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BURIAL HISTORY AND SOURCE ROCKS CHARACTERISTICS OF THE MONTNEY FORMATION, ALBERTA BASIN, CANADA

BY

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Thesis submitted in partial fulfilment of the requirements for the degree of Masters in the Earth Science department at the University of the Western Cape.

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Abstract

More than 300 samples from the Montney Formations in the Alberta basin, offshore, Canada have been analysed with locations in various parts of the Alberta basin. These samples were mainly analyzed from two wells (well M28 & M22) to assess the organic quality, quantity as well as thermal maturation by Tmax versus PI (Production Index) from Rock-Eval Pyrolysis and Vitrinite Reflectance data. Two well locations (301 & 306) have been chosen for calibrating burial history and thermal maturation models in the Alberta basin because of their measured bottom hole temperature data which was assumed to be taken from the nearby well. These well locations also have measured Vitrinite Reflectance data which was taken directly from coal-bearing Mannville Group.

The Triassic Montney Formation silty shale and shale, was deposited within an anoxic depositional environments and shows a wide variability of organic oil and gas prone Type II, II-III and III source rocks. M22 samples display excellent organic matter quantity (TOC up to 5.80%), and Type II and Type III kerogens, which are favourable for hydrocarbon generation. The high TOC values generally indicate that the condition during the deposition of sediments was favourable for organic matter production and preservation. The genetic potential (GP) and hydrogen Index (HI) is above the minimum values required for a potential source rock, suggesting that the sediments have gas and oil generating potential**.** However, in M22, only few samples met the requirements for the organic matter quantity, quality, and thermal maturity in order to be called source rocks. This could be because the samples from M28 were collected from outcrops which are easily affected by weathering. This significantly changed the TOC values and affected thermal maturation and Rock-eval Pyrolysis parameters.

The burial history plots shows that location (306 and 301) experienced a period of non-deposition and/or erosion that began between latest Devonian-earliest Carboniferous. The second major erosional event was caused by the Late Cretaceous regional uplift that influenced petroleum generation, migration, and accumulation. The Vitrinite Reflectance values have been measured for all stratigraphic units in the Alberta basin. The immature phase for oil and gas generation is (< 0.54%), early mature (0.54-0.70%) mid mature (0.70-1.00%), late mature (1.00-1.30%) wet gas (1.30-2.00%) and dry gas generation (2.00-2.60%). The maturity history suggests that the deepest parts of the assigned source rock units entered the hydrocarbon generation already during the Triassic. The maturity increased during the upper Jurassic and reached a peak during Early Cretaceous. The burial history plots for well 301 location indicates that the timing for the start of oil generation occurred within a relatively narrow range, around 139 Ma. The generation of gas from the cracking of Woodbend group oil started from the Mid- Cretaceous to Late Cretaceous. In well 306 location, the generation of gas from the cracking of Wabamun oil began at about 80 Ma**.** However**,** the source interval matured much earlier than at well 301 location. Early oil generation began as early as 205 Ma (Upper Triassic), when burial depth was just 1703 m. The main phase of oil generation occurred 127 Ma later when the basin was buried at 1712 m**.**

DECLARATION

I declare that my research work titled ‘’ Burial history and Source rocks characteristics of the Montney formation, Alberta basin, Canada’’ is my own work, and that it has not been submitted before for any degree or examination in any other university and that all the sources I have used or quoted have been indicated and acknowledged by means of complete references.

Zandile Dwane , 2016-07-04

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Signature

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CHAPTER ONE

1.1. Introduction

The study summarizes the burial history, maturation and generation of petroleum in two well locations of the Montney Formation in the central Alberta basin part of the western Canada sedimentary basin. The Montney Formation unconformable overlies the carboniferous of Permian strata and comprises of interbedded fine grained sediments with calcareous shells of zooplankton material commonly referred to as pelagic material. This material causes the upper Montney shale to be more organic rich and radioactive. The upper Montney formation contains extremely low permeability highly laminated organic clay and silt. The Montney formation is overlain by highly radioactive shale of the doig formation and the halfway formation of the middle Triassic age. The interval between the Montney and doig formation contain organic rich stratas that have excellent potential as source rocks for the petroleum generation (Davies and Moslow., 1998).

The Alberta basin comprises approximately of about 270 billion cubic metres of conventional oil and gas. They have the oil gravity which ranges from 10-15^0 API and are hosted from the cretaceous reservoir rocks. These deposits are mostly found in the Mannville group reservoir rocks situated in the eastern part of the Alberta basin with a gravity of 15-20^0 API range. The conventional review of hydrocarbon migration is that the complete maturation of the source rocks in the Alberta basin only started during early cretaceous time. The burial history modelling show that the main hydrocarbon generation for the entire source rock in the Alberta basin started around 101 Ma. It was concluded that oil arrived at the reservoir rocks roughly at the same time span. The distribution of oil produced from cretaceous reservoir rocks in the Alberta basin maybe explained by variation in the quality, quantity and maturity of the source rock and by burial as well as thermal evolution of the basin. The Triassic source rocks formations are identified as possible source for oil and gas within the cretaceous reservoir rocks (Davies, 1997).

The evolution of the source rocks study aims to evaluate the generating hydrocarbon potential by overseeing at the capacity of sediments for the hydrocarbon generation, type of kerogen present as well as the type of hydrocarbons to be expected after generation and how the thermal maturation of sediments has influenced petroleum generation.

The maturation and source rock potential of the Triassic Montney formation was examined by Kalkreuth and McMechan (1997) and evaluated the possibilities for oil and gas generation. The geochemical result of his work show that the sediments of the Montney formation contain rich potential organic matter with type I-II and Type III kerogens which are favourable for hydrocarbon generation.

Three parameters that were used to evaluate the petroleum generation potential of the Triassic Montney formation are namely: Total Organic Carbon, Type of Kerogen and degree of thermal maturation of the kerogen. The geochemical data used for this study is the Rock Eval Pyrolysis and the Vitrinite Reflectance data.

The main objective of this research is to evaluate the Montney formation source rocks located in the central Alberta part of the Western Canada Sedimentary Basin (WCSB) by determining the quality, quantity and maturity as well as burial/thermal history. The secondary objective is to use Vitrinite Reflectance (VR) for temperature calibration on depth of burial.

The petroleum generation, accumulation and migration of the Alberta basin was influenced by two major erosional events. The older event is called the sub-mannville erosional unconformity which started from 386 and 197 Ma and was ended at about 119 Ma. The second erosional event occurred between 104 and 100 Ma and is also recorded at the burial history locations (Edwards el al., 1999).

1.2. GEOLOGICAL OVERVIEW

1.2.1. Location of the Study Area.

The Alberta basin is located on the eastern side of the Rocky Mountains in the western Canadian sedimentary basin. It stretches from the British Columbia through the Saskatchewan (fig.1). Alberta basin was formed as a result of rifting of the North American craton during the late Proterozoic. The basin is overlain by a stable Precambrian platform and bounded by Canadian Precambrian shield to the north east and Tathlina high to the north and is separated by the bow island arch from the Williston basin to the south east (Fig.1). The british Columbia and the peace river arch of the Alberta developed during the early carboniferous- Permian time. The Alberta basin was located at ≈ 30^0 N during the Triassic time. At that time, the paleoclimate ranged from mid-subtropical climate. These warm climate conditions led to the deposition of the shallow water carbonates as well as evaporates with intervention of shale at the base of a Middle Cambrian to Middle Jurassic successions in the Alberta basin (Porter, 1994).

1.2.2. *Well location*

The study area is located in the Alberta basin, offshore, Canada (figure 1). 40 wells located in the Montney formation were drilled but only two (2) wells were the main focus of the work. There wells are M22 and M28 respectively (figure 2). Only two well locations have been chosen for the burial history reconstruction. These well locations are well 301 and well 306 and are shown in figure 3.

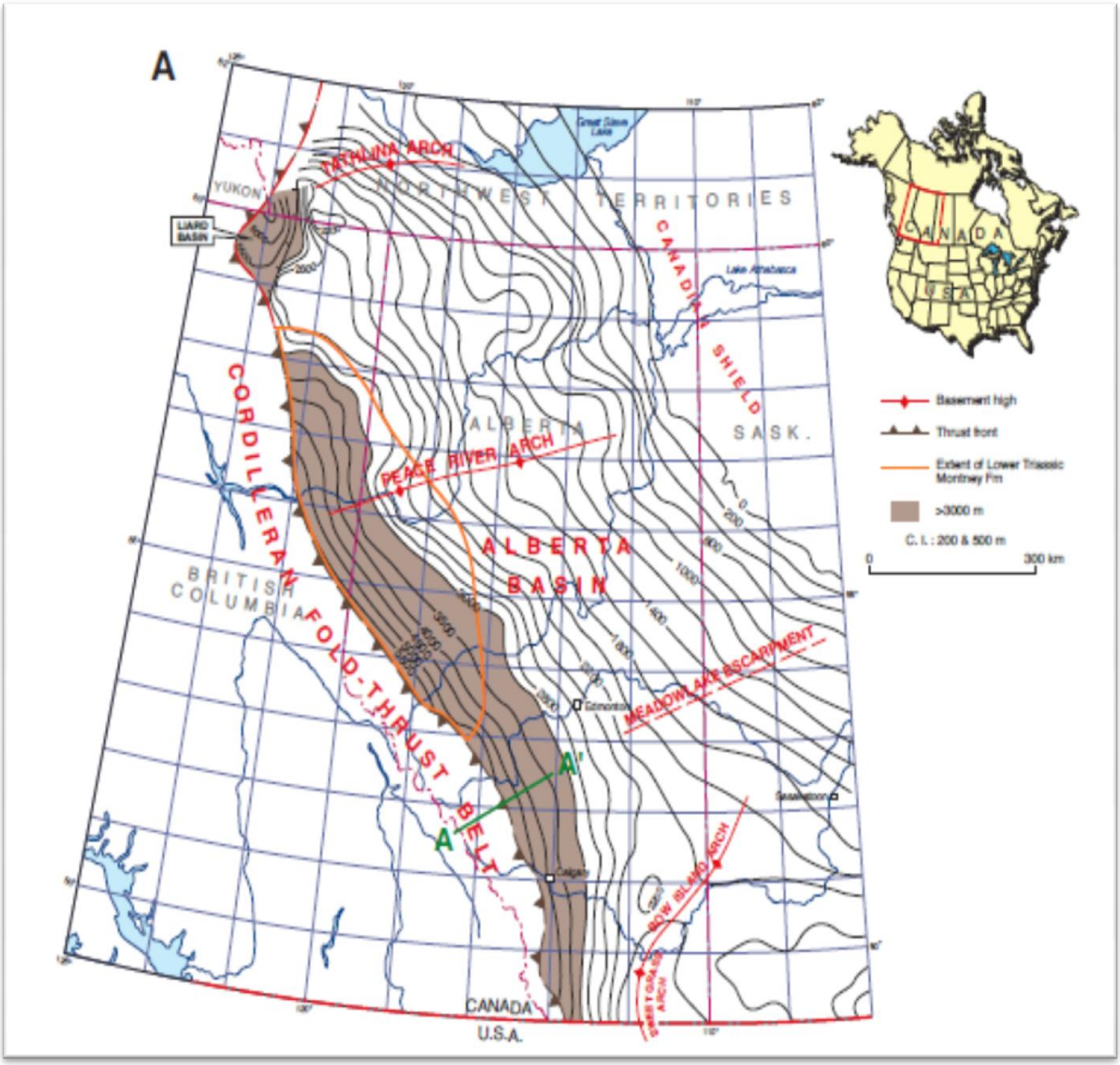

Figure 1: Shows the location map of the Alberta basin, offshore, Canada modified from (Porter, 1994)

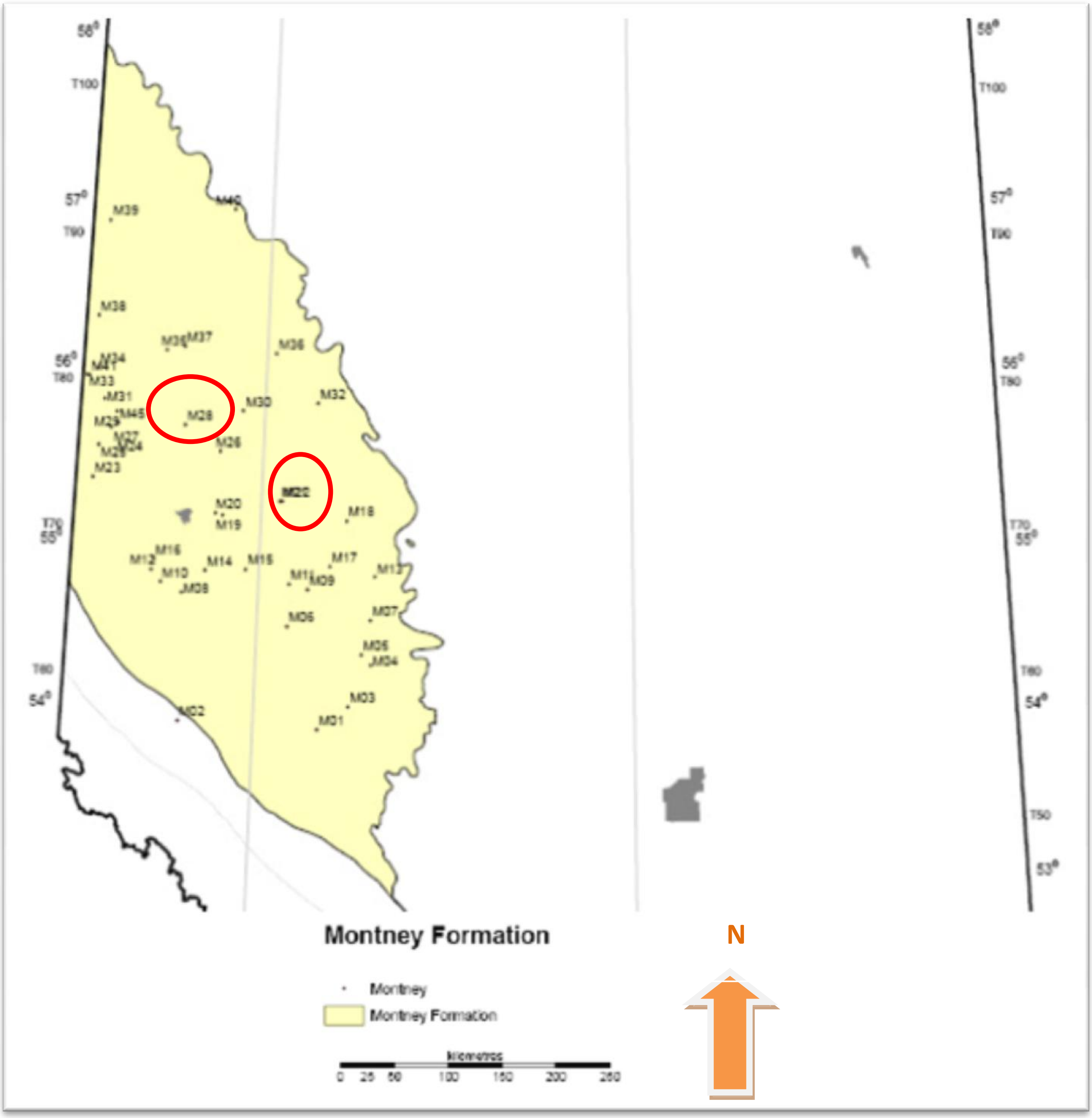

Figure 2: Shows the well location map that were drilled at the Montney formation modified from (Edwards et al., 1994)

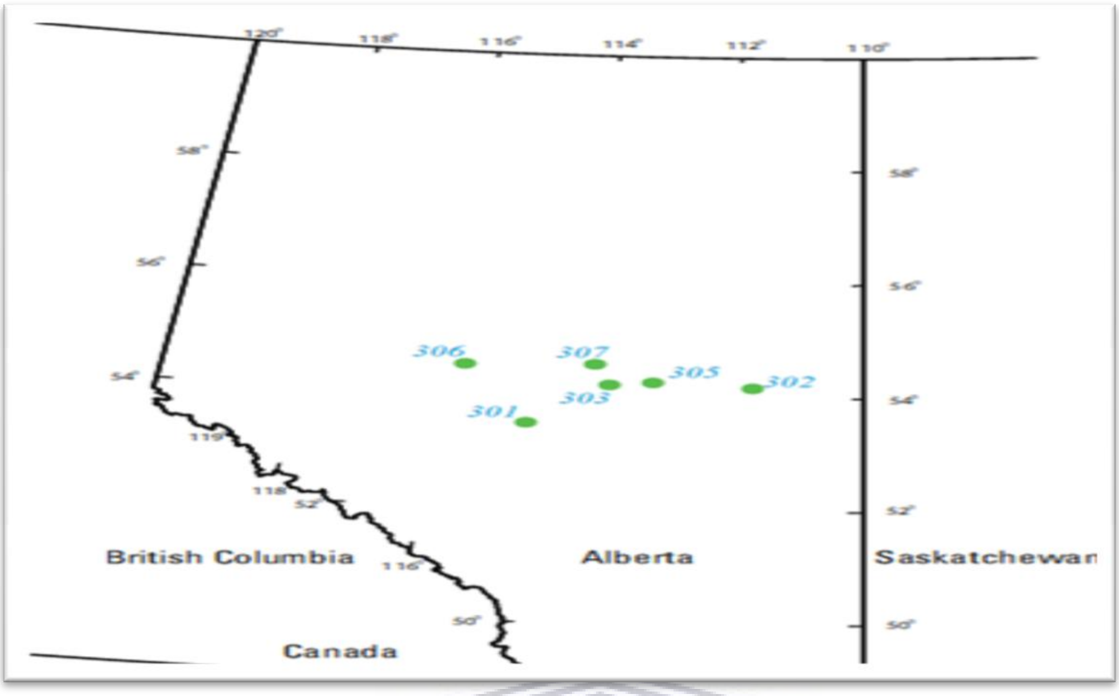

Figure 3: Shows location map of wells used in burial history reconstruction modified from (Richards, 1998)

1.2.3. Stratigraphy and Depositional Facies

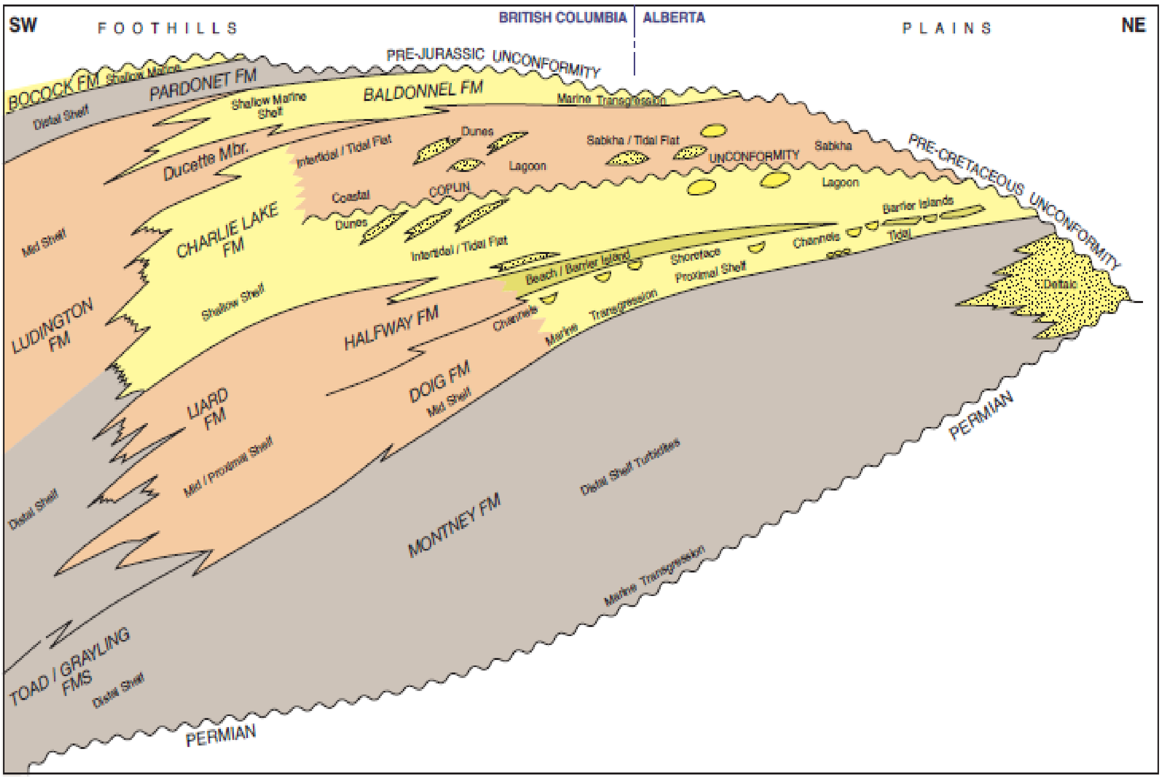

Figure 4: Schematic cross section showing the stratigraphic relationship of Triassic formation modified from (Edwards et al., 1994).

According to Lee (1998), the peace river arch subsurface comprises of the Triassic formations of the Alberta basin and these formations were deposited as a series of the 3 major T-R (Transgressive – Regressive) third order cycle. As shown in figure 4, the Triassic formations include the Montney, Doig, Halfway, Charle Lake, Baldonnel and Pardonate formations (oldest-youngest). The first cycle includes the the sediments which are deposited along the delta as well as those sediments that are influenced by tides. The environment of deposition shows similarities to tidal coastlines and barrier island whereas the third environment is characterised by shallow water carbonates deposits (deposited under warm climate conditions).

The deposition of the lower Triassic started with a major marine transgression eastward and was followed by a regression. The results of this Transgression-regression deposition cycle was the deposition of the Montney formation which is 395 m thick. The first deposition occurred in the westward open-shelf marine environment. The middle Triassic epoch began with the second of the three T-R cycles, a regional transgression depositing sediments of the doig formation (185 m thick) which is mainly phosphatic shales, siltstone and conglomarates, this suggest that the basin was subjected to submarine erosion or to an interval of non deposion prior to cycle two transgression. Following the transgression, the shelf was again subjected to regression during which the halfway formations was deposited. These stratas form part of the coarsening-upward profile. This formation represents the deposition in the deep-water distal- mid shelf environment which is manly sandstone. After the deposition of halfway formation, the sea continued to shallow; this led to the deposition of the Charlie lake formation which contains sediments which are deposited in a shallow inner shelves and tidal inlets representing the final and major regressive phase of the second T-R cycle. The Charlie lake formation has a maximum thickness of 404 m and is dominated by near-shore marine sedimentation with deposits accumulating in environment such as coastal dunes with dominant sandstones and carbonates. It consists of dolomitic to calcareous sandstones, siltstone, sandy limestone and dolostone (Edwards et al., 1994).

After the deposition of the Charlie, the deposition of the Baldonnel formation occurred. During the deposition of the Baldonnel formation the environment changed from the shallow restricted marine to deeper and open marine shelf conditions. This formation consists of shallow upward parasequence and is dominated by shandy and silty carbonates with a thickness of approximately 300m. The Baldonnel formation is overlain by Pardonet formation which is mainly transgressive carbornates, siltstones, limestones as well as sandstone and shale. Pardonet formation was deposited as the see was deepening and transgressing the shelf area. This formation has a thickness of 180m and is dominated by carbonates sediments which are more or less the same as those of baldonnel formation (Edwards et al., 1994).

1.2.4. ***Basin Evolution***

Figure 5 shows the Cambrian-Lower Jurassic cratonic platform succession that is occurring in the Alberta Basin. According to Kent and Williams (1994), this cratonic platform is divided into six mega-sequences using major unconformities, namely: ‘’ *Cambrian-Lower Ordovician, Middle-Upper Devonian, Lower Carboniferous, Upper Carboniferous-Permian, Triassic, and Lower Jurassic’’*. During the Cambrian-Early Ordovician, the area of the Alberta Basin was situated on the continental platform where the north-east trending peace river arch make a positive structural feature which is evidenced by the thinning of the middle-upper Cambrian sediments that consists of up 1000m of clastic and shallow-shelf carbonates in the south east of the Alberta basin. The tilting that occurred westward and the uplift phase in the Silurian created strong erosion that removed middle Ordovician- lower Devonian sediments of the Alberta basin (Halbertsma, 1995).

During the early- middle Devonian, a transgression from the north east initiated a new marine embayment known as the Elk point basin over the Alberta basin. The elk point basin was separated to the west from the ocean by the western Alberta ridge and the Peace River arch. The dominated carbonates rocks which are associated with fine clastic sediments of the Ernestina lake, cold lake and chinchiga formations were deposited over basal continental red beds as shown in figure 5 (Williams, 1994). The sea level fluctuations formed a west dipping carbonate ramp. The Beaverhills lake group across the western platform rimmed to the west by the shelf-edge carbonate build-up during the middle Devonian with an inner basin of fine grained clastics, evaporates and carbonates (Halbertsma, 1995).

A marked change in subsidence patterns occurred during the early-late carboniferous when the Peace River arch subsided and became a west oriented graben which produced a marine embayment that connected with the rapidly collapsing north trending trough. After the wide spread deposition of the Exshaw formation (Organic rich shale) and maximum transgression, the continental platform became under the influence of a shallow sea and sedimentation was marked by transgressive-regressive elements of oolitic carbonates (Debolt/Rundle group) advancing landward into near shore silisiclastic, evaporates and carbonates as shown in figure 5 (Cant and Stockmal, 1994).

The deltaic sediments of the Stoddard Group and the rockl mountain accumulated in the peace river embayment during the early carboniferous while the fine grained clastic sediments of the mattson formation were deposited further to the north (Richards, 1998).

The sea level fall of the late Permian revealed most of the continental platform to erosion and the continental red-beds deposition in this area took place during the Triassic under arid climate conditions. The marine source rocks of the doig (Doig?) formation as well as shallow to deep-shelf carbonate rocks of the Baldonnel formations were deposited during the transgressive phases. The Liard sub basin comprises of a thick section of the lower Triassic shale overlain by cretaceous shale (Gibson and Barclay, 1999).

According to Kent (1992), ‘’ *the Alberta basin was subjected to erosion during the Triassic time prior to Jujurassic transgression and onlap marking the change to the subsidence of the foreland basin’’* (figure 5). The Jurassic to early tertiary foreland basin was filled with six regressive unconformity clastic wedges in response to thrust sheets occurring in the orogenic belt to the west. These clastic wedges began with the deposition of shale and marine incursion and was followed by eastward progradation of marine as well as coarse grained fluvial sediments which consists of sandstone reservoirs in many parts of the Alberta basin (Leckie and Smith 1993).

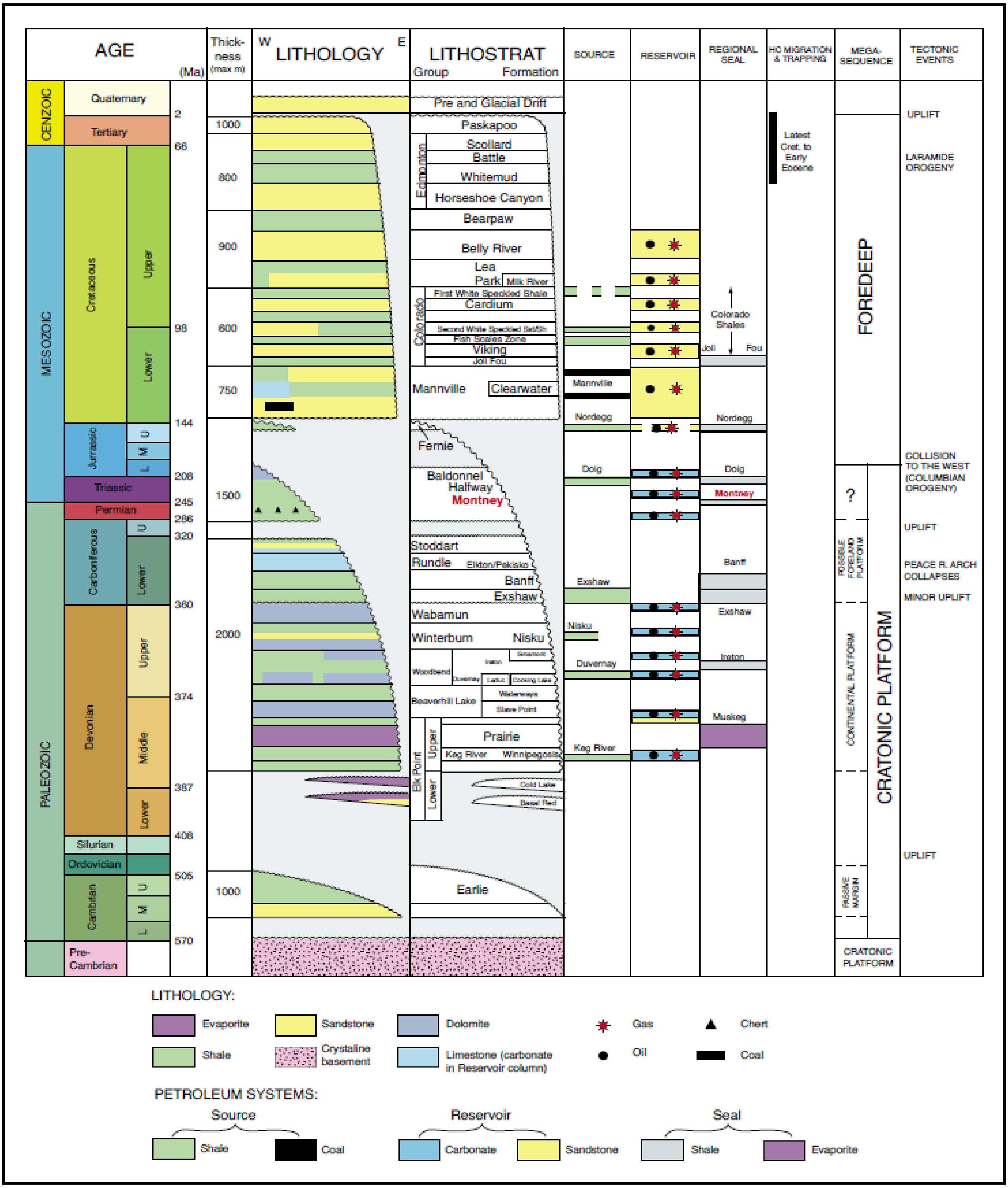

Figure 5: Generalised stratigraphy of the Alberta Basin Modified from (Lee, 1998).

CHAPTER TWO

2.1. Literature Review

This review includes some major consideration that needs to be addressed when evaluating the source rocks. The study investigates quantity (petroleum potential), quality (kerogen types) and level of thermal maturation of analysed samples in the Montney formation of the Alberta basin. Attention is also paid to the processes that are involved in the thermal maturation of the source rocks including the parameters that influence the thermal history such as heat flow, burial history and boundary conditions (e.g. Paleo surface temperatures). It is important to understand the key points that are needed in order to know if the source rocks will be able to generate and expel hydrocarbons at the right timing.

Petroleum formation has specific aspects that need to be considered in order for oil or gas deposit to form. This aspect includes Temperature, Pressure, Time, carbohydrates from once living things as well as the appropriate geological settings. The formation of petroleum according to Creaney (1999) is based on the hydrocarbon generation by the action of heat and accumulated organic matter as well as accumulation of organic matter from living organisms. Different types of sedimentary rocks all over the world can form and generate petroleum and this has resulted from the generation of hydrocarbons from the organic matter within the sedimentary rocks. Since more than 70 % of hydrocarbons contained in most fine grained sediments are autochthonous, the migration processes have not significantly altered this distribution. During the formation of petroleum, temperature and tome are the most studied aspects because they play a major role in the transformation of organic matter to hydrocarbons. In sedimentary basin the formation of oil is relatively at low temperatures between 150^0 F and 300^0 F (Creaney, 1999). These Temperatures are thought to have been reached in the Alberta basin for the hydrocarbon generation.

The thermal maturation, burial history and timing of hydrocarbon generation in the Alberta basin varies widely and depends on the location and source rocks types. This type of information is needed for delineating areas of hydrocarbon generation and for evaluating the unrecovered hydrocarbon resources in the Alberta basin. In this study, generation of oil bearing rocks in the western Alberta began from the Triassic-Jurassic age. This ranges from 207 up to 160 Ma. Alberta basin is an old basin compared to many oil producing basins. Most formations in the Alberta are at their current burial depths since early in the Mesozoic which is several hundred Ma (Porter, 1994). Therefore the correct temperature and time to this research is the key paradigm and that it can prove to be very effective in oil and gas formation. The maximum temperatures over a short period of time can prove to produce oil. However, the equivalent degree of oil generation should be realised at lower temperatures over a longer period of time. According to Burnham (1993), 100 degrees Celsius for 100 Ma can reach a Vitrinite Reflectance of 0.68, which is reasonable to begin oil generation.

According to Macqueen and Powell (1993), '*'Vitrinite Reflectance has been successfully demonstrated as a reliable indicator of organic maturation in sedimentary rocks and is widely used in the petroleum industry for the evaluation of kerogens''*. In the Alberta basin, the oil exploration started from the 20th century. The successes recorded significantly triggered the interest of the oil industries and geologist in the mapping geological structures and subsequently geochemical studies of oil and petroleum source rocks potential in the basin.

In the north-eastern part of the Alberta basin, the Montney formation comprises of thick successions of shale and siltstone and is interpreted as the deposits in the lower shoreface through proximal offshore to distal settings (Dixon, 2007).

The maturation and source rock potential of the Triassic Montney formation was examined by Williams (1994) and evaluated the possibilities from the formation for oil and gas generation. The geochemical result show that the sediments of the Montney formation contain rich potential organic matter with Type I-II and Type III kerogens which are favourable for hydrocarbon generation. Oliver (1996) on the other hand investigated the kerogen facies and the thermal maturity. The results of his work showed that kerogen facie is controlled by the paleogeography and sedimentation rate of the basin. This caused Type III kerogen to be predominating in the margin areas of the basin, Type II kerogen to be restricted at the centre of the basin and Type II-III kerogens to be prevalent over the intermediate shelf area. Oliver (1996) further investigated the geochemical and petrographic studies which showed that the eastern part of the Montney formation have a wide range of TOC up to 7% as well as the hydrogen index values. This could be because montney formation invoked the deposition of the organic sediments under anoxic water column with a redox boundary that fluctuated above and below the water- sediment interface.

Porter, (1994) established two major types of kerogen and their hydrocarbon generation potential, namely: Amorphous kerogen which was oxidised with minor concentrations of telalginite and lamalginite, vitrinite and trace amounts of oil inclusions which were deposited in a fluctuating anoxic depositional facies forming Type II,II-III and Type III kerogens. Most of silt and shale in the Montney Formation are from this type of organic matter. The second organic facies was observed to be a mixture of prasinophyte type with vitrinite and amorphinite2 forming Type II kerogen source rocks. These organic facies include abundant solid bitumen and oil fluid inclusions. The results of these facies revealed that the identified kerogen types have the ability of generating both oil and gas. in addition, Porter (1994) also observed that Triassic formations have enough organic matter content to be source rocks for hydrocarbons. In the eastern part of the Montney Formation the selected shale is rich in kerogen and contains more Vitrinte resulting in the formation of Type III kerogen source rocks.

CHAPTER 3

3.1. RESEARCH METHODOLOGY

3.1.1. The maturity and quality of the source rocks

The quality and maturity of the source rocks in the central Alberta part of the Western Canada Sedimentary Basin (WCSB) were assessed using the data provided from the Rock Eval pyrolysis and Vitrinite Reflectance (VR).

According to Undehill (2002), the analysis of the rock- eval pyrolysis gives 4 (four) important parameters, Namely: The total free hydrocarbons released at T= 300^0C (from S1 peaks), The amount of hydrocarbons released at T= 600^0C from the S2 peak during the thermal cracking of the kerogen, The amount of carbon dioxide (CO_2) released during the heating of the organic matter from the S3 peaks, and the high temperature at which the maximum amount of hydrocarbons has been released during pyrolysis (T_{max}). The Montney formations samples of the Alberta basin have been analyzed from two wells (well M28 & M22) to evaluate the organic Quality, Quantity as well as thermal maturation. The maturation of the organic matter was estimated by Tmax versus PI (Production Index) from Rock-Eval pyrolysis as well as by making use of Vitrinite Reflectance data .

Mossop and Shetsen (2001) defined hydrogen index as the ratio of the amount of hydrocarbon released during the thermal cracking of the kerogen to the total organic carbon. It is calculated from the rock eval pyrolysis data using the equation below:

HI= 100*S2/TOC %

Where TOC is the total organic carbon and S2 is the amount of hydrocarbon released during the thermal cracking of the kerogen at T=600^0 C**.** In this study, the hydrogen index was plotted against the oxygen index to provide assessment of hydrocarbons for the petroleum generative potential of the source rock.

The following parameters were plotted against depth:

- Total Organic Content (TOC)
- (HI) Hydrogen Index and,
- S2/S3

The following cross-plots were also generated from the Rock Eval data using Microsoft excel to determine the quality of the hydrocarbons that the source is likely to generate.

- PI (Productivity Index) versus Tmax,
- (HI) Hydrogen Index versus (OI) Oxygen Index,
- Hydrogen Index versus Tmax,
- Genetic Potential versus Tmax,

S2 versus TOC (Total Organic Carbon) was plotted from the S2 to the S3 ratio to give information about the type of organic matter and to determine the type of hydrocarbon which is likely to be generated and released from the source rock during the peak maturation. The hydrogen index was calculated as explained by Mossop and Shetsen (2001). The Vitrinite Reflectance will be plotted against depth using IP Software to determine the maturity and the type of the hydrocarbon generated by the source rock. The onset of oil generation and oil window in oil-prone shale was correlated to a reflectance (Ro %) of 0.6-1.35%, while the onset of generation in gas-prone shale was correlated to a reflectance of 0.8%- 2% and the various cross plots were produced. The source rocks in both wells (well M22 and M28 28) were determined by the type of organic material that the maceral was derived from. The kerogen were classified into four types, namely: Type I, II,II-III, III and Type IV by making use of organic geochemical technique. These types of kerogens were based on the chemical composition of the amount of carbon, hydrogen and the oxygen present in the sample. Higher carbon content in the kerogen was corresponded to the higher gas generative potential of the rock

3.2. Basin modelling

The basin modeling gives the basic understanding of the evolution of hydrocarbons in the basin though time. The hydrocarbon evolution is simulated by making use of initial model such as boundary conditions. It is used to model the properties of the layers within the basin such as temperature, pressure and thermal maturation (Majorowicz and Jessop, 1998) In this study, it will therefore be very useful in evaluating the prospectively of the basin. The thermal history and hydrocarbon generation were based on the evolution of the thermal regimes within the Alberta basin. This is linked to the burial depth of the source rocks and the thermal gradient within the basin. The modeling was also used to predict hydrocarbon accumulation and timing of petroleum generation. Only 1D basin modelling was conducted in the study.

The work flow below was used to describe the main steps that were followed when conducting 1D basin modelling.

- The litho- stratigraphic model of the basin was addressed which includes thicknesses of the layers and lithological properties of the various formations in the basin.
- The characteristics of the main source rocks units were addressed. This includes mainly the TOC, HI, kerogen types, etc.
- The boundary conditions such as heat flow, paleo-water depth and surface water interface temperature were defined to reconstruct the evolution of the thermal gradient at various stages within the basin. The heat flow was modelled based on the tectonic setting as well as the basin evolution.
- The outcome of the model was calibrated to the measured data by making use of Vitrinite Reflectance data and temperature data. The measured bottom hole temperature data was taken from the nearby well which have a measured Vitrinite Reflectance data taken directly from coal-bearing Mannville Group which helped to aid in calibrating burial history models.

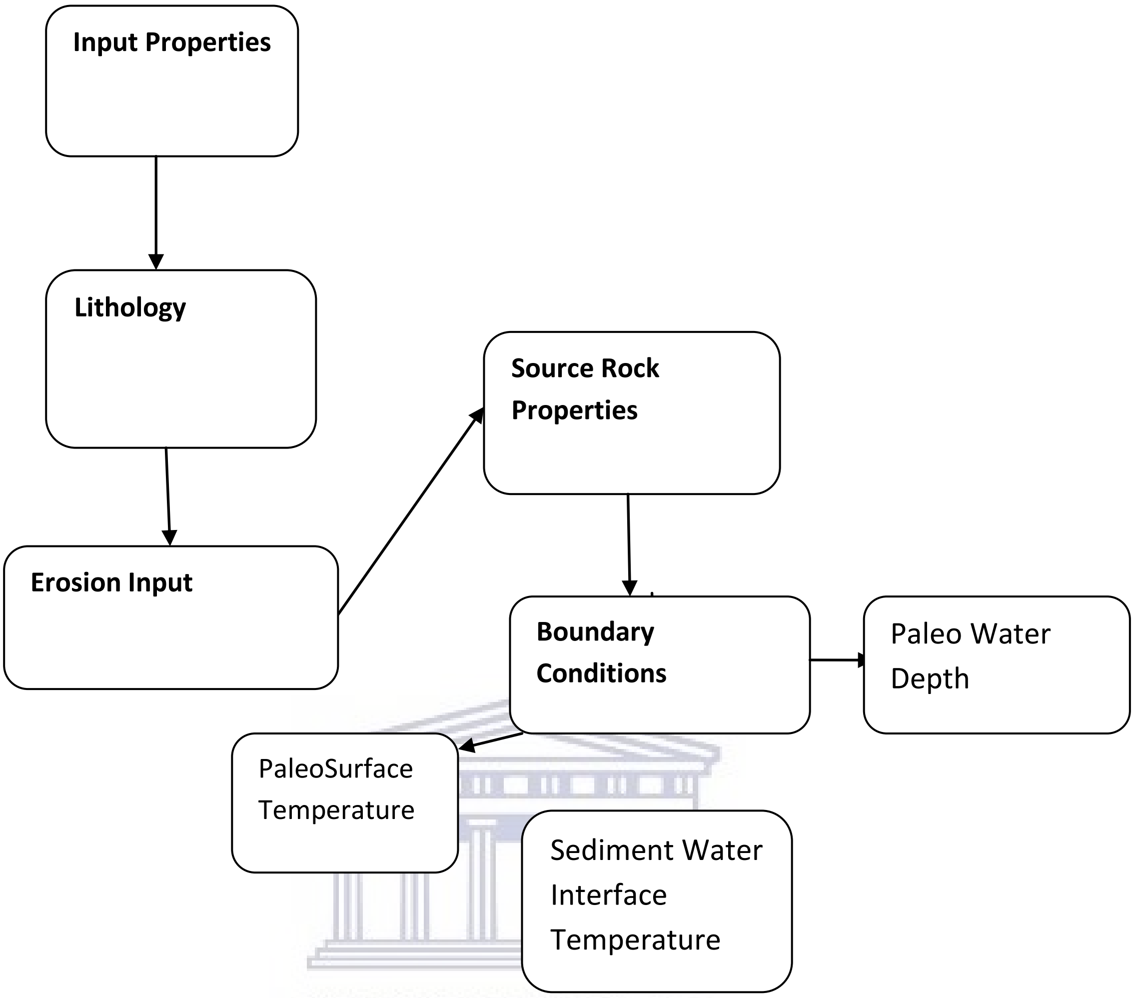

Figure 6: Flow chat of the burial history research Methodology

3.2.1. Input: Properties

The Agat laboratories table of formations was taken from the open file and was used to estimate the ages of stratigraphic units and periods of non-deposition/ erosion. The lithologies were only generated for modeling purposes. The type of lithologies were estimated from the lithostratigraphic layers of the formations. PetroMod was used to generalize lithologies by selecting *''user-defined lithologies''*

3.2.2. Erosional input

Only two major erosional events described in the study by Williams (1994) influenced petroleum generation, migration and accumulation. The older event is the sub-Mannville erosional unconformity which started from 386 and 197 Ma and was ended at about 119 Ma. The second erosional event occurred between 104 and 100 Ma and is also recorded at the burial history locations. 1D PetroMod offers the option of modelling erosion in sections with variable amounts of erosion. The depositional thickness of the unit is the required input from which the present day thickness is subtracted to give the amount of erosion.

3.2.3. Properties of the Organic matter

The literature review revealed that the Montney formation displays excellent organic matter quantity (TOC up to 7%), and Type II and Type III kerogens, which are favourable for petroleum generation.

3.2.4. Boundary Conditions

The boundary conditions namely: Heat flow, Paleo water depth and sediment water interface temperatures were used in order to define the energetic conditions for the thermal maturation of the source rocks. The sediment water interface temperature was automatically assigned in Petromod by defining the hemisphere and latitude of the Alberta basin.

The PetroMod software uses paleo surface temperatures to present day temperatures to calculate the thermal history of the basin. The paleo surface temperatures at the sediment water interface was calculated by the software which takes into account paleo water depth and the evolution of the ocean surface temperatures through time depending on the paleo-latitude of the area. According to Halbertsma, (1994), *''the average annual surface temperature for all the burial history locations in the Alberta basin is as follows: 24^{0}C from the time the oldest layers were deposited and decreased uniformly to 20^0 C by 200 Ma, then increased to 24 °C by 100 Ma, and decreased again to 15 °C by 40Ma. Finally, from about 33 Ma the surface temperature cooled gradually to the present average annual surface temperature of 5°C''.*

3.2.5. Paleo basal heat flow:

The basal heat flow in the study area was modelled using the basal heat flow modelling tool PetroProb. These tool uses sedimentation, uplift and erosion history for a single well to predict the evolution of the basal heat flow for a well. It therefore takes into account the tectonic evolution of the basin and requires the user defined model of the lithosphere. The value of the heat flow is very important to the input parameter for the PetroMode software and was therefore used for the burial history reconstruction.

3.2.6. Calibration

The model was calibrated using measured Vitrinite Reflectance data taken directly from coal-bearing Mannville Group and the bottom hole temperatures data to check the accuracy of the model.

CHAPTER 4

4.1. RESULTS AND INTERPRETATION

4.1.1. Burial History

Only two well locations (301 & 306) have been modelled in 1D to understand the burial history, thermal maturation and timing of petroleum generation of the Alberta basin. These wells were chosen because they have a measured bottom hole temperature data taken from the nearby well and they have measured Vitrinite Reflectance data taken directly from coal-bearing Mannville Group which will aid in calibrating burial history models in the Alberta basin. The burial history reconstruction of the Alberta basin based on the modelled wells is shown in Figure 7a and 7b below.

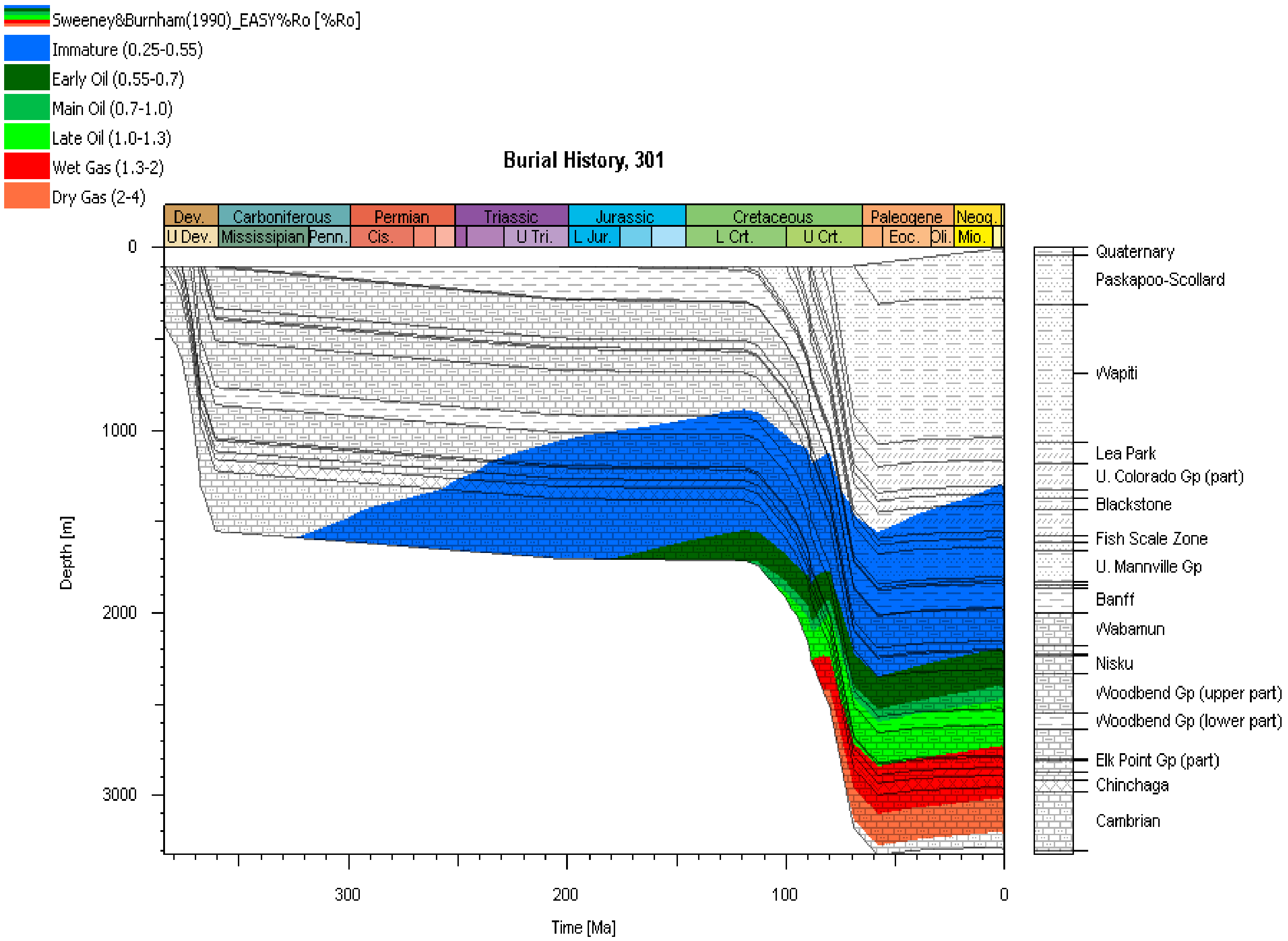

Figure 7a: Burial History location at 301 with maturity overlay

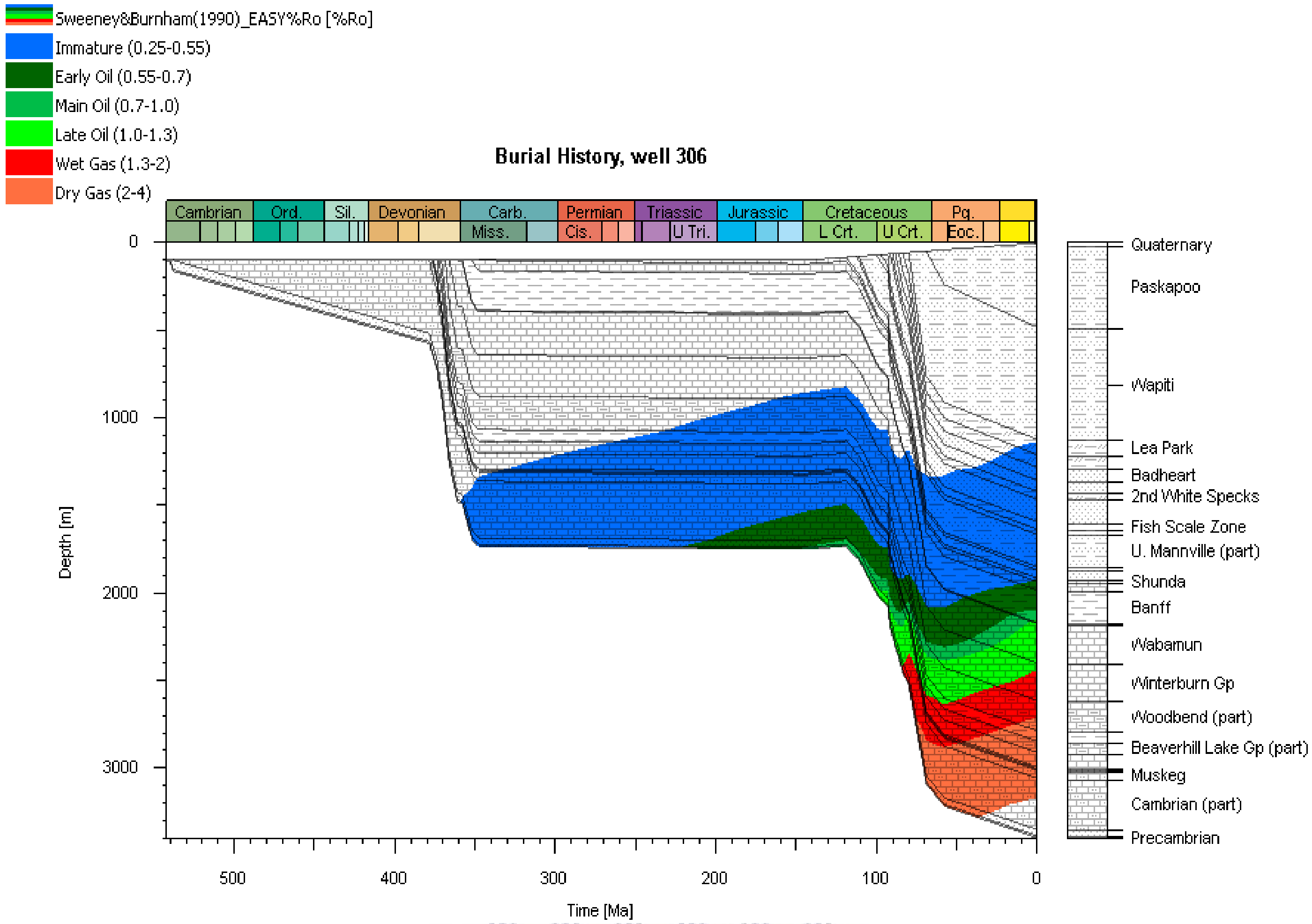

Figure 7b: Burial History location at 306 with maturity overlay.

From the above Figures (7a&7b), the modelled locations experienced a period of non-deposition and/or erosion, the 1st erosional event is called a sub-Mannville erosional unconformity that began between latest Devonian-earliest Carboniferous. The second major erosional event was caused by the late Cretaceous regional uplift, which led in the removal of an estimated 650 to 1400 m of strata in the study area that influenced petroleum generation, migration, and accumulation. The maximum burial depth was reached at 58 Ma as the basin subsided during Laramide deformation; this was followed by uplift and erosion from mid-late Cretaceous and is recorded from both locations.

Well 306 shows the deepest burial compared to 301 because it is located near the deeper centre of the Alberta basin. The basin experienced relatively slow and fairly constant subsidence from the mid – late Devonian**.** The basin then experienced very rapid and accelerated subsidence between 79 and 69 Ma, reaching a burial depth of about 1066 m. During this period close to 1049 m of sediments were deposited, as shown by the thickness of the Wapiti sediments in figure 7a. The basin continued to subside rapidly from upper Cretaceous until Eocene, reaching a maximum burial depth of approximately 3174 m at 68 Ma (well 306, fig.7b).

The burial history at well 306 location is similar to the well 301. However, this location experienced a shorter period of erosion and/or non-deposition and the subsidence rate was slower than that of 301 in comparison during the Upper Cretaceous-Eocene. This resulted in a little or more than a quarter thickness of sediments deposited at this location. When faulting was active during the Upper Cretaceous-Paleocene, the fault zone of the Peace River Arch possible limited the downward movement of fault block at the well vicinity hence resulting in reduced subsidence and accommodation space for sediments to accumulate. The maximum depth of 3214 m in well 306 was reached at 58 Ma.

4.1.2. History of maturity and hydrocarbon generation

For each burial history location, the history of maturation was calibrated based on matching as closely as possible the measured Vitrinite Reflectance (Fig.7c). Figure 7c, indicates that the modelled maturity is in a good agreement with measured values in 2 wells covering the High and the Platform area. Similar to the temperature, maturity evolution can be related to the formation depth and its burial history.

Figures 7a and 7b shows %Ro (Vitrinite Reflectance) overlays superimposed on the burial history curves. In figure 7a, the Chinchaga Shale has generated hydrocarbons. The source rock interval was generally immature from the Carboniferous until the late Triassic. From the upper Cretaceous time, maturity increased correspondingly as the basin rapidly subsided to greater depths.

The Wabamun formation in the study area from figure 7a appears to be immature. The modelled maturity for this layer at this location is 0.39 – 0.49 Ro % (Figure 7a). In figure 7b the Wabamun layer is currently mature because it was drilled in a deeper depositional environment, as a result of this, it will attain higher thermal maturation because of higher geothermal gradient as compared to the depositional environment of well 301 in figure 7a which was drilled at shallower depth. The modelled vitrinite reflectance ranges between Ro 1.0- 1.3 % (Figure 7b). The layer entered the late oil window during the upper cretaceous to present day. The Winternberg group and the Beaverhill Lake is generally in the gas window (Fig.7b).

In the 301 location (Fig.7a), early oil was generated around 160 Ma when the basin was buried to a depth of about 1648 m. The main phase of oil generation occurred at around 110 Ma later when the basin had been buried to 1753 m. Both oil and gas were generated simultaneously from the Mid Cretaceous to Late Cretaceous. Since that time the source interval at this location has generated mainly oil and gas. Maturity occurred much later at the 306 location.

The source interval at the 306 location matured much earlier than at the other location (301). Early oil generation began as early as 205 Ma (Upper Triassic), when burial depth was just 1703 m. The main phase of oil generation occurred around 127 Ma later when the basin had been buried to 1712 m. The Shunda Fm, Banff and Wabamun became mature for oil generation about 95 Ma with peak oil generation occurring at about 90 Ma. The Woodbend formation and Beaverlake group from well 306 became mature for gas generation approximately 80 Ma and generates gas to present day.

It is important to know that the main maturity pulses occur when the formations are at their deepest burial (Underhill, 2002). The maturity history indicates that the deepest parts of the assigned source rock units entered the hydrocarbon generation ranges already during the Triassic –Jurassic period. The maturity increased during the Lower Cretaceous and reached a peak during Upper Cretaceous.

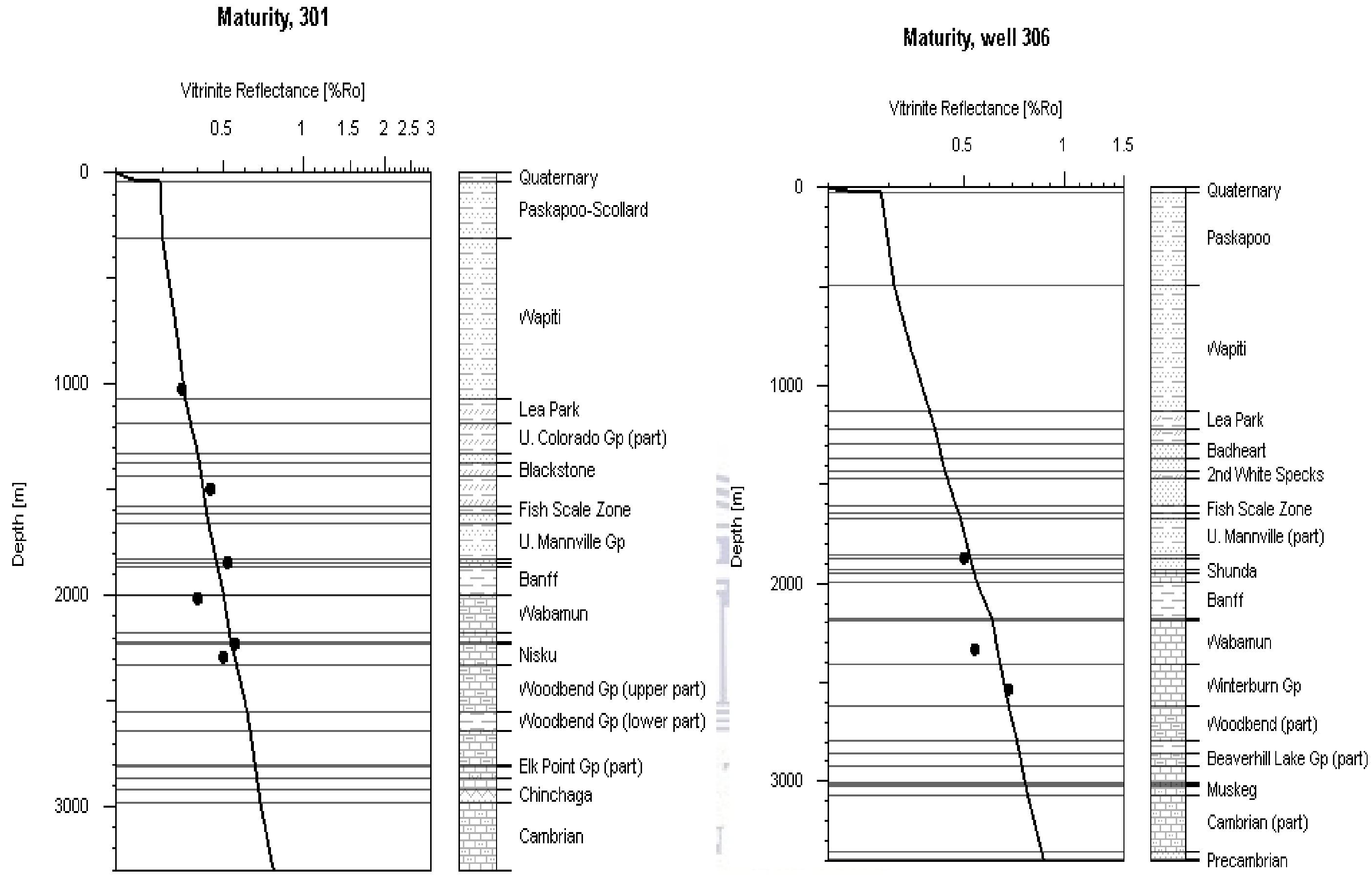

Figure 7c: Calibrated Vitrinite Reflectance for 301 and 306 well locations.

The charts of petroleum events from the figure below (Figure 7d) show the time interval of occurrence of the various play elements and processes. As shown, trap formation occurred as the basin subsided during the upper Cretaceous. On the other hand, the generation of petroleum as well as migration and accumulation occurred in the Upper Cretaceous, except in well 306 where it was earlier.

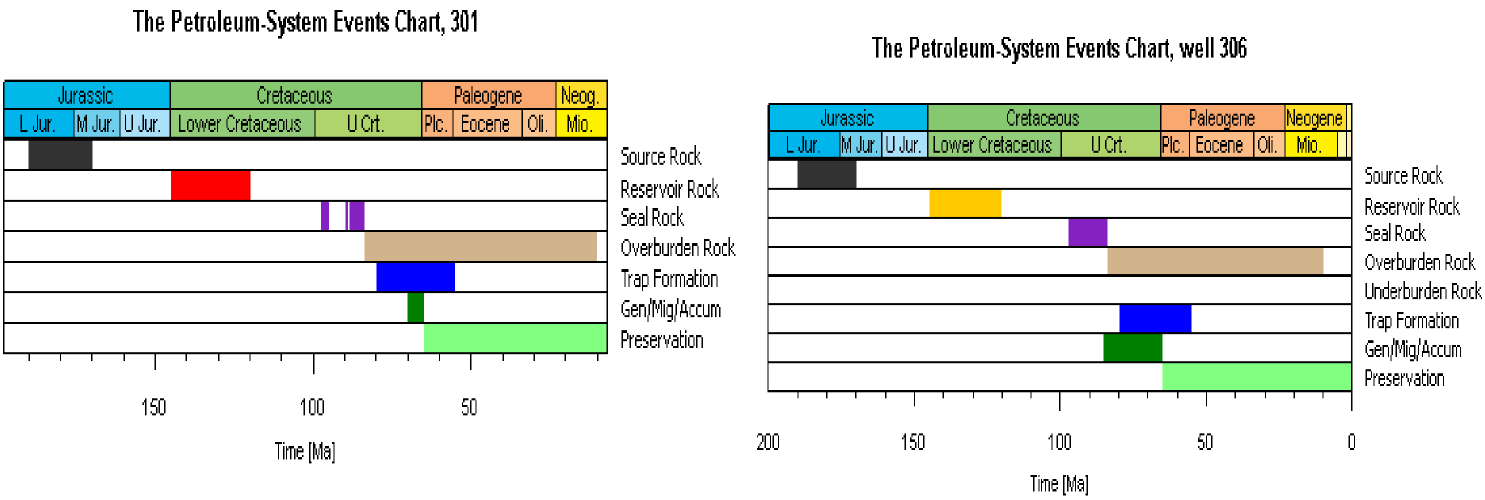

Figure 7d: The chat of petroleum events for 301 and 306 well locations

4.2. Maturity and Petroleum Generation History

4.2.1. Thermal history

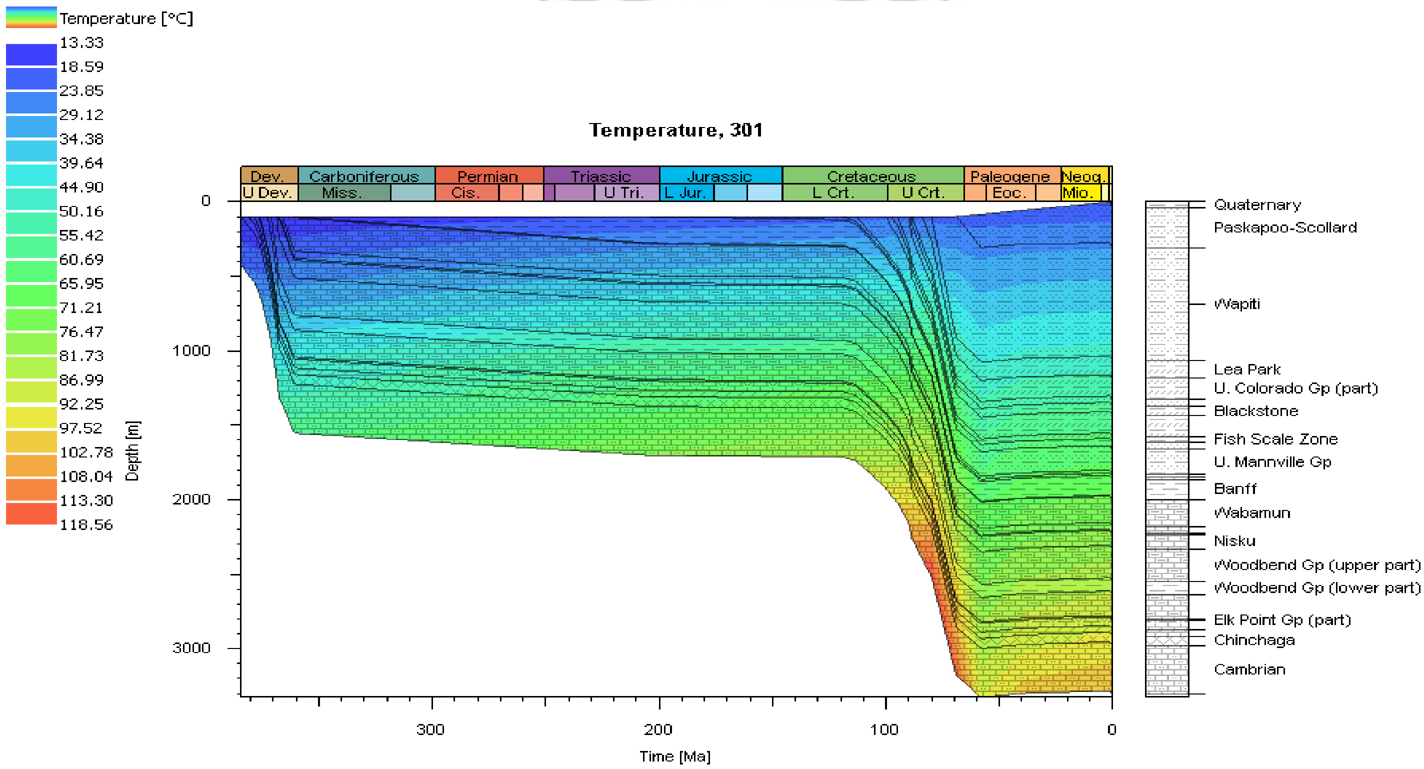

Figure 7e: Modelled present-day temperatures for well 301

The first maximum temperature in the above figure 5e in well 301 was caused by late Tertiary regional uplift units and was reached during the late cretaceous. The Cambrian layer reached a temperature higher than 100 °C and the temperature of the overlying Chinchaga and Woodbend group ranged between 102 °C to 108 °C. During the Upper Cretaceous, the temperatures of the Wapiti formations decreased as a result of the subsidence which occurred during Laramide deformation. In well 306 (Fig.7f), the temperature of the Muskeng layer varied between 105 °C to 113 °C during the Palaeocene–present day. The temperature of the overlying Beaverhills Lake and Woodbend group ranged between 98 °C to 103 °C.

In general, burial histories show a direct relationship between the burial depth of the formations and their temperatures. The maximum temperatures are reached when the layers are at deepest burial.

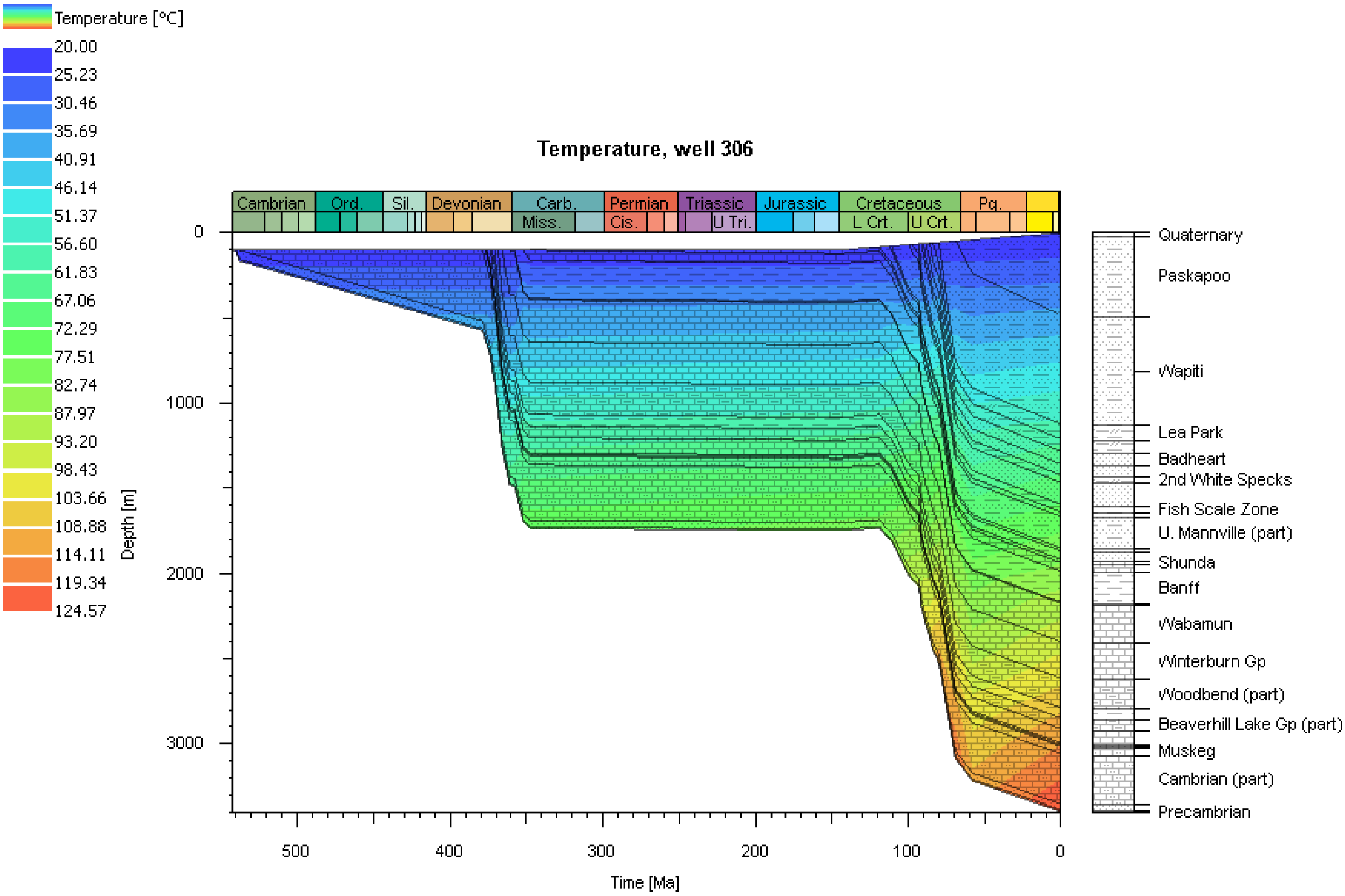

Figure 7f: Modelled present-day temperatures for well 306

4.3. Source Rock Richness, Potential, and Maturation

More than 300 samples of cuttings from the Montney formations of the Alberta basin have been analysed in a couple of locations within the Alberta basin. These samples were mainly analysed from two wells, namely well M28 (located in the north western part of the basin) & M22 (located in the north eastern part of the basin) to evaluate the organic quality, quantity as well as thermal maturation by T_{max} versus PI (Production Index) from Rock-Eval pyrolysis and Vitrinite Reflectance data. Production Index (PI) is the amount of already present free hydrocarbons normalized to the total carbon potential and is therefore used to characterize the evolution level of the organic matter (Bird, 2001).

The illustration of various parameters of the Rock Eval pyrolysis to determine the quality, maturity and total organic carbon analysis illustrating the source rock quantity of all sediments is shown in the figures below. The major parameters on organic richness, source rock potential and maturation (data on organic carbon content; hydrogen index; Tmax & Vitrinite Reflectance; and production index) of both wells (M22 & M28) of the Montney formation are plotted as follows:

4.3.1. Well M22 PLOTS

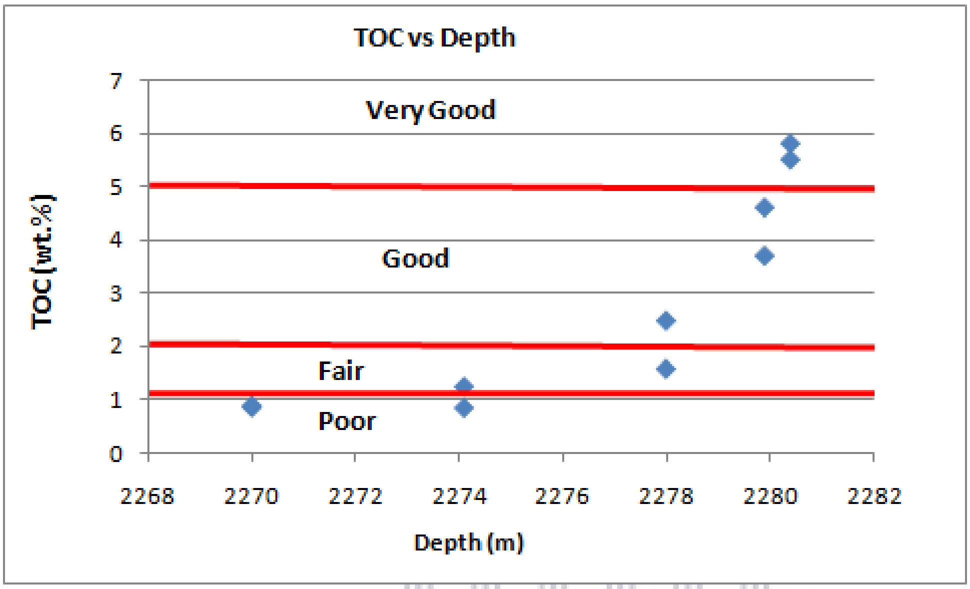

Figure 8a: Plot of TOC (Total organic carbon) versus Depth (red lines are the cut-offs showing the position of TOC with respect to depth from poor to very good source rocks).

Figure (8a) above shows that the Total Organic Content (TOC) steadily increases with depth. The values of TOC between 0.50 – 1.00 % shows a poor source rock generative potential. TOC values varying from 1.00- 2.00 % shows a fair generative potential. TOC values between 2.00 and 5.00 % reflect a good hydrocarbon generative potential (Bird, 2001). In line with the above criteria, the results of TOC from the rock samples indicate that the analysed samples contain a good-fair generative potential respectively. This may indicate that the conditions during the deposition of sediments were favourable for the production of the organic matter and the subsequent preservation.

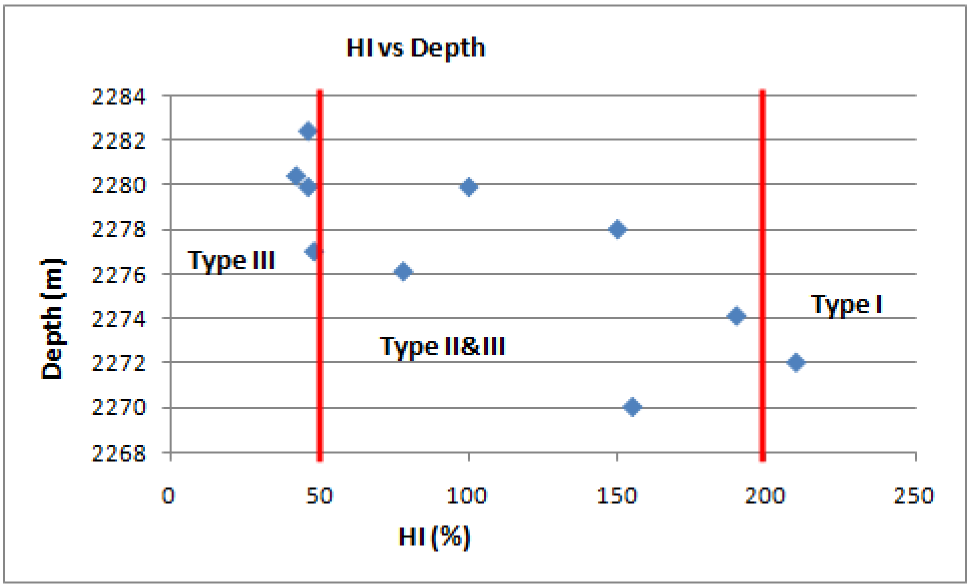

Figure 8b: Plot of Hydrogen Index versus Depth

In figure 8b above, the majority of the points show type II& III kerogen, and only small fraction that shows kerogen type I. This simple means that source rocks intersected by these wells are good enough to generate any hydrocarbons mainly oil and gas.

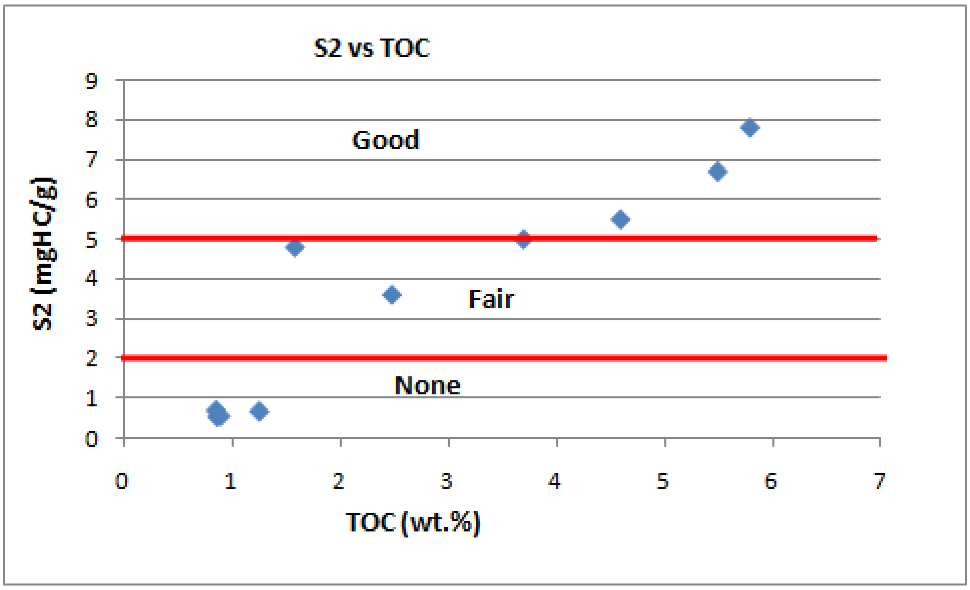

Figure 8c: Plot of TOC versus S2

Figure 8c shows that the source rock has a good potential because of the high values of S2. This simple means that the S2 from this well seems to have a good quality than the one from well M28.

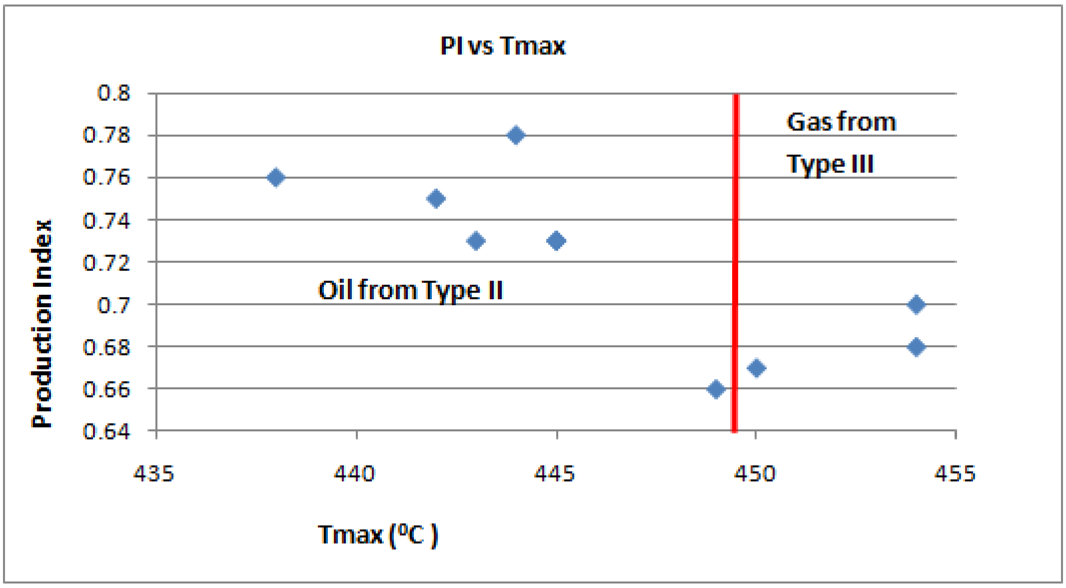

Figure 8d: Plot of Production Index (PI) versus Maximum Temperature (T_{max}) from Rock Eval Pyrolysis data-well M22

Well M22 from figure 8d shows most of the samples in the oil from Type II kerogen. Tmax (>435^{0}C) with only few samples in the gas from Type III kerogen.

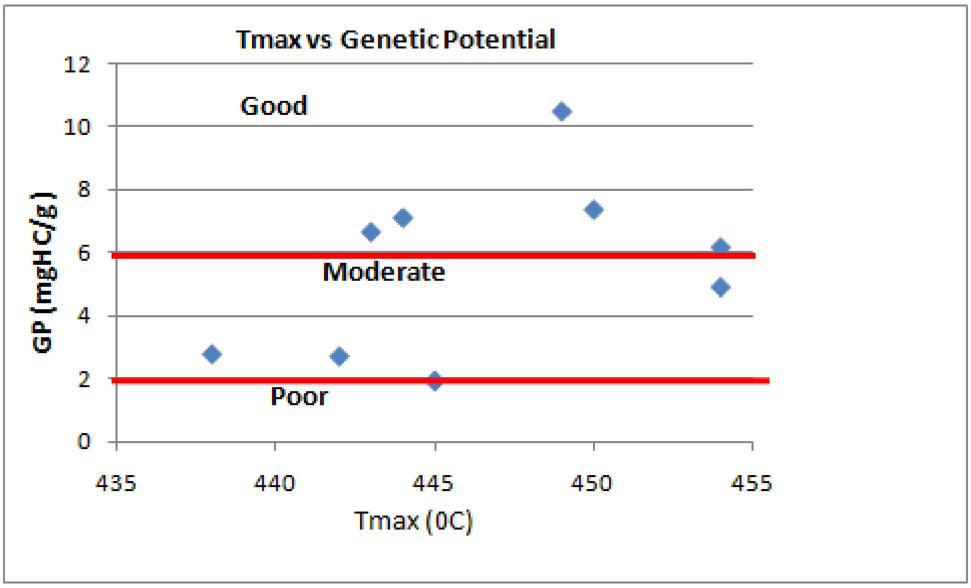

Figure 8e: Plot of Generation Potential versus T Max

Figure 8e shows the plot of T_{max} against Genetic Potential (GP=S1+S2) (S1= The total free hydrocarbons released at T= 300^0C, S2= The amount of hydrocarbons released at T= 600^0C during the thermal cracking of the kerogen,). This plot was done in order to analyse the quality of the source rocks. From the figure, the source rocks (most of it) have good quality. A very small fraction of the source rocks have moderate quality, indicating that the source rock can generate hydrocarbons.

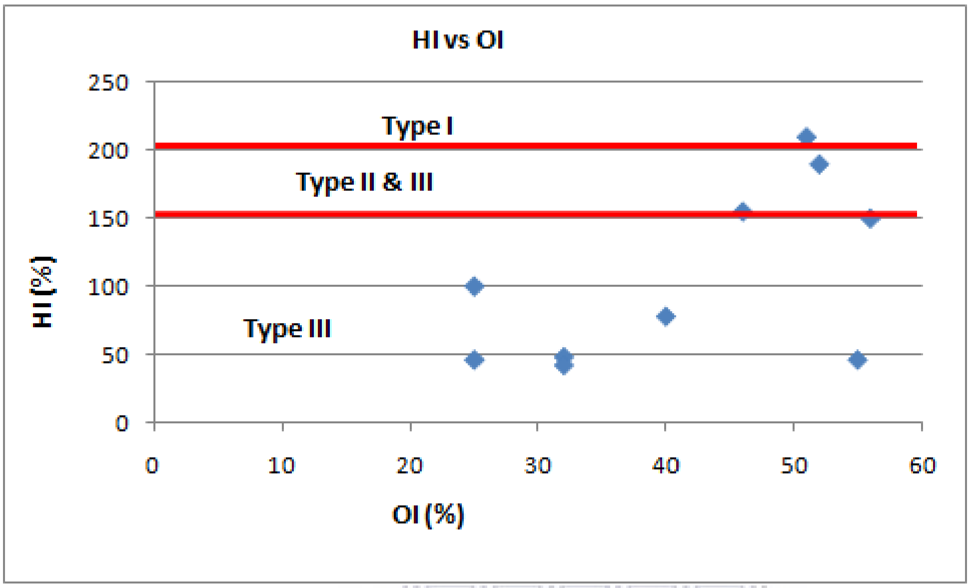

Figure 8f: Shows the Oxygen Index (OI) versus Hydrogen Index (HI) plot for the samples analysed from M22 well.

Figure 8f shows the majority of the samples in Type III kerogen with only few samples from type II&III kerogen. Therefore this well is likely to generate gas.

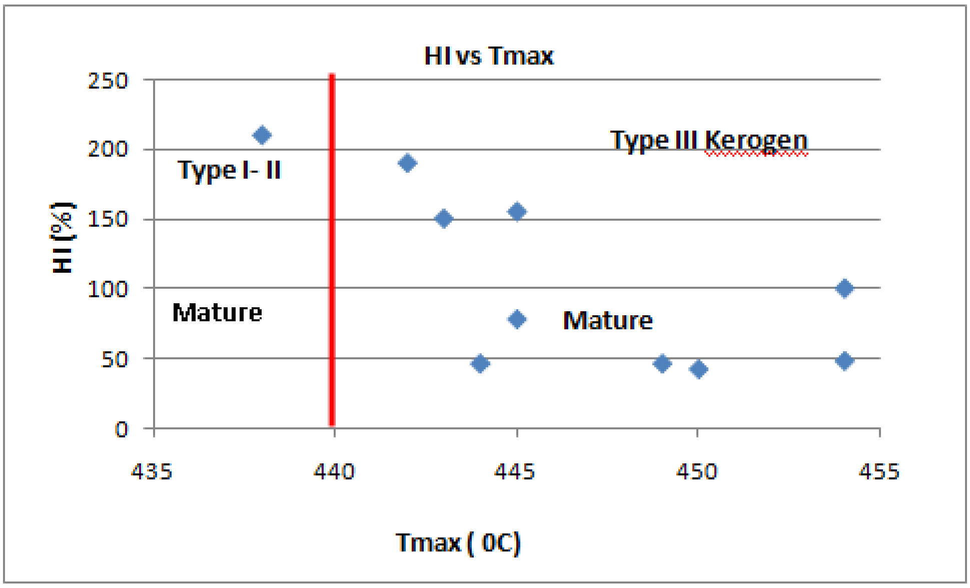

Figure 8g: Plot of Tmax versus HI (Hydrogen Index)

Figure 8g shows the relationship between Tmax and HI for samples taken from well M22. The majority of the samples falls within type III kerogens in mature phases. Only one sample shows Type II kerogen. This indicates that this well intersected a gas prone source rock and initially the composition of the gas will show high content of C4 to C10 (wet gas and condensate).

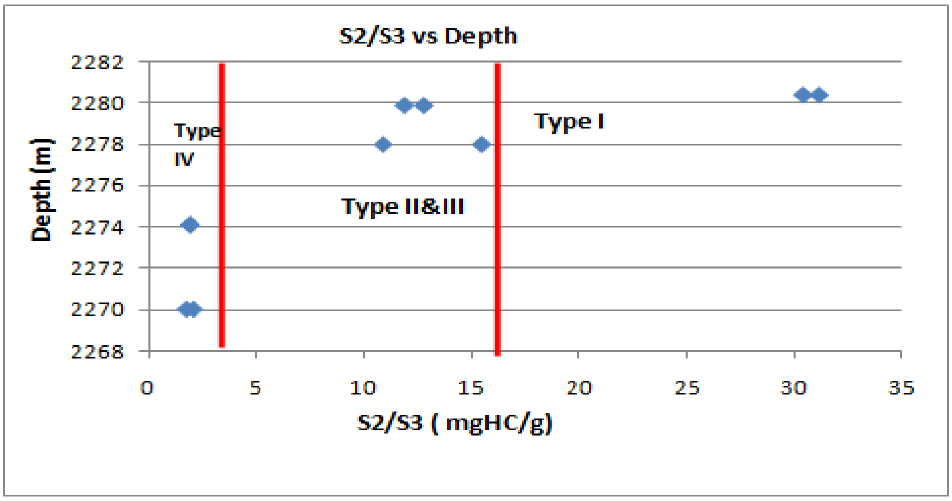

Figure 8h: Plot of S2/S3 versus Depth

Figure 8h shows that most of the samples are Type II&III kerogen. Only few samples appear to be Type IV and the one showing Type I kerogen could possibly be an outlier. In this case Type IV of kerogen represents an extreme of Type III and contains very little hydrogen. This figure also shows how much oil is released as compared to oxygen as the temperature increases with depth. This can be used to assess the type of organic matter. From 2270 - 2280m the amount of S2/S3 increases. This represents highly mature kerogen.

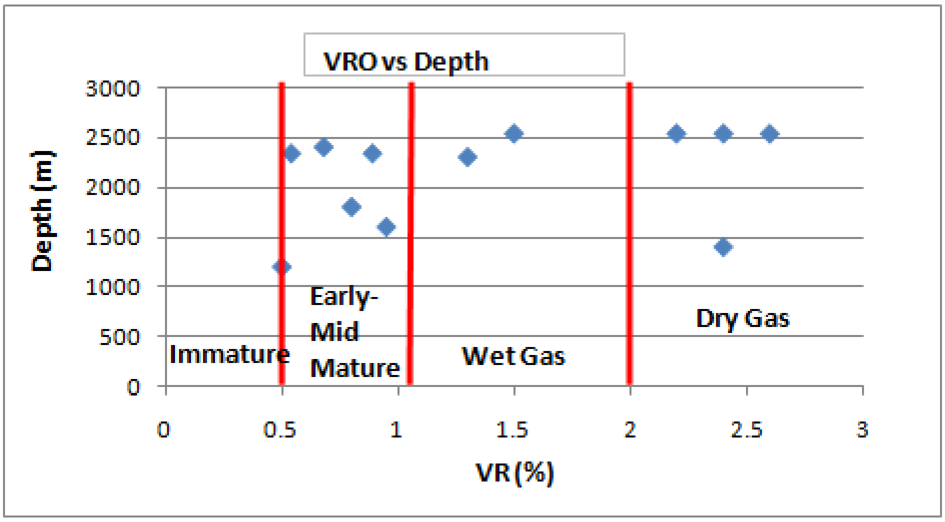

Figure 8i: Plot of Vitrinite Reflectance versus depth from well M22

The Vitrinite Reflectance in the above figure (figure 8i) ranges from 0.4-2.6 and most of the samples fall within the early to mid-mature and gas zone, this indicates that the samples are thermally mature and have entered the mature to late mature stage of petroleum generation.

4.3.2. WELL M28 PLOTS

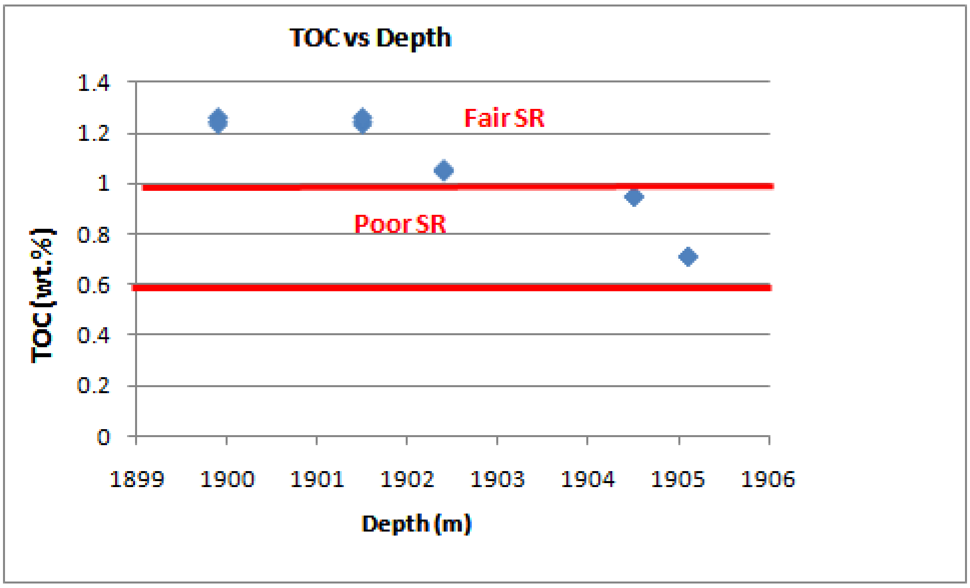

Figure 9a: Plot of TOC (total organic carbon) versus Depth

The above graph shows that, as depth increases the TOC decreases. The quality of the organic matter is a mixture of poor and fair quality of the source rock >2%, this indicates that the source rocks from this well can only generate hydrocarbons if exposed to sufficient temperatures at deeper depth.

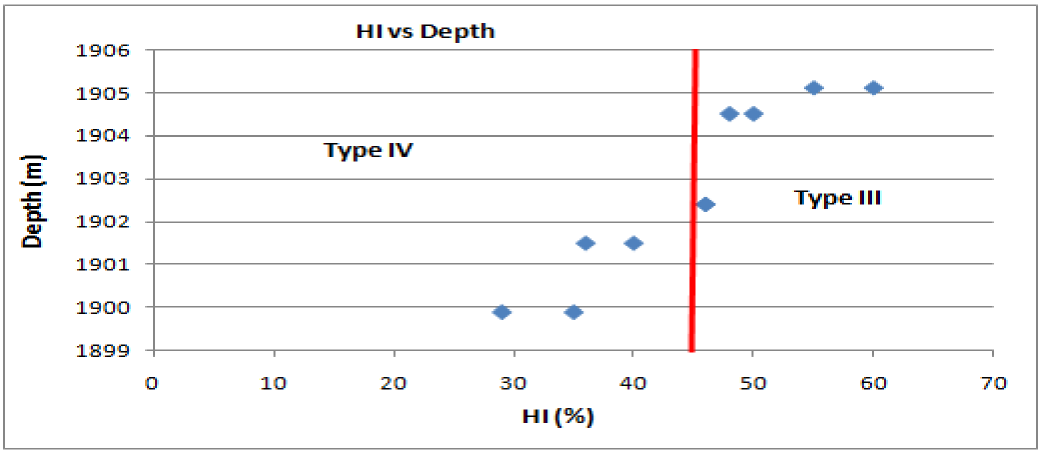

Figure 9b: Shows the HI (Hydrogen Index) versus Depth plot from well M28

The figure 9b above shows the variation of HI with depth. It shows the decrease of HI as the depth increases and the HI is less than 150. The type of kerogen rages from type III –IV.

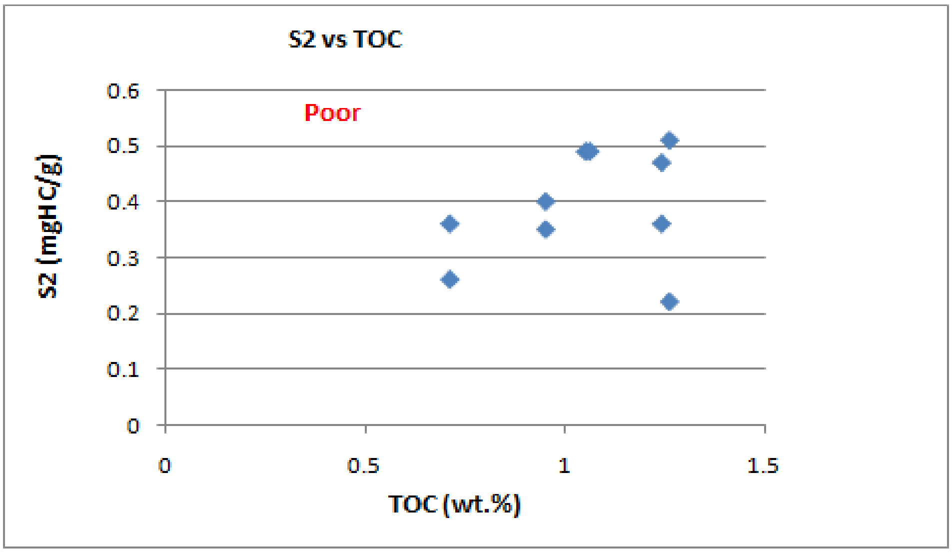

Figure 9c: Plot of TOC versus S2

Figure 9c above shows that source rock has poor potential (< 2 mgHC/g)) because of the low values of S2. This means that the S2 from this well seems to show none quantity potential.

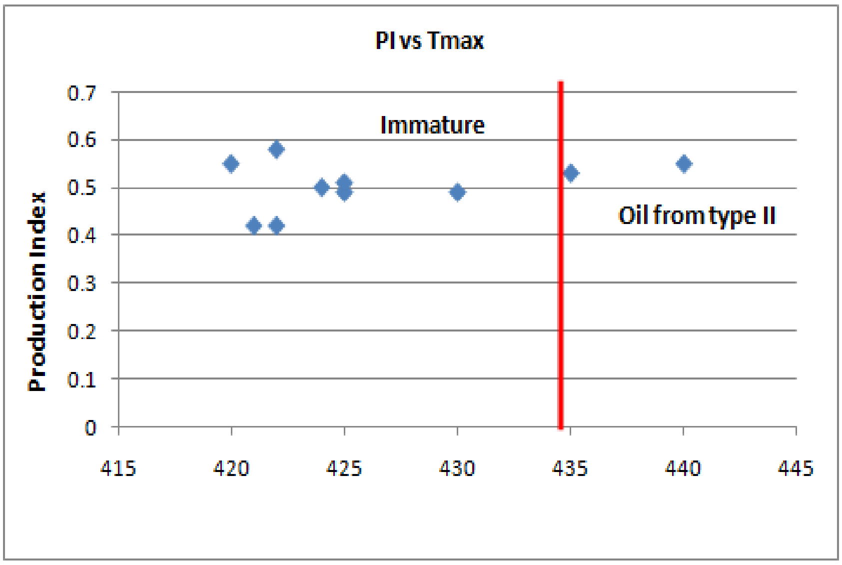

Figure 9d: Plot of PI versus T_{max}

This well shows gas generation because PI is above 0.3 but T_{max} is less than 435^0C for most of the samples, only few samples show higher T_{max}. According to Porter (1994), T_{max} values would be considered more reliable than PI because T_{max} is measured at maximum temperature where the kerogen begins to crack and it also depends on the type of organic matter, while the S1 peak of the production index (S1/(S1+S2) measures free hydrocarbons that can be vaporised without cracking of the kerogen and can be easily be affected by weathering or diagenetic degradation in the outcrop samples. Therefore the source rocks from this well are likely to generate hydrocarbon if exposed to sufficient temperatures.

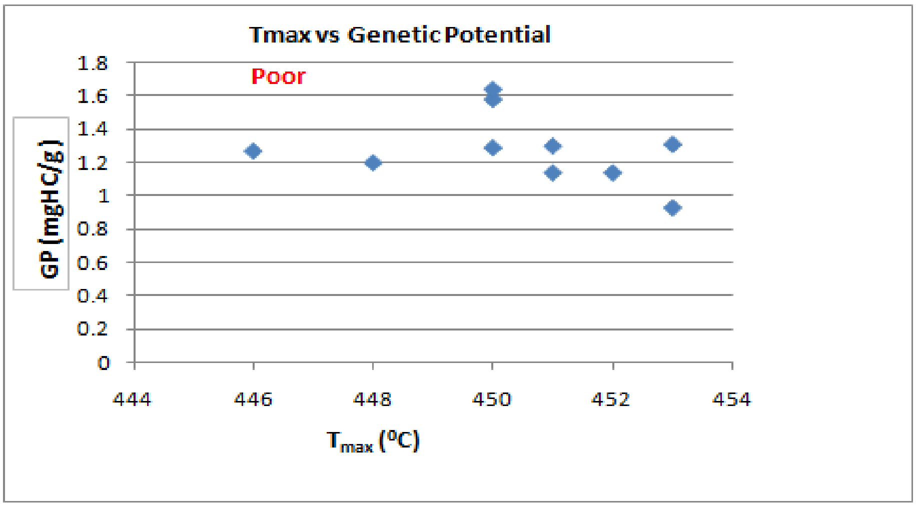

Figure9e: Plot of Genetic Potential versus T Max

Well M28 appears to have source rocks of even poorer quality compared to M22 (<2 2mgHC/g). This indicates that the source rocks from this well are not matured enough to generate hydrocarbon.

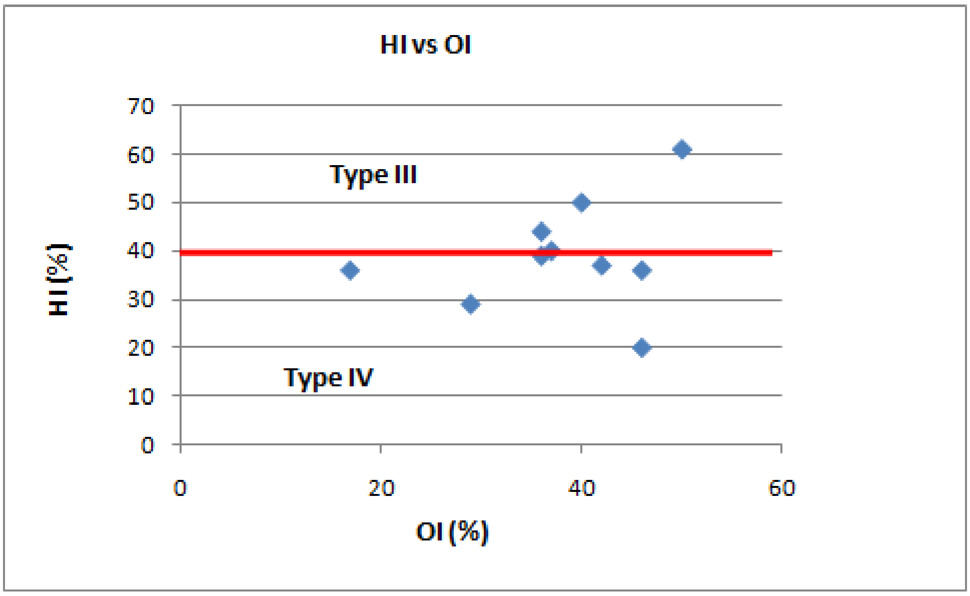

Figure 9f: Shows the OI (Oxygen Index) versus HI (Hydrogen Index) plot obtained from the Rock-Eval Pyrolysis data

The plot of OI versus HI t shows that the majority of the samples from M28 fall in type IV kerogen with only few from type III kerogen. The samples from this well generally have lower OI and thus, lower OI values typically have Type III kerogen, this indicate that the source rock has matured thermally to generate gas. In other words, this is gas-prone source rock.

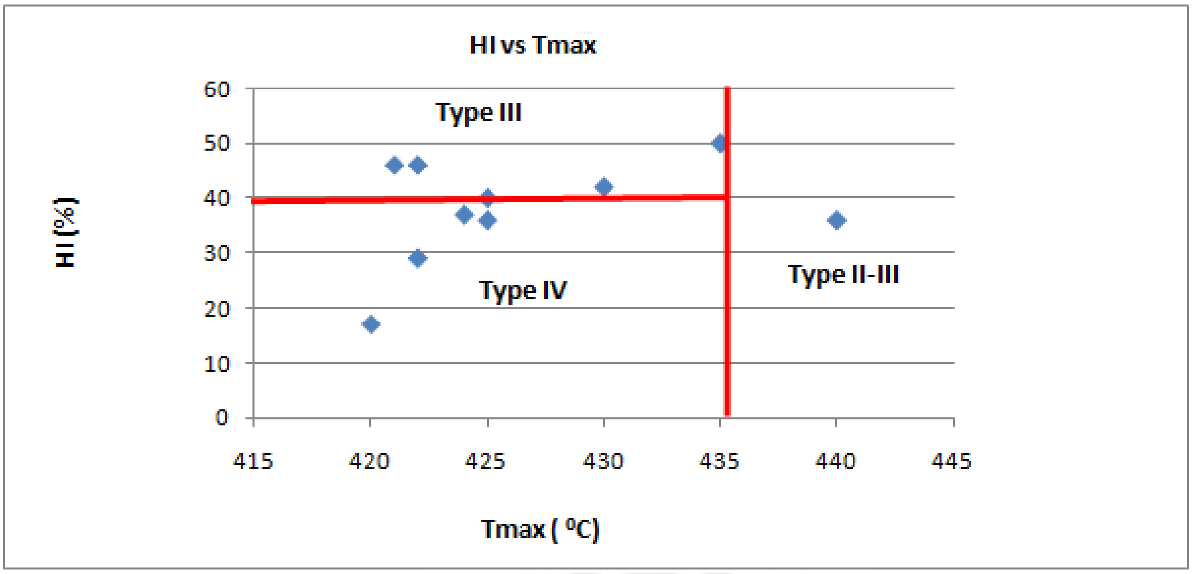

Figure 9g: Plot of Hydrogen Index versus Tmax

Figure 9g shows that most of the samples represent kerogen Type III-IV with only few points representing Type II-III kerogen.

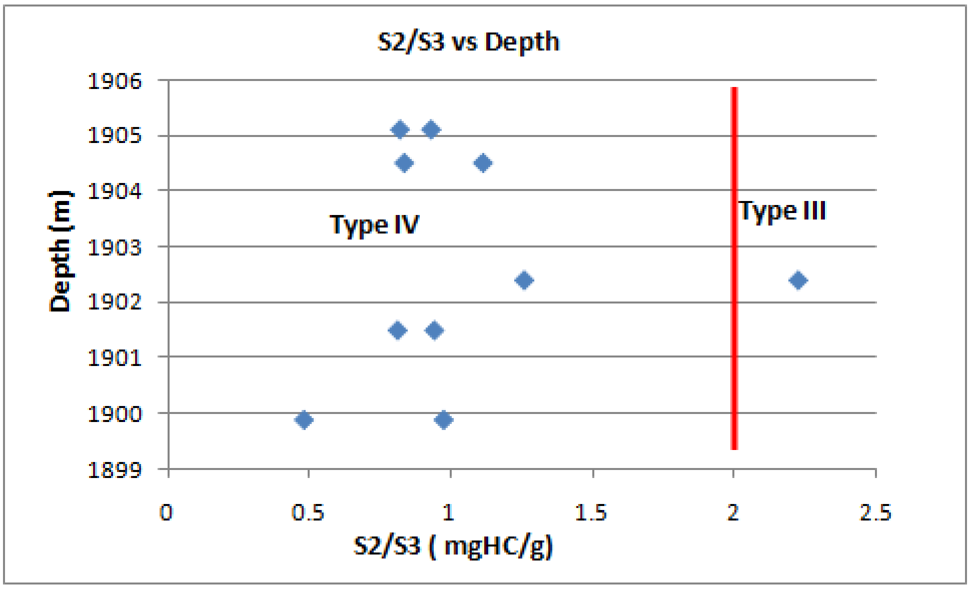

Figure 9h: Plot of S2/S3 versus Depth

Figure 9h above shows how much oil is released as compared to oxygen as the temperature increases with depth. This can be used to indicate the type of organic matter. From 1900 - 1905m the amount of S2/S3 increases. However, the figure shows the majority of the samples in Type IV kerogens, this indicate that there was no hydrocarbon that was released.

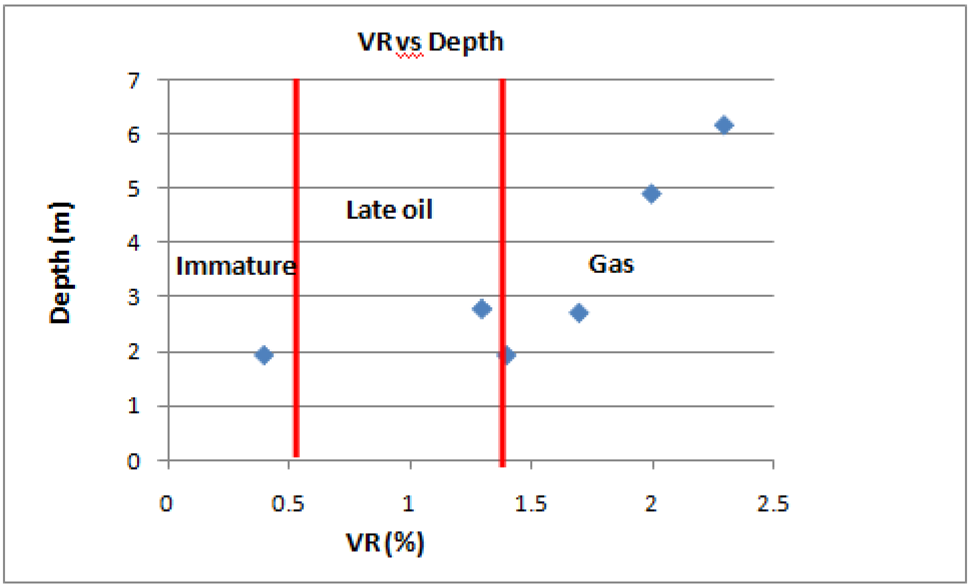

Figure 9i: Shows the plot of VR (Vitrinite Reflectance) versus depth form well M28

In Figure 9i, the VR ranges between 0.40-2,40 % and most of the samples fall within the late mature and gas generating zone, this shows that the these samples are thermally mature for petroleum generation.

4.4. Interpretation

4.4. 1 The Parameters of the Rock-Eval Pyrolysis

The Rock- Eval Pyrolysis analysis gives 4 (four) important parameters, Namely: The total free hydrocarbons released at T= 300^{0}C (from S1 peaks), The amount of hydrocarbons released at T= 600^{0}C from the S2 peak during the thermal cracking of the kerogen, The amount of carbon dioxide (CO_2) released during the heating of the organic matter from the S3 peaks, and the high temperature at which the maximum amount of hydrocarbons has been released during pyrolysis (Tmax) (Ricketts, 1987). These values are shown in the table below. The M22 well has higher values for S1, S2, S3 and Tmax than M28.

Well name	depth	TOC	S1	S2	S3	Tmax
M22	2270	0.86	1.41	0.54	0.31	445
	2274	1.25	2.13	0.67	0.35	438
	2278	2.48	1.31	3.6	0.33	454
	2279	4.6	1.62	5.5	0.42	443
	2280	5.8	2.67	7.8	0.22	450

M28	1899	1.26	0.71	0.22	0.46	420
	1901	1.24	1.11	0.47	0.5	424
	1902	1.06	0.8	0.49	0.22	421
	1904	0.95	0.85	0.35	0.42	425
	1905	0.71	0.95	0.36	0.44	445

Table 1: Rock Eval parameters from M22 and M28 samples.

4.4.2. Quality of the organic matter (kerogen type)

According to Bird (2001), '*'The quality of the source rock is measured by determining the type of kerogen contained in the organic matter as well as by using the genetic hydrocarbon potential''*. The genetic hydrocarbon potential gives the total of the amount of free hydrocarbon (S1) that has already been generated from the kerogen (S1) with the quantity of remaining hydrocarbon which is generated at higher temperature (S2). This can be mathematically expressed as (S1+S2) measured in mg/g of rock (Creaney et al., 1999).

The modified van Krevelen or HI versus OI plots obtained from Rock- Eval Pyrolysis (Figure 10) are the most common method used to determine the types of kerogen (Dixon., 2007). The plots of Hydrogen index (HI) versus oxygen index (OI) from figures 8f&9f shows four main types of kerogens. Type I kerogen is the algal and very oil prone kerogen and it originates mainly from lacustrine algae. Type II kerogens are oil prone and the most common for petroleum source rocks. It is a lipid-rich type of kerogen and its major contributors are Phyto-and Zooplankton marine organisms. Type III is a humic and gas-prone type of kerogen and represents terrigenous organic matter. Inert kerogen is typically referred to as type IV, It doesn't generate any hydrocarbons and would plot near the bottom of HI versus OI diagram (Figure 10) (Lee .,1998).

Well M22 shows the majority of the samples in type II & III kerogen (oil and gas) and type III kerogen (gas prone) whereas M28 shows the majority of the samples in type IV (inert) kerogens with only few in type III. M22 samples stand out from M28 samples and show highly gas- prone (type III) and oil prone (type II & III) kerogens. This may suggest that M22 is less favourable for the generation of oil and may give convenient gas source rocks. M28 samples generally have type III kerogen (Vitrinite) and consists mainly of mainly higher land plants and vegetal debris showing low H/C and high O/C ratios which indicate that the source rock is matured enough to generate hydrocarbons.

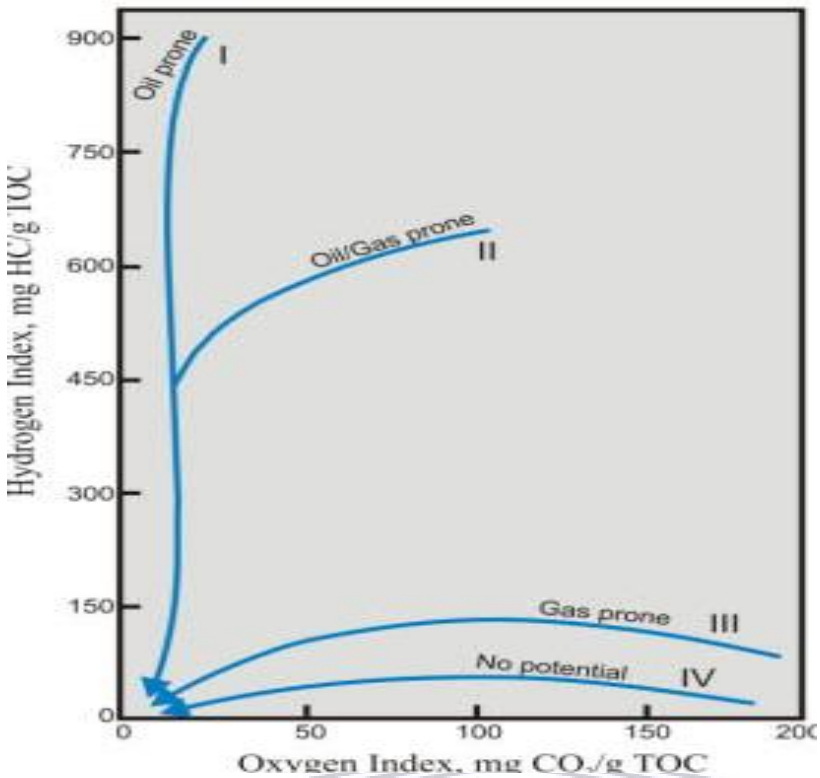

Figure 10: Modified Van Krevelen Plot showing all types of Kerogens (modified from (Tissot et al., 1974)

The HI versus T_{max} plots from figures 8g and 9g reveals a kerogen Type of I-III and Type IV organic matter. According to Kent (1992), these plots are used to avoid the influence of oxygen index for determining the type of kerogen. In well M22, the majority of the samples plot within Type III kerogens and only few samples are considered to be higher oil prone Type I-II kerogens (Figure 8g). These samples have been transformed to Type II-III and III kerogens because of their loss in TOC (Total Organic Carbon). Therefore samples from M22 are land in origin and are likely to generate gas; this type of kerogen is rich in carbon. Well M28 samples shows Type IV kerogen with only few samples within Type II-III /& III kerogens but most of the samples have Tmax below 435^0C. This shows that samples from M28 are thermally immature to generate hydrocarbons. Thiese samples have been altered by diagenesis but yet to be exposed to sufficient temperatures for thermally generated hydrocarbons and are highly oxidised, meaning, they contain large amount of oxygen.

On the other hand, the hydrocarbon genetic potential of the organic matter for well M28 is poor but contrarily good for well M22 which is absolutely consistent with the recent organic matter potential which was taken for the total hydrocarbon generation potential (GP=S1+S2) and the total organic carbon (TOC, % wt). It is shown that well M22 has a very good source rock potential contrary to M28 (figs. 8e & 9e). Table 2 below is used to compare the genetic potential values.

Source Potential (mg/g of Rock)	Genetic Potential (mgHC/g)
Poor	<2
Moderate	2-6

Good	>6

Table 2: Genetic potential value and their comparable source rock quality (Kalkreuth and McMechan 1998)

4.4.3. Quantity of Organic matter

Porter (1994) explained that the quantity of the organic matter can be measured by the amount of the total organic compound contained in the rock and that one of the most common methods used to assess the quantity of the organic matter is by plotting the TOC versus S2. Table 3 is used to assess the TOC and the S2 content. The plot of S2 versus TOC of all the samples in well M22 indicate that about 30% of the analysed samples from the Montney formation are considered to have good to excellent source rock potential. The deeper source rocks (>2200 m) mostly show an excellent source rock potential. The fast majority of the source rocks may possibly have been depleted in hydrocarbons indicating a currently fair hydrocarbon potential because of their advanced maturity.

Total organic carbon (TOC) of well M28 ranges from 0.71 to 1.26 wt% which is considered fair potential source rock while S2 is showing none source rock quantity (<2 mgHC/g). Well M22 has the highest TOC wt. % (0.9- 5.8) content as compared to M28 well, indicating that the condition during the deposition of sediments was favourable for organic matter production and preservation. The analysed samples may have been deposited in oxidizing environment. The calculated S2/S3 equals for well M22 is more than 10. These values indicate gas-oil prone organic matter and good to excellent potential for hydrocarbon generation. Therefore it can be concluded that well M22 samples display the best organic matter quantity among all the samples from well M28. Based on TOC data, well M22 demonstrate good and fair quantity of organic matter respectively. The rest of well M28 samples do not show significant petroleum generation, however most of them had TOC values of fair (0.7 to 1.3%) which shows fair quality.

SOURCE ROCK QUALITY	**TOC, %**	**Pyrolysis S2, mg hydrocarbons/g rock**
None	<0.5	<2
Poor	0.5 - 1	2-3
Fair	1 -2	3-5
Good	2-5	5-10
Very Good	>5	>10

Table 3: Showing the quality of the source rock (Porter, 1994).

4.4.4. Source Rock thermal maturation

The Vitrinite reflectance data together with Tmax versus Production Index (PI) from the rock eval pyrolysis data were used to estimate the thermal maturation of the organic matter. There are three different maturity phases of the organic matter, namely: Thermal immature phase which has been altered by diagenesis but yet to be exposed to sufficient heat , Mature phase which has been converted to petroleum via thermal processes and is within the oil window

(Catagenesis), Thermally post-mature which have altered the gas window and have already generated petroleum (Metagenesis), in so doing they have exhausted all hydrogen necessary for hydrocarbon generation (Leckie, and Smith, 1993). Table 4 was used to determine the level of thermal maturity for different types of organic matter estimated from the Tmax range.

Stages of thermal maturity of oil		Tmax (Type I)	Tmax(type II)	Tmax (Type III)
Immature		<440	<435	<445
	Early	440	435	445
Mature	Peak	445	440	450
	Late	450	460	470
Post-mature		>450	>460	>470

Table 4: Thermal maturation for different types of organic matter (Porter, 1994)

4.4.5. Tmax and PI Range

An estimation of thermal maturity can be made based on where samples plot on the HI vs. OI diagram. However, the main indices for thermal maturity are Tmax and production index (PI) as well as Vitrinite Reflectance as mentioned above. Tmax is measured at maximum S2 generation and mostly depends on time/temperature conditions and organic matter type, while PI = S1/(S1+S2) indicates the volume of hydrocarbons that can be generated from a source rock (Porter, 1994). The S1 peak measures free hydrocarbons that can be vaporized without cracking kerogen of the rock and can be easily affected by weathering and/or diagenetic degradation in outcrop samples. Thus, Tmax values would be considered more reliable than PI, although samples with S2 peak less than 2.0 mg HC/g rock Tmax are reported to be inaccurate and shouldn't be taken into account (Ricketts, 1987). However, only 6 samples out of total 10 analyzed samples showed S2 values more than 2.0 mg HC/g rock in M22**.**

Samples with reliable Tmax data on a PI vs. Tmax diagram were plotted and these are shown on Figure 8d and 9d. All samples from well M22 are matured based on this plot (Tmax >435^{o}C), while the rest of the samples in M28 are in the immature stage (Tmax= 420 -435^{o}C) – Mature stage (435-445^{0}C) respectively. Most of the samples from well M22 has oil from Type II kerogens (Tmax= 435-450^{0}C) and the rest of the samples have gas from Type III kerogens (Tmax = 550-455 ^{0}C).

4.4.6. Vitrinite Reflectance

Vitrinite is one of the common macerals in kerogen that is derived from woody- plant material and typically indicates organic matter of terrestrial origin. Vitrinite, like Tmax provide a sensitive response to changes in time/temperature conditions by increases in reflectance of Vitrinite with thermal maturity (Porter, 1994). The Vitrinite Reflectance (R_0%) in well M22 and M28 is used to assess the maturation of the organic matter. The R_0 values vary depending on the type of kerogen and thus the values of gas shows a corresponding increase over those of oil. The Vitrinite reflectance from well M22 ranges from 0.4 to 2.6 %, while those of M28 ranges from 0.5-2.4 % indicating that the samples are matured and have entered the mature to late mature stage of petroleum generation.

The gas generation values show a corresponding increase over those of oil. Both oil and gas values reflect that the source rocks are immature to marginally mature with respect to hydrocarbon generation. According to Davies, (1997) values for immature phase is (< 0.54%), early mature (0.54-0.70%) mid mature (0.70-1.00%), late mature (1.00-1.30%) wet gas (1.30-2.00%) and dry gas generation (2.00-2.60%) respectively. Whereas the maturity of the samples taken from well M28 are in the late oil-gas window. Figure 8i & 9i shows distribution of VR data versus depth indicating that both samples taken from well M22 & M28 are sufficiently thermally mature for petroleum generation.

CHAPTER FIVE

5.1. Discussion

The generation of the hydrocarbons is determined by the maturity of the source rocks as they undergo physical and chemical changes after deposition. On the other hand, the type of the hydrocarbon generated is determined by the quality of the organic matter.

According to the results, well M22 of the Montney formation displays the best organic matter quantity, quality and thermal maturity as compared to well M28. From the total of 300 samples of the Montney formation, the TOC analysis revealed up to 5.8 % with values of 0.3-0.7 % common. S2 pyrolysis peak yield values up to 7.8 mg HC/g rock also indicates excellent source potential (figure 8c). The hydrogen Index (HI) values reached 250 mg HC/g TOC which indicate Type II and III kerogens for samples with reliable rock eval pyrolysis results. Visual kerogen analysis also suggested highly oil prone and gas prone kerogens. The organic rich shales from well M28 samples appears to be thermally immature with only few samples that show generation of gas based on Tmax values (421-445^0 C). In contrast, values of Ro ranges from 0.4 % to 2.4 % indicating immature, late oil window maturity to gas window level of thermal maturation. Therefore well M28 is likely to generate gas (wet or dry gas) which evolve along with non-hydrocarbon gases such as CO_2, N and H_2S (hydrogen sulphide). During maturation, the concentration of nitrogen, sulphur, hydrogen and oxygen decreases.

The major components of kerogen are C,H,O,N and S. This kerogens are classified as Type I, II, III, and IV and different kerogens are constrained by well-defined boundaries on the H/C versus O/C plots as indicated in figure 8f and figure 9f respectively. They provide good indication of kerogen maturity levels and the nature of products that a particular kerogen is expected to generate at appropriate levels of maturity (Davies and Moslow, 1998).

Kalkreuth and McMechan (1998) suggested that *''The HI (Hydrogen Index) show similarity to the quality and the quantity of the amount of hydrocarbons released during the thermal cracking of the kerogen to the total organic carbon in the samples (mg HC/g TOC) and can be used successfully to evaluate the hydrocarbon generating potential of the rock as well as the type of the organic matter ''.* The OI (oxygen index) is directly related to the quantity of terrestrial organic matter in the sample (mg CO_2/g COT). Both hydrogen index and oxygen index indicates a good correlation with the atomic ratios H/C and O/C obtained by elemental analysis of kerogen and give enough information about the origin and degree of maturity of organic matter. According to Porter (1994), '' *the kerogen composition with respect to oxygen and hydrogen gives the genetic potential and the amount of oil and gas that can be generated during burial''.*

When comparing the trend of TOC, HI and S2/S3 versus depth in well M22 and M28 (Figure 8a&9a, 8b&9b, 8h&9h), the TOC increases with depth, whereas HI and S2/S3 show a different trend, that is, a peak followed by an abrupt decrease in their relative amounts. From 2270-2280 m in well M22, an increase in TOC is followed by a decrease in HI while in well M28 this is occurring at different depth (1905-1899 m). At that interval S2/S3 does not exists.

The relationship between TOC and HI reveals the relative amount of hydrocarbon released from TOC at certain depth. If the TOC is decreasing the HI will show its highest peaks where hydrocarbon is generated.

5.1.1. Burial history and Maturation history

The maturation history, burial history and timing of hydrocarbon generation were modelled for the two locations (301 and 306) in the Alberta basin. The results show that the maturation history, burial history as well as timing of hydrocarbon generation varies widely and this will depend on the location and on the kerogen types.

Two major erosional events occurred in the Alberta basin that influenced petroleum generation, migration, and accumulation. The older one is a sub-Mannville erosional unconformity that began between 368.5 and 197 Ma and ended about 119 Ma (Edwards el al., 1999). The Ro was measured directly from the coal in the Mannville Group because the coal from this group is more reliable than those from other lithologies and also because coal contains the true vitrinite maceral from which the best reflectance values can be measured. Therefore, the burial history models were calibrated using the measured Ro values of the Mannville group and the measured bottom-hole temperatures.

The burial history plots for well 301 location in figure 7a show that the timing for the start of oil generation occurred within a relatively narrow range, around 139 Ma. The gas generation from the cracking of Woodbend group oil started from the Mid- Cretaceous and Late Cretaceous. Since that time the source interval at this location has generated mainly oil and gas**.** The start of oil generation for the Nisku Shale occurred from Late Jurassic except on 306 location where generation of Shunda oil started earlier (Mid-Late Triasic). In 306 location, the generation of gas from the cracking of Wabamun oil began at about 80 Ma**.** The source interval at the 306 location matured much earlier than at 301 location. Early oil generation began as early as 205 Ma (Upper Triassic), when burial depth was just 1703 m. The main phase of oil generation occurred 127 Ma later when the basin had been buried to 1712 m**.** Gas-prone source rocks of the Elk point and Chinchaga formations in 301 location began generating gas at about 80 Ma and still generates gas to present day. The petroleum events chart shows the trap formation occurring as the basin subsided during Laramide deformation in the upper Cretaceous- Paleocene. Hydrocarbon generation, migration and accumulation, on the other hand, occurred in the upper Cretaceous, except in well 306 where it was earlier.

CHAPTER SIX

6.1. Summary and Conclusion

This research project presents an evaluation of possible source rocks units and the thermal history in the Alberta basin that includes the Triassic Montney formation. This study described the quantity (hydrocarbon potential), quality (kerogen types) and level of the thermal maturation of the analysed samples. The maturity is mostly dependant on the depth of the samples. A vast majority of the source rocks are either within the oil window or in the condensate/wet gas zones-dry gas. As a result of this evaluation, well M22 displayed excellent organic matter quantity (TOC up to 5.8%), and Type II and Type III kerogens, which are favourable for oil & gas generation. The pyrolysis S2 yield is 7.8 mg HC/g rock, Plot of HI versus OI show that it is composed of Type III kerogen (mainly vitrinite from continental vegetation. However only few samples from well M28 met the requirements for the organic matter quantity, quality, and thermal maturity in order to be called source rocks otherwise the rest of the samples was immature. This could be because the samples from well M28 were collected from outcrops easily affected by weathering. This significantly changed the TOC values and affected thermal maturation and Rock-Eval pyrolysis parameters. If the facies of these rock samples were found in deeper places in the basin, they could generate significant quantities of hydrocarbons.

Most mature source rocks of both wells in the Montney formation lies near the deformation zone and west-central section along the deformation front of the foothills of Alberta. Mostly dry and wet gas in this region could be connected to a higher maturity gradient which is possibly related to major faults or higher stress regimes. Most of the immature to early oil rich source rocks such as those ones from well M28 samples are restricted to the western part of the Alberta basin. Despite this, the samples in well M28 are of less value than the samples in well M22.

Maturation history has been based on calibrating the measured VR and temperature for each burial history location. As previously discussed, the immature phase for oil and gas generation is (< 0.54 %), early mature (0.54-0.70 %) mid mature (0.70-1.00 %), late mature (1.00-1.30 %) wet gas (1.30-2.00 %) and dry gas generation (2.0-2.6 %).

The Vitrinite Reflectance values have been measured for all stratigraphic units in the Alberta basin. Maturation history of the source rocks is directly controlled and determined by the history of thermal regime in the area. Consequently, all parameters that influence the thermal history affect the maturity. This includes the heat flow, burial history, boundary conditions (e.g. paleo surface temperatures), proximity of the salt structures and the burial history. The main maturity phase occurs when the formations are at their deepest burial. The maturity history indicates that the deepest part of the assigned source rock units entered the hydrocarbon generation already during the Triassic. The maturity increased during the upper Jurassic and reached a peak during Early Cretaceous.

6.2. Recommendations

The study area shows a good generating potential and a type of kerogen in most of the samples in the western part of the Montney formation. The variation shown in these types of kerogens may have been assigned to the relative stratigraphic positions of the sample outcrops within the Alberta basin. The outcome of this study showed a good generating potential of oil and gas from the Montney formation. Thus, core samples together with log data must also be undertaken because they give accurate information regarding the Total Organic Carbon contained in the rock as well as the depth of the source rocks. Log analysis needs to be conducted to estimate the total organic carbon. The quality of the organic matter and the total organic carbon needs to be evaluated within the sequence stratigraphic framework. A broader seismic survey should also be conducted in order to give a clear understanding of the area and to find hydrocarbon accumulation and distribution in terms of their stratigraphic and structural trap.

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