ANALYSIS OF VELOCITY VARIATION WITH AZIMUTH (VVAZ) FOR NATURAL FRACTURE AND STRESS CHARACTERIZATION, VACA MUERTA FORMATION, NEUQUÉN BASIN, ARGENTINA

by

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

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ABSTRACT

The upper Tithonian – lower Valanginian Vaca Muerta Formation, located in the Neuquén Basin, Argentina, is one of the most prolific unconventional shale plays in the world. It spans an area of around 30,000 km$^2$, covering four different provinces, Neuquén, Mendoza, La Pampa, and Rio Negro. Because the unit requires multistage horizontal wells in order to produce commercially, detailed analysis of the regional stress and natural fractures of the area is needed.

Previous studies have shown that both the Neuquén Basin and the Vaca Muerta Formation are highly affected by stress due to their proximity to the Andes chain, and also that the unit may present a high density of natural fractures. This study is located in a block operated by Wintershall Holding GmbH, where previous research projects focused on natural fractures analysis from well images, seismic inversions for mechanical parameters prediction, and well based anisotropic geomechanical models.

Using well log and wide-azimuth seismic data, analysis for natural fractures and stress characterization was performed. Well based anisotropic geomechanical models were built for the three wells in the area using well logs, laboratory measurements and completion data. Stresses were calculated and calibrated with fracture data. For the studied block, the stress regime in the Vaca Muerta Formation is mainly strike-slip ($S_H>S_V>S_h$), with local areas showing normal ($S_V>S_H>S_h$) and thrust ($S_H>S_h>S_V$) regimes. In this thesis, the Lower Vaca Muerta section is recommended as a possible landing zone based on stress and fracability analysis, and considering previous studies and current practices in the basin.

Anisotropy and azimuthal analysis from wide-azimuth seismic data showed that maximum horizontal stress is oriented between 105º and 120º. It also proved the presence of two sets of extensional fractures oriented at 50º and 150º, formed at different stages during the
development of the basin. All these observations show a reasonable calibration with log and microseismic data.

Finally, following the azimuthal analysis and results from the geomechanical models, new drilling areas and landing points are suggested for the studied block.
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CHAPTER 1
INTRODUCTION

In 2013, the Reservoir Characterization Project (RCP) at the Colorado School of Mines began a project with the operator Wintershall Holding GmbH: Exploration and development of the Vaca Muerta Formation in the Neuquén Basin, Argentina. This unconventional shale play requires horizontal drilling and massive hydraulic fracturing to produce commercially. Thus a complete reservoir characterization based on well log, core, seismic and completion data, is required. The main focus of the project is to understand the factors that control commercial production, and also to maximize hydrocarbon recovery from the Vaca Muerta Formation through an integrated analysis of geological, geophysical, and engineering data.

1.1 Study Objectives

An extensive reservoir characterization comprising geology, geophysics and geomechanics is important to improve hydrocarbon recovery of an unconventional play. For this reason, previous research completed by the RCP’s Vaca Muerta Team students has emphasized these studies. In particular, mapping geomechanical parameters, natural fractures, and stresses may significantly improve well placement, horizontal landing points, and hydrocarbon recovery.

Using well log data and wide-azimuth seismic data, the main objective of this study is to identify possible fractured areas and also to understand the regional and local stress conditions in Wintershall’s block by building well based geomechanical models and performing azimuthal analysis. These results will help to improve future well completions and hydrocarbon production.
1.2 Scope of Work

To understand the main objectives of this thesis and the processes applied for the analysis, this chapter begins describing the data set available. Seismic acquisition and processing methods are described. Also, it explains the methodology used for calculation and interpretation of the different parameters employed during this study.

To set the stage for the studies presented in this thesis, Chapter 2 begins by describing the geology of the basin and the area of interest. The Neuquén Basin and the Vaca Muerta Formation are extensively documented in the literature, and analyzing this body of work is the starting point to understand the characteristics and the petroleum potential of the play. Basin development and stratigraphy is described in detail. Also, a structural framework of the basin and the surroundings of the study is given. Finally, a summary of previous research completed by RCP students (Bishop, 2015; Fernandez-Concheso, 2015; Barbosa-Murillo, 2017; Convers-Gomez, 2017; Johnson, 2017) are reviewed to illustrate the progress of the RCP’s Vaca Muerta Project, and also to understand how these can be applied to the present study.

Chapter 3 gives background information about Vaca Muerta properties such as maturation, type of oils, geomechanics, stresses, natural fractures, and other parameters. Comparing to US unconventional plays, the Vaca Muerta Formation presents some characteristics that makes it unique, such as its large areal extension and pay thickness, but also its mechanical characteristics and stress regimes. All these characteristics are explained in detail in this chapter.

Chapter 4 provides an overview on how mechanical parameters and stresses are calculated from well logs. Shale reservoirs tend to present a strong Vertical Transverse Isotropy (VTI) anisotropy because of their intense horizontal layering, while naturally fractured reservoirs
often show Horizontal Transverse Isotropy (HTI) anisotropy due to vertical fractures. Thus, a
description of the different types of anisotropy types is presented. Mechanical parameters and
stresses are described and calculated considering a VTI medium. Results from the well log
analysis such as mechanical parameters and stresses are shown and interpreted.

Chapter 5 introduces observations from the wide-azimuth seismic data. Azimuthal
seismic data analysis can provide valuable information such as the presence of open fractures
and the direction of them. But also, it gives information on horizontal stress anisotropy and the
direction of the maximum horizontal stress. First, seismic interpretations such as horizons and
structures are shown. Then, anisotropy and azimuth attributes are presented. These were
extracted from the main stratigraphic surfaces to observe their variation in the area and in the
vertical section. Interpretation of results is given.

Chapter 6 discusses the possible origins for the different sets of fractures observed in the
data. Fractures may form as extensional fractures parallel to the maximum horizontal stress, or
they may form as two sets of shear fractures located at around 30º from it. Another possibility is
that fractures might form as microfractures due to the explosion of hydrocarbons. These three
different theories are presented and discussed based on the observations from well log and
seismic data. Also, new well locations and landing points are suggested based on well log and
seismic interpretations.

Chapter 7 summarizes key findings and contributions of this research to the exploration
and development of the Vaca Muerta Formation in the studied block. Future suggestions for the
Vaca Muerta Project are also given.
1.3 Dataset

The data for this project were provided by Wintershall Holding GmbH, as part of an agreement with the Reservoir Characterization Project Consortium (RCP). The data set available is from a block operated by Wintershall, and consist of three vertical wells with full suite of logs, a narrow and wide-azimuth 3D seismic surveys that cover all the block, and a new multicomponent seismic survey covering an area of 80 km$^2$ (Fig. 1.1). Due to privacy agreements, information such as depths, well and block names are not given in this thesis.

![Legend and Data Availability](image)

Figure 1.1: Geographical layout of the research area and data available.

All the wells are located within the wide-azimuth seismic survey, while only two (G and I) are inside the 3C-3D seismic survey. They all present a full suite of logs, while Wells G and I include core data, well images, litho-scanner, sonic-scanner, surface vertical microseismic data, and completion data (Table 1.1). Well G also includes production data, geomechanical laboratory tests, fracture tests, and a walkaround, walkaway, and zero offset Vertical Seismic Profiling (VSP).
Table 1.1: Data available for Well A, Well G, and Well I.

<table>
<thead>
<tr>
<th>Logs</th>
<th>Well A</th>
<th>Well G</th>
<th>Well I</th>
</tr>
</thead>
<tbody>
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<td>Gamma Ray</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>P-sonic</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>S-Sonic</td>
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<td>X</td>
<td>X</td>
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<td>Sonic Scanner</td>
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<td>X</td>
<td></td>
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<tr>
<td>Bulk Density</td>
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<td>X</td>
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<table>
<thead>
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<td>Production Data</td>
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<tr>
<td>Well Reports</td>
<td>X</td>
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</tr>
</tbody>
</table>

Vertical microseismic on Well G is composed of 4 stages, 3 located within the Middle Vaca Muerta (MVM) and one within the Upper Vaca Muerta (UVM), while microseismic on Well I comprises 5 stages, 1 within the Lower Vaca Muerta (LVM), 3 located in the MVM, and one in the UVM (Fig. 1.2).

Figure 1.2: Approximate locations of the stages for both Well’s G and I (taken from Johnson, 2017).
The wide-azimuth seismic survey was acquired in 2016 by UGA Seismic, and time and depth imaging were processed out by Seiscenter. The survey covers almost the entire block. The data is formed of high fold, dense sampling, long offsets and wide azimuth coverage (Fig. 1.3), which allows the analysis of the rock physics and anisotropy behavior of the Vaca Muerta Formation (Curia et al., 2018c).

Figure 1.3: Full-fold diagram (left), and number of traces, offset and azimuth distribution (right) from the processing report.

From the wide-azimuth seismic data, final volumes were given to RCP both in time and depth by Wintershall. These consist of Root Square Mean (RMS) $\alpha_{\text{slow}}$, $\delta_{\text{alpha}}$, and $V_{\text{fast}}$ Azimuth, and interval $\alpha_{\text{slow}}$, $\alpha_{\text{fast}}$, $\delta_{\text{alpha}}$, $V_{\text{fast}}$, $V_{\text{slow}}$, and $V_{\text{fast}}$ Azimuth volumes. All these attributes were calculated as follows:

\begin{align*}
\alpha_{\text{slow}} &= \frac{V_{\text{slow}} - V_{\text{VTI}}}{V_{\text{VTI}}} \quad \text{(1.1)} \\
\alpha_{\text{fast}} &= \frac{V_{\text{fast}} - V_{\text{VTI}}}{V_{\text{VTI}}} \quad \text{(1.2)} \\
\delta_{\text{alpha}} &= \frac{V_{\text{fast}} - V_{\text{slow}}}{V_{\text{VTI}}} \approx \text{HTI Anisotropy Magnitude} \quad \text{(1.3)}
\end{align*}
$V_{VTI}$ represents Vertical Transverse Isotropy (VTI) velocities (refer to Chapter 4 for definitions) that were used as background for calculation of the other seismic attributes. $V_{\text{fast}}$ and $V_{\text{slow}}$ are fast and slow seismic velocities for a Horizontal Transverse Isotropy (HTI) medium (refer to Chapter 4 for definitions), respectively. $\delta_{\text{alpha}}$ is calculated as the difference between $V_{\text{fast}}$ and $V_{\text{slow}}$, and could be considered proportional to the anisotropy magnitude for an HTI medium. In thesis, $\delta_{\text{alpha}}$ will be referred as HTI anisotropy magnitude.

The 3D-3C seismic survey was acquired in 2016 by UGA Seismic and processed in 2017 by Unified Geosystems LLC. In the acquisition, 600 3C receivers were used and set at 120 m apart. The distance between sources was 60 m, and the separation between source lines and receiver lines was 300 and 600 m, respectively (Fig. 1.4). Because of battery and other operational issues, several sources in the southern part of the survey were not acquired. However, the final azimuthal coverage was sufficient for seismic anisotropy characterization of the Vaca Muerta Formation (Curia et al., 2018a).

![Figure 1.4: Acquisition layout of the survey: east-west lines are sources and north-south lines are receivers. The color map is the PS fold at 1500 ms (calculated using asymptotic binning with gamma = 2) (taken from processing report).](image)
During the processing, all three components of the data were processed simultaneously in order to treat the data set as a full vector wavefield. Processing concluded with 5D regularization that allowed the filling of gaps in the seismic survey and a regular output more suitable for anisotropy analysis. Using regularized common offset-common azimuth (COCA) gathers, fast shear ($V_{\text{fast}}$), slow shear ($V_{\text{slow}}$), and the azimuth of the fast shear were calculated (Fig. 1.5) (processing report; Curia et al., 2018a).

![Figure 1.5: Example of the estimation of $V_{\text{fast}}$, $V_{\text{slow}}$, $V_{\text{fast}}$ Azimuth, and $V_{\text{fast}} - V_{\text{slow}}$ ($\delta \alpha \approx \text{HTI anisotropy}$) (modified from Inks et al., 2014).](image)

This thesis will study the wide-azimuth seismic data. The multicomponent seismic data will be analyzed in detail in another student’s thesis.

### 1.4 Methodology

The first step in this project was to calculate mechanical properties such as Young’s Modulus (YM) and Poisson’s Ratio (PR), and also the stresses for the three wells in the block. To do that, correlations obtained using laboratory measurements in Well G were used to estimate both dynamic and static YM and PR. Then, stresses where calculated using the static parameters.
Since no laboratory measurements were available for Well A and Well I, the same correlations from Well G were used to calculate the mechanical parameters. Finally, dynamic and static properties were calibrated using laboratory measurements, while stresses were adjusted using instantaneous shut in pressure (ISIP) and pore pressure ($P_p$) values obtained from diagnostic fracture injection test (DFIT).

On the other hand, as mentioned before, from both the wide-azimuth and 3D-3C seismic data, the $V_{fast}$, $V_{slow}$, and the azimuth of $V_{fast}$ attributes can be calculated. The azimuth of the $V_{fast}$ tends to be aligned parallel to fracture planes, while if the rock is not fractured it tends to be aligned to the maximum horizontal stress (Hardage et al., 2011) (Fig. 1.6). While the amount of azimuthal anisotropy ($V_{fast} - V_{slow}$) is proportional to either the fracture density or the difference in horizontal stresses (Liu and Martinez, 2013; Curia et al., 2018a).

![Figure 1.6: Model relating fracture orientation (left) and maximum horizontal stress direction (right) with $V_{fast}$ azimuth (Curia et al., 2018c).](image)

All these attributes can be used to characterize the stress and the presence of natural fractures in an area, which helps to optimize well placement, landing points, and orientation of the horizontal wells within the target (Curia et al., 2018a).
CHAPTER 2
GEOLOGY BACKGROUND

2.1 Neuquén Basin

The Neuquén Basin is located on the east side of the Argentinian Andes and in central Chile, between 32° - 40°S latitude and 67° - 70°W longitude. It covers an area of 120,000 km², including Mendoza, Neuquén, La Pampa, and Rio Negro provinces (Legarreta and Uliana, 1991, 1996; Yrigoyen, 1991; Leanza et al., 2000; Howell et al., 2005).

The basin limits to the northeast and southeast with the Sierra Pintada system and the Northpatagonic massif, respectively, both of cratonic nature. It is also limited on the west by the volcanic arc with a NNW-SSE orientation which, on the north Chilean locality of Curepto, separates the basin from the “surco de Curepto”. Finally, south of Curepto, the volcanic arc lies on a dorsal emerged during the Jurassic and Neocomian, called Tierras de Conepcion (Cecioni, 1970) or Chubut Dorsal (Aubouín et al., 1973; Chotin, 1977; Digregorio et al., 1984) (Fig. 2.1).

![Figure 2.1: Geographic location, geometry and limits of the Neuquén Basin (modified from Sagasti et al., 2014). The square represents the study area.](image_url)
The basin presents a triangular geometry, with two easily recognizable regions: the Neuquén Andes to the west, and the Neuquén Embayment to the east and southeast (Howell et al., 2005).

2.2 Basin Development and Evolution

The Neuquén Basin development began during Permo–Triassic times. Initially, during the Early Permian, an active margin was installed in west Gondwana associated with this supercontinent breakup, acting as a compressive phase called the San Rafael orogenic phase by Azcuy and Caminos (1987). This initial phase was followed by a relaxation period, spanning to the Early Triassic (Llambías et al., 2007). During this stage the Choiyoi Group was developed, composed of andesites, dacites and rhyolites (Kleiman and Japas, 2009). This unit acts as the Neuquén Basin basement from south Neuquén (Turner and Cazau, 1978), to central-west San Juan province (Marín and Nullo, 1988; Nullo and Marín, 1990).

Legarreta and Gulisano (1989), Legarreta and Uliana (1991, 1996) and Vergani et al. (1995) analyzed the evolution of the Neuquén Basin from Late Triassic to the Tertiary and defined three important tectonic phases for its formation: a synrift initial stage (Late Triassic – Early Jurassic), a postrift stage (Early Jurassic – Early Cretaceous), and a final foreland stage (Late Cretaceous – Paleocene) (Fig. 2.2).

The synrift phase initiated because of the regional extension that the Gondwana continent suffered during the Triassic – Early Jurassic lithosphere weakening. This extension produced several retroarc and intracratonic basins along the pacific margin (Legarreta, 2002). During this initial phase, the basin filled with continental and volcanic sediments, generated by the intense extensive volcanism (Riccardi and Gulisano, 1990).
Figure 2.2: Tectonic phases of the Neuquén Basin (taken from Howell et al., 2005). A) Synrift phase (Late Triassic – Early Jurassic), characterized by a rifting previous to the subduction. B) Postrift phase (Jurassic – Early Cretaceous), when a subduction complex is developed west of the South American continent which forms the Andes mountains. This uplift produces periodic disconnections of the basin from the Pacific Ocean. C) Foreland phase (Late Cretaceous). Uplifting of the Andes belt and development of a fold and thrust belt. Complete disconnection from the Pacific Ocean and periodic Atlantic transgressions.
Later, the opening of the South Atlantic during the Middle Jurassic produced a positive convergence along the South American pacific margin, and a magmatic arc was formed. In this manner, during the Jurassic and Cretaceous (postrift phase) the basin behaved as a retroarc basin, with episodical marine transgressions from the Pacific Ocean (Legarreta and Uliana, 1991; Legarreta, 2002).

Finally, during Late Cretaceous, an increase in the plate’s convergence formed a fold and thrust belt that progrades towards the east, shaping the Andes Cordillera. This way, the basin stayed completely disconnected from the Pacific Ocean, and behaved as a foreland basin (Howell et al., 2005; Ramos and Folguera, 2005).

Finally, Ramos and Kay (2006) described three Cenozoic tectonic phases, all related with variations in the subducted slab inclination: extensive phase (Oligocene – Early Miocene), compressive phase (Middle – Late Miocene), extensive phase (Pliocene – Quaternary), and a final compressive phase (Late Quaternary – today).

The extensive phases are associated with the slope increase in the subducted slab. They are commonly characterized by the presence of a basaltic magmatism as seen in Payenia area, originated during the second extensive phase (Pliocene – Quaternary).

The compressive phases are related to the slope decrease of the subducted slab. This causes the deformation and magmatism to move towards the foreland, plus it causes the inversion of previous structures.

2.3 Stratigraphy

Initially, Groeber (1929, 1946), who studied the Jurassic – Cretaceous successions in the Neuquén Basin, defined three Mesozoic sedimentary cycles: Jurásico, Ándico, and Riográndico
cycles (Fig. 2.3). Meanwhile, the first cycle was subdivided in three well differentiated subcycles, based on the fauna and on the regional facies distribution. Thereby, the Jurásico cycle was divided in Cuyano, Loteniano, and Chacayano subcycles. This cycle spans from the Hettangian to the middle – upper Bajocian. Furthermore, the Andico cycle, which goes from Tithonian to Coniacian, was also subdivided between the Mendocino, Huitriniano, and Diamantino subcycles. Finally, the Riograndico cycle was subdivided between the Neuqueniano, Malalhueyano, and Pircaliano subcycles, covering an age from the Pichipicuense to the Rocanense.

Later, Groeber et al. (1953), considering the zonations and stratigraphic subdivisions previously established (Groeber, 1946, 1947a, b, c), proposed a new chronostratigraphic scheme still in use today. In the Jurasico cycle, the Cuyano subcycle remained unchanged; however, the Loteniano subcycle included the Calovian. On the other side, the Chacayano subcycle was subdivided in Bayense, Manguense, Auquilcoense, and Tordillense, spanning an age that goes from the Oxfordian to the early Tithonian.

This last chronostratigraphic scheme was then modified by Stipanicic (1969), who adapted it to the lithostratigraphic classification system. Thus, the Cuyo Group, the Lotena Formation, and the Chacayense Group were defined. Moreover, this last author divided the Cuyano subcycle, previously defined by Groeber (1946), into a lower and upper sector, both limited by an intraliasic discordance. Ultimately, he put an intermalmic discordance on top of the Jurassic sequence.

Gulisano (1981), who studied the sedimentary sequences in south Mendoza province, redefined the Cuyano cycle used by Groeber et al. (1953). This author also identified a new
sedimentary cycle within the Jurassic named Precuyano cycle. This last cycle underlies the Cuyano cycle, and is characterized for including continental deposits.

The Upper Jurassic – Lower Cretaceous sequence stratigraphic framework has been interpreted from low-resolution seismic data. Mitchum and Uliana (1985) defined nine depositional sequences (A to I) for the lower Tithonian – lower Valanginian interval and correlated them to third-order depositional sequences. Legarreta and Gulisano (1989), who studied the sedimentary filling of the basin by the use of sequence stratigraphy, included this set of depositional sequences (Mi₁ to Mi₉) within the lower Mendoza mesosequence. Mi₁ includes the Tordillo Formation and the basal section of the Vaca Muerta Formation, while the last sequence from the Vaca Muerta – Quintuco system is separated from the Mulichinco Formation by the Intra-Valanginian unconformity or its correlative conformity. These last authors also subdivided the sedimentary filling in depositional sequences, mesosequences and supersequences. They defined three supersequences: lower, middle, and upper. Each of these supersequences corresponds to the Jurasico, Andico and Riograndico cycles, respectively, previously defined by Groeber (1946). Furthermore, these authors also subdivided each supersequence in several mesosequences. The lower supersequence was subdivided into the Precuyo, Cuyo and Lotena mesosequences. The middle supersequence was divided into the Lower Mendoza, Middle Mendoza, Upper Mendoza, Huitrin, and Rayoso mesosequences. Finally, the upper supersequence comprises the Neuquén and Malargüe mesosequences (Fig. 2.3).

More recently, Kietzmann et al. (2014) defined five composite depositional sequences (CS-1 – CS-5) in outcrops from the southern Mendoza area of the Neuquén Basin based on
sequence stratigraphy. Kietzmann et al. (2016) also defined five composite depositional sequences from outcrops in the Chos Malal fold and thrust area, in Neuquén province.

Figure 2.3: Stratigraphy from the Neuquén Basin and sequences for the Lower Mendoza Mesosequence (modified from Kietzmann et al., 2016). A) Stratigraphic chart for the Neuquén Basin (after Legarreta and Gulisano, 1989). B) Lithostratigraphic subdivision and environmental interpretations of the Mendoza mesosequence in Neuquén Province. C) Depositional sequences identified by Mitchum and Uliana (1985) and Legarreta and Gulisano (1989) through seismic stratigraphic studies. D) Depositional sequences identified by Kietzmann et al. (2014) in outcrops from the southern Mendoza area of the Neuquén Basin.

The following stratigraphic characterization comprises only the Vaca Muerta – Quintuco system. Both of them are included in the Andico cycle of Groeber (1946), and in the Lower Mendoza Mesosequence of Legarreta and Gulisano (1989).

2.4 Mendoza Group (Stipanicic et al., 1968)

This unit was defined by Groeber (1946) as Mendociano, a term that was modified by Stipanicic (1969), who named it Mendoza Group. Legarreta and Gulisano (1989) include this unit within the Mendoza Mesosequence. Furthermore, these last authors divided the Mendoza Mesosequence in three shallowing – upward cycles: Lower Mendoza (upper Kimmeridgian – lower Valanginian), Middle Mendoza (lower Valanginian), and Upper Mendoza mesosequences (lower Valanginian – lower Barremian).

The Mendoza Group is limited on the base by the Intramalmic discordance (Gulisano et al., 1984b) or Araucanic (Stipanicic and Rodrigo, 1970a, b), of Kimmeridgian age. Meanwhile, the top is limited by the Pampatrilic discordance (Leanza, 2009), described first by Stipanicic and Rodrigo (1970b).

In central Neuquén Basin, the lower Mendoza mesosequence starts with the continental deposits of the Tordillo Formation (Kimmeridgian – lowermost lower Tithonian), which underlay marine basinal deposits of the Vaca Muerta Formation (uppermost lower Tithonian – upper Berriasian to lower Valanginian). To the east, the basinal facies change to shoreface deposits of the Quintuco Formation (upper Tithonian – lower Valanginian), to the sabkha deposits of the Loma Montosa Formation (lower Valanginian) and to the continental deposits of the Puesto Gonzalez Formation (lower Valanginian), forming a mixed carbonate – siliciclastic depositional system (Mitchum and Uliana, 1985; Carozzi et al., 1993) (Kietzmann et al., 2016).

2.4.1 Vaca Muerta Formation

Background

This unit was initially defined by Weaver (1931) to describe a group of Tithonian age beds, composed by dark shales and limestones, and characterized by a large fauna of ammonites. Later, based on the recommendation of Fosa Mancini et al. (1938) to use the denomination “Formacion (de la) Vaca Muerta”, the term was widely used in the geological literature by YPF geologists in the 40s decade (Leanza et al., 2011). Then, Groeber (1946) named it Vacamuertense, including it in the Andico cycle, and assigning it an early – middle Tithonian age.

Some authors like Marchese (1971) and Digregorio (1972) divided the unit into two different formations: the Vaca Muerta Formation (Tithonian) and the Quintuco Formation (Berriasian - lower Valanginian). These formations are easily distinguishable in the Sierra de la Vaca Muerta area, but are difficult to differentiate them when moving away from this locality. Lately, Leanza (1973) extends the Vaca Muerta Formation to the base of the Mulichinco Formation in Neuquén province, or to the base of the Chachao Formation in south Mendoza province (Leanza et al., 1977; Leanza 1993).

For the Rio Salado area, Leanza et al. (1977) suggested the use of Formacion Mendoza, term initially proposed by Dessanti (1973). In this manner, they took the Vaca Muerta and
Chachao formations to the categories of members, and established a new member, Cieneguitas, as a lateral equivalent of the Agrio Formation in the Neuquén province. These definitions have not been widely used in the literature, thus the Leanza (1973) definition was kept in use by following geologists.

**Areal Distribution**

The Vaca Muerta Formation is widely distributed in the Neuquén Basin, and extends from the Piedra del Aguila region (south of Neuquén province), through the Picun Leufu and Chacaico areas (east and west of Neuquén, respectively) (Leanza et al., 2011), reaching the north of Mendoza province (Legarreta et al., 1993), and in subsurface to the Rio Negro province (Gonzalez Tomassini et al., 2015).

**Lithology characteristics and sedimentary environment**

The Vaca Muerta Formation is composed of decimeter-scale rhythmic alternations of marls, bituminous shales and limestones (Scasso et al., 2002, 2005; Kietzmann et al., 2011, 2014, 2015), the latter described as bioclastic mudstones, wackestones, packstones and floatstones (Kietzmann et al., 2008; Kietzmann and Palma, 2009) (Fig. 2.4).

The Vaca Muerta Formation deposits generated from the inundation of the basin, when distal platform shales deposited under restricted and anoxic waters, favoring the preservation of organic matter (Legarreta and Uliana, 1991, 1996).

The sedimentary environment of this unit was traditionally interpreted as basin and slope deposits by various authors like Leanza (1973), Mitchum and Uliana (1985) and Legarreta and Uliana (1991, 1996) for the Embayment area. For the Chos Malal area, Kietzmann et al. (2016)
described the Vaca Muerta Formation as a distal low-gradient carbonate ramp. In Mendoza province, Kietzmann et al. (2008, 2011, 2014), Kietzman and Palma (2009a) and Kietzmann (2011), defined the unit as a homoclinal carbonate ramp system, showing basin, outer and middle ramp deposits.

The deposition depth of the Vaca Muerta Formation was estimated by Mitchum and Uliana (1985) based on seismic clinoforms, getting a bathimetric range of 250 m for the Embayment area. A similar value was obtained by Leanza et al. (2011) based on the fauna. For the south Mendoza province area, Kietzmann et al. (2008) estimated a depth less than 200 m, based on the radiolarian ratio proposed by Kiessling (1996), while Kietzmann and Palma (2009a) estimated a range between 30 and 120 m based on fauna analysis.

The Vaca Muerta Formation is characterized for a high organic matter content that makes it very interesting, since it acts as the most important source rock for conventional and unconventional hydrocarbon reservoirs of the Neuquén Basin (Legarreta et al., 1993). The high organic matter content (2% - 12%) might suggest dysaerobic – anaerobic sea-bottom conditions as a result of a stratified water column and positive hydrological balance in the Neuquén Embayment (Legarreta and Uliana, 1996). According to Spalletti et al. (2000) these conditions may be associated to an interchange of anoxic waters with the Pacific Ocean, where an oceanic upwelling was produced and thus, an important minimum oxygen layer was formed, which helped to preserve the organic matter. The Pacific upwelling could have affected the Neuquén Embayment with secondary gyres detached from the main oceanic current (Scasso et al., 2002, 2005).

The Vaca Muerta Formation presents a marked rhythmicity, formed by shale-limestone or marl-limestone rhyhtmites. The origin of this rhyhtmites is associated with carbonate material
transport from shallow areas, and its periodicity lies within the Milankovitch cycle frequencies band (Scasso et al., 2005; Kietmann et al., 2011, 2015).

**Stratigraphic relations and thickness**

To the north of the Huincul Dorsal, the base of the Vaca Muerta Formation shows a sharp contact with the continental deposits of the Tordillo Formation. On the south, the unit overlies the Quebrada del Sapo Formation, while around the Huincul Dorsal area it can be found on top of the Lotena and Lajas formation. In some areas, like Estancia Santa Isabel, the unit lies directly on Precuyo deposits (Cucchi and Leanza, 2005; Leanza et al., 2011).

The Vaca Muerta Formation underlies the Carrin Cura Formation near Catalan Lil river, and the Picun Leufu Formation near the Picun Leufu anticline area. In the Sierra de la Vaca Muerta area it changes to shoreface deposits of the Quintuco Formation. Meanwhile, in northern Neuquén it has a discordant contact (Intravalanginian unconformity) with the Mulichinco Formation (Leanza et al., 2011).

The thickness of the unit varies across the basin. At the depocenter it can reach a maxim of more than 600 m. In the Picun Leufu depocenter it attains thickness of more than 150 m. Meanwhile, in the Chiuidos and Huincul uplifts the unit shows local minimums (Sylwan, 2014). North of the Neuquén Basin, in Mendoza Province, several sections studied by Kietzmann et al. (2014) reached thickness from 130 to 350 m.

**Fossil content and age**

The Vaca Muerta Formation is characterized by a large fossil record, composed by ammonites, bivalves, radiolarians, foraminifers, and marine vertebrates (Spalleti et al., 1999).
Various Upper Jurassic – Lower Cretaceous ammonites biozones schemes were proposed. The first attempt was performed by Gerth (1925). It was then followed by numerous schemes, like the ones proposed by Burckhardt (1930), Windhausen (1931), and Weaver (1931). Finally, Leanza (1945), who performed a detailed study of the Upper Jurassic – Lower Cretaceous ammonite fauna in the Sierra Azul, Mendoza province, proposed a biostratigraphic scheme that is widely used today. This scheme was later adopted and improved by Leanza (1981a, 1981b, 1996). Thus, the ammonite biozonation scheme for the Tithonian – Valanginian in the Andean sector includes the *Virgatosphinctes mendozanus*, *Pseudolissoceras zitteli*, *Aulacosphinctes proximus*, *Windhauseniceras internispinosum*, *Corongoceras alternans* and *Substeuroceras koeneni* biozones for the Tithonian, the *Argentiniceras noduliferum*, and *Spiticeras damesi* for the Berriasian, and finally, the *Neocomites wichimanni*, *Lissonia riveroi*, *Olcostephanus (O.) atherstoni*, and *Pseudofavrella angulatiformis* biozones for the Valanginian.

Figure 2.4: Vaca Muerta Formation outcrops. A) Outcrops from Las Loicas, Mendoza province (taken from Benítez, 2015). B) Outcrops from Yesera del Tromen, Neuquén province.

Based in the large biostratigraphic information of the Vaca Muerta Formation, the unit was defined as early Tithonian – early Valanginian in the Neuquén province (Leanza, 1973,

### 2.4.2 Quintuco Formation

**Background**

The Quintuco Formation was originally defined by Weaver (1931) to characterize Early Cretaceous dark shales and limestones, which is enriched in sandstones at the top. The Quintuco shales and the limestones and carbonaceous shales described by Weaver (1931) in the Neuquén Basin depocenter and in the Lotena and Picun Leufu areas, respectively, were difficult to differentiate from the lower Vaca Muerta Formation for mapping purposes (Leanza et al., 2011). This situation was advertised by Leanza (1973) who grouped the latter in the Picun Leufu Formation, which spans from Middle Tithonian to Early Berriasian, and extends through the southeast of the Neuquén Basin. Furthermore, Leanza (1973) proposed to extend the Vaca Muerta Formation to the base of the Mulichinco Formation in depocenter areas (Leanza et al., 2011).

The term “Quintuco” has been used for different meanings, both for surface and subsurface descriptions. Quintuco *sensu stricto* (s.s.) is a term used to describe nearshore siliciclastic outcrops covering the black shales of the Vaca Muerta Formation along the basin.
While, on subsurface, the name Quintuco Formation is employed to describe all the sediments that go from the top of the Vaca Muerta Formation to the base of the Centenario Formation (Leanza et al., 2011).

**Areal distribution**

The new definition of this unit proposed by Leanza et al. (2011) reduced its geographic distribution only to central Neuquén province expositions, where outcrops in the Sierra de la Vaca Muerta highlight.

**Lithology characteristics and sedimentary environment**

The Quintuco Formation was described by Weaver (1931) as being composed of dark shales and limestones, with gradual sandstone enrichment towards the top. Later, Leanza et al. (2011) proposed a new lithological characterization. These authors analyzed the unit in the Sierra de la Vaca Muerta, where it was described as a upward-shallowing succession consisting of marine siliciclastic deposits with storm, tidal and wave influence. In the same area, Olivo et al. (2016) described prodelta, delta front, and delta plain facies, dominated by fluvial process and slightly influenced by waves (Fig. 2.5). Along the Chos Malal fold and thrust belts, Kietzmann et al. (2016) interpreted the Quintuco Formation as a mixed siliciclastic and carbonate shelf depositional system.

**Stratigraphic relations and thickness**

The basal contact of the Quintuco Formation is gradual and regionally challenging to identify (Sylwan, 2014). In Sierra de la Vaca Muerta the Quintuco s.s. Formation lays
concordantly on top of the Vaca Muerta Formation, while the top of the unit is associated with a regional discontinuity (Intravalanginian unconformity) which separates the deltaic deposits of the Quintuco s.s. Formation from the continental deposits of the Mulichinco Formation.

To the east of the Mallin Quemado area, the unit shows a thickness of 350 m. In Puerta Quintuco it reaches less than 30 m, while in depocenter areas, the unit is absent.

**Fossil content and age**

Fossil content in the unit is scarce, formed mainly by bivalves, ammonites, and fossil traces associated with Skolithos, Repichnia, and Cruziana ichnofacies.

Based on their new lithological characterization, Leanza et al. (2011) proposed a late Berriasian – early Valanginian age for the Quintuco Formation. In the Chos Malal fold and thrust belts sections, based on ammonite biostratigraphic data, Kietzmann et al. (2016) dated the unit as early Valanginian (uppermost part of the *Neocomites wichimani* and *Lissonia riveroi* biozones).

Figure 2.5: Quintuco Formation outcrops from the Sierra de la Vaca Muerta area (taken and modified from Olivo et al., 2016). A) Sand channel deposits. B) Wave ripples in sandstones. C) Cross-stratified sandstones. (Yellow squares show reference scales).
2.5 Structure

The Neuquén Basin presents various structural features such as the Agrio fold and thrust belt, the Huincul Dorsal, and the Chihuidos and Entre Lomas highs, among others. These last two structures surround the study area (Fig. 2.6).

![Figure 2.6: Structural framework in the area surrounding the study area (blue square) (modified from Curia et al., 2018a).](image)

The Agrio fold and thrust belt is a strip of outcropping Jurassic and Lower Cretaceous rocks, some 50 km wide (Ramos, 1978). Across the belt, folds and reverse faults trend either north or northwest (Cobbold and Rossello, 2003). Early workers interpreted the structure as thin-skinned folding, due to detachment on evaporite or shale (Bracaccini, 1970a; Ramos, 1978; Allen et al., 1984). While recent research has proposed a thick-skinned deformation, due to reactivation of Mesozoic normal faults (Manceda and Figueroa, 1995; Zapata et al., 1999).

The Huincul Dorsal is a complex structure that presents a high angle trend to the orogen. It is formed by a northwest-dipping normal fault of Triassic to Jurassic age that was reversed in
the Late Cretaceous, separating the basin in two during Albian times (Cobbold and Rosello, 2003). The dorsal is a good candidate for a structural trap; in fact, several oil fields follow the crest (Cruz et al., 2000).

Los Chihuidos and Entre Lomas fault systems played a key role in the tectonic history of the Neuquén Embayment. Both were formed during the Jurassic and Early Cretaceous, but with different local stress and uplift histories. The Los Chihuidos High is a series of grabens and half-grabens formed by crustal attenuation during Late Triassic – Jurassic rifting (Vergani et al., 1995), which were inverted by transpression during the Jurassic and Early Cretaceous (Mosquera and Ramos, 2006). It is considered a good prospect with many oil fields found on its crest (Cobbold and Rosello, 2003). The Entre Lomas system consists of a series of NW-trending symmetric anticlines and associated E-W-trending structures. This system extends 200 km from north to south and is 100 km across. During Jurassic times, the western flank of the Entre Lomas system was uplifted by inversion of half-grabens. In the Late Cretaceous and then during the Miocene, inversion of structures were more pronounced and anticlines formed (Mosquera and Ramos, 2006).

Even though the study area is surrounded by structural highs, it does not present a high degree of structural complexity. However, some normal and strike-slip faults can be identified, affecting different stratigraphic levels (Curia et al., 2018a).

2.6 Summary of the Vaca Muerta Project

As mentioned in the introduction chapter, RCP’s Vaca Muerta Project began in 2013 with the operator Wintershall as sponsor. For this project five Master’s of Science thesis have been written to date, four of them being on geophysics and one on geology. The general objective of
the project is the exploration and development of the Vaca Muerta Formation (VMF) using an interdisciplinary approach of geology, geophysics, and engineering. Core, logs, seismic and completion data has been widely used, and it is still being used, to characterize the VMF play with the objective of improving well placement, landing points, and also help to increase production.

The first two students were Jorge Fernandez-Concheso and Kyla Bishop. Fernandez-Concheso (2015) thesis was based on a narrow-azimuth, regional P-wave seismic volume. He performed post-stack and pre-stack inversions for geomechanical parameters estimation, in order to be able to analyze the variability of these and how they relate to lithology, stress state and TOC. He concluded that rock composition has a strong influence on the mechanical behavior of the VMF.

Bishop (2015) study was based on well log analysis. She worked with 5 wells, inside and outside of our study area. Composition analysis were performed to study the vertical variation of minerarology along the formation. Using borehole images such as Oil Based Micro Imager (OBMI) and Formation Micro Imager (FMI) tools, she interpreted pre-existing natural fractures, stress directions, and discontinuities. Her work concluded that clay content is fairly constant along the VMF, while silica, carbonate and TOC show metre scale variability. From image logs she observed that the Middle Vaca Muerta (MVM) is the most fractured section, with both conductive and resistive fractures being present. Conductive fractures described in Well G show N50° and N145°. Because of the hydrocarbon saturation, presence of open fractures, and its brittleness, Bishop suggested MVM as a highly prospective zone.
Barbosa-Murillo (2017) was based on well log analysis and laboratory tests. She built an anisotropic model for Well G and integrated it with previous natural fracture analysis done by Bishop (2015), microseismic and production data.

Convers-Gomez (2017) built different correlations between Young’s Modulus (YM), Poisson’s Ratio (PR), and TOC. He also predicted lateral and vertical heterogeneity of rock properties in the VMF using neural networks. The conclusion of his work is that there is a strong correlations between brittleness and YM, however, PR shows low correlation with brittleness and YM, thus for the VMF only YM is sufficient as a brittleness indicator. Also, mapping geomechanical parameters, he concluded that the most prospective zones are located in the MVM and in a thin section between Middle Vaca Muerta and Lower Vaca Muerta (LVM).

Johnson (2017) performed geostatistical analysis of well logs, seismic inversions, and microseismic. His thesis concluded that stimulation of the rock volume correlates with TOC, YM, bulk modulus, and shear modulus. He also assessed the relationship between geomechanical parameters and microseismic events observed in Well G and Well I.

Current projects are based on seismic anisotropy using wide-azimuth and multicomponent seismic analysis. This thesis’ goal, as mentioned in the introduction, is to build well based geomechanical models for all the wells in the block to better characterize the vertical variation of the reservoir. Also, perform anisotropy and azimuth analysis in relation to the presence of natural fractures and stresses using wide-azimuth seismic data. On the other hand, Corwin’s studies are focused on a joint PP-PS inversion using the newly acquired multicomponent seismic data.
3.1 Vaca Muerta – Quintuco Sequence

The Vaca Muerta – Quintuco system has been studied in a sequential manner by several authors. Mitchum and Uliana (1985) defined nine depositional sequences (A to I) for the lower Tithonian to lower Valanginian interval (Kietzmann et al., 2016). These authors integrated available subsurface data and interpreted a progradation of the system from SE, near Neuquén city subsurface, to NW, near the Chiuidos Dorsal (Fig. 3.1). This set of sequences is composed by three main stages: an Early to Middle Tithonian ramp, a Late Tithonian to Berriasian slope interval, and finally, a platform interval for the Valanginian sequences (Leanza et al., 2011).

![Sketched E-W cross section based on a 2D seismic montage covering approximately 150 km (taken from Sylwan, 2014 and modified after Leanza et al., 2011).](image)

Figure 3.1: Sketched E-W cross section based on a 2D seismic montage covering approximately 150 km (taken from Sylwan, 2014 and modified after Leanza et al., 2011).

Legarreta and Gulisano (1989) included the previous set of sequences (Mi1 to Mi9) within the lower Mendoza mesosequence (Fig. 3.2). The first sequence defined by these authors (Mi1) includes the Tordillo Formation and the basal section of the Vaca Muerta Formation, while the
top of the last depositional sequence of the system is marked by the Intravalanginian unconformity, which separates the Vaca Muerta – Quintuco system from the Mulichinco Formation (Gulisano et al., 1984a; Leanza, 2009; Schwarz and Buatois, 2012) (Kietzmann et al., 2016).

More currently, Gonzalez Tomassini et al. (2015) who studied the subsurface of central Neuquén embayment, recognized 5 transgressive – regressive sequences for the Vaca Muerta – Quintuco interval. A similar number of sequences were recognized by Kietzmann et al. (2016), who defined 5 composite depositional sequences and 15 high-frequency depositional sequences in the Chos Malal fold and thrust belt area. For the southern Mendoza sector, Kietzmann et al. (2014) also identified 5 composite depositional sequences (CS-1 to CS-5) and 15 high-frequency depositional sequences (HFS-1 to HFS-15), which together show a regressive trend (Fig 3.2).

![Depositional sequences](Figure 3.2: Depositional sequences identified by Mitchum and Uliana (1985) and Legarreta and Gulisano (1989) through seismic stratigraphy studies, and depositional sequences identified by Kietzmann et al. (2014) in outcrops from the southern Mendoza area of the Neuquén Basin.)

### 3.2 Petrophysics

Argentina has large unconventional hydrocarbon resources estimated at 27 billion barrels of crude oil (BBO) for shale oil (EIA, 2013) and 800 trillion cubic feet (TCF) for shale and tight gas (Barredo and Stinco, 2014). It is estimated that the Vaca Muerta Formation has more than 16
BBO of risked technically recoverable oil (EIA, 2013) and 220 TCF of recoverable gas (Barredo and Stinco, 2014).

The Vaca Muerta Formation has exceptional characteristics that make it one of the most important shale oil/gas plays in the world. The areal distribution of the play reaches about 30,000 km², with a variable thickness that goes from 30 m to more than 500 m in the West sector of the basin (Table 3.1). Taking into account a total organic carbon (TOC) cut off of 2%, the play thickness reduces to 250 m. This last characteristic is one of the most remarkable features of the play since no other shale play in the world presents such value (Askenazi et al., 2013).

Table 3.1: Comparison between the Vaca Muerta Formation and the main US shale plays (taken from Askenazi et al., 2013).

<table>
<thead>
<tr>
<th>Shale Play</th>
<th>Barnett</th>
<th>Marcellus</th>
<th>Fayetteville</th>
<th>Haynesville</th>
<th>Woodford</th>
<th>Lewis</th>
<th>Eagle Ford</th>
<th>Vaca Muerta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Age (Ma)</td>
<td>320</td>
<td>410</td>
<td>330</td>
<td>150</td>
<td>370</td>
<td>85</td>
<td>95</td>
<td>140</td>
</tr>
<tr>
<td>Extension (km²)</td>
<td>13000</td>
<td>250000</td>
<td>23000</td>
<td>23000</td>
<td>28900</td>
<td>26000</td>
<td>5000</td>
<td>30000</td>
</tr>
<tr>
<td>Depth (km)</td>
<td>2.0 - 2.6</td>
<td>1.2 - 2.6</td>
<td>0.3 - 2.1</td>
<td>3.2 - 4.2</td>
<td>1.8 - 3.4</td>
<td>0.9 - 1.8</td>
<td>1.2 - 4.2</td>
<td>2.0 - 3.5</td>
</tr>
<tr>
<td>Pay (m)</td>
<td>15 - 60</td>
<td>15 - 60</td>
<td>15 - 60</td>
<td>61</td>
<td>35 - 67</td>
<td>61 - 92</td>
<td>25 - 100</td>
<td>50 - 350</td>
</tr>
<tr>
<td>Kerenken Type</td>
<td>II</td>
<td>II - III</td>
<td>II - III</td>
<td>III</td>
<td>II</td>
<td>II - III</td>
<td>II</td>
<td>II</td>
</tr>
<tr>
<td>Thermal Maturation (% Ro)</td>
<td>0.5 - 1.5</td>
<td>0.5 - 2.0</td>
<td>1.0 - 3.0</td>
<td>0.94 - 2.62</td>
<td>0.5 - 3.0</td>
<td>1.7 - 1.9</td>
<td>0.5 - 2.2</td>
<td>0.5 - 2.6</td>
</tr>
<tr>
<td>TOC (%)</td>
<td>3.0 - 6.0</td>
<td>3.0 - 12</td>
<td>4.0 - 9.8</td>
<td>4.0 - 10</td>
<td>0.6 - 1.0</td>
<td>0.45 - 2.5</td>
<td>4.5 - 5.5</td>
<td>2.0 - 12</td>
</tr>
</tbody>
</table>

Some authors have divided the Vaca Muerta Formation into two distinct sections: Lower Vaca Muerta (LVM) and Upper Vaca Muerta (UVM) (Askenazi et al., 2013; Cuervo et al., 2014; Lazzari et al., 2014; Sagasti et al., 2014; Sylwan, 2014). The first presents higher TOC (3 to 11%, media of 6.1%) and gamma ray (GR) values, with a thickness of 5 – 35 m; the latter shows
lower TOC (0.5 to 5%, media of 2.05%) and GR values, with thickness of up to 600 m (Sylwan, 2014).

Other authors have divided the unit into three sections: Lower Vaca Muerta (LVM), corresponding to an inner carbonate platform that consists mostly of marls, carbonates and limestones; a Middle Vaca Muerta (MVM), related to slope deposits, with higher siliciclastic content than the other two sections; and Upper Vaca Muerta (UVM), which returns to a carbonate platform environment (Garcia et al., 2013; Ejofodomi et al., 2013, 2014; Badessich et al., 2016).

The kerogen type that constitutes the Vaca Muerta Formation is not homogeneous and it varies depending on the distance to the coast and depth of deposition. The unit is composed mainly by amorphous organic matter, associated with marine microplankton and scarce participation of terrestrial material (Uliana et al., 1999). According to Pepper and Corvi (1995) organofacies classification, this kerogen may be considered of type B and A, respectively. These also can be equivalent to type II and II/II “S” kerogen from Tissot et al. (1974) classification, and later contribution of Orr (1986) (Sylwan, 2014).

Estimating the thermal maturity is complicated because it is problematic to find vitrinite particles, since the Vaca Muerta Formation was deposited in a deep marine environment (Sylwan, 2014). Other methods to obtain a vitrinite reflectance equivalent (VRE) may be used. One possible way is the VRE calculation based on Tmax values, established by Jarvie et al. (2001). Another possible method is the estimation of the gas-oil ratio (GOR). This value rises as source rock matures, thus giving an idea of the maturity of the rock. Yet, another way to estimate the maturity of the source rock is the transformation ratio (TR) developed by Jarvie et al. (2007), in which the percentage of generative organic matter that has been converted to hydrocarbon is
calculated. Sylwan (2014) constructed three maps for these three maturity method for the Vaca Muerta Formation (Fig. 3.3). According to this author, the shapes of the three maps (VRE, GOR, TR) are similar, reflecting the thermal maturity of the basin.

Figure 3.3: Thermal maturity of the Vaca Muerta Formation. A) Vitrinite reflectance equivalent (VRE%) map. B) Gas-oil ratio (GOR) map made out of values taken from well initial production (unit: m$^3$/m$^3$). C) Transformation ratio (TR%) (modified from Sylwan 2014).

Sylwan (2014) also estimated the volume of hydrocarbon generated from the Vaca Muerta Formation, using the method of Schmoker (1994). For the LVM, this author obtained a value of 50000 m$^3$/km$^2$ per meter of source rock of generated hydrocarbon for the basinal sector of the Embayment region. Total hydrocarbon generated for this section reaches values up to 1.2 million m$^3$/km$^2$. The UVM shows values up to 12,000 m$^3$/km$^2$ per meter of source rock for the central sector of the basin. This section generated more than 6 million m$^3$/km$^2$ of hydrocarbon generated. Even though the generative quality of the UVM is less than the LVM, the thickness of the UVM allowed the generation of larger amounts of hydrocarbon than the LVM (Sylwan, 2014).
Wavrek et al. (1994), Villar et al. (1998) and Legarreta et al. (1999) recognized four types of oil generated by the Vaca Muerta Formation: type A-1 (Embayment region), type A-2 (Northeast Platform), type A-3 (north of Malargue-Agrio fold and thrust belt), and type A-4 (Picun Leufu depocenter). Type A-1 oil are light, mature, with an API gravity from 30 to 45, and low sulfur content (<0.5%). Type A-2 are heavier oils (25 – 35 API gravity), with higher sulfur content (0.5 to 3.0%). Oil type A-3 presents API gravity from 15 to 40 and sulfur content up to 3%. Finally, the A-4 oil type show low API values (15 – 25) and sulfur levels between 1 to more than 3% (Sylwan, 2014).

Table 3.2: Petrophysical information of the VMF (taken from Herrero et al., 2014).

<table>
<thead>
<tr>
<th></th>
<th>Min</th>
<th>Average</th>
<th>Max</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top VM (m)</td>
<td>2989</td>
<td>3039</td>
<td>3089</td>
</tr>
<tr>
<td>Thickness (m)</td>
<td>100</td>
<td>110</td>
<td>125</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>5</td>
<td>6.5</td>
<td>8</td>
</tr>
<tr>
<td>Matrix Permeability (md)</td>
<td>60</td>
<td>134</td>
<td>218</td>
</tr>
<tr>
<td>TOC (%)</td>
<td>0.8</td>
<td>3.5</td>
<td>10</td>
</tr>
<tr>
<td>Kerogen type</td>
<td>II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ro (%)</td>
<td>0.78</td>
<td>0.85</td>
<td>0.94</td>
</tr>
<tr>
<td>Vstatic (Mpsi)</td>
<td>0.23</td>
<td>0.26</td>
<td>0.28</td>
</tr>
<tr>
<td>Gstatic (Mpsi)</td>
<td>0.66</td>
<td>1.8</td>
<td>8.45</td>
</tr>
<tr>
<td>Estatic (Mpsi)</td>
<td>1.25</td>
<td>4</td>
<td>3.29</td>
</tr>
<tr>
<td>Pore Pressure Gradient (psi/ft)</td>
<td>0.74</td>
<td>0.78</td>
<td>0.82</td>
</tr>
<tr>
<td>API</td>
<td>23</td>
<td>24</td>
<td>26</td>
</tr>
<tr>
<td>GOR</td>
<td>200</td>
<td>225</td>
<td>250</td>
</tr>
</tbody>
</table>

3.3 Geomechanics

The Vaca Muerta Formation can be found from outcrops to more than 4,000 m deep. Taking into account the usual depth where the horizontal wells are being landed by YPF, the Vaca Muerta reservoir is located between 2,000 – 3,500 m depth. The play is deeper than other US shales plays and it is overpressured. Pore pressure has been estimated between 0.5 psi/ft in
the basin borders, and 1.1 psi/ft, in the basin center (Askenazi et al., 2013). Garcia et al. (2013) and Fantin et al. (2014) estimated pressure gradients between 0.65 psi/ft up to 1.02 psi/ft, with media around 0.82 psi/ft for the Lower Vaca Muerta section. Cuervo et al. (2014) estimated pore pressures around 1.02 psi/ft for the El Trapial area. These authors interpreted overpressures as associated with the large amount of hydrocarbon generated from kerogen.

The stress regime throughout the majority of the Neuquén Basin is strike-slip but transitions to normal, and decreases in stress anisotropy to the East, away from the influence of the Andes Mountains (Garcia et al., 2013). The magnitude of the maximum horizontal stress (S_H) decreases gradually towards the East, where some areas with normal stress regimes are present (Fig. 3.4). In addition, S_H tends to show an W-E direction in response to the compressive force created by on-going subduction and uplift of the Andes to the West, with some areas showing rotations due to local changes related to structures in the area.

![Stress data from Garcia et al. (2013), showing a transition from normal in the far East of the basin to full strike-slip to the West, where thrust and reverse faulting may also occur. Also, stress orientations for different areas are shown.](image)

Figure 3.4: Stress data from Garcia et al. (2013), showing a transition from normal in the far East of the basin to full strike-slip to the West, where thrust and reverse faulting may also occur. Also, stress orientations for different areas are shown.

Cuervo et al. (2014) obtained an overburden gradient of 1.09 psi/ft for El Trapial area. They also observed high horizontal stress anisotropy in the area, with S_H and S_h differences

<table>
<thead>
<tr>
<th>Zone</th>
<th>Pore Gradient, psi/ft</th>
<th>S_h, psi/ft</th>
<th>S_H, psi/ft</th>
<th>S_v, psi/ft</th>
<th>Stress Regime</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.83</td>
<td>0.91</td>
<td>1.03</td>
<td>1.06</td>
<td>Normal to strike slip</td>
</tr>
<tr>
<td>2</td>
<td>0.65</td>
<td>0.82</td>
<td>1.08</td>
<td>1.06</td>
<td>Normal to strike slip</td>
</tr>
<tr>
<td>3</td>
<td>0.75</td>
<td>0.85</td>
<td>0.92</td>
<td>1.06</td>
<td>Normal</td>
</tr>
<tr>
<td>4</td>
<td>0.85</td>
<td>0.92</td>
<td>1.14</td>
<td>1.06</td>
<td>Strike slip</td>
</tr>
</tbody>
</table>
around 10%. This anisotropy is mainly observed in central and west regions of the Neuquén Basin, and is related with the Andean tectonism (Guzman et al., 2007).

The study of natural fractures in unconventional shale reservoirs is of main importance because they interact with hydraulic fractures, and they may affect production in a detrimental or beneficial way (Gale et al., 2014). Natural fractures in the Vaca Muerta Formation were identified by many authors using FMI and seismic data (Lazzari et al., 2014; Bishop, 2015; Rimedio et al., 2015; Cruz et al., 2017). All these authors described different set of fractures, mainly oriented NE and SW.
CHAPTER 4
WELL BASED GEOMECHANICAL MODELS

It is well known that detailed mechanical models from vertical wells are needed to decide the best landing zones for horizontal wells, and also to improve completion. Thus, in this thesis anisotropic geomechanical models for the three wells located in the block were built. Both vertical and horizontal mechanical parameters were calculated using well logs and laboratory measurements. Also, vertical, maximum and minimum horizontal stresses were obtained and calibrated using fracture tests.

4.1 Introduction

According to linear elasticity theory, strain and stresses are related as (Sosa Massaro et al., 2017):

\[ \sigma_{ij} = C_{ijkl} \epsilon_{kl} \] \hspace{1cm} 4.1

\[ \epsilon_{ij} = S_{ijkl} \sigma_{kl} \] \hspace{1cm} 4.2

where \( C_{ijkl} \) is known as the stiffness tensor and \( S_{ijkl} \) is the compliance tensor \( (S_{ijkl}=C^{-1}_{ijkl}) \), \( \sigma_{ij} \) is the stress tensor, and \( \epsilon_{ij} \) is the strain tensor. The simplest strain-stress model assumes a linear relationship between stresses and the corresponding deformations (Fig. 4.1) (Sosa Massaro et al., 2017).
The most general linear elastic anisotropic material has 21 independent stiffness constants from the original 81. Using the Voight notation (Voigt, 1928), the 21 $C_{ijkl}$ constants can be expressed as $C_{\alpha\beta}$ (Thomsen, 1986; Radovitzky, 2003):

$$
\begin{bmatrix}
\sigma_{11} \\
\sigma_{22} \\
\sigma_{33} \\
\sigma_{23} \\
\sigma_{13} \\
\sigma_{12}
\end{bmatrix} =
\begin{bmatrix}
C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\
C_{21} & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\
C_{31} & C_{32} & C_{33} & C_{34} & C_{35} & C_{36} \\
C_{41} & C_{42} & C_{43} & C_{44} & C_{45} & C_{46} \\
C_{51} & C_{52} & C_{53} & C_{54} & C_{55} & C_{56} \\
C_{61} & C_{62} & C_{63} & C_{64} & C_{65} & C_{66}
\end{bmatrix}
\begin{bmatrix}
\varepsilon_{11} \\
\varepsilon_{22} \\
\varepsilon_{33} \\
\varepsilon_{23} \\
\varepsilon_{13} \\
\varepsilon_{12}
\end{bmatrix}
$$

4.3

The number of constants can be further reduced when the material presents symmetries in its structure. Here it is considered: Vertical Transverse Isotropy (VTI), Horizontal Transverse Isotropy (HTI) and Orthorhombic (Orthotropic) media. The two most common types of anisotropy are VTI and HTI (Fig. 4.2). VTI is often caused by fine horizontal layering sediments, HTI common mechanism is vertical aligned fractures embedded in an isotropic background medium, while orthorhombic anisotropy is a combination of both VTI and HTI, vertical aligned fractured embedded in a finely layered background (Jenner, 2011).
Figure 4.2: Anisotropic mechanical models. Vertical Transverse Isotropy (VTI) model and Horizontal Transverse Isotropy (HTI) model. In the case of VTI, properties in the horizontal plane ($X_1 - X_2$) are isotropic, while they are anisotropic in the vertical plane ($X_2 - X_3$). In the case of HTI, properties are isotropic in the vertical plane ($X_2 - X_3$), while they are anisotropic in the horizontal plane ($X_1 - X_2$) (taken from Danek et al., 2010).

Because of the horizontal layering of the Vaca Muerta Formation, the unit is widely known to present a strong VTI behavior (Fyrdman et al., 2016), which can be characterized using six independent elastic parameters (Ejofodomi et al., 2014), represented by the following matrix (Fjaer, 2008):

$$
\mathbf{C}^R_{ij} = \begin{bmatrix}
C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\
C_{12} & C_{11} & C_{13} & 0 & 0 & 0 \\
C_{13} & C_{13} & C_{33} & 0 & 0 & 0 \\
0 & 0 & 0 & C_{44} & 0 & 0 \\
0 & 0 & 0 & 0 & C_{44} & 0 \\
0 & 0 & 0 & 0 & 0 & C_{66}
\end{bmatrix}
$$

The five independent dynamic stiffness coefficients for a VTI model can be calculated from laboratory measurements using the following equations (Sosa Massaro et al., 2017):
\( C_{33}^{\text{dyn}} = a \rho V_p^2(0^\circ) \)  \hspace{1cm} 4.5

\( C_{44}^{\text{dyn}} = a \rho V_s^2(0^\circ) \)  \hspace{1cm} 4.6

\( C_{11}^{\text{dyn}} = a \rho V_p^2(90^\circ) \)  \hspace{1cm} 4.7

\( C_{66}^{\text{dyn}} = a \rho V_s^2(90^\circ) \)  \hspace{1cm} 4.8

\( C_{12}^{\text{dyn}} = C_{11}^{\text{dyn}} - 2C_{66}^{\text{dyn}} \)  \hspace{1cm} 4.9

\[
C_{13}^{\text{dyn}} = C_{44}^{\text{dyn}} + \frac{1}{2} \left[ C_{11}^{\text{dyn}} + 2C_{44}^{\text{dyn}} + C_{33}^{\text{dyn}} - 8 \rho a (V_s(45^\circ))^2 - 2(C_{11}^{\text{dyn}} - C_{33}^{\text{dyn}}) \right]^{\frac{1}{2}}
\]  \hspace{1cm} 4.10

where \( V_p(0^\circ) \) is P-wave velocity normal to bedding, \( V_p(90^\circ) \) is P-wave velocity parallel to bedding, \( V_s(0^\circ) \) is S-wave velocity normal to bedding, \( V_s(90^\circ) \) is S-wave parallel to bedding, \( V_p(45^\circ) \) is P-wave velocity at 45\(^\circ\) to bedding (all velocities are in ft/\( \mu \)s), \( \rho \) is the bulk density (in g/cm\(^3\)), and \( a \) is a conversion constant factor to PSI, whose value is 0.01347445.

On the other hand, dynamic stiffness coefficients were calculated from well data using sonic logs and different correlations obtained from dynamic laboratory measurements from cores of Well G. \( C_{33} \) and \( C_{44} \) were obtained using sonic and density logs; \( C_{11}, C_{66}, \) and \( C_{13} \) were calculated using correlations from dynamic laboratory measurements (Fig. 4.3); \( C_{12} \) was calculated using \( C_{11} \) and \( C_{66} \).
Figure 4.3: Correlations between $C_{11}$, $C_{33}$, $C_{44}$, $C_{66}$, $C_{13}$ and $C_{12}$ built from dynamic laboratory measurements from cores of Well G (with interception in “0”).

The above correlations from dynamic laboratory measurements show good agreement.

With this, dynamic stiffness coefficients can be calculated using the following equations:

\[ C_{33}^{\text{dyn}} = \frac{13474.45\rho}{DTC^2} \]  \hspace{1cm} 4.11

\[ C_{44}^{\text{dyn}} = \frac{13474.45\rho}{DTS^2} \]  \hspace{1cm} 4.12

\[ C_{11}^{\text{dyn}} = 1.1472C_{33}^{\text{dyn}} \]  \hspace{1cm} 4.13
\[ C_{66}^{\text{dyn}} = 1.1612 C_{44}^{\text{dyn}} \]  \hspace{1cm} (4.14) \\

\[ C_{12}^{\text{dyn}} = C_{11}^{\text{dyn}} - 2 C_{66}^{\text{dyn}} \]  \hspace{1cm} (4.15) \\

\[ C_{13}^{\text{dyn}} = 0.8992 C_{12}^{\text{dyn}} \]  \hspace{1cm} (4.16)

where \( \rho \) is density, DTC is compressional slowness and DTS is shear slowness from well log data. Dynamic elastic moduli are measured using ultrasonic procedures which main disadvantage is that it measures mechanical parameters indirectly (Martinez-Martinez et al., 2012), considering that the velocity of sound propagation through a material relates to its mechanical parameters. Industry tends to use dynamic calculations using sonic and density logs as an approximation to estimate elastic parameters (Zunino et al., 2014). However, static and dynamic properties must be calibrated using empirical correlations or by using laboratory-derived values (Gallego and Muzzio, 2014). Static measurements are much more indicative of the mechanical properties of the reservoir, and thus they are a better representation of the reservoir’s characteristics (Yale and Jamieson, 1994).

Using static Young’s modulus (YM) and Poisson’s ratio (PR) measured in laboratory tests, static stiffness coefficients can be calculated as follows (Sosa Massaro et al., 2017):

\[
C_{11}^{\text{sta}} = \frac{E_h^{\text{sta}} \left( 1 - \frac{E_{v}^{\text{sta}}}{E_v} v_v^{\text{sta}} \right)}{(1 + v_h^{\text{sta}}) \left( 1 - 2 \frac{E_{v}^{\text{sta}}}{E_v} v_v^{\text{sta}} - v_h^{\text{sta}} \right)}
\]  \hspace{1cm} (4.17) \\

\[ C_{12}^{\text{sta}} = C_{11}^{\text{sta}} - 2 C_{66}^{\text{sta}} \]  \hspace{1cm} (4.18)
\[ C_{13}^{sta} = \frac{E_h^{sta} v_v^{sta} (v_h^{sta} + 1)}{(1 + v_h^{sta}) \left(1 - 2 \frac{E_h^{sta}}{E_v^{sta}} v_v^{sta2} - v_h^{sta}\right)} \]  

\[ C_{33}^{sta} = \frac{E_v^{sta} \left(1 - v_h^{sta2}\right)}{(1 + v_h^{sta}) \left(1 - 2 \frac{E_h^{sta}}{E_v^{sta}} v_v^{sta2} - v_h^{sta}\right)} \]  

\[ C_{44}^{sta} = \frac{E_v^{sta}}{2(1 + v_v^{sta})} \]  

\[ C_{66}^{sta} = \frac{E_h^{sta}}{2(1 + v_h^{sta})} \]  

where \( E_v^{sta}, E_h^{sta}, v_v^{sta} \) and \( v_h^{sta} \) are the static elastic properties at both vertical and horizontal directions.

Finally, using dynamic and static stiffness coefficients, both dynamic and static YM and PR were estimated using the following equations (Frydman et al., 2016; Sosa Massaro et al., 2017):

\[ E_h = \frac{(C_{11} - C_{12})(C_{11} C_{33} - 2C_{13}^2 + C_{12} C_{33})}{C_{11} C_{33} - C_{13}^2} \]  

\[ E_v = C_{33} - \left(\frac{2C_{13}^2}{C_{11} + C_{12}}\right) \]  

\[ PR_h = \frac{C_{13}}{C_{11} + C_{12}} \]  

\[ PR_v = \frac{C_{12} C_{33} - C_{13}^2}{C_{11} C_{33} + C_{13}^2} \]
4.2 Stress Logs Calculation

Next, dynamic and static stiffness coefficients, vertical and horizontal dynamic and static YM and PR calibrated with laboratory measurements are shown for Well G (Fig. 4.4):

Figure 4.4: Mechanical parameters for Well G. Dots represent calibration points measured in laboratory. Track 1: Vaca Muerta Formation divisions; Track 2: Lithology from gamma ray spectroscopy tool; Track 3: Dynamic stiffness coefficients in MPSI; Track 4: Static stiffness coefficients in MPSI; Track 5: Dynamic horizontal and vertical Young’s modulus in MPSI; Track 6: Static horizontal and vertical Young’s modulus in MPSI; Track 7: Dynamic horizontal and vertical Poisson ratio; Track 8: Static horizontal and vertical Poisson ratio.
All the curves show good calibration with laboratory measurements. However, some core measurements show a stiffer behavior than the calculated curves for both dynamic and static properties. This could be related to differences in frequency measurements from well logs and laboratory (Sosa Massaro et al., 2017; Pateti and Ortega, 2018).

Both dynamic and static stiffness tensors and YM show that stiffness increases toward the UVM. As mentioned in many previous studies, it is expected that brittle lithologies, like limestones, will show high YM and low PR, while ductile lithologies like shales will display low YM and high PR (Barree et al., 2009). LVM shows a more ductile behavior, with static YM below 2.5 MPSI. MVM shows values around 4 MPSI, while in the UVM, static YM reaches values close to 8 MPSI. Same results were described for the VMF in different areas of the basin (Garcia et al., 2013; Ejofodomi et al., 2014; Gallego and Muzzio, 2014; Varela et al., 2016; Convers-Gomez, 2017; Sosa Massaro et al., 2017, 2018a). Looking at the petrophysics log, it can be seen that clay content is constant along the VMF, however carbonate, clastics and TOC content vary (Bishop, 2015). LVM presents the lowest carbonate content and the highest TOC values. This composition would make the rock to behave in a more ductile manner, something that explains the low YM values seen in this section. Carbonate content increases upwards, while TOC decreases. MVM presents average contents of carbonate and TOC, while UVM presents the highest carbonate values and lowest TOC contents. This explains why UVM shows the highest YM values and thus it will behave in a more brittle manner.

On the other hand, PR is interesting. Previous authors described high PR for middle and upper Vaca Muerta and low PR for the lower section (Gallego and Muzzio, 2014; Varela et al., 2016, Convers-Gomez, 2017). This characteristic contradicts what one would expect, because of the lithology and the YM distribution along the unit. Dietrich (2015) studied the relationship
between TOC and geomechanical parameters in the VMF for the Loma Jarillosa block. This author described a positive correlation between YM and TOC, however for the PR, no dependency with TOC was found. Convers-Gomez (2017) analyzed PR extracted from pre-stack inversions in the study area and concluded that PR should not be used as an indicator of brittleness in the VMF because of its poor correlation with YM (Fig. 4.5) and TOC. Further research on the relationship between PR and brittleness is needed.

Figure 4.5: Correlations between Poisson’s ratio (PR) and Young’s modulus (YM). Left: Expected correlation, with high PR and low YM showing ductile behavior, and low PR and high YM showing brittle behavior (taken from Grazulis, 2016). Right: PR and YM relation seen in the Vaca Muerta Formation in the study area (taken from Convers-Gomez, 2017). No direct correlation can be seen between the two.

Mechanical anisotropy in shales has been widely reported in the laboratory for both static (Amadei, 1996; Suarez-Rivera et al., 2011) and dynamic conditions (Wang, 2001) to be as high as 400%. Mechanical anisotropy in the VMF can be as high as 250% (Frydman et al., 2016). Cuervo et al. (2014) described a 40% difference between vertical and horizontal elastic parameters for the El Trapial area from well log data. For the same field, Sosa Massaro et al. (2017) estimated vertical and horizontal YM differences to be around 40% for the upper, 45% for the middle, and 40% for the lower Vaca Muerta sections from laboratory measurements.
While for vertical and horizontal PR these authors documented differences between 50-55% for the upper and lower sections, and between 45-50% for the Middle Vaca Muerta. In the present study, lower values of mechanical anisotropy were obtained from laboratory measurements. Differences between vertical and horizontal YM and PR average 35% and 15%, respectively, on samples from the MVM section.

Assuming isotropic properties in the modeling may underestimate the true horizontal elastic properties and consequently affect the horizontal stress estimation (Frydman et al., 2016). The VMF proved to be highly anisotropic in this study and thus, VTI anisotropy was accounted in order to estimate stresses in the wells. For stress calculation, the following equations were used (Thiercelin and Plumb, 1991; Savage et al., 1992):

\[
S_v = \int_0^z \rho(z) g dz
\]

\[
S_h = \alpha_h P_p + \frac{E_h}{E_v} \frac{v_v}{1 - v_h} (S_v - \alpha_v P_p) + \frac{E_h}{1 - v_h} \frac{E_h v_h}{1 - v_h} \epsilon_h + \frac{E_h}{1 - v_h} \frac{E_h v_h}{1 - v_h} \epsilon_H
\]

\[
S_H = \alpha_h P_p + \frac{E_h}{E_v} \frac{v_v}{1 - v_h} (S_v - \alpha_v P_p) + \frac{E_h}{1 - v_h} \frac{E_h v_h}{1 - v_h} \epsilon_h + \frac{E_h}{1 - v_h} \frac{E_h v_h}{1 - v_h} \epsilon_H
\]

where \(S_v, S_h\) and \(S_H\) are vertical, minimum and maximum horizontal stresses, \(\alpha_h\) and \(\alpha_v\) are horizontal and vertical Biot’s coefficients, \(P_p\) is pore pressure, \(E_h\) and \(E_v\) are horizontal and vertical YM, \(v_h\) and \(v_v\) are horizontal and vertical PR, and \(\epsilon_h\) and \(\epsilon_H\) are the tectonic strains in the minimum and maximum stress direction. Depending on their relative magnitudes and
orientations, three different stress fields can be defined: normal (\(S_V > S_H > S_h\)), strike-slip (\(S_H > S_V > S_h\)), and reverse or thrust (\(S_H > S_h > S_V\)) (Fig. 4.6).

Figure 4.6: Stress fields and their relative magnitudes (Fox et al., 2013).

Pore pressure \(P_p\) is a fundamental input into minimum and maximum horizontal stress calculation. Accurate pore pressure prediction is an important factor to ensure proper stress calculation, but it is difficult to measure directly in low permeability formations. One way to estimate \(P_p\) is using Eaton’s method (Eaton, 1975):

\[
P_{pg} = OBG - (OBG - P_{ng}) \left(\frac{\Delta t_n}{\Delta y}\right)^3
\]

where \(P_{pg}\) is the formation pore pressure gradient, \(OBG\) is overburden stress gradient, \(P_{ng}\) is the hydrostatic pore pressure gradient, \(\Delta t_n\) is the sonic transit time or slowness in shales at the normal pore pressure, \(\Delta t\) is the sonic transit time in shales obtained from well logging. This method uses the relation of sonic velocity alteration of normally and abnormally compacted formation to the ratio of pore pressure of corresponding formations (Fig. 4.7) (Song and Hareland, 2012).
However, we have to take into account that Eaton’s methodology is problematic because the exponent is an indication of the insensitivity of compressional velocities to effective stress. As the exponent increases, the relationship between P-wave velocity and effective stress becomes less pronounced. Adjusting the observable velocity with the Eaton exponent implies that the velocity controls effective stress, when in reality, there is an effective stress component that influences velocity. Furthermore, the method does not account for petrophysical parameters (such as porosity and lithology) that have a noticeable effect on pore pressure (Ebrom et al., 2007; Herzog, 2014). Herzog (2014) compared the $P_p$ values obtained with Eaton’s against a modified Bowers approach proposed by Sayers et al. (2003) in the VMF. This author found more reasonable results using the modified Bowers methodology. This method is complex, and since the analysis of $P_p$ is not the main purpose of this thesis, the modified Bowers method was not tried. Therefore, because of the problems related to Eaton’s methodology and the difficulty of the Bowers approach, the use of a pore pressure gradient obtained from DFIT in Well G was chosen, following Sosa Massaro et al. (2017) methodology. Because $P_p$ values from DFIT were not

Figure 4.7: Schematic plots showing sonic transit time ($\Delta t$) measured in shale, the normal compaction trend of the transit time in the normal pressure condition ($\Delta t_n$), and the pore pressure response to the transit time ($\Delta t$) (taken from Zhang, 2011).
available for the other two wells, the same gradient from Well G was used in order to be able to calculate the horizontal stresses.

Minimum horizontal stress ($S_h$) can be calculated with considerable accuracy through hydraulic fracturing (Hubbert and Willis, 1957) and calibrated using the ISIP from DFIT. ISIP values for the three wells in the area are available. On the other hand, maximum horizontal stress ($S_H$) is more complicated to measure directly and that is why most of the existing methods involve different equations in order to estimate it indirectly. Tectonic strains are used for calibration of stresses in relation to the ISIP values and to the regional stress regimes. In this case, tectonic strains relations were given by personal communication with Wintershall. With $S_H$ and $S_h$ calculated, differential horizontal stress ratio (DHSR) can be computed. DHSR is the relative difference between $S_H$ and $S_h$. This parameter is very important in determining how a reservoir is likely to fracture. In general, when DHSR is large, hydraulic fractures will tend to occur as one single planar fracture parallel to $S_H$. In contrast, when DHSR is small, hydraulic fractures will tend to grow in a variety of directions (Fig. 4.8).

![Figure 4.8: Different fracture geometries created by hydraulic stimulation and their relation with differential horizontal stress ratio (DHSR) (modified from Warpinski et al., 2009).](image-url)
This multidirectional fracture network tends to increase the stimulated reservoir volume (SRV), providing a better access to the hydrocarbons in the reservoir (Gray et al., 2012). DHSR can be estimated using the following equation (Gray et al., 2010) (Fig. 4.9):

\[ \text{DHSR} \approx \frac{S_H - S_r}{S_H} \times 100 \]

Figure 4.9: Stress logs for Well A, Well G, and Well I. Dots represent calibration points from DFIT. Track 1: Vaca Muerta Formation divisions; Track 2: Pore pressure (PP - blue), minimum horizontal stress (Sh - gray), maximum horizontal stress (SH - orange), vertical stress (SV - black), all in PSI; Track 3: Differential horizontal stress ratio (DHSR) in percentage.
From the stress logs good calibration between $S_h$ and ISIP is seen for the three wells, except for a few points that are out of range. As mentioned by Frydman et al. (2016), low permeability in the VMF prevents fracture closure within a reasonable period of time, therefore minimum principal stress from DFIT may not be reliable. Moreover, the low permeability prevents attainment of radial flow, thus the obtained $P_p$ may not be reliable either. In this case, ISIP could be used as an upper limit for the minimum principal stress.

In the three wells it can be seen that the VMF shows different stress regimes. UVM tends to be highly stressed, showing mainly a thrust regime. This could be related to the higher carbonate content of the section. Even though carbonate-rich zones may be brittle areas, in active tectonic environments these zones will be highly stressed, with $S_h$ reaching $S_v$, and are not recommended as a fracture stage or landing point (Frydman et al., 2016). Hydraulic fracturing on these high-stress zones with thrust regimes could result on inclined or even horizontal fractures, increasing also the potential for T-shape fractures (Cuervo et al., 2018). In addition, fractures in these zones may close expelling proppant, creating a restriction, pinch point, or barrier (Frydman et al., 2016). This would negatively affect the contact area between hydraulic fractures and the reservoir, and the connectivity between the fractures and the perforations (Cuervo et al., 2018).

Horizontal stress decreases downwards with the MVM showing both strike-slip and normal regimes, and LVM with mainly normal regimes. Other authors described similar regimes. Garcia et al. (2013) described normal to strike-slip regimes around the Huincul area. Varela et al. (2016) also observed normal to strike-slip regimes near the Añelo depocenter area. In the study area, Curia et al. (2018b) described a mixed zone, with both normal and strike-slip regimes. This trend could be related to lower YM values observed in the MVM and especially in the LVM. From equations 4.28 and 4.29 it is possible to see that $S_h$ and $S_H$ are directly related to YM, and
thus, sections with low YM values will show low stress magnitudes. Also, as observed by Cuervo et al. (2018), transitions between different stress regimes are controlled by material properties such as rock stiffness. These authors mention that the stress regime changes from normal to strike-slip to thrust with increasing rock stiffness. Thus, as mentioned above, carbonate-rich zones tend to be highly stressed in active tectonic environments, while zones with higher clay and TOC content may show lower stress values. This could explain why stresses decrease downwards towards the middle and lower VMF.

Finally, DHSR logs show that stress anisotropy increases towards the UVM. In this section, DHSR can reach values around 7%, while MVM shows average values and LVM presents numbers mainly below 2%. This increase in DHSR towards the upper section could be related to an increase in stiffness of the rock, making the upper sections of the Vaca Muerta Formation to be highly stressed. Considering Gray et al. (2010, 2012) cut-off value of 6% for DHSR, during fracture stimulation, UVM will tend to generate planar hydraulic fractures aligned to the maximum horizontal stress, while in middle and lower Vaca Muerta fractures will grow in a variety of directions and therefore intersect. This multidirectional fracture network will provide much better access to the hydrocarbons in the reservoir.

Previous studies done by Convers-Gomez (2017) in our study area concluded that the best landing zones for horizontal wells would be MVM and a thin section between MVM and LVM. This conclusion came from the brittleness analysis of the reservoir. According to Gray et al. (2010, 2012) rocks with YM above 2.5 MPsi can be considered as brittle and therefore they are more likely to fracture. UVM and the entire MVM section present YM above 2.5 MPsi and thus hydraulic stimulation will easily break the rock in these zones. However, the brittleness concept is not applicable in the VMF because it is tectonically induced (Frydman et al., 2016).
Moreover, brittleness is a single function that does not account for stress, pore pressure and host rock permeability, thus, it is impossible that it can define anything related to the performance of a multi-frac well (Buijs and Ponce, 2018). Bai (2016) challenges the validity of the brittleness index method. Instead the author recommends the use of the fracability approach. The author states that formation brittleness and ductility are more related to the rock strength such as unconfined compressive strength (UCS) or fracture toughness, but not to mechanical properties such as YM and PR. UCS is a material’s strength to uniaxial compression under no confinement stress (Sosa Massaro et al. 2018b), while fracture toughness represents the ability of a material to withstand a given stress field intensity at the tip of a fracture and to resist progressive tensile fracture extension (Bai, 2016). According to Bai (2016), fracability is associated to the UCS or the fracture toughness of the rock, where rocks with high strength (high UCS and fracture toughness) such as carbonates may act as fracture barriers, and rocks with low strength (low UCS and fracture toughness) such as shales, are easier to frac. Sosa Massaro et al. (2018b) developed a well based mechanical model for the Vaca Muerta Formation considering the UCS and the fracture toughness of the rocks. The authors concluded that the carbonate beds present in the unit act as fracture barriers due to the high strength of the rocks and the high lateral stresses that these present. Generally speaking, in the VMF carbonate zones are not recommended as possible landing or fracturing zones because of their high strength, their high resistance to fracture extension, and their high lateral stresses.

In this chapter, from the stress log analysis, LVM is suggested as a possible landing point. This section was proved to be successful for completion and production (Williams et al., 2016; Boyd et al., 2018). Moreover, production data from 254 horizontal wells around the basin
shows that wells landed in the LVM produce around 75% more than a P50 type curve, and above 60% more than the wells landed within the MVM and UVM (Fig. 4.10) (Johanis, 2018).

Even though LVM shows low YM values mainly below 2.5 MPa, it may be more fracable due to the high shale content of this section. DHSR shows values below 6% in the MVM and LVM. However, LVM is widely known to be the richest section with high TOC values and high hydrocarbon saturations (Cuervo et al., 2016; Cuervo and Lombardo, 2017; Pateti and Ortega, 2018), thus it is the section with the best reservoir quality (Ejodofomi et al., 2014; Varela et al., 2016).

4.3 Summary

From the stress models built for the three wells in the block, some conclusions can be drawn. Mechanical parameters such as stiffness tensors and YM show an increase in stiffness
upwards in the section. This corresponds with the larger content of carbonate of the MVM and UVM. LVM shows a more ductile behavior with lower YM values, while MVM and UVM present a more brittle characteristic with higher YM values.

Stress analysis show that the VMF in the study area is mainly under strike-slip regimes, with some sections showing also thrust and normal regimes. Because of these highly stressed conditions, the MVM and UVM may not be the best targets for hydraulic fracturing because these carbonate-rich zones may generate horizontal fractures, expel proppant, create a restriction or pinch point, or act as fracture barriers. Moreover, based on previous studies, carbonates are less fracable because of their high strength and high resistance to fracture propagation, while lower strength rocks such as shales are easier to frac. Thus, the low DHSR values and the good reservoir quality of the LVM suggest this section as a possible landing point for horizontal wells in the area.
CHAPTER 5
WIDE-AZIMUTH SEISMIC ANALYSIS

As previously mentioned, the main objective of this study is to examine HTI anisotropy using seismic Velocity Variation with Azimuth (VVAZ) in order to characterize stresses and natural fractures. This section starts with an overview of the theory behind VVAZ, followed by anisotropy and azimuthal analysis.

5.1 Overview of VVAZ

Seismic azimuthal anisotropy (HTI, refer to Chapter 1 and Chapter 4 for more detail) can be observed using two methods: Amplitude Variation with Azimuth (AVAZ) and Velocity Variation with Azimuth (VVAZ). VVAZ appears as sinusoidal variations in seismic travel time with seismic shot-receiver azimuth in a Common-Offset, Common-Azimuth (COCA) cubes (Gray, 2008) (Fig. 5.1).

Figure 5.1: Full-azimuth reflection angle gathers, showing subtle azimuthal RMO in the VMF (taken from the processing report). Red box shows a sinusoid due to velocity variations.
Velocity variations increase in intensity with increasing shot-receiver offsets. It is generally considered that velocities vary due to the presence of fractures, although there are other possible sources of these variations (Gray, 2008).

A number of assumptions are made when the VVAZ technique is used for prediction of fractures in a reservoir. These are (Gray, 2008):

1) Small contrasts in elastic parameters: P-wave velocity, S-wave velocity and density, between the reservoir and the surrounding rock;

2) Weak seismic anisotropy;

3) The reservoir is dominantly Horizontally Transverse Isotropic with a single set of vertical fractures;

4) The seismic wave strikes the reservoir at small angles from vertical;

5) The azimuth of the wave at the reflection point is equivalent to source-receiver azimuth.

VVAZ affects the amplitudes of the seismic stack and thus its effects are usually removed as a pre-condition to extract AVAZ (Gray, 2008). Typically, the AVAZ method provides superior spatial resolution compared to VVAZ, but it is less stable (Todorovic-Marinic et al., 2005; Wang et al., 2007). VVAZ is more stable because it inverts traveltime rather than amplitude, and in practice, it is not easy to preserve relative amplitude information in the presence of noise (Wang et al., 2007).

If fractures behave as an HTI anisotropic media (Thomsen, 2002; Liu and Martinez, 2013), fracture density and their orientation can be measured using azimuthal variations of the velocity, time, or amplitude of the wide-azimuth seismic data (Curia et al., 2018a). VVAZ
effects can be easily measured, providing information about seismic anisotropy such as magnitude and strike (Gray, 2008). Thus, using regularized COCA gathers, values of $V_{\text{fast}}$, $V_{\text{slow}}$, and the azimuth of $V_{\text{fast}}$ attributes can be calculated (Fig. 1.4) (Curia et al., 2018a). As mentioned in Chapter 1, in the presence of vertical open fractures, $V_{\text{fast}}$ is the fast velocity that tends to be aligned parallel to them, while $V_{\text{slow}}$ is the slow velocity and will align perpendicular to the fracture plane. In the case of unequal horizontal stresses, $V_{\text{fast}}$ will be parallel to the maximum horizontal stress. The difference between $V_{\text{fast}}$ and $V_{\text{slow}}$ is the amount of azimuthal anisotropy, and this is considered to be proportional to either the fracture density or the difference in horizontal stress (Hardage et al., 2011; Liu and Martinez, 2013; Curia et al., 2018a).

For this thesis, RMS $\alpha_{\text{slow}}$, $\delta_{\alpha}$, and $V_{\text{fast}}$ Azimuth, and interval $\alpha_{\text{slow}}$, $\alpha_{\text{fast}}$, $\delta_{\alpha}$, $V_{\text{fast}}$, $V_{\text{slow}}$, and $V_{\text{fast}}$ Azimuth were given (refer to Chapter 1 for definitions). As mentioned in Chapter 1, $\delta_{\alpha}$ is calculated as the difference between $V_{\text{fast}}$ and $V_{\text{slow}}$, and in this thesis, it will be referred as HTI anisotropy magnitude. These volumes were used to describe VVAZ anisotropy and direction for fracture and stress characterization in the block. Results from this analysis will be compared with previous FMI studies performed by Bishop (2015) and microseismic data.

### 5.2 Seismic Description

All the different seismic cubes used in this study are in depth. This allowed to pick horizons by following well known markers. Lower Vaca Muerta in this case will be called Cocina, while within the Middle Vaca Muerta two horizons were picked: Parrilla and MVM. The final horizons picked were: Tordillo, Cocina, Parrilla, Middle Vaca Muerta (MVM), Upper Vaca Muerta (UVM), Middle Quintuco, and Quintuco (Fig. 5.2). Cocina is located between the Tordillo and Parrilla horizons.
As can be seen, all the horizons align very well with the well markers, except for UVM in Well G and Well I. The top of Vaca Muerta Formation is usually a weak reflector that is hard to pick because of its low contrast in acoustic impedance with the upper Quintuco Formation. For this study, analysis will be concentrated between UVM and Tordillo horizons, which represents the target zone for production.

After selection of the main horizons, various attributes were extracted to visualize and pick the main faults present in the block. Structure attributes were also used. These are: Variance, Maximum Curvature and Minimum Curvature.

Variance computes and maps a normalized cross correlation between adjacent traces in the same survey (Chopra and Marfurt, 2005), emphasizing the unpredictability of seismic horizons. High variance values may indicate the presence of faults (Fragomeno, 2018).

Curvature is a two-dimensional property of a curve and measures the bending of a particular point along a curve, that is how much the curve deviates from a straight line at this point (Roberts, 2001). Maximum curvature indicates how much above the line the curve deviates, while minimum curvature indicates how much below the line the curve deviates. The
relationship between curvature and fractures is well known (Lisle, 1994); however, the precise relationship between open fractures, paleostructure and present day stress is not yet clearly understood. This attribute helps to emphasize small-scale features such as depositional elements or small-scale faults (Chopra and Marfurt, 2005).

From structural attributes extracted within the Cocina section (Fig. 5.3), different features are exhibited. The main structures that affect the base of the VMF can be easily seen in the three maps. NW-SE oriented *en echelon* normal faults can be found mainly to the NE and SW areas. However, other structures can be observed. Variance and maximum curvature only show the effects of large faults, while minimum curvature gives more detail about small-scale features. It also shows the N-S fault located in the center of the block. This fault is located below the VMF, and it produces an anticline that affects mainly the LVM section. As mentioned before, curvature allows detecting minor scale features such as small-scale faults. From minimum curvature, most lineaments present N-S and NW-SE directions, following the main structures in the block. Thus, these could be considered as possible small-scale faults that affect the base of the VMF.

Figure 5.3: Different structure maps extracted within the Cocina section and interpreted faults (yellow circles). Left: Variance. Middle: Maximum curvature. Right: Minimum curvature.
Moving upwards in the section, attributes were also extracted at a level located in the middle of the Middle Vaca Muerta section (Fig. 5.4). Here fewer features are observed, with only the faults located to the NE of block being easily recognizable. Other mayor faults and minor features are diffuse.

![Middle MVM Variance](image1) ![Middle MVM Maximum Curvature](image2) ![Middle MVM Minimum Curvature](image3)

Figure 5.4: Different structure maps extracted within the middle MVM and interpreted faults (yellow circles). Left: Variance. Middle: Maximum curvature. Right: Minimum curvature. Maps show less amount of structures and features.

Finally, maps extracted at the UVM section (Fig. 5.5) show that the structures observed at the base of the unit disappear and only the faults located to the NE are present. In addition, no small-scale features are observed in the minimum curvature map. This suggests that the top of the VMF is less structured and only large faults affects the upper section.

![UVM Variance](image4) ![UVM Maximum Curvature](image5) ![UVM Minimum Curvature](image6)

Figure 5.5: Different structure maps extracted from the UVM section and faults interpreted (yellow circles). Left: Variance. Middle: Maximum curvature. Right: Minimum curvature.
As can be seen in Figure 5.6, faults located in the NE of the block affect the entire VMF section. These NW-SE oriented faults are generated deep below the base of the VMF. *En echelon* normal faults affecting Jurassic sequences have been widely described in the basin (Cristallini et al., 2005, 2009; Silvestro and Zubiri, 2008; Sagasti et al., 2014; Licitra et al., 2015; Vittore et al., 2018). These structures are associated to pre-existing extensional structures in the basement, which were subjected to a NE-SW stress field during Upper Triassic-Lower Jurassic times that produced NW trending half-grabens. These structures reactivated as a right lateral strike-slip system during the Mesozoic through a NW stress field, producing *en echelon* normally-faulted Upper Jurassic sequences (Cristallini et al., 2009; Licitra et al., 2015; Silvestro and Zubiri, 2008).

![Seismic section showing en echelon normal faults located in the NE of the block.](image)

Figure 5.6: Seismic section showing *en echelon* normal faults located in the NE of the block.

It is widely known that orientation of paleostresses and current tectonic stress acting at a given point of the upper crust largely control local structures (Pollard and Segall, 1987; Mandl, 1988; Rebaï et al., 1992; Hardebeck and Hauksson, 1999; Martínez-Díaz, 2002). Thus, structures
observed in the block will be analyzed in more detail in the following chapters to see how they affect stress directions.

5.3 RMS Anisotropy Analysis

As previously mentioned, VVAZ analysis allows the extraction of seismic anisotropy magnitude and strike. HTI attributes were calculated after removing VTI and other effects. For this thesis, both RMS and interval volumes of HTI anisotropy magnitude ($\delta_{\text{alpha}}$) and $V_{\text{fast}}$ Azimuth were given. Next, an analysis of these attributes is described.

RMS values are measured from the earth’s surface and show cumulative overburden effects from the surface down to each impedance boundary (Inks et al., 2014; McLain, 2014). Thus, it takes into account the anisotropy effect of all HTI formations above (processing report).

Both RMS HTI anisotropy magnitude and $V_{\text{fast}}$ Azimuth attributes were extracted using different windows suggested by Wintershall, that allowed for a detailed characterization of the VMF (Fig. 5.7). The Cocina section was analyzed using an average window of 15 m above the Tordillo horizon. In this study the MVM was divided in three different sections: Lower MVM was extracted using a 40 m window above the Parrilla horizon; for the Middle MVM a shift of minus 80 m was applied to the MVM horizon in order to establish a new horizon right in the middle of the section, and an average window 40 m above and below was applied that allowed the characterization of the whole Middle MVM section; Upper MVM was analyzed using a 40 m window below the MVM horizon. The UVM was extracted using a 40 m window below the UVM horizon.
Figure 5.7: Well G type log and windows used for attribute extraction. Left: Well G showing GR log and different markers. Right: Windows used in the Vaca Muerta Formation are shown.

Figure 5.8 shows RMS HTI anisotropy magnitudes ($\delta_{\text{alpha}}$) extracted from different horizons. From the histogram and from a random cross-section (Fig. 5.9), it can be seen that anisotropy magnitudes decrease upwards in the section, with VMF (dark bars) showing higher anisotropy values than the Quintuco Formation (bright bars). Cocina shows the highest values, reaching a maximum value of 6%, while other surfaces in the VMF present in general lower values.
On the other hand, most of Quintuco’s HTI anisotropy magnitudes fall below 1%, represented by all the blue colors in the cross-section (Fig. 5.9). In addition, it can be noted that signal seems stable along the section, with smooth changes in magnitudes.

It can be argued that HTI anisotropy magnitudes ($\delta_{\text{slow}}$) observed in the RMS volumes are low. As demonstrated by Omar (2018), who studied the added value of shear wave
components over P-wave data in VVAZ analyses in Wattenberg field, Colorado, the P-wave velocity anisotropy is visually indistinguishable when fractured layers are too thin. In the case of the Wattenberg field, the author showed that when the fractured interval thins to less than 25 m, P-wave shows little to no HTI related VVAZ response. This could also be the case for the VMF. If the overburden presents thin fractured layers, then P-wave VVAZ will become ambiguous and low velocity anisotropy will be recorded. This could be compensated by acquiring multicomponent seismic data. Converted and pure shear waves present higher resolution than P-wave data, and thus thin, fractured layers could be better resolved at small offsets (Omar, 2018).

Looking at a section of RMS $V_{\text{fast}}$ Azimuth (Fig. 5.10), signal also looks stable along the section, with azimuths almost constant above the Quintuco and below the Tordillo.

![Figure 5.10: Seismic section showing RMS $V_{\text{fast}}$ Azimuth. Azimuths remain relatively constant in the overburden and below the reservoir, the former showing NE directions, while the latter shows SW orientations. Between Quintuco and Tordillo both NE and SE directions are observed, with some areas showing an E-W azimuth.](image)

In the overburden it predominates a NE direction (blue), while below the reservoir, mainly a SE trend can be seen (red). On the other hand, azimuthal variations can be observed...
between the Quintuco and Tordillo horizons. Here, both NE and SE directions are observed, with some areas showing an E-W trend (white).

Since RMS velocities and azimuths are basically an average of the overburden, the magnitudes that we see in the reservoir are not representative of the exact interval’s values. That is why inverting RMS values to interval values will give more detail about the reservoir’s characteristics and therefore it can be analyzed more effectively.

5.4 Interval Anisotropy Analysis

As mentioned before, RMS velocities are an average calculation, thus anisotropy effects observed on shallow reflections propagate onto deeper events. To obtain meaningful information on a specific zone, RMS velocities must be inverted to interval properties (Schmidt et al., 2013), which are more closely associated with individual geologic layers (McLain, 2014). Interval velocities were calculated from the RMS velocities by the processing contractor using a generalized Dix equation. This process removes the anisotropy of the shallow layers to obtain local parameters of the layers from the effective parameters of the top and bottom horizons (Koren and Ravve, 2014).

Looking at the same cross-section as the RMS but for interval HTI anisotropy magnitudes (Fig. 5.11), velocities seem unstable, with unrealistic patches of high anisotropy values (around 50%), and vertical striping that cuts through the horizons. These features are physically and geologically unreasonable. Also, areas with lateral continuity, like between Tordillo and Parrilla or MVM and UVM, suggest which possible horizons were used as an input for Dix equation.
To obtain interval values from Dix inversion, intervals are selected with different thicknesses based on window sizes. If the windows are too small, unrealistic interval velocities may be observed when RMS velocities change significantly over an interface. Horizons are generally used as boundaries for the windows, however there are some limitations like isochron size (if too short, interval velocities may become unreasonably large or small), horizon availability (the event may not be picked with confidence), and the effect of strong reflections between horizons that dominate the cross-correlations and trim statics values. This is why using strong coherent reflections to sample and extract interval properties may help with some of these issues (Schmidt et al., 2013).

Regarding the anomalous interval HTI anisotropy magnitudes observed in this data, one possible reason could be that short windows were used for Dix inversion. Another cause could be that noisy and weak horizons were picked for the inversion. All these cases would result in unrealistic anisotropy values.
The same issues can be observed in a section of interval $V_{\text{fast}}$ Azimuth (Fig. 5.12). The azimuths look unstable, with quick changes in directions and vertical striping. These issues prevent obtaining a reasonable general trend of azimuths and detailed reservoir characterization. All these observations strongly suggest that small windows were used to calculate interval parameters, giving unpredictable azimuthal directions.

Figure 5.12: Seismic section showing interval $V_{\text{fast}}$ Azimuth. Azimuths look unstable, showing strong variations in direction and vertical striping.

The best way to improve the interval data would be to apply a new Dix inversion using larger windows and picking strong and traceable horizons like Quintuco and Tordillo, which may allow for better characterization of the reservoir interval. To calculate azimuthal parameters, VTI velocities were estimated first and then used as a background model for a final orthorhombic migration (from processing report). To estimate RMS $V_{\text{fast}}$ and $V_{\text{slow}}$, $V_{\text{VTI}}$ is also needed as shown in equations 1.1, 1.2 and 1.3. However, as mentioned in Chapter 1, only RMS $\alpha_{\text{slow}}$ and $\delta_{\text{alpha}}$ were made available and not $V_{\text{VTI}}$, impeding the calculation of RMS $V_{\text{fast}}$ and $V_{\text{slow}}$, and thus a re-calculation using Dix inversion was not possible.
Another quick and easy way to effectively improve this data is to apply a median filter to both interval HTI anisotropy magnitude ($\delta_{\alpha}$) and $V_{fast}$ azimuth volumes. In signal processing, the median filter is a simple and effective method to eliminate seismic noise and spikes (Liu et al., 2006). A 2D median filter was applied on the interval data in order to remove or reduce noise such as vertical striping and anomalous anisotropy values, using the following parameters: cross-line radius = 8, in-line radius = 8, depth radius = 8. Figure 5.13 shows the median filtered section of interval HTI anisotropy magnitude.

Figure 5.13: Seismic section showing filtered interval HTI anisotropy magnitude. 2D median filter removed most of the vertical striping and reduced patches of anomalous anisotropy values.

The parameters used for the median filter removed most of the vertical striping and also reduced the patches with anomalous anisotropy values. Comparing the filtered interval HTI anisotropy magnitude ($\delta_{\alpha}$) section with the RMS section (Fig. 5.9), it can be seen that high anisotropy values areas seem to match in both. In addition, magnitudes decrease upwards, with the VMF showing higher HTI anisotropy values at the base, with some patchy areas of maximum values in the MVM and UVM, while Quintuco Formation shows lower values in general. Even though the filter reduced some of the anomalous patches, it was not capable to remove them, thus
patches of high anisotropy values can still be observed. It is noted that these are extremely high anisotropy values, most likely due to Dix inversion issues and may need to be scaled or recomputed in the future.

With the filtered data, interval HTI anisotropy values were extracted from the main horizons (Fig. 5.14). Interval magnitudes are much higher than those observed in RMS data (Fig. 5.8). Also, it can be seen that almost half of the values are below 15%, while the other half is above this value. In addition, similar to the RMS magnitudes, interval HTI anisotropy values decrease upwards in the section. The VMF in general (dark bars) presents higher anisotropy values than the Quintuco Formation (bright bars), with most of the surfaces showing mainly values above 15%, while the Quintuco in general shows values mainly below the 15% value.

![Figure 5.14: Histogram of interval HTI anisotropy magnitudes extracted from various surfaces.](image)

For anisotropy and azimuthal analysis, it is necessary to consider a feasible cut-off value for anisotropy. If there are low HTI anisotropy magnitudes, the azimuth of $V_{\text{fast}}$ cannot be computed accurately. When HTI anisotropy values are high, the “sinusoid” representing VVAZ can be calculated with confidence (Inks et al., 2014). Several authors have used HTI anisotropy
cut-off values of 3% (Inks et al., 2014), 6% (Gray, 2010; Gray et al., 2010, 2012), or 10% (Bailey, 2017). Following the analysis above, a cut-off of 15% was used for this thesis.

The median filter also improved interval $V_{\text{fast}}$ Azimuth (Fig. 5.15). Now directions vary smoothly and most of the vertical striping was removed. Comparing this section with the RMS $V_{\text{fast}}$ Azimuth (Fig. 5.10), it can be seen that both sections show similar trends, with the overburden depicting a constant NE direction, while the reservoir interval presents variations between NE and SE azimuths, with some areas showing N-S trends, especially in the UVM section.

Figure 5.15: Seismic section showing filtered interval $V_{\text{fast}}$ Azimuth. 2D median filter removed most of the vertical stripping and smoothed the azimuthal variation.

For a detailed characterization of the VMF, both HTI anisotropy magnitude ($\delta_{\text{alpha}}$) and $V_{\text{fast}}$ Azimuth attributes were extracted using the windows described in Figure 5.7. Maps of HTI anisotropy values and $V_{\text{fast}}$ Azimuth were built for all the sections (Fig. 5.16). Both anisotropy magnitude and $V_{\text{fast}}$ Azimuth were filtered, so only areas where anisotropy values are above 15% are shown.
Figure 5.16: HTI anisotropy magnitude and $V_{\text{fast}}$ Azimuth attribute maps extracted in different sections of the VMF. Background color represents interval HTI anisotropy values, going from the cut-off value of 15% to a maximum of 50%. Arrows represent interval $V_{\text{fast}}$ Azimuth. Arrow length is constant.
From Figure 5.16 it can be seen that HTI anisotropy magnitudes ($\delta_{\text{alpha}}$) decrease upwards, with the Upper MVM and UVM showing larger areas below 15% anisotropy value, while Cocina and Lower MVM present wider areas above 15%. According to Williams and Jenner (2002), HTI anisotropy values may vary by 5% in a very short distance, and this is mainly due to fracture intensity. Thus, the patchy high anisotropy value areas observed in the maps could be related to fracture corridors. However, as mentioned above, these large (≈50%) values may be caused by Dix inversion issues. The median filter helped to reduce some of these patches. In any case, these high anisotropy value areas could have a physical reason such as the presence of open natural fractures, but caution must be advised.

Azimuth estimates show some general trends. $V_{\text{fast}}$ Azimuth align to the *en echelon* faults located to the NE of the block, where also high anisotropy values are observed. Rose diagrams (Fig. 5.17) built from the maps above (Fig. 5.16) allow for an easy way to find the main trends in directions. Starting with Cocina and Lower MVM, these show similar trends, with the main direction located between 105° and 135°. Also, Lower MVM presents a smaller secondary trend around 45° - 75°. Moving upwards to the Middle MVM a rotation of the main trend is appreciable, now being around 120° - 150°. A secondary trend is found between 30° - 75°, while some N-S directions are also observed. Finally, Upper MVM and UVM show a strong rotation N-S. These directions diverge from the regional maximum stress direction of the basin which is mainly E-W.

There are some reasons for these trends in the UVM. Bishop (2015) described discontinuities from FMI in Well G, some of them showing N-S directions. The author interpreted these to be related to bedding, concretions, or rock anomalies. In the studied block, Curia et al. (2018b) interpreted a set of fractures oriented N-S from horizontal microseismic in
wells landed within the MVM section. These directions could also be related to N-S oriented features that are not observed from well data, but may be possible to distinguish from seismic. Finally, they could also be related to issues originated from Dix inversion. It is widely known that the top of VMF is a weak reflector, thus if this horizon was used for interval calculations, then magnitudes and directions observed within this section may not be reliable. Moreover, if MVM was also used as an input for Dix inversion, then the window is too small and that may also have affected the values.

Figure 5.17: Rose diagrams of $V_{\text{fast}}$ Azimuth. It is possible to see the main trends in directions for all the different depths.

For the Cocina and Lower MVM a marked trend is observed. Maximum horizontal stress ($S_{\text{H}}$) direction from microseismic in Well G and Well I in the MVM (Fig. 5.18) was measured
between 100° and 110°. Same directions were observed in different areas of the basin. Ejofodomi et al. (2014) observed 120° directions for $S_H$ from breakouts. Also from breakouts, in the Loma Campana field located south of the study area, Licitra et al. (2015) described $S_H$ directions between 90° and 110°, while Rimedio et al. (2015) observed a 110° direction from seismic and microseismic data. Cruz et al. (2017) described stress directions around 100° from image logs. Also, regional stress estimated from breakout data indicates that around the study area stress direction is ESE (Guzman et al., 2007).

![Figure 5.18: Directions observed from microseismic in Well G and Well I, depicting a maximum horizontal stress direction between 100° and 110°. Also, from Guzman et al. (2007) stress directions estimated from breakouts around the block (yellow square) are close to ESE.](image)

All this information suggests that the main trends observed in Cocina, Lower MVM and Middle MVM are related to the current maximum horizontal stress direction. On the other hand, Middle MVM shows more variation in directions, presenting secondary trends (Fig. 5.17). Some of these secondary trends can also be observed in Lower MVM. In order to prove if the secondary trends in this data are related to the presence of open natural fractures, $V_{fast}$ Azimuth was extracted around Well G in the Middle MVM section, where Bishop (2015) described open natural fractures from FMI (Fig. 5.19).
Figure 5.19: Directions observed from FMI and seismic in Well G. Left: Fracture intensity log from Bishop (2015) and Middle MVM window used for attribute extraction. Middle: Bishop (2015) open natural fractures interpretation from FMI in Well G. Right: Azimuths observed around Well G from seismic. Bars were changed to orange to match open natural fractures directions interpreted by Bishop (2015).

The same two sets of fractures were described by Curia et al. (2018b) from microseismic analysis in four horizontal wells landed within the MVM from Well G (Fig. 5.20). The authors also described a third set of fractures oriented N-S, and maximum horizontal stress direction around 95°. This stress direction does not match exactly the direction observed from seismic, however it could be considered as a good approximation.

Figure 5.20: Comparison between microseismic maximum horizontal stress and fracture directions (orange) observed from horizonal wells landed within the MVM (Curia et al., 2018b) and directions extracted from seismic.
Considering the direction of $S_H$ observed from microseismic in Well G and Well I in the MVM, and the two sets of fractures that Bishop (2015) interpreted in Well G and the ones described by Curia et al. (2018b) from horizontal microseismic within the MVM, it can be assumed that the main trend observed from the seismic data located between 105º and 135º indicates $S_H$ direction, while the two secondary trends correspond to two different sets of fractures oriented at 50º and 150º. Similar fracture orientations were described by various authors in different areas of the basin. In the Loma Campana field, Rimedio et al. (2015) observed three sets of fractures oriented at 55º, 100º, and 150º from seismic attributes and microseismic. While Cruz et al. (2017) interpreted a set of fractures oriented around 55º from microseismic. Thus, from the Middle MVM rose diagram in Figure 5.17 it can be assumed that the dispersion in azimuths is related to the presence of both set of fractures along the section, and the $S_H$ direction.

Attributes were also extracted around Well A and Well I using the same window (Fig. 5.21). Around Well A and Well I trends are a little different from the ones observed around Well G.

Figure 5.21: Directions observed around Well A and Well I. Orange bars represents a set of fractures.
It can be seen that the set of fractures oriented NE predominates over the second set oriented SE, which shows a higher dispersion. On the other hand, on Well A maximum horizontal stress direction is clear between 120° and 135°, while on Well I this trend is weak.

In order to characterize these fractures around the block, an ant-tracking attribute was run. Seismic attributes such as curvature and ant-tracking are very useful tools to highlight small scale discontinuities that may be related to fractures. Ant-tracking can help to understand the development of fracture systems at different stratigraphic intervals (Licitra et al., 2015). Following Frydman et al. (2018) ant-tracking workflow applied to the VMF, first a structural smoothing was used in order to remove noise from the data, then variance attribute was applied to detect discontinuities, and finally two passes of ant-tracking for discontinuity/edge enhancement. For calibration of the ant-tracking, the attribute was extracted around Well G at the Middle MVM section to see if there is a match between the ant-tracking and fracture directions observed from FMI and seismic (Fig. 5.22).

Figure 5.22: Correlation between ant-tracking and directions observed from FMI and seismic around Well G. Left: Ant-tracking extracted around Well G. Middle: Bishop (2015) fracture interpretation from FMI. Right: \( V_{\text{fast}} \) directions interpreted from seismic. Orange bars represent interpreted open fractures from seismic. Blue main trend represents \( S_H \) direction.
Ant-tracking around Well G shows two orthogonal sets of fractures with similar directions to the two sets observed from FMI and anisotropy analysis on the seismic, with the NE set being the dominant and matching the direction observed from anisotropy analysis on the seismic. Also, an ant-tracking section around Well G (Fig. 5.23) shows a fracture corridor cutting through the Middle MVM section, where Bishop (2015) described high fracture intensities.

Figure 5.23: Ant-tracking map and section around Well G showing a fracture corridor cutting through the Middle MVM section. To the right is Bishop (2015) fracture intensity log.

Looking at ant-tracking maps from all the sections described in this chapter (Fig. 5.24), it is possible to observe various features. First, *en echelon* faults located to the NE of the block are easily distinguishable through the whole section, while the faults located to the south of Well A penetrate the Lower MVM. Features observed may be considered as potential fractures. Cocina and Lower MVM present a higher density of fractures than the upper sections. This may explain why anisotropy decreases upwards in the section, as observed on the histogram on Figure 5.14 and the maps on Figure 5.16. Most of the fractures observed present a SE orientation, following
directions of the faults and matching the SE set of fractures observed from FMI and the ones described from anisotropy analysis on the seismic. Some others, but in less quantities, show N-S and NE directions. Also, Upper MVM and especially UVM sections show many N-S oriented features. This could be the reason for the strong unexpected N-S trend observed in the rose diagrams (Fig. 5.17).

![Ant-tracking maps extracted from different sections of the VMF.](image)

Figure 5.24: Ant-tracking maps extracted from different sections of the VMF.

### 5.5 Summary

In this chapter, application of VVAZ analysis to the seismic data was discussed. Using RMS and interval HTI anisotropy magnitude ($\delta_{\text{alpha}}$) and $V_{\text{fast}}$ Azimuth attributes, characterization of stresses and natural fractures was possible.
RMS data seem stable, however interval attributes look rather unstable, showing unreasonable anisotropy magnitudes, strong variations in azimuth, and vertical striping. This may have been caused by an aggressive use of Dix inversion during interval calculations. The use of small windows or weak horizons might be some of the reasons. To improve the interval data, 2D median filter was the only option available, while re-calculation of Dix interval values was not possible due to missing data. This helped to remove most of the vertical striping, reduce patches of anomalous anisotropy values, and smooth azimuthal variations.

Extraction of interval $V_{\text{fast}}$ Azimuth attribute using different windows helped to characterize the whole VMF interval in detail. The main trend located between 105° and 135° represents the maximum horizontal stress direction, matching the observations from vertical microseismic in Well G and Well I and regional data. Two orthogonal sets of fractures were identified in the Middle MVM section, one around 50° and the other around 150°. These fracture directions match FMI observations by Bishop (2015) in Well G and horizontal microseismic interpretations from Curia et al. (2018b). The same fracture sets were also described by other authors in different areas of the basin.

Finally, the ant-tracking attribute helped to identify fractured areas along different sections of the VMF. A fracture corridor was observed within the Middle MVM section around Well G. Also, lower sections such as Cocina and Lower MVM exhibit higher density of fractures than the upper sections. Most of these features show SE directions. This is consistent with seismic anisotropy observations. Upper MVM and UVM present several N-S features which may explain why these sections show an unexpected N-S main trend in their directions.
In this chapter, theories for the formation of the different set of fractures observed in the previous chapter will be given. Also, based on all previous observations, suggestions for new drilling areas and landing points are mentioned.

### 6.1 Fracture Formation Theories

In strike-slip regimes like the observed in the VMF, stress-induced fractures can generate as extensional or shear fractures. Extensional fractures propagate parallel to the maximum stress direction, while shear fractures grow at an angle of approximate $30^\circ \pm 7.4^\circ$ to it (Fig. 6.1) (Twiss and Moores, 1992). The two sets of fractures observed from seismic and described in Chapter 5 may have formed by either of these two mechanisms.

![Figure 6.1: Relationships between stress fields and fracture planes.](image)

**Figure 6.1:** Relationships between stress fields and fracture planes. Extensional fractures B align parallel to maximum stress vector $\sigma_1$ ($S_H$). Shear fractures A and C propagate at an approximate angle of $30^\circ$ from the maximum stress vector $\sigma_1$ ($S_H$) (taken from Hardage et al., 2011).

#### 6.1.1 Extensional Fractures

Considering the strike-slip stress regime observed in the geomechanical models in Chapter 4, $\sigma_1$ from Figure 6.1 represents the maximum horizontal stress ($S_H$ in this thesis), which
from seismic data was estimated to be oriented around 105° - 135°. During the basin history, the incidence angle of subduction plate located to the west of South America changed several times, rotating from around 140° during Jurassic times, to 70° during the Tertiary, and reaching today’s 90° direction (Fig. 6.2) (Mosquera and Ramos, 2005).

Figure 6.2: Relationship between maximum horizontal stress direction through the basin history and fractures interpreted from seismic. Left: Stratigraphic column and tectonic evolution (yellow square indicates VMF - Quintuco deposition times), showing incidence angle of tectonic plates in the Pacific margin (modified from Mosquera and Ramos, 2005). Right above: Diagram showing convergence angle between Nazca and South American plates for the last 70 My (Paleocene - Quaternary) (modified from Guzman et al., 2011). Right bottom: Rose diagram of $V_{\text{fast}}$ Azimuth extracted from seismic in the Middle MVM around Well G. The two sets of fractures interpreted from seismic are highlighted.

Bishop (2015), based on fracture sets cross-cut relations from FMI log at Well G, interpreted that the set of fractures oriented at 150° formed first, while the 50° set formed second. This order follows the maximum horizontal stress directions through the basin history. Mosquera and Ramos (2005) mention that in the Upper Jurassic (during the VMF deposition), to the West
of the South American plate, the Aluk plate subduction direction was close to 140° (Fig. 6.2). During the Cretaceous, the Farallon plate subducted following a direction of 100°, and finally during the Tertiary the Nazca plate subduction direction was around 70°. Furthermore, Guzman et al. (2011) who studied the azimuths of Eocene and Oligocene volcanic dikes present in the VMF interpreted maximum horizontal stress directions of 70° and 50° during these times. Following these observations, the two sets of open fractures observed in this study may be interpreted as extensional fractures propagated parallel to the maximum horizontal stress direction, with the first set (150°) formed during Upper Jurassic times and the second (50°) formed during the Eocene - Oligocene.

6.1.2 Shear Fractures

Another possibility would be to consider these two sets of fractures as shear fractures. From the geomechanical models in Chapter 4, mainly strike-slip regimes were interpreted along the VMF. From Figure 6.3, $\sigma_1$ is maximum horizontal stress, $\sigma_2$ is vertical stress, and $\sigma_3$ is minimum horizontal stress, which in this thesis represents $S_H$, $S_V$, and $S_h$, respectively. Following Hardage et al. (2011) and Rossello (2018) diagrams (Fig. 6.3), this could be the case for the fractures observed in the VMF.

Figure 6.3: Shear fractures and their relationship with maximum horizontal stress direction in a strike-slip regime ($\sigma_1 > \sigma_2 > \sigma_3 = S_H > S_V > S_h$). Left: Picture taken from Hardage et al. (2011). Right: Picture taken from Rosello (2018).
Comparing these relationships with the azimuths observed from different data in the study area, we may consider that the two sets of fractures observed from seismic, FMI and microseismic formed following today’s strike-slip regimes and maximum horizontal stress direction (Fig. 6.4). It can be seen that if the two sets of fractures observed are considered as shear fractures, directions from seismic do not match with those diagramed by Hardage et al. (2011). However, looking at the interpretations done by Curia et al. (2018b), it is possible to say that directions match partially. With this it is possible to say that the idea of a shear origin for the two sets of fractures observed is inconclusive.

Figure 6.4: Relationship between fractures and maximum horizontal stress, considering shear fractures and strike-slip regimes. Left above and bottom: Diagram modified from Hardage et al. (2011), rotated to match maximum horizontal stress directions from rose diagrams. Right above: Directions interpreted in Middle MVM around Well G from seismic. Right bottom: Directions interpreted from horizontal microseismic within the MVM by Curia et al. (2018b).
6.1.3 Fractures Due to Hydrocarbon Expulsion

The third possibility would be to consider these fractures as microfractures originated during hydrocarbon expulsion. It is considered that permeability in shales is too low for primary hydrocarbon migration, thus a network of microfractures could explain the high deliverability of shales. Hydrocarbon expulsion in shales causes volume expansion and an increase in pressure, a mechanism that can generate microfractures (Al Duhailan et al., 2013). Considering this, when the VMF generated and expelled hydrocarbons, microfractures may have been formed following current maximum horizontal stress direction.

Different ages were given for Vaca Muerta’s hydrocarbon generation in different areas of the basin. In Bajo de Añelo - Loma La Lata areas, Legarreta et al. (1999) established oil generation during the Albian (104 My). To the west of Loma La Lata, Veiga et al. (2001) mentioned two pulses of oil generation in the VMF, one during Aptian - Albian times (104 - 90 My) and a second one during the Upper Cretaceous (80 - 74 My). Cruz et al. (1999) mentioned that the sedimentation of the Neuquén Group (Upper Cretaceous) may have triggered VMF’s hydrocarbon generation. These authors also state that the VMF is still in the oil window in the Embayment area, and it reached its peak generation in the center and to the west area of the basin.

Considering all the different oil generation ages mentioned above, the main one seems to be the Albian. According to Mosquera and Ramos (2005), during this time the maximum horizontal stress direction was around 100°. If the two sets of fractures observed in this study were microfractures generated from expansion during VMF’s hydrocarbon expulsion, then the main direction of them should be parallel to the maximum horizontal stress direction at that time,
around 100°. This interpretation does not match with the directions observed from seismic, thus this third theory would not be consistent.

From the three theories for fracture generation presented above, the one that seems to agree with all the information shown in this thesis is the first one. The two sets of fractures described from FMI, microseismic and seismic data can be considered as extensional fractures, propagated parallel to the maximum horizontal stress direction, and generated in different stages. The set oriented at 150° formed first during the Upper Jurassic, when the convergence direction of the Aluk plate was around 140°. While the second set located at 50° probably was formed during the Eocene - Oligocene, when the Nazca plate subducted in a direction around 50°.

6.2 New Well Drilling Locations

As mentioned in Chapter 4, interpretations from the geomechanical models suggest the possibility of landing the horizontals at the LVM section. LVM (or the Cocina) is widely known to be the richest section of the VMF, showing in general high hydrocarbon saturations. As discussed in Chapter 4, even though this interval shows a more ductile behavior from mechanical parameters, the LVM may be more fracable because of the lower strength and the lower fracture toughness of the shales present in this section.

Maximum horizontal stress direction in the Cocina and Lower MVM sections shows a strong SE trend, between 105° and 120°. Also in the Middle MVM, the direction is around 120° and 135°. The optimum direction to drill a horizontal well will be perpendicular to these, around 15° and 30° for the Cocina and Lower MVM sections, and between 30° and 45° for the Middle MVM.
With the help of seismic attributes such as HTI anisotropy magnitude, $V_{fast}$ Azimuth, and ant-tracking, different areas were mapped. Where anisotropy values are below 15%, maximum and minimum horizontal stress difference is low, so the hydraulic fracture will tend to grow in a more complex way, contacting more of the reservoir rock. Where anisotropy is above 15%, three different trends were mapped from seismic data. Directions around 105° and 120° are interpreted to be related to the maximum horizontal stress direction, while areas showing 50° and 150° azimuths are associated with the presence of open fractures. Thus, it is always strongly recommended to drill the horizontal wells perpendicular to the maximum horizontal stress direction, no matter if the well will be drilled in a low or high anisotropy area. Another recommendation is to drill horizontal wells in areas where 50° and 150° directions are observed. There might be a high chance of contact open natural fractures in these locations, which may improve hydrocarbon production.

The locations and landing zones for new wells in the area was based on the results from this thesis and also based on background information. Table 6.1 shows the main parameters obtained from this project and some public information from the Vaca Muerta Formation. In bright yellow the main parameters used for definition of the landing zones are highlighted.

It can be seen that the LVM (Cocina) and Lower MVM present the optimum values for landing horizontals and complete the wells. Both present high fracture densities and hydrocarbon saturations. Also both of them may present high fracability values. And both present low DHSR values. From Figure 4.10 it can be seen that the LVM in general produces around 75% more than a the P50 type curve, while the Lower MVM produces 29% less. However, this last section was proved to be efficient in some areas in the basin (Acevedo and Bande, 2018), and it may be productive in the block studied in this thesis. Finally, the LVM shows low thickness, while the
Lower MVM presents interesting thickness. Even though the thickness of the LVM seems to be low, the high stiffness and strength values of the Parrilla (above) and Tordillo (below) sections may cause them to act as fracture barriers, thus the hydraulic fractures would be contained within the Cocina level.

Table 6.1: Parameters calculated in this thesis and public information from the Vaca Muerta Formation. Main parameters used to define the landing zones are colored in bright yellow.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>LVM</th>
<th>Lower MVM</th>
<th>Upper MVM</th>
<th>UVM</th>
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<tr>
<td>HTI Anisotropy (%)</td>
<td>18 - 20</td>
<td>18 - 20</td>
<td>15 - 18</td>
<td>10 - 15</td>
</tr>
<tr>
<td>VTI Anisotropy (%)</td>
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<td>20 - 25</td>
<td>30 - 35</td>
<td>35 - 40</td>
</tr>
<tr>
<td>YM (MPSI)</td>
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<td>2.5 - 3</td>
<td>4 - 6</td>
<td>5 - 8</td>
</tr>
<tr>
<td>PR</td>
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<td>0.28</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Fracability</td>
<td>↑↑</td>
<td>↑</td>
<td>↓</td>
<td>↓↓</td>
</tr>
<tr>
<td>SH Direction</td>
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<td>125º</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>DHR (% )</td>
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<td>2 - 3</td>
<td>4 - 5</td>
<td>5 - 7</td>
</tr>
<tr>
<td>Fracture Density</td>
<td>↑↑</td>
<td>↑</td>
<td>↓</td>
<td>↓</td>
</tr>
<tr>
<td>Fracture Directions</td>
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<td>50º - 150º</td>
<td>≈ 0º</td>
<td>≈ 0º</td>
</tr>
<tr>
<td>Carbonate Content</td>
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<td>↓</td>
<td>↑</td>
<td>↑↑</td>
</tr>
<tr>
<td>TOC (%)</td>
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<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Hydrocarbon Saturation</td>
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<td>↓</td>
<td>↓</td>
</tr>
<tr>
<td>Production (%)</td>
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<td>- 29</td>
<td>- 45</td>
<td>+ 15</td>
</tr>
<tr>
<td>Thickness (m)</td>
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<td>40</td>
<td>120</td>
<td>40</td>
</tr>
</tbody>
</table>

Following these observations, Figure 6.5 shows HTI anisotropy magnitude and $V_{fast}$ Azimuth, and ant-tracking maps with suggested new drilling areas of horizontal wells within the Cocina and Lower MVM sections. Multi-lateral wells are strongly suggested. Drilling from multi-well pads is encouraged for the VMF in order to reduce costs and improve logistics (Rimedio et al., 2015). Currently, multi-well pad locations of 4, 6, and 8 wells are drilled and completed in the VMF (Martinez et al., 2015). This can increase the oil drainage area, improve oil well production, and greatly reduce reservoir development cost by drilling several lateral wells in one borehole (Elyasi, 2016).
Figure 6.5: Cocina and Lower MVM maps showing anisotropy and \( V_{\text{fast}} \) Azimuths in areas with magnitudes above 15% (above), and ant-tracking (below). New drilling areas (wells 1, 2, 3 and 4) and horizontal wells are recommended. Wells 1 and 2 are located in areas with possible open fractures, and wells 3 and 4 are located in less fractured zones but with low anisotropy values, thus low DHSR magnitudes.
With the previous analysis, eight horizontal wells can be suggested from Well A, Well G, and Well I, four landed within the Cocina interval, and four in the Lower MVM section. Moreover, four new wells are recommended. Well 1 and Well 2 are located to the NW of the block, and they are close to areas were open natural fractures seem to be present. This can be seen from the 50º and 150º $V_{f\text{ast}}$ directions, and the high fracture intensities from the ant-tracking around the wells. On the other hand, Well 3 and Well 4 are located to the SE of the block, in less fractures areas but with low anisotropy magnitudes (low DHSR values), where development of complex hydraulic fractures is possible.

6.3 Summary

In this chapter, different theories for fracture formation were discussed. The characteristics of the two sets of fractures observed from FMI, microseismic and seismic data suggest that they were formed as extensional fractures, propagated parallel to maximum horizontal stress direction in different stages. The first set oriented 150º formed in the Upper Jurassic, when the convergence direction of the Aluk plate was around 140º. While the second set located at 50º probably was formed during the Eocene - Oligocene, when the Nazca plate subducted in a direction around 50º.

Considering the results from the geomechanical models, the maximum stress direction and the two sets of fractures observed from seismic, new well locations are suggested. Eight laterals from Well A, Well G, and Well I, four landed within the Cocina interval, and four in the Lower MVM section. Also, four new wells are proposed. Well 1 and Well 2 are located to the NW of the block, and they are close to areas were open natural fractures seem to be present. Well
3 and Well 4 are located to the SE of the block, in low anisotropy areas, where development of complex hydraulic fractures is possible.
CHAPTER 7
CONCLUSIONS AND SUGGESTIONS

7.1 Conclusions

Based on the information and interpretations presented in this thesis, the following conclusions can be drawn:

- Well based geomechanical models show an upward increase in stiffness based on mechanical parameters analysis, with the LVM showing more ductile characteristics, and MVM and UVM more brittle.

- Based on stress analysis from the three wells, and rock strength and fracture toughness (fracability) considerations in the VMF, LVM is considered as a possible landing interval for future horizontal wells.

- Based on seismic azimuthal analysis, maximum horizontal stress direction is estimated to be between 105° and 120°. Also, two sets of fractures were observed, one at 150° and a second one at 50°.

- Fractures are described as extensional, formed parallel to maximum horizontal stress direction during different stages in the basin history.

- Based on this, future horizontal wells are recommended to be oriented between 15° and 30°, and landed within the Cocina or the Lower MVM sections.

7.2 Recommendations

This thesis was based on an integration of well log, seismic, and completion data. However, there are some recommendations for the future that could be highly beneficial for this project.
1. Improve seismic data

In this thesis some problems with the computed seismic attributes were encountered. It is possible that an aggressive application of Dix equation was the reason for some of the unrealistic values observed in the interval anisotropy and $V_{\text{fast}}$ Azimuth attributes. The use of small windows or weak horizons might have been the cause. Thus, it is strongly recommended for future seismic work to follow a more appropriate Dix inversion. A careful inversion would most likely improve seismic analysis, and thus better and more detailed results will be derived from it.

2. Include borehole microseismic and production data

In this thesis, no horizontal microseismic or production data were available. This project would strongly benefit if this data is accessible or even acquired. Borehole microseismic will give detailed information about stress orientations and natural fractures. This data can improve well and seismic model calibrations.

Also, adding production data such as PLTs or fiber optics can strongly help to characterize the most productive zones within the VMF. Including this information into the project would be beneficial for future completion projects.

3. Build a Discrete Fracture Network (DFN) model

It is widely known that in unconventional reservoirs, open natural fractures contribute to hydrocarbon production. Building a DFN model by the integration of outcrop, core, log and seismic data may help to predict with more detail highly fractured areas, and at the end, predict the best drilling areas and landing points, improving hydrocarbon production.
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