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**Seismic Sensitivity to Variations of Rock Properties in the Productive
Zone of the Marcellus Shale, WV**

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by

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Dedication

I dedicate this thesis to my parents.

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Abstract

Seismic Sensitivity to Variations of Rock Properties in the Productive Zone of the Marcellus Shale, WV

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The University of Texas at Austin, 2013

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The Marcellus Shale is an important resource play prevalent in several states in the eastern United States. The productive zone of the Marcellus Shale has variations in rock properties such as clay content, kerogen content and pore aspect ratio, and these variations may strongly effect elastic anisotropy. The objective of this study is to characterize surface seismic sensitivity for variations in anisotropic parameters relating to kerogen content and aspect ratio of kerogen saturated pores. The recognized sensitivity may aid to characterize these reservoir from surface seismic observations for exploration and production of hydrocarbon.

In this study, I performed VTI anisotropic modeling based on geophysical wireline log data from Harrison County, WV. The wireline log data includes spectral gamma, density, resistivity, neutron porosity, monopole and dipole sonic logs. Borehole log data were analyzed to characterize the Marcellus Shale interval, and quantify

petrophysical properties such as clay content, kerogen content and porosity. A rock physics model was employed to build link between petrophysical properties and elastic constants. The rock physics model utilized differential effective medium (DEM) theory, bounds and mixing laws and fluid substitution equations in a model scheme to compute elastic constants for known variations in matrix composition, kerogen content and pore shape distribution.

The seismic simulations were conducted applying a vertical impulse source and three component receivers. The anisotropic effect to angular amplitude variations for PP, PS and SS reflections were found to be dominantly controlled by the Thomsen ϵ parameter, characterizing seismic velocity variations with propagation direction. These anisotropic effect to PP data can be seen at large offset ($>15^\circ$ incidence angle). The most sensitive portion of PS reflections was observed at mid offset (15° - 30°). I also analyzed seismic sensitivity for variations in kerogen content and aspect ratio of structural kerogen. Elastic constants were computed for 5%, 10%, 20% and 30% kerogen content from rock physics model and provided to the seismic model. For both kerogen content and aspect ratio model, PP amplitudes varies significantly at zero to near offset while PS amplitude varied at mid offsets (12 to 30 degree angle of incidences).

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Chapter I: Introduction

BACKGROUND OF SHALE GAS PLAYS

Shales have been traditionally defined as fine-grained, siliciclastic sedimentary rocks; that is, Shales are made up dominantly of silt size ($1/16$ - $1/256$ mm) and clay size ($<1/256$ mm) particles (Boggs, 2006). Shale usually has very low permeability. Therefore, shale has been known for long times as cap rock or seal in the conventional petroleum system. Shale also forms the source rock when it contains sufficient organic matter or kerogen. Some of these source rocks can act as a reservoir as well as seal and have recently become known as resource shale. These shale reservoirs are also known as organic shale, shale gas, oil shale and gas shale depending on the fluid content. These organic shales, compared to normal shales, contain kerogen which is a complex organic matter prospective to yield hydrocarbons. Until recently Shale reservoirs were not exploited for hydrocarbon because the reservoir's low permeability prevents hydrocarbon to flow. The development of large offset horizontal drilling, in conjunction with hydraulic fracture stimulation, effectively increases the permeability in the shale by injecting water, sand and chemicals into the formation allowing the fluids to flow at a profitable production rate. Though application of the fracturing technique began to in the 1950s, commercial shale gas production didn't occur on the large scale until about the year 2000 with production from the Barnett Shale of Texas. Currently, number of shale gas plays in North America have gathered attention for exploration and production of hydrocarbons. These includes Marcellus Shale, Barnett Shale, Haynesville Shale, Woodford Shale and

several others. A map of North American unconventional plays is shown on Figure 1.1. The shale gas production in the United States increased from 0.3 trillion cubic feet in 2000 to 9.6 trillion feet (~40% of USA dry natural gas production) in 2012 (EIA, 2013). Exploration of shale gas resources is also rapidly growing outside United States. A 2013 EIA (U.S. Energy Information Administration) ranking of top 10 countries with technically recoverable shale oil and shale gas resources are given in the Table 1.1.

Figure 1.1: Shale Gas plays in United States and Canada. Both established and emerging plays are shown here. (Wang and Gale, 2009)

Rank	Country	Shale oil (billion barrels)		Rank	Country	Shale gas (trillion cubic feet)	
1	Russia	75		1	China	1,115	
2	U.S. ¹	58	(48)	2	Argentina	802	
3	China	32		3	Algeria	707	
4	Argentina	27		4	U.S. ¹	665	(1,161)
5	Libya	26		5	Canada	573	
6	Venezuela	13		6	Mexico	545	
7	Mexico	13		7	Australia	437	
8	Pakistan	9		8	South Africa	390	
9	Canada	9		9	Russia	285	
10	Indonesia	8		10	Brazil	245	
World Total		345	(335)	World Total		7,299	(7,795)
¹ EIA estimates used for ranking order. ARI estimates in parentheses.				¹ EIA estimates used for ranking order. ARI estimates in parentheses.			

Table 1.1: Top ten countries of technically recoverable oil and gas resources (EIA, 2013)

Shale gas can be of biogenic, thermogenic or combined biogenic-thermogenic origin (Curtis, 2002) with depth of reservoir ranging 200ft to 18000ft (Wang and Gale, 2009). Key control parameters to evaluate the shale gas prospect have been proposed by different authors in different ways (Curtis, 2002, EIA, 2013, Wang and Gale, 2009). Wang and Gale (2009) also proposed a set criteria for screening and ranking shale gas systems with preliminary list of screening parameters which includes TOC, Ro (Vitrinite reflectance to express thermal maturity), gas content (free and adsorbed gases), tectonic setting and burial history, type of pressure system, temperature, porosity, permeability, shale thickness, depth, mineral composition, brittleness and fracture barriers and hazard.

Russum (2005) suggested that thickness >30ft are potential candidates for shale gas production. However, for deeper reservoirs much greater thickness is required, like for Burnet Shale a minimum thickness of 100ft was preferred (Bowker, 2007).

INTRODUCTION TO THE MARCELLUS SHALE

The Marcellus Shale is a giant field in the Appalachian basin that is believed to have trillions of cubic feet natural gas in place. It extends widely across several states in the eastern United States including New York, Pennsylvania, Ohio and West Virginia. The Marcellus Shale also extends in small areas of Maryland, Kentucky, Tennessee and Virginia. The Marcellus Shale is a black organic rich shale. Geologists and Geophysicists working in the Appalachian basin knew the Marcellus Shale for long time because of its distinctive black color in the outcrop and radioactive signature on the geophysical well log. It was not however, considered as a potential source of natural gas until Range Resources –Appalachia, LLC established a promising flow of natural gas in 2003.

Depositional Setting

The Appalachian basin is a foreland basin. It trends northeast to southwest. It was developed during the Taconic orogeny in the Middle to Late Ordovician period. At that time, North America comprised most of the Laurasian continent and oceanic crust was subducted under the North American plate and major highlands were developed due to the accretion of terrains onto the continental margin (Figure 1.2).

Figure 1.2: Paleogeography of Appalachian basin and its surroundings during the Middle Devonian (~ 385 Ma). The red ellipse identifies the study area. The Appalachian basin was bound by the Cincinnati arch (1) to the west, the Acadian mountains (2) to the east and Rheic ocean to the south. (Modified from Blakey, 2010)

The Taconic orogeny formed the Taconic highlands to the east creating a barrier for the Appalachian basin. Therefore, flexural loading along the craton side of the highlands created Appalachian basin as an elongated continental basin trending parallel

to the highlands. During Devonian time, paleoclimate and paleogeography allowed for organic-rich black shale to deposit on the basin. Schwietering (1981) suggested that the basin was shallow during the deposition of shale and black shale where bottom waters were oxygen restricted. Thus, it was postulated that the Marcellus Shale was deposited in a relatively shallow basin (water depth ~ 70 m) (Schwietering, 1981) where anaerobic conditions were present allowing preservation of large amount of organic matters.

Stratigraphy and Lithofacies

The Marcellus Shale Formation forms the basal unit of the Hamilton Group in the Appalachian basin. It is widely distributed and distinct across New York, Pennsylvania, Ohio and West Virginia in the eastern United States. The Marcellus shale is overlain by the Onondaga Limestone formation and underlain by the Mahantango Shale formation (Figure 1.3). The Onondaga Limestone, which is a fine-grained limestone formation, can be easily identified in the wireline logs and it has a sharp contact with the overlying Marcellus Shale. The Marcellus Shale in outcrop and core is predominantly gray-black to black thinly laminated organic-rich shale. The Marcellus comprises two shale intervals separated by the Purcell Limestone which is a sequence of limestone, shale, and a lesser sandstone of variable thickness (Clarke, 1903; Cate, 1963; de Witt et al., 1993).

Age	Formation		Member
Upper Devonian	Alexander		
	Huron		
	Rhinstreet Shale		
	Harrell Shale		
Middle Devonian	Tully Limestone		Purcell Limestone
	Mahantango Shale		
	Marcellus Shale	Upper	
		Lower	
	Onondaga Limestone		
	Huntersville Chert		
	Needmore Shale		
	Oriskany Sandstone		

Figure 1.3: A generalized stratigraphic column of the Upper and Middle Devonian rocks of the studied area of West Virginia. The stratigraphic column was compiled from Boyce (2010).

The Upper Marcellus interval is widely known as the Oatka Creek Member and the lower interval is known as the Union Springs Member. It has been reported (Clarke, 1903; Cooper, 1930; Rickard, 1989; Lash and Engelder, 2011) that the Union Springs Member thickens to the east and southeast from western New York; and it is especially thick in northeastern Pennsylvania where it exceeds 160ft (49 m). The Union Springs Member is very distinctive in wireline logs as a thin, radioactive (high Gamma Ray value), low-density interval immediately above the Onondaga Formation and below the Purcell Limestone Member. The contact of the Union Springs Member and the underlying Onondaga Formation has been interpreted to be a regional unconformity (Potter et al., 1982; Rickard, 1989). The Union Springs member comprises dark-grey to black fissile organic-rich shale. Pyrite and iron bearing carbonated concretions are common (Harper, 1999). X-ray diffraction analysis of a single core sample of the Union

Springs member taken from West Virginia showed the following primary constituents: Quartz 59%, Illite 21%, Pyrite 2-8%, Calcite 2% and TOC 5-20% (Boyce, 2010).

Thin Laminations and fractures

Joints in the organic-rich shale in the Appalachian basin were recognized in a century ago (Sheldon, 1912). Two sets of regional joints (J1 and J2) from outcrops and geophysical well logs in different parts of the Appalachian basin have been documented and analysed by numerous authors. It is postulated that these joints formed close to or at peak burial depth as natural hydraulic fractures induced by abnormal fluid pressures generated during thermal maturation of organic matter (Engelder et al, 2009). The overall trend of J1 joint is east-northeast while the J2 joint trends northwest. Thin beds and horizontal laminations are also reported to be common from the outcrop, core and well log data of the Marcellus Shale (Milani, 2011).

Production

The Marcellus Shale is the largest shale play in the Appalachian basin. The Marcellus may contain natural fractures as well as quartz rich layers. The quartz rich organic layer usually has low Poisson's ratio and high Young's modulus which are often used to identify brittle zones in the rock formation for hydraulic fracturing. Commercial production from Marcellus Shale dates back to 2003 with Range Resources Corporation. However, gas production from the Marcellus Shale increased significantly from 2010. In

2010, natural gas production from the Marcellus play was reported as 20 mcf/day whereas production is reported to 160 mcf/day in the August, 2013 (Figure 1.3).

Figure 1.3: Gas production per day form the Marcellus shale in different years starting from 2007(EIA, 2013). According to the statistics gas production in the Marcellus shale is increasing in every year and in 2013 it exceeded 160 mcf/day.

DATA UTILIZED

Geophysical wireline log data from a vertical well of West Virginia were used for this thesis research. The borehole log data contains spectral gamma, density, resistivity, caliper, photo electric (PE), neutron porosity, monopole and dipole sonic log. Utilizing borehole logs, reservoir properties such as lithology, kerogen content and porosity were estimated. The formation depth and thickness were also determined. Then, full waveform synthetic seismograms were numerically generated for isotropic and VTI anisotropic

model. These synthetic seismogram consisted of large-offset profiles of surface related seismograms suitable for analysis of P-P & P-SV reflectivity with source-receiver offset.

OBJECTIVE

The main objective of this study was to analyze the sensitivity of seismic amplitude for discrimination of VTI anisotropic parameter variations in the Marcellus shale. Numerical seismic simulation based on rock physics analysis for the description of sub-surface rock properties is a useful tool to correlate well logs to surface seismic reflection data. Hence, I used well log data to numerically simulate the surface seismic response to various rock physics models of potentially productive zones. However, a single vertical borehole log does not contain enough information about the anisotropy of the Marcellus Shale. Therefore, I hypothesize various anisotropy situations, varying anisotropy parameters in the model within the theoretical valid range of values. I analyzed the seismic reflection amplitude variations with offset for the productive Marcellus interval from synthesized full waveform seismograms. These AVO variations are for different reflected wave types; P-P, P-SV and SV-SV waves have distinct effects for variations in anisotropic parameters. I also found that the sensitivity to AVO variations not only depends on anisotropy parameters, but also on the rock matrix properties, kerogen content and aspect ratio of structural kerogen pores. Thus, this study helps to obtain better understanding of the seismic response of the productive Marcellus Shale.

THESIS ORGANIZATION

This thesis contains six chapters. The first chapter provides a brief overview of the exploration of unconventional shale gas and an introduction of the Marcellus Shale in the Appalachian basin. A short description of the production and depositional history of the Marcellus shale is also introduced here.

Chapter 2 gives a brief theoretical background of seismic anisotropy and estimation of anisotropic parameter from geophysical wireline logs. This chapter provides basics of seismic anisotropy for transversely isotropic media and introduces the Thomsen (1986) weak anisotropic parameters for it. Also, the relationship of anisotropic parameters with the P- and S-wave velocities in different propagation and polarization directions is discussed here. Moreover, the methods to estimate and constrain some of the Thomsen (1986) parameters (i.e. γ and ϵ) at well borehole locations from monopole and dipole sonic logs is another important section in this chapter.

Chapter 3 provides information of borehole data and gives analysis of the petrophysical parameters. The borehole geophysical log data from one well of West Virginia were examined. Petrophysical properties such as lithology, porosity, kerogen content and fluid saturation were interpreted. Evidence of seismic anisotropy from dipole sonic data was also investigated.

Chapter 4 and chapter 5 constitute the principal part of this research. Chapter 4 consist rock physics analysis and modeling. Rock physics modeling builds a connection between petrophysical properties and elastic properties of the Marcellus Shale. Therefore, elastic constants for known variations of rock and fluid properties can be estimated using the proposed rock physics workflow.

Chapter 5 starts with a brief overview of AVO and numerical seismic simulation for anisotropic layered media. In this chapter, isotropic and VTI anisotropic models are introduced and their seismic responses were analyzed. Seismic sensitivity for variations in anisotropic parameters as well as rock and fluid parameters are also discussed.

Chapter 6 provides a brief summary and conclusions of this thesis.

Chapter II: Seismic Anisotropy

The goals of this chapter are to:

1. Introduce the fundamentals of seismic anisotropy description.
2. Understand transverse anisotropy (TI) system and its tensor representation.
3. Introduce Thomsen (1986) parameters for TI system.
4. Overview of estimation of anisotropic parameters from Dipole Sonic log.
5. Overview of the cause's of anisotropy of Shale.

INTRODUCTION TO SEISMIC ANISOTROPY

The term anisotropy is defined as a variation in a physical property with direction. In a homogenous anisotropic medium, properties may change with the direction in which they are measured such as the propagation path for seismic waves, or with the polarization direction of seismic shear wave, or both (Tatham and McCormack, 1991). The seismic wave propagation velocity in an isotropic media does not vary with either polarization or propagation directions, but the velocity does often vary significantly with propagation or polarization directions for the anisotropic media (Figure 2.1). In particular, shear wave velocity in an anisotropic media vary both with the propagation direction and polarization direction of seismic shear waves.

A media can be anisotropic for a variety causes. The general causes that often attributed for the existence of anisotropy in rocks are the occurrence of thin layering, clay mineral in shale, fractures or cracks. Quantification of fracture orientation and intensity

(fracture density) are important for reservoir exploitation, especially for drilling and fracturing completion as these fracture and layering may serve as conduits for fluid flow.

Figure 2.1: Polarization and propagation directions defined for an anisotropic case of a layered medium. The polarizations are defined in terms of the indicated line direction, and both horizontal and vertical propagation directions are considered. In Figure 2(a) the case of flat layers are considered, while Figure 2(b) addresses the case of vertical layerings or perhaps vertical fractures. The figures provide a means of rationalizing velocity differences with different propagation and polarization directions. (Tatham and McCormack, 1991).

The simplest anisotropic system is axisymmetric system (Transverse Isotropy) where the symmetry axis can be either vertical or horizontal, popularly known as VTI (Transversely Isotropic with vertical axis of symmetry) and HTI (Transversely Isotropic with Horizontal axis of symmetry). An example of VTI system is horizontally stratified

thin layers which is very common in geologic formations. An example of HTI system is a medium with parallel vertical fractures.

According to Hooke's law for a general anisotropic linear elastic solid, the stress (σ_{ij}) is linearly proportional to the strain (ε_{kl}) and can be expressed by:

$$\sigma_{ij} = C_{ijkl} \varepsilon_{kl} \quad (2.1)$$

where (σ_{ij}) is a second rank stress tensor, (ε_{kl}) is a second rank strain tensor and C_{ijkl} is a fourth rank stiffness tensor. In general, C_{ijkl} has 81 components, but due to the symmetry conditions of the stress and strain tensors, it is reduced to 36 independent components. Further, the requirement of unique strain energy, stiffness tensor is represented by 21 independent elements. This reduction in the ranks of independent element leads to the reformulation of the stress (T) and strain (E) as follows; known as abbreviated Voigt notation (Auld, 1990).

$$T = \begin{bmatrix} \sigma_1 = \sigma_{11} \\ \sigma_2 = \sigma_{22} \\ \sigma_3 = \sigma_{33} \\ \sigma_4 = \sigma_{23} \\ \sigma_5 = \sigma_{13} \\ \sigma_6 = \sigma_{12} \end{bmatrix}, \quad E = \begin{bmatrix} e_1 = \varepsilon_{11} \\ e_2 = \varepsilon_{22} \\ e_3 = \varepsilon_{33} \\ e_4 = 2\varepsilon_{23} \\ e_5 = 2\varepsilon_{13} \\ e_6 = 2\varepsilon_{12} \end{bmatrix}$$

The subscripts of stiffness matrix C_{ijkl} can be replaced i(j) by $c_{ij} = C_{ijkl}$ in each pair of indices ij (kl) with the relations below :

ij (kl)	i(j)
11	1
22	2
33	3

23,32 4

13,31 5

12,21 6

The abbreviated stiffness matrix C_{ij} for the simple elastic mediums can be expressed as follows:

1) Isotropic media

$$C_{ij} = \begin{bmatrix} c_{11} & c_{12} & c_{12} & 0 & 0 & 0 \\ c_{12} & c_{11} & c_{12} & 0 & 0 & 0 \\ c_{12} & c_{12} & c_{11} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{44} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{44} \end{bmatrix} \quad (2.2)$$

Here, only two constants are independent and $c_{12}=c_{11}-2c_{44}$.

2) VTI media

$$C_{ij} = \begin{bmatrix} c_{11} & c_{12} & c_{13} & 0 & 0 & 0 \\ c_{12} & c_{11} & c_{13} & 0 & 0 & 0 \\ c_{13} & c_{13} & c_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{55} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{66} \end{bmatrix} \quad (2.3)$$

Here, $c_{12}=c_{11}-2c_{66}$. VTI medium has five independent elastic constants.

3) HTI media

$$C_{ij} = \begin{bmatrix} c_{11} & c_{13} & c_{13} & 0 & 0 & 0 \\ c_{13} & c_{33} & c_{23} & 0 & 0 & 0 \\ c_{13} & c_{23} & c_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & c_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & c_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & c_{55} \end{bmatrix} \quad (2.4)$$

Here, $c_{23}=c_{33}-2c_{44}$. HTI medium has five independent elastic constants.

THOMSEN (1986) ANISOTROPIC PARAMETERS FOR TI MEDIA

From elasticity theory, a TI medium can be described by five independent elastic constants. An illustration of VTI independent elastic constants is shown in Figure 2.2. Thomsen (1986) introduced a set of dimensionless parameters in terms of elastic constants for weak anisotropic VTI media. Thomsen (1986) parameters are given as,

$$\begin{aligned}\varepsilon &= (C_{11} - C_{33})/2C_{33} \\ \gamma &= (C_{66} - C_{44})/2C_{44} \\ \delta &= (C_{13} + C_{44})^2 - (C_{33} - C_{44})^2 / 2C_{33}(C_{33} - C_{44})\end{aligned}\tag{2.5}$$

Figure 2.2: VTI system showing all five independent stiffness moduli. C_{11} and C_{33} are the horizontal and vertical compressional moduli. C_{44} determines the vertically travelling horizontally polarized shear wave velocities, C_{66} determines horizontally travelling horizontally polarized shear wave velocities, and C_{13} determines the P- and SV wave velocities at oblique directions.

Denoting V_{ij} as the elastic wave velocity propagating along i-axis and polarized along j-axis and ρ as density, the velocities in different direction can be given as,

$$V_{11} = V_{22} = \sqrt{\frac{C_{11}}{\rho}}, V_{33} = \sqrt{\frac{C_{33}}{\rho}}, \quad V_{31} = V_{13} = V_{23} = V_{32} = \sqrt{\frac{C_{44}}{\rho}}$$

$$V_{12} = V_{21} = \sqrt{\frac{C_{66}}{\rho}} \quad (2.6)$$

Therefore, ϵ is the fractional difference between horizontal and vertical p-wave velocities, and γ is the shear wave anisotropy. δ is relatively complex in description and known to control near vertical anisotropy (Thomsen, 1986).

The HTI system is equivalent to VTI system when the symmetry axis is rotated to the horizontal direction. Hence, Ruger (1997) and Tsvankin (1997) extended the weak anisotropic parameters to HTI media and suggested Thomsen-style parameters.

$$\epsilon = (C_{11} - C_{33})/2C_{33}$$

$$\gamma = (C_{55} - C_{44})/2C_{44} \quad (2.7)$$

$$\delta = (C_{13} + C_{55})^2 - (C_{33} - C_{55})^2 / 2C_{33}(C_{33} - C_{55})$$

THOMSEN (1986) VTI ANISOTROPIC PARAMETER FOR A VERTICAL BOREHOLE

Present day borehole sonic tools may use a combination of monopole and dipole sources and receivers to observe different waves such as P, S and Stoneley waves. Conventional monopole sources (sonic logs) give measurements of P-wave velocity (slowness) (therefore, estimation of vertical P wave velocity). The dipole log is used because of the inability of monopole log to measure shear velocity in many low-velocity

formations such as gas saturated zones, zones containing natural fractures, thinly laminated intervals, and many types of shales (Zemanek et al., 1991). A dipole source in a vertical borehole induces horizontally oriented positive pressure and negative pressure equally on opposite side of the borehole to create a horizontally polarized flexural wave (like bending the borehole) propagating vertically in the direction of the borehole (Figure 2.3). Due to borehole geometry effects, the flexural wave is very dispersive. However, the flexural wave velocity at the low frequency range is very close to the formation shear wave velocity. In modern cross-dipole tools, slowness ($1/V$) of these shear waves is recorded at several azimuthally distributed receivers at the same depth. The fast and slow shear orientations can be determine mathematically from the receiver data at the same depth, because shear wave travel faster along the stiffest direction than the compliant direction.

For a vertical borehole, C_{33} , C_{44} and C_{55} can be measured directly from the vertically propagating P-wave velocities, fast and slow shear velocities and formation density. A subsurface formation is a VTI media if the fast and slow shear velocities are equal, hence C_{44} and C_{55} are also equal. C_{66} is sometimes estimated by some log analysis from the monopole Stoneley wave log data, usually zero-frequency asymptote of the borehole Stoneley dispersion curve. If C_{44} and C_{66} are available, then Thomsen (1986) shear anisotropy parameter γ can be estimated. The problem with sonic log is that we do not observe C_{11} and C_{13} directly. Since anisotropy parameter γ is observed to be correlated with ϵ (Wang, 2002), we may, with some assumptions estimate C_{11} . Another

issue with the Thomsen (1986) parameter estimation is that the Stoneley wave is often constrained by the mud velocity and may be limited in its sensitivity to C_{66} . Therefore, C_{66} and C_{13} pose limitations for estimating total anisotropic description of a VTI media from vertical borehole dipole sonic log data.

Figure 2.3: (a) Generation and detection of S-waves using a dipole source creating flex in the horizontal plane (Zemanek et al., 1991). (b) Shear wave travels in an anisotropic formation with different speeds. In this example, anisotropy is caused by the vertical fractures, faster shear wave propagates along the fracture strike (Y-axis) whereas slow shear wave propagates across the fracture strike (Brie et al, 1998).

CAUSES OF ANISOTROPY IN SHALE

Before discussing anisotropy in shale, first we need to know ‘what is Shale?’ Holt (2011) listed three attributes of Shale: (1) clay minerals should constitute the load-bearing framework; (2) shale’s have nanometer pore sizes and nanodarcy permeability; (3) surface area is large, and water is adsorbed on surfaces or bound inside clay platelets. The above definition also applies for all fine grained sedimentary rocks. These fine grained rocks composed of varying amount of silt and clay sized particles and including a wide range of textures, fabrics and compositions are referred to as shales, mudstones, claystones, siltstones or mudrocks (Ruppel and Loucks, 2008). The term shale has traditionally been restricted to indurated and fissile fine grained rocks, though practical use may vary among authors. However, the word “clay” is used in two ways: as an indicator of grain-size (< 3.9 micrometers), or as an indicator of mineralogy, denoting illite, smectite, chlorite, kaolinite, and other hydrous phyllosilicates. Most clay-size grains in shales are clay minerals, but most shales contain significant amounts of clay- and silt-sized grains of nonclay minerals. Clay minerals like Illite and Chlorite are highly anisotropic due to their platy shape, so a general assumption is that occurrence of clay minerals in shale also make the rock anisotropic. However, clay minerals are also subject to diagenetic processes and alterations, hence anisotropy effect due to clay mineral may also change. Occurrence of kerogen in shale may make shale anisotropic, because kerogen usually layered. Shale can also be anisotropic due to ‘Rock fabric’. Bandyopadhyay (2009) listed several fabric type causes of shale anisotropy, which are:

- 1) alignment of platy clay minerals in a '*clay domain*'
- 2) alignment of the domains
- 3) alignment of the non-spherical pores and micro-cracks
- 4) alignment of fractures at scales larger than the scale of pore and grains, but smaller than the seismic scale
- 5) fine-scale lamination of shaly materials, silty materials and organic materials.

VTI ANISOTROPIC EFFECT ON AVO

The anisotropic parameters are linked with the physical description of the media associated with the seismic wave propagation. Therefore, anisotropic parameters may have an effect on seismic amplitudes. Several authors including Thomsen (1993), Chen (1995) and Ruger (1997, 2001) investigated the reflection amplitude variations with offset (AVO) of surface seismic observations for VTI media. A few approximate forms of reflectivity equations for PP, PS and SS wave have also been proposed. It was found that AVO response under anisotropic case could be observably different from isotropic AVO response, especially at far offset. I discuss in detail the VTI anisotropic effect on AVO in Chapter V as this is an integral component of that chapter.

SUMMARY

This chapter provides basics of seismic anisotropy for transversely isotropic media and introduces the Thomsen (1986) weak anisotropic parameters for it. The relationship of anisotropic parameters with the P- and S-wave velocities in different

propagation and polarization directions is also discussed. Some of the Thomsen (1986) parameters (i.e. Υ and $\mathcal{E}$) can be estimated and constrained at well location from monopole and dipole sonic logs, while other parameter (i.e. δ) cannot be estimated with the currently available tools. These anisotropic parameters may have a significant effect on AVO which is addressed in Chapter 5. As this thesis involves seismic sensitivity of organic shale, a brief overview of the causes of anisotropy of shale is also summarized.

Chapter III: Borehole Geophysical Log Analysis

The goals of this chapter are to:

1. Describe the basic log properties such as velocity, density, resistivity and radioactivity of the Marcellus Shale from geophysical wireline log data.
2. Describe the lithology, porosity and kerogen content of the productive interval of the Marcellus Shale.
3. Find possible types of anisotropy from dipole sonic log analysis.

INFORMATION AVAILABLE ON THE MARCELLUS SHALE

This study is based on the borehole wireline log data from a vertical well in Harrison County, West Virginia, USA. In addition to wireline log data, kerogen content analysis data from core samples are also available for this study. Well log data includes sonic logs, fast and slow shear slowness (dipole S1 and S2), spectral gamma ray, caliper, photoelectric factor (PEF), density and resistivity. Some of these wireline log data are shown in Figure 3.1. The spectral gamma logs provide K, Th and U fractions, which are very useful for identification of source rock. There are four resistivity logs with various radial depth of investigation in the rock formation. The log data were acquired using Baker Hughes tools and instruments. The sonic data were measured using a commercial tool known as XMAC. The XMAC contains monopole and crossed dipole tools and delivers compressional, stoneley, and slow and fast shear measurements.

Figure 3.1: Gamma ray, caliper, density, resistivity (deep), Vp (P-wave velocity), Vs (Shear wave velocity) (from dipole logs) and Azimuthal Anisotropy log from Cather 4 well at Harrison county of West Virginia. The anisotropy log represents the fractional differences between the fast and slow shear wave velocities of the recorded dipole sonic log.

Figure 3.2: Wireline log data including gamma ray, Thorium/ Uranium ratio (Th/U), Thorium/ Potassium ratio (Th/K) and resistivity logs of Cather-04 well from West Virginia. The organic shale interval is highlighted by yellow color. A very low Th/U ratio (plotted on a log scale) and high resistivity are particularly noticeable in the Shale gas formation.

DEPTH AND THICKNESS

The ratio of P-wave velocity and shear wave velocity is known as V_p/V_s and is a unitless quantity. Results from researchers (Pickett, 1963; Domenico, 1984; Tatham,

1982; Tatham and McCormack, 1991) on Vp/Vs have shown that Vp/Vs provides a useful correlation with lithology and can be used as a lithology indicator. The values of Vp/Vs of liquid-saturated Shale have a wide range of variation which is generally from 1.7 to 3.0 or more and typically between 1.5 to 1.6 for gas-saturated porous rocks (Tatham and McCormack, 1991). The average Vp/Vs in the radioactive zone (7305ft-7355ft) is 1.6 (Figure 3.2) which is unusually low to be typical high gamma response for shale. However, Vp/Vs of quartz rich rocks ranges from 1.59-1.76, and the Vp/Vs for gas saturated rocks is near 1.5 . At this stage I forward to the spectral gamma ray log that provides U, Th and K responses which can be useful for organic shale identification.

From the spectral gamma ray log, the organic rich interval can be easily identified by very low Thorium(Th) to Uranium(U) ratio in addition to very high GR response (>300 GAPI) (Figure 3.2). The Uranium response commonly increases with the increase of organic matter (OM) and Th is associated with clay minerals (Fertl and Chilingar, 1988). Therefore, low Th/U ratio may relate to high organic content and low clay content. All resistivity (shallow and deep) values on the order of 10^3 in a clastic sequence (i.e. sand-shale) might indicate that resistive components, such as OM and gas, are present in the formation. Density porosity and neutron porosity are corrected for shaly sand matrix. More details about porosity will be discussed in the subsequent section. Both the P-wave and S-wave have a noticeable decrease in velocities in the interpreted Marcellus interval (Figure 3.1). Based on the above analysis and rationale, it is found that the organic rich

Marcellus interval is 50 ft thick beginning at a depth of 7305ft measured from the KB (Kelly Bushing).

LITHOLOGY INTERPRETATION FROM LOG DATA

Organic shale lithology can be highly variable. Wang (2012) studied data from 707 wells along with XRD (X-ray diffraction) and PNS (pulsed neutron spectroscopy) data of the Marcellus Shale of WV. He found that Marcellus Shale mineralogy varies highly in quartz, illite, chlorite, kerogen, feldspar and pyrite content. Here pyrite has very different properties such as density, PEF, elastic moduli and resistivity. Therefore, if the pyrite effect is not properly corrected, PEF log interpretation can be problematic. However, pyrite has high PEF value (18 b/e) and high density (4.93 g/cc); therefore, a PEF-density cross plot can identify pyrite affecting data. However, most data shows much lower density (<2.58g/cc) and lower PEF (<6 b/e) to have any major amount of Pyrite (<5 %) (Figure 3.3). Therefore, log data were not corrected for pyrite. After checking for pyrite, the spectral GR data were plotted on a Th-K plot to identify the dominant clay mineral type (Figure 3.4). Most of the data fall in the illite domain which also agrees with all previous works on the Marcellus Shale.

Because it is confirmed that lithofacies of the selected log interval do not contain any major minerals other than quartz, clay and kerogen, these constituents can be quantitatively interpreted in the following ways. First, both density porosity and neutron porosity can be corrected for quartz matrix. Then, the volume of clay in the solid fraction of the rock is interpreted using the following equation:

$$V_{clay} = (N_{\phi} - D_{\phi}) / (N_{\phi(sh)} - D_{\phi(sh)}) \quad (1)$$

Where, N_{ϕ} = Neutron Porosity (assuming shaly sand matrix)

D_{ϕ} = Density Porosity (assuming shaly sand matrix)

$N_{\phi(sh)}$ = Neutron Porosity at pure Shale

$D_{\phi(sh)}$ = Density Porosity at pure Shale

Figure 3.3: Log data is plotted on the PEF-density cross plot. The plot shows that the maximum density is 2.58 gm/cc and maximum PEF is 6 b/e. Therefore, pyrite which has high density (4.93 gm/cc) and high PEF (18 b/e) might not present in a significant quantities. However, data are separated out in two domains (circled in the figure), which might translate to a quartz rich domain and illite-rich clay domain.

Figure 3.4: Log data is plotted on the Slb Lith-2 plot. Plot shows that most of the data is concentrated on the illite zone.

If core data, XRD, ECS or PNS log data are available at any point of the selected interval, then the Vclay value can be corrected and normalized. In the absence of above mentioned measurement, the pure shale point can be taken as the point that shows the maximum difference between neutron porosity and density, and high Th/K ratio. Basically, neutron porosity sees H ions, and H ion is present in the formation fluid, kerogen and clay mineral. The density porosity also sees kerogen as pores because of the low density of Kerogen (0.6 gm/cc – 1.5 gm/cc).

POROSITY

The average porosity from neutron porosity and density porosity logs is 20%. Both density porosity and neutron porosity were corrected for shaly sand matrix (Figure 3.5). Twenty percent porosity in organic shale is quite high. Both density log and neutron log overlook organic matter as explained in previous paragraph. Therefore, the total volume of kerogen and pores can be estimated by the following equations,

$$(k + \phi_t) = (\rho_{\text{matrix}} - \rho_{\text{log}}) / (\rho_{\text{matrix}} - \rho_f) \quad (2)$$

where k is the kerogen content, ϕ_t is the total porosity. The density of the pore fluid (ρ_f) is taken as constant 1.05 gm/cc regarding the fact that density tool mostly senses the mud filtrate. It was also assumed that the density of kerogen is close to the density of the pore fluid. The matrix density (ρ_{matrix}) was taken as 2.71 gm/cc to account for the specific siliciclastic rock which contains mainly quartz (density 2.65 gm/cc) and clay where the dominant clay mineral is illite (2.78 gm/cc). It was also assumed that the rock contains other minor (<5%) heavier minerals like calcite (2.71 gm/cc) and pyrite (4.93 gm/cc).

Figure 3.5: Neutron porosity and density porosity of the Marcellus Shale at Harrison County, WV. Note that both of the logs were corrected for shaly sand lithology.

TOC ESTIMATION

There are several methods proposed in the literature for estimation of TOC utilizing spectral GR (i.e Th/U ratio), density porosity, resistivity, sonic porosity and PE data. However, density is one of the most common log, and I used the empirical method that Myers and Jenkyns (1992) proposed to estimate TOC from density log by the following equations; results are shown in Figure 3.6.

$$TOC (\%) = \frac{0.85 * \rho_k * \phi_{fl}}{\rho_k * \phi_{fl} + \rho_{ma} * (1 - \phi_{fl} - \phi_k)} \quad (3)$$

$$\text{Where, } \phi_{fl} = \frac{\rho_{ns} - \rho_{ma}}{\rho_{fl} - \rho_{ma}}, \phi_k = \frac{\rho_s - \rho_{ns}}{\rho_k - \rho_{ma}}$$

Where, ρ_{ns} =Density reading at the vertically adjacent shale interval that does not contain kerogen (averaged a value from the log)

ρ_s =Density reading at the productive interval

ρ_{ma} =2.71 gm/cc , assumed matrix density

ρ_k =1.3 gm/cc , assumed kerogen density

ρ_{fl} =1.05 gm/cc, density of brine

ϕ_{fl} =Water filled porosity, ϕ_k =Kerogen filled porosity

Figure 3.6: Interpreted clay content (Vclay), water saturation (Sw), clay pore and TOC (%) from the log data in the soft productive interval. The dotted line separates two distinct intervals mainly for variation in clay content. The lower interval (7325-7350 ft) also contains higher TOC and lower Sw which translates that this interval is more promising for hydrocarbons than the upper interval.

EVIDENCE FOR ANISOTROPY

The theory and method for the estimation of seismic anisotropy from seismic velocities observed from the borehole logs were discussed in chapter 2. I also discussed the borehole sonic data available for this study earlier in this chapter. As horizontal compressional velocity is not observable for a vertical borehole, seismic anisotropy cannot be defined from compressional wave data. However, slow and fast shear velocities for vertically propagating wave are readily available from dipole logs in a vertical well. As illustrated in Figure 2.1 in previous chapter, slow and fast shear velocities for vertically propagating shear wave are related to the type of anisotropic medium. A vertical shear wave propagating in a HTI medium splits(birefringence) into two components, the faster component (S1) is polarized parallel to the fracture directions, and the slower component (S2) is polarized perpendicular to the fracture direction. The dipole sonic tool (XMAC) measures both S1 and S2. However, the fractional difference between S1 and S2 velocities are negligible (on average less than 1%) in the Marcellus Shale interval as shown on anisotropy (%) track in Figure 3.1. Therefore, no obvious HTI anisotropy is observed in the Marcellus Shale interval at the well bore locations. Thus, the Marcellus Shale is either isotropic or VTI media. Such negligible azimuthal shear anisotropy might also be possible for a more complicated case of two sets of near perpendicular fracture sets in a medium.

SUMMARY

The borehole geophysical log data from one well of West Virginia were examined, and petrophysical properties and seismic anisotropy were investigated. Depth and thickness and V_p/V_s ratio for that well were briefly discussed. Lithologic

interpretation of the borehole log data suggests that the productive Marcellus interval is a kerogen rich shaly sand comprised of predominantly quartz with illitic clay. Finally, the observed S1 and S2 shear slowness of the dipole sonic data presented negligible azimuthal shear anisotropy; hence, the productive Marcellus interval may be either isotropic or VTI media.

Chapter IV: Rock Physics Modeling

The goals of this chapter are to:

1. Find elastic parameters that have a distinctive signature of the productive zone of the Marcellus Shale.
2. Isolate the elastic responses of rock, kerogen and pore shape properties.
3. Build a model to estimate elastic moduli for known variations in lithology, kerogen content and pore aspect ratios.

INTRODUCTION

The main purpose of this thesis is to analyze potential seismic attributes and their sensitivities for seismic models with varying rock and fluid properties of the Marcellus Shale play. Seismic models require elastic constants based on both the reservoir rock and fluid properties. Rock physics analysis and modeling provides such a relationship between the elastic constants and reservoir properties. Reservoir properties such as lithology, kerogen content, porosity, pore size and shape distribution, pore fluid and pore fluid saturation might have distinct sensitivity on specific elastic constants and elastic parameters such as bulk modulus, shear modulus, Young's modulus or Poisson's ratio. This chapter deals with establishing a correlation model between elastic parameters and reservoir properties of the productive zone for Marcellus Shale formation.

The rock physics analysis and modeling in this chapter improves our understanding of elastic moduli by isolating three reservoir properties: 1) mineral composition of the rock, 2) kerogen saturation and 3) pore fluid saturation. Theories for the limits on values (bounds) of elastic parameters provide an empirical method to evaluate and understand elastic moduli for a certain mineral compositions of rock. Hence, a data fitting method from the elastic bounds may provide an estimate of elastic moduli

of zero porosity solid rock. The second part of rock physics analysis devotes to building relationships between elastic moduli and kerogen saturation. The differential effective medium (DEM) theory was used for this purpose. In the last part, Gassmann (1951) fluid saturation equation was used for fluid saturation in the pore space.

THEORIES

Bounds and Mixing laws

One way to evaluate and estimate the isotropic elastic moduli of the observed elastic data is through theoretical bounds and mixing laws. Widely used elastic bounds are Voigt upper bound, Reuss lower bound and Hashin-Shtrikman-Walpole bound. They all are based on isotropic linear elasticity and assume simple geometric arrangements of constituent grains and pores. The Hashin-Shtrikman-Walpole bound gives the narrowest possible range for mixtures of more than two phases. The equations of Hashin-Shtrikman-Walpole bound for elastic moduli are given as (Mavko et al., 2009),

$$K^{HS+} = \Lambda(\mu_{max}), \quad K^{HS-} = \Lambda(\mu_{min}),$$

$$\mu^{HS+} = \Gamma(\zeta(K_{max}, \mu_{max})), \quad \mu^{HS-} = \Gamma(\zeta(K_{min}, \mu_{min}))$$

$$\Lambda(z) = \left\langle \frac{1}{K(r) + \frac{4}{3}z} \right\rangle^{-1} - \frac{4}{3}z, \quad \Gamma(z) = \left\langle \frac{1}{\mu(r) + z} \right\rangle^{-1} - z, \quad \zeta(K, \mu) = \frac{\mu}{6} \left(\frac{9K + 8\mu}{K + 2\mu} \right)$$

where K and μ are the bulk and shear modulus of individual phases and the brackets $\langle . \rangle$ indicate averages weighted by their volumetric proportions. Upper bounds corresponds to ‘+’ and lower bound to ‘-’.

The Voigt upper bound of effective elastic modulus is

$$M_v = \sum_{i=1}^N f_i M_i$$

Where f_i is the volume fraction of the i -th phase and M_i is the elastic modulus of the i -th phase.

The Reuss lower bound is given as

$$\frac{1}{M_R} = \sum_{i=1}^N \frac{f_i}{M_i}$$

The Voigt-Reuss-Hill average is simply the arithmetic average of the Voigt upper bound and Reuss lower bound. The average is expressed as

$$M_{VRH} = \frac{M_V + M_R}{2}$$

Differential Effective Medium (DEM)

The DEM is an inclusion based model for a two-phase composite material where inclusions are added incrementally to the matrix phase (phase 1) (Cleary et al., 1980; Norris, 1985; Zimmerman, 1991). The matrix phase is the host material and the effective moduli depend on the construction path taken to reach the final composite. The isotropic

formulation for effective bulk (K^*) and shear moduli (μ^*) are given in a coupled system of ordinary differential equations as, (Berryman, 1992)

$$(1 - y) \frac{d}{dy} [K^*(y)] = (K_2 - K^*) P^{(*)}(y)$$

$$(1 - y) \frac{d}{dy} [\mu^*(y)] = (\mu_2 - \mu^*) Q^{(*)}(y)$$

Initially, $K^*(0)=K_1$, and $\mu^*(0)=\mu_1$, where K_1 and μ_1 are the bulk and shear moduli of the matrix material, K_2 and μ_2 are the bulk and shear moduli of the inclusion material, and y is the concentration of the inclusion material. $P^{(*)}$ and $Q^{(*)}$ are the geometric factors that depend on inclusion shapes. The system of equations can be solved by Runge-Kutta 4th order method for ordinary differential equations.

In DEM, taking material 1 as the host and material 2 as the inclusion will not result in the same effective properties as taking material 2 as the host even if the final concentrations are the same in both cases. The original model was given for isolated inclusions, i.e. the elastic frame stays connected until the inclusions form the total volume. Therefore, critical porosity (Nur et al., 1991), which defines the boundary between the load bearing phase and suspension phase, was introduced in the DEM by Mukerji et al. (1995). Mukerji et al. (1995) proposed that the moduli of the critical phase can be estimated by a Reuss (1929) average of the end members. Moyano et al. (2012) disclosed that threshold porosity (i.e. critical porosity) is also controlled by aspect ratios of the inclusions.

A general illustration of the effect of the incrementally added inclusion content and inclusion shape on the host material is shown in Figure 4.1. The host matrix was considered a solid rock of 40% quartz with clay, and the inclusion was a kerogen. The elastic moduli of the host matrix were estimated using Voigt-Reuss-Hill average. The moduli of individual minerals used here are given in Table 4.1. The critical porosity was

Figure 4.1: An illustration of the DEM scheme for understanding the effect of inclusion moduli and inclusion shape to host material. Here, the host is a solid rock of 40% quartz with clay, and kerogen is the inclusion. It shows that aspect ratio of the kerogen inclusions play a significant role in this scheme; a lower aspect ratio produces much lower elastic moduli than higher aspect ratios.

taken as 0.5. The inclusion shapes are described by aspect ratio (ar), the ratio of shorter to longer axes of an ellipsoid representing the kerogen inclusions. Four aspect ratios were considered; 1 (equant or spherical pore), 0.1, 0.01 and 0.001. It was found that there are negligible sensitivities to both k (bulk moduli) and μ (shear moduli) for inclusion aspect ratios of 0.01 and 0.001. However, there are significant differences in elastic response among lines for aspect ratios 1, 0.1 and 0.01. For example, a change of aspect ratio from 0.1 to 0.01 at 13% inclusion content contributed to a reduction in the bulk moduli of 5.5% and shear moduli of 7.5%.

Gassmann (1951) fluid substitution equations

The Gassmann (1951) equations for different pore fluid cases correspond to very low frequency situations where pore pressure has enough time to equilibrate throughout the pore space. Gassmann (1951) relations for fluid substitution in isotropic rocks can be stated as (Mavko and Bandyopadhyay, 2009),

$$K_{sat} = K_m \left(\frac{K_{dry} + Q}{K_m + Q} \right)$$

$$\text{Where, } Q = \frac{K_{fl}}{\phi} \left(\frac{K_m - K_{dry}}{K_m - K_{fl}} \right)$$

with $\mu_{sat} = \mu_{dry}$. Here K_{dry} , K_{sat} , K_m , and K_{fl} are the bulk moduli of the dry rock, the saturated rock, the solid mineral, and the saturating pore fluid, respectively. The shear moduli of the dry rock and the saturated rock are μ_{dry} and μ_{sat} . The Gassmann (1951) equations assume a homogeneous mineral modulus and statistical isotropy of the pore space, but it is free of assumptions about pore geometry (Mavko et al., 2009).

METHOD

The rock physics modeling scheme is outlined in Figure 4.2. The modeling utilizes parameters interpreted in the previous chapter from geophysical wireline logs. These data include mineral composition, kerogen content, porosity and water saturation. The mineral composition data were used at the first stage to estimate effective elastic moduli using bound and mixing laws. These effective moduli serve as the background matrix for the next stage at DEM modeling. The background matrix moduli were estimated for Voigt upper bound, Reuss lower bound, Voigt-Reuss-Hill average and Hashin-Strikman-Walpole average. In the DEM model, the background matrix serves as the host and three types of inclusion were added successively which are clay pore (water wet), kerogen and interparticle pore (dry).

The inclusions in the DEM were simulated to represent actual pores, such that

$$\Phi_t = \Phi_{\text{Clay}} + \Phi_{\text{IP}} + \Phi_k$$

Here, Φ_t , Φ_{Clay} , Φ_{IP} and Φ_k represents total porosity, clay porosity, interparticle porosity and kerogen percent. Clay porosity was estimated using the equation $\Phi_{\text{Clay}} = V_{\text{sh}} * \Phi_{\text{sh}}$; where V_{sh} is the volume of clay content and Φ_{sh} is the density porosity at pure shale sequence in the log interval. Φ_{sh} was 0.11 for this borehole log. The elastic moduli for clay pore and kerogen are taken as elastic moduli of brine and keorgen as given in Table 4.1. The pore shapes for all three types of inclusions were assumed to be elliptical, and pore aspect ratio was simulated for best-fit random numbers. The histograms of the

distribution of pore shapes for clay pore, kerogen and interparticle pore used in the modeling are given in Figure 4.3, Figure 4.4 and Figure 4.5

Figure 4.2: A schematic workflow of the project. Rock physics modeling using DEM constitutes the central part. Input data to DEM was provided by petrophysical interpretation of log data. Background matrix moduli in the DEM were estimated by mixing laws. Kerogen and pores were incorporated in the DEM as inclusions.

	Bulk modulus (GPa)	Shear modulus (GPa)	Density (gm/cc)
Quartz	36.6	45	2.65
Clay	25	8	2.7
Kerogen	2.9	2.7	1.3
Brine	2.4	0	1.02
Gas	0.07	0	0.2

Table 4.1: Moduli and densities of minerals used in this study

The elastic moduli estimated from the DEM model is provided for fluid saturation in interparticle dry pores using Gassmann (1951) isotropic equations.

Figure 4.3: Histogram of aspect ratios of the clay pores.

Figure 4.4: Histogram of aspect ratios of the kerogen masses.

Figure 4.5: Histogram of aspect ratios of the interparticle pores.

ANALYSIS AND DISCUSSION OF MODELING RESULTS

The elastic properties of the organic shale may vary widely depending on matrix composition, kerogen content, pore size and pore shape distribution. The elastic properties of the Marcellus Shale used in this study are found to have a clean signature in LamdaRho-MuRho ($\lambda\rho$ - $\mu\rho$) plot (Figure 4.6). The productive Marcellus Shale interval can be easily distinguished by low $\lambda\rho$ and $\mu\rho$ response from the background rocks. The productive interval also exhibits low Poisson's ratio than the vertically adjacent shale layers. This low $\lambda\rho$, $\mu\rho$ and low Poisson's may come from mineral quartz and organic matter as quartz is known to have lower value on these elastic properties than other sedimentary rocks such as limestone, calcite, dolomite and shale.

Figure 4.6: Observed well log data on the $\lambda\rho$ - $\mu\rho$ plot with background data and productive Marcellus Shale data. The productive Marcellus interval data are plotted with squares. Note that all data are color coded by Poisson's ratio. The distinct signature of productive Marcellus shale (shown in the red ellipse) is that it has lower $\lambda\rho$, $\mu\rho$ and Poisson's ratio than the background rocks.

The rock physics modeling was accomplished according to the workflow given in Figure 4.2. One important step in the modeling scheme was to estimate elastic moduli of the background matrix. I used several different estimate such as Voigt-Reuss-Hill average, Reuss average and Hashin-Strikman-Walpole average for the elastic moduli of the background matix in the DEM model. The Voigt-Reuss-Hill average and Hashin-

Strikman-Walpole averages gave similar results and provides a good match with the observed data in the lower interval (7325ft-7350ft) (Figure 4.7 a). However, a composite estimate from the Reuss average provide good result for upper interval (7310-7325 ft) (Figure 4.7 b). Note that the lithological data for the upper interval (7310-7325ft) is actually different from the lower interval (7325-7350ft). The upper interval contains higher clay volumes and lower kerogen content than that of lower intervals. Contrarily, the lower interval contains more quartz and kerogen content. Therefore, the difference in the elastic signature may relate to compositional difference in rocks, which again may relate to geological depositional environment. From a fracturing point of view for this unconventional shale play, the lower interval should be more easily fractured. Thus elastic response of kerogen rich and quartz rich shale reservoir indeed provides a good link with reservoir properties. Finally, modeling data and observed data were plotted with the Hashin-Strikman elastic bounds (Figure 4.8). Hashin-Strikman elastic bounds is defined to give the narrowest possible range for elastic moduli without specifying anything about the geometries of the constituents (Mavko et al, 2009), and hence provide the narrowest elastic limits to check the modeling results. The elastic bounds in these plots are directly computed for clay-sand-kerogen compositions. A constant kerogen content (10%) was considered. For matrix compositions, I used 10% and 60% clay content to simulate lowest and highest possible clay content in the Lower Marcellus Shale. Therefore, sand (i.e quartz) percentages for the considered elastic bounds were less

than 70% and less than 30%, as because gas saturated pores also considered in the computation.

Figure 4.7: Final model data with the observed data of the shale gas interval. (a) Shows the results (7310ft-7350ft) for cases when the Voigt-Reuss-Hill average was used for background matrix moduli. (b) Shows results in the upper portion of the interval (7310ft-7325ft) when Reuss average was used for background matrix moduli. Everything else was considered the same for both cases.

Figure 4.8: Theoretical bounding lines along with observed and model data for bulk moduli (a) and shear shear moduli (b). Bound lines are plotted for two cases; 15% clay and 60% Clay with quartz, kerogen and pore fluid. 10% kerogen content was considered for all elastic bounds here. The observed and model data are color coded by kerogen content.

SUMMARY

In this chapter I used rock physics modeling and analysis from the rock and fluid properties data. The productive Marcellus interval found to have lower λ/ρ and lower Poisson's ratio signature than that of the background rock. The modeling scheme effectively connects elastic constants with the mineralogical composition and kerogen content. Therefore, for a known lithological composition elastic constants can be estimated using this model. From this elastic modeling, it can be said that kerogen as well as low aspect ratio elliptical pores makes the reservoir elastically softer than adjacent zones and exhibits lower P- and S-wave velocities than background trend in the borehole log. Moreover, modeling success suggests that reservoir may contain low aspect ratio pores with bedding parallel, sub-parallel kerogen masses.

Chapter V: Surface Seismic Modeling

The goals of this chapter are to:

1. Provide an overview of numerical modeling of full waveform synthetic seismograms of surface seismic data for isotropic and VTI anisotropic media.
2. Evaluate the sensitivity of seismic reflection coefficients and reflection amplitudes to variations in Thomsen (1986) VTI anisotropic parameters.
3. Evaluate the conventional surface seismic resolution for variations in reflectivity with a thin layer.
4. Analyze the sensitivity of seismic amplitude variations for kerogen content and aspect ratios of kerogen saturated pores.

INTRODUCTION

In two earlier chapters (III & IV), I applied petrophysical analysis and rock physics analysis using assumptions of isotropy from elastic information recorded in borehole log data. Borehole log data, however, are “sampled” on the order of centimeter scale while surface seismic data are “sampled” by the propagating seismic waves on a scale of the order of tens of meters. Moreover, the overall seismic reflection response is affected by several parameters such as reflection coefficients at bed boundaries, effects of several interfering reflections in layered media, effects of layer thickness, bulk anisotropy, seismic wavelet character, mode conversion effects and attenuation. Ultimately, it is important to understand the sensitivity of surface seismic reflection data

to variations of elastic and petrophysical properties of the rock. In this chapter, I consider some simple seismic modeling and reflection amplitude analyses for varying rock properties to investigate the sensitivity of reflection amplitudes particularly, variations in amplitude with offset, to variations in bulk seismic parameters. I considered both isotropic and VTI anisotropic models. The objective focuses on address amplitude variations with angle of incidence or offset (AVA/AVO). Two different approaches were used: First, conventional AVO analysis (variations in reflection coefficients with respect to angle of incidence) for an single isolated interface using Ruger's (2001) equations of plane wave solutions is considered. The second is AVO analysis of reflection amplitudes from synthetic seismograms simulated for numerous interfering reflections in layered media. Synthetic seismograms were simulated using a frequency-wavenumber algorithm of Mallick & Frasier (1987) which generates a full elastic wave response in anisotropic media. The objective is to use these two comparative methods to understand the behavior and sensitivity to variations in seismic parameters. Following the full wave AVO analysis of the seismic response for anisotropy parameters, I proceed to seismic modeling including actual rock parameters of kerogen content and aspect ratio of kerogen saturated pores. The seismic simulations including kerogen content and aspect ratios focused on a simplified Marcellus Shale represented as a VTI media with constant Thomsen (1986) anisotropy parameters. Thus, AVO sensitivity analysis of P-P, P-SV and SV-SV reflectivity included for variations in parameters such as Thomsen (1986) parameters (ϵ , γ and δ), layer thickness, kerogen content and aspect ratios of kerogen saturated pores.

BACKGROUND THEORY

1. Reflectivity at a single Interface

Reflectivity at a single isolated reflecting interface provides a first step in our understanding of reflection amplitude resulting from variations with the partition of energy at a single reflecting interface. Partition of energy from a propagating plane wave describes reflection, transmission and mode-conversion of P-P, P-SV and SV-SV waves (Figure 5.1).

Figure 5.1: The reflection, transmission and mode-conversion of rays at an interface between two semi-infinite anisotropic elastic half spaces for an incident P-waves.

Conventional AVO analyses of reflections from a single interface are, in practice, primarily applied to plane P-wave reflection coefficients in isotropic media. Many subsurface formations, particularly Shale formations are anisotropic. Reflectivities in an anisotropic media are complex and depend not only on wave amplitude of incident waves

but also on anisotropic parameters which describes asymmetric phase velocity surfaces. AVO analyses for simple anisotropic symmetries such as VTI and HTI media, have also gained attentions in last several years. Thomsen's (1993), and later by Rüger's (1997), simplifications provide easily applicable equations for P-wave reflection coefficients in the weakly anisotropic VTI media. Further, the corresponding SV-SV reflectivity in VTI media has been derived in Rüger (2001). The Ruger (1997) equations for the P-P reflectivity between two VTI media is given as,

$$\begin{aligned} \text{P-P reflectivity, } R_{PP}(\theta) &= R_{PP-iso}(\theta) + R_{PP-aniso}(\theta) \\ R_{PP-iso}(\theta) &\approx \frac{1}{2} \left(\frac{\Delta Z}{\bar{Z}} \right) + \frac{1}{2} \left[\frac{\Delta \alpha}{\bar{\alpha}} - \left(\frac{2\bar{\beta}}{\bar{\alpha}} \right)^2 \frac{\Delta \mu}{\bar{\mu}} \right] \sin^2 \theta + \frac{1}{2} \left(\frac{\Delta \alpha}{\bar{\alpha}} \right) \sin^2 \theta \tan^2 \theta \\ R_{PP-aniso}(\theta) &\approx \frac{\Delta \delta}{2} \sin^2 \theta + \frac{\Delta \epsilon}{2} \sin^2 \theta \tan^2 \theta \end{aligned}$$

The P-S converted wave reflectivity between two VTI media (Ruger, 2001) is given as

$$\begin{aligned} R_{ps}(\theta_s) &= R_{ps-iso}(\theta_s) + R_{ps-aniso}(\theta_s) \\ R_{ps-iso}(\theta_s) &\approx -\frac{1}{2} \left(\frac{\Delta \rho \sin \theta_p}{\bar{\rho} \sin \theta_s} \right) - \frac{\bar{\beta}}{\bar{\alpha}} \left(2 \frac{\Delta \beta}{\bar{\beta}} + \frac{2\rho}{\bar{\rho}} \right) \sin \theta_p \cos \theta_p \\ &\quad + \left(\frac{\bar{\beta}}{\bar{\alpha}} \right)^2 \left(2 \frac{\Delta \beta}{\bar{\beta}} + \frac{2\rho}{\bar{\rho}} \right) \left(\frac{\sin^3 \theta_p}{\cos \theta_s} \right) \end{aligned}$$

$$\begin{aligned}
R_{\text{PS-aniso}}(\theta_s) = & \left[\left(\frac{\bar{\alpha}^2}{2(\bar{\alpha}^2 - \bar{\beta}^2) \cos \theta_s} - \frac{\bar{\alpha}\bar{\beta} \cos \theta_p}{2(\bar{\alpha}^2 - \bar{\beta}^2)} \right) (\delta_2 - \delta_1) \right] \sin \theta_p \\
& + \left[\frac{\bar{\alpha}\bar{\beta} \cos \theta_p}{(\bar{\alpha}^2 - \bar{\beta}^2)} (\delta_2 - \delta_1 + \varepsilon_1 - \varepsilon_2) \right] \sin^3 \theta_p \\
& - \left[\frac{\bar{\alpha}^2}{(\bar{\alpha}^2 - \bar{\beta}^2) \cos \theta_s} (\delta_2 - \delta_1 + \varepsilon_1 - \varepsilon_2) \right] \sin^3 \theta_p \\
& + \left[\frac{\bar{\beta}^2}{2(\bar{\alpha}^2 - \bar{\beta}^2) \cos \theta_s} (\delta_1 - \delta_2) \right] \sin^3 \theta_p \\
& + \left[\frac{\bar{\beta}^2}{(\bar{\alpha}^2 - \bar{\beta}^2) \cos \theta_s} (\delta_2 - \delta_1 + \varepsilon_1 - \varepsilon_2) \right] \sin^5 \theta_p
\end{aligned}$$

$$\text{SV-SV reflectivity, } R_{sv}(\theta_s) = R_{sv-iso}(\theta_s) + R_{sv-aniso}(\theta_s)$$

$$R_{sv-iso}(\theta_s) \approx \frac{1}{2} \left(\frac{\Delta Z_s}{Z_s} \right) + \frac{1}{2} \left[\frac{7\Delta\beta}{2\bar{\beta}} + \left(\frac{2\rho}{\bar{\rho}} \right)^2 \frac{\Delta\mu}{\bar{\mu}} \right] \sin^2 \theta_s + \frac{1}{2} \left(\frac{\Delta\beta}{\bar{\beta}} \right) \sin^2 \theta_s \tan^2 \theta_s$$

$$R_{sv-aniso}(\theta_s) \approx \frac{\bar{\alpha}^2}{2\bar{\beta}^2} (\Delta\varepsilon - \Delta\delta) \sin^2 \theta_s$$

where,

$$\begin{aligned}
\theta &= (\theta_1 + \theta_2)/2 & \Delta\varepsilon &= \varepsilon_2 - \varepsilon_1 \\
\bar{\rho} &= (\rho_1 + \rho_2)/2 & \Delta\rho &= \rho_2 - \rho_1 & \Delta\gamma &= \gamma_2 - \gamma_1 \\
\bar{\alpha} &= (\alpha_1 + \alpha_2)/2 & \Delta\alpha &= \alpha_2 - \alpha_1 & \Delta\delta &= \delta_2 - \delta_1 \\
\bar{\beta} &= (\beta_1 + \beta_2)/2 & \Delta\beta &= \beta_2 - \beta_1 & \mu &= \rho\beta^2 \\
\bar{Z} &= (Z_1 + Z_2)/2 & \Delta Z &= Z_2 - Z_1 & Z &= \rho\alpha \\
\bar{Z}_S &= (Z_{S1} + Z_{S2})/2 & \Delta Z_S &= Z_{S2} - Z_{S1} & Z_S &= \rho\beta \\
\bar{\mu} &= (\mu_1 + \mu_2)/2 & \Delta\mu &= \mu_2 - \mu_1
\end{aligned}$$

θ_1 = P – wave incident angle

θ_2 = P – wave transmission angle

ρ_1 and ρ_2 are the densities of the upper and the lower layer

α_1 and α_2 are vertical P – wave velocities of the upper and the lower layer

β_1 and β_2 are the vertical S – wave velocities of the upper and the lower layer

$\varepsilon_1, \gamma_1, \delta_1$ and $\varepsilon_2, \gamma_2, \delta_2$ are Thomsen (1986) parameters of the upper and the lower layer

The application and results of Ruger's (1997, 2001) equations for P-P, P-SV and SV-SV reflection coefficients will be discussed in the results section of this chapter. Ruger's equations are for single interface reflection coefficients. A more sophisticated approach is elastic modeling of thinly layered media. In the following paragraph, an overview of elastic wave modeling and resultant simulated seismograms are discussed.

2. Full waveform seismograms for layered media

The elastic wave modeling was accomplished by using a more sophisticated algorithm designed to model all components of a spherical wave for a 1D(vertical variations only) layered earth model. It is also able to create multiples and mode-converted waves. The algorithm is a Fourier frequency-wave number numerical modeling method introduced in the 1970's and follows a series of publications by many authors, particularly those works by Frasier (1970) and Kennett (1979, 1980). In this study, I have used the algorithm given of Mallick and Frasier (1987, 1988, 1990, 1991). This algorithm generates complete or partial three component synthetic seismograms for a sub-surface comprised of isotropic and/or anisotropic layers. A vertical impulsive source was assumed, which may be used as a proxy of a vertically oriented Vibroseis source. This source directly generates P-waves and S-waves, resulting in P-P, P-SV and SV-SV reflections. This type of source is different from an explosive source, which can generate only P-P energy resulting a P-P and P-SV reflections. A vertical impulse source does allow us to generate and record multicomponent seismic data in three cartesian components (X, Y and Z) both of which includes both P and S-wave data. In general a single sweep of a vertical source with an array of 3C receivers, (three Cartesian components X, Y and Z) will record P-P (PP), P-SV (PS) and SV-SV (SS) reflections. Note that the mode-converted P-SV reflections contains only shear waves (SV) polarized in the vertical plane defined by the source receiver geometry. The direct shear wave generated by the vertical impulsive source, also has SV polarization; SH reflections are not present

here. Therefore, a single line of receivers will record only Z (vertical) and X (radial) components. An aerial grid of receivers has to be used to observe the Y (transverse) component.

A Ricker (1953) wavelet with a central frequency of 45 Hz was used for all simulated seismograms in this chapter.

Before addressing the modeling results in the next section, a brief introduction of prestack multicomponent seismic data is given. For this purpose, a synthetic seismogram consisting of a source gather of receivers in a 2D model was generated using model parameters given in Table 5.1. Figure 5.2 shows the vertical, radial and transverse components of the generated synthetic shot at varying source-receiver offset with P-P, P-SV and SV-SV seismic reflections. The transverse (Y) component of the seismogram didn't record any response as shown in the Figure 5.2. In the vertical component, the P-P reflection amplitudes are strongest in the near offset and decreases with offset, and SV-SV amplitudes are strongest on the far offset. Due to source offset, the amplitude responses on radial component are quite different from the vertical component. However, the P-SV amplitudes are strongest at mid offset and SV-SV amplitudes are strongest at far offset on both X and Z component. Note that there is a polarity reversal of the SV-SV reflections on radial component approximately 26° incidence angle.

	P-wave velocity (m/s)	S-wave velocity (m/s)	V_p/V_s	Density (gm/cc)	Thickness (m)
Layer 1	4000	2265	1.77	2.660	2226
Layer 2	3000	1923	1.56	2.320	100
Layer 3	5000	2840	1.76	2.710	Infinite

Table 5.1: Model parameters of the 1D layered media, used for generating multicomponent full-waveform seismograms. Note that all the layers were considered isotropic.

Figure 5.2: Synthetic seismograms generated for a vertical impulsive source using model parameters given in Table 5.1. The upper left figure shows the recorded vertical component of the seismogram, and the upper right figure shows the recorded radial component of the seismogram. No seismograms were recorded on the tangential component.

SIMULATED RESULTS FOR VARIOUS EARTH MODELS

1) VTI Modeling Results

The actual seismic reflection is a function of seismic wavelet and reflection coefficient at a bed boundary. The reflection coefficient is associated with the contrast of elastic parameters between two rock formations, and is rather stable. The seismic wavelet however, undergoes change with time and source-receiver offset, even for a constant contrast in elastic parameters. Further, the radiation pattern for an impulsive vertical source can be quite complex, especially for SV energy.

Here, I calculated both reflection coefficients and simulated seismic amplitudes to understand the sensitivities of seismic reflections of P-wave, mode converted shear wave and direct shear wave for isotropic and VTI anisotropy models. Reflection coefficients were calculated analytically using Ruger (1997,2001) equations given earlier in this chapter. Seismic reflection amplitudes were picked from the numerically simulated synthetic seismograms. The model parameters for reflectivity modeling and synthetic seismogram modeling are listed in Table 5.2. Note that Ruger (1997, 2001) equations are for a single interface between two half-space layer; therefore layer thickness is not required. The numerical algorithm however requires layer thickness at least for layer 1 which was set to the reservoir depth. Further, the energy generated by the seismic source is not uniformly distributed at all angles of departure from the source position. For all models, Thomsen's (1986) weak anisotropy parameter ϵ was set equal to γ .

While modeling for seismic sensitivity, I tried to understand the relative importance of anisotropic parameter ϵ and δ . Therefore, for some models I set one parameter, either ϵ or δ to 0.0 and varied the other parameter to a narrow range of reasonable values. The resulting reflection coefficients and seismic amplitudes are plotted side by side using the same scale to better understand their relative seismic responses.

	P-wave velocity (m/s)	S-wave velocity (m/s)	Vp/Vs	Density (gm/cc)	Thickness (m)	Type
Layer 1	3000	1923	1.56	2.320	2326	Isotropic, VTI
Layer 2	5000	2840	1.76	2.710	Infinite	Isotropic

Table 5.2: Parameters of the half space model, used for reflection coefficients and synthetic seismogram modeling. Note that thickness is used only for synthetic seismogram modeling.

The P-wave reflection coefficients (R_{pp}) and observed PP amplitudes for models with constant δ (0.0) and variable ϵ (0, 0.1 and 0.2) are shown in Figure 5.3. The R_{pp} and PP amplitudes for a second set of models with constant ϵ (0.0) and variable δ (-0.1, 0 and 0.1) are shown in Figure 5.4. The plotted amplitudes are the scaled absolute amplitudes (i.e. $\sqrt{X^2 + Z^2} * P$, where P is the scaling factor normalizing the amplitudes to the reflection coefficient at normal incidence) calculated from the amplitudes of the radial (X) and vertical (Z) component of the seismogram. For the first set of modeling results (Figure 5.3), there are almost no differences at near incidence angles (0-15 degrees), between isotropic and anisotropic reflection coefficients. However, isotropic R_{pp} started to diverge from VTI R_{pp} at an angle of 15 degrees and the divergence increases with

increase in offset, the higher the anisotropic parameter value (i.e. ϵ) the higher the divergence from isotropic response. Unlike ϵ , the δ can be negative. For negative δ , the Rpp increase with angle instead of decreasing. However, positive δ has a similar effect like ϵ , i.e Rpp decreases with increasing δ . For a 10% changes in δ (at $\epsilon = 0$), there is 6% decrease in Rpp from isotropic response at a 40 degree incidence angle. For 20% changes in ϵ (at $\delta = 0$), the decrease in Rpp from the isotropic response at 40° is 8.5% (Figure 5.4). Next I consider the results from the numerical simulations. Note that the numerical simulations are a comparatively more sophisticated method than reflection coefficients modeling and account for both source type and anisotropic wave propagation in the layered media. At increasing incidence angles, PP amplitudes decrease (hence a PP amplitude gradient) with the increase of anisotropic parameter values. However, amplitude decreases are mostly due to variations in epsilon parameters. For 10% changes in ϵ (from isotropic to $\epsilon = 0.1$), there is 48% change in reflection amplitude at 40 degree angle of incidence. However, for 10% changes in δ (from isotropic to $\delta = 0.1$), there is 44% change in reflection amplitude at 40 degree angle of incidence. The most important parameter for PP amplitude appear to be, however the difference between ϵ and δ i.e. ($\epsilon - \delta$). For ($\epsilon - \delta$) > 0 cases (i.e, $\epsilon = 0.2$, $\delta = 0.0$; $\epsilon = 0.1$, $\delta = 0.0$ and $\epsilon = 0.0$, $\delta = -0.1$ cases), there is significant amplitude decrease with angle, > 65% amplitude decreases at 40° from the zero degree incidence angle. The larger values of the anisotropic parameters for a fixed positive ($\epsilon - \delta$) model, the larger the influence on AVO. For instance, there is a 78% amplitude decrease at 40° from the vertical for $\epsilon = 0.2$, $\delta = 0.0$ while there is 65% amplitude

decrease from the vertical to 40° for $\mathcal{E}=0.0$, $\delta=-0.1$. Positive values of $(\mathcal{E}-\delta)$ may be typical for many subsurface formations (Tsvankin, 2001). Therefore, anisotropic parameter $\mathcal{E}$ is probably the most important parameter controlling the PP seismic response in VTI media.

Figure 5.3: P-wave reflection coefficients and reflection amplitudes for isotropic over anisotropic a layered half space model. Left figure shows variations in Reflection coefficients with incidence angle. Right figure shows variations in seismic amplitudes with incidence angles. Note that Thomsen (1986) anisotropic parameter $\mathcal{E}$ and Υ were set equal and δ was set constant at 0.0 for this VTI model.

Figure 5.4: P-wave reflection coefficients and reflection amplitudes for isotropic over anisotropic a layered half space model. Left figure shows variations in Reflection coefficients with incidence angle. Right figure shows variations in seismic amplitudes with incidence angles. Note that Thomsen (1986) anisotropic parameter $\epsilon=\gamma=0.0$ were set for this VTI model.

The mode converted P-SV reflection coefficients and PS amplitudes for constant δ (0.0) and variable ϵ (0, 0.1 and 0.2) are shown in Figure 5.5. The P-SV reflection coefficients and PS amplitudes for constant ϵ (0.0) and variable δ (-0.1, 0 and 0.1) are shown in Figure 5.6. For both of these, VTI R_{p-sv} started to diverge slightly from the isotropic R_{p-sv} at an angle of about 20 degrees. The difference between isotropic response and anisotropic response increase with the increase in p-wave anisotropy parameter (hence increase in shear wave anisotropy parameter since models are for $\epsilon = \gamma$ here). For 10% change in ϵ parameter at $\delta=0$ (Figure 5.6), there is 42% change in reflection coefficients from the isotropic response computed at 30 degree incidence angle.

Similar seismic response is also noticed for the PS amplitudes in the synthetic seismograms.

Figure 5.5: Converted wave (P-SV) reflection coefficients and PS amplitudes for isotropic and anisotropic a layered half space model. Note that Thomsen (1986) anisotropic parameter ϵ and γ were set equal and δ was set constant at 0.0 for the VTI models here.

The shear wave reflection coefficients and amplitudes for direct shear reflections are plotted on Figure 5.7 and Figure 5.8, in the same fashion as done for P-P and P-SV reflections. There is polarity reversal at around 20 degree angle of incidence both in the reflection coefficients and SS amplitudes. Reflectivity as well as zero crosses incidence angle change with the changes in anisotropy parameters. Gradients of R_{sv-sv} decrease

with the increase of ϵ values whereas gradients of R_{sv} increase with the increase of δ values. For 10% change in δ at $\epsilon = 0.0$ (Figure 5.7), reflection coefficient changes 65% of isotropic response at 30 degree incidence angle. However, for 10% change in ϵ at $\delta = 0.0$ (Figure 5.8), reflection coefficient changes 80% of isotropic response at 30 degree incidence angle.

Figure 5.6: Converted wave (P-SV) reflection coefficients and PS amplitudes for isotropic and anisotropic a layered half space model. Left figure shows variations in reflection coefficients with incidence angle. Right figure shows variations in seismic amplitudes with incidence angles. Note that Thomsen (1986) anisotropic parameter $\epsilon = \gamma = 0.0$ were set for the VTI models here.

Figure 5.7: Shear wave reflection coefficients and amplitudes for isotropic and anisotropic layered a half space model. Left figure shows variations in reflection coefficients with the incidence angle. Right figure shows variations in seismic amplitudes with the incidence angles. Note that Thomsen (1986) anisotropic parameter ϵ and γ were set equal and $\delta=0.0$ in the VTI models here.

Figure 5.8: Shear wave reflection coefficients and amplitudes for isotropic and anisotropic layered a half space model. Left figure shows variations in Reflection coefficients with incidence angle. Right figure shows variations in seismic amplitudes with incidence angles. Note that Thomsen (1986) anisotropic parameter $\epsilon=\gamma=0.0$ were set for the VTI models here.

2) Layer thickness and surface seismic resolution

One of the concerns of surface seismic data is whether a particular formation (“thin” layer) is resolvable in seismic reflection data. To investigate the thickness effect, I considered a three layer isotropic model. The first layer was taken as the overburden layer above the Marcellus Shale, the second layer was the Marcellus Shale and the third layer (half space) was everything below the Marcellus shale. I considered two cases, one using an actual thickness of the Marcellus Shale (Model 1) and one taking the Marcellus

interval as a thick layer (Model 2). Model 1 parameters are given in Table 5.3. Model 2 parameters are same as given earlier in Table 5.1 while used for generating multicomponent synthetic seismograms. Figure 5.9 and Figure 5.10 shows the synthetic seismograms for the model 1 and model 2 respectively. For Model 1, there is only one composite reflection for each seismic reflection of P-P, P-SV and SV-SV wave (Figure 5.9) on both vertical and radial seismic section. Synthetic seismograms for model 2 however, clearly shows two reflections for each of the P-P, P-SV and SV-SV waves, one for the upper interface and one the lower interface of the Marcellus Shale for the three layer model. So, it is clear that the productive Marcellus interval (15 m) is not individually identifiable in the surface seismic data.

	P-wave velocity (m/s)	S-wave velocity (m/s)	Vp/Vs	Density (gm/cc)	Thickness (m)
Layer 1	4000	2265	1.77	2.660	2226
Layer 2	3000	1923	1.56	2.320	15
Layer 3	5000	2840	1.76	2.710	Infinite

Table 5.3: Model parameters for the actual thickness model (Model 1).

Figure 5.9: Synthetic seismograms generated using a vertical impulse source for Model 1. Right figure shows the vertical component and left figure shows the radial component of the seismogram. Notice that only one composite reflection is present in the seismogram for each P-P, P-SV and SV-SV reflections though the original model 1 contains 2 interfaces above and below the thin layer.

Figure 5.10: Numerically generated synthetic seismograms using an impulsive source for Model 2. Right figure shows the vertical component and left figure shows the radial component of the seismogram. Notice that two reflections from the top and bottom of the Marcellus Shale are clearly visible in both seismograms.

3) Effect of Kerogen Content on AVO

In chapter 4, I showed that kerogen content has a first order control on the formation velocity of the reservoir rock. To further investigate the effect of kerogen content on surface seismic data I have generated full-waveform synthetic seismograms for varying kerogen content models. The models representing 5%, 10%, 20% and 30% of

kerogen in the Marcellus Shale were considered. The Marcellus Shale was considered as a VTI media and Thomsen (1986) parameters were set $\epsilon=\gamma=\delta=0.10$ for all models. Layer 1 and layer 3 were set to isotropic. All model parameters are given in Table 5.4. Model Parameters for Layer 2 which represents thick Marcellus Shale were varied as given in Table 5.4. Figure 5.11 ,Figure 5.12 and Figure 5.13 shows the PP , PS and SS amplitudes, respectively with angles for the considered models. The amplitudes are the scaled absolute amplitudes calculated from the X and Z components of the seismograms. The overall shape of the PP AVA curves are similar. However, there are higher anomalies among the amplitudes at zero to near angle of incidence. As the angle of incidence increases, the amplitude anomalies decrease. For models of 5% and 10% kerogen content, a variation of 5% kerogen content contributes a 25% change of PP amplitudes at normal angle of incidence.

		Vp (0°) (m/s)	Vs (0°) (m/s)	Density (gm/cc)	Thickness (m)
Layer 1		4000	2265	2.660	2226
Layer 2	Model 1 (5% K)	3880	2300	2.53	100
	Model 2 (10% K)	3760	2250	2.40	
	Model 3 (20% K)	3600	2175	2.12	
	Model 4 (30% K)	3500	2140	1.90	
Layer 3		5000	2840	2.710	1000

Table 5.4: Parameters for different models with various amounts of kerogen content in the layer 2. Note that only vertical P-wave and vertical S-wave velocities are given here. All models were assumed VTI media with anisotropic parameter $\xi=\gamma=\delta=0.10$.

The signature of the PS amplitude variations with incidence angles is quite different than PP amplitudes. The maximum amplitude anomalies in the PS data were found at mid offset ranges i.e. at between 15 to 30 degree angles of incidences. A 5% change in kerogen content, i.e. a change from 5% to 10% kerogen content , contributes a 25% change in PS amplitude at 19 degree incidence angle.

The SS amplitude variations for kerogen content variations varies widely. The most sensitive incidence angles are 10 to 20 degrees. The most amplitude variations are noticeable for 10 to 20% kerogen content variations, computed as much as 143%.

Figure 5.11: P-wave reflection amplitude variations with incidence angles for different kerogen content models. Note Thomsen (1986) weak anisotropic parameter in the models were set as $\mathcal{E}=\Upsilon=\delta=0.1$. Note the differences in amplitude gradients as the angles of incidence increase, even for angles less than 20° .

Figure 5.12: P-SV reflection amplitudes with incidence angles for different kerogen content models. Note Thomsen (1986) weak anisotropic parameter in the models were set as $\mathcal{E}=\Upsilon=\delta=0.1$. Note the differences in reflectivity at about 20° .

Figure 5.13: SS reflection amplitudes with incidence angles for different kerogen content models. Note Thomsen (1986) weak anisotropic parameter in the models were set as $\epsilon=\gamma=\delta=0.1$. Note the differences in reflectivity at an angle range of 10-15°.

4) Kerogen Aspect Ratio

To investigate the effect of aspect ratios of the structural kerogens on the amplitudes of the surface seismic data, I used two models with kerogen aspect ratios of 0.1 and 0.01. The P-wave velocities, S-wave velocities and densities were taken from Chapter four for 10% kerogen content. The Marcellus Shale was assumed as a VTI media

and the Thomsen (1986) parameters were set to $\xi=\gamma=\delta=0.1$. The layer 1 and layer 3 were assumed isotropic. All model parameters are given in Table 5.5.

		V _p (0°) (m/s)	V _s (0°) (m/s)	Density (gm/cc)	Thicknes s (m)
Layer 1		4000	2265	2.660	2226
Layer 2 (10% K)	Model 1 (AR 0.01)	3760	2250	2.40	100
	Model 2 (AR 0.001)	3660	2200		
Layer 3		5000	2840	2.710	1000

Table 5.5: Model parameters for the aspect ratio models. Note that only vertical P-wave and vertical S-wave velocities are given here. All models were assumed VTI media with anisotropic parameter $\xi=\gamma=\delta=0.10$.

Figure 5.13, 5.14, 5.15 shows the PP, PS and SS reflection amplitudes with angle of incidence for both aspect ratio models. The PP reflection amplitudes are most sensitive at zero to near angle of incidence whereas PS reflection amplitudes are most sensitive at mid-angle ranges at around 18 degree incidence angles. The maximum PP amplitude variation is 10% and maximum PS amplitude variation is 8% for a change of kerogen aspect ratio from 0.1 to 0.01. SS amplitudes are probably least sensitive for aspect ratio changes.

Figure 5.14: P-wave reflection amplitudes with incidence angles for different kerogen aspect ratios models. Note that a constant scalar was applied to the absolute amplitudes.

Figure 5.15: P-SV reflection amplitudes with incidence angles for different kerogen aspect ratios models. Note that, a constant scalar was applied to the absolute amplitudes.

Figure 5.16: SS reflection amplitudes with incidence angles for different kerogen aspect ratios models. Note that, a constant scalar was applied to the absolute amplitudes.

SUMMARY

In this chapter, isotropic and VTI anisotropic models are introduced, and their seismic responses were compared with isotropic responses and dominant anisotropic parameter were investigated. The models were built on the basis of well log data and rock physics analysis (chapter 4). Significant differences between isotropic and anisotropic seismic responses were found for both reflection coefficients and seismic amplitudes.

Therefore, different plots and sensitivity analysis will provide a guide to analyze the actual seismic data.

For VTI anisotropy AVO, the most important parameter is probably the Thomsen (1986) P-wave anisotropy parameter (ϵ). For all types of data including P-P, P-SV and SV-SV data, ϵ parameter has found to have a dominant influence on AVA gradient. For usual positive (ϵ - δ) model cases, angular PP amplitude variations is very significant, P-wave amplitude can decrease as much as 78% from zero to 40° incidence angle even for the narrow ranges of weak anisotropy parameters. For commonly used AVO range of angles (0 - 40°), VTI signature in the P-wave data should be found at the large angles of incidence, whereas VTI signature on P-SV data should be found at mid offset angles (15 - 30° incidence angles). On the SV-SV data, amplitude variations can occur from near angle of incidence to large angle of incidence, however large angle data should be better for AVA interpretations.

In actual subsurface formation Thomsen (1986) anisotropy parameter may or may not be directly associated with kerogen content and aspect ratio of kerogen structural pores. However, increased kerogen content and lower aspect ratio pores usually decrease the formation interval velocity. Therefore, seismic signature for kerogen content and kerogen aspect ratio may have signature on surface seismic data. This signature for constant seismic parameters should be seen at zero to near angle p-wave data and mid-angle on PS data.

Chapter VI: Conclusion and Discussion

I performed VTI anisotropic modeling of surface seismic reflection data and rock physics analysis based on borehole log data to the productive zone of the Marcellus Shale, WV. The goal was to test seismic reflection sensitivities for variations in anisotropic parameters and variations in rock and fluid properties. Isotropic elastic parameters for the seismic models were computed from a rock physics model. Anisotropic seismic models were simulated for scenarios with varying Thomsen (1986) parameters.

The petrophysical analysis and rock physics analysis from the geophysical wireline log data suggests that the productive zone of the Marcellus Shale contains dominantly quartz (>60%) with very high kerogen content. Consequently, elastic properties of the productive shale are mineralogically controlled by quartz and kerogen content. There is a significant decrease in seismic wave propagation velocities in the productive Marcellus zone (avg 19% in V_p and avg 17% in V_s) below velocities of vertically adjacent Shale layers; which may also be attributed to this compositional variations. Another properties that can be used to distinct productive Marcellus Shale layer are lower λ_p, μ_p and Poisson's ratio (avg 0.19) than the adjacent layer. The rock physics model utilized DEM theory, bounds and mixing laws and fluid substitution equations to a model scheme to compute elastic constants for known variations in matrix composition, kerogen content and pore shape (both interparticle pore and structural kerogen).

The seismic simulations were conducted using a vertical impulse source and three component receivers. The vertical impulse source generated PP, PS and SS

reflections. A two dimensional acquisition geometry with one shot and one line of receivers were considered.

The VTI anisotropic modeling was performed using a two layer half space model. The upper layer was considered VTI and set to actual reservoir depth. Note that Thomsen (1986) parameter γ was set equal to ϵ in all models. The amplitudes from the synthetic seismograms were picked for analysis. Besides seismic amplitudes, reflection coefficients from Ruger (1997, 2001) equations also examined for the same models. For models with positive ($\epsilon - \delta$), there were significant PP amplitude drop with offset, therefore notable AVO gradient variation than that of the isotropic response. The most sensitive portion of PS reflections was observed at mid offset (~15 degree incidence angle). Shear wave reflection coefficients and reflection amplitudes started to diverge from isotropic response at around 6° angle of incidence and divergence increased with increase on offset. For both PP and PS reflections, the Thomsen (1986) anisotropic parameter ϵ had more influences on seismic sensitivities than parameter δ . For instance, for 10% change in ϵ with constant δ , there was 12.4% and 80% change in PS and SS reflection coefficients respectively from isotropic response at 30 degree angle of incidence. Under similar cases, 10% change in δ with constant ϵ , the difference from isotropic response at 30 degree angle of incidence were 7.3% and 65% for PS and SS reflection coefficients respectively.

I also analyzed seismic sensitivity for variations in kerogen content and aspect ratio of structural kerogen. A three layer seismic model was considered in this case and middle layer was taken as VTI. Elastic constants were computed for 5%, 10%, 20% and 30% kerogen content from rock physics model and provided to the seismic model.

Seismic models for kerogen aspect ratios were simulated in the same way and kerogen aspect ratios of 0.1 and 0.01 were considered. For both kerogen content and aspect ratio model, PP amplitudes varies significantly at zero to near offset while PS amplitude varies at mid offsets (12 to 30 degree angle of incidences) for changes in kerogen content.

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