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UNIVERSITY OF CALGARY

Measurement of Minimum Horizontal Stress from Logging and Drilling Data in

Unconventional Oil and Gas

by

Lisa Song

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE OF MASTER OF SCIENCE

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Abstract

This study utilizes logging data, drilling data and core reports to generate the minimum horizontal stress (Sh) profile for two Montney wells in North East British Columbia. Specific value of tectonic stress or strain determined from injection fall off analysis is included in the calculation.

The conventional method calculates Sh by solving the linear poro-elasticity equations. The Blanton Olson method incorporates the tectonic, thermal effect and rock mechanical properties at each incremental depth. The vertical transverse isotropy (VTI) method, assumes different rock properties and tectonic strain in different directions. The Harikrishnan method calculates the Sh from the rock strength value at a given depth obtained either from logging or drilling data.

The conventional method yields the Sh magnitude without any distinctive characteristic. VTI method shows higher stress magnitude above the Montney and reveals some good zone containment for hydraulic fracturing design. All methods have equivalent stress magnitude for Montney formation.

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Symbol	Definition
a	Raymer Hunt sonic porosity constant
An	Weight percentage of mineral (fraction)
ARS	Apparent Rock Strength (Psi)
ARSL	Apparent Rock Strength Log
a _s	Rock dependent coefficient value
b	Raymer Hunt sonic porosity constant
b _s	Rock dependent coefficient value
C_0	Unconfined compressive strength (Psi)
C ₁ , C ₂	Blanton/Olson constant (Psi)
CCS	Confined Compressive Strength (Psi)
C_{ij}	Stiffness moduli (Psi)
Conv	Conventional
Ср	Correction factor for sonic porosity (unitless)
d	Depth (km)
DFIT	Diagnostic Fall off Injection Test
Е	Young's Modulus (GPa)
f	Depth compaction factor (dimensionless)
Frac	Fracturing, Fracture
g	Acceleration of gravity (9.81 m/s^2)
G	Shear modulus (GPa)
ISIP	Instantaneous Shut-In Pressure (Psi)
Κ	Bulk modulus of incompressibility (GPa)
K_0	Coefficient of earth at rest (unitless)
KB	Kelly Bushing
Kmin	Grain modulus of mineral (GPa)
Ks	Bulk modulus (GPa)
MD	Measure Depth (meter)

List of Symbols, Abbreviations and Nomenclature

Symbol	Definition
PDC	Polycrystalline Diamond Compact bit
Pe	Confining pressure (Psi)
Pn	Normal hydrostatic pore pressure (Psi)
Рр	Pore pressure (Psi)
PV	Plastic Viscosity (cp)
ROP	Rate of Penetration (m/hr)
RPM	Rate Per Minute (rpm)
\mathbf{S}_1	Maximum principal stress (Psi)
S_2	Intermediate principal stress (Psi)
S_3	Least principal stress (Psi)
\mathbf{S}_{h}	Minimum horizontal stress (Psi)
\mathbf{S}_{H}	Maximum horizontal stress (Psi)
sqrt(t)	Square root time (\sqrt{hr})
Sv	Vertical stress/overburden stress (Psi)
TVD	Total Vertical Depth (meter)
UCS	Unconfined Compressive Strength (Psi)
Vp	Compressional wave velocity (m/s)
Vs	Shear wave velocity (m/s)
VTI	Vertical Transverse Isotropy
WOB	Weight on Bit (ton)
Х	Pore pressure exponent (unitless)
Ζ	Depth (m)
α_{P}	Biot's constant (unit less)
α_{T}	Thermal coefficient of expansion (/F)
β	The angle of internal friction at failure (degrees)
$ ho_b$	Formation density (kg/m ³)
$ ho_{\mathrm{f}}$	drilling fluid density (kg/m ³)
σ_0	Unconfined compressive strength (Psi)

Symbol	Definition
σ_{tect}	Tectonic stress (Psi)
Δt	Sonic transit time from the sonic log (μ s/m)
ϵ_{tect}	Tectonic strain (unitless)
v	Poisson's ratio (unit less)
ε _h	Tectonic strain parallel to Sh direction (unitless)
ε _H	Tectonic strain parallel to S _H direction (unitless)
φ	Porosity (v/v)
$ ho_{ma}$	Matrix density (kg/m ³)
$\rho(z)$	Density of formation at depth z (kg/m ³)
δ_{ARS}	Apparent rock strength (Psi)

CHAPTER 1: INTRODUCTION

Today's unconventional oil and gas plays are economically successful, thanks largely to the advancements in horizontal drilling and multistage fracturing technologies. Horizontal stress profiles play an important role in the design of hydraulic fracturing and the determination of wellbore stability. The use of logs has become the industry standard for determining the stress profile in the reservoir. By employing such services as sonic and density logging, reservoir properties such as Poisson's ratio, overburden and pore pressure may be determined which are key parameters in calculating minimum horizontal stress profiles.

Logging in horizontal drilling however is not only time consuming and expensive, it is also sometimes impossible to do, due to the geometry of the well. This project is an attempt to correlate logging derived stress magnitude to a drilling derived stress magnitude. In doing so, the author will start by introducing stress in general and minimum horizontal stress (Sh) in particular with its measurement and applications in Chapter one. Chapter two will discuss in detail the direct measurement and analysis of Sh with the use of the diagnostic fall off injection test method. It will be followed with the importance of overburden stress and pore pressure to Sh, and their measurement and prediction in Chapter three. Chapter four starts with the rock mechanical properties calculation from logging and drilling data which are correlated to core laboratory values, followed by tectonic stress or strain calibration from Sh measurement data. Chapter five reports the results and discusses them and Chapter six concludes the findings and gives future recommendations.

1.1.PRINCIPAL STRESS

"Stress" measures the average force per unit area of a surface within a deformable body on which internal forces act, specifically the intensity of the internal forces acting between particles of a deformable body across imaginary internal surfaces (Chen and Han, 2007). The principal stresses are defined as those normal components of stress that act on planes that have shear stress components with zero magnitude (Hudson and Harrison, 1997).

Stress is a tensor and, as such, can be fully described as a point within the rock mass in terms of magnitudes and orientation of three orthogonal principal stresses; overburden or vertical stress (S_V), maximum horizontal stress (S_H), and minimum horizontal stress (S_h). Stress is however not compositional, it amounts to a directionally dependent force per unit area, and measuring its magnitude requires that the affected rock body be disturbed to some degree, thereby contaminating the measurements (Hudson and Harrison, 1997). The stress level determines whether a rock is critically loaded or not.



Figure 1.1: Principal stress tensor is defined in coordinate system in which shear stress vanish (Modified after Zoback, 2007).

1.2. MINIMUM HORIZONTAL STRESS

Minimum horizontal stress is one of three principal stresses which measurement and calculation can be technically accomplished. The vertical stress, Sv is usually inferred from the overburden load and is further discussed in Chapter three. Its calculation requires good density estimation of rocks unit above the point of interest. When a density

log is available, the full in-situ stress field can be determined by resolving the magnitude and orientation of the two horizontal stresses. Despite the importance of the determination of S_H in geomechanics, it has long been accepted that it is the most difficult component of the stress tensor to be precisely calculated, especially because it cannot be measured directly (Zoback, 2007).There has been numerous published reports on estimating S_H from S_h and S_V either by empirical correlations or direct equations. S_h , on the other hand, are typically directly measured from smaller or larger rock formation fracturing tests or predicted from logging data.

1.2.1. Application of Minimum Horizontal Stress

Both the direction and magnitude of these stresses are required for (a) planning borehole stability during directional drilling, (b) hydraulic fracturing for enhanced production, (c) estimation of wellbore collapse and/or sand production which can benefit in selective perforation to prevent collapse or sanding during production to mention some (Sinha, et al., 2008). Due to its unconventional properties, all these applications are especially important for shale and tight gas development in western Canada. Shale, a sedimentary rock of extremely low permeability and porosity, can only be produced with advanced stimulation techniques which promote a sufficient pathway for migration of gas or oil into the wellbore. To expose the wellbores to more of the reservoir and take advantage of natural fractures in a field, operators are increasingly performing horizontal drilling combined with multistage fracturing (Boyer, et al., 2006). Application and importance of minimum horizontal stress in particular and in-situ stress in general, are broadly discussed and well known in the petroleum and mining geomechanics community.

Bell in 1996 published a series of studies for in-situ stress measurement techniques and application in Canada Petro Geosciences (Bell, 1996). He emphasized how stress orientation and magnitude help assess the likelihood of serious borehole wall collapse during drilling, whereas stress magnitudes alone help determine in which rock units hydraulic fractures will advance. He further stated that fluid production rates appear to be inversely related to stress magnitude in coalbed methane deposits and it is likely that a

similar situation exists with respect to conventional oil and gas reservoirs. A thorough similar publication was also made available by Alberta Geological Survey for Western Canada in 1994 (Alberta Geological Survey, 1994).

Below are summaries of minimum horizontal stress applications vastly implemented from several known practices and publications.

1.2.1.1. Geomechanical Characterization of Reservoir

According to Bell one of the most comprehensive applications of stress measurements is to obtain enough of them to be able to characterize a basin in terms of its overall geomechanics, including the relationship between the sedimentary section and the underlying rocks (Bell, 1996).

1.2.1.2. Mapping Stress Orientation in Basin

Quoting Bell "Mapping horizontal stresses in a basin is a worthwhile endeavour." According to Bell, the exercise will show how the stress trajectories changes across the basin and establishes the expected stress orientations in a particular area and what the anomalous directions are (Bell, 1996). McCallum and Bell (1995) suspected that many "horizontal stresses" in the Rocky Mountain Foothills are slightly inclined. They found some indications from drilling induced fractures that one of the principal stresses is not exactly vertical, but is affected by bed altitude and possibly topography (McCallum and Bell, 1995).

1.2.1.3. Flow Anisotropy in Reservoir

Bell in his work stated that studies have shown that preferred flow directions are approximately aligned with S_{H} . Fluids flow easier through rocks at the direction of least compression. He further declared that preferred flow direction appears to be largely independent of depositional fabrics or of fracture geometry. It is a very significant finding since it affects the optimum locations for hydrocarbon production wells. When the wells

are located so as to comply with flow anisotropy, it is possible to drain a field with fewer wells (Bell, 1996).

1.2.1.4. Borehole Stability

Knowledge of *in-situ* principal stress directions is critical for planning best orientations of inclined and horizontal wells. This proper planning will minimize borehole instability and formation break-outs. The formations most susceptible to instability are the weakest ones, which are those possessing the lowest in-situ shear and tensile strength and or stiffness modulus. Wellbore penetrating such formations, especially those drilled in non-principal stress directions where there is a strong contrast in the principal stresses, may experience collapse or convergence problems, particularly with increased time of exposure to drilling mud or wellbore fluids (McLellan, 1996). The amount of spalling can be mitigated by orienting a well so that it is subject to a low degree of stress anisotropy in the specific regime in which it is being drilled (Bell, 1996).

A well understood geomechanical solution would suggest drilling directional wells at the right angles to the chosen trajectories. The necessary calculations require stress orientation and magnitudes. As shown in Figure 1.2 below, knowing the minimum horizontal stress allows a better mud weight window planning and hence reduces the chance of wellbore break-out or wellbore unintentional fracturing.



Figure 1.2: Minimum horizontal stress magnitude is used in deciding safe mud weight window during drilling (Modified after International Petroleum Industry Multimedia System, 1995).

1.2.1.5. Hydraulic Fracturing

A valuable application of knowing the directions and magnitudes of principal stresses is that it permits one to predict the orientation of hydraulically induced fractures which will open in the plane perpendicular to the least principal stress (Bell and Babcock, 1986). Hydraulic fractures will propagate in the plane of two largest principal stresses and perpendicular to the smallest principal stress.

A good stress profile can definitely help the engineer determine whether individual zones are separated by horizontal barrier zones to allow individual treatment or whether, because of the lack of good barriers, multiple zones should be treated simultaneously. As shown in Figure 1.3 (a), fracture will open in the plane perpendicular to the least principal stress. The fractures must be confined to the targeted rocks and should not extend upward or downward into the water bearing zone, as shown in Figure 1.3 (b). This can be achieved if the target reservoir is under lower stress than the rocks above and below it. In such case then, fractures can be propagated at pressures that exceed the smallest principal stresses acting on the reservoir rocks, which are lower than the smallest principal stresses acting on the enclosing zone. Stress profile logs, empirically corrected to measured-stress data, provide a good tool for determining the presence of possible

fracture barriers, for selecting treatment intervals and for designing treatments (Gatens and Lancaster, 1990).



Figure 1.3 : (a) Minimum principal stress defines fracture geometry. (b) Minimum horizontal stress magnitude to predict zone barrier (Modified after International Petroleum Industry Multimedia System, 1995).

Warpinski and Teufel (1989) have presented a good review of rock mechanics and fracture geometry, in which they state that in-situ stresses are clearly the single most important factor controlling hydraulic fracturing propagation (Warpinski and Teufel, 1989).

Predicting fracture propagation directions can be advantageous. If the target location is known, it may be possible to connect the well to the reservoir by hydraulic fracturing. Other hydraulically induced fracture advantages include designing optimum well configuration for best field development, increasing sweep efficiency in water or steam flood fields. In thick pay zones we can also drill inclined wells and space a series of fractures along them to increase the recovery and recover investments in a shorter time.

1.2.1.6. Hydrocarbon Production

Bell in his work shows that stress magnitude has a significant control on reservoir permeability and the rates at which fluid will flow out of permeable rocks. When hydrocarbon production lowers reservoir pressures, the horizontal stress magnitude also declines. When using data from a depleted reservoir in the assessment of lateral variations in horizontal stress magnitudes, one of the major concerns are the decline in reservoir pressure due to the reduction in virgin stress caused by fluid removal (Bell, 1996).

1.2.2. Measurement of Minimum Horizontal Stress

Both direction and magnitude of minimum horizontal stress are equally important for any petroleum and mining geomechanical purpose. Below is a brief discussion on the measurement of both magnitude and orientation of minimum horizontal stress.

1.2.2.1. Magnitude of Minimum Horizontal Stress

There are methods of 'direct' stress measurement and there are methods of estimating the stresses via various 'indirect' or 'indicator' methods recommended by the International Society of Rock Mechanics (ISRM) (Hudson and Harrison, 1997). A further discussion on direct measurement using the hydraulic fracturing principle is discussed in Chapter two. Indirect method of minimum horizontal stress prediction utilizing logging and drilling data is discussed in Chapter four of this thesis.

1.2.2.2. Orientation of Minimum Horizontal Stress

Stress orientation measurements concentrate largely on determining the axes of S_h and S_H , since the vertical principal stress is assumed to be in the vertical direction. Horizontal stress directions can be determined from the failure at the borehole wall. The failures

occur in the period after drilling and prior to logging can be detected by borehole logging tools (Fjaer, et al., 2008).

The failure at the borehole wall produces intervals with noncircular cross sections which has long axes at the same orientation. Breakouts are the intervals where the shorter diameter of the borehole corresponds to the drill-bit diameter. When reliable in-situ stress measurements are available, the mean breakout axes can be shown to be parallel to S_h and therefore perpendicular to S_H . Therefore, breakouts are used to indicate the orientations of the principal horizontal stresses affecting the borehole.

Breakouts can be felt by the hydraulically extendible pads of four or six arm caliper tools from the width of the spalled sections of the borehole walls that have broken out,. These tools are generally raised up wells at approximately 10m/min, and torque is applied to the running cable to cause the tool to rotate in the wellbore (Bell and Babcock, 1986). Borehole image logs generated either from electrical (resistivity) imaging log or acoustical imaging logs discussed in the next section can also pick up the breakout images.

a. Caliper Log

The caliper tool (four-arm) has commonly been used to estimate horizontal stress directions from breakout orientations. This tool provides two diameters of the borehole cross-section (Fjaer, et al., 2008). Plumb and Hickman published several criteria to identify stress induced borehole breakouts from caliper reading. The borehole elongation should be clearly seen in the log. One pair of arms must show a relatively sharp ascent and descent of the borehole diameter. The smaller of the caliper readings is close to bit size, or if the smaller caliper reading is greater than bit size it should exhibit less variation than the larger caliper. The direction of elongation should not consistently coincide with the high side of the borehole when the hole deviates from vertical (Plumb and Hickman, 1985).



Figure 1.4 : Four armed power positioning caliper tool. Mark of Schlumberger



Figure 1.5: (Left) Four arms caliper log showing good in-gauge hole; (Right) Six arms caliper log showing oval shape hole.

b. Image Log

The image logs consist of electrical (resistivity) imaging log and acoustical imaging logs. The electrical imaging tool has a large number of electrodes distributed over several pads on independent arms (four or six). These arms are hydraulically open and come in contact with the formation during logging. This shallow electrical investigation is well suited for investigation of fine structures like bedding planes, natural fractures and also drilling induced fractures (Fjaer, et al., 2008).

The acoustical imaging tool functions from the reflection of acoustic waves from the borehole wall. It records the travel time and amplitude of the reflected pulses. The pulses are generated by a rapidly rotating piezo-electric crystal, thus creating a helix-shape logging path with a short distance between each revolution. This tool is best suited for detection of borehole breakouts, as drilling induced fractures do not create significant changes in borehole radius or reflectivity (Fjaer, et al., 2008).



Figure 1.6: (Left) Electrical imaging tool: Formation Micro Imager Mark of Schlumberger (Right) Acoustical imaging tool: Ultrasonic Borehole Imager. Mark of Schlumberger



Figure 1.7: Electrical imaging log showing drilling induced and borehole breakout with the orientation.



Figure 1.8: Acoustical imaging log showing several bedding planes and borehole washouts.

1.3. OBJECTIVES AND SCOPE

The objectives for this study are:

1. Utilize logging data as well as drilling data to generate minimum horizontal stress (Sh) profile.

- 2. Investigate specific values of tectonic stress and strain to be added in the models estimating Sh.
- 3. Compare the Sh values obtained using logging derived and drilling derived stress models.

The scope of this study is limited to data from four wells and information from Altares field of north east British Columbia. As shown on Figure 1.9, B015 and C085 are wells with logging and drilling data available for minimum horizontal stress prediction and CB65 and CD65 are wells with minimum stress measurement data available.



Figure 1.9: Position of wells related to each other: C085 and B015, 6.7 km apart, are vertical wells with logging and drilling data available. CD65 and CB65 are horizontal wells with testing data (DFIT) available.

The upper Montney is a tight, low permeability siltstone reservoir, in the micro-darcy range of permeability. No obvious vertical flow barriers are apparent. Experience in other Upper Montney plays has shown that is not possible to drain the entire formation from a single horizontal well. As a result, two vertically stacked horizontal wells have been drilled into different parts of the Upper Montney from the same pad in the study area.

The offsetting distance use was approximately 125 meters. Lateral length within the formation for each well was 2100 meters (Wood, 2011).

CHAPTER 2: STRESS MAGNITUDES FROM INJECTION FALL-OFF ANALYSIS

2.1. INTRODUCTION

Minimum horizontal stress or principal stress in general, cannot be measured directly without disrupting the original condition of the stress itself. For decades, geoscientists have had several ways and techniques trying to best represent the condition of stress on earth inferred from different measurements at numerous locations throughout the earth. Those techniques, however, were just ways to correlate to the stresses and not methods of directly measuring the stresses. According to Zoback, magnitude of the least principle stress can be determined from micro-frac, mini-frac and extended leak off test. Micro-frac is a very small-scale hydraulic fracture induced only to measure stress at a particular depth, usually at a specific depth through perforations in a cemented casing. Mini-frac is a relatively small-scale frac made at the beginning of a larger hydraulic fracturing operation intended to stimulate production in a low permeability formation. Extended leak off test is a full pressurization of an open section of a well to the point that a hydraulic fracture is created and the magnitude of the least principal stress can be determined (Zoback, 2007).

Hubbert and Willis (1957) used a sand box experiment injected with gelatin to simulate fractures. They proved their theory of the wellbore fluid pressure that would be needed to create fractures in rock mass under a given state of the in-situ stress. When the pressure is increased in the wellbore, where the ratio of S_H over S_h is higher than one, a wellbore pressure of 1.6 times the S_h is sufficient to reduce the circumferential stress to zero across one vertical plane at the walls of the hole. In all cases when the ratio of S_H over S_h is greater than 1, the vertical plane across which the circumferential stress first becomes zero, as the wellbore pressure is increased, is that perpendicular to the least principal stress. They verified with all their experiments that fractures in the earth always propagate perpendicular to the orientation of the least principal stress, because it is the least energy configuration needed. A horizontal fracture is formed on the sand box where overburden stress is set as the least principal stress and vertical fracture is formed on the

sand box with horizontal stress set as the least principal stress. Fairhurst and Scheidegger have shown that the Hubbert and Willis' wellbore pressure equation could be used inversely to infer the principal and tectonic stress from the well fracturing data. This fundamental point is the basis for using hydraulic fracturing to measure the magnitude of the least principal stress (Fairhurst, 2003) (Scheidegger, 1960).

2.2. INJECTION FALL OFF TEST

The injection fall off test (a.k.a DFIT test, Mini Frac) is a short duration test done as a small volume fracturing operation, where a small amount of water is pumped until fracture is initiated and propagated into the formation. The well is then shut-in, allowing the pressure to fall-off naturally over the course of hours to days depending on the condition of the formation. The intention is to fracture the formation during injection period and observe closure of the fracture system during the following fall-off period. As with any well test, pressure is measured throughout the process and recorded for consequent analysis. This test is performed to obtain formation parameters (i.e. fracture closure pressure, fracture gradient, fluid efficiency, formation leak off characteristic, fluid loss coefficient, formation permeability and formation pressure) for hydraulic fracture treatment design and production/reservoir engineering. There are two ways to perform an injection fall off test, surface injection and downhole injection.

2.2.1. Surface Injection Test

Surface injection test is usually performed after the well is cased and perforated in which hydraulic water is injected from surface to fracture the rock through the perforated zone. A pressure instrument placed at the surface well head or down hole can be used as the pressure recorder. A surface pressure recorder has several advantages compared to the bottom hole recorder. Using the surface recorder it is possible to have a real time display of data and there is less risk of losing the instrument and data downhole. However, a surface injection test is applicable only if the fracturing pressures are higher than the hydrostatic head of the fluid column (Nolte, 1988). Reservoir pressure can be obtained from the surface recorder only if it is greater than the hydrostatic head (Nolte, 1988).

Surface injection will fracture all formations connected by all perforated zones. Firstclass hydraulic fracture design will need parameters acquired from injection tests which cover the gross interval of zone of interest and is usually covered by the perforation interval. Hence, surface injection is a more favourable method for accurate closure pressure prediction (Gulrajani and Nolte, 2000). Surface injection tests also have the advantage of being easy to operate and less hazardous.

During a surface injection fall off test, a fracture is created over the entire thickness of the gross pay interval, which requires a much larger injection rate and volume. Significantly higher net pressure occurs with this procedure. Thus the fracture closure pressure can be considerably different from the instantaneous shut-in pressure (ISIP), and it must be estimated with alternative procedures (Gulrajani and Nolte, 2000).

Depending on the condition of the formation and the purpose of the fracturing, a proper design needs to be planned before-hand for any type of injection test. At higher injection rates it will give a bigger fracture and more representative data. Unfortunately, a bigger fracture means it will also take longer to close and to acquire the after closure information (Fekete Associates Inc., 2012). In tight formation, such as the Montney and Horn River, a lot of time is needed to collect enough after closure data to get good estimates of permeability and initial reservoir pressure. On the other hand, minimizing injection volume and rate will generate a relatively small size of fracture which will close in a faster time (Fekete Associates Inc., 2012). However, a small fracture may not represent the overall zone of interest and could cause uncertainty in the results from the analysis.

2.2.2. Downhole Injection Test

Downhole injection is performed during wireline operations with a closed chamber test tool. It is performed in open hole where fluid inflow is isolated by two packers. The tool consists of two inflatable packer elements that seal against the borehole wall to isolate an interval of the borehole. The length of the test interval (i.e. the distance between the two packers) ranges from 1 meter to 2.4 meter. The fracture is created by pumping wellbore fluid into the interval between the inflatable packers element (Schlumberger, 2011).

The wireline closed chamber tool covers a small interval of the formation and obtains fracture closure pressure for only a small thin layer and hence does not represent fracture closure pressure of gross interval of zone of interest. Running a stationery wireline tool in open hole, how wireline closed chamber fracture tool needs to be run, has more possibility of getting stuck and difficulty in getting down into horizontal well. There is also some interpretation concern on a packer-induced stress and packer-induced fracture on borehole which may be problematic during the injection job itself as discussed by Warren and Smith (1985).

To estimate the magnitude of local stress, wireline closed chamber tool requires the creation of small fracture by using relatively small fluid injection rate and volume. Hence a smaller net pressure occurs when a smaller fracture is created, and the shut-in pressure is commonly used as a first order approximation of the stress.



Figure 2.1: Wireline closed chamber test tool sketch (Desroches and Kurkjian, 1999).

2.3. DETERMINATION OF CLOSURE PRESSURE

Following Hubbert and Willis, Warren and Smith (1985) have shown that the overall trajectory of fracture propagation is controlled by the orientation of the minimum principal stress. Although pre-existing fractures and faults also have some influence on fracture propagation. They also revealed that the direction of the initial fracture at the borehole surface will not be the same as the direction of the fracture in the far field under conditions where the borehole is not aligned with the principal stress direction. Thus the fracture plane is expected to change direction as the fracture grows away from the borehole. Hydro fracturing creates a crack which eventually propagates in a plane that is perpendicular to the minimum principal stress. They also confirmed that instantaneous shut in pressure is slightly greater than the minimum principal stress.

Scheidegger (1960) showed that the wellbore pressure during the well fracturing operation is determined from 4 variables which are the 3 principal stresses and the rock strength. He pointed out that the Hubbert and Willis wellbore pressure equation could be use inversely to infer the principal and tectonic stress from the well fracturing data. He also pointed out the fluid pressure, which is the wellbore net pressure, as an amount of pressure needed to be subtracted from all the stress values.

Fairhurst in his work confirmed that application of pressure to the borehole walls during injection generates a tangential tension in the wall of the borehole. When the tangential tension is high enough to overcome the tangential compression induced around the hole by the in-situ stress state and further, to reach the tensile strength of the rock, a fracture develops along the length of the packed-off interval (Fairhurst, 2003). The pressure required to first initiate the fracture is identified as breakdown pressure. A continuous injection of water after a breakdown will extend the fracture and further open up the fracture at fracture-extension pressure. Instantaneous shut-in pressure is the pressure at which the pump is shut-in and pressure is allowed to flow back. Quoting Nolte "If the flowback rate is within the correct range, the resultant pressure decline will show a characteristic reversal of curvature that must be from a positive to negative curvature at the closure pressure. The accelerated pressure decline at the curvature reversal is caused by the flow restriction introduced when the fracture closes" (Nolte, 1982).

The fracture closure pressure is defined as the fluid pressure at which an existing fracture globally closes (Weng, 2002). Mathematically, for a linear relation between the fracture width and pressure, fracture pressure equals the minimum principal in-situ stress in the reservoir (Gulrajani and Nolte, 2000). For formation with an existing fracture before injection, Nolte defined closure pressure as the fluid pressure required while initiating the opening of that existing fracture. This pressure is also equal to and counteracts the minimum principal stress in the rock, which is perpendicular to the fracture plane (Nolte, 1982).

In their works, Hubbert and Willis proved that when the breakdown pressure is substantially higher than the injection pressure, it corresponds to a horizontal fracture
from a relatively smooth wellbore or to a vertical fracture under conditions in which the two horizontal principal stresses were nearly equal (Hubbert and Willis, 1957). On the other hand, they also observed that when there is no distinct pressure breakdown during the injection treatment, the pressure required to start the fracture is less than or equal to the injection pressure. This would correspond to a horizontal or vertical fracture starting from a pre-existing opening or to a vertical fracture in a situation where the ratio of maximum horizontal stress over minimum horizontal stress was greater than 2 (Hubbert and Willis, 1957).

Nolte (1988) in his work has proved that the closure pressure will generally be less than the breakdown pressure required to initiate a fracture and is always less than the pressure required extending an existing fracture i.e. fracture-extension pressure. The extension pressure is greater than the closure pressure because of the fluid friction in the fracture and a finite resistance to extension. In addition, the upper bound for closure pressure can be approximated by the initial shut-in pressure after the breakdown of a fracture treatment (Nolte, 1988).

Figure 2.2 shows that pressure decline after shut in is slower before the fracture is closed. There is a change of pressure decline rate after the fractures are closed. Nolte addressed this matter and determined that the break (inflection) point can go at a faster or slower rate depending on the relative fracture and reservoir characteristics. After the fracture closure time, the fracture walls are closing together from tip toward the wellbore. The closing of the fracture reduces the area for the fluid loss in the relatively high loss area of the tip and consequently reduces the net rate of loss and pressure decline (Nolte, 1979).



Figure 2.2: A schematic injection test showing pressure as a function of time. (Modified after Zoback, 2007).

Gulrajani and Nolte (2000) mentioned that after a fracture has been created, the pressure response during flowback has two distinctly different profiles while the fracture is closing and after the fracture closes. Comprehensive simulations indicate that the fracture closure pressure is identified by the intersection of the two straight lines that define these two periods. The characteristic "lazy S" signature exhibited by the pressure during the flowback period is in contrast to the multiple inflections commonly observed with the shut in decline test (Gulrajani and Nolte, 2000).

Closure pressure, which is the reference pressure for fracture behavior, is the most important parameter for fracturing pressure evaluation. For each analysis technique several curves are used to help identify fracture closure pressure. On each plot the curves are labeled as the primary (y vs. x), the first derivative (dy/dx), and the semi log derivative (x dy/dx). For convenience, the primary curve is plotted on the left y-axis and

all derivatives are plotted on the right y-axis for all Cartesian plots. For the log-log plot all curves are shown on the same y-axis. For pre-closure analysis, and consistent identification of fracture closure, three techniques are illustrated for each example: Gfunction, Square root time and Log-log plot of pressure changed with shut in time. All these analyses begin at shut-in.

2.3.1. G-function

According to Baree, et al., the point where the semi-log derivative of pressure with respect to G-function (GdP/dG) departs from the straight line is the fracture closure pressure. The primary P vs. G curve also should follow a straight line at this point (Barree, Barree and Craig, 2009).

2.3.2. Square Root Time

The Primary P vs. sqrt(t) curve should form a straight line during fracture closure, as with the G-function plot. Barree, et al. emphasized that the indication of the closure is the inflection point on the P vs. sqrt(t) plot which can be found by plotting the first derivative of P vs. sqrt(t) and find the point of maximum amplitude of the derivative. The semi log derivative of the pressure curve is also shown on the sqrt(t) plot. This curve is equivalent to the semi log derivative of the G-function. The closure pick falls at the departure from the straight line through the origin on the semi-log derivative of the P vs. sqrt(t) curve (Barree, Barree and Craig, 2009).

2.3.3. Log-Log Pressure Derivative

According to Barree, et al. the pressure difference and derivative curves are commonly parallel to each other immediately before closure on a log log pressure derivative plot. The separation of the parallel lines represents fracture closure and confirms consistent closure identification. (Barree, Barree and Craig, 2009).

Gulrajani and Nolte suggested the use of both plots the square-root time and G-function to determine the value of closure pressure. However, the interpretation of log-log shut in plot in contrast, is based on identifying reservoir flow regime changes to obtain bounding value of closure pressure (Gulrajani and Nolte, 2000).

On the other hand, Meyer and Hagel (1989) observed that pressure plotted against Gfunction will generally yield a better inflection point at closure than if the data is plotted vs. the square root of time. This is especially true if the closure is relatively fast (Meyer and Hagel, 1989). The combination of the upper bound estimate of closure pressure from the intersection of the matrix and the fracture extension lines on a step rate test, the lower bound of closure pressure determined from the rebound pressure and the estimate of closure pressure from the y-axis intercepted of the fracture extension line as well as the intersection of the two lines during a flowback provides multiple, independent values that establish a firm basis for defining closure pressure (Gulrajani and Nolte, 2000).

CHAPTER 3: OVERBURDEN STRESS AND PORE PRESSURE PREDICTION

3.1. OVERBURDEN STRESS

3.1.1. Introduction

The overburden stress, or sometimes referred to as vertical stress (Sv), is one of the principal stresses which direction is pointing directly to the center of the earth. The vertical stress, Sv, is the maximum principal stress (S_1) in normal stress faulting regimes, the intermediate principal stress (S_2) in strike slip stress regimes and the least principal stress (S_3) in reverse stress faulting regimes (Zoback , 2007). The magnitude of Sv is equivalent to the integration of rock densities at each incremental depth from surface to the depth of interest. Rock density data is most commonly acquired from wireline logging data or logging while drilling (LWD) data.

3.1.2. Theory and Background

3.1.2.1. Density Measurement

Density tools provide measurement of formation density, formation photoelectric factor, and borehole diameter. The density data are used to calculate porosity, lithology analysis for identification of minerals, rock mechanical properties calculation, and determination of overburden stress (Schlumberger, 2012). There are many different types of density measurement tools in the industry today. Some have three detectors which use the third detector located close to the radiation source as a backscatter density measurement. The density tool with additional detector supersedes the predecessor of the density tool with only two detectors and provides higher resolution and quality of measurement. Density tools also come in sizes for different wellbore diameters and different temperature and pressure ratings for different environments.



Figure 3.1: Three detectors density wireline measurement tool (Modified after Schlumberger, 2001).

The density tools are active gamma ray tools that use the Compton scattering of gamma rays to measure the electron density of the formation. A radioactive source is used and emits medium energy gamma rays into the formations. These gamma rays collide with the electrons in the formation. At each collision a gamma ray loses some energy and may also be captured by another electron. The scattered gamma rays reaching the detector, at a fixed distance from the source, are counted as indication of formation density (Buryakovsky, et al., 2012). Using appropriate lithology corrections, the electron density is converted to mass density with reasonable accuracy (Fjaer, et al., 2008). Density measurement is performed with a skid pad which makes full contact with wellbore during measurement. A good wellbore without washout or mud cake, is more conducive to good pad contact between the tool and wellbore, and thus correctly measures the formation density. In poor borehole conditions, an "environmental" mud correction is applied to the density algorithm.

The density tool gives an erroneous formation density value when run in borehole with high barite content in the drilling mud. This is because barite has electron density of 267

barns/electron compared with values of less than 6 barns/electron for most common minerals (Schlumberger, 1985). Barite is such an efficient absorber of gamma rays that it reduces the level of gamma rays to levels too low to be measured accurately (Glover, 2000). The work of Wahl et al. (1964) indicated that a mudcake containing 60 percent barite by weight can have a bulk density of 2.5 g/cc, but its effect might be the same as that of a barite free mudcake with a density of 3.5 g/cc (Wahl, et al., 1964). A study done by Nieto et al. in 2005 for high density and photoelectric factor reading in northern Alberta has confirmed some density correction requirement for western Canada formation with large anisotropy in the stress field that resulted in elliptical or rugose borehole. The study included the effect of borehole size, pad contact, temperature effect, barite mud and mudcake thickness to the quality of density and photoelectric value. Although some effects cancel each other, a certain amount of correction is needed for borehole rugosity and effect of heavy mud weight due to the amount of barite (Nieto, et al., 2005).

3.1.2.2. Overburden Stress

Overburden stress, also called vertical stress or lithostatic pressure, is pressure or stress exerted on earth's formation from the weight of overlying rock and soil. The magnitude of overburden stress, Sv, is equivalent to integration of rock densities from the surface to the depth of interest, z.

$$S_V = \int_0^Z \rho(z) * g * dz$$
 (3.1)

Where $\rho(z)$ is the density as a function of depth, g is gravitational acceleration. Note that the z-axis is pointing vertically downward, with z=0 corresponding to the Earth surface. The rock above any given depth will have various lithology and porosity, hence varying density. A more accurate determination of overburden pressure can be obtained by adding the pressure fraction of density from each incremental depth. Some of the practical problems associated with the computation of Sv using the above equation relate to the fact that density logs frequently measured anomalously low density when the well is rugose with high barite mud content. On top of that, density log is often not measured all the way up to the ground level or rig floor. Hence it is necessary to extrapolate densities to obtain the overburden stress as a function of depth.

3.1.3. Methodology

3.1.3.1. Density Correction

Being only 6.7km apart, comparison between density log of wells C085 and B015 have shown different density value of averagely 100-200 kg/m³. C085 has lower density value compare to B015 for the same formation. Both wells, C085 and B015, have density data from total depth to surface at around 650 meter, just below surface casing. Further investigation from drilling reports revealed that both wells were drilled with high barite content mud. Barite, barium sulfate is a mineral frequently used to increase the weight or density of drilling mud (Drill-Tek MWD, 2001). Being gamma rays absorber, barite will cause less gamma ray returns to the detector and hence increase the density correction. C085 was logged with drilling mud of 1795 kg/m³ and B015 was logged with 1455 kg/m³ mud weight. About 300% of extra barite was used in C085 compared to B015. According to drilling reports, 6496 sacks of barite were added to the mud system in C085, compared to 2329 sacks for B015.

The density measurement is generally affected by hole rugosity as indicated by the caliper log. For the purpose of this study, the density data has been filtered to account for erroneous data caused by large washouts. For caliper readings 15% larger than bitsize, the density data has been eliminated.

Since the density tool cannot measure formation density inside a casing, proper care should be taken not to include density data above surface casing depth. Interpretation from caliper and resistivity data along with drilling reports, the surface casing was confirmed to end around 650 meter, and therefore density values above 651 meter are discarded from any calculation.

Since both wells have some cores taken and analyzed, correction was made to logging density data for both wells by direct correlation between core density and logging data density as shown on Figure 3.2. Logging density data from C085 was corrected to yield higher values, while logging density data from B015 were corrected to yield a lower value.



Figure 3.2: Correction performed each on C085 and B015 log density data from core density data. C085 corrected logging density value is increased and B015 corrected density value is decreased from the initial value.

3.1.3.2. Overburden Stress Calculation

Both C085 and B015 wells were logged from surface casing until total depth. Density of formation behind surface casing from ground level to 650m was assumed to be equal to the density of rock just below surface casing depth. Overburden pressures for both wells were calculated with the equation below:

$$S_{V_1} = [\rho_1 * g * z_1] \tag{3.2}$$

$$S_{V_n} = [\rho_n * g * (z_n - z_{n-1})] + S_{V_{n-1}}$$
(3.3)

 ρ_1 is the bulk density at 651 meter and z_1 is depth at 651 meter.

After density is corrected to its true value, the overburden stress calculation is a straightforward integration of density at each incremental depth toward total depth for both wells.

3.2. PORE PRESSURE PREDICTION

3.2.1. Introduction

Pore pressure value is a fundamental input into minimum horizontal stress calculation for all the methods. Accurate pore pressure prediction is an important factor to ensure proper stress calculation, but is difficult to measure directly in low permeability formation, like the Doig and Montney in western Canada. Pore pressure prediction involves quantifying pore pressure from rock property variation, in particular, changes in sonic velocity or resistivity (Tingay, et al., 2009). Eaton method of pore pressure prediction will be used in this study considering it is the most common method with the data that is available for this project. Eaton pore pressure prediction uses the relation of sonic velocity alteration of normally and abnormally compacted formation to the ratio of pore pressure of corresponding formations.

3.2.2. Theory and Background

3.2.2.1. Normal Compaction Curve

The normal compaction curve is the trend line of certain rock properties with depth of burial at normal hydrostatic pressure. Normally compacted formations will have its properties following a certain trend with depth of burial. The normal compaction curve is required to identify any overpressure related indications from the sonic- and density-log-derived porosities. A normal compaction curve is also required for pore-pressure prediction from the Eaton (1975) method used in this study.

A study done by Hermanrud et al. (1998) found that the effect on neutron and density response in overpressured formations was insignificant compare to the effect on sonic and resistivity response. All techniques were calibrated such that they would yield the same porosity in normally pressured shales. However, log comparisons revealed that neutron and density responses show no significant porosity difference, whereas sonic and resistivity responses show higher porosities in the over-pressured area. An inspection of density and sonic log data from about 30 North Sea wells supports the findings. The sonic log acted as a better discriminator between over-pressure and normally pressured zones (Hermanrud, et al., 1998).

Similarly, Sayers in 2010 also presented a study relating density and velocity changes on difference pressure zones. He concluded that the sonic velocity can drop significantly, whereas density changes by only a small amount for an over-pressured zone. A velocity/density cross-plot therefore can help to distinguish between normal and abnormal pressure zone (Sayers, 2010). Compressional sonic waves travel faster through the matrix than the pore fluid. Hence, a reduction of the effective stress on grain contacts may result in a slower sonic velocity (higher interval transit time) and give rise to a higher apparent porosity from sonic log data. The apparent shale porosity anomalies observed from sonic log data were interpreted to be the result of small textural changes in the rock properties directly associated with pressure (Tingay, et al., 2009).

3.2.2.2. Eaton Method

The Eaton method relates changes in pressure to changes in compressional velocity of sonic logging measurements. The basic assumption of the Eaton method is that a ratio of compressional velocity obtained from regions of normal and abnormal pressure is related to the ratio of normal and abnormal pressure to the region through an exponent that can be determined empirically (Eaton, 1975). Currently, this methodology is the most commonly used algorithm for pore pressure prediction.

Formation of fluid sealed in the subsurface and development of the zone of abnormally high pore pressure is a highly complex mechanism (Donaldson, et al., 2002). According to Tingay, et al., the overpressure generation mechanism can be separated into two categories: disequilibrium compaction mechanism and fluid expansion mechanism. Overpressures generated by disequilibrium compaction are associated with anomalously high sediment porosities (undercompaction) and are thus easier to detect. Another mechanism caused by the expansion of post depositional fluid such as kerogen-to-gas maturation, is not associated with anomalous porosity and is more difficult to detect and quantify (Tingay, et al., 2009). Additionally, overpressure is not static but a transient hydrodynamic phenomenon that can be transferred within reservoirs through faults and fractures (Tingay, et al., 2009).

In disequilibrium compaction, there exists an imbalance between increasing compressive stress and the ability of the formation to expel water. Normally as compressive stress gradually increases, most rocks compact normally while gradually expelling pore fluid. However in the case of disequilibrium compaction, fluids cannot be expelled proportionately to the rate of compaction causing some of the compressive load is borne by the pore fluids and overpressure occurs (Tingay, et al., 2009).

According to Tingay et al. fluid expansion mechanisms of overpressure generation involve an increase in pore-fluid volume within a confined rock framework. Hence, pore volume cannot increase as the pore fluid expands and pore pressure increases as a result. Several potential fluid expansion mechanisms are observed, most commonly kerogen-togas transformation, clay diagenesis, and aquathermal expansion. However, of all the proposed fluid expansion mechanisms, only kerogen-to-gas transformation has the potential for generating high-magnitude overpressures (Tingay, et al., 2009).

Sonic measures the easiest (fastest sonic velocity) path between the transmitter and receiver. Hence, it is more susceptible to subtle textural changes in sediments as well as to changes in bulk porosity (Tingay, et al., 2009). Sayers and Noeth have proved that pore-pressure estimation from velocity is usually performed in shales rather than in sands because of shale platy clay minerals. The alignment of the compacted clay platelets has yielded a strong sensitivity of velocity to effective stress. This suggests the use of velocities measured in interbedded shales to estimate pore pressure in heterogeneous tight gas sand reservoirs (Sayers and Noeth, 2010).

3.2.3. Methodology

3.2.3.1. Normal Compaction Curve

Following the work of Tingay et al. (2009), Sayers (2010) and Hermanrud et al. (1998), density and sonic data are used to generate a normal compaction curve where the pore pressure is believed to be compacted normally (following hydrostatic pressure). To be able to compare both sonic and density on the same scale, porosity generated by both sonic and density are used as the basis for the analysis. Density porosity ($\phi_{density}$) was estimated from density log data using the equation

$$\phi_{density} = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)} \tag{3.4}$$

where ρ_{ma} is the matrix density, ρ_b is the bulk density measured from the density log, and ρ_f is the pore fluid density. An average shale matrix (or grain) density of 2700 kg/m³ was used. Shale grain densities typically varied from 2600 to 2800 kg/m³. Pore fluid density was assumed to be 1000 kg/m³ (Schlumberger, 1985). The sonic shale porosity is estimated from sonic log data with the Raymer equation. A correction factor is applied to better estimate the porosity in shales and unconsolidated sediments.

$$\phi_{Sonic} = \frac{\left(\frac{1}{C_p}\right)(\Delta t - \Delta t_{ma})}{(\Delta t_f - \Delta t_{ma})} \tag{3.5}$$

where ϕ_{sonic} is the calculated porosity from sonic log data, Δt_{ma} is the matrix interval transit time, Δt is the measured interval transit time from the sonic log, Δt_f is the pore fluid interval transit time, and Cp is an empirically determined correction factor. The main goal of this investigation is to examine and compare the sonic and density log response to overpressure. Hence precise determination of true porosity is not crucial.

The sonic porosity (ϕ_{Sonic}) must be calibrated to approximate the density-derived porosity in normally pressured and normally compacted sediments to compare the sonic and density log responses to overpressure. The sonic porosity estimator was calibrated to the density porosity by cross plotting interval transit times versus density porosity to empirically determine a matrix transit time and correction factor. The above equation is rewritten as

$$\phi = a\Delta t - b \tag{3.6}$$

$$a = \frac{1}{\left[C_p(\Delta t_f - \Delta t_{ma})\right]} \tag{3.7}$$

$$b = \frac{\Delta t_{ma}}{[C_p(\Delta t_f - \Delta t_{ma})]}$$
(3.8)

The Cp and Δt_{ma} can thus be determined using linear regression (least squares fit) from the density porosity – Δt cross-plot.



Figure 3.3: Calibration of the sonic porosity to density porosity. The density porosity log data are plotted against the sonic transit time to determine the matrix transit time (Δt_{ma}) and correction factor (Cp).

Values of $\Delta t_{ma} = 136 \ \mu\text{s/m}$ and Cp = 2.54 were obtained from the linear regression. A typical value for Δt_f of 620 $\mu\text{s/m}$ was assumed (Schlumberger, 1985). A normal shale compaction curve was defined using sonic and density log-derived porosity values used to calibrate ϕ_{sonic} . A best-fit exponential shale normal compaction curve (ϕ_{norm}) was fitted to the data, yielding

$$\phi_{norm} = 0.1659 \ x \ e^{-0.001Z} \tag{3.9}$$

where z is depth in meters.

3.2.3.2. Eaton Method

The Eaton method is used herein to carry out pore pressure prediction from sonic log data. The Eaton method estimates pore pressure from the ratio of acoustic travel time in normally compacted sediments to the observed acoustic travel time. Pore pressure (Pp) is estimated using the equation

$$P_P = S_V - [S_V - P_n] \left(\frac{\Delta t_{norm}}{\Delta t}\right)^x$$
(3.10)

where S_V is the overburden stress, P_n is hydrostatic pore pressure, Δt_{norm} is the acoustic travel time from the normal compaction trend at the depth of investigation, and Δt is the observed acoustic travel time from the sonic log, x is an exponent. The hydrostatic pressure is equal to the vertical height of a column of water extending from the surface to the formation of interest (Chilingar, Serebryakov and Robertson, 2002). A hydrostatic constant of 0.465 Psi/ft is thought to fit this formation. Following the work of Contreras et al. for Western Canadian Basin, an exponent of 1 is used for this study (Contreras, et al., 2011). The acoustic travel time for normally compacted sediments was determined by combining and rearranging the normal compaction curve and shale sonic porosity estimator (Tingay, et al., 2009) as

$$\Delta t_{norm} = 136 + 204.323 * e^{-0.001Z}$$
(3.11)

Due to the unavailability of intermediate and surface data for C085, the same correlation from well B015 is used for C085.

CHAPTER 4: CALCULATION OF MINIMUM HORIZONTAL STRESS

4.1. INTRODUCTION

Microfrac, or injection fall off test, is a technique used to accurately measure minimum horizontal stress directly in the formation. However, other than being expensive and time consuming, this test does not give a continuous minimum horizontal stress profile. To expose more wellbores to the reservoir and take advantage of natural fractures in a field, unconventional resources operators are increasingly performing horizontal drilling combined with multistage fracturing (Boyer, et al., 2006). Continuous minimum horizontal stress profile is especially important for hydraulic fracturing design for formations like the tight Montney formation in Western Canada. With its thickness between 300 to 600 meters, understanding the detail of minimum horizontal stress will provide the engineers with options for perforation design and zone containment analysis before the hydraulic fracturing operation. Due to the high formation pressure in this area, a continuous minimum horizontal stress profile is also important for a superb safe mud weight window during drilling. All these applications are especially important for the sky-rocketing development of unconventional resources of any kind. Shale, an abundant sedimentary rock of extremely low permeability and porosity, can only be produced with advanced stimulation which promotes a sufficient pathway for the migration of oil or gas into the wellbore (Boyer, et al., 2006).

Mechanical properties calculations are discussed and presented for the Young's modulus and Poisson's ratio in this chapter assuming isotropic and anisotropic. Correlations are made between dynamic properties calculated from logging data with static properties acquired from core data. Rock strength values are calculated from logging data with Onyia and Andrews's method, as well as from drilling data with the Optimizer software (Drops Technology AS, 2006). Minimum horizontal stress is calculated with 3 methods from the Young's modulus and Poisson's ratio properties and 1 method from rock strength properties using the Harikrishnan method. Tectonic stress or strain effects are calculated from the minimum horizontal stress value acquired from testing data. Further analysis and discussion are in the result section in Chapter 5.



Figure 4.1: Minimum horizontal stress calculation methodology from logging and drilling data via rock properties: Young's modulus, Poisson's ratio and rock strength.

4.2. ROCK MECHANICAL PROPERTIES VALUES

Rocks' responses are functions of their mechanical properties, the pressure of the fluids within them, and the magnitudes and orientations of the forces that are applied (Bell, 1996). Industry has been using sonic borehole data for estimation of formation mechanical properties for decades. Acoustic logging tools measure acoustic wave velocities, i.e. compressional velocity and shear velocity, which together with density log and the appropriate formulae provide the elastic properties. The primary theory for using borehole sonic data to estimate rock stresses is based on acoustoelastic effects in rocks. Acoustoelasticity refers to changes in elastic wave velocities caused by changes in the pre-stress in the propagating medium (Sinha, et al., 2008). Once the velocities are measured, Poisson's ratio can be calculated and when density is known, Young's modulus is calculated from Poisson's ratio and density. Therefore the quality of reservoir's stress analysis can be related to the basic measurements of compressional velocity (V_p), shear velocity (V_s) and formation density (ρ_b) (Coates and Denoo, 1980).

4.2.1. Young's Modulus and Poisson's Ratio Value

Following Hudson and Harrison (1997) and Jaeger et al. (2007), Young's modulus and Poisson's ratio are derived as follow:

$$E = \frac{axial \ stress}{axial \ strain} = \frac{\sigma_a}{\varepsilon_a} \tag{4.1.}$$

$$\nu = \frac{\text{lateral strain}}{\text{axial strain}} = \frac{\varepsilon_l}{\varepsilon_a} \tag{4.2.}$$



Figure 4.2: (a) Young's modulus (E) as defined from its relation of stress and strain.
(b) Poisson's ratio (v) is defined as the ratio of lateral strain over axial strain of a material (Modified after Hudson and Harrison, 1997).

Young's modulus is the ratio of uniaxial stress over the uniaxial strain of a material following Hooke's Law. It is a measure of a stiffness of material, material resistance against being compressed by uniaxial stress. Young's modulus is the ratio of stress, which has units of pressure, to strain, which is dimensionless; therefore Young's modulus has the units of pressure (Hudson and Harrison, 1997).

Poisson's ratio is the ratio of the fraction of expansion divided by the fraction of compression when a material is compressed in one direction. It is a measure of lateral expansion relative to longitudinal contraction.

4.2.1.1. Isotropy

Isotropic linear elasticity is simply the most commonly used form for the stress-strain relationship for rocks. An isotropic medium is defined as a medium in which properties are equivalent in all directions. In other words, a material which response is independent of the orientation of the applied stress. Isotropic rock has the property of vertical Young's modulus and Poisson's ratio equal to that of the horizontal Young's modulus and Poisson's ratio equal to that of the horizontal Young's that the components of stress are linear functions of the component of strain. Written in terms of the principal coordinate system, the stress-strain law of isotropic elasticity, often called "Hooke's Law" takes the form:

$$\begin{bmatrix} \sigma_1 \\ \sigma_2 \\ \sigma_3 \end{bmatrix} = \begin{bmatrix} (\lambda + 2G) & \lambda & \lambda \\ \lambda & (\lambda + 2G) & \lambda \\ \lambda & \lambda & (\lambda + 2G) \end{bmatrix} \begin{bmatrix} \varepsilon_1 \\ \varepsilon_2 \\ \varepsilon_3 \end{bmatrix}$$
(4.3)

$$\sigma_1 = (\lambda + 2G)\varepsilon_1 + \lambda\varepsilon_2 + \lambda\varepsilon_3 \tag{4.4}$$

$$\sigma_2 = \lambda \varepsilon_1 + (\lambda + 2G)\varepsilon_2 + \lambda \varepsilon_3 \tag{4.5}$$

$$\sigma_3 = \lambda \varepsilon_1 + \lambda \varepsilon_2 + (\lambda + 2G)\varepsilon_3 \tag{4.6}$$

The coefficient λ and G are the elastic moduli, known as Lame's parameters. G is also known as the modulus of rigidity, or the shear modulus. G is a measure of the sample's resistance against shear deformation (Fjaer, et al., 2008). For an isotropic material, only two elastic moduli are independent, if any two are known, the others can be determined from equations such as those given above. As stated by Jaeger et al. (2007), Zoback (2007) and Fjaer et al. (2008), other useful relations between E, K, v, λ and G are as follows:

$$\lambda = \frac{Ev}{(1+v)(1-2v)}, \qquad G = \frac{E}{2(1+v)}, \qquad K = \frac{E}{3(1-2v)};$$
$$\lambda = \frac{2Gv}{(1-2v)}, \qquad E = 2G(1+v), \qquad K = \frac{2G(1+v)}{3(1-2v)};$$
$$\lambda = K - \frac{2}{3}G, \qquad E = \frac{9KG}{3K+G}, \qquad v = \frac{3K-2G}{6K+2G}$$

In elastic, isotropic, homogenous solid rock the elastic moduli can be determined from velocity of compressional waves (Vp) and shear waves (Vs) using the following relations

$$v = \frac{\left(0.5 \left(\frac{V_p}{V_s}\right)^2\right) - 1}{\left(\frac{V_p}{V_s}\right)^2 - 1}$$
(4.7)

$$G = \rho_b V_s^2 \tag{4.8}$$

$$E = 2G(1+\nu) \tag{4.9}$$

The elastic moduli are all ratios of stresses to strains. Since the strains are dimensionless, the moduli must have a dimension of stress (Jaeger, Cook and Zimmerman, 2007). In the petroleum engineering industry, it is common to use pounds per square inch (Psi). The official SI unit for stress is Pascal, which is 1 Newton per square meter (Pa = N/m^2). As Pascal is a much smaller value than usually occur in rock mechanics, it is common to measure stresses in MegaPascals (1 MPa = 10^6 Pa) and moduli in GigaPascals (1 GPa = 10^9 Pa).

4.2.1.2. Anisotropy

Most rocks are anisotropic to one extent or another. When Young's modulus is measured under uniaxial compression from cores that are cut in the horizontal and the vertical direction, the values will differ from one another. In contrast to the condition for isotropic rock, the generalized Hooke's Law for an anisotropic rock will have more than two independent elastic coefficients (Fjaer, et al., 2008). This relationship is often written as

$$\sigma = C\varepsilon, \tag{4.10}$$

where C is known as elastic stiffness (Jaeger, Cook and Zimmerman, 2007).

$$\begin{bmatrix} \sigma_{xx} \\ \sigma_{yy} \\ \sigma_{zz} \\ \sigma_{yz} \\ \sigma_{xz} \\ \sigma_{xy} \end{bmatrix} = \begin{bmatrix} C_{11} & C_{12} & C_{13} & C_{14} & C_{15} & C_{16} \\ C_{21} & C_{22} & C_{23} & C_{24} & C_{25} & C_{26} \\ C_{31} & C_{32} & C_{33} & C_{34} & C_{35} & C_{36} \\ C_{41} & C_{42} & C_{43} & C_{44} & C_{45} & C_{46} \\ C_{51} & C_{52} & C_{53} & C_{54} & C_{55} & C_{56} \\ C_{61} & C_{62} & C_{63} & C_{64} & C_{65} & C_{66} \end{bmatrix} \begin{bmatrix} \varepsilon_{xx} \\ \varepsilon_{yy} \\ \varepsilon_{zz} \\ 2\varepsilon_{yz} \\ 2\varepsilon_{xz} \\ 2\varepsilon_{xy} \end{bmatrix}$$
(4.11)

Jaeger et al. (2007) stated that two of the cross partial derivatives of the strain energy functions with respect to two different strains must be equal. Since the matrices of elastic stiffness are always symmetric, so in fact at most, only twenty-one of the stiffness coefficients can be independent. However, if a material exhibits any physical symmetry, the number of independent stiffness can be reduced further (Jaeger, Cook and Zimmerman, 2007).

A common form of anisotropy observed in rocks is the case when one of the three axes is an axis of rotational symmetry, in the sense that all directions perpendicular to this axis are elastically equivalent. In this case, the rock is isotropic within any plane normal to this rotational symmetry axis. A rock processing this type of symmetry is known as "transversely isotropic" (Jaeger, Cook and Zimmerman, 2007).



Figure 4.3: Simplified anisotropy geometries: (Left) In vertical transverse isotropy medium, elastic properties are uniform horizontally but varies vertically. (Right) Horizontal transverse isotropy formation in which elastic properties are uniform in the vertical plane but vary in perpendicular direction. Both vertical and horizontal transverse isotropy have the axis of symmetry which may be rotated about the axis to produce a medium with the same properties (Modified after Haldorsen, et al., 2006).

The vertical transverse isotropic method describes a rock that has an axis of symmetry with property similar in horizontal direction but varies in the vertical direction. Under a microscope, the rock appears as stacks of more or less horizontally aligned platelets piled irregularly upon one another (Schoenberg, Muir and Sayers, 1996). The stiffness tensor for the material can be defined by the matrix below:

$$C = \begin{bmatrix} C_{11} & C_{12} & C_{13} & 0 & 0 & 0 \\ C_{21} & C_{22} & C_{23} & 0 & 0 & 0 \\ C_{31} & C_{32} & C_{33} & 0 & 0 & 0 \\ 0 & 0 & 0 & C_{44} & 0 & 0 \\ 0 & 0 & 0 & 0 & C_{55} & 0 \\ 0 & 0 & 0 & 0 & 0 & C_{66} \end{bmatrix}$$
(4.12)

A vertical transversely isotropic formation can be quantified by five independent elastic stiffness's including, $C_{11} = C_{22}$, $C_{12}=C_{21}$, $C_{13}=C_{31}=C_{23}=C_{32}$, $C_{44}=C_{55}$, C_{33} . Additionally, C_{11} and C_{12} can be related to C_{66} , as shown on equation 4.16 below. For a vertical well with flat bedding planes, C_{33} represents the vertically propagating compressional wave, 44

 C_{44} is the shear wave and C_{66} can be estimated from the tube wave velocity (Walsh, Sinha and Donald, 2006). An advanced sonic tool will be needed to provide compressional, shear and tube wave velocity for each depth. The relation of transverse isotropy moduli with the sonic velocity are derived as follow:

$$C_{33} = \rho_b V_P^{\ 2} \tag{4.13}$$

$$C_{44} = C_{55} = \rho_b V_S^2 \tag{4.14}$$

$$C_{66} = \frac{\rho_f V_f^2}{\left(\frac{V_f^2}{V_T^2} - 1\right)}$$
(4.14)

$$C_{12} = C_{13} = C_{33} - 2C_{55} \tag{4.15}$$

$$C_{11} = C_{12} + 2C_{66} \tag{4.16}$$

Vertical and horizontal Young's modulus and Poisson's ratio are then calculated from those velocities data (Higgins, et al., 2008).

$$E_{vert} = C_{33} - 2 * \frac{C_{13}^{2}}{C_{11} + C_{12}}$$
(4.17)

$$E_{horz} = \frac{\left((C_{11} - C_{12}) * \left(C_{11}C_{33} - 2 * C_{13}^2 + C_{12}C_{33}\right)\right)}{C_{11}C_{33} - C_{13}^2}$$
(4.18)

$$v_{vert} = \frac{c_{13}}{c_{11} + c_{12}} \tag{4.19}$$

$$v_{horz} = \frac{C_{33}C_{12} - C_{13}^{2}}{C_{33}C_{11} - C_{13}^{2}}$$
(4.20)

Vertical direction is defined as direction perpendicular to bedding plane and horizontal direction is parallel to bedding plane for all data and calculations presented in this project.

4.2.1.3. Dynamic Vs. Static Mechanical Properties

Using the stress strain relationships, elastic constants may be determined from a specimen of the rock under load in a testing machine; these are usually referred to as the static elastic constants. Dynamic elastic constants are the stress-strain relationship calculated by the propagation velocity of elastic wave in the rocks. For an ideally elastic material, the static and dynamic constants are the same; i.e. the material exhibits a perfectly linear stress-strain relationship over load range. For rocks, this is not the case. Rock formations appear stiffer in response to an elastic wave than in a rock mechanics laboratory test. The weaker the rock, the larger the difference between the elastic properties derived from sonic measurements (dynamic properties) and those derived from laboratory experiments (static properties). The dynamic elastic constants are consistently higher than the static constants. At low confining stresses, rocks exhibit a nonlinear stress-strain relationship. At high confining stresses the behaviour becomes more linear and there is a better agreement between the dynamic and static elastic constants (Tixier, Love and Anderson, 1975).

Relevant elastic property for hydraulic fracturing is the unloading modulus measured during laboratory experiments which is the static elastic constants (Economides and Nolte, 2000). Hence, to acquire a continuous static elastic constants/modulus of the rock, correlations were developed by comparing elastic properties from laboratory tests on core samples to elastic properties determined from sonic logs run in the cored wells.

4.2.2. Rock Strength Value

The rock strength value is the value of applied stress at the point when the rock sample starting to deform during a compression test. Failure of rock is such a complex occurrence which involves the microscopic interaction between grain contacts creating tiny tensile cracks during compression. Zoback (2007, p. 87) suggest that in brittle rock, the loss occurs catastrophically, with the material essentially losing all its strength. In more ductile materials (such as poorly cemented sands) failure is more gradual. The

strength is defined as the peak stress level during a deformation test after which the sample weakens (Zoback, 2007).

The strength of rock depends on how it is confined. Uniaxial compressive test is a test in which one simply compresses a sample axially (with no radial stress) until it fails at a value defined as the unconfined compressive strength usually termed as UCS or C_0 .

When core samples are not available for laboratory testing, various correlations are performed to simulate the rock value. Rock strength value has long been related to other rock measureable value from logging or drilling data. The basis for these relations is the fact that many of the same factors that affected rock strength also affect elastic moduli and other parameters, such as porosity (Zoback, 2007). For this study UCS is calculated with Onyia equation using compressional velocity data, Andrews equation using compressional velocity data, and also rock strength computed from the drilling Optimizer software exploiting ROP model from drilling mechanics and bit data.

4.2.2.1. The Onyia Equation

The use of sonic velocity to determine elastic properties of rock is not new. Onyia in his paper presented the formula for general apparent rock strength formula from compressional transit time from a research test well. Sonic models produced the best agreement with the triaxial test results analyzed for the comparison. Onyia concluded that the sonic model may be used to develop continuous rock strength with the equation below:

$$\delta_{ARS} = \frac{1}{5.15E^{-8}(\Delta t_c - 23.87)^2} + 2 \tag{4.21}$$

The above formula is valid for sandstone, shales and limestone lithologies. In low porosities rock, especially carbonates where the porosity is predominantly secondary (fractures and vugs), sonic waves tend to travel via the continuous phase and miss the randomly distributed secondary porosities. Thus the travel time does not vary significantly in such formations (Onyia, 1988). The Montney formation somehow fit this profile and hence this formula is shortlisted to calculate rock strength for this project.

4.2.2.2. Andrews Equation

While Andrews et al. (Andrews, et al., 2007) found that the rock strength can also be estimated by considering the porosity and compaction of the rock using equation

$$\delta_{ARS} = \frac{149595[(1-\phi^{0.18})f]}{(\Delta t_c - 40)^{0.42}} \tag{4.22}$$

Where ϕ is the porosity of rock, Δtc is sonic compressional travel time in μ sec/m and f is a dimensionless depth compaction factor defined as

$$f = -0.0016d^4 + 0.0181d^3 - 0.0757d^2 + 0.3121d + 0.5$$
(4.23)

Where d is depth in km.

4.2.2.3. Apparent Rock Strength Log (ARSL) from Drilling Data

Apparent rock strength log quantifies the unconfined compressive rock strength of the formation as a function of depth. ARSL is calculated from Rate of Penetration (ROP) models using the drilling optimization software Optimizer. The ROP models is a function of known drilling operation conditions, bit properties, wear and coefficient, mud properties, hydraulics and ROP during drilling. The drilling simulation software requires three input files to generate an ARSL: bit file, lithology file and drill file.

The bit file contains all sorts of bit information such as diameter of bit, bit wear, depth in and out, and bit specific technical data depends on the type of drilling bit. All bits require input of nozzle sizes and for Polycrystalline Diamond Compact (PDC) bits information on number and size of PDC cutters, cutter geometry, and junk slot area are required. The drill file contains drilling operational parameters versus depth: rate of penetration (ROP), weight on bit (WOB), drill string rotation in revolutions per minute (RPM), flow rate, mud plastic viscosity and mud weight information. The lithology files contain the percentages of rocks such as shale, sandstone, limestone as a function of depth. All of the above mentioned information is acquired from the drilling department of the operating company. A proper data quality control is very crucial before generation of ARSL data. Unreasonable values are deleted or smoothed out before plotting the data. WOB values below 1 ton and above 30 tonnes are deleted. RPM values below 50 and above 350 are deleted. ROP values below 0 and above 100 meters/hour are also deleted. General detailed quality control is performed by plotting WOB, ROP, RPM and Pump Flow rate versus depth and eliminating data points that are out of norm. This corrected data is consequently copied into the drill file.

The software iterates bit wear through the ROP models to calculate ARSL for each bit run. It initially assumes very little bit wear and the ARSL is calculated as a function of depth. Convergence is obtained when iterated bit wear and field reported bit wear are equivalent (Abdrazakov, 2011).

Andrews, et al in their work suggested the use of rock strength value calculated from logging data as a second support for a precise prediction. There are times when the drilling data are not recorded with great accuracy and affect the prediction of ARSL. Problem commonly occurred during drilling operation such as down-hole and stick slip vibration will also affect the quality of predicted rock value from drilling data. The reliability of the procedure is highly dependent on the quality of the field drilling data recorded (Andrews, et al., 2007).

Apparent rock strength generated from the Optimizer is converted to UCS before being used in minimum horizontal stress calculation.

$$UCS = \frac{ARSL}{(1+0.3*Pe^{0.7})}$$
(4.24)

Where Pe is the pressure differential between minimum horizontal stress and pore pressure as discussed in the Harikrishnan method.

4.3. MINIMUM HORIZONTAL STRESS CALCULATION

Minimum horizontal stress was first derived by academician Dinnik in 1925 (Hudson and Harrison, 1997). It was first assumed that the three principal stresses of a natural in-situ stress field are acting vertically (one component) and horizontally (two components).

Using the elasticity theory for isotropic rock and above principal stress assumption, it was possible to predict the magnitude of the horizontal stress.



Figure 4.4: Vertical and horizontal strain on a small element of rocks (Hudson and Harrison, 1997).

When a rock is compressed uniaxially from a vertical direction, the total strain will be vertical strain minus two perpendicular horizontal strains as described on equation 4.25:

$$\varepsilon_V = \frac{\sigma_V}{E} - \frac{v\sigma_{H1}}{E} - \frac{v\sigma_{H2}}{E}$$
(4.25)

Likewise, if the rock is compressed uniaxially from one of the horizontal directions, the total strain value on that direction is described by equation 4.26:

$$\varepsilon_{H1} = \frac{\sigma_{H1}}{E} - \frac{\nu \sigma_{H2}}{E} - \frac{\nu \sigma_V}{E}$$
(4.26)

When we assume one of the strains to be zero, $\varepsilon_{H1} = 0$ and both horizontal stress are of the same magnitude, $\sigma_{H1} = \sigma_{H2}$, we acquire the minimum horizontal stress equation in relation to Poisson's ratio and vertical stress as shown on equation 4.28.

$$0 = \frac{\sigma_{H1}}{E} - \frac{\nu \sigma_{H2}}{E} - \frac{\nu \sigma_V}{E}$$
(4.27)

$$\sigma_h = \frac{\nu}{1-\nu} \sigma_V \tag{4.28}$$

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These calculations indicate the likely values of the vertical and horizontal natural in-situ stress components based on the application of elasticity theory to an isotropic rock.

4.3.1. Method 1: Conventional

The concept of elasticity applies only to the deformation of the matrix material (Whitehead, et al., 1986). Total stress is equal to matrix stress (σ) plus pore pressure. Hence the minimum horizontal stress is obtained by solving the linear poroelasticity equation for horizontal stress with vertical stress set equal to overburden. Dinnik equation of minimum horizontal stress is for effective stress, hence equation 4.28 evolved from effective stress to total stress and became:

$$(S_h - P) = \frac{v}{1 - v} (S_V - P)$$
(4.29)

or

$$S_h = \frac{v}{1 - v} (S_V - P) + P \tag{4.30}$$

The parameter known as Biot's constant was first defined by Maurice Biot in 1957 as a factor to help account for the deformation of a poroelastic material as the pore pressure changes (Biot and Willis, 1957). Biot's constant describes how much of the total stress and pressure changes get converted to effective stress change. Further detail of Biot's constant calculation can be found on Appendix A. The stress equation then becomes:

$$S_h = \frac{v}{1-v}(S_V - \alpha P) + \alpha P \tag{4.31}$$

Due to the discrepancy from measured values of horizontal stress magnitude, it was considered necessary to add the tectonic stress by shifting the log-derived stress profile, as discussed further in the next sub-chapter. Closure pressure from testing analysis is the assumed measured minimum horizontal stress. Adjustment is made by adding an additional stress term as mentioned in the work of (Ahmed, Markley and Crary, 1991)

(Cipolla, Liu and Kyte, 1994) (Iverson, 1996) and (Gatens and Lancaster, 1990), hence shifting the profile to match the measured value, based on the following equation:

$$S_h = \frac{v}{1-v}(S_V - \alpha P) + \alpha P + \sigma_{tect}$$
(4.32)

However, with this method, depending on which formation the tectonic stress was calibrated from, it only applies to that same type of formation. If the tectonic stress gradient is based on matching closure pressure from sandstone, the log will mimic the strain-corrected log for all the sandstone but will be very different in shale. If we had calibrated the tectonic stress from shale, then the log would have matched the corrected log in shale and be less accurate in sand. (Blanton and Olson, 1999)

4.3.2. Method 2: Blanton Olson

Blanton and Olson (1999) developed new constants which involved the properties of the rock Young's modulus and Poisson's ratio for each incremental measurement.

$$C_1 = \frac{E}{1 - \nu^2}$$
(4.33)

$$C_2 = \frac{vS_V + (1 - 2v)\alpha P + E\alpha_T \Delta T}{1 - v} \tag{4.34}$$

In the absence of measured value for the thermal coefficient of expansion α_T , 5.56E-6/F can be used for sandstones, 5.00E-6/F for shale and 4.44E-6/F for carbonates. ΔT can be included from local knowledge of geothermal gradient or estimated from the static bottom hole temperature versus depth (Blanton and Olson, 1999). The minimum horizontal stress equation is given by:

$$S_h = \nu C_1 \varepsilon_{tect} + C_2 \tag{4.35}$$

$$\varepsilon_{tect} = \frac{S_{h}^{'} - C_{2}^{'}}{\upsilon C_{1}^{'}} \tag{4.36}$$

The primes in the last equation indicate that these terms are associated with the particular depth at which the minimum horizontal stress has been measured with testing data. Since this strain corrected method accounts for the variation in rock properties through the section, we can calibrate it using closure pressure data from either shale or sandstones and still get a good overall match.

4.3.3. Method 3: Transverse Isotropy

Based on its sedimentary property, unconventional reservoir formation minimum horizontal stress is often calculated by the transverse isotropic vertical method. A calibrated anisotropic stress model provides a stress profile which better defines zone containment and often changes the perforating and staging strategy from that suggested by an isotropic model (Higgins, et al., 2008). The poroelasticity model of minimum horizontal stress calculation is done with the equation below:

$$S_{h} = \frac{E_{horz}}{E_{vert}} \frac{v_{vert}}{(1 - v_{horz})} \left(S_{V} - \alpha P \right) + \alpha P + \frac{E_{horz}}{1 - v_{horz}^{2}} \varepsilon_{h} + \frac{E_{horz} v_{horz}}{1 - v_{horz}^{2}} \varepsilon_{H}$$
(4.37)

Due to the unattainable method to measure tectonic strain on different directions, ε_{H} , is assumed to be two times ε_{h} .

4.3.4. Method 4: Harikrishnan

Harikrishnan and Hareland in 1995 (Harikrishnan and Hareland, 1995) developed minimum horizontal stress from a normalized Mohr failure envelope for different lithologies. Their equation is modified by adding the poroelastic constant and becomes

$$S_h = K_0(S_V - \alpha P) + \alpha P \tag{4.38}$$

Depending on lithology Ko, the coefficient for earth at rest is defined differently. Ko is defined as in equations 4.39

$$K_0 = (1 - \sin\beta) \tag{4.39}$$

 β is the angle of internal friction at failure. The equation for obtaining the angle of internal friction is given by

$$\beta = \arcsin\left(\frac{\sigma_2 - \sigma_1}{\sigma_2 - \sigma_1 + 4\Delta}\right) \tag{4.40}$$

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$$\sigma_1 = \sigma_0 [1 + a_S (P_e - \Delta)^{b_S}]$$
(4.41)

$$\sigma_2 = \sigma_0 [1 + a_s (P_e + \Delta)^{b_s}]$$
(4.42)

 σ_0 is unconfined compressive strength of rock which is acquired from Onyia equation, Andrews equation and Optimizer software. Pe is in-situ nominal confining pressure which is the pressure difference between minimum horizontal stress and pore pressure of formation. The minimum horizontal stress is obtained from equation 4.38 using the following procedure (Hareland and Harikrishnan, 1996):

- 1. An initial guess for σ_h is assumed
- 2. The values of $Pe\pm\Delta$ are calculated as the difference between the value of initial guess for σ_h and pore pressure P, $Pe\pm\Delta = \sigma_h - P$
- 3. The value of lithology dependent coefficient a_s and b_s have been previously determined, see appendix B. Angle of internal friction β is then calculated from equation 4.40.
- 4. The value of β calculated from step 3 is then used in Ko equation. This value of Ko is then used in equation 4.38 to calculate σ_{h} .
- 5. The value of σ_h obtained from step 4 is then compared to the initial guess and inputted as the guess for the next iteration. The process is repeated until successive value of σ_h converge.

4.4. TECTONIC STRESS AND STRAIN CALCULATION

Strain may be regarded as normalized displacement. When a structure is subjected to a stress state, it will deform with different magnitude of deformation depends on the size of the structure and the amount of applied stress. In order to provide the deformation as a scale-independent parameter, the concept of strain (which in its simplest form is the ratio of displacement to the underformed length) is utilized. Such displacements can also occur naturally in rock masses through the application of tectonic stresses resulting from past and present geological processes (Hudson and Harrison, 1997).

The tectonic stress value is added to conventional stress equation due to some discrepancies between the independent measured horizontal stress magnitude and log derived magnitude. A calibration is made by shifting the profile to match the measured value as reported in (Ahmed, Markley and Crary, 1991) (Cipolla, Liu and Kyte, 1994) (Iverson, 1996) and (Gatens and Lancaster, 1990). The tectonic stress is acquired by subtracting the calculated log derived stress value from measured minimum horizontal stress value as shown on equation below.

$$\sigma_{tect} = S_h' - \frac{v}{1-v}(S_V - \alpha P) - \alpha P \tag{4.43}$$

Likewise for the Blanton Olson method, tectonic strain is inversely calculated from the minimum horizontal stress equation using measured stress value.

$$\varepsilon_{tect} = \frac{S_h^{'} - C_2^{'}}{vC_1^{'}} \tag{4.44}$$

Both conventional and the Blanton Olson method assume horizontal strain in one direction equal to zero. The vertical transverse isotropy (VTI) method has different strain value from maximum and minimum horizontal direction in its equation. Due to the unattainable method to measure tectonic strain on different directions, tectonic strain in maximum horizontal stress direction, ε_{H} , is assumed to be two times tectonic strain in minimum horizontal direction, ε_{h} . The tectonic strain is calculated with the equation below:

$$\varepsilon_H = 2\varepsilon_h \tag{4.45}$$

$$S_{h} = \frac{E_{horz}}{E_{vert}} \frac{v_{vert}}{(1 - v_{horz})} \left(S_{V} - \alpha P \right) + \alpha P + \left[\frac{E_{horz}}{1 - v_{horz}^{2}} + \frac{2E_{horz}v_{horz}}{1 - v_{horz}^{2}} \right] \varepsilon_{h} \quad (4.46)$$

$$\varepsilon_{h} = \frac{S_{h}' - \left[\frac{E_{horz} \quad v_{vert}}{E_{vert}(1 - v_{horz})}(S_{V} - \alpha P) + \alpha P\right]}{\left[\frac{E_{horz} + 2E_{horz} v_{horz}}{1 - v_{horz}^{2}}\right]}$$
(4.47)

CHAPTER 5: RESULT AND DISCUSSION

Complete data was supplied by Talisman Energy Inc. and are available from well C085 for this project. Hence all calculations were performed for this well. On the other hand, a second set of data supplied by Talisman Energy Inc., B015 does not have advanced sonic and drilling data. The anisotropy method and rock strength calculation are therefore not performed for B015. Core data was only available from well C085. Dynamic to static correlations are performed using the data from well C085, and the same correlation results are then used for well B015.

5.1. STRESS MAGNITUDE FROM INJECTION FALL OFF ANALYSIS

For Well CD65 and CB65's injection fall off test data that were supplied by Talisman Energy Inc. are analyzed with Meyer & Associates MinFrac software (Meyer and Associates Inc., 2010). MinFrac was developed to aid the fracturing engineer analyze the data recorded during mini-frac treatments. It provides a method of estimating fractures efficiency, closure pressure, instantaneous shut in pressure (ISIP), net pressure, fracture dimensions and leak off coefficients prior to designing a full-scale fracture treatment. This software is a very practical tool to generate pressure vs. G-function, pressure vs. square root time and a semi log-log plots from pressure and time data acquired from the Talisman Energy Inc. The lines were drawn to decide the fracture closure time and pressure on the graphs from each well with the methods and techniques as mentioned above.

Both wells were perforated at 2644 TVD in the Lower Montney formation. CD65 was injected with 5.8 m³ of water during the test. The well was shut-in for fall-off for 13 days before the pressure recorder was retrieved. Fracture closure was identified at 29.25 kPa/m. CB65 was injected with 4.1 m³ of water. The well was shut-in for fall-off for 11 days before the recorders were retrieved. Fracture closure was identified at 30.18 kPa/m. Results of CB65 and CD65 DFIT analysis are presented on Figure 5.1 and 5.2 respectively.



Figure 5.1: Injection fall off analysis of well CB65, closure pressure is identified at 79.8 MPa for the Montney formation perforated at 2644 meter TVD. Closure pressure gradient is 30.18 kPa/m.


Figure 5.2: Injection fall off analysis of well CD65, closure pressure is identified at 77.3 MPa for the Montney formation perforated at 2644 meter TVD. Closure pressure gradient is 29.25 kPa/m.

On the CD65 DFIT test a second closure pressure with a magnitude of 24.3 kPa/m was identified from the injection fall off analysis approximately 12 hours after the first closure pressure, as shown on Figure 5.3. This value is equivalent with the overburden stress calculated from the density log data. We believe that during the water injection, the pressure has caused both a horizontal and vertical fracture to initiate. The horizontal fracture opened against overburden stress which is a lower magnitude stress and the vertical fracture opened against minimum horizontal stress at a higher magnitude. During the pressure fall off period, the vertical fracture closed before the horizontal fracture. As illustrated on Figure 5.4, the vertical fracture opened against minimum horizontal fracture closing at a lower pressure value. Overburden (vertical stress) is computed by integrating formation density. This means that in the case of having the closure pressure equal to the computed overburden, the minimum horizontal stress may be equal or greater than the vertical stress (Frydman and Ramirez, 2006).



Figure 5.3: Second closure pressure identified for CD65 at 64.3 MPa for the Montney formation perforated at 2644 meter TVD with 24.3 kPa/m pressure gradient.



Figure 5.4: Horizontal wellbore cross-section of fractures from CD65. (a) Represent condition of both fractures after pressure injection. (b) Vertical fracture which opened against S_h closed at 29.7 kPa/m as shown on first closure pressure from DFIT analysis. (c) Horizontal fracture which opened against Sv closed afterward at a lower pressure at 24.3 kPa/m.

Hubbert and Willis (1957) has mentioned that in regions which are being short-ended, either by folding or thrust faulting, the least stress should be vertical and equal to the pressure of the overburden, while the greatest stress should be horizontal and probably between two and three times the overburden pressure.

For quantitative analysis of the data, a sensitivity level of about 5 Psi (35kPa) and an accuracy level of about 25 Psi (175kPa) are generally sufficient (Nolte, 1988).

Fairhurst (2003) confirms the possibility that a horizontal fracture could develop and propagate from the well in preference to the vertical fracture if stress acting along the axis of the borehole is low compared to the tangential stress required causing the vertical fracture. Bedding planes that intersect the hole would further facilitate opening and propagation of the horizontal fracture (Fairhurst, 2003).

5.2. OVERBURDEN STRESS

The before and after correction of log density readings compared to core density for each C085 and B015 are shown on Figure 5.5. Core density values from C085 were higher compared to the logging density values and core density from the B015 values were lower than the logging density values. Due to the higher barite amount used in well C085, it is suspected that it was overcorrected for its density, hence has a lower density reading. Well B015, on the other hand, has less barite value, and was probably not barite corrected during the logging operation by the service company. The small amount of barite in B015 still managed to increase the density reading by about 50 kg/m³ on the average. It is common knowledge that different service companies have different density correction algorithms and different standard operating procedures for this practice. Typically a correction request is made from either the geologist or petrophysicist in the operating company. Data provided for both wells are in LAS format without printed logs from the service company. Therefore there are no means to track any prior correction made on this data.



Figure 5.5: Comparison of bulk density from logging data in the green curve before and after correction toward density from side wall plug data of well C085 on the left and B015 on the right.

After the correction, C085 has a higher density reading and B015 has a lower density reading, each matched to its core density value correspondingly. Comparison of the log density value for both wells is shown on Figure 5.6. Log density values of C085 and B015 has an improved agreement after the correction. Due to the difference of formation thickness and formations exact depth, B015 bulk density data is not shown continuously in Figure 5.6.

Figure 5.7 shows the overburden stress comparison for well B015 and C085 before and after density was corrected. There was about 3.2MPa (464 Psi) difference in overburden magnitude before correction and 2.1MPa (300Psi) after correction on the average for the final overburden value. This value is quite significant considering 2 MPa difference will require an extra 1x 1000 horsepower pump during the hydraulic fracturing operation with a pumping rate of 80 bpm (LaFollette, 2010).



Figure 5.6: Comparison of C085 bulk density logging data in red to B015 bulk density logging data in blue before correction (Left) and after correction (Right). Due to the difference of formation thickness, B015 bulk density data is not shown continuously.



Figure 5.7: Overburden comparison from well B015 and C085 before and after density was corrected. There was 3.2MPa (464 Psi) differences in magnitude before correction and 2.1MPa (300Psi) after correction on average.

5.3. PORE PRESSURE

To provide a better comparison between density and sonic data on the same scale, both data are compared in their calculated porosities using equation 3.4 and 3.5 for density and sonic porosity respectively. Figure 5.8 compares the density and sonic porosities in respect to gamma ray value and depth. Depth, on Y-axis is increasing going down, while porosity in X-axis is increasing going right. Gamma ray value in gapi is increasing from blue to red color code, with dark blue for gamma ray less than 40 gapi and dark red for gamma ray between 140 to 180 gapi. The density does not show any distinctive pattern and is almost analogous with change of depth and gamma ray. Sonic porosity decreases with increasing depth and increases with increasing gamma ray. The sonic porosity is clearly indicating a better pattern of change in pore pressure than the density porosity does. It is confirmed that more accurate pore pressure can be predicted from sonic log for this study. The sensitivity of the sonic porosity in shales, high gamma ray material, suggests that sonic velocities from the interbedded shales may be used to estimate pore pressure in heterogeneous tight gas reservoirs such as the Montney and Doig formations.



Figure 5.8: Density and sonic porosity from well B015 with variation in gamma ray. Above: Density porosity is almost constant with depth and does not vary with variation in gamma ray. Below: Sonic porosity showing decreased porosity with depth but increase with the increase of gamma ray.

From the calculated normal compaction profile, over-pressured zones are spotted from depth 1300-1485 meters and 2100 meters until total depth as seen in Figure 5.9. An increase in mud density was also observed during drilling of these zones as reported in daily drilling reports. As per Chilingar, et al., the coexistence of normal and abnormal formation pressures in the same geologic state can happen if one or more of the formations are impermeable to the vertical hydraulic communication. The hydrostatic, fluid pressure gradient cannot exceed the pressure gradient of the total overburden stress. Thus, any reservoir with a hydrostatic gradient between 0.465 and 1.0 Psi/ft is considered to have an abnormally high pressure (Chilingar, Serebryakov and Robertson, 2002).

The predicted pore pressure for well B015 can be observed in detail in Figure 5.10 which is plotted with hydrostatic pressure, drilling mud pressure and overburden pressure. The resulted pore pressure estimation as discussed in the methodology section herein fit perfectly with the real circumstances of the rest of the pressure related data. The pore pressure is equal to the hydrostatic pressure value on zones where the formations were compacted normally. Conversely, in the zone where overpressure is observed, pore pressure is higher than hydrostatic pressure but lower or comparable to the drilling mud pressure. Pore pressure itself will not extend higher than the total overburden or vertical pressure because pore pressure and rock effective pressure will add up to the value of the overburden stress.

Even though the pore pressure is higher than the mud pressure around depth 1400– 1500 meters, one may not expect a kick. There was no kick reported during drilling for both of these wells. It is because, like any other oilfield activity, drilling is a very complex process. A blowout or kick during drilling does not happen merely because the pore pressure is higher than the drilling mud pressure. It depends on the rock mechanical properties and permeability, and might cancel out the effects of each other. Rock with higher permeability will have a good mudcake built during drilling, hence a slight increase of pressure differential during drilling will not cause formation fluid to enter the wellbore and vice versa.

Calculated formation pore pressure for both C085 and B015 wells are compared in Figure 5.11. The pore pressures in the same formations in both wells were predicted with value of less then 8% difference. Well B015 was drilled right after C085 was drilled and took only 50 days to complete, compared to 63 days for C085. With the similar pore pressure trend as C085, well B015 was drilled with lower drilling mud weight safely.



Figure 5.9: (Left) Calibrated normal compaction curve from both density and sonic porosity on a normally compacted zone. (Right) Density and sonic porosity from well B015 indicating overpressure at depth 1300-1485 meter and 2100 meter to TD.



Figure 5.10: B015 pore pressure predicted with sonic velocity log data compared to hydrostatic, drilling mud pressure and overburden pressure.



KB = 819.03 m





Figure 5.11: Comparison of C085 (Left) and B015 (Right) pore pressure predicted from sonic velocity log data. B015 well was drilled after C085, notice the decrease in mud density during the drilling of B015.

5.4. ROCK MECHANICAL PROPERTIES

5.4.1. Young's Modulus and Poisson's Ratio

5.4.1.1. <u>Isotropy</u>

The correlation between isotropy core static elastic properties and sonic calculated dynamic properties are correlated as shown on Figure 5.12. Isotropy Young's modulus and Poisson's ratio for well C085 and B015 are shown on Figure 5.13. The average dynamic Young's modulus' value is 8 GPa higher than the static value. Dynamic Poisson's ratio is slightly higher than the static Poisson's ratio too. The correlation of static from dynamic Young's modulus and Poisson's ratio used for both wells are specified below:

 $E_{static} = 0.809 E_{dynamic}$ $v_{static} = 0.9857 v_{dynamic}$



Figure 5.12: Isotropy Young's modulus (Left) and Poisson's ratio (Right) correlations between core elastic properties static value (Y-axis) and sonic calculated dynamic value (X-axis).

Even though both B015 and C085 wells are logged with different version of sonic tools, Young's modulus and Poisson's ratio properties from well B015 are strongly comparable to corresponding properties from C085 well for similar formation. Young's modulus from well B015 matched very well with Young's modulus from C085 for the Doig Phosphate and the Montney formation, and with slightly higher values for the formation above the Doig. Poisson's ratios from B015 are slightly lower than C085 for the entire formation.

Shaly formation has a higher Poisson's ratio as compared to less shaly formation. Due to the content of clay in the shale formation, the axial and transverse strain deformation will not be similar, resulting in higher Poisson's ratio value. This is true for both the static and dynamic Poisson's ratio values for shaly formations. Due to the content of shale, sonic waveform will travel slower compared to the sonic velocity in stiffer rock. This resulted in higher compressional transit time and even higher shear transit time, which are the components required for the Poisson's ratio calculation. Both the Doig Phosphate and Montney are shaly formation with higher Poisson's ratio. However, Young's modulus is lower on shaly formation or less brittle formation such as the Montney and Doig and higher for more brittle formation on top of the Doig.



Figure 5.13: Comparison of isotropy dynamic (green curve) and static (blue curve) Poisson's ratio and Young's modulus for well C085 (Left) and B015 (Right) related to each formations. Core static Poisson's ratio and Young's modulus (red dot on C085 log) are available from C085 and are used as the correlation point for both wells.

5.4.1.2. Anisotropy

Regression analysis of static properties from core data and dynamic properties from sonic data are performed for each corresponding depth as shown on Figure 5.14. The correlations for dynamic and static mechanical properties are established as follow:

 $E_{vert static} = 0.8466 E_{vert dynamic}$ $E_{horz static} = 0.6393 E_{horz dynamic}$ $v_{vert static} = 1.2604 v_{vert dynamic}$ $v_{horz static} = 1.1552 v_{horz dynamic}$

The average dynamic horizontal Young's modulus' value is 12 GPa lower than the average dynamic vertical Young's modulus value. Static horizontal Young's modulus has a higher range of variation compared to static vertical Young's modulus. Horizontal Young's modulus has a higher range between its lowest and highest value, but vertical Young's modulus has less variant. This indication is clearly noticeable from the core static value for both vertical and horizontal Young's modulus as shown on Figure 5.15. On the other hand, vertical Young's modulus has a more character following the change of lithology compared to the horizontal Young's modulus. Overall the Young's modulus signature is similar with the isotropy result, where shaly formation has lower Young's modulus and more brittle sandy formation has higher Young's modulus.

Poisson's ratio value for static and dynamic, as well as horizontal and vertical direction, are all almost equal, with less than 0.05 difference on the average. Vertical Poisson's ratio value is slightly higher than horizontal Poisson's ratio. In general, the Poisson's ratio value is following the lithology where shaly formation has higher Poisson's ratio and sandy formation has lower value.



Figure 5.14: Anisotropy Young's modulus (Left) and Poisson's ratio (Right) correlations between core elastic properties static value (Y-axis) and sonic calculated dynamic value (X-axis) each for vertical direction (green) and horizontal direction (blue).



Figure 5.15: Comparison of anisotropy dynamic (green curve) and static (blue curve) Poisson's ratio (middle track) Young's modulus (right track) for well C085 each for vertical and horizontal direction compare to the axis of formation bedding plane. Core static Poisson's ratio and Young's modulus are shown in red dot on each log.

5.4.2. Rock Strength

The rock strength value results are presented on Figure 5.16. Onyia rock strength is merely depended on the sonic compressional velocity value as shown on equation 4.21. Andrews rock strength was calculated using equation 4.22, which use velocity and porosity in the equation. Both Onyia and Andrews rock strength match reasonably well, with less than 40 MPa difference on the average. Andrews rock strength is higher, 50 MPa on the average, compared to the Onyia rock strength for the Doig and Montney formations which has a very low porosity. On the other hand, the Onyia calculated rock strength resulted in slightly higher values for all other formations above the Doig compared to the Andrews calculated rock strength. Both Onyia and Andrews rock strength has lower value for the shaly formation such as the Montney and Doig and has higher value for less shaly formation above the Doig. Rock strength values for the Montney and Doig are around 120 MPa, while the less shaly formation above them has an average 185 MPa value.

The Apparent Rock Strength Log (ARSL) was generated from the Optimizer software and show more signature as compared to the Onyia and Andrews rock strengths. Other than the strong relation with pore pressure, the ARSL was also calculated from drilling data such as ROP and WOB which fluctuated during drilling. The ARSL is also strongly affected by pore pressure. Formation with high pore pressure such as that of depth 2100 – 2150 meters and below 2300 meters have a high rock strength value. For the normally compacted formation with normal pore pressure around 2150-2290 meters, the ARSL rock strength is equivalent to the Onyia and Andrews results. The ARSL for the Montney and Doig are quite high, averagely around 250 MPa. Generally, the ARSL result match better to static core rock strength from laboratory data than compared to the Onyia and Andrews methods.



Figure 5.16: C085 rock strength value calculated with the Onyia equation (black curve), the Andrews equation (red curve) and the Optimizer software (purple curve). Core acquired rock strength value are presented in red dot.

Figure 5.17 shows the original result of the ARSL from the Optimizer software from depth 1890 – 2640 meters for well C085 before the ARSL was converted to UCS value using equation 4.24. First track is the lithology track showing the amount of shale for each depth with the name of formation on the track. The Doig Phosphate and the Montney have the highest shale value which is shown on a darker green scale. Second track is apparent rock strength show in MPa scale from 0-1000. The rest of the track in a sequence order are ROP, WOB, RPM, Flowrate, Plastic Viscosity of drilling mud, Pore Pressure (pink curve) and Mud Weight (blue) in same track, Bit Wear and Bit Info track on the right.



Figure 5.17: The ARSL from the Optimizer software shown on second track with blue curve. The ARSL is generated from drilling, bit and lithology data.

5.5. TECTONIC STRESS AND STRAIN

Tectonic effects for both wells are calibrated from the Lower Montney formation at depth 2500-2550 meters from calculated logging data. Minimum horizontal stress value used for the calibration purpose is acquired from DFIT analysis results of well CB65 and 81

CD65. The average value between those two data is used as the calibration value. Closure pressure from well CB65 and CD65 is 79,811 kPa and 77,351 kPa respectively. Average value of 78,581 kPa is used as a calibration point for well C085 and B015 at depth 2550 meters.

The tectonic stress and strain value from the inverse calculation of all four methods of minimum horizontal stress equation is then correlated to depth 2550 meters and zero value is used for ground level. A linear relation is drawn for each method from value at surface ground level to total depth. Linear equation of each method is used to calculate the tectonic stress and strain value for each incremental depth which is later use to calculate minimum horizontal stress.

Conventional method used equation 4.43 to calculate tectonic stress. Tectonic stress for well C085 is 6437.6 Psi and B015 is 6720.8 Psi at depth 2550 meters.

Conventional Method	C085	B015
Sh'	11397 Psi	11397 Psi
$\left(\frac{v}{1-v}(S_V - \alpha P) + \alpha P\right)$	4959.4 Psi	4676.2 Psi
σ_{tect}	6437.6 Psi	6720.8 Psi

$$\sigma_{tect} = S_h' - \left[\frac{v}{1-v}(S_V - \alpha P) + \alpha P\right]$$
(4.43)

Table 5.1: Tectonic stress calibration value for conventional method.



Figure 5.18: Conventional method tectonic stress calibration for well C085 (Left) and B015 (Right).

Blanton Olson method uses equation 4.44 to inverse calculate tectonic strain value. Tectonic strain for well C085 and B015 is 5.474E-03 and 5.159E-03 at depth 2550 meters respectively.

$$\varepsilon_{tect} = \frac{S_h^{'} - C_2^{'}}{\nu C_1^{'}} \tag{4.44}$$

Blanton Olson Method	C085	B015	
Sh'	11397 Psi	11397 Psi	
V	0.1985	0.2104	
C1	5.925E06 Psi	6.191E06 Psi	
C2	4959.8 Psi	4677.8 Psi	
E _{tect}	5.474E-03	5.159E-03	

 Table 5.2: Blanton Olson tectonic strain calculation for well C085 and B015



Figure 5.19: Blanton Olson method tectonic strain calibration for well C085 (Left) and B015 (Right).

The vertical transverse isotropy method is only applied to well C085 due to the unavailability of advanced sonic data for well B015. VTI method uses equation 4.47 to inverse calculated tectonic strain value. Tectonic strain for well C085 is 8.156E-04 at depth 2550 meters.

$$\varepsilon_{h} = \frac{S_{h}' - \left[\frac{E_{horz} \quad v_{vert}}{E_{vert} (1 - v_{horz})} (S_{V} - \alpha P) + \alpha P\right]}{\left[\frac{E_{horz} + 2E_{horz} v_{horz}}{1 - v_{horz}^{2}}\right]}$$
(4.47)

VTI Method	C085
Sh'	11397 Psi
V _{Horz}	0.1762
E _{Horz}	5.747E6 Psi
$\frac{E_{horz}}{E_{vert}} \frac{v_{vert}}{(1 - v_{horz})} (S_v - \alpha P) + \alpha P$	4854.7 Psi
ε_h	8.156E-04

 Table 5.3: Vertical transverse isotropy tectonic strain calculation for well C085.



Figure 5.20: Vertical transverse isotropy method tectonic strain calibration for well C085.

Minimum horizontal stress calculated from rock strength does not match well with measured minimum horizontal stress results. Hence tectonic stress is added to the calculated value similar to the conventional method. Below describes the tectonic value added to each stress generated from rock strength from Onyia, Andrews and ARSL respectively.

Harikhrisnan Method	Onyia	Andrews	ARSL
Sh'	11397 Psi	11397 Psi	11397 Psi
Sh	4821.9 Psi	4443 Psi	4307.2 Psi
σ_{tect} (2550m)	6575.1 Psi	6954 Psi	7090.2 Psi

 Table 5.4: Tectonic stress calculation for Harikrishnan method with three different rock strength values.



Figure 5.21: Tectonic stress calibration for Harikhrishnan method, each for stress generated from rock strength using the Onyia equation (Top Left), Andrews equation (Top Right) and the Optimizer (Bottom).

5.6. MINIMUM HORIZONTAL STRESS

In general, the conventional methods predicted a very plain minimum horizontal stress profile for both wells across the Inga formation to the Montney formation at around 30kPa/m. The tectonic stress calculated from the conventional method is 1.2 times higher than the initial calculated stress before calibration. Due to the high tectonic effect in this area, merely adding tectonic stress to the whole profile has produced a flat minimum horizontal stress in regard to the different formations. Conventional method will not provide any zone barrier information for hydraulic fracturing design in this area.

VTI and Blanton Olson methods, on the other hand, incorporated the changes of rock mechanical properties at each incremental depth to the minimum horizontal stress after

the tectonic strain is added. However, unlike VTI method, Blanton Olson method does not put into account the effect of the different rock properties on horizontal and vertical direction. Blanton Olson method predicted the highest minimum horizontal stress among all other methods due to the lower Poisson's ratio value calculated assuming isotropy. Lower Poisson's ratio will generate a higher minimum horizontal stress. VTI method are affected the most by the horizontal Poisson's ratio which is higher compared to the isotropy Poisson's ratio and resulted in a lower VTI minimum horizontal stress.

It is also worth noting that tectonic affects minimum horizontal stress the most of all parameters for this area. A 30% decrease in tectonic strain will cause 20% decrease in all minimum horizontal stress calculated with any method.

There are several zones where all three methods are measuring similar minimum horizontal stress magnitudes, such as the Doig formation at depth 2190-2210 meters and 2250-2255 meters. These are the formation which is more isotropic compared to other formations from the same well. Hence the rock properties in different directions are equal and produce equal Sh magnitude for all methods. This conclusion is confirmed from the borehole image log from the same depth, in which the formation does not show a bedding plane. The formation seems to be very homogenous with some borehole breakouts which also confirm that the minimum horizontal stress was lower compared to other formations which resulted in borehole breakout on Sh direction. Details from the formation borehole image log compared side by side with the Sh magnitude is shown on Figure 5.23 for depth 2190-2210 and 2250-2255 meters.

On the other hand, formations where all three methods of Sh calculation show different magnitudes are anisotropy formations. Figure 5.24 shows anisotropy formations between 2210-2240 meters from well C085. Formation with anisotropy and have higher Sh value is a good zone containment formation for hydraulic fracturing. This is key information required during the fracturing design, before the completion engineer decides perforation and hydraulic fracturing depths, which is not available from the conventional Sh calculation alone.

Injection fall off pressure decline analysis revealed two closure pressures at 29.7 kPa/m and 24.3 kPa/m which correspond to the minimum horizontal stress and overburden stress respectively. This finding confirms that both horizontal and vertical fractures were opened in this well during pressure injection. During the pressure fall off period, the vertical fracture which corresponds to minimum horizontal stress closed first and several hours later the horizontal fracture, which represent overburden stress, closed. It also confirms that this area is a thrust fault regime where overburden stress is the least principal stress.



Figure 5.22: Minimum horizontal stress result from the Conventional (green curve), the Blanton Olson (red curve) and the VTI method (blue curve) for C085 (Left) and B015 (Right).



Figure 5.23: Borehole image log showing isotropy formation for depth 2190-2210 meter (Left) and 2250-2255 meter (Right) from well C085. These are formations with lower Sh hence encountered break out during drilling. At depth 2258 meter, on the right picture shows a distinct separation from isotropy formation to anisotropy formation between 2257-2258 meter.



Figure 5.24: Borehole image log showing formation between 2210-2240 meter to be transversely isotropy with lots of bedding planes show perpendicular to borehole axis. Sh calculation shows some effects of anisotropy to the Sh magnitude.

Minimum horizontal stress calculated with Harikrishnan method with three different rock strength properties, each from Onyia equation, Andrews equation and the Optimizer software is presented in Figure 5.25. Sh calculated from Onyia and Andrews rock strength have flat results with very little fluctuations. It has fewer signatures than the Sh from the conventional method. Other than the high tectonic stress effect, Harikrishnan method tends to smooth out the Sh curves from all the calculated rock strength values. The Sh from ARSL shows equivalent value with all other methods for Montney formation. Similar with the rock strength, Sh from ARSL is highly affected by the pore pressure value. Formations with higher pore pressure has higher Sh magnitude calculated using the ARSL. Sh generated from rock strength has a proportional relation with the value of rock strength, the higher the rock strength, the higher the stress.

Figure 5.26 shows Sh comparison for Montney formation only, which has equivalent Sh magnitude with all 4 methods of calculation.



Figure 5.25: Minimum horizontal stress comparison of well C085 with all methods of calculation.



Figure 5.26: Minimum horizontal stress comparison of well C085 for the Montney formation.
CHAPTER 6: CONCLUSIONS AND FUTURE RECOMMENDATIONS

6.1. CONCLUSIONS

From this study and using the data provided by Talisman Energy Inc. in the Altares area in British Colombia, Canada, the following conclusions can be drawn.

- 1. Injection fall off pressure decline analysis revealed two closure pressures at 29.7 kPa/m and 24.3 kPa/m which correspond to the minimum horizontal stress and overburden stress respectively. During the pressure fall off period, the vertical fracture which corresponds to minimum horizontal stress closed first and several hours later the horizontal fracture, which represents the overburden stress, closed. It also confirms that this area is a thrust fault regime where overburden stress is the least principal stress.
- 2. High barite content in drilling mud will increase density readings. However, a standard barite correction algorithm may over correct the density value. A proper logging density correlation with core density data is the best approach to accurately correct the density value.
- 3. Overburden stress calculation is a straightforward integration from corrected density logging data. Proper quality control of density logging data is important for an accurate overburden stress computation.
- 4. Pore pressure value is an important factor for stress calculation, but is difficult to measure directly in low permeability formation such as the Montney and Doig.
- 5. Sonic velocity values show significant change between a normally compacted formations and abnormally compacted formations. Sonic velocity is a good indication for pore pressure prediction.
- 6. Minimum horizontal stress is generated with three methods from the Young's modulus and Poisson's ratio properties and one method from rock strength properties. Tectonic stress or strain effects are calculated from minimum horizontal stress value measured from testing data.

- Even though both B015 and C085 wells are logged with different version of sonic tools, their Young's modulus and Poisson's ratio properties are strongly comparable for similar formations.
- Shaly formation, such as the Montney, has higher Poisson's ratio and lower Young's modulus, while more brittle formations have a higher Young's modulus and lower Poisson's ratio.
- 9. Horizontal Young's modulus has a higher magnitude than vertical Young's modulus. However, the vertical Young's modulus has more "character" following the trend change of lithology compared to the horizontal Young's modulus.
- 10. The static and dynamic Poisson's ratio values for horizontal and vertical direction are almost equal, with less than 0.05 difference averagely. The vertical Poisson's ratio value is slightly higher than horizontal Poisson's ratio.
- 11. Onyia and Andrews' rock strength have lower value for shaly formation such as the Montney and Doig at about 120 MPa and has higher value for the less shaly formation above the Doig around 185 MPa.
- 12. The ARSL is strongly affected by pore pressure. Formation with high pore pressure has a high rock strength value. In the normally compacted formations, the ARSL rock strength is equivalent to the Onyia and Andrews' result. The ARSL result has a better match to static core rock strength from the laboratory compared to the Onyia and Andrews rock strength.
- 13. Average value of 78,581 kPa is used as tectonic calibration value for well C085 and B015 at depth 2550 meters. Tectonic stress of 6437.6 Psi and 6720.8 Psi is added to the conventional method for C085 and B015 respectively. Tectonic strain for well C085 and B015 is 5.474E-03 and 5.159E-03 respectively. VTI tectonic strain for well C085 is 8.156E-04. Tectonic stress of 6575.1, 6954 and 7090.2 Psi is added for the Onyia, Andrews and ARSL Harikrishnan method respectively.
- 14. The conventional method predicted a very plain minimum horizontal stress profile for both wells across the Inga to the Montney formation at around 30 kPa/m. The tectonic stress calculated from conventional method is 1.2 times higher than the initial

calculated stress before calibration. Due to the high tectonic effect in this area, merely adding tectonic stress to the whole profile has produced a flat minimum horizontal stress across the different formations. The conventional method will not provide any zone barrier information for hydraulic fracturing design in this area.

- 15. The VTI and Blanton Olson methods incorporate the changes of rock mechanical properties at each incremental depth to the minimum horizontal stress. The Blanton Olson method does not put into account the effect of the different rock properties on horizontal and vertical direction. The Blanton Olson method predicts the highest minimum horizontal stress among all other methods. Lower Poisson's ratio generates a higher minimum horizontal stress. The VTI method is affected the most by horizontal Poisson's ratio which is higher compared to the isotropy Poisson's ratio and resulted in a lower VTI minimum horizontal stress.
- 16. Some formations are more isotropic compared to others. Isotropic formations, which rock properties are equal in different directions, produce equal Sh magnitude calculated from all methods. This conclusion is confirmed from the borehole image log from the same depths.
- 17. Anisotropic formations have higher Sh value and are good containment zones for hydraulic fracturing.
- 18. All Sh generated from 4 methods and different rock strength calculations have equivalent magnitude for the Montney formation.

6.2. FUTURE RECOMMENDATIONS

- 1. Generate a correlation of drilling-derived Sh to logging-derived Sh for horizontal well application. This would further confirm the possibility of calculating Sh without logging data in a difficult logging environment such as the horizontal wells.
- 2. Perform Sh calibration with more than one closure pressure from DFIT data at different formations. This would improve the calibration methodology and confirm the accuracy of continuous Sh magnitude in more than one formation.

- 3. Use micro-seismic data to confirm the direction of fracture propagation for the formation to confirm the precision of DFIT data analysis.
- 4. Evaluate current methodology with more wells' logging and drilling data for the Montney or any other field, in mountainous or non-mountainous area. This would further confirm these methodologies for a wider field application.

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APPENDIX A. BIOT'S CONSTANT CALCULATION

The parameter known as Biot's constant was first defined by Maurice Biot in 1957 (Biot & Willis, 1957) as a factor to help account for the deformation of a poroelastic material as the pore pressure changes. In various situations, Biot's constant is also known as a reduction factor, a poroelastic constant, an α factor. Terzaghi defined effective stress as shown in equation A.1, and Biot added his factor to effective stress determination as shown in equation A.2 (Miskimins, Ramirez, & Graves, 2004).

$$\sigma_e = S_t - P \tag{A.1}$$

$$\sigma_e = S_t - \alpha P \tag{A.2}$$

Biot's constant relates stress and pore pressure and illustrates how compressible the dry skeletal frame is with respect to the solid material composing the dry skeletal frame of the rock. Biot's constant measures the ratio of fluid volume squeezed out to the volume change of the rock if the latter is compressed while allowing the fluid to escape (Klimentos, et al., 1998). Biot's constant is a complex function of several parameters including porosity, permeability, grain sorting, and confining pressures. It is described as

$$\alpha = 1 - \frac{K_S}{K_{min}} \tag{A.3}$$

where

$$K_S = \frac{E}{3(1-2\nu)} \tag{A.4}$$

Ks is bulk modulus of the rock, while Kmin is modulus of the mineral or grain that make up the rocks. Bulk modulus of a material measures the material's resistance to uniform compression. Bulk modulus is calculated from E, Young's modulus, and v, Poisson's ratio which are calculated from compressional and shear velocity of sonic log data. It can be seen that α is related to the values of Young's modulus and Poisson's ratio for the matrix and reservoir, as shown below (Miskimins, Ramirez, & Graves, 2004)

$$\alpha = 1 - \frac{\frac{1 - 2v_{min}}{E_{min}}}{\frac{1 - 2v_S}{E_S}}$$
(A.5)

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Stiffer rocks have alpha less than one, while soil and unconsolidated rocks have alpha equal to one (Bachman, et al., 2011).

For this project, rock bulk modulus is calculated from sonic logging data to acquire a continuous bulk modulus profile using equation A.4. Bulk modulus calculated from sonic data is dynamic bulk modulus. Continuous static bulk modulus is then generated from a correlation of dynamic bulk modulus and static bulk modulus acquired from bulk modulus of core sample. The relation between dynamic and static bulk modulus is found to be



$$K_{s\,static} = 0.6592K_{s\,dynamic} \tag{A.6}$$

Figure A.1: Correlation of static bulk modulus from dynamic bulk modulus from well C085.

Due to the unavailability of static core data, same correlation is used to calculate B015 well static bulk modulus. The results of the semi-quantitative X-Ray diffraction (XRD) analysis are presented in Table A.2 for well C085 and Table A.3 for well B015. XRD tables list bulk mineralogy in relative weight percent along with clay abundances relative to bulk sample. Grain modulus for common known minerals is listed on Table A.1 below

from rock physics handbook (Mavko, Mukerji, & Dvorkin, 1998). Grain modulus for each core is calculated from the total mineral modulus time percentage of each mineral within that core using the equation below

 $K_{min} = (A_1 * K_{min1}) + (A_2 * K_{min2}) + (A_3 * K_{min3}) + \dots + (A_n * K_{minn})$ (A.7) $A_n = Weight of mineral n from each core (fraction)$ $K_{minn} = grain modulus of mineral n (GPa)$

Mineral	Kmin (GPa)
Quartz	37
K feldspar	37.5
Plagioclase	75.6
Calcite	70
ankerite dolomite	80
dolomite	80
pyrite	143
Fluorapatite	86.5
illite-smectite	23
illite-mica	23
Kaoline	1.5
Chlorite	1.5

Table A.1: Grain modulus for common known mineral (Mavko, Mukerji, &
Dvorkin, 1998).

Comparison of rock bulk modulus (Ks) and mineral modulus (Kmin) calculated from sonic logging data and core XRD analysis respectively is shown on Figure A.2 below for both wells. Notice mineral modulus is higher than bulk modulus of rock. This is due to the pore and fluid amount in rock samples which cause the bulk modulus to measure lower compared to grain or mineral modulus.



Figure A.2: Comparison of bulk modulus of the rock, Ks (red) and modulus of the mineral or grain that make up the rocks, Kmin (blue) between well C085 (Left) and B015 (Right).

After mineral modulus of each core is calculated, Biot's constant is calculated as per equation A.3 for each depth which has core data. Biot's constant for depth between two cores is generated from linear correlation between the cores as shown on Figure A.3. For



the rest of the depth above and below core depth, an average value of 0.6 is used as Biot's constant.

Figure A.3: Biot's Constant calculated from rock bulk modulus and grain modulus for well C085 (Left) and B015 (Right).

When the rock frames become much stiffer, the bulk modulus Ks increase. This leads to the decrease in the Biot's constant. Klimentos et al. show that clean sandstone with similar porosity to argillaceous sandstone, but a higher permeability and different type of grain to grain contact and a better sorting, exhibits a lower Biot's constant.

Klimentos et al. has shown several examples in their work how Biot's constant is a very important poroelastic parameter to the petroleum industry in particular. In his example, the predicted horizontal stress changes by about 800 Psi if the Biot's constant changes by as much as 0.25. For rock failure and sand production prediction models, Klimentos' work shows that the predicted critical flow pressure changes by about 500 Psi if the Biot's constant changes by just 0.25. This error in the prediction of critical flow pressure below which sanding takes place is too high to be ignored.

APPENDIX B: ROCK DEPENDENT COEFFICIENT (As AND Bs)

CALCULATION

as and bs are rock coefficient value for equation

$$CCS = UCS(1 + a_S P e^{b_S}) \tag{B.1}$$

Where CCS is rock confined compressive strength, UCS is rock unconfined compressive strength, Pe is the confining pressure applied during rock laboratory test or the differential pressure between borehole pressure and pore pressure in real wellbore. a_s and b_s are rock dependent coefficient which is chosen such as $a_s Pe^{bs}$ become dimensionless.

Following (Hareland and Hoberock, 1993), (Hunt, Hoberock, & Hareland, 1992) a_s and b_s are found to be 0.00881 and 0.6565 respectively.

Lithology	a _s	b _s
Shale (general)	0.00432	0.742
Sand (general)	0.0133	0.571
Average value	0.00881	0.6565

Table B.1: Confined rock strength lithology coefficients (Hunt, Hoberock, &
Hareland, 1992).