Eagle Ford shale has been of importance in the oil and gas industry with the new advent of unconventional technology in recent years. Previous studies have shown that Eagle Ford shale is a world-class source rock. Rock physics models help characterize the elastic properties of conventional and unconventional reservoirs.

In this thesis, I present a novel rock physics model for organic-rich shales. The extended Maxwell homogenization scheme is utilized as a rock physics model for transversely isotropic media. Since shales have complex structures, different components of the rock are modeled as multiple inclusions. First, I estimate the anisotropic clay matrix. This is then used as the host matrix, and quartz, calcite, kerogen, and fluid-filled pores are modeled as inclusions with different aspect ratios. Representation of multiple inhomogeneities with different aspect ratios is non-trivial. Yet, I suggest a solution to the representation difficulty using this new model. The Maxwell homogenization scheme honors the aspect ratio of each inclusion embedded in an effective inclusion domain.

Combined rock physics models have been used to obtain elastic properties of clays and shales. Notwithstanding, there is no consistent method for modeling both. The developed rock physics model and workflow thoroughly handle the estimation of elastic stiffness coefficients of both clays and shales in anisotropic media. This study shows that this rock physics model can be readily applied to other unconventional reservoirs.

Dipole sonic log and core measurements of the Eagle Ford shale field are utilized to constrain the modeling results. I process and interpret dipole sonic logs to obtain elastic stiffness coefficients C_{33} , C_{55} and C_{66} . Subsequently, I use these coefficients to validate the outcomes of the Maxwell homogenization scheme. To my knowledge, this is one of the first studies that verify the robustness of this rock physics template with field data. After obtaining the elastic stiffness tensor of the Eagle Ford shale in VTI media, I estimate the Thomsen parameters (i.e. anisotropy parameters). Anisotropy parameters ϱ, γ and δ, on average, are 0.19, 0.29 and 0.04, respectively based on my modeling results in Eagle Ford shale. Anisotropic modeling results exhibit a good correlation with dipole sonic logs. Both dipole sonic log analysis and rock physics results demonstrate that clay content is the main driver of anisotropy in the field, and there is a direct relationship between clay volume and anisotropy parameters of ϱ and γ. In addition, kerogen and fluid-filled pores have second-order influence on anisotropy in shales. Anisotropic analysis is of importance in this study because neglecting anisotropy can lead to erroneous seismic interpretation, processing, and imaging in the area of interest. This new model allows one to estimate geomechanical properties as well as seismic properties. The directional dependence of geomechanical properties should be taken into account in order for operators to optimize hydraulic fracture design and to develop the field more efficiently.

In addition, I investigate implications of the modeling results on multicomponent seismic data. Amplitude variation with angle (AVA) analysis shows increasing anisotropy in the reservoir could result in significant variation in P-wave, C-wave and S-wave datasets. I show that the isotropic assumption results in deviation at the mid and far angles.

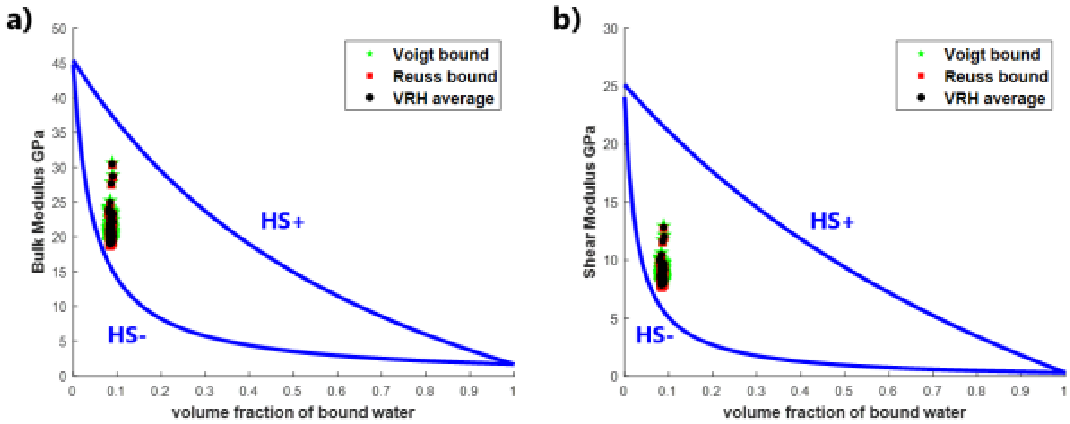

Figure 3.15: a) Upper (HS+) and lower (HS-) Hashin-Shtrikman bounds of bulk modulus of water-clay composite with overlain Maxwell homogenization scheme results. b) Upper and lower HS bounds of shear modulus of water-clay composite with overlain Maxwell homogenization scheme results

3.5.2 Shale Matrix

Since clay platelets are connected to each other, clay minerals fabricate load-bearing skeleton of shales (Hornby *et al.*, 1994). Hence, estimated clay stiffness coefficients are used as background matrix to model Eagle Ford shale. The rest are modeled as inclusions with different aspect ratios (Figure 3.16). For instance, quartz and calcite are known to be isotropic minerals, and represented as spherical inclusions in this model. The other two inclusions are kerogen and fluid-filled pores. Section 3.1 shows how to obtain effective moduli of fluid phases. For kerogen, the values from Table 3.5 are used. I did a grid search in order to find best fit of aspect ratios of kerogen and pores using Equation 3.11. Using this objective function, I minimize the RMS error of C_{33}, C_{55}, and C_{66} between the actual dipole sonic log values and my modeling results so that I obtain aspect ratio estimates of each inclusion for the Eagle Ford layer. The best fit aspect ratios for kerogen and fluid-filled pores are 0.48 and 0.35, respectively. This result is reasonable because Sone & Zoback (2013) showed that Eagle Ford inclusions have the lowest aspect ratio among all shale samples examined from various formula suggested by Sevostianov (2014).

Although well logs, core measurements, and seismic inversion could help us calculate some of the geomechanical and reservoir properties, they are limited in understanding the anisotropy in the reservoir. For this reason, rock physics models are necessary to be able to analyze the reservoir and estimate parameters essential for completion design and well placement. With the help of the rock physics model I present in this chapter, one can analyze the anisotropic effects on geomechanical and seismic properties.

Since acoustic core measurements with increasing pressure is not provided by the vendor in this project, incorporating pressure dependence into the rock physics model is not possible. However, from the literature review, one can see that pressure dependence of seismic velocities and anisotropy is negligible in Eagle Ford shale. I suspect the small effect of pressure dependence as demonstrated by Sone & Zoback (2013) and Mokhtari *et al.* (2016) is not detectable.

3.13 Summary

The presented rock physics model and workflow an be applied to unconventional fields to estimate elastic stiffness coefficients of both clay and shale matrix in anisotropic media. For this application, one needs to constrain the modeling results using dipole sonic logs and/or core measurements taken from the field. Aspect ratios and elastic moduli (bulk and shear modulus) of some of the minerals such as quartz, calcite and pyrite are well known. Yet, the elastic properties of clays and kerogen needs to be constrain with a priori to obtain robust results using this rock physics model, the extended Maxwell homogenization scheme. Based on the results from this new rock physics model, Thomsen parameters obtained for Eagle Ford shale are $\epsilon = 0.19$, $\gamma = 0.29$ and $\delta = 0.04$.

In Chapter 1, I introduce the Eagle Ford project, available datasets, and some of the geological features in the area of interest.

In Chapter 2, I show how to process and analyze dipole sonic log data in anisotropic formations. Additionally, I review dipole sonic logging and Stoneley wave. Based on the interpretation of dipole sonic log, Eagle Ford shale clearly exhibits strong transverse isotropy with vertical axis of symmetry (VTI). However, the overlying Austin chalk is interpreted as isotropic. Most importantly, I find a strong correlation between the clay content in the Eagle Ford formation and anisotropy parameter (γ). This result implies that clay minerals and their alignments are the main cause of anisotropy in shales. I also indicate that stiffness coefficients obtained from dipole sonic logs can be used to constrain rock physics modeling results.

In Chapter 3, I present a novel rock physics model, extended Maxwell homogenization scheme, to predict elastic properties of unconventional reservoirs. This new model and the workflow I developed can handle modeling of both a clay matrix and organic-rich shales. In addition, the shape of the effective inclusion domain is taken into account for further analysis, because certain assumptions regarding this shape can cause an unrealistic estimation of elastic stiffness tensor. To obtain an accurate shape for the inclusion domain, I suggest using a method to calculate the aspect ratio of the effective inclusion domain by honoring the aspect ratio and volume fraction of each inhomogeneity. Subsequently, the fidelity of this new model is tested using field data of Eagle Ford shale.

In Chapter 4, I investigate the effect of the clay content (i.e. anisotropy) on seismic properties. Using amplitude-variation-with-angle (AVA) analysis in VTI media, one can see the implications of the rock physics model in different seismic wave modes. I show that making an isotropic assumption in an anisotropic shale reservoir would result in significant error in mid and far angles in the AVA analysis. I also indicate that modeling fluid substitution in the pore space is possible using this new rock physics model. Even though different fluid components slightly change the results, it can be detected in this model. One can also simulate kerogen content in shales at different maturity stages with the help of the Maxwell homogenization scheme. Compared to horizontal shear wave (SH) mode, vertical shear wave (SV) mode is more sensitive to clay content variation in Eagle Ford shale.

5.2 Suggestions for Future Work

In order to further constrain my rock physics modeling results, I suggest taking additional core measurements in different directions so that anisotropy parameters can be obtained and the rock physics model can be further constrined. In addition, due to lack of information about alignment of clay platelets, I have assumed that clay minerals are aligned perfectly with respect to the symmetry axis. However, this assumption is not necessarily accurate in the nature. To better understand the distribution of clay platelets inside shales due to compaction and diagenesis, SEM images of cores in microscale should be acquired. One can then extract the orientation distribution function from the images and apply it to the extended Maxwell homogenization scheme. This process should enhance the accuracy and the physical explanation of the model.

Eagle Ford shale is known to have volcanic ash beds throughout the play. Since I do not have a direct information about this heterogeneity, I do not take ash beds into account in my rock physics modeling. Since volcanic ash beds can cause anisotropy, this should also be modeled in the Maxwell Homogenization scheme as inclusion. Volcanic ash beds and their 66effects on elastic properties can be another area of research in the future project for this field.

Some engineering work done on this Eagle Ford project demonstrate inconsistency with geophysical analyses. This is due to poor assumptions and the failure to use the results from geophysical data sets. Isotropic assumptions regarding reservoir properties generally lead to incorrect results. For this reason, engineers should incorporate geomechanical properties estimated accurately in anisotropic media in their planning to improve well stimulation and well placement. Organic-rich shales such as Eagle Ford exhibit complex anisotropic structure. Thus, different data sets should be evaluated to obtain robust results regarding elastic properties in the area of interest. In this context, this new rock physics model can help one to update various reservoir parameters and understand their main drivers comprehensively.

4.5 Discussion

In this chapter, I show that kerogen maturity and pore fluids slightly affect amplitude variation with angle compared to the clay content. It is well known that clay alignment is the main driver of anisotropy in shales. This chapter indicates that even though other heterogeneties inside the medium have impact on anisotropy and elastic properties, the influence of clay minerals is the most significant on both anisotropy and AVA analysis. This study also demonstrates that the new rock physics model is sensitive to the effect of fluid substitution inside the pore space. This allows one to estimate possible changes in seismic data in the case of enhanced oil recovery (EOR) or similar applications in the reservoir. Eagle Ford shale, specifically, is shown to be sensitive to VTI anisotropy in AVA analysis. This analysis solidifies that isotropic assumption in a highly anisotropic shale reservoir could lead to inaccurate outcomes in seismic properties. In AVA analysis, isotropic assumption deviates considerably in mid and far angles.

4.6 Summary

AVA analysis is helpful to identify the sensitivity of different seismic wave modes to intrinsic complexities in shales. It is clear that clay variation inside the reservoir could have an impact on different seismic wave modes. In contrast to clay volume variation, the models created from pore fluid and kerogen maturity do not exhibit comparable variation in seismic wave amplitudes. Increasing kerogen content decreases the amplitude of P-wave, whereas it increases the reflection coefficient of PS-wave. As for S-wave modes, the SV-wave shows the unique feature of a polarity around 25°. After 25°, increasing clay content has different impact and lowers the reflection coefficient of the SV-wave mode. Compared to SH wave, SV-wave shows more sensitivity to varying clay content.