understanding of the variability in the sands. The sands vary from clean aeolian sands, interdune, fluvial, and alluvial sands so heterogeneities are likely. This improvement is significant given the quality of the PS data at the reservoir. In Chapter 2 we discussed the effect of the Grid sands attenuating the seismic energy before reaching the reservoir. In the PP data, the chalk was the only large impedance contrast that caused challenges. In the PS data, the Grid sands and the chalk are the obstacles. The Grid sands have a have a far stronger shear impedance contrast than P-impedance and the chalk has a slightly stronger shear impedance response. This all contributes to the decline of the reservoir quality in the PS data which is already lower frequency and lower signal to noise to start. Given this understanding, the
improvement from adding the PS data is notable. Higher quality PS data would likely result in even larger improvements in the shear impedance.

4.6 Discussion

Thus far, we have shown that in application to the Edvard Grieg field data, AVA information improves the P-impedance estimate, and addition of PS data improves the calculated Vp/Vs from a slightly improved shear impedance estimate. This S-impedance may contain error in the variability of the geology, but when used in conjunction with wells and the P-impedance, will provide another geophysical perspective in understanding the heterogeneity of the field. The previous analysis utilized 6 wells from the background model and 2 blind wells. The reasoning behind choosing these wells for the background model was that they had reliable logs and represented the variable geology of the field. Unfortunately, this leaves the shorter logs and deviated logs for QC purposes. Although the logs are only used for low frequency content, they are not completely blind, an accurate starting trend is given. This is why to utilize all the wells in analysis we can bandpass filter the logs and the inversion results to remove the low-frequency input from the initial model (Francis & Syed, 2001; Lancaster & Whitcombe, 2000). This can give a better look at how the inversion is performing without bias from including a well in the initial model.

Figure 4.30 shows the relative P-impedance models with the low frequencies removed in the model and logs. The values of the impedance are arbitrary, the purpose of this display is to measure the accuracy of the inversion by comparing the logs with the model parameter. The PP pre-stack and PP-PS pre-stack values are nearly identical, the largest improvement in the inverted P-impedance comes when AVA information is included. The fluctuations previously observed in the post-stack P-impedance can also be seen in this filtered version. As discussed, the chalk is not accurately captured by post-stack data alone. Additionally, the low impedance values of the reservoir at Well E are not captured by the full stack data. Ultimately, the AVA information allows the inversion to recognize sharper changes in impedance like the base and top of the sand while the post-stack estimate appears smoothed.
This is particularly noticeable in the aeolian fingers around well K and the base of the reservoir throughout the survey.

Next we can take this same filtering approach on the S-impedance and density derived from the PP pre-stack inversion and the PP-PS pre-stack inversion (Figure 4.31). The shear impedance for the inversions are similar but in certain locations where the background trend does not suffice for S-impedance estimation there is clear improvement in the joint inversion. The aeolian fingers in the joint inversion S-impedance are better separated and more distinguishable. At well A, there is a thin interval of marine sands followed by alluvial sandy matrix sediment. Both units are in the oil column. In the PP prestack derived S-impedance estimate, there is no differentiation in the lithology going into lower reservoir quality conglomerates. This is most likely due to the P-impedance estimate incorporating the hydrocarbon response and S-impedance simply being calculated from a linear relationship with this P-impedance, erroneously leaving fluid response in the shear estimate. The S-impedance response from the joint inversion recognizes this drop in impedance and reservoir quality with depth. By incorporating PS data, the S-impedance is better able to recognize the lithological changes below the main sand body, not only in well A, but also in wells H,
Figure 4.31 Filtered S-impedance and density results from PP post-stack inversion, PP pre-stack inversion, PP-PS pre-stack inversion.

K, E, F, and C.

An interesting feature in both relative S-impedance volumes is that the inversion is detecting heterogeneity in the large sand body at well B that the log does not show. The seismic contains continuous coherent reflectors indicating variations in the sand that are not shown in the log. These coherent reflectors align with the topography of the top chalk, suggesting they may be peg-leg multiples of the chalk. Multiples of the chalk can actually be seen in all areas of the inversion, particularly the alluvial section. The inversion assumes the multiple reflectors are changes in impedance and introduce the beds seen in all inversion
results. Future work can be done to remove the multiples to decrease this effect.

The joint inversion and PP inversion estimate for density are practically identical. The addition of PS did not change the result other than adding another component of noise. The angle range for PP and PS are limited to $34^\circ$, which is not large enough to extract an accurate density term. This density term in equation 3.13 contains a very small variance value of 0.03 suggesting that this term has minor influence on the model parameters. Additionally, angle ranges past $55^\circ$ for PS and $60^\circ$ for PP seismic data have been noted to be necessary an improved density estimation (Khare & Rape, 2007). The density results from the pre-stack inversions follow the background trend set by the well logs, which will be the result until extremely wide angles are included in the inversion. Unfortunately, wide angles are not feasible in this dataset given the critical angle of the chalk.

4.7 Summary

By looking at the inversion results in a filtered format we can better understand the relative changes that the inversion is producing without considering the absolute values that the initial model introduces. Well F, which was not included in the model and showed erroneous results in the model estimates, shows a match in this filtered domain. This shows that the inversion has correctly predicted the relative changes from the seismic but because the initial model does not have the absolute values in the range of the high impedance conglomerates in this area, the absolute results will be incorrect.

From this analysis we can confirm that the inversion algorithm is accurately predicting relative changes in the model parameters. The PP prestack inversion best estimates P-impedance, the PP-PS prestack inversion best estimates S-impedance, and neither inversion is able to correctly predict density due to angle range. The main improvement from including AVA in the PP inversion derived P-impedance is that sharp changes at the top and base of the reservoir become more clear and beds like the aeolian-alluvial strata become more separable. By adding PS data for joint inversion, the S-impedance and Vp/Vs is better able to characterize lithological changes in sands and conglomerates. In this study, we have
assessed the best combination of technologies to identify the reservoir quality of the subsurface in Edvard Grieg. We have also discovered bottlenecks of the inversion that correlate with seismic quality, such as the multiples in the chalk introducing heterogeneities in the rock properties. For future work, efforts to reduce multiples may improve the inversion, but for purposes of monitoring 4D changes, the multiples should not have an effect. This analysis was done on the baseline survey, moving forward with the same parameters, we can invert the monitor survey and observe time-lapse changes in impedance from both PP and PS seismic datasets.
The previous chapters have shown the theory and benefits of inversion, the rock physics of the field, and the inversion of the 3D field data. These methods will be modified and applied to the 2016 and 2018 vintages of the PP and PS seismic data for time lapse purposes. Enough time has surpassed between these surveys to see an effect from pressure and saturation change. Here, the value from the 4D dataset will be explored adding the dimension of time to the analysis. This chapter will cover time-lapse data preparation, 4D reflectivity signatures, time shifts, and inversion results of the 4D data.

5.1 Cross Equalization

When seismic surveys are acquired for time-lapse purposes, there is great care in replicating acquisition geometry and co-processing the seismic data to retain repeatability (Calvert, 2005). The goal is that the only differences between the two vintages of seismic, 2016 and 2018, would be as a result of production and injection. However, there is often a measure of noise that may be different between surveys that is independent of the changes in the subsurface geology. For instance, while the 2018 seismic survey in Edvard Grieg was being acquired, multiple other seismic operations were occurring simultaneously in neighboring fields causing seismic interference and external noise that was not present in the 2016 survey. Other factors can also cause differences in the surveys, such as tidal effects, changes in the seabed sediment, shot-generated noise (multiples and scattering), and random noise (Johnston, 2013). Therefore we have to further calibrate the seismic vintages through cross equalization to reduce differences caused by noise and illuminate the differences from development occurring in the reservoir (Rickett & Lumley, 2001; Ross et al., 1996).

Cross equalization steps were applied to the monitor (2018) surveys only, with the baseline (2016) surveys used as a reference for matching. The final cross equalization workflow is
shown in Figure 5.1. These steps provided an improved 4D match without overly conditioning the data, as the seismic data had been co-processed and matched for 4D purposes by the seismic processing contractor. It is important to note that the degree of cross equalization required, and its ultimate success, depends on the consistency in acquisition and in prior processing of the baseline and monitor surveys (Johnston et al., 2000). To test if the workflow improved the 4D signal, the repeatability was calculated before and after each cross equalization step was applied. The most common metric for repeatability is the normalized RMS difference or NRMS. NRMS is expressed as a percentage of nonrepeatability written as (Johnston et al., 2000; Kragh & Christie, 2002),

$$NRMS = \frac{200 \times RMS(\text{monitor} - \text{baseline})}{RMS(\text{monitor}) - RMS(\text{baseline})}.$$  \hspace{1cm} (5.1)

This measurement is extracted from a window in the overburden where no production or injection is occurring, therefore the differences should only be due to nonrepeatability of the surveys. The lower the NRMS, the higher the repeatability. An NRMS value is also extracted from the reservoir interval to track the effects of each step of cross equalization. The NRMS calculation, like all other repeatability measurements, is not perfect (Johnston, 2013). It can be biased by the amplitude content in the chosen extraction window. If the NRMS is calculated in a window of high reflectivity, it will be biased towards smaller values because the denominator of equation 5.1 will be small (Johnston, 2013). If the window contains low reflectivity, the NRMS will be biased towards larger values. With this idea in mind, the windows used in the seismic datasets for overburden and reservoir are shown in Figure 5.2. The overburden window in PP time for PP seismic data is 800ms from 900ms

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**Figure 5.1** Chosen cross equalization workflow. Steps are calculated from both surveys and applied to the monitor.
to 1700ms. For the PS data the overburden window covered the equivalent depth but in PS time the window was 1390ms, from 2150ms to 3540ms. It is important that both windows capture the same geology and avoid large acquisition footprints.

The range of NRMS values in Edvard Grieg surveys before cross equalization is 10-20% for PP seismic data and 30-40% for PS data. Previous time lapse studies have established a range of acceptable NRMS values for PP seismic surveys (Helgerud et al., 2013; Koster et al., 2000; Lumley, 2010; Pevzner et al., 2011; Urosevic et al., 2011). Offshore NRMS typically ranges from 10-25%. Permanent reservoir monitoring surveys often have even lower NRMS (below 10%), OBC and OBN surveys have slightly higher NRMS, and streamer data is typically on the highest end of offshore NRMS. Onshore NRMS ranges from 20-50% as onshore seismic data contains more noise (Detomo, 2012). According to these studies, even before cross equalization, the 12% NRMS of Edvard Grieg PP seismic data has excellent repeatability. The PS seismic data has poorer repeatability at 25-40%, but still within the range of an average onshore survey. The low NRMS values show that the data was well processed for time-lapse purposes.

Figure 5.2 Windows used for both cross equalization processes and NRMS measurements in PP and PS seismic data. The overburden window is where all cross equalization parameters were calculated for application to the entire survey. The reservoir window is for keeping track of the integrity of the reservoir response throughout the cross equalization steps. Spatial extent of these windows was the entire survey.
In the conventional cross equalization workflow, frequency scaling, trace by trace phase shifts, and time variant time shifts are applied (Ross et al., 1996). However, we omitted these steps. The frequency content of both PP and PS data were already scaled between vintages with no room for improvement. The global amplitude, phase, and time shifts were very minor shifts for refinement as the processor had previously applied global scalars. Trace by trace phase operations were not used because when applied to both PP and PS datasets, the NRMS increased in areas of the reservoir interval where no production or injection is occurring. These incorrect phase shifts are calculated from an interval with cemented sand bodies and heavy faulting that is unreliable as we discussed in Chapter 2. The phase shift calculation on unreliable reflectors will induce erroneous 4D amplitude. Finally, time variant time shifts are typically used to correct for shifts caused by production and injection. Unfortunately, these shifts were localized to a short window of time. The time shift operator is unable to separate a 10ms shift from surrounding reflectors and would cause false time-lapse responses as did the trace by trace phase shifts. More on these steps will be discussed in the following sections. Ultimately, the workflow in Figure 5.1, provided improvement in the repeatability of the datasets without damaging the time-lapse response, and was applied to the monitor angle stacks for the PP and PS datasets.

5.1.1 Amplitude Scaling

The first step of the cross equalization is to scale the amplitudes of the monitor to match that of the baseline using a single global scalar. This is done by measuring RMS amplitude variation at each trace between the baseline and monitor surveys. This forms an RMS scalar at each trace location shown in Figure 5.3. These scalars are averaged to obtain the global amplitude scalar. The spatial extent of the extraction was limited to the area of high fold for averaging purposes to keep the low fold areas from heavily influencing the global scalar with noisier data. The global amplitude scalars are shown in Table 5.1. The scalars for PP and PS seismic datasets are very minor but generally increase with offset. The trace by trace amplitude scaling uses the RMS scalars calculated at each trace, shown in map view
in Figure 5.3, and applies them to the entire volume. Each trace is multiplied by a different scalar.

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<th>PP Global Amplitude Scalar</th>
<th>PS Global Amplitude Scalar</th>
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<tr>
<td>0-34°</td>
<td>1.014</td>
<td>1.011</td>
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</tbody>
</table>

Figure 5.3 Trace by trace amplitude scalar on full stack PP (left) and PS (right) datasets.

5.1.2 Phase and Time Shift

Variations in phase and time between monitor and baseline were addressed by applying a global phase and time shift to the monitor, followed by a trace by trace time shift. The global value is calculated by cross-correlating traces in the overburden window. This produces the trace by trace time shift calculation and phase shift calculation, shown respectively in map view in Figure 5.4 and Figure 5.5. In this same step, a cross-correlation map is made, assigning a value from 0-1 to every location. Before applying the global phase and time shift, we enforce a conditional statement where the phase and time will only be averaged and applied if the cross-correlation in that area is over 0.9. This avoids unreliable traces in the global scalar from low fold areas at the edges of the survey. The applied global phase and
time shifts are shown in Table 5.2. The global shifts are minor and cause minimal change in NRMS.

<table>
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<th>PS Global Phase</th>
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</thead>
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<td>0.178°</td>
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<td>-0.547°</td>
<td>-0.140ms</td>
<td>-0.075°</td>
<td>-0.028ms</td>
</tr>
</tbody>
</table>

Figure 5.4 Trace by trace time shifts on full stack PP (right) and PS (left) datasets.

When applied, the trace by time shift showed improvement in overall data quality as did the trace by trace amplitude shift from the previous section. The only drawback to these applications is an erroneous 4D response produced in the North of the field. However, upon inverting the data before and after this application, there were vast improvements in the 4D joint inversion when these corrections were applied. Major time shifts were apparent in the chalk, that were corrected for with this trace by trace application, yet trace by trace phase shifts only caused complications. The phase shifts calculated for both the PP and PS seismic data are heavily influenced by the injectites in the overburden. The PP data is influenced solely by the shallow cemented injectites and the PS data is also influenced by the Grid sand injectites, discussed in Chapter 2. These phase differences are caused by ray path obstacles in the overburden. Applying the trace by trace phase shift increases the NRMS by up to
3% and produces an acquisition footprint. Unfortunately, the cross correlation conditional statement is not possible in trace by trace operations to avoid unreliable areas. Therefore, we will not apply the phase shift trace by trace operator. Nonetheless, the PS trace by trace phase correction maps can be a tool to highlight zones of nonrepeatability, potentially caused by distortion in the wave field from heterogeneous overburden. Two features are highlighted in the PS maps, (1) geometric positive phase corrections associated with the Grid sand injectite pathways in the polygonal fault system, (2) an anomalous negative phase feature South of the platform.

Figure 5.5 Trace by trace phase shifts on full stack PP (right) and PS (left) datasets. Not applied in cross equalization workflow.

5.1.3 NRMS Analysis

In the cross equalization workflow, the NRMS was taken after every step to measure the success or failure of each application. The lower the NRMS, the better the repeatability and lower the noise in the survey, meaning the data is able to capture smaller 4D responses. This is not the only QC step that went into determining the cross equalization workflow. The step that provided by far the most improvement in NRMS of the overburden was the time-variant time shifts. However, the reservoir difference response was completely altered. Because this dataset was history matched and processed for 4D purposes, the only steps that were necessary were global scaling factors and two trace by trace scaling steps. The NRMS in the overburden did not always decrease from this application as seen in Figure 5.6, and
phase and time shifts for PP data in particular typically did not change the NRMS values. However, the steps overall provided minor improvement in the reservoir response.

<table>
<thead>
<tr>
<th>Overburden</th>
<th>PP</th>
<th>PS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Angle Stack</td>
<td>Raw</td>
<td>Global Amp</td>
</tr>
<tr>
<td>0-17</td>
<td>21.96</td>
<td>21.29</td>
</tr>
<tr>
<td>17-25</td>
<td>16.16</td>
<td>15.71</td>
</tr>
<tr>
<td>25-30</td>
<td>15.65</td>
<td>15.03</td>
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<tr>
<td>30-34</td>
<td>16.81</td>
<td>17.48</td>
</tr>
<tr>
<td>0-34</td>
<td>10.87</td>
<td>11.18</td>
</tr>
</tbody>
</table>

Figure 5.6 NRMS measured between baseline and monitor surveys for PP and PS data between each step of cross equalization in the overburden window. P=phase, T=time, TbT=trace by trace.

The NRMS of overburden is 15-20% in the PP data, and 25-45% for the PS data. The near stack for both datasets is consistently the noisiest. Angle dependent 4D analysis is advised based on this variation. The NRMS of the reservoir where no changes are occurring is much smaller and more indicative of both the level of noise in our area of interest and what 4D signal the data is able to resolve. Interpreting increases and decreases in the NRMS at the target is more complex than in the overburden. Although increasing NRMS in the reservoir where production or injection is occurring are actually preferred, the NRMS should not increase in areas where production and injection are not occurring. To QC both zones, the NRMS window was analyzed in map view over each step as shown in Figure 5.8. At the reservoir, the PP data has an NRMS range of 9-14%, while the PS has an NRMS of 12-23%, detailed in Figure 5.7. Again the nears contain the most noise and the full stack has the least noise.

After the cross equalization process, we can look at the final NRMS slices in the reservoir to assess the repeatability of the PP and PS datasets. Major high NRMS events should be associated with production or injection. In the PP dataset this is clear as the highest values of NRMS (disregarding the low fold areas at the edge of the surveys), are due to injection. Minor NRMS highs around producers in the East and below the platform could be changes as a result of production. However, between the injectors to the West, there is an incoherent high NRMS event that correlates with the strongest shallow cemented sand
Figure 5.7 NRMS measured between baseline and monitor surveys for PP and PS data between each step of cross equalization in the reservoir window. P=phase, T=time, TbT=trace by trace. Note in the reservoir, increased NRMS implies the 4D response is getting stronger, which is preferred. Care was taken to ensure that the increase is associated with the development effects, not random noise.

body identified previously in Figure 2.20. The seismic signal below all sand injectites suffers, but this injectite is by far the highest amplitude anomaly. In the PS data, the NRMS is much larger due to overall decreased data quality. The platform footprint also extends much farther spatially in the PS dataset, particularly south of the platform, due to PS acquisition geometry. Additionally, the Grid sands in the overburden act as a major ray path obstacle in the PS data. Calvert (2005) suggests that the major source of nonrepeatability in seismic data lies in the scattering and distortion of the wave field as it passes through heterogeneous overburden. The Grid sands likely contribute to the significantly lower PS NRMS. From this analysis, the cross equalization steps are analyzed to produce the best match between monitor and baseline and identify zones of low NRMS.

Figure 5.8 Reservoir NRMS slice from PP and PS full stack datasets after cross equalization.
5.2 Time-Variant Time Shifts

Time-variant time shifts correct for the temporal effects of production and injection, and hopefully expose 4D amplitude only anomalies. These shifts are calculated by cross correlating an 80ms window in PP time at every sample with a maximum allowable time shift of 4ms. Time shifts induced from reservoir development in the PP data were typically less than 2ms. Applying time shifts caused the NRMS to drop significantly for most of the angle stacks, while the 4D amplitude response decreased in magnitude. This decrease in amplitude was expected because when the reservoir reflectors are not perfectly aligned in time where time shift is present, the 4D difference response is magnified (Calvert, 2005). Correcting for these time shifts should decrease the amplitude difference, as done in this case. Theoretically, this application appeared sound. However, there was a larger change in the difference amplitude after the time variant shifts were applied than expected (Figure 5.9).

![Figure 5.9: Full stack PP amplitude difference (a) before and (b) after time variant trim statics application, with (c) applied time shifts. Negative time shift above chalk introduced by noise.](image)

The 4D response near the water injector post time-shift application (Figure 5.9) warranted further analysis as the effect of time shift was expected to decrease the amplitude of the 4D response, but not show variations above the chalk. The seismic response seen at the chalk and reservoir in the PP seismic data is a peak-trough pair, both in baseline and monitor. If there was only a small time shift in the data, the difference should look like the time derivative, which is not what is seen in Figure 5.9b. This was tested by applying the calcu-
lated time shifts to the baseline data, then subtracting the time shift applied baseline data from the original baseline. The result was a zero phase response as theoretically expected, suggesting the difference in our data is either solely amplitude change or the time shift is very complex. Traces were individually examined before the time shift was applied. In Figure 5.10, the only reflector with a very minor time shift is the trough below the chalk, which is the reservoir. The time shift is localized to 10ms which is far smaller than the correlation window of 80ms. This window cannot be reduced to 10ms as arbitrary time shifts throughout the survey would be created, matching noise, even with the preconditioning conditions that depend on cross-correlation.

Figure 5.10 Sparsely sampled traces in PP seismic data at the injectors before time variant trim statics application.

Figure 5.11 shows the result of applying the time-variant time shift. The upwards shift of the monitor survey calculated from the trough corrects for the trough at the reservoir, but causes erroneous 4D response in the near overburden and the chalk that can be seen clearly in Figure 5.9. This trough is not continuous in the survey and nonexistent in most locations of the PS data, making horizon picking for time shift correction impossible. Although the time variant time shifts improved the NRMS for the angle stacks, to avoid errors in time-lapse interpretation, this step was omitted from the workflow.
Figure 5.11 Sparsely sampled traces in PP seismic data at the injectors after time variant trim statics application.

5.2.1 Time Shift Analysis

The time shifts induced by production and injection are in the data because a common migration model is used for both datasets, and updating the model would be very costly (MacBeth et al., 2019). Even so, depth migration velocity models do not contain this level of detail. The preferable and least costly option is post-stack alignment correction for the small time shifts. Although these shifts are typically removed from the data for reflectivity analysis and inversion, with recent advances in the repeatability of 4D surveys they have been proven to show interpretation value (MacBeth et al., 2019). Time shifts can be caused by geomechanical effects and fluid saturation changes. Changes associated with time-shifts are long wavelength if they correspond to stress/strain geomechanical effects due to depletion or injection, but are more localized when influenced by fluid saturation and contact movement (MacBeth et al., 2019). This can aid in identifying the effects of stress versus saturation further than from solely using amplitude changes, as these measurements have different resolution and influencing factors (Johnston, 2013). Using the attributes jointly can aid interpretation, so although the time shifts were not utilized in the cross equalization workflow they can be used for interpretation purposes.
There are various scenarios in the Edvard Grieg field that may produce time shifts including water injection, gas injection, production, and gas exsolution. Sufficient time (two years) passed between surveys to observe geomechanical changes as well as saturation changes. Water fronts typically travel between 0.1 and 2 km/year and gas fronts between 5 and 13 km/year (MacBeth et al., 2019). Relative to fast diffusion and equilibration of pressure, saturation changes are slow to develop and are more localized in nature (MacBeth et al., 2019). Time shifts are influenced by a combination of saturation and pressure changes, and the result is a composite response. In the case of water injection, a pressure increase creates reservoir expansion resulting in a velocity slow down and positive time shift, while injected water replacing the oil will increase the velocity resulting in a negative time shift. The time shifts deconstructively interfere and may cancel each other out. However, for gas injection the time shift from saturation and pressure reinforce each other. Previous work has suggested that time shifts produced from geomechanics are far greater than those created by saturation changes (MacBeth et al., 2019). Only a few MPa of pressure change overpowers the water replacing oil mechanism (Omofoma & MacBeth, 2016). However, the exact transition point between pressure and saturation influence depend on its compressibility and porosity. The higher the pore compressibility and porosity values the larger the time shifts.

5.2.2 PP Time Shifts

The PP time shifts at the chalk level are shown in Figure 5.12 for each angle stack. These time shifts were calculated with the baseline as reference, so a positive time shift would indicate a softening or velocity slow down, while a negative time shift suggests a hardening or velocity speed up. The time shifts increase with offset due to larger offset raypaths spending more travel-time within the slower interval. The time shifts at the edges of the survey are due to the low fold areas, and the noisy time shift between the two northern injectors is directly beneath the highest-amplitude cemented sand body. Although these areas cannot be used for interpretation purposes, the rest of the survey shows reliable time shift calculations.
Four scenarios are interpreted to cause these time shifts, labeled on Figure 5.12. These numbers are assigned to specific 4D scenarios and will remain consistent in later sections. Situation (1) is updip of water injectors W-1, W-2, and W-3. This area is where there is seawater injection, causing a pressure build up and a subsequent velocity slow down. However, the response is spatially extensive and short wavelength in time indicating a change due to saturation. The effect’s extent is also limited to updip of the injectors also indicative of saturation change. This should cause the opposite effect, a hardening and negative time shifts (velocity increase). The operator of the field hypothesizes that this shift is due to the velocity model, but the relative magnitudes are correct. If the velocity model is too slow in the reservoir interval for the monitor, using the same velocity model will image the reservoir deeper in time and cause a positive time shift as we see. Theoretically, a method in which
a slowdown can occur in the case of water injection is chiefly due to geomechanical effects. The pressure increase could be driving the response, although the effect is much smaller wavelength than expected in a geomechanical effect, so this is most likely not the case. The issue is likely attributed to the processing of the datasets. However, relative changes of magnitude can still be interpreted. Injector W-1 shows the largest response as this injector only contained water while the other, W-2, injected a combination of water and gas. Gas and water injection produce opposing time shift responses which cause the combination injection to cancel out and decrease the overall time shift. Although the time shift in W-2 is smaller, it is more dispersed to the East, potentially in a stratigraphic finger of aeolian sediment.

Situation (2) is a negative time shift or hardening associated with water replacing oil, as the water has faster velocity, suggesting this may be the water front. Situation (3) is a negative time shift around injector W-2, the combination gas and water injector. The negative time shift indicates a speedup which again opposes the theory that gas injection into water or oil would cause a slow down. The error in time shift direction could be the same as the operator hypothesized for scenario (1). The speedup can be due to water replacing oil but the same response would be expected updip as well. Situation (4) is more uncertain. All other time shifts increase with offset as expected except scenario 4 suggesting that the response may not be real. The interpretation of situation 4 is a slow down resulting from an increase in pore pressure or decrease in velocity. This area is surrounded by producers with one water injector. It is the most updip portion of the survey and has been interpreted as a zone of potential gas exsolution. Gas coming out of solution and migrating updip, thereby displacing oil, would in fact cause this slow down. Scenario 4 contains more uncertainty in interpretation but correlates with the zone of gas exsolution.

The strongest time shift response in the PP seismic data comes from the pressure response proximal to injectors W-1 and W-2. The response from W2 is shown in cross section in Figure 5.13. At W-2, there is a long wavelength column of positive time shift with a max shift of 3ms. This slowdown is due to the pressure effect from the injector mixed with the
saturation change from gas injection. The time shift from W-1 is only a result of pressure effect since this injection is water into 3 meters of oil which is undetectable. The effect captured at the reservoir shown in Figure 5.12 is much smaller in amplitude and mostly influenced by saturation change. At the reservoir interval (20ms below the chalk), situations 1, 2, and 3 are shown as effects from the injector, however situation 4 does not have a clear cause and does not increase with amplitude, supporting the hypothesis that it could be a time shift driven by noise.

Figure 5.13 Cross section of PP Time shifts calculated from full stack dataset. Section goes through well W-2 and the producing cluster of wells around the platform.

Injectors W-2 and W-1 produce strong time shifts from pressure, saturation, or a combination of both. According to the map view of the extracted time shifts for PP data at the reservoir, W-2 shows the largest time shifts. However, the largest time shifts that occurs below the chalk at the injector perf locations are not captured in the previous map. The time shift in W-2 is larger than W-1 shown in Figure 5.14. This is because W-2 injects gas and water. Gas injection causes a softening and adds constructively to the softening effect from pressure, where W-1 is water injection that is hardening and subtracts from the softening caused by pressure. This causes the largest time shifts to occur proximal to W-2.
5.2.2.1 Time Shift Modeling

The time shift calculated in the interval from water injection is complex and localized to the reservoir. 1D modeling of this scenario with well E suggests that a minor positive time shift is expected but not the 1ms magnitude seen in this area. Well E represents the aeolian facies more indicative of the sediment at injector W-1. Injector W-2 consists of interbedded sands of fluvial content and fluvial rework with alluvial sediment. The 4D response in lower porosity sediment should be smaller in amplitude, however, there could be a component of thickness involved and the added time shift from gas saturation. The sands in W-2 have more variable thicknesses and may contain a more complicated effect from tuning. To test this hypothesis, we created a wedge model for baseline and monitor using the Aki Richards equations at the central angle of 21°, shown in Figure 5.15.

This wedge model uses a wavelet from the PP seismic data and the exact lithology of well E; incorporating the full log instead of a blocky model, with the shale in the overburden, the two units of chalk, the aeolian reservoir, and the conglomerates at the base. The wedge consists of the aeolian reservoir with oil representative of baseline conditions. For the monitor conditions, I assume 83% water saturation and pressure increase. By using the exact values
Figure 5.15 Wedge modeling done with Well E. Wedge consists of aeolian reservoir with interdune inclusion capped by a tuned unit of Ekofisk and Tor chalk with tight conglomerate base. Monitor modeled for injection scenario with 83% change in water saturation and pore pressure increase of 53 bars. Sedimentology replicating interpreted geology at area of injection.

found in the field we can best replicate the injection scenario. The post-stack synthetics were calculated, then difference and time shifts were calculated by cross-correlation with the same parameters as the field data. This analysis was done both in Hampson Russell and
Rokdoc software to confirm results.

Figure 5.16 Time shift from modeling done on well E for the single variable 83% water saturation change scenario vs double variable water saturation plus pore pressure increase scenario.

The chalk aeolian reflectors show a peak-trough pair, the difference response should be the derivative, a zero phase response, until tuning is hit where the difference becomes a trough peak pair. With decreasing reservoir thickness (into tuning), the amplitude difference increases as do the time shifts. This increase in amplitude is seen at both the top and base of the reservoir. We see that the time shift is chiefly in the base of the reservoir, the peak at the base of the wedge. When the 80ms cross-correlation window includes the reflection at the base reservoir, the time shift is at maximum. As the thickness of the reservoir decreases, the time shift increases to 0.5ms, which is less than the max time shift we see in the injectors in the PP seismic data. This is because in one scenario, W-2, the proximal injector response includes gas, but exact gas saturation information was not provided. The other injector injects into the water leg chiefly with only 3meters of oil, in which time shift is dominated by pore pressure increase, the positive shift seen in the data.
In Figure 5.16, we compare the time shift in a scenario where water saturation increases 83%, to the scenario previously shown that combined this saturation change with a pressure change. When the reservoir is less than 50 meters, there is a positive time shift, but at larger thicknesses the time shift becomes negative as expected in a hardening scenario where the velocity is increasing. The thinning of reservoir largely effects both the magnitude and sign of the time shift.

From this modeling we can conclude that the time shifts in the data and the 4D difference have been amplified from the tuning at the reservoir and the time shifts are actually the largest at the base reservoir. Additionally, because thickness strongly alters time shifts, interpretations on time shifts are complicated in thin reservoir zones.

5.2.3 PS Time Shifts

Thus far only time shifts for PP seismic data have been discussed, but it is also possible to observe large time shifts in PS data that can be roughly twice the size of PP time shifts. The challenge here comes in the processing of the PS data as multicomponent data is more difficult to process and error is more likely than in PP seismic data. Nonetheless, previous studies suggest PS time shifts are most influenced by reservoir pressure but can also be correlated with gas saturation changes (Bishop Jr & Davis, 2014). Trani et al. (2011) suggests PP and PS time shifts can used jointly in interpretation to aid in separating pressure and saturation effects. Although benefits of PS time shift analysis have been found, they are not commonly used in industry practice.

Theoretically, the time shifts in the PS data should be caused by geomechanical effects and not saturation changes. Figure 5.17 shows the PS time shifts with angle extracted exactly at the chalk horizon, no distinction can be made vertically between the chalk and reservoir given the time shift window. These time shifts were calculated in 120 ms windows at each sample with a max time shift of 8 ms. In the PP data, the time shifts increased with offset but in the PS data, particularly for the anomaly South of the platform, the time shift is the greatest at the mid angles. This is most likely due to the PS AVA. The PS time shifts
overall are far noisier than the PP time shift throughout the survey but two features can be noted through the noise. First, at well W-1 there is a minor response at the reservoir, indicating that the larger pressure driven time shift is under the chalk. Secondly, there is a speedup South the platform causing an anomalous time shift. This speedup is potentially due to pressure drop and compaction at the reservoir.

Looking in cross section at these two features in section E-E’ in Figure 5.18, we can note that the long wavelength geomechanical effect of the injector at W-1 is twice as large as the PP time shift. In section F-F’, injector W-2 shows a very small positive time shift. PS data are not influenced by saturation changes as much as PP data, therefore a smaller time shift in W-2 is from a lower positive pressure change at the injector. The PP time shift is large at W-2 due to the residual gas saturation.
Figure 5.18 Cross section of PS time shifts calculated from full stack dataset. Section E-E’ goes through well W-1 and the producing cluster around the platform. Section F-F’ goes through well W-1 and W-2 with CS as the unreliable zone under a large shallow cemented sand body. The zone marking production is the PS anomaly South of the platform.

The positive anomaly in E-E’, observed in the map view is clear in the cross-section to be long wavelength and starts above the chalk. The anomaly is most likely related to a geomechanical change due to its temporal extent and could be from a local compaction at the chalk or reservoir due to production. The event is not located directly where the most production is occurring as expected, but farther south where the largest phase shift was calculated, potentially indicating a pressure differential in the reservoir. This area is also roughly associated with where the half graben wedge enters tuning, however, tuning effects are much stronger farther South, lowering the likelihood that the event is due to thickness. Additionally, tuning can amplify the time shift but is not known to cause them (Falahat et al., 2011).
In the Ekofisk field in the Norwegian North Sea, the reservoir is the Ekofisk chalk, which is part of the Shetland chalk seal in Edvard Grieg. A challenge faced in the Ekofisk field is that the chalk reservoir has compacted with the pressure drop from production, enough to cause seafloor subsidence (Keszthelyi et al., 2016). In the Edvard Grieg field, there may be similar compaction of the chalk seal or the reservoir during production that causes the anomaly South of the platform. Although this is more unlikely, as the Ekofisk chalk is the seal, not the reservoir. Additionally, there is a layer of the Tor chalk which is a much tighter and harder limestone between the Ekofisk chalk and the reservoir. It is unlikely that there could be leakage into the seal if the Tor chalk is present throughout the field.

These time shifts can then be used in conjunction with amplitude difference analysis and inversion results to better understand the effects of development onto the reservoir. However, there may be mistie between time shifts and amplitudes (Falahat et al., 2011). Time-lapse changes in amplitude are the result of impedance change, the product of density and velocity. Time shifts are only dependent on velocity, so if density and velocity are not correlated, the 4D attributes will have different information (Johnston, 2013). Time shifts are not caused by tuning while amplitudes are strongly effected by tuning and interference from nearby reflections as we see in the reservoir and chalk in Edvard Grieg. Time shifts are only dependent on wavefield kinematics and have smaller impact from non-repeatability and noise of acquisition geometry. Conversely, amplitudes are strongly influenced by the velocity model and migration algorithm (Kvalheim et al., 2007), wave attenuation, and nonrepeatable noise. Even though the time shifts and amplitudes may not be consistent, the interpretations should follow the well and production data of the field. This more concrete data can be used as a calibration to decrease the nonuniqueness of the time shift and amplitude difference interpretation while maintaining consideration of the factors differentially influencing each 4D attribute.
5.3 4D Amplitude Difference

The amplitude difference of the PP and PS seismic data can show how PS data can add to conventional PP 4D interpretation. The quality of the amplitude difference influences how the well the inversion algorithm can perform. Additionally, in joint PP-PS inversion, there can be leakage of P-impedance into S-impedance as shown in Chapter 4. Analyzing these inversion results without context may muddle interpretations, if not used in conjunction with the original reflectivity. For analysis, the amplitude difference is taken at each angle stack. However, for the purposes of our discussion, full stack reflection data suffices. The reservoir is class 4 meaning it contains little to no AVO, so the AVO will follow the background AVO trend for PP and PS seismic data. Therefore, an AVO inversion to convert to intercept-gradient (AI-GI) domain would not provide any additional information as found in previous work done by AlMustafa & Giroldi (2013). Discussed in Chapter 2, the AI-Vp/Vs and AI-SI domain may provide more useful insight on rock properties and fluids. For these reasons, model based inversion was performed and reflectivity analysis was limited to amplitude and offset.

5.3.1 4D PP Amplitude Difference

Figure 5.19 shows the mean amplitude extraction of the reservoir interval including 10ms above the trough of the reservoir and 40ms below. A positive amplitude difference shows a hardening while a negative amplitude difference shows a softening. The values of the scenarios correlate to those of the PP time shifts. Situation (1) shows the water front caused by the seawater from injectors W-1 and W-2. W-2 looks to be stronger in amplitude, but in time shifts W-2 showed a larger fluid response. The time shifts also appeared more dispersed in the injection at W-2, as the response continued into one of the aeolian sand fingers. In the amplitude difference, this dispersion is seen in the response from injector W-1 to a different aeolian finger in the South.
Situation (2) shows the effects of reservoir depletion, not captured by the time shifts. The amplitude difference shows a hardening along the producing wells. This hardening can come from a drop in pressure associated with production as well as a reduced gas saturation. The saturation change is most likely reduced gas saturation. This is caused by pressure dropping below bubble point from production, inducing gas exsolution at the 2016 baseline, before water injection began, then subsequent gas migration updip or gas production. A hardening can also come from water replacing oil. This may be the case for the stronger 4D response around Well R, as Well R has been producing seawater (the water that was injected) since the summer of 2018. This could suggest that the water front is complex and may be propagating farther from injector W-2 due to the permeability of the underlying...
sediment.

Injector W-2 contains a thick column of sand but moving updip, eastward, the sand thins quickly. Water fronts follow simple gravitational laws before reaching a contrast in permeability. A low permeability layer on top of the reservoir may push the water down, and a low permeability layer on the bottom of the reservoir may squeeze the water through the top. Because the water front from the northern injector travels from a thick to thin reservoir relatively quickly, low permeability layers of alluvial sediment may force the water into a smaller area of sands. According to theories of basic flow and conservation of energy such as Bernoulli’s equation, decreasing area of flow causes increasing velocity (Shames & Shames, 1982). Although these theories have assumptions violated in this case, like constant lack of friction and streamline flow, this may be an explanation for why the seawater from injector W-2 has extended to Well R. Additionally, the hardening response continues farther North than expected, but this could be from the thinning of the reservoir from a 40m aeolian column to the 5m marine Asgard sand moving North of the fault, outside of the half graben.

Situation (3) is a softening event due to the gas injection at W-2. The slowdown is a combined effect from gas saturation and pressure increase proximal to the well. Situation (4) shows a softening at the updip portion of the reservoir. Potentially caused by gas exolution and migration updip, leaving the heavier oils to cause the response in scenario (2). Finally a smaller anomaly in scenario (5) is consistent in all extractions. Although not as clear as other 4D responses, scenario (5) may show a secondary gas cap and gas compartmentalized from heavy faulting and changes in stratigraphy.

The difference amplitudes in cross-sections shown in Figure 5.20 align with the interpretations described in map view. Both injectors cause a hardening from water saturation (Situation 1). In cross section, we can see the difference around the injector as a response due to pressure and saturation change. The response around the injector is much stronger in W-2 because gas injection and pore pressure increase cause amplitude response that adds constructively and leads to softening around the reservoir.
Figure 5.20 Cross-section of PP difference amplitude calculated from full stack dataset shifted to quadrature phase for interpretation purposes. Sections go through injectors and producers. Producing wells are hidden due to a lack of log data to accurately tie the wells in depth.

Residual gas close to the well could amplify this response and cause the stacked signature of layers seen in the 4D. Figure 5.21 shows that the troughs in the difference amplitudes typically align with higher reservoir quality zones with low velocity and high porosity. These pockets of high porosity could confine the residual gas. In injector W-1, there is a smaller response as the water is injected into the water column (with an undetectable 3m oil column), any response is from pressure increase. There is an anomalous small 4D effect below the perforated interval due to a positive time shift from pressure effect. This is important to note. Because the time variant time shifts aren’t corrected for, there may be erroneous 4D effects or amplified 4D effects caused by mismatched reflectors.

Situations (2) and (4) are also highlighted in the cross-sections shown in Figure 5.20. The peak in the middle of the survey is a result of depletion and is strongest around Well R in line B-B’. Finally a clear softening from gas concentration at the most updip portion of
the half graben is seen in both sections as situation (4).

Figure 5.21 Cross-section at injector W-2 showing residual gas accumulations in higher reservoir quality intervals.

5.3.2 4D PS Reflectivity

In PS reflectivity, we expect to see only effects caused by geomechanics, with minimal effect from saturation change. Figure 5.22 shows the mean amplitude extraction of the full stack difference of the PS data. This extraction shows higher levels of noise than in the PP data. The fluid response from the injectors is no longer seen nor is the gas exolution in the updip reservoir, or the reduced gas saturation near the injectors. This confirms that situations (1), (2), and (4) are driven by saturation change.

There are two major geomechanical effects seen in the PS reflectivity that correlate to those in the PS time shifts. Situation (1) being the injectors W-1 and W-2, the PS data only recognizes the softening negative amplitude difference caused by pressure increase proximal to the injector. The response from W-1 is stronger than W-2, indicating that although W-2 is alternating gas and water injection, the injection at W-1 induces more pressure change. Situation (6) is the same anomaly described in the time shift section. This is a long wavelength response with a peak at the chalk indicating a hardening. This event is most likely due to a compaction of the reservoir or chalk combined with pressure drop from
depletion. Although a hardening response is feasible, the magnitude is much larger than expected and could be heavily amplified by residual time shifts.

![Figure 5.22 Mean amplitude extraction of the PS difference full stack. Window was taken 10ms above the top reservoir and 100ms below the top reservoir. Circled numbers represent different 4D scenarios.](image)

Crosslines C-C’ and D-D’ in Figure 5.23 highlight the two strongest anomalies seen in the PS amplitude difference. W-1 again shows stronger 4D response and a cyclical long wavelength time response, while W-2 shows a smaller 4D response. The anomaly south of the platform in D-D’ is very long wavelength in time and begins above the chalk which may support the hypothesis that the chalk is compacting. This amplitude however should decrease significantly if time shifts are corrected. Overall, in these cross sections it is clear that PS difference is much noisier than PP due to the heightened acquisition and processing challenges of PS data.
5.4 4D Pre-Stack PP Inversion

In previous chapters, we discussed and tested various inversion techniques on the 2016 baseline surveys. To perform a 4D inversion, the same parameters and wavelets are used on the 2018 cross-equalized dataset, then the inversion results are subtracted (monitor minus baseline). Inversion parameters are consistent to insure the changes between inversion results are only due to 4D response. Even if parameters could be changed, the logs used for inversion analysis QC were acquired before production and would not be an accurate representation of the reservoir post production and injection. We begin with PP prestack inversion.

The model estimates of the PP prestack inversion are shown in Figure 5.24. The P-impedance change correlates strongly with the PP amplitude difference. However, the P-impedance extraction is much sharper and 4D events are more separable and clear. The
chief concern in the PP prestack result is in the S-impedance. This parameter simply mimics the changes in P-impedance, illustrating points discussed in the previous chapter that the S-impedance in PP prestack inversion follows the linear background relationship with P-impedance. This background trend does not hold for saturation and pressure changes. Ideally, these changes produce an AVA that is anomalous to the background, and should be included in the delta terms. For multiple reasons, in this field the delta terms are not captured. One potential cause could be that in the geology of Edvard Grieg, the fluid does not strongly impact $V_p/V_s$ as shown in Chapter 2, therefore, the fluid does not show the anomalous AVA trend expected in this theory. Additionally, the variations or delta terms can be dampened out by the model covariance or prewhitening. This results in a S-impedance that is derived from the estimated P-impedance instead of from the actual inversion as far enough angles for shear extraction are not included in our PP dataset due to the chalk reflector.

![Figure 5.24 Mean amplitude extraction of the PP prestack inversion model estimates (a) P-impedance and (b) S-impedance. Window was taken 10ms above the top reservoir and 40ms below the top reservoir. Circled numbers represent different 4D scenarios.](image)

The same cross sections shown for reflectivity analysis will be used for 4D inversion analysis, shown in Figure 5.25 and Figure 5.26. The P-impedance estimate captures the situations expected from full stack reflectivity. The result resembles a cleaner quadrature phase amplitude difference. The amplitude response deeper in W-1 is shown here as a
softening event and deeper into the basement, a similar anomaly is replicated. These are most likely due to time shifts remaining in the PP data. The main benefit of this inversion result is a cleaner and more separable representation of the 4D differences, reduction of sidelobe, and quantification of 4D response the rock physics parameter of P-impedance.

![Cross section of Zp difference estimated from PP prestack inversion.](image)

Figure 5.25 Cross section of Zp difference estimated from PP prestack inversion. Sections go through injectors and producers. Producing wells are hidden due to a lack of log data to accurately tie the wells in depth.

The S-impedance estimation in Figure 5.26 looks very similar to the P-impedance. Theoretically, S-impedance should show chiefly geomechanical effects, with minor influence of saturation change simply due to the density term in S-impedance. Using only PP data with limited angles results in a S-impedance derived from the coupled relationship with P-impedance and results in a S-impedance that replicates the relative changes in P-impedance. This is why the S-impedance still clearly shows the fluid effect from water injection and gas injection with the resulting water fronts. Even the minor response from gas exsolution can be identified in line A-A'. Overall, the S-impedance derived from the one mode inversion would not provide any additional information for rock physics calculations. The estimation is practically a noisier and scaled down version of P-impedance. The 4D prestack PP inversion
is able to capture changes in P-impedance and improve the 4D separation from reflectivity but is unable to accurately estimate the changes in S-impedance.

Figure 5.26 Cross section of Zs difference estimated from PP prestack inversion. Sections goes through injectors and producers. Producing wells are hidden due to a lack of log data to accurately tie the wells in depth.

5.5 4D Pre-Stack PP-PS Inversion

The addition of PS data allows the inversion algorithm to extract S-impedance directly from the data instead of solely relying on the coupling relationship between P-impedance and S-impedance. This results in a S-impedance that is more accurate when the background trend derived from the logs does not suffice as in saturation and pressure changes. The findings from the 4D pre-stack PP-PS inversion showed that the P-impedance 4D response was significantly damaged throughout the survey. The noise from the PS data overpowered the large fluid response of the injectors and the injector response became very dim in comparison to the PS effects. For 4D analysis the P-impedance from the PP-PS inversion will not be used. However, the PS data significantly improved the S-impedance difference.
The 4D PP-PS inversion was performed on the cross equalized monitor and the original baseline survey, then subtracted for difference model parameters. Using only global cross equalization and trace by trace shifts produced the best PP-PS inversion results. Time variant time shifts were left in the data for reasons mentioned in the previous section. However, the PS data contains larger magnitude time shifts, such as the 5 ms anomaly South of the platform and leaving this in the data may cause an erroneous 4D response. In order to understand this effect further, the time shifts were corrected for and tested.

Figure 5.27 Cross section of PS difference amplitude calculated from full stack dataset after time shift application. Sections goes through injectors and producers. Producing wells are hidden due to a lack of log data to accurately tie the wells in depth.

The PS difference amplitude after time-variant time shift application, in sections with the largest PS anomalies, situations (1) and (6), is shown in Figure 5.27. Both time-lapse responses are decreased in amplitude when time shifts are corrected. This is expected as a time shift amplifies the 4D difference. Situation (6) is particularly decreased in amplitude, and in Figure 5.28, we can see that the 4D signature seems to drop throughout the survey. However, the 4D response is more discontinuous in both 3D and 2D. After time variant time shift application, the 4D amplitude extraction appears noisier, and when jointly inverted
this noise is amplified. The chalk reflector becomes the dominant 4D effect in the majority of the survey, and situation (6), which was previously thought to be a result of time shifts, actually becomes a stronger feature in the inversion result when the time shifts are corrected. This may be caused by erroneous and brute force time shift application that can decrease the amplitude of the anomaly but increases the noise in the surrounding units, causing an overall more spatially extensive feature in the 4D inversion result. Thus the time-variant time shift was not applied even for the PS dataset.

Figure 5.28 100ms mean amplitude extraction below chalk for PS difference amplitude (a) before and (b) after time shifts are applied.

In pre-stack PP inversion, the S-impedance difference simply replicates the trend of P-impedance as shown in Figure 5.24. With the addition of PS data in the joint PP-PS inversion, the S-impedance was able to deviate from the background trend established from the well logs. The mean amplitude extractions in Figure 5.29 illustrate that without the PS data, the S-impedance estimate captures not only pressure changes around the injectors W-1 and W-2 as expected, but also the interpreted water front, reduced gas saturation, and gas exsolution. The S-impedance should not be capturing the saturation changes as strongly as those from pressure. The only effect saturation change should have is on the density term in S-impedance. The S-impedance derived from joint inversion is more reasonable in that it only shows a response in areas with an interpreted pressure change. The changes occurring
in the PS data should be most similar to the S-impedance change, while the changes occurring in the PP data should reflect the P-impedance change. Pressure data suggests W-1 shows the largest pressure response, yet the PP prestack inversion derived S-impedance indicates W-2 causes the largest pressure response, erroneously mixing saturation and pressure effects. With the addition of PS data, the derived S-impedance correctly indicates W-1 causes the largest pressure change.

Figure 5.29 Mean amplitude extraction in the same 80ms window of S-impedance difference, monitor minus baseline, from model estimates using (a) PP prestack inversion versus (b) PP-PS prestack inversion. Note different colorbars are used.

The anomalies noted that are the strongest in the PS reflectivity are the pressure response proximal to the injectors and the less intuitive geomechanical effect South of the chalk. The shear impedance difference sections in Figure 5.30 actually contains less noise than the amplitude difference, which cannot be said for the P-impedance difference derived from the PP prestack inversion. The large wavelength 4D effect from pore pressure increase is clear in well W-1, which in the PP prestack inversion was minor, mainly consisting of a single softening reflector below the perforated zone as the PP data showed. The anomaly south of the platform is lower in amplitude from applying the time shifts but still remains a very strong time-lapse response. Most likely, this anomaly is a compaction at the chalk, future vintages can confirm or disprove this theory. At this location there is a mix of low frequency from the PS data and high frequency in the PP data, showing the leakage between the two.
Figure 5.30 Cross section of S-impedance estimate from Joint PP-PS inversion in areas with largest PS anomalies.

Looking at lines A-A’ and B-B’ again in Figure 5.31, for the shear impedance derived from the joint inversion, we can observe that fluid response still remains in the S-impedance estimate. The reason for this was discussed in Chapter 3. In PP inversion, the P-impedance drives the model parameters. Meaning if a variation is shown in the seismic, the P-impedance estimate will be adjusted to match this variation and the S-impedance and density are estimated accordingly from the relationship with P-impedance. The PP data alone with limited offset is not sufficient to estimate accurate perturbations from the background model or the delta terms ($\Delta L_S$ and $\Delta L_D$) in the modified Fatti’s equations (Simmons Jr & Backus, 1996). In PP-PS inversion, for variations from the background trend, the P- and S-impedance will hit a middle ground of accuracy where the effect will be averaged between the two parameters. This causes the P-impedance from PP-PS inversion to be less accurate than that of the PP prestack inversion as we observed in the field data, but also causes the S-impedance to be more accurate than that of the PP prestack inversion. The averaging effect adjusts the S-impedance in the correct direction. Ultimately, this produces a S-impedance
with both pressure effect given by PP and PS data, and a reduced saturation effect from PP data leakage.

Figure 5.31 Cross section of S-impedance estimate from Joint PP-PS inversion in areas of pressure change and saturation change.

5.6 Summary

By looking at time shifts and amplitude difference from the PP and PS seismic data we can better understand the inputs driving the inversion. The result of the 4D inversion strongly depends on the quality of the data, the processing, and the cross equalization steps. The chances of obtaining a reliable inversion result from a dataset with low data quality is minimal. At the reservoir, the PS data contains low signal to noise and a peak frequency is approximately 9Hz in PP time. The Grid sands and the chalk in the PS data attenuate the seismic energy at the reservoir and the underlying units. Given these data quality issues, the PS dataset was not expected to provide beneficial constraints to the inversion. However, in our analysis utilizing the PS data allowed for better separation of the pressure effect and saturation effect with an improved estimation of S-impedance. Although the S-
impedance is noisier than that which was derived from the PP prestack inversion due to the PS data quality, it is more accurate. The PP prestack derived S-impedance simply followed the background trend with P-impedance. The S-impedance contains residual error from leakage of the PP data, but PP data also provides a high frequency stabilization to the PS dataset. PS prestack inversion on its own has been shown to lack resolution due to the narrow bandwidth of the PS data which is highly probable for the 9Hz peak frequency of the PS seismic dataset post registration (Barnola & Ibram, 2014). The focus of this chapter was to assess the best combination of technologies to identify changes in the rock properties, and we found that the S-impedance 4D response improved using PP-PS inversion, while the P-impedance 4D response was best captured by the PP pre-stack inversion.
After converging to the optimal results for P-impedance, S-impedance, and density for each inversion method, I concluded that PP prestack inversion produced the best estimate of P-impedance while the PP-PS pre-stack inversion produced the best S-impedance. Thus far we have evaluated various inversion techniques. The next steps are to use these volumes to better understand the heterogeneity in the Edvard Grieg field, particularly the aeolian and alluvial reservoirs and the chalk seal.

6.1 Baseline Interpretations

The geology of the Edvard Grieg field is highly complex as discussed in Chapter 1. The reservoir consists of Triassic age aeolian sands, fluvial sands, alluvial sands and conglomerates, and a thin unit of lower Cretaceous bioclastic shelfal sands. These are capped by the Cretaceous age Shetland group chalk formed during a major transgression, being followed depositionally by large packages of marine shales and sands. As previously mentioned, this is an oil bearing field and the oil water contact exists in most of the field at 1946m depth, roughly marked by the downdip edge of the field outline. The contact becomes deeper in the southwest of the field. Spatial understanding of the reservoir and chalk can directly impact the decisions/interpretation on how to best extract hydrocarbons and further field development. Given the work done in previous chapters, we are now able to characterize the reservoir using the seismic reflectivity, the inverted model parameters, and the 4D response. All these datasets can be integrated to update the geologic model of the reservoir.

The reservoir lies in a half graben on the Haugaland high, the southern area of the Utsira basement high in the North Sea. The structure of the half graben (Figure 6.1) is formed from the fault striking east-west with a max throw of about 1 kilometer. Towards the northwest of the survey, the flank of the Utsira high going into the Viking Graben is visible. This
Figure 6.1 Structure map of basement, interpreted from PP seismic data. Major interpreted faults overlain.

... is where hydrocarbons migrated from the Jurassic Draupne shale through basement faults and fractures to the inverted high trap (Ziegler, 1992). The field is heavily influenced by tectonics as discussed in Chapter 1. Extensional regimes, basin subsidence, and sediment infill transpired from the Devonian to late Jurassic and created the accommodation space for reservoir deposition. The major Edvard Grieg fault that formed the half graben becomes inactive by the Cretaceous, where a transgression event lead to major sea level rise and the deposition of the shelfal sand reservoir and Shetland chalk caprock. The tectonic regime of the North Sea drove both the deposition and hydrocarbon migration for the Edvard Grieg field, and is important background for generating a comprehensive geologic model.

6.1.1 Seal Analysis

First we can look into the seal, the Shetland Chalk. The chalk is a relatively flat bed dipping 1-2° north-west shown in the structure map in Figure 6.2. This chalk unit has minor fluctuations, but according to the operator of the field, Lundin Energy Norway, each fluctuation interpreted from the seismic is found erroneous when the unit is actually drilled.
This began the “flat chalk” theory that the chalk is marked by sheet-like smooth architecture despite what the seismic may indicate. This suggests that there may be inaccuracies in the smooth interval velocities used for Kirchhoff prestack depth migration. Typically, the S-wave velocity in migration velocity models is more erroneous than P-wave. The fluctuations in depth are much larger in the PS seismic data, shown in Figure 6.3. The major changes in the chalk in the PS data can be correlated to the overlying grid sands. The combination of polygonal faulting and high velocity injectites produce a highly complex overburden with large lateral velocity variations not included in the velocity model. Additionally, transmission path effects in the faulted overburden strongly decrease the reflection signal at the chalk and reservoir intervals particularly in the PS data. The ray path variations due to the faults and high velocity sands in the overburden were observed in the azimuthal analysis done in Chapter 2. The model parameters derived from PP data show impedance variations in the chalk that may have influence from these shallow injectites, but also may provide important information on the spatial heterogeneity in the chalk composition.

Figure 6.2 Structure map of Shetland Group chalk, interpreted from PP seismic data. Contour interval (CI) is 20 meters.
Figure 6.3 PP and PS cross section taken diagonally through the survey. PS is not fully registered to PP time as this registration is simply using the velocity model.

Although the structural a priori assumption of the chalk is a continuous sheet-like bed, the variations in the seismic and inversion result should be analyzed to assess if there are correlations to lithology. The Shetland group is composed of two chalks, the upper Ekofisk chalk and the deeper high velocity Tor chalk. In other areas of the North Sea, reworked units within the Ekofisk and Tor units are hydrocarbon bearing reservoir, but in the Edvard Grieg field the chalk is tight enough to act as a seal for the reservoir interval (Swarbrick et al., 2010). However, the variations in lithology could have an impact on seal integrity and geomechanical responses to production and injection.

An example of this lithological importance is in the nearby Ekofisk field, targeting the Ekofisk chalk reservoir. With production, the chalk has undergone significant compaction, enough to subside the sea floor (Keszthelyi et al., 2016). According to log data at Edvard Grieg, the Ekofisk chalk has a porosity of 18-25%, while Tor porosity is in the range of 7-14%. Although the Shetland Group contains high porosity chalk, the permeability is in the microDarcy range. This indicates the pore geometry is not in communication and most likely extensively cemented. Swarbrick et al. (2010) suggests that the presence of the base Chalk or Tor chalk is highly correlated to whether the Shetland chalk is a successful seal.
The Tor chalk is ultimately the most robust seal in the Edvard Grieg field and fluctuations in the chalk observed in the inversion result may help identify both the thickness variations of the chalk and where the Tor chalk is most prevalent as it has the highest impedance.

Figure 6.4 Root mean square attribute maps taken from (a) the PP baseline survey 10ms above the chalk horizon and 10ms below, (b) the PS baseline survey 30ms above the chalk horizon and 30ms below, (c) the P-impedance estimate from top chalk to top reservoir, and (d) the $V_p/V_s$ estimate from top chalk to top reservoir. Polygons indicate regions of energy loss from shallow cemented sand injectites. Interpretation outside of the half graben is unreliable due to tuning effects.

The RMS amplitude maps in Figure 6.4 show the fluctuations at the chalk from the seismic and the inversion results. Noting the amplitude loss in areas under cemented sands and the platform, the resulting impedance and input seismic look similar as anticipated.
However, the PS seismic extraction is more discontinuous due to the Grid sands as seen in cross section Figure 6.3. The calculated Vp/Vs shows this discontinuity, but S-impedance in the chalk looks similar to P-impedance. This suggests that the minor fluctuations in the chalk interval that cause the discontinuities in the PS data can be attributed to the shallow ray path obstacles, but the larger scale trends of the chalk are due to the lithology and thickness. The chalk signature is highest impedance in the North of the field where there is little reservoir, this could be due to tuning. Inside the half graben, the chalk shows an increasing amplitude trend moving to the southwest. The trend is a sequence of kilometer scale features of varying amplitude.

Figure 6.5 Cross section through velocity logs highlighting the Shetland Chalk variation.

Based on the log signature of the chalk, in Figure 6.5, the Shetland chalk thickens towards the East to wells D and C. The areas that contain the thickest chalk show the lowest inverted impedance and amplitude. This correlation indicates that the fluctuation in the chalk reflector amplitude is highly controlled by tuning thickness. However, this does not hold true for injector W-1, which only has a total 9 meters of chalk but still marked by low impedance. This is the only well in which the Tor chalk is lower velocity. The Tor chalk is typically significantly higher velocity than the Ekofisk, and an absence of this unit or varia-
tion to a higher porosity Tor chalk, causes a lower impedance value. From this correlation we can identify zones in the reservoir that may contain thinner or more porous Tor chalk, particularly in the western portion of the field that is amplified from tuning. Lower impedances in the North-West corner of the half graben and along the fault may also correlate to thin Tor chalk, as the Tor chalk unit thins from Well E to Well F. This relationship may be particularly important in the Edvard Grieg field as the Tor chalk is the most effective seal in the Shetland Group and an absence may lower seal capacity, or potentially cause compaction (in the case that the injected water enters the Ekofisk chalk pore space).

The ability of any rock to act as a capillary seal for hydrocarbon accumulation depends on the diameter of the largest interconnected pore throat (Sutton et al., 2004). Clays can fill this pore space and expand in the presence of fluids, often causing cementation in the pores. Therefore, sealing capacity is strongly linked to clay content; increasing clay content forms a tighter seal (Dawson & Almon, 1999; Fisher & Knipe, 1998). The relationship between $V_P/V_S$ and P-impedance can highlight porosity and clay content. Higher $V_P/V_S$ with low P-impedance can indicate porosity, while high $V_P/V_S$ in general can be correlated to higher clay content (Odegaard & Avseth, 2003). Within the North-East of the half graben, the chalk is marked by higher $V_P/V_S$ with variable P-impedance. This information combined with the log signature from Eastern wells in Figure 6.5 suggests higher $V_P/V_S$ may indicate high clay content more so than porosity. Conversely, the region below the platform and towards the west with lower $V_P/V_S$ may indicate low clay content in the Shetland chalk. In these regions, the seal has the highest risk of compaction or breach of seal capacity.

From this seal analysis, the apparent depth and amplitude fluctuations in the chalk are explained. The major cause for discontinuity in the PS data chalk amplitude are transmission path obstacles from the Grid sand injectites in the overburden. The remaining changes in the chalk can be attributed to thickness and composition. The chalk is thinnest towards the West of the field, identifiable from high amplitude response due to tuning. Lower impedance chalk in the East corresponds to the thickest chalk units that contain both Ekofisk and Tor
chalk units. Local small scale lows in impedance, such as those around injector W-1, may indicate areas where the Tor chalk is not as thick or permeable. Chalk with lower clay content, thereby higher seal risk, has been identified in low $V_P/V_S$ regions to the south and west of the platform. This evaluation has direct implications for understanding seal integrity and extent in the field.

6.1.2 Geologic Reservoir Analysis

The reservoir of Edvard Grieg is spatially and temporally complex. There are three major depositional systems. The aeolian-fluvial system, the alluvial system, and the shallow marine system. The Cretaceous marine sands are the most uniform unit of the reservoir and exist as a sheet sand capping the entire reservoir. These bioclastic shelfal sandstones contain excellent porosity and permeability but are only 3-5 meters thick, and therefore, are not seismically detectable. The northern production well T geosteers into this thin unit as the chief target, extracting oil from both the shelfal sands and the alluvial conglomerates and fractured basement below. The two other primary depositional systems, aeolian and alluvial, are both Triassic in age and have considerable interaction. The generalized spatial distribution of these systems within the reservoir window is shown in map view in Figure 6.6 and as a cross section in Figure 6.7.

The sands in the field are chiefly aeolian sediment with an average porosity of 27% and multiDarcy permeability. However, this depositional environment is not only composed of clean aeolian sands. The system is characterized by other morphological bodies of aeolian-derived and related sediment deposits, such as interdune, sand sheets, lacustrine systems, and perennial, intermittent and ephemeral fluvial systems (Al-Masrahy & Mountney, 2015).

Lithology classification of the producers and injectors suggest that fluvial reworking of aeolian sediment is a common facies in this field. This suggests that the water table levels at the paleo-dunes were high enough to allow externally sourced fluvial systems to penetrate into the interior of the dune system (Al-Masrahy & Mountney, 2015). Therefore, it is clear that the aeolian system of Edvard Grieg is a wet system, confirmed from the significant
Figure 6.6 Map view schematic of facies distribution in the reservoir interval of Edvard Grieg. Interpolated facies consist of sands, alluvial sandy matrix, alluvial silty matrix, alluvial clay tight matrix, and lacustrine sediment. Interpolation represents the average sediment in the reservoir window. Silty-Clay dominant matrix extends to the North below the sands. Lithology logs from producers and injectors are overlain. Note injectors are vertical; lithology logs shown in map view are not representative of true thickness. Lithology logs were interpreted by Lundin Energy Norway.

presence of interdune deposits visible in core. These interdunes are first order boundaries in aeolian systems and can act as baffles to flow. Fluvial systems most commonly occur in these interdune areas, but there may be bulk shifting of boundaries between aeolian dominated areas and fluvial dominated areas which produce distinctive sedimentological and geomorphological assemblages (Bullard & McTainsh, 2003).

According to the well logs, fluvial reworking of aeolian sediment in the Edvard Grieg field is most frequent on the outskirts of the aeolian dunes and as the cap or base of the aeolian unit. Al-Masrahy & Mountney (2015) suggest that fluvial features are commonly formed between dune structures or on the border of the dune field, limiting its extent, as seen in
Edvard Grieg. The wells toward the South (L) and far North (W-2) contain the most fluvial input. Well L penetrates 1 km of lacustrine sediment interbedded with fluvial sands that are composed of reworked aeolian sediment. This section is a higher porosity fluvial deposit as it is composed of transported aeolian sediment. Farther South in well L contains 500 meters of fluvial sediment reworked from the alluvial unit, interbedded with thick lacustrine deposits. The fluvial stream systems feed into the lacustrine lake systems, which contain low porosity clay rich sediment. The challenge with the lacustrine deposit is that like shales, it is low impedance and difficult to separate from the low impedance sand bodies.

Figure 6.7 Seismic interpretation of the Edvard Grieg Field overlain on PP seismic data. Reservoir in the half graben includes alluvial sediment (interbedded with lacustrine and fluvial deposits), aeolian sands (interbedded fluvial rework), and thin seismically unresolvable marine sands capped by the Shetland Chalk unit. Velocity pull up below injectites produces the false-depth structure on chalk.

The alluvial system is the next major component of the reservoir and is composed of alluvial sands and conglomerates. Deposition is from higher slope fans sourced by flooding events or colluvial slides with gravity drive, short duration mass deposits. Alluvial geomorphology consists of aggradational fan features that vary widely in radial length, but generally range

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from several hundreded meters to a few kilometers in length (Moscariello, 2018). This system is the most complicated in deposition and interpretation due to rapid waning flow stages that do not allow for effective sorting and reworking as in most other clastic depositional systems (Moscariello, 2018).

Reservoir quality of the alluvial deposits mainly depend on three components, (1) the matrix mineralogy, (2) matrix dissolution, and (3) the clast size. The matrix mineralogy varies from sands, silts, and clays, which strongly changes the permeability of the conglomerate. This facies distribution can be correlated with distance from the fan apex. Proximal-fan association forms massive pebbly conglomerates interstratified with course to medium grained structureless or flat-laminated sandstones typically generated from flood and slump gravity flows (Nemec et al., 1980). These are often higher net to gross and have higher amalgamation of course-grain channel fills (Moscariello, 2018). Distal-fan deposits consists of fine pebble conglomerates interbedded with sandstone and mud (Porebski, 1984). These are often deposited as lobate extensions of the proximal gravels, or distal isolated channel systems consisting of mud-rich matrix supported conglomerates. Proximal-fans contain 80-150m thick sequences and distal fans contain 20-120m sequences so both sequences can be seismically resolvable (Porebski, 1984). Typically thicker sequences contain larger clast sizes (Porebski, 1984). Smaller sequences are fan-fringes which contain sharp-based fine to medium grained sandstones with silty mudstone and little composition of pebbly conglomerate (Porebski, 1984). Finally the basin and interlobe association is formed from slow settling of suspended load, resulting in thick packages of mudstone with variable thin packages of siltstone and sandstone. Understanding the fan distance and drive provides insights on spatial variation in matrix composition and permeability.

Next, matrix dissolution can be a concern. The Edvard Grieg fault system uplifted the basement around the half graben and because of this vertical displacement, alluvial fan sequences were deposited in the lowlands in the half graben from eroded basement. This sediment contained high feldspar content which can undergo chemical weathering in the
Figure 6.8 Debris-flow fan deposition versus waterlain alluvial fan deposition (Moscariello, 2018).

process of hydrolysis and turn into clays. This eodiagenesis is driven by subhumid and warm surface climate conditions and occurs soon after deposition (Maraschin et al., 2004). In the far Eastern portion of the field, outside of the survey, wells have been drilled with high hematite content in the pore space destroying permeability. The overlying aeolian unit contains high potassium feldspar content but is preserved as the climate was too dry for feldspar dissolution to occur.

Finally, clast size is an important property in the alluvial unit that can greatly alter permeability. This can be correlated with the proximal-distal association discussed previously. Large clast sizes may produce a clast supported conglomerate. Clast supported conglomerates may have matrix that was deposited simultaneously with the clasts or filtered in at a later time, while matrix supported conglomerates are usually debris flows with simultaneous transport of fine and course material (Harms et al., 1975). This is important because the clast mineralogy may vary significantly from matrix mineralogy and cause challenges in
separating good from bad quality matrix zones with impedance and density, as these measurements would average the composition of matrix and clasts. Additionally, large clast sizes in contact have been seen to block pore throats and lower permeability.

6.1.2.1 Edvard Grieg Flow Systems

All these components are crucial in identifying reservoir quality conglomerates. From current wells in Edvard Grieg, two fan systems can be identified. The northern fan most likely being a debris flow alluvial fan while the the eastern fan is most likely a waterlain alluvial fan, schematically shown in Figure 6.8. The northern alluvial system is composed of a clay to silt matrix of low porosity with minor sands. This could be representative of a more distal-fan dominantly aggraded by cohesive debris flows which produce high volumes of clay-rich colluvial material (Moscariello, 2018). These are triggered by short duration flood events and hyper-concentrated flows that cause poor sorting and connectivity (Moscariello, 2018).

The second system is sourced from the East and composed of sandy matrix conglomerate. This was most likely formed by a waterlain fan. This sediment could potentially be deposited by non-cohesive debris flows, as more turbulent water flows tend to wash out volumes of silt and clay, however, the system has high permeability thus is more likely a waterlain fan (Moscariello, 2018). Waterlain fans are driven by fluid-gravity flows consisting of well sorted sandy to gravelly lenses, overall, they are better sorted facies with less clays (Moscariello, 2018). Relative lack of debris flows enhance vertical permeability and internal connectivity, therefore, the spatial distribution of sand is relatively homogeneous (Moscariello, 2018). Barriers to flow in this system can be the fine grained fan fringes and interlobe deposits between aggrading fans. This sandy alluvial system interacts with the aeolian system. The center of the survey contains interbedded aeolian and alluvial deposits shown in Figure 6.7. This suggests that the alluvial system was driven by major flood events that buried and preserved the aeolian dunes. After relative alluvial inactivity the aeolian dunes migrated back over and covered the alluvial fan as a continuous sand blanket, comparable to the
occurrences in north Panamint Valley, California (Anderson & Anderson, 1990). This process repeated to create the 20 meter aeolian-alluvial interbedded strata seen in cross section and in extractions.

Figure 6.9 RMS amplitude extracted from the P-impedance estimate below the top reservoir horizon as reference in 10ms-20ms intervals, with (a) 0 to 10ms below, (b) 10ms to 20ms below, (c) 20ms to 30ms below, (d) 30ms to 50ms below, (e) 50ms to 70ms below, and (d) 70ms to 80ms below. Southernmost linear east-west oriented amplitude is an effect from tuning at the half graben hinge.

6.1.3 Seismic Derived Reservoir Analysis

With an understanding of the chief components of reservoir in this field and their spatial distribution, we can begin to use the seismic data and inversion results to spatially refine the geologic model. In the RMS extractions of the P-impedance model estimate over the reservoir interval, particularly in zones that could be oil bearing, we can better understand the spatial distribution of the reservoir. In Figure 6.9a, the focus is the very top of the reservoir unit. The lowest impedance area, indicative of the best oil bearing sand is in the center of the survey and has an angular pinchout towards the east. This edge correlates to the major normal fault in Edvard Grieg, showing that the aeolian sands were deposited while
the major fault was active, synrift. Other fault systems extending from the Edvard Grieg fault were most likely active at this time, causing the pinchout in the Eastern portion of the angular sand feature. South of the lowest impedance event there are parallel elongate features oriented east to west, extending 4km in length and approximately 800m in width. These features become stronger in Figure 6.9b and Figure 6.9c. The linear features correspond to the aeolian fingers interbedded with the sandy alluvial sediment seen in Figure 6.7, the high impedance being alluvial section and low impedance being aeolian. Moving farther down in depth from Figure 6.9c to d, we begin the transition to below the oil water contact throughout the graben, indicated by the sudden drop in impedances. Here the sands in the East of the graben begin to diminish and the alluvial sediment dominates. The sands in the west are much thicker but within the water leg, downdip of the oil-water contact.

Looking outside the graben towards the north in the shallowest extractions, the maps show an oblate low impedance feature with a 1.5 km radius. This feature is not an artifact from seismic tuning, but may be amplified by the tuning effect. Because the northern Edvard Grieg fault limits the aeolian sand deposition, this potential sand is most likely sourced from the northern alluvial system. Similar lobe like architecture features in alluvial systems have been characterized as crevasse splay complexes (Shields et al., 2017). Studies show the radius of a crevasse splay signature ranges from 500m-2km, similar to the feature highlighted in the RMS amplitude maps (Pendleton & Hardage, 1999; Shields et al., 2017). A clear input channel is not visible within this survey to support this interpretation. The feature may also be a localized, better sorted, waterlain fan in the North produced by an isolated flood event, but does not show fan like structure. Given the uncertainty in either interpretation, this is noted as a high risk sand body, but potentially high reward.

From these P-impedance extractions, the differentiation between the alluvial system sourced from the North versus that sourced from the East is more apparent. The eastern sourced fan system is lower impedance indicating higher reservoir quality, best shown in Figure 6.9c. This system oscillates with the aeolian sands in the center of the survey
causing the elongate low impedance features. In cross section these elongate features are steeply dipping to the North, seen in Figure 6.7, not from deposition, but from active fault movement tilting the beds from relatively flat at deposition to high slope. These features continue far deeper than the oil water contact. The aeolian fingers contain higher composition of fluvial reworked aeolian sediment than the thick aeolian unit towards the North, drilled by well E, which is reflected in their relative impedances from the inversion results. As water flows become lower energy and the alluvial system is no longer active, the environment may shift to fluvial dominated flow to aeolian resulting in the aeolian strata to be of a wetter system (Moscariello, 2018). However, the easternmost edges of the large sand bodies and sand lineations have the lowest impedance values associated with the highest reservoir quality. According to core measurements, these sands contain low interdune content, further supporting the idea that the the north-eastern sands originate from a drier aeolian system.

Overall reservoir quality of the sand body improves moving north-east as the system becomes dryer, with exceptions being the internal structure at the center of the aeolian fingers. The east sourced alluvial fan is limited in extent by syndepositional faulting in the north-east, as seen in the drop of amplitude moving North. This fan is clearly more porous as it has a larger response to fluids, seen in the contrast in overall amplitude between Figure 6.9c and Figure 6.9d.

The sand isopach map, Figure 6.10, was formed based on deterministic mapping of the P-impedance and $V_P/V_S$ volumes to illustrate thickness distribution of the aeolian and fluvial sands. The sand is relatively separable from the surrounding lithologies in the impedance domain, other than the underlying lacustrine sediment. Towards the west of the field, lacustrine shales lie at the base of the sand bodies. This shale has the same impedance as the sand, however, the $V_P/V_S$ volume showed clear separation and was used to differentiate the lacustrine sediment from the clean sands. The isopach map shows that aeolian sand distribution is wedge like and has a maximum apparent thickness nearest the fault, suggesting synrift deposition. Multiple elongate features run parallel to the fault suggesting activity
Figure 6.10 Thickness of low impedance sands. Potentially grouping aeolian, fluvial, and alluvial sands. Mapped based on inversion results.

from a network of faults at the time of deposition, as hypothesized from the RMS amplitude maps. The thickness of the linear aeolian features is approximately 20-30 meters.

The max thickness of the sand is around 90 meters and close to the major injectors W-1 and W-2. There is a thinning between these two sand bodies parallel to the fault. Towards the north-east, a small low impedance body is mapped as two northern extending sand splay that cut through the main fault around producer S. With this sand map, we can analyze the inversion results for spatial distribution of rock properties like P-impedance and S-impedance.

Low P- and S-impedance correlates strongly with the thickest intervals, as shown overlain in Figure 6.11. This is not an exact correlation, and the lowest RMS values are actually more indicative of reservoir quality. The lowest P-impedance corresponds to where there is the cleanest oil bearing reservoir. S-impedance has less influence from saturation and shows the best reservoir quality sands, which generally corresponds to the highs in P-impedance. The only discrepancy is that the lowest zone of P-impedance, is not as relatively low in S-impedance, due to hydrocarbon lowering the P-impedance while S-impedance is unaffected.
The sands contain impedance lineations that are parallel to the east-west striking elongate aeolian fingers. These features are also approximately parallel to the major fault system, which indicates that they may be due to the synrift deposition of the aeolian unit. Because this hanging wall block was continuously downthrown during deposition, the aeolian facies is wedge-like as seen in the isopach and contains steeply dipping strata as seen in the seismic line in Figure 6.7.

The cap of the aeolian wedge was eroded by a major Cretaceous transgression, leaving the map view of the aeolian facies to be an equivalent to an oblique cross section view. The sands towards the South within the 50 ms reservoir interval below the chalk are chronostratigraphically older than those in the North-East, potentially why the northern sands contain different properties than the southern. The system began as a very wet system with more fluvial influence as seen in the South and with time became drier, resulting in the cleaner sands found in the north-east of the half graben. This is observed more clearly by the variations in the aeolian fingers. The impedance drop and reservoir quality improves between each strata moving North. There is also a barrier in the large sand bodies to the West between injectors. This barrier is relatively high impedance, and separates the more isolated northern
low impedance body from the larger sand body in the south-west seen in Figure 6.11. This feature, is again parallel with the fault and is about 500 meters in width as are the aeolian fingers. This unit may contain more fluvial sediment and can act as a flow baffle or barrier between sand bodies.

The alluvial sediment in these extractions show low reservoir quality in the North outside of the half graben, but a relatively high value for S-impedance. This could correlate with a higher porosity body in the North with lower clay content, resulting in increased S-impedance (Mavko, 2000). The eastern sourced water-lain fan is of higher reservoir quality indicated by the lows in P- and S-impedance. This fan begins outside of the half graben and shows highest reservoir quality most proximal to the fault, suggesting either a cleaner proximal fan unit or an artifact from the fault in the seismic data. The lower sand finger interbedded with the sandy alluvial sediment is shown to extend all the way to the confining Eastern fault in the S-impedance estimate. This finding brings uncertainty to the interpretation of the thinner sands that intersect the fault in the North, because if the fault was active during deposition, as the isopach suggests, the sands should be confined to the half graben.

Figure 6.12 $V_P/V_S$ RMS amplitude extraction taken from reference horizon to 50ms below, with 10m and 20m sand thickness contours overlain.
From the estimated impedances, I calculated $V_P/V_S$, the ratio between seismic compressional and shear-wave velocities, shown in map view in Figure 6.12. By using PP-PS inversion, we were able to obtain a better baseline S-impedance as shown in Chapter 5. Previous work has suggested that an association exists between $V_P/V_S$ and fluids, lithology, porosity, and pore aspect ratio (Eastwood et al., 1983; Tatham, 1982).

Firstly, $V_P/V_S$ is sensitive to fluids. In the case of hydrocarbon saturation, $V_P$ decreases, while $V_S$ increases due to a decrease in density, overall decreasing the $V_P/V_S$. The northern portion of the half graben with the highest reservoir quality and lowest impedance values correlates to the very low $V_P/V_S$ area indicating hydrocarbon. The lowest $V_P/V_S$ ratio appears to taper to the northwest into the upper fault. The south of this taper where there are higher $V_P/V_S$ correspond to the parallel feature that was hypothesized from the impedance maps to be less clean sediment that could act as a baffle to flow.

Porosity and pore aspect ratio also drive $V_P/V_S$. Higher porosity values moderately increase the $V_P/V_S$, while pore cementation and high pressure grain to grain contact significantly reduce $V_P/V_S$ (Avseth & Veggeland, 2015). Pore aspect ratio is the ratio between the smallest and largest radius of each pore space. In the case of a spherical pore (as in a clean sand), the aspect ratio will be large, in a fracture, the aspect ratio will be very small. For high aspect ratios expected in well sorted sands, $V_P/V_S$ is mainly dependent on porosity, but if the aspect ratio is small it becomes an influence on $V_P/V_S$ (Eastwood et al., 1983). In the sands, high porosity increases $V_P/V_S$, while hydrocarbon decrease $V_P/V_S$. Hydrocarbon typically overpowers the $V_P/V_S$ effect of the porosity. The southern aeolian finger shows higher $V_P/V_S$, but also lies underneath the platform which can cause issues in the seismic quality, not recoverable from inversion. The lows of the $V_P/V_S$ in the oil bearing zone corresponds to hydrocarbon, even in the area below the platform that is composed of alluvial silty-sandy matrix. In this region, there could be a combination response from fluids and low aspect ratio in conglomerate with more angular pores, as it is more of a breccia deposit according to core data.
Tuning effects from the hinge of the graben in the south causes a large linear amplification of all impedance estimates, which may be interfering with the sandy to silty conglomerate section directly North of the hinge. The northern areas outside the graben also contain low \( V_P/V_S \) values that may actually be indicative of heavily fractured basement rock as seen in core (Eastwood et al., 1983). The \( V_P/V_S \) volume contains noise from the platform, cemented sands, and influence of the PS data quality, but shows accurate trends that correlate with the well data and highlight the porous oil bearing zones.

### 6.1.4 Lithology Prediction

![Rock physics template](image)

Figure 6.13 Rock physics template for modeling brine and gas saturated sandstones and for shales (Avseth & Veggeland, 2015)

In order to tie geology and the seismic data more quantitatively, a rock physics template can be derived from logs and used to understand the relationship between lithologies in the inverted estimates. The rock physics template for Edvard Grieg is described and shown in Chapter 2 in Figure 2.6 (Odegaard & Avseth, 2004). Crossplotting \( V_P/V_S \) versus acoustic impedance is a common rock physics template used to differentiate lithologies and fluids, schematically shown in Figure 6.13. Using this template, calibrated at the wells for the
lithologies of Edvard Grieg, I analyzed the inversion results for $V_P/V_S$ calculated from the two prestack inversions impedance estimates. From this analysis I was able to confine facies to particular combinations of P-impedance and $V_P/V_S$ from the inversion results, as shown in Figure 6.14. These zones have a degree of uncertainty in lithology, as alluvial sediment quality is difficult to distinguish even in well logs. Additionally, the fluid effect in $V_P/V_S$ is clear for clean sands but does not show a strong effect in the alluvial section. The chief contribution of the $V_P/V_S$ is its ability to separate clay rich sediment such as the chalk, lacustrine, and shale sediment from the sand and alluvial sediment. The clean oil bearing aeolian sands and the fluvial rework have the same P-impedance as the clay rich sediment, but much lower $V_P/V_S$. Higher acoustic impedance and $V_P/V_S$ is associated with the fluvial reworked aeolian sediment, reflecting the relatively lower porosity, higher clay content, and smaller fluid effect of the fluvial sediment compared to the aeolian deposits. The alluvial sediment is mainly distinguishable in the impedance domain, $V_P/V_S$ did not vary greatly unless the alluvial conglomerate contained more clays. There is however, a minor decrease in $V_P/V_S$ associated with lowering porosities as shown in Chapter 2. Overall, this crossplot is able to separate facies but unable to capture the fluid effect in sediments other than the aeolian sands as log analysis predicted.

With this facies association, the zonage was applied to the entire seismic volume to create a lithology cube. In Figure 6.15, the same cross-sections defined in Figure 4.9 are displayed for this facies analysis. The aeolian sands are cleanest when located nearest to the fault around well E. The steeply dipping interbedded sands and alluvial sediment in line X-X’ suggest that the fault activity increased after deposition significantly, and shows that the interbedded alluvial section is good quality. This supports the argument that the eastern sourced alluvial fan was a water-lain fan and deposits were driven from large flooding events that overtook the aeolian dunes. Towards the North of the X-X’ line, cleaner facies are shown. This could be a result of seismic tuning at the basement high causing error in the inversion as previously noted.
Figure 6.14 Vp/Vs vs Acoustic Impedance from inverted model parameters extracted from 50ms above the chalk and 100ms below the chalk in crossline X-X’. Facies zones were guided using rock physics templates created with known log data.

The shallowest portion of basement, outside of the tuning window is marked as a silty matrix alluvial or fractured basement. The basement high remained subareal for a large portion of time and underwent significant erosion, causing the basement rock to be heavily fractured in the North. In both cross-sections in the southwest, the sediment that appeared from the impedance inversion results to be a thick sand sequence, now is correctly identified as a thick lacustrine section, supported by log data.

The purpose of section Z-Z’ (Figure 6.16), is to understand if this facies separation is sufficient to differentiate sandy, silty, and clay rich matrix alluvium. Reservoir quality is generally low in the north, and improves southward. The silty matrix alluvial sediment extends below the aeolian sands in the central producers (Wells R, W, and H). This underlying sediment is important as it strongly correlates to pressure drive. Higher permeability sand matrix conglomerate allows for easier fluid flow and pressure support in the reservoir. In the lithology cube, the southern portion of the graben shows a tight 30 meter alluvial section
capping a clean sandy matrix alluvial section. However, the chalk is the most updip in the southwest, allowing a thicker oil column that is able to fill the pore space in the sandy matrix alluvial unit. In the northern portion of the field, reservoir tuning appears to interfere with the facies separation. Tuning in the chalk drops the $V_P/V_S$ into the reservoir range. Below this feature that could be mistaken for reservoir, the sediment ranges from sandy/silty matrix to tight alluvial. Most likely the tuning issues are interfering with this response and causing the reservoir to appear marginally better than log data shows. Because of this effect, the facies marking in this region can be downgraded in reservoir quality, making the interpretation for the alluvial section in the north to be silty matrix to tight clay matrix conglomerate.
6.1.5 Interpretive Value of 2016 PS dataset

Given the data quality of the PS data at the reservoir, the addition of PS data for inversion was not expected to improve model estimates for interpretation purposes. However, in the previous chapters it was found that the PS data improved the shear-impedance response. From this improved estimate, we revisited the geologic interpretations of the Edvard Grieg field. First, the seal signature was determined to be heavily influenced by overburden complexity but still showed a relationship with thickness and lithology. The chalk generally thickens to the East, and the southwest region of the field contains the thinnest chalk but large composition of Tor chalk which is ultimately the most crucial component of the Shetland Chalk. The area around well W-1 and in the upper north-east corner of the half graben have been identified as regions with potentially low composition of Tor chalk that may cause seal integrity challenges. Finally, low clay content regions of chalk have been identified as higher risk seals.

The analysis of the inversion derived model estimates have allowed facies identification of the reservoir. The aeolian sand quality is shown to increase towards the north-east sand edges. This is not driven by tuning, but rather by the chronostratigraphic age of the sands, with north-eastern sands being the youngest. The aeolian system began as a very wet system.
but became slightly drier with time and produced cleaner sands. The aeolian and alluvial environments occurred synchronously, resulting in areas of lower porosity within the large sand body that can act as baffles to fluid flow. The alluvial sands sourced from the east show highest reservoir quality particularly when interbedded in the aeolian facies and most proximal to the North-East section of the fault. Sandy alluvial sections continue throughout the south but are interbedded with tighter conglomerates seen in the facies cube cross-section Z-Z’, potentially acting as permeability boundaries. The northern alluvial section contains lower reservoir quality alluvial section, but significant fractured basement capable of holding hydrocarbon. With the improved model parameters from inversion, I was able to update the geologic understanding of the reservoir and identify potential high porosity permeable zones as well as baffles and barriers to flow.

6.2 Time Lapse Interpretations: Overview

Time-lapse seismic reservoir monitoring is the process of acquiring and analyzing multiple seismic surveys repeated in the same area over calendar time (Lumley, 2001). 4D seismic technology can be an essential element for reservoir management (Johnston, 2013). Reservoir management, defined by Wiggins et al. (1990), is ”the set of operations and decisions by which a reservoir is identified, measured, produced, developed, monitored, and evaluated from its discovery through depletion and final abandonment.” In order to make the best decisions on reservoir management, the reservoir heterogeneity needs to be characterized at multiple scales, through fine log and core scale to the broad coverage of seismic data. Previous work suggests that the scales of heterogeneity that control reservoir quality variations are covered by well data, but the scales of heterogeneity that control producibility are covered by seismic data (Johnston, 2013). Therefore, the time-lapse seismic provides information on reservoir heterogeneities that ultimately control hydrocarbon recovery (Johnston, 2013).

4D surveys provide valuable information on fluid flow and pressure changes in the reservoir as a result of production and injection, rather than solely relying on simulation models which can often be incorrect. This added information can help optimize injector and pro-
ducer well placement for future development plans. For the Edvard Grieg field, surveys were acquired in 2016 and 2018. Production began in November 2015 and water injection began August 2016, meaning the 2018 vintage is acquired after 2 years of water injection and 2.5 years of production. These datasets were history matched in processing and cross equalized as discussed in Chapter 5 for highest repeatability with an NRMS of around 11% for PP and 24% for PS data.

After the data is conditioned to observe clearest 4D anomalies, the data is calibrated using modeling steps from the well log to build confidence that the 4D seismic is not from artifacts of acquisition or processing (Lumley, 2001). This was done using well E and for the various scenarios expected in the field. The results showed a match with the seismic data, confirming the seismic changes are real. Finally these 4D amplitude difference anomalies can be interpreted qualitatively. However, interpretations can be complicated by nonuniqueness in the 4D amplitude difference, as this anomaly is a combination of fluid change, pressure change, compaction, or temperature (Jenkins et al., 1997; Lumley, 1995). To quantify the changes in terms of geologic properties we performed various AVO inversions to obtain P-impedance and S-impedance change from before and after development. With the background of the production history, these changes can be qualitatively and quantitatively correlated to production and injection. In this project, the exact production and injection data were not made available ruling out potential quantitative interpretation ability. Additionally, the 4D seismic difference is subject to the effects of tuning as shown in Figure 5.15. The seal and reservoir is often within tuning in the Edvard Grieg field, and as a result, the interpretation of this data is qualitative unless the effects of tuning have been removed (Johnston, 2013).

### 6.2.1 Production and Injection History

Before diving into the final 4D anomaly interpretation, it is important to have a comprehensive understanding of the production and injection history of the field. The Edvard Grieg field contains 10 producers and 4 injectors (and potentially more, not available to RCP). Injectors W-1 and W-2 being the larger injector sites. Injection began with W-2 and
production started in wells R, Q, and J before the baseline was acquired in August 2016. Production in these three wells was occurring without pressure support for nine months and caused the pressure around wells Q and J to drop below the bubble point.

The initial bottom hole pressure of the reservoir is 195 bars. Bubble point is 165 bars but due to the quick dispersion away from the wells, gas out of solution is expected if the bottom hole pressure is less than 155 bars. Well Q at the time of the baseline survey, had a bottom hole pressure of 127 bars, while K had a bottom hole pressure of 131 bars, suggesting gas came out of solution. Well R maintained pressure above bubble point throughout production. This well was most likely able to retain pressure because the oil column is in a thicker aeolian sand, therefore, the underlying aquifer support is able to flow more easily through the combination of more permeable lower aeolian sediment and upper alluvial sediment in Well R compared to the lower permeability alluvial unit underling the thin aeolian units at wells Q and J.

Figure 6.17 Change in bottom hole pressure (BHP) from September 2016 to September 2018 based on history matched simulated BHP. Sizing corresponds to relative pressure change. Large uncertainty in injectors.
Injection from W-1 began in November 2016. This pressure support was not sufficient to increase the pressure at well J to above bubble point by the monitor (2018) survey acquisition. The change in pressures are shown in Figure 6.17. The sand at well J is thinner than well Q, therefore the water drive has to move through a low permeability alluvial section. When eastern wells P and N began production, near wellbore pressures dropped below bubble point causing gas exsolution. Production from the North of the field began mid 2017 after the eastern production had begun. These wells maintained higher pressures, most likely from proximity to the western injectors but still fell below bubble point at certain times. When the monitor survey was shot, most central wells had returned to stable pressures above bubble point, other than well Q. Spatially between baseline and monitor, the pressure variation in the North experienced minor differences, pressure decreased in the East, and pressure very slightly increased in the central producers. These pressure variations are important to recognize to understand potential geomechanical effects at the reservoir and seal, and saturation effects from gas exsolution.

As for cumulative production and injection between baseline and monitor (Figure 6.18), W-2 and W-1 injected the most fluids, with W-1 surpassing W-2 by 6%, and W-3 only injectiong 3% of the cumulative injected water of the field. Well W-3 began injecting seawater late in February 2018. W-2 is unique in that it injected a combination of seawater and gas, due to gas capacity issues. Gas injection recovers crude oil by generating a zone where in situ oil and injected gas are miscible. The crude oil swells and decreases viscosity ultimately lowering the tension between in situ and injected fluids (Iqbal & Satter, 2010). In W-2, water is injected alternately with gas, which can improve the mobility ratio between displacing phase and the oil (Johnston, 2013). W-3 had complications from borehole damage and difficulty injecting water, thus strong 4D responses are not expected. W-4 began as a producer but was unsuccessful as it only produced water, therefore, the well was converted to an injector as shown by the two different bubbles on Figure 6.18. Cumulative production is by far the highest in the central producers, the largest 4D response from extraction should
be expected near the platform.

6.2.1.1 Producing Wells

By analyzing each producer and injector using exact borehole measurements varying with time, we can calibrate our 4D seismic interpretations. From the feasibility study done in Chapter 2 on the aeolian sands, assuming the NRMS of the overburden in Figure 2.10, pressure changes of 60 bar may be detectable as well as 2% changes in S-impedance and P-impedance (approximately 400 ft/s*g/cc P-impedance and 200 ft/s*g/cc S-impedance). The NRMS of the reservoir is much lower than that of the overburden. The method of modeling NRMS is typically conservative, so it may be likely that smaller pressure and impedance changes can be seen in the data (Johnston, 2013). On the contrary, 4D effects in the alluvial section are smaller in magnitude mainly due to the lower porosity. Each well provides a control point to regulate the time-lapse interpretation and discern the pressures and impedance changes the seismic can resolve. The production well responses are summarized in Figure 6.19

Beginning with well Q, pressure increased from baseline to monitor (127 bars versus 170 bars), with an overall 43 bar increase. Prior to the baseline survey, this well extracted 6% of the fields cumulative oil. By the time of the monitor survey, 24% of the cumulative oil had been extracted. Additionally, within the year before monitor acquisition, this well produced 60% of the fields cumulative water production. This is most likely due to the horizontal leg of the well dipping into the waterleg in the perforated zones. Overall, the reservoir had undergone gas exsolution at the baseline but the gas most likely went back into solution, was produced, or migrated away. Both reduced gas saturation and pore pressure increase cause a hardening response in seismic or increase in S- and P-impedance.

At well J, pressure at baseline and monitor remained under bubble point (131 bars to 151 bars), an overall 20 bar increase. Prior to the baseline survey, this well extracted 5% of the fields cumulative oil, and by the time of the monitor had extracted 24%, with 0% water production. This response should be very similar to the hardening at Well Q. Well R, the
Figure 6.18 Cumulative oil and water production, and water injection per well at the baseline. Note at the baseline time, only injector W-2 was active along with producers, R, Q, and J. Sizing corresponds to relative amount. Well Q contains the same oil production as well H but much larger water production, accounting for the larger bubble size.

The final producer that was active at the baseline, targets the thickest oil bearing zone. The pressure increases 9 bars, from 159 to 168 bars, from baseline to monitor, and continuously remains above bubble point. Well R produced 9% of the fields cumulative oil at baseline, and 32% at the monitor, along with 12% of the cumulative produced water. This well is the largest producer in the field, here the effect from reduced gas saturation should be minimal, the chief 4D effect should be hardening from the pressure increase. This hardening should be smaller in magnitude than Well Q and J.

All other producers began activity after the baseline was shot, so the baseline pressure is the reservoir pressure of 195 bars. These wells all have different pressures than the central producers suggesting there could be separate pressure compartments due to lithology. Well S targets sandy alluvial sediment, undergoes a pressure drop of 95 bars, significantly below
bubble point to 100 bars. This well has produced 6% of the cumulative oil in the field and no water. The expected seismic response should be softening from gas exsolution in P-impedance and potential hardening from pressure in S-impedance.

Well P also targets the sandy alluvial section and undergoes a pressure drop of 60 bar to below bubble point, produces 11% of the cumulative produced water, and 5% of the cumulative produced oil. This pressure drop should cause a hardening in P- and S-impedance, smaller in magnitude than 4D effects in the aeolian due to the significantly lower porosity of the alluvial section. However, there should be a significant softening particularly in P-impedance from gas exsolution.

Well N undergoes a pressure drop of 53 bars from production reaching below bubble point, and produces 2% of the cumulative produced oil with no water production. This should also show a softening response in P-impedance from gas exsolution particularly as the well is located in the updip region of the trap, leaving no room for migration. The pressure induced hardening is most likely not reflected in the shear data as the resolution is lower and the sediment is less porous.

Producers L and M in the North have each extracted 1% of the cumulative produced oil of the field. Well L perforations target fluvial reworked aeolian sediment, fluvial sediment, and sandy matrix conglomerate. Well M targets silty alluvial sediment, the thin marine sands, and the sandy matrix conglomerate. Well L undergoes a 93 bar pressure drop and Well M undergoes a 63 bar pressure drop. Both producers drop the reservoir pressure to below bubble point. This should appear as a softening in the 4D response driven by gas exsolution mixed with a hardening from pressure.

Finally, Well T targets the 5 meter thick marine sand, and contributes minimal cumulative field production as it is a recently drilled well. There is a production induced pressure drop of 48 bars to pressures below bubble point. Although this response is large, it is not seismically resolvable due the thickness of the sands.
6.2.1.2 Injectors

Water injection began before the baseline at well W-2. The amount of injection at W-2 increased from 2% to 45% of the cumulative injected water from baseline to monitor. Statistics on the gas injection were not made available. The pressure change in the injectors is more difficult to quantify as pressure change is practically instantaneous with each injection. During the 3 month monitor survey acquisition, the pressure at the injectors varied widely. It is difficult to pinpoint when exactly this pressure change was captured by the seismic, thus a range of potential pressure changes will be given for each injector. The range for W-2 is from -42 bars to 9 bars. There is water and gas injection and a pressure change. Proximal to the well the gas injection will cause a softening. In P-impedance, this saturation driven softening will dominate the response. The S-impedance at the well can either be a minor hardening or softening from pressure. Updip of the injector, a hardening response should be expected in the P-impedance from the water front.

Well W-1 began injection after the baseline was shot and by the monitor time had injected 51% of the cumulative injected water. This results in a pressure increase ranging from 19 to 57 bars. W-1 injects water into the waterleg (with a 4 meter oil column that is not detectable), and should have a minimal saturation effect other than the updip waterfront as the water drive replaces the oil. The proximal effects should be pore pressure increase seen in both P-impedance and S-impedance, a softening effect from pressure that is stronger than

<table>
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<td>-63</td>
<td>1</td>
<td>Softening</td>
<td>Hardening</td>
</tr>
<tr>
<td>T</td>
<td>-48</td>
<td>0</td>
<td>Softening</td>
<td>Hardening</td>
</tr>
</tbody>
</table>

Figure 6.19 Table of statistics for producers at baseline and monitor. Red ΔPressure notes that at monitor the pressure is below bubble point.
that of W-2.

Injector W-3 only contributed 3% of the cumulative injected water but experienced a change in pressure ranging from 0 to 86 bars. This may appear as a softening effect in the impedance.

Well W-4 is more complex. This well was previously a producer but was converted to an injector. As a producer, only water had been produced accounting for 12% of the cumulative water production of the field. As an injector, W-4 has only contributed 1% of the cumulative injected water but has caused a large pressure increase ranging from 90 to 118 bars. This pressure response should dominate the proximal region around W-4 and cause a softening, with a decreased effect due to the hardening caused by the minor water injection and the lower porosity alluvial sediment.

6.2.2 4D Seismic Derived Interpretation

Figure 6.20 Mean amplitude extraction at the reservoir window of the (a) PP seismic data full stack difference (10ms above top reservoir 40ms below) and (b) PS seismic data full stack difference (10ms above top reservoir 60ms below).

With this background we are able to interpret the seismic difference amplitudes (Figure 6.20) and impedance estimates qualitatively, as done in the previous chapter, and characterize seven scenarios shown in Table 6.1. The 4D amplitude interpretation is based on
differences in full-stack data because of the higher signal-to-noise values compared to partial stacks. However, even when the 4D response is dominated by saturation changes, thus primarily impacted by changes in P-impedance, full stack data does not represent the true zero-offset seismic response (Johnston, 2013). Therefore, the data can be inverted for more robust estimates of P-impedance change, reduction of sidelobes that exists in quadrature-phase difference data, and quantitative estimates of impedance changes that can be calibrated to rock physics models (Johnston, 2013). Additionally, conventional understanding expects to obtain S-impedance that can assist in interpreting pressure changes and provide better Vp/Vs values to constrain reservoir presence (Johnston, 2013). However, the previous chapter shows that if only prestack PP data is inverted, the S-impedance and Vp/Vs simply reflect a relationship to P-impedance in the logarithmic domain. In order to obtain a more reliable S-impedance, either large angles are necessary or PS data is necessary.

Table 6.1 4D Scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Cause</th>
<th>Effect</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Water Injection from W-1 and W-2</td>
<td>Water Replacing Oil</td>
</tr>
<tr>
<td>2</td>
<td>Production</td>
<td>Reduced Gas Saturation</td>
</tr>
<tr>
<td>3-1</td>
<td>W-1 Injection</td>
<td>Water Saturation + Pore Pressure Increase</td>
</tr>
<tr>
<td>3-2</td>
<td>W-2 Injection</td>
<td>Water + Gas + Pore Pressure Decrease</td>
</tr>
<tr>
<td>4</td>
<td>Gas Exsolution</td>
<td>Gas saturation + Pore Pressure Decrease</td>
</tr>
<tr>
<td>5</td>
<td>Local Gas Exsolution</td>
<td>Gas saturation + Pore Pressure Decrease</td>
</tr>
<tr>
<td>6</td>
<td>Production</td>
<td>Compaction</td>
</tr>
</tbody>
</table>

The resulting P-impedance from PP prestack inversion and S-impedance from PP-PS prestack inversion more clearly depict 4D changes in the reservoir than the PP and PS amplitude difference. In time-lapse studies, an improved S-impedance used in conjunction with P-impedance can allow separation between saturation effects and pressure effects. The 4D scenarios are given in Table 6.1. When one variable changes, as in scenarios 1, 2, and 6, 4D interpretation is more straightforward. In general, however, saturation and pressure both change which often have opposite effects. In an injector, water replacing oil should cause a hardening while a pore pressure increase causes a softening. These responses destructively
interfere and result in a diminished 4D anomaly. Conversely, in W-2, gas injection causes softening that adds constructively with the pressure softening. This can lead to misinterpretation of time-lapse data.

Table 6.2 4D Scenario Seismic Response

<table>
<thead>
<tr>
<th>Scenario</th>
<th>PP Response</th>
<th>PS Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hardening</td>
<td>None</td>
</tr>
<tr>
<td>2</td>
<td>Hardening</td>
<td>None</td>
</tr>
<tr>
<td>3-1</td>
<td>Small Softening</td>
<td>Large Softening</td>
</tr>
<tr>
<td>3-2</td>
<td>Large Softening</td>
<td>Small Softening</td>
</tr>
<tr>
<td>4</td>
<td>Softening</td>
<td>None</td>
</tr>
<tr>
<td>5</td>
<td>Softening</td>
<td>None</td>
</tr>
<tr>
<td>6</td>
<td>None</td>
<td>Hardening</td>
</tr>
</tbody>
</table>

Given the development scenarios of Table 6.1, the respective seismic and model estimate responses are shown in Table 6.2. For saturation only changes, no changes are seen in the PS seismic. A saturation change combined with a large pressure change is detectable in both PP and PS data. Correspondingly, if only pressure changes, a response should be seen in the PP data and the PS data, yet this is not what is seen in scenario 6. The anomaly in the PS data is long wavelength in depth, it begins above the chalk and extends below the basement. At this location the time shifts are approximately 6 ms, and when these shifts are corrected for, the 4D amplitude decreases significantly but the anomaly is still present as shown in Figure 5.28. The seismic signature is a peak-trough starting at the chalk and repeating cyclically with depth. This peak trough indicates a hardening. As discussed previously, the hypothesis is that the chalk may be compacting from the pressure drop, however, this should be seen in the PP data as well if this was the case.

In the impedance estimates, the PP pre-stack inversion produced 4D P-impedance that showed scenarios 1-5. The PP-PS pre-stack inversion produced a 4D S-impedance that showed scenarios 3-1, 3-2, and 6. Scenario 1 is water replacing oil in the water front. Scenario 2 is a hardening caused by reduced gas saturation and production. The effect around wells Q and J is much stronger, as expected from the log values described above, as these wells cause
the reduced gas saturation from the pressure drop below bubble point and subsequent rise. Well R still shows a response, mostly due to pressure drop from production, and potentially minor reduced gas saturation, as this system may be in communication with the two southern producers. Production data suggests that well R is also producing the injected seawater, potentially this water contribution is replacing the oil and adding to the hardening effect. This production associated 4D effect is localized in the central producers as the central wells have the most cumulative production in Edvard Grieg, have been producing for the longest extent of time, and penetrate the thickest aeolian reservoir.

Eastern wells target conglomerate reservoir that is lower porosity resulting in lower 4D effect from pressure change but all wells in the East contain pressures below bubble point, causing gas exsolution. Northern wells target the marine sands which are max thickness of 5 meters, below the seismic detection limit, thus would not be seen in the 4D response (Johnston, 2013).

Scenario 3-1 is the water injection from well W-1. This well began injection after W-2, but over the 2 years between baseline and monitor injected more cumulative water and caused a larger pressure response seen in the S-impedance estimate from joint inversion and the PS data.

Scenario 3-2 is water injection from well W-2. This well began water injection 2 months before baseline acquisition and fluctuated between water and gas injection, therefore producing the largest response in P-impedance from residual gas saturation. There is a minor softening in S-impedance indicating a very minor pressure increase. In Figure 5.18, we saw that W-2 showed much smaller time shifts than W-1 but still positive, confirming a slowdown in velocity from pressure increase with injection.

Scenario 4 is gas exsolution in the updip region of the half graben. All producing wells in this Eastern region are at pressures below bubble point, not yet pressure supported by W-4. As no gas cap was hit initially in the wells, this response is most likely the generation of a gas cap or lighter oil unit.
Scenario 5 is another case of gas exsolution in a local high. This gas accumulation follows the same depth contour as scenario 5. The accumulation is most likely from gas coming out of solution from pressure drop at well T then migrating through fractures to the local high.

Scenario 6 is more difficult to understand as it does not correlate to the sand body or any particular wells. It does however correspond to the low clay content Shetland chalk zone, identified in Figure 6.4 as high risk seal. This long wavelength peak trough response can be tied to a hardening geomechanical effect, potentially a compaction in the chalk seal or unconsolidated sediment. High uncertainty lies in this interpretation as the inverted estimate also appears as an oscillating peak trough-pair and is nonexistent in the P-impedance which should also respond to pressure change. However, this may not be a determining correlation since well W-1 is water injected into the water leg with only a pressure response and in the PP data, the only response is due to a time shift. In this dataset the PS seismic is better able to capture pressure change. Therefore, this compacting response can be a result of the significant pressure drop at well L and M in the marine sands, the fluvial aeolian rework, the silty alluvial sediment, or the low clay content zone of the seal. The magnitude of the 4D response is amplified from time shifts. Uncertainty in this scenario comes from the proximity to the platform signal loss zone and the beginning of a tuning effect in the PS data from the wedging of the half graben.

6.2.2.1 4D Geologic Tie

With an understanding of the cause and effect of the 4D anomalies in the impedance domain, the responses can be tied to our geologic interpretation. Figure 6.21 and Figure 6.24 show the change in P-impedance and S-impedance from the inversion results overlain with the sand body contour. One of the primary goals in 4D seismic interpretation is to improve reservoir characterization, identify compartmentalization, and map permeability pathways (Johnston, 2013). This is directly linked to the rock properties and heterogeneities of the reservoir.
Four primary forces have been proven to control the distribution and movement of fluids in pore space, these being gravity, capillary, viscous and inertial forces (Johnston, 2013). Gravity is a function of density contrast and typically dominates in shallow, thick, highly permeable, and steeply dipping reservoirs as was expected in the western portion of the field with thick sands and injection (Johnston, 2013). Capillary force is a function of wettability and allows a wetting fluid to enter a small pore space and push oil and gas into a larger pores. Viscous force is a function of pressure, it pushes fluids from high pressure areas to low pressure areas like the producing wells. Inertial force is a function of pore geometry and tortuosity, demonstrating how in rock pore space, fluids contain complicated flow paths depending on grain sorting and permeability (Johnston, 2013). With these factors in mind, the fluid flow of the Edvard Grieg injection and production can be analyzed.

Figure 6.21 Mean amplitude extraction of the PS difference full stack. Window was taken 10ms above the top reservoir and 40ms below the top reservoir horizon. Circled numbers represent different 4D scenarios. Sand contour and perforation for production wells overlain.

Correlations from the 4D and permeability can chiefly be made from the changes in P-impedance as P-waves reflect fluids changes. Focusing on Figure 6.21, we can identify multiple time lapse responses and geometries that tie with the geomorphology of the sands.
Firstly, the largest response lies in the water front, scenario 1. The fluid response exists as two major oblate compartments with kilometer scale elongate features extending updip to the East (Figure 6.21). Compartmentalization of the water front suggests that there is a barrier or baffle to flow in this thick body of aeolian to fluvial sands. This barrier was identified in the previous section from the relative high impedance parallel feature visible in the RMS amplitude map. This feature is shown in cross section view in Figure 6.22. There is a topographic high at the barrier, not associated with any pull up caused by shallow cemented sands. This high correlates to the basement notch at the bottom of the half graben. Southwest of the high, the architecture of the shallow sediment in the half graben is relatively flat, but towards the northeast the beds are much steeper and flatten towards the major normal fault. This indicates that multiple normal faults were synchronously active. Potentially, this feature is a small horst between two grabens caused by a system of northwest-southeast trending faults. The overall architecture suggests that prior to the deposition of the aeolian sands, fault activation formed the horst structure, while the major Edvard Grieg fault was still active.

Figure 6.22 Crossline through P-impedance estimate highlighting flow baffle. Dashed line represents shift in sediment slope from variable throw fault activity.
This area was most likely a high at the time of deposition which caused the aeolian and fluvial sediment to bypass. Therefore, the high is most likely made up of the less porous alluvial material sediment or fluvial sands that lay beneath the aeolian package. From Figure 6.23, it is clear that this high consists of higher impedance lower porosity sediment compared to the surrounding units. The 4D response does not continue through this feature because the high is low permeability alluvial sediment. The tectonics of the field impeded the deposition of sands, therefore, alluvial sediment of low permeability remains within the oil column adjacent to the large package of sands towards the North and South. This flow baffle extends parallel to the fault northwest-southeast as described in the previous section.

Figure 6.23 Zoomed crossline through P-impedance estimate highlighting flow baffle. With (a) baseline full stack PP seismic, (b) full stack PP difference phase rotated to quadrature, (c) baseline P-impedance estimate, (d) P-impedance difference from inversion.

The water front also highlights permeability pathways within the sands. The elongate features extending East from the major compartments of water flooding correlate to the high permeability sand lineations as seen in the RMS amplitude map. This response extends to
the central cluster of producers, particularly well Q and R. Well Q has produced the highest amount of water in the field, 60% of the total water production and well R has produced 12% of the total water production. It is known that well R has been producing the injected seawater for months before the monitor was acquired. This could be due to the waterfront bypassing low permeability zones and barriers to move updip in this clean sand body.

The internal architecture of the large sand package is composed of elongate sand fingers with high connectivity possibly correlated to varying climate aeolian units that control the fluvial aeolian interplay as described previously. The water front elongate extension in the South contains curvature leading the water drive farther south rather than going directly East. This could due to a baffle to flow such as an interdune first order aeolian barrier or clay rich fluvial section. The water front also experiences more flow constraints in the southern sand finger penetrated by well J because this sand is much thinner and the oil column also contains significant silty alluvial sediment that may be acting as a baffle for the water front. The differential water-flow in this waterfront is most likely leaving bypassed and undrained reservoir downdip of the central producers.

The production effect in Figure 6.21, scenario 2, also shows correlation with the high porosity elongate aeolian sand packages and the angular thick package targeted by well R. The largest 4D effects occur around wells Q and J. These wells caused higher amounts of gas exsolution that was either produced or migrated away from the area as hypothesized, leaving reduced gas saturation oil. Well R was under production during baseline and monitor but remained above bubble point for most of the production history, causing a smaller hardening response.

Gas accumulation is involved in scenarios 4 and 5. Scenario 4 correlates to the updip region of the chalk where the gas exsolution from surrounding producers migrates, shown nicely in Figure 5.20. The saturation effect is minimal around W-4 as it only contributes 1% of the cumulative injected water, there is more of a response from the large pressure increase which is a softening. Additionally the effect of gas exsolution overpowers any minor hardening
response from water injection. Looking at the change in shear impedance (Figure 6.24), this gas exsolution area appears as more of a positive response, which could be indicating the drop in pressure at the wells. However, this response is very noisy thus difficult to derive firm correlations, the case of gas exsolution may not be resolvable in the PS data. Scenario 5 is gas accumulation at a local high that shares the same depth contour, clear in the seal structure map in Figure 6.2. This high actually correlates to the sand map from the impedance estimates as two sand extensions. The gas from the north-eastern producers, most likely well T, is able to migrate to this local high and cause accumulation in two sand avulsion features. The approximate depth of the gas cap lies at 1855 meters according to the depth converted time-lapse volume.

![Figure 6.24 Mean amplitude extraction of S-impedance difference, monitor minus baseline, in the 80m window below top reservoir horizon. S-impedance from PP-PS prestack inversion. Circled numbers represent different 4D scenarios. Sand contour and perforation for production wells overlain.](image)

Scenario 3-1, well W-1 should cause minimal change in P-impedance, pressure should be the main effect. This pressure increase can be best seen in the shear impedance estimate derived from the PP-PS inversion in Figure 6.24. The corresponding response in P-impedance
is a result of a time shift. Injector W-2 began water injection before the baseline survey was shot. This well underwent alternating water and gas injection causing a larger softening response in the W-2 well in P-impedance from residual gas saturation remaining in sand packages proximal to the injector. However, the pressure effect is minimal as the monitor bottom hole pressure increased only marginally. This is why the event at injector W-2 has a smaller S-impedance response, the pressure change is smaller than W-1. W-3 caused a smaller pressure increase and is not measurable from S-impedance even in the sand body. Injector W-4 caused a larger pressure change but is located in the alluvial section with lower porosity, greatly decreasing the 4D response.

Finally scenario 6 does not correlate to the aeolian sand package, but rather to the fluvial and silty matrix alluvial sediment and the low clay content zone of the chalk seal south of the platform. The response is a peak-trough pair indicating a geomechanical hardening effect. The hardening can be a result of the large pressure drop at injectors L and M causing compaction at the reservoir or chalk. The Ekofisk chalk reservoir in the Ekofisk field shows significant compaction causing subsidence at the seafloor (Keszthelyi et al., 2016). The reservoir may undergo significant compaction particularly with loose unconsolidated sands of high gas content (Geertsma et al., 1973). Clay and sand layers actually compact almost to the same extent, the main variation is that low permeability of clays prevents instantaneous compaction and leads to an effect attributable to creep, subsidence effects in the surface are delayed (van der Vlis et al., 1967). The interbedded fluvial and clay rich silty matrix conglomerate undergoing large pressure drop and a rise of the water level may cause compaction. Nonetheless, this hypothesis contains uncertainty due to the cyclical nature of the anomaly in the S-impedance, the anomalously high amplitude, and the data quality issues of the PS data due to tuning thickness in the half graben.

From this time-lapse analysis we have evaluated each well location as control points in interpretation, identified major zones of 4D response, and correlated the responses to the geology of the field. Potential baffles and barriers to flow are identified within the sand
body that cause the compartmentalization of the water front. High permeability zones in 
the aeolian sand fingers have been distinguished linking the water front to the producers.
Possible water corridors are noted in the central producers. Gas caps have been classified as 
a result of pressure drop in the Eastern wells. Overall we have identified the flood pattern, 
possible compartmentalization, permeability pathways, and potential bypassed reserves.

6.2.3 Saturation Change vs Pressure Change

As previously discussed, time-lapse data allows the ability to monitor fluid flow changes 
during field development. For favorable reservoir conditions, dynamic reservoir properties 
such as pressure and fluid saturation can be observed in the 4D impedance. These properties 
overlap in their impedance response. Often the resulting impedance change is a combination 
of pressure and saturation change, either destructively or constructively interfering. The 
resulting 4D response is entirely nonunique, multiple scenarios of pressure and saturation can 
produce the same amplitude difference. Crossplotting S-impedance change and P-impedance 
change has been shown to aid in the separation between pressure effects and saturation 
effects (Tura & Lumley, 1998). Understanding and distinguishing these dynamic estimates 
can illuminate the magnitude of impedance associated with geomechanical changes versus 
fluid response, thereby providing a better look at what combination of effects are caused by 
production and injection in the reservoir.

The effects of saturation and pressure can be separated in the crossplot domain as shown 
in Figure 6.25. This schematic is a simplification of the steps going into the crossplot. In re-
ality, changes in pressure and saturation are either represented by approximations of change 
in reflectivity, impedance, or calculated using multiple rock properties (Landro et al., 2003). 
Nonetheless, the basic concept of the crossplot is that points that lie on the X-axis are dom-
ninated by saturation change (ΔPressure=0). The larger the angle, θ, the more influence of 
pressure change. Points on the Y-axis are pressure only effects (ΔSaturation=0). Typically, 
reflectivity or impedance estimates are crossplotted, then the crossplot is calibrated with 
well data and seismic data. Known scenarios of saturation only and pressure only effects
Figure 6.25 Schematic of ideal pressure change and saturation change plot. Theta representing the angle between the saturation only change and the plotted trend of points.

are plotted, their best-fit axis is then used as the X and Y axes respectively. This axes transformation allows for the produced crossplot to be near to the ideal pressure change and saturation change plot shown in the schematic in Figure 6.25.

Figure 6.26 Mean amplitude extraction at the reservoir window of the (a) P-impedance and (b) S-impedance estimates from inversion. Overlain with polygons noting scenarios 1-5.

In order to utilize this crossplot method to analyze the separability of pressure and fluid changes, the interpreted scenarios were investigated. The 4D response for scenarios 1-5 in Table 6.1 were defined in map space from the P-impedance change with the polygons shown in Figure 6.26. These polygons were used for the S-impedance estimate as well. Scenario 6
was left out due to uncertainty, but the event still interferes with the polygon from production derived from the PS inputs. Using these polygons, RMS extractions between the chalk and basement were taken in the P- and S-impedance volumes derived from PP prestack inversion, and the P-impedance from PP pre-stack inversion combined with the S-impedance from the PP-PS inversion. The RMS amplitudes were then designated as positive or negative based on the sign of the mean amplitude response.

A common industry practice is to analyze PP derived difference estimates to interpret changes as either pressure effect or fluid effect (Landrø et al., 2003; Tura & Lumey, 1999). Incorporating PS data will improve the interpretations given agreeable reservoir properties, as discussed in Chapter 2 (Landrø et al., 2003). First, we will go over the more conventional process of PP prestack inversion.

Figure 6.27 Crossplot of change in S-impedance vs change in P-impedance derived from PP prestack inversion using RMS extractions from the top reservoir to the basement. Scenarios 1-4 are plotted.
PP prestack inversion outputs a volume for P-impedance and S-impedance. However, as discussed in Chapter 4 and 5, the S-impedance derived from a limited offset PP pre-stack dataset will not be independent of P-impedance. Looking at the crossplot in Figure 6.27, this is clear. There are a lack of points around zero due to the noise level in the PP data, changes below 100 to 150 ft/s^2/g/cc difference are not recoverable as they lie within the noise window. Nevertheless, the scenarios map from these estimates do not provide information for distinguishing development effects. S-impedance data follows the trend of P-impedance completely. There is no θ, or separation in pressure and saturation. S-impedance derived from this PP inversion does not add any value in highlighting pressure changes as it is calculated from the simple linear relationship with P-impedance that assumes brine filled clastic sediment with small reflectivity. Changes in pressure cause deviations from this background trend relationship, but independent delta terms cannot be captured using PP prestack data with a max angle of 34°.

With PP-PS inversion, even with the limited angle range, shear impedance estimates are improved, particularly where the background trend fails such as in pressure and saturation change. This improved S-impedance used in conjunction with the P-impedance from PP prestack inversion is cross-plotted in Figure 6.28. The lack of points around zero show the noise level of the data includes impedance of changes up to 150(ft/s)*(g/cc). The fluid effects from the water front and gas exsolution lie closest to the ΔZ_P axis. Water replacing oil (blue) produces a positive linear response leaning to the P-impedance axis, while gas exsolution (red) is a negative response leaning to the P-impedance axis indicating minimal pressure influence. Gas exsolution is marked by more scattered from noise in the ΔZ_S estimate within the large defined the polygon.

The production effect, which is a small drop in pressure and reduced gas saturation at the central producers, causes a hardening in both impedances but the main trend is influenced by P-impedance due to the saturation change. The S-impedance is influenced by the scenario 6 anomaly. The production area that overlaps with scenario 6 shows a trend parallel to the PS.
Figure 6.28 Crossplot of change in S-impedance (Y-axis) from PP-PS prestack inversion vs change in P-impedance (X-axis) derived from PP prestack inversion using RMS extractions from the top reservoir to the basement. Scenarios 1-4 are plotted. Axes of transformation overlain.

reflectivity. This is expected as the anomaly does not exist in the PP data, high uncertainty exists in the interpretability of the anomaly.

Moving to the injectors, there is the case of an injector with high saturation effect from gas injection and low pressure change, W-2, and the case of an injector with no saturation change but with large pressure change, W-1. This difference can be seen in the crossplot (Figure 6.28). Points from injector W-2 deviate marginally from the gas exsolution case, indicating mainly saturation influence and minor pressure influence. Points from injector W-1 shows a much larger $\theta$ indicating a larger contribution of pressure change and minimal saturation change.

It is important to note that the scenarios of mainly saturation change such as water replacing oil, are slightly deviated away from the x-axis, meaning there is a very small but present S-impedance response. This is due to the PP-PS data leakage. As described in the
previous chapter, where the S-impedance deviates from the background trend (ie. pressure and fluid effects) there will be an averaging effect between S- and P-impedance causing P-impedance leakage into S-impedance and vice versa. Even so, the S-impedance from PP-PS inversion versus PP inversion shows notable improvements in separating pressure and saturation changes.

6.2.3.1 Saturation and Pressure Map

Thus far we have analyzed multiple scenarios supported with well log data in map and crossplot domain. By using these known scenarios for pressure only changes, injector W-1, and for saturation only changes, water replacing oil or gas exsolution, the pressure and saturation axes can be determined. These axes form the basis for a coordinate transform into the pressure-saturation domain (Lumley et al., 2003). In general, attributes that are closer to the raw seismic data such as the amplitude difference in the nears and fars are more robust for this transform, but produce more qualitative pressure vs saturation results (Lumley et al., 2003). The benefit of more processed inversion attributes, such as the prestack inversion derived impedance estimates, is a more quantitative pressure vs saturation result, but again this method is less robust in the presence of seismic noise (Lumley et al., 2003).

For determining the pressure and saturation axes in the crossplot, three calibration scenarios are available. The saturation only axis can be identified by a best fit linear line from the origin through the water replacing oil scenario and the gas exsolution scenario. For the pressure only axis the sole reliable control point is injector W-1. These axes of transformation are overlain in Figure 6.28, approximately 30° and 60°. Using these best fit lines, PhD student Payson Todd applied a linear coordinate transform using the methodology established in Lumley et al. (2003). This rotation allows the changes in S- and P-impedance from inverted estimates to be converted to changes in pressure and saturation.

First, this transformation was applied using the 4D PP pre-stack inversion estimates. The result is shown in Figure 6.29. With this result, no separation in pressure and saturation can be made. Practically no pressure change is detected, even at injector W-1, which should
Figure 6.29 Pressure and saturation change RMS maps transformed from PP prestack inversion estimates of change in P- and S-impedance. Using the axes of transformation from the PP-PS joint inversion analysis plot. RMS window is from chalk to basement. High noise level outside of graben is due to a narrow extraction window at those locations.

show large change in the clean aeolian section. In this case, the transformation axes were defined by the joint PP-PS inversion results.

Figure 6.30 Pressure and saturation change RMS maps transformed from PP prestack inversion estimates of change in P- and S-impedance. Using the axes of transformation from the PP prestack inversion analysis plots. RMS window is from chalk to basement. High noise level outside of graben is due to a narrow extraction window at those locations.
In an attempt to extract more information from the PP prestack inversion estimates, arbitrary transformation axes were chosen using the erroneous PP prestack inversion results from Figure 6.27. These much narrower axes were used for transformation and produced the map in Figure 6.30. The pressure change map seems to be dominated by noise and incorrectly identifies the injector W-2 as causing the largest pressure response. Based on this analysis it is clear that the PP prestack inversion result for S-impedance provides no benefit in separating pressure from saturation change.

Using the accurate transformation axes and the S-impedance from joint inversion, the pressure and saturation maps show large improvement (Figure 6.31). The inclusion of PS data does add a level of noise to the maps, but it also allows for reliable separation between pressure effect and saturation effect. The noise outside the half graben is particularly strong due the thinning of the extraction window (chalk to basement window is practically zero outside half graben). There is also a large noise level in the south-west of the pressure map. This noise is common in inversion results as this product is more tampered with than the original data (Lumley et al., 2003).

With the maps from joint inversion, injector W-2 is correctly identified as chiefly a saturation effect and W-1 as chiefly a pressure effect as well data suggests. The strongest pressure effect is South of the platform but continues North and into the central producers, particularly well R that targets the thickest oil bearing aeolian sand. The pressure change in the Eastern producers is not seen in the data most likely due to the significantly lower porosity of the conglomerate lithology relative to the sands in the East. Lower reservoir quality in this case causes the 4D amplitude response from pressure change to drop to below the noise level of the data.

In the saturation map, the water front from W-1 shows the largest effect. This could be from the interference of gas and water in the front from injector W-2, but it is most likely due to a higher porosity in the sands updip of W-1. Minor amounts of saturation change can be seen at injector W-3. W-3 is within the water leg, however, updip at well B, there is a 9
Figure 6.31 Pressure and saturation change RMS maps transformed from PP prestack inversion estimates of change in P-impedance estimate from 4D PP prestack inversion and S-impedance from 4D joint PP-PS prestack inversion. Using the axes of transformation from the PP-PS joint inversion analysis plot. RMS window is from chalk to basement. High noise level outside of graben is due to a narrow extraction window at those locations.

Meter oil column marked by an oil water contact (OWC) deeper than the common OWC seen in the other wells. This suggests that there is pressure compartmentalization in the South, and the saturation response indicative of water replacing oil directly updip of W-3 supports the hypothesis. Additionally, the saturation change proximal to the two northern injectors is clearly differentiated. The saturation change at well W-2 shows a very strong response from residual gas and while the injector at W-1 shows no saturation change. Towards the updip south-east portion of the field there is a combined effect of decreasing pore pressure and gas exsolution, however, the major response is only attributed to saturation change. This effect continues to the platform, potentially indicating the reduced gas saturation in the central producers. The RMS extractions used to make these transformed dynamic property maps include uncertainty from the large size of the window and ignores the sign of the response, but amplifies signal to noise.

The attribute of mean amplitude can be used in the same methodology to decrease the window size and include sign. The mean amplitude extractions from modeled scenarios 1-
Figure 6.32 Crossplot of change in S-impedance from PP-PS prestack inversion vs change in P-impedance derived from PP prestack inversion using mean amplitude extraction window 10ms above reservoir horizon and 60ms below. Scenarios 1-4 are plotted.

4 are crossplotted in Figure 6.32. This attribute includes much higher noise content than the large window RMS extraction. This mean amplitude was taken in a 70ms window using the top reservoir horizon as a reference; 10ms above the horizon and 60ms below the horizon adequately captured the 4D response around the reservoir for both P- and S-impedance. Another major change when using mean amplitude is that the axes for saturation and pressure are different. These axes (85° and 15°) are much closer to the X and Y axes than the points from RMS extraction. Gas injection and water replacing oil lie very close to the X axis, and points from injector W-1 are closer to the Y axis. The trend of injector W-2 is approximately 45°, indicating both pressure and saturation response, as log data suggests. Additionally, this mean impedance domain clearly shows that gas injection, water replacing oil, and production are not captured by shear-impedance. The shear impedance for these saturation dominated effects is scattered noise, while the injectors that contain pressure influence are more coherent.
Figure 6.33 Pressure and saturation change mean amplitude maps transformed from PP prestack inversion estimates of change in P-impedance estimate from 4D PP prestack inversion and S-impedance from 4D joint PP-PS prestack inversion.

Transforming the mean amplitude axes to pressure and saturation and moving back into map space results in Figure 6.33. In the mean amplitude domain we are able to observe the differences in hardening and softening response for pressure and saturation, but also add a level of noise. The most interesting feature in this domain is separation between well R and wells Q and J. The southern wells Q and J undergo pressures below bubble point and produce the reduced gas saturation effect we have described as scenario 2. Because well R hits the thickest reservoir, the aquifer or pressure-support travels through permeable sediment and is quicker and more efficient in maintaining pressures. Because of this, pressure did not drop to below bubble point and reduced gas saturation did not occur at well R. This notion is captured in the mean amplitude saturation change map. These various attributes can be adjusted but show the benefits that PS data can provide for time-lapse interpretation.

6.2.4 Interpretation Summary

In order to gather a full picture of the effects of production and injection, the pressure vs. saturation maps have been used in conjunction with the seismic difference, inversion estimate difference, and time shift data. With this time-lapse analysis, we have tied our
interpretations not only to the geology but also to dynamic reservoir information such as production, injection, and pressure changes. Qualitative interpretation of saturation changes has allowed identification of the water front spatial extent and differential drive. Potential baffles and barries to flow have been highlighted that tie with the geologic findings in the area. Permeability pathways are identifiable in the results that disprove the prior concept that the reservoir is a thick homogeneous clean sand. This differential water front may potentially leave bypassed oil downdip of the central producers. Pressure change interpretation has aided in identifying potential compartmentalization of pressure and fluid due to lower permeability interdune, fluvial, and alluvial sediment.

Often, saturation change and pressure change occur in the same location. For these cases, the identified 4D scenarios were mapped in impedance crossplots, transformed with ties from known production and injection data, into pressure and saturation maps. This lowered the uncertainties that arise from competing pressure and saturation change and gave a clearer picture of the interplay between effects. The incorporation of the 4D joint PP-PS inversion derived S-impedance has proved to be crucial in differentiating pressure and saturation effects. Without the PS data, the correlation between S-impedance and pressure was nonexistent.
CHAPTER 7
CONCLUSIONS AND RECOMMENDATIONS

The work done in this thesis is meant to evaluate the benefits of using 4D multicomponent data in characterizing reservoir heterogeneity in a complex field and understanding reservoir response to development. My results and findings are summarized in this chapter.

7.1 Theoretical Value of Multicomponent Data in Edvard Grieg

Firstly, we established from the Aki and Richards (Aki & Richards, 2002) approximations, given the datasets limited angle range, to 34°, PP data is unlikely to produce reliable estimates for S-impedance and density. Incorporating PS data with the same limited angle, may improve the S-impedance estimate but no improvement in density should be expected. We found that S-impedance, P-impedance, and $V_P/V_S$ rock properties can distinguish reservoir facies of clean sands, alluvial sandy matrix deposits, and alluvial silty matrix deposits. A rock physics template was created from log data to aid in interpretation of inversion results. Therefore, the improved S-impedance from incorporating PS data would provide useful information for characterizing reservoir heterogeneity. Model-based inversion is expected to produce better results than intercept-gradient inversion due to the class 4 nature of the sands, moving from a low $V_P/V_S$ chalk to a sand with the same $V_P/V_S$. The feasibility study done for the 4D scenarios in the sands produced a conservative idea of the signal expected to be visible in the seismic data. This modeling illustrated the development scenarios at the Edvard Grieg field, known from log data, theoretically should be seen in the seismic.

Data quality of the PP and PS seismic datasets was analyzed to identify potential sources of error that could be reflected in the inversion results. In both PP and PS datasets shallow conical cemented injectites and the platform produced signal loss and pullup in the reservoir unit. The PS data was also preferentially damaged by the deeper and more consistent Grid sand injectites, which showed much larger S-impedance contrast than P-impedance. The
heterogenous overburden of polygonal faulting and injectites were further assessed through azimuthal binning and QC steps. Not only is the chalk a major obstacle for the PS data as in the PP data, but so are the Grid sands. This causes significant signal decay in the reservoir for the PS data which ultimately contains a peak frequency of only 9 Hz in the reservoir when registered to PP time. Finally, the data were conditioned with trim statics by azimuth and again within each gather, followed by equal fold stacking for optimal reflectivity sampling.

7.2 Synthetic Data Tests

Prior to the testing on the field data, the inversion methods were tested on synthetics generated from well A to determine the optimal parameters for the inversion and evaluate the influence of each parameter. The findings from the synthetic testing showed that incorporating AVA information improves the P-impedance estimate, while PS data marginally improves the S-impedance estimate, but no improvements are seen in density. The reliance of each inversion on the background trend derived from the well log data is tested. The coupling relationship is utilized in Hampson Russell for stabilization. Tests showed that for limited offset range, the PP prestack inversion produces a S-impedance and density that are derived from a linear relationship with P-impedance in logarithmic space. The delta terms ($\Delta L_S$ and $\Delta L_D$) are not indicative of the true deviations. This produces an erroneous S-impedance in areas that the background trend does not suffice. In the synthetic PP-PS inversion, the PS/PP ratio was found to have minimal impact on the seismic misfit for the PP data, suggesting that the PP data is heavily relied on even when the weight is set orders of magnitude smaller than the PS data. The major benefit found from using the PS data is an improvement in S-impedance that lies where the background trend from the log data does not suffice such as fluid changes, pressure changes, or largely varying geology. In these locations, the PP-PS inversion produces an averaging effect in the P- and S-impedance where the S-impedance becomes closer to the true value but the P-impedance deviates that same amount from its true value.
7.3 Field Data Application

Three inversion methods were applied on the field data, PP post-stack inversion, PP prestack inversion, and PP-PS prestack inversion. All methods used the same low frequency background model derived from 6 wells in the survey chosen particularly as the wells that adequately sample the range of geology in the Edvard Grieg field. This background model was heavily iterated to avoid bullseyes around wells in the inversion results, as this is often the bottleneck of model-based inversion. Our findings show that the kriging method in Petrel produced the best interpolation result. Deterministic wavelets with minor phase for PP and PS data were chosen as they produced the least misfit in seismic and model estimates in the inversion results at both the wells and spatially away from the wells.

The post-stack inversion results showed a good estimate for P-impedance but smoothed through many of the important geologic features, such as the top and base of the reservoir along with the clean aeolian packages interbedded in the alluvial sediment. Additionally, large erroneous chalk variations were seen in the post-stack inversion estimates. This is because the PP AVA is decreasing, utilizing the full stack dataset to represent normal incidence will underestimate the reservoir amplitude. With the addition of AVA data, the P-impedance estimate was able to capture sharper impedance changes at the top and base reservoir, along with identifying the lowest impedance zones in the clean oil bearing reservoir.

Multiple registration techniques were tested but the optimal workflow consisted of using the KPSDM velocity model in conjunction with horizon matching for refinement. With the addition of the registered PS data in joint PP-PS prestack inversion, the resulting S-impedance showed significant improvement while P-impedance marginally decreased in accuracy and density did not change as expected. This conclusion was confirmed by analyzing filtered inversion results with filtered logs to avoid bias from logs used in the background model and to see the accuracy of the relative impedance changes calculated from the inversion. The seismic misfit was used as a tool to monitor the areas of error in the inversion result, often correlated to multiples of the chalk and noise. Overall, the model estimate for
P-impedance was most reliable from PP prestack inversion while the model estimate for S-impedance was most reliable from PP-PS prestack inversion. Using both estimates produces a largely improved calculation for $V_P/V_S$.

Following the baseline inversion, the monitor dataset was cross equalized to the baseline using global scalars and trace by trace methods per angle stack to optimize repeatability. Time shifts from production and injection were calculated, and with synthetic modeling and careful trace by trace analysis we narrowed the window of the time shift to the base reservoir reflector. Because of this localization, the shifts were left in the data but used for interpretation purposes. The long wavelength time shifts were correlated with geomechanical effects and short wavelength associated with fluid response. The time shifts highlight northern fluid pathways not seen in the amplitude data. Because time shifts respond more sensitively to geomechanical changes than saturation changes, they are used in conjunction with the amplitude difference to refine interpretations.

Using the final cross equalized 2018 vintage datasets, the PP prestack and PP-PS prestack inversion was performed. The result from 4D PP prestack inversion showed that the P-impedance resembled a sharper quantitative version of the PP amplitude difference. This response correlated with areas of saturation change and mixed pressure and saturation change. However, the 4D S-impedance response approximated to a scaled version of P-impedance. This S-impedance adds no 4D value because it was derived from the background relationship with P-impedance that does not take saturation and pressure change into account. With the incorporation of PS data in PP-PS 4D inversion an improved S-impedance estimate was derived that shows mainly pressure changes but still contains minor leakage of saturation change from the PP dataset.

7.4 Baseline Inversion Analysis

Post-inversion work consisted of geologic analysis of the seal and reservoir of Edvard Grieg. Given the data quality of the PS at the reservoir, the addition was not expected to improve the model estimates for interpretation purposes, however, the $V_P/V_S$ was sig-
significantly improved using the PP-PS inversion derived S-impedance. The Shetland chalk impedance variations were determined to be heavily influenced by overburden heterogeneity, but also in large scale related to the thickness of the chalk group, clay content, and the presence of the most robust seal in the field, the Tor chalk.

The baseline inversion results allowed for facies identification in the reservoir. The aeolian sand reservoir quality is shown to increase towards the northeast driven by the chronostratigraphic age of the sands with north-eastern sand being youngest. Using the inversion results, supported with lithologic information from well logs, I found that the aeolian system transitioned from a wet system to a dry system, leaving the southern sediment with higher fluvial and alluvial deposits. This spatial change is also due to the synrift deposition of the sands and subsequent erosion from a major transgressive event. The alluvial facies is found to be highest quality in the south of the field and when interbedded with the aeolian fingers, supported by extractions from the inversion results. Finally using the P-impedance and S-impedance estimate, a lithology volume was made that separated good quality from poor quality reservoir.

7.5 4D Inversion Analysis

The 4D inversion result showed excellent correlation with production and injection data from well logs. The results were separated into 7 scenarios of water replacing oil, reduced gas saturation from production, gas exsolution, and proximal injector effects. Ties to the geologic interpretation allowed identification of potential reservoir compartmentalization, barriers and baffles, as well as the permeability pathway of fluid flow. With this analysis, we are better able to understand the dispersion of the injected seawater front and its influence on the producers.

Quantitative seismic-derived maps of change in P-impedance and S-impedance were produced and transformed to pressure and saturation maps. These maps are valuable to the asset team for separating the effects of pressure and saturation from development in the field. The maps illuminate the saturation driven change in injector W-2 and the pressure driven
change in injector W-1. Saturation changes are strongest in the water front produced by
W-1, most likely due to more porous sands in the fluid pathway. W-3 shows minor saturation
change in the water front and supports to the concept that the oil water contact is variable
towards the south-west.

The central producers cause a mix of pressure and saturation change, from pressure in-
crease and reduced gas saturation. This saturation change is not expected in well R which
remained above bubble point, this notion is shown in the generated pressure vs saturation
change maps. The updip section of the chalk shows strong saturation change associated
with gas exsolution, little change from pressure drop at the Eastern producers. With the
PP prestack inversion, the S-impedance follows the trend of P-impedance and provides no
added value for 4D interpretation as the estimate did not deviate from the background trend
established by logs. Deviations from the background trend include pressure and saturation
change, therefore the S-impedance from 4D PP prestack inversion provides no added value
for time-lapse interpretation. Theoretically S-impedance should respond to pressure change
only, while P-impedance responds to saturation and pressure change. Using this theory for
reservoir monitoring will only reap benefits if a good estimate of S-impedance is acquired,
which is why the incorporation of PS data proved crucial in making our time-lapse interpre-
tations. Using the S-impedance estimate from joint PP-PS inversion, we achieved improved
separation between pressure and saturation effects on the reservoir.

7.6 Recommendations

Based on observations made throughout this work, I have several recommendations for
future work and processes that could be done to refine the results and make the analysis
more robust.

Our conclusion shows that the PS dataset contributed to improved S-impedance. This
PS dataset contained large fluctuations in amplitude due to the overburden complexity. Az-
imuthal dependency was studied in this project, but further work should be done to attempt
to correct for this azimuthal variation. Additionally, the Grid sands in the PS data signifi-
cantly decreased the frequency content and amplitude signature of the reservoir. Refinement of the S-wave velocity model using Q-migration techniques, full-waveform inversion (FWI), or analysis on potential S-wave splitting may prove useful in improving PS data quality. Ultimately, this improved data quality would improve the estimated S-impedance.

Nevertheless the PS did improve the model estimate in many areas. Identifying where the PP-PS inversion failed could provide insight on what inversion method may be more appropriate for further work. All inversion methods contain assumptions, the assumptions for this model based inversion were small reflectivity and that the lithology in the background trend consisted of brine filled clastic sediment. Zoning in the background trend in Hampson Russell is not possible and may potentially have changed the inversion results. Additionally, Hampson Russell actually inverts for the natural log of P-impedance and two delta terms described in Chapter 2 but does not output the delta terms. These delta terms show model estimate deviation from the background trend which can better identify where exactly the PS data is showing improvements and be used for anomaly detection. A previous RCP student, developed a code to output these terms which may be useful in this analysis (Tuppen, 2019). This analysis may also provide insight to support manual changes of the covariance terms, the goal being to test if lower weight on P-impedance in the background model for PP prestack inversion may provide more accurate S-impedance estimates.

A PS inversion alone may provide added registration refinement and prevent leakage from the PP data to the S-impedance term. However, the PP data was used here due to the added stability rather then relying on the 9Hz peak frequency from the PS data which contains depth fluctuations caused by errors in the S-wave migration velocity model.

Further work could be done to improve the 4D interpretation of the field. The time shifts in this dataset were not applied due to the time shift calculation window size limitation. Estimating time shift using a method that does not require cross correlation may improve the calculation and be sufficient to correct for production and injection effects. This application will improve the accuracy of the estimated model parameters. With regards to the final
saturation vs pressure analysis, multiple components could be added to strengthen and extend analysis. The seismic amplitude difference can be studied to perform a qualitative pressure vs saturation transform that may produce more robust results. More attributes with varying windows can be transformed to add support to the field observations. This work needs more refinement to hold weight in interpretation.

The seismic vintages available were shot in 2016 and 2018, this two-year time period can detect pressure and saturation change but with increasing time the 4D response will grow and change. A third survey will be acquired in the summer of 2020. With this survey, the 4D changes will be larger and provide more insight for asset management and development decisions. Additionally, the interpretations can be affirmed or disproved with the added information, particularly important for the more ambiguous 4D amplitudes such as the geomechanical effect observed in the PS data below the platform. Further work on this dataset can aid in decreasing risk and uncertainty in the 4D interpretations.

7.7 Final Thoughts

Overall, I have shown the value and limitations of the PS seismic dataset in Edvard Grieg for characterizing reservoir heterogeneity and reservoir response to production and injection. Rock physics analysis conveyed the expectation and bottlenecks of this particular PS dataset, recognizing the direct influence of seismic quality in the ultimate result. Synthetic data testing illustrated the dependencies inherent in the model-based inversion algorithm. Edvard Grieg is not a “stealth” reservoir according to its definition, however, the PS data still provides added value in an improved shear-impedance, even with limited angle range and significant data quality loss from heterogeneous overburden. I have shown the major improvement in S-impedance from joint PP-PS prestack inversion and the benefits it grants in $V_P/V_S$ for facies analysis and in reservoir monitoring. Finally, my work is a key step to achieve the goals for RCP’s North Sea project, and paves the way for significant future work and analyses.
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