Geological and Geophysical Evaluation of the Thebe Field, Block XX, Offshore Western Australia

A Thesis in Petroleum Geosciences

By

BRETT BAILEY

Submitted in partial fulfilment of the requirements for the degree of

Magister Scientiae in the Department of Earth Sciences,

University of the Western Cape

March 2013

Supervised by Dr. M. Opuwari

Co-Supervised by Mr. V. Mashaba

DECLARATION

I declare *Geological and Geophysical Evaluation of the Thebe Field, Block XX, Offshore Western Australia* is my own work, 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

Brett Bailey   March 2013

_____

Signature

UNIVERSITY *of the*

WESTERN CAPE

Abstract

The North West Shelf of Australia is a prolific gas province. The Thebe Gas Field is situated within the northern central Exmouth Plateau in the Northern Carnarvon Basin. The Exmouth Plateau is a submerged continental block whose culmination lies at about 800m below sea level. The seismic data used for this study is the HEX07B survey which was conducted in 2007.

The objective of this study was to interpret all available seismic data, of which six horizons were picked, generating two-way-time structure maps and an average velocity map, performing depth conversion and generating various depth maps. The horizons picked were the economic basement, Triassic Mungaroo, Murat Siltstone, Muderong Shale, Gearle Siltstone and the Sea Bed. The horizon of interest was the Triassic Mungaroo Formation and therefore it was the only horizon with an average velocity map. The seismic sections were used in conjunction with the structure maps generated to identify possible locations for appraisal wells to be drilled. Prospect X was identified on the basis of amplitude and structure present within the Triassic Mungaroo Formation. The final task was to calculate the volumes present and a Monte-Carlo Simulation was used for this.

The results obtained showed that Prospect X has a good petroleum system in place. The Mungaroo Formation is identified as being the possible source and reservoir rock, the Muderong Shale is the seal, structural traps are provided by large fault block and faults provided the migration pathways from the source in to the reservoir.

The volumes were calculated using three areas identified on the structure maps by three closing contours. These areas are the P90, P50, P10 and the volumes for the gas in place were as follows, P90 = 893 Bcf (0.9Tcf), P50 = 1128 Bcf (1.1 Tcf), P10 = 1367 Bcf (1.4Tcf).

Using the various parameters the probability of success for Prospect X was calculated to be 20%.

Acknowledgements

Table of Contents:

List of Figures:

List of Tables:

.

Chapter 1

1.1. Introduction

The North West Shelf of Australia is a prolific gas province.

Australia's North West Shelf is a marginal rift and covers an area of 720,000 km^2 and extends for more than 2400kms from the Exmouth Gulf in the south to Melville Island in the north. Four sedimentary basins are covered by the North West Shelf, from south to north; these basins are the Northern Carnarvon Basin, the Offshore Canning Basin, the Browse Basin and the Bonaparte Basin *(Purcell et al.., 1988)*.

The goal of any seismic interpretation is to produce a rational geologic model from the available seismic data. Over time the interpretation of seismic data has evolved and it has developed the way in which geoscientists search for hydrocarbons and the development thereof. The improvement in seismic data over the last couple of years has been partly responsible for the improvements in exploration and production in the oil and gas industry.

After all the seismic sections have been interpreted the next step in exploration is the creation and interpretation of subsurface geological maps. The interpretation of subsurface geological maps is the one of the most important steps used in the oil and gas industry to explore for undiscovered hydrocarbons and hence develop proven hydrocarbon reserves *(Tearpock et al..,1991) (Gluyas et al..,2004)*.
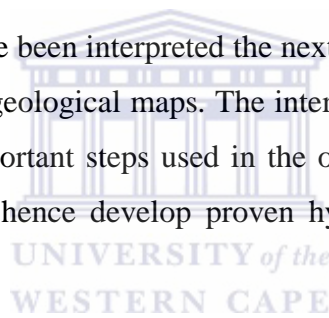
1.2. Aims and Objectives

1.2.1 Aims.

The scope of the research program is to assess the extent and potential resources of the gas discovery named the Thebe field on block XX offshore Western Australia.   The geological control will be provided from the two wells drilled into the discovered reservoir (Thebe-1 and Thebe-2) and two further wells on adjacent structures named Scarborough-4 and Jupiter-1. The key deliverable will be structural maps on the top reservoir section (Top Mungaroo Formation).

1.2.2 Objectives

☐   Depositional history of the study area tied with interpretation of facies distribution

☐   Utilize 3-D seismic data to visualize the formation structures

☐   Gain better understanding of the formation architecture through integrated assessment of 3-D seismic data/ interpretation, depositional environments of the area.

☐   Seismic well tie

☐   Determine the petrophysical properties of the reservoir (Porosity, Water Saturation, on representative wells.

☐   Generate time structure, average velocity and depth maps for the evaluation of Hydrocarbon volumes.

1.3 Location of the Study Area.

The Thebe Gas Field is situated in the north central Exmouth Plateau in the Northern Carnarvon Basin. It is approximately 50km north of the Scarborough Gas Field, 320km northwest of Onslow and approximately 380km northwest of Dampier on the Pilbara Coast, offshore North Western Australia (Fugro, 2006).
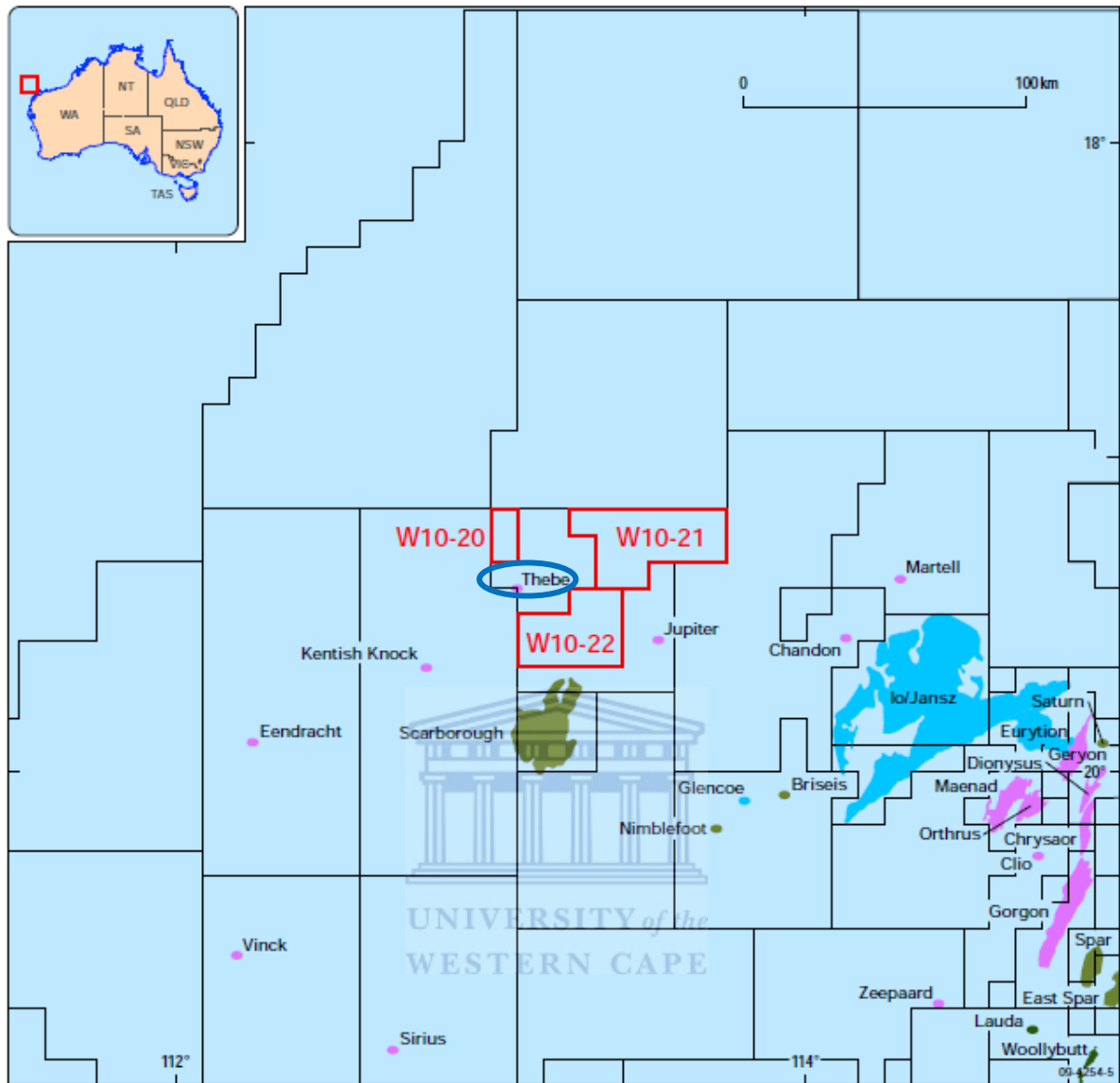
Figure 1.1. Location of the Thebe Gas Field, indicated by the blue oval (modified after Australian Government, 2010)

1.4 Well Exploration History.

Exploration on the deep water Exmouth Plateau took place in two phases. The first phase started in 1979 and mainly targeted oil exploration. The second phase started in the mid-1990s (and is currently on-going). This phase is for the exploration of gas (*Australian Government, 2012*).

Below is a table containing a summary of the wells drilled on the Exmouth Plateau, it contains the well name and year, operator, water depth, total depth and the targeted formation.

Well Name and Year	Operator	Water Depth (m)	Total Depth (m)	Target Formation
Investigator 1 (1979)	Esso Australia Ltd	841m	3745 mKB	Barrow Group
Jupiter 1 (1979)	Phillips Australian Oil Company	960m	4946 mRT	Mungaroo Formation
Scarborough 1 (1979)	Esso Australia Ltd	912m	2364 mKB	Barrow Group
Vink (1980)	Esso Australia Ltd	1383m	4600 mKB	Mungaroo Formation
Eendracht (1980)	Esso Australia Ltd	1354m	3410 mKB	Mungaroo Formation
Sirius (1980)	Esso Australia Ltd	1173.9m	3500 mKB	Barrow Group, Mungaroo Formation
Jacala (1996)	BHP Billiton Petroleum Pty Ltd	1062m	2217 mRT	Zeepard Formation
Thebe 1 (2007)	BHP Billiton Petroleum Pty Ltd	1169m	2510 mRT	Mungaroo Formation
Thebe 2 (2008)	BHP Billiton Petroleum Pty Ltd		2550 mRT	Mungaroo Formation
Kentish Knock 1 (2009)	Chevron Australia Pty Ltd	1228m	2525 mRT	
Brederode 1 (2010)	Chevron Australia Pty Ltd	1387m	2750m	
Tiberius (2010)	Woodside Energy Ltd	1660m	2856m	Mungaroo Formation
Alaric (2010)	Woodside Energy Ltd	1961m	4563m	Mungaroo Formation

Table 1. Well exploration history of the Exmouth Plateau.

1.5. Project Outline.

The research project is made up of six chapters which will be mentioned below:

Chapter 1: Gives a general introduction of the project, it includes the aims and objectives, the location of the study area, a summary of the well exploration history and the project outline

Chapter 2: Gives an overview of the geology of the Carnarvon Basin, the Northern Carnarvon Basin and the Exmouth Plateau. It includes basin evolution and stratigraphy of the Northern Carnarvon Basin and the depositional environments of the Northern Carnarvon Basin. It also includes the petroleum elements of the Exmouth Plateau.

Chapter 3: Focuses on the data and methods used in the study to obtain the results.

Chapter 4: Includes all the results with brief interpretations. These include all the geophysical and petrophysical results.

Chapter 5: Focuses on the discussion of the Mungaroo Formation and the identification of Prospect X and includes the volumetrics and probability of geological success thereof. It also includes a summary of Prospect X.

Chapter 6: Is made up of the conclusions and recommendations regarding Prospect X.
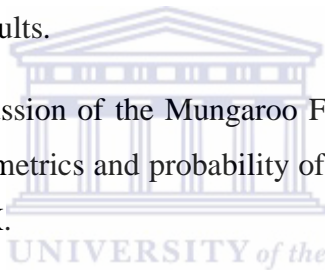
Chapter 2: Regional Geology

2.1. The Carnarvon Basin

2.2. The Northern Carnarvon Basin

    2.2.1. Regional Geology of the Northern Carnarvon Basin

    2.2.2. Tectonic development of the Northern Carnarvon Basin

    2.2.3. Basin Evolution and Stratigraphy of the Northern Carnarvon Basin

2.3. The Exmouth Plateau

2.4. Petroleum elements

2.5. Petroleum elements of the Exmouth Plateau

2.1 The Carnarvon Basin

The Carnarvon Basin is an epicontinental basin situated at the southernmost end of the Late Palaeozoic to Cenozoic Western Australia (Westralian) Superbasin. It underlies the north-eastern continental margin of Australia from North West Cape in the south to the Arafura Sea in the North. *(Australian Government, 2010)(Condon, 1954).*
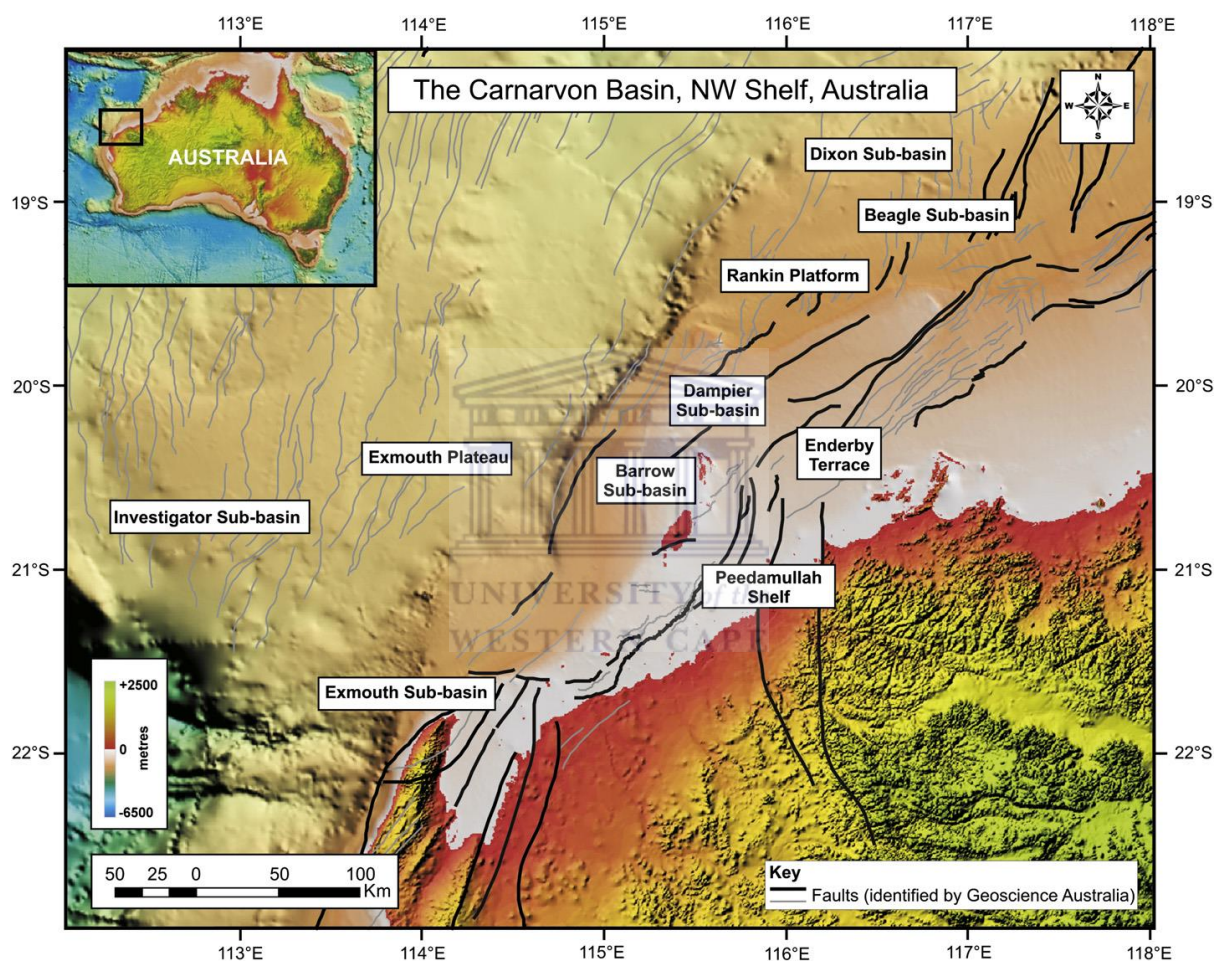
Figure 2.1. A map showing the location of the Carnarvon Basin on Australia's North West Shelf, *(King et al, 2010).*

The Carnarvon Basin is made up of a network of complex Palaeozoic half grabens and tilted fault blocks. The Carnarvon basin is subdivided into two sectors, the Northern Carnarvon Basin and the Southern Carnarvon Basin (Figure 2.1). The Northern Carnarvon Basin is mainly offshore and covers an area of approximately 535000km^2 and it is composed mainly of Mesozoic offshore depocentres. The Southern Carnarvon Basin is situated mainly onshore

and covers an area of approximately 185000 km^2; it is composed mainly of Ordovician to Permian depocentres. *(Eyles et al, 2003).*
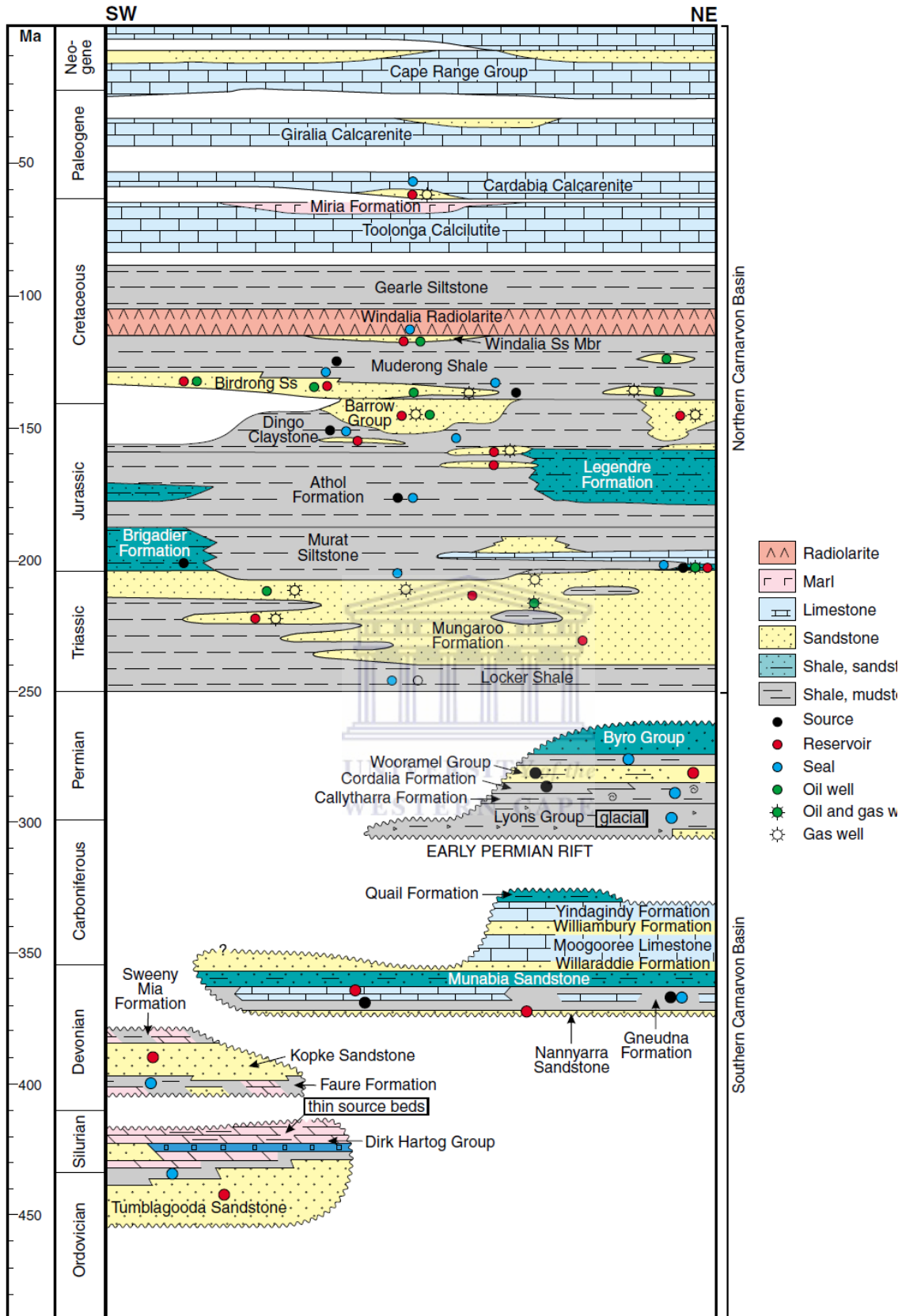
Figure 2.2. Generalized stratigraphy of the Carnarvon Basin, showing the subdivision into the Northern and Southern Carnarvon Basin (*Government of Western Australia, 2010*).

The Carnarvon Basin development commenced in the Early Palaeozoic with the deposition of Ordovician and Silurian sandstones, evaporites and carbonates exceeding over four kilometres in thickness. Following uplift and broad distortion in the mid-Devonian, marine conditions then resulted in the deposition of Devonian sediments and reef development during the Frasnian. A shallow shelf had formed by Late Devonian and this shelf had deepened slightly by the end of the Tournasian.

Prevalent glacial conditions influenced sedimentation in the Late Carboniferous. The Overlying Permian sediments consist of marine and marginal marine successions. In the early Late Permian, Palaeozoic sedimentation was terminated by rifting and as a result of this a large portion of the southern part of the Carnarvon Basin remained emergent into the Early Cretaceous *(Baillie et al..,1994).*

Deposition in the Late Permian in the northern part of the Carnarvon Basin involved a thin sandy transgressive succession. During the Middle and Late Triassic, interbedded sands and muds were deposited in marine and marginal marine conditions in a fluvio-deltiac coastal complex. A shale unit was deposited in a marine environment during the Late Triassic *(Baillie et al.., 1994).*

In either the latest Triassic or earliest Jurassic, rifting recommenced and the structural elements which define the present day Carnarvon Basin developed primarily at this time. In the Late Neocomian, a major regional transgression was responsible for the deposition of marine shales which now form the regional seal in the Carnarvon Basin for the majority of the hydrocarbon accumulations. The Carnarvon Basin developed as a margin-sag basin and calcareous pelagic deposition commenced in the middle Late Cretaceous. Carbonate sedimentation dominated offshore deposition through most of the Cainozoic with relatively little siliciclastic deposition in the Eocene and Miocene *(Baillie et al.., 1994).*

2.2 Northern Carnarvon Basin

2.2.1 Regional Geology of the Northern Carnarvon Basin

The Northern Carnarvon Basin is located at the southern end of Australia's North West Shelf, *(He et al, 2002)*, it covers an area of approximately 535000km^2 *(Australian Government, 2012)*. The Basin which is mainly offshore extends north from the Pilbara Craton to the continental crust. It is transitional into and overlies the Southern Carnarvon Basin which is mainly onshore *(Explorers Guide, 2009)*.

The Northern Carnarvon Basin is bounded by the Roebuck and Offshore Canning Basins to the northeast, by the cratonic Pilbara Block to the southeast, by the Southern Carnarvon Basin to the south and by the Argo, Cuvier and Gascoyne abyssal plains to the northwest *(Australian Government, 2010)*. The Northern Carnarvon Basin, from southeast to northwest, is divided into marginal shelves, namely the Peedamullah and Lambert shelves, two complex grabens, the Barrow and Dampier Sub-basins, a mid-basin ridge, the Rankin Platform, and an outer series of faulted troughs, the Exmouth Sub-basin, Investigator Sub-basin, Dixon Sub-basin and the Kangaroo Trough *(Hocking et al.., 1994)*.

Through the Palaeozoic, Triassic and Early Jurassic the Northern Carnarvon Basin underwent sag-basin and internal rift development when deposition was primarily shallow marine shelf and continental conditions.

The Northern Carnarvon Basin is subdivided mainly into the Exmouth Plateau, Barrow, Dampier and Beagle Sub-basins, the Rankin Platform and the Exmouth *(He et al, 2002)*.

2.2.3. Tectonic development of the Northern Carnarvon Basin

The tectonic development of the Northern Carnarvon Basin commenced in the Permian, through the Jurassic and ended in the Cenozoic *(He et al.., 2002).*

Starting in the Permian (late Palaeozoic) the offshore part of the Northern Carnarvon Basin developed from a pre-rift broadly sagging basin, through tectonically active sub-basins in the Jurassic and in the Cenozoic to a passive margin carbonate shelf *(Australian Government, 2012).*

2.2.4. Basin Evolution and Stratigraphy of the Northern Carnarvon Basin

According to the Australian Government (2012), the evolution of the Northern Carnarvon Basin can be divided into six key stages:

1. Silurian to Toarcian: Pre-rift
2. Toarcian to earliest Callovian: Early syn-rift
3. Earliest Callovian to Berriasian: Main syn-rift
4. Berriasian to Valanginian: Late syn-rift Barrow Delta
5. Valanginian to mid-Santonian: Post-breakup subsidence
6. Mid-Santonian to Present: Passive margin

1. Silurian to Toarcian: Pre-rift

The break-up of Gondwana strongly influenced the evolution of the Northern Carnarvon Basin and it most probably began with the deposition of several sedimentary sequences from the Ordovician to the Permian in an elongated basin between the Achaean Pilbara Craton and continental blocks to the northwest *(Explorers Guide, 2009).* Shallow marine clastics and carbonates were deposited during the Late Permian, accompanied by the formation of northeast-southwest trending depocentres *(Longley et al, 2002).* The Early Triassic saw the deposition of a regional marine transgression sequence, known as the Locker Shale which is composed mainly of marine claystone and siltstone with relatively minor amounts of paralic sandstone and shelfal limestone. The Locker Shale grades upwards into a thick fluvial and paralic sequence of sandstone, siltstone and claystone with minor amounts of coals and conglomerate known as the Middle to Upper Triassic Mungaroo Formation *(Hocking, 1988).*

During the Late to Early Jurassic thinly bedded shelfal siltstone, claystone and marl of the Brigadier and Murat Siltstone were deposited as a result of rapid subsidence.

2. <u>Toarcian to earliest Callovian: Early syn-rift</u>

The early syn-rift stage consists of the Athol Formation, which is composed of restricted marine claystone and siltstone, and the Legendre Formation which is composed of regressive deltaic sandstone. According to Hocking (1988), subsequent to the rift-onset unconformity, persistent transgression and subsidence resulted in more widespread deep marine environments in which the Athol Formation was deposited, except along the Rankin Trend and Lambert and Peedamullah Shelf. At these shelves during the Callovian, swift uplift and erosion occurred *(Kopsen et al.., 1985)*. The erosion provided the foundation for the submarine fan sands of the Biggada Formation in the central Barrow Sub-basin and in the eastern Dampier Sub-basin, the continuation of sandy deposition formed the upper Legendre Formation. The Learmouth Formation was continually deposited adjacent to the Paterson and Rough Range faults *(Hocking, 1988)*. Even though the initial rifting began in the Pliensbachian with localised deepening of marine environments, the Callovian rift development is considered as ending the pre-rift phase *(Kopsen, 1994)*.

3. <u>Earliest Callovian to Berriasian: Main syn-rift</u>

During the Callovian to Oxfordian, seafloor spreading and the separation of Argo Land from Australia took place in the Argo Abyssal Plane *(Jablonski, 1997) (Australian Government, 2012)*. The Callovian unconformity was produced by uplift and erosion concomitant with initial extension. According to He et al (2002), the actual continental breakup is dated as being associated with the main unconformity in the Northern Carnarvon Basin. In the Beagle and Dampier Sub-basins the main unconformity is seen as the contact between the Callovian and the Oxfordian sequences as well as between the Lower Oxfordian and Middle-Upper Oxfordian rocks *(Barber, 1994) (He at al.., 2002)*.

During the Late Jurassic persistent post-breakup faulting uplifted and tilted the Rankin Platform and Exmouth Plateau, with sediments being supplied to adjacent depocentres. The Dingo Claystone, which is a thick, deep marine succession, formed as a result of rapid tectonic subsidence. The Dingo Claystone, overlapped the flank of the Barrow, Dampier and Exmouth Sub-basins *(Tindale et al.., 1998) (Australian Government, 2012)*. During the Late Jurassic on the eastern part of the Exmouth Plateau, sandy shelfal facies occurred within

restricted shallow basins. In the Southern Exmouth Plateau, uplift of the footwall of tilted Triassic fault blocks on the Rankin Platform resulted in the formation of the Kangaroo Syncline, as well as in the northern part of the Exmouth Sub-basin *(Sinhabaedya, 2011)* *(Jenkins et al.., 2003)*. Until the Berriasian, in uplifted areas, coarse clastic sediments were derived from the erosion of the Triassic Mungaroo Formation and transported into the syncline.

In parts of the Northern Carnarvon Basin, the Upper Jurassic sandstones are fundamental as reservoir formations *(Jenkins et al.., 2003) (Geoscience Australia, 2012)*. During the Early Berriasian, another episode of uplift and erosion terminated deposition and marked the onset of rifting between Greater India and Australia *(*Sinhabaedya*, 2011).*

4. <u>Berriasian to Valanginian: Late Syn-rift Barrow Delta</u>

During the Berriasian to Valanginian, the extensive Barrow Delta and the deposition of the Barrow Group dominated. The lower and upper Barrow Delta lobes formed as a result of progradation during the late syn-rift phase. The lower Barrow Delta lobe formed as a result of the delta prograding northward to the west of the Barrow Island and across the Exmouth Plateau. The upper Barrow Delta lobe formed as a result of progradation which initiated in the Late Berriasian. The upper Barrow Delta lobe formed in the Barrow and Dampier Sub-basins about 250km to the east of the deltas earlier depocentre *(Ross et al.., 1994)*.

The sediments of the lower Barrow Delta lobe are collectively known as the Malouet Formation. The Malouet Formation consists of horizontal reflections. The upper Barrow Delta lobe sediments are known as the Flacourt Formation which consists of inclined, progradational reflections *(Hocking, 1988)*. In parts at the top of the Barrow Group the sandstone is known as the Zeepard Formation and Flag Sandstone. Deposition of the Zeepard Formation took place in the Early Valanginian across the Barrow and Exmouth Sub-basins, Rankin Platform and the Exmouth Plateau as progradational top set units of the Barrow Delta. The Flag Sandstone was deposited in front of the delta foresets, as a basin-floor fan in the north-eastern Barrow Sub-basin.

The beginning of continental breakup to the southwest of the Exmouth Plateau stopped the supply of sediment to the Barrow Delta system *(Hocking, 1990)*. During the breakup, the Exmouth Plateau and Exmouth Sub-basin were inverted tectonically, but in the Barrow and

Dampier Sub-basins marine sedimentation and subsidence still continued *(Australian Government, 2012)*.

5. <u>Valanginian to mid-Santonian: Post-breakup subsidence</u>

Seafloor spreading is understood to have commenced in the Valanginian. The seafloor spreading was associated with the separation of Australia and Greater India and the formation of the Cuvier Abyssal Plain and the Gascoyne Abyssal Plain to the south and west of the basin *(He at al.., 2002)*.

The Birdrong Sandstone and glauconitic Mardie Greensand formed as a result of localised paralic and shelf deposition, this was followed by the basin wide deposition of the transgressive Muderong Shale, Windalia Radiolarite and the Gearle Siltstone. During the Early Santonian in the southern Exmouth Sub-basin, a phase of uplift formed the Novara Arch and caused the erosion of the Gearle Siltstone *(Tindale et al.., 1998) (Geoscience Australia, 2012)*.

6. <u>mid-Santonian to present: Passive Margin</u>

After the breakup, the Northern Carnarvon Basin developed as a passive continental margin and experienced a thermal sag phase *(He et al.., 2002)*. The marine shales together with local sandstones dominated the Cretaceous sedimentary rocks that were deposited after the breakup *(Hocking, 1988)*. The major lithologies from the Santonian are the calcareous sediments *(Barber, 1982)*. By the mid-Santonian, the siliciclastic sedimentation stopped and this was caused by tectonic stability and a decreasing supply of terrigenous sediment.

Short episodes of compression, during the Cainozoic, which resulted from the convergence between Australian and Asian plates, resulted in localized structural deformation. In the Northern Carnarvon Basin the Cainozoic strata are carbonate –dominated sequences *(He et al.., 2002) (Hocking, 1988)*.

During the Late Cretaceous and Cenozoic prograding shelfal sediments were deposited on the passive continental margin *(Geoscience Australia, 2012)(Refer to figure 2.3 and 2.4)*.
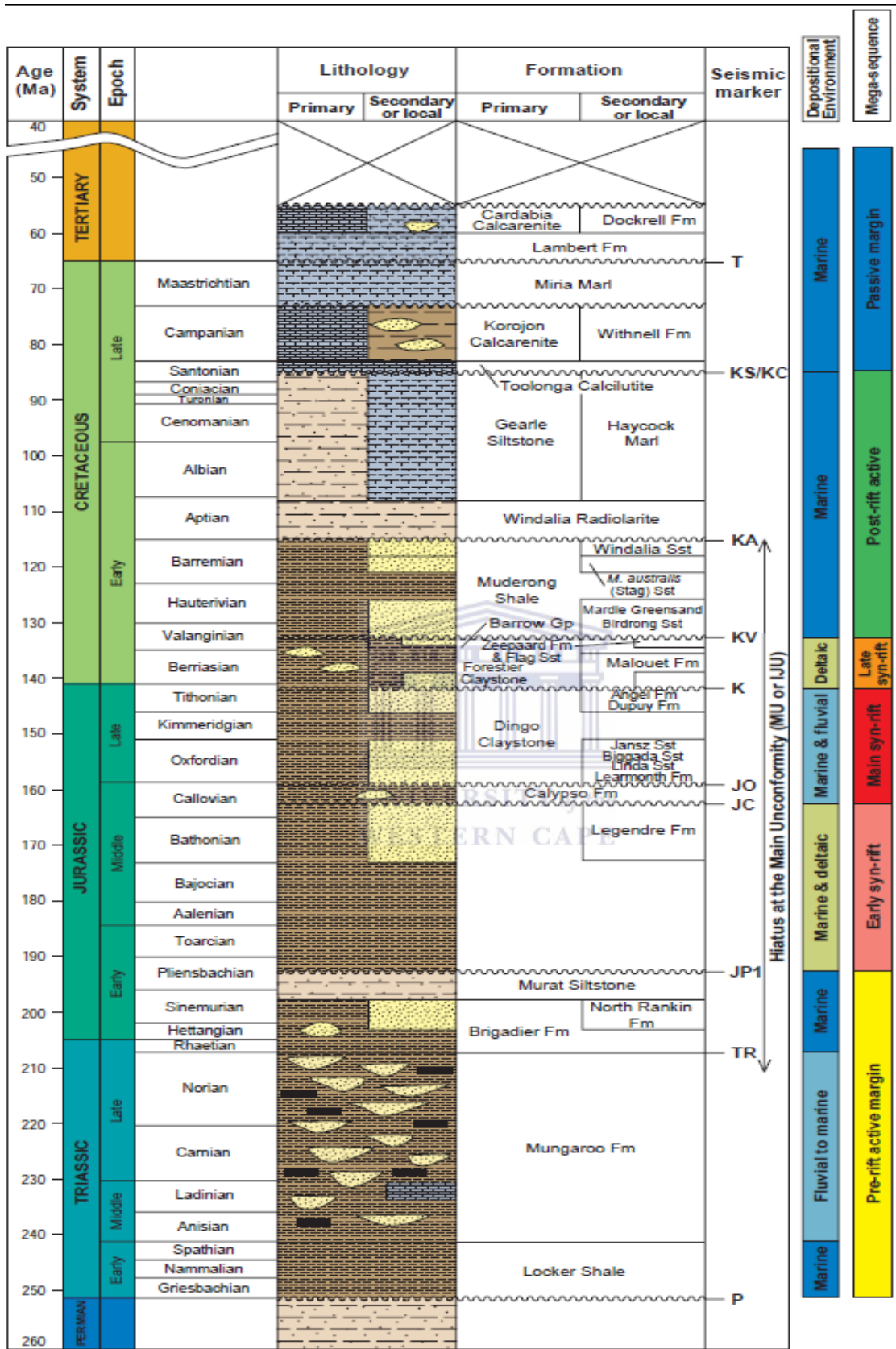
Figure2.3. Stratigraphic chart of the Northern Carnarvon basin which includes the depositional environment and the mega sequences *(modified after Australian Government, 2010)*

2.3. The Exmouth Plateau

The Exmouth Plateau, as presented in Figure 2.4, is a submerged continental block off the North West Shelf of Australia, whose culmination lies about 800m below sea-level *(Exon et al, 1982)*. It forms the northern part of the Carnarvon Basin and it is part of the Exmouth-Barrow-Dampier intra-cratonic rift system *(Rek et al, 2003)*. It is elongated in a north-northeast direction. It is bordered on three sides by oceanic continental crust domains at water depths greater than 4000m. These oceanic continental crusts are the Argo Abyssal Plains to the northeast, the Gascoyne Abyssal Plain to the northwest and the Cuvier Abyssal Plain to the southwest *(Barber P, 1988)*.
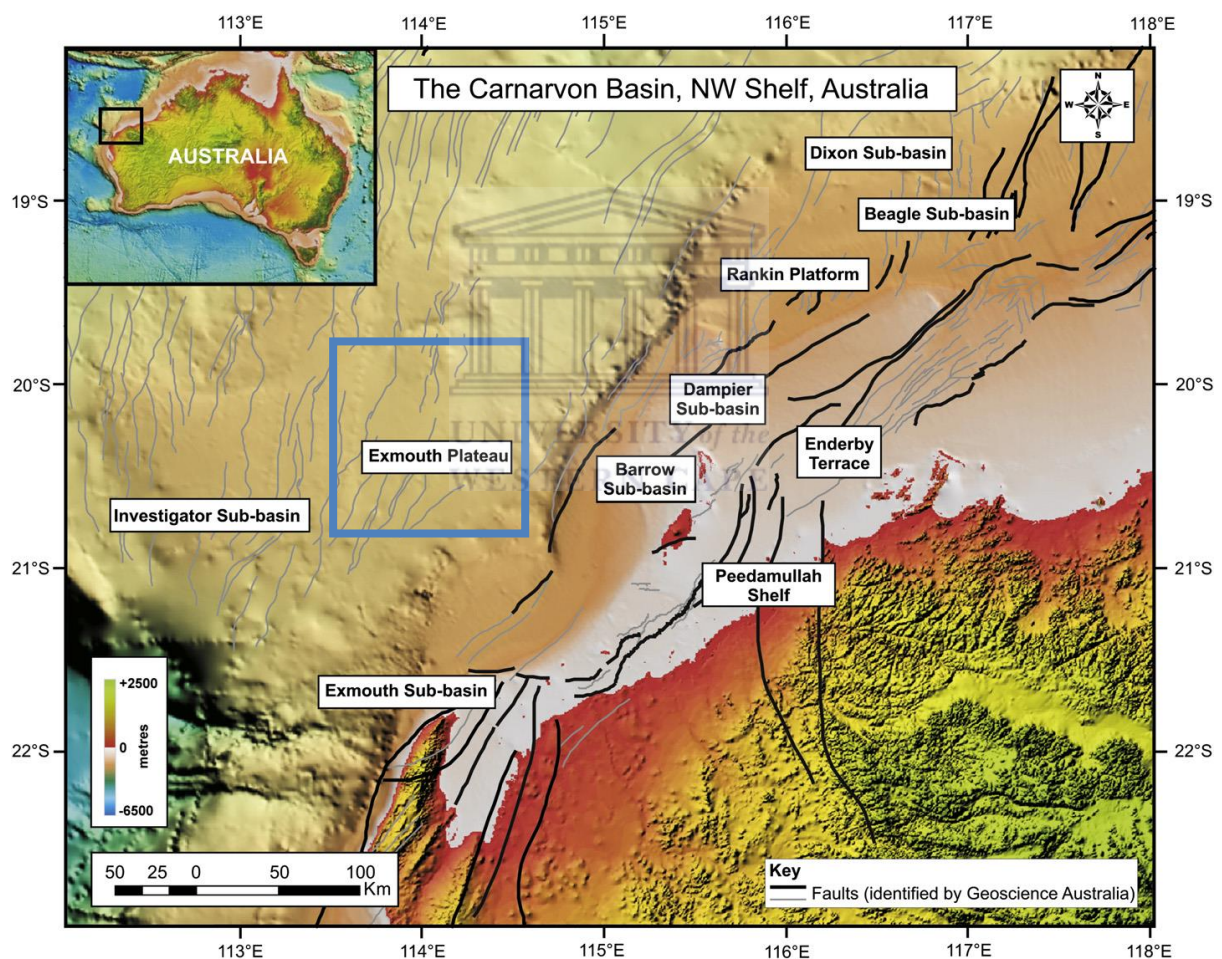
Figure 2.4. Map showing the location of the Exmouth Plateau, shown by the blue square *(modified after King et al, 2010)*.

The Exmouth was part of the northern margin of Gondwana on the southern shore of Tethys for long periods during the Mesozoic, and a major part of its sequence is composed of Triassic fluvio-deltiac sediments. Block faulting developed as a result of rifting during the Late Triassic to Middle Jurassic and numerous grabens on the northern and eastern margins

of the Exmouth Plateau contain a thick fill of Jurassic shallow marine carbonates and coal measures. The two most important unconformities on the Exmouth Plateau are the Callovian-Oxfordian and Valanginian unconformities and they are associated with breakup along its margins. The Callovian-Oxfordian unconformity, which is the oldest, formed during the Late Jurassic when a micro-continent separated from northern Gondwana and this resulted in the oceanic crust of the Argo Abyssal Plain being left behind. The Valanginian unconformity, which is the youngest, formed in the late Valanginian when Greater India separated from east Gondwana, which resulted in the oceanic crust of the Gascoyne and Cuvier Abyssal Plains being left behind to the west and southwest of the subsiding Exmouth Plateau. With the abyssal plains surrounding the Exmouth Plateau terrigenous input immensely decreased after the breakup. Shallow marine Lower Cretaceous sediments gave way to bathyal carbonates as the Exmouth Plateau underwent thermal subsidence *(Exon et al.., 1994)* (Refer to Figure 2.5).

The Exmouth Plateau is a representative of western structural elements of the Northern Carnarvon Basin and it is predominantly underlain by 10-15km of flat-lying and block faulted tilted Lower Cretaceous, Jurassic, Triassic and older sedimentary sections that were deposited during periods of extension that occurred before the break-up of Australia and Argo Land in the Middle Jurassic and then Greater India in the Early Cretaceous *(Australian Government, 2010)*.

The Exmouth Plateau region has the largest undeveloped gas resources in Australia *(Edwards et al, 2005)*.
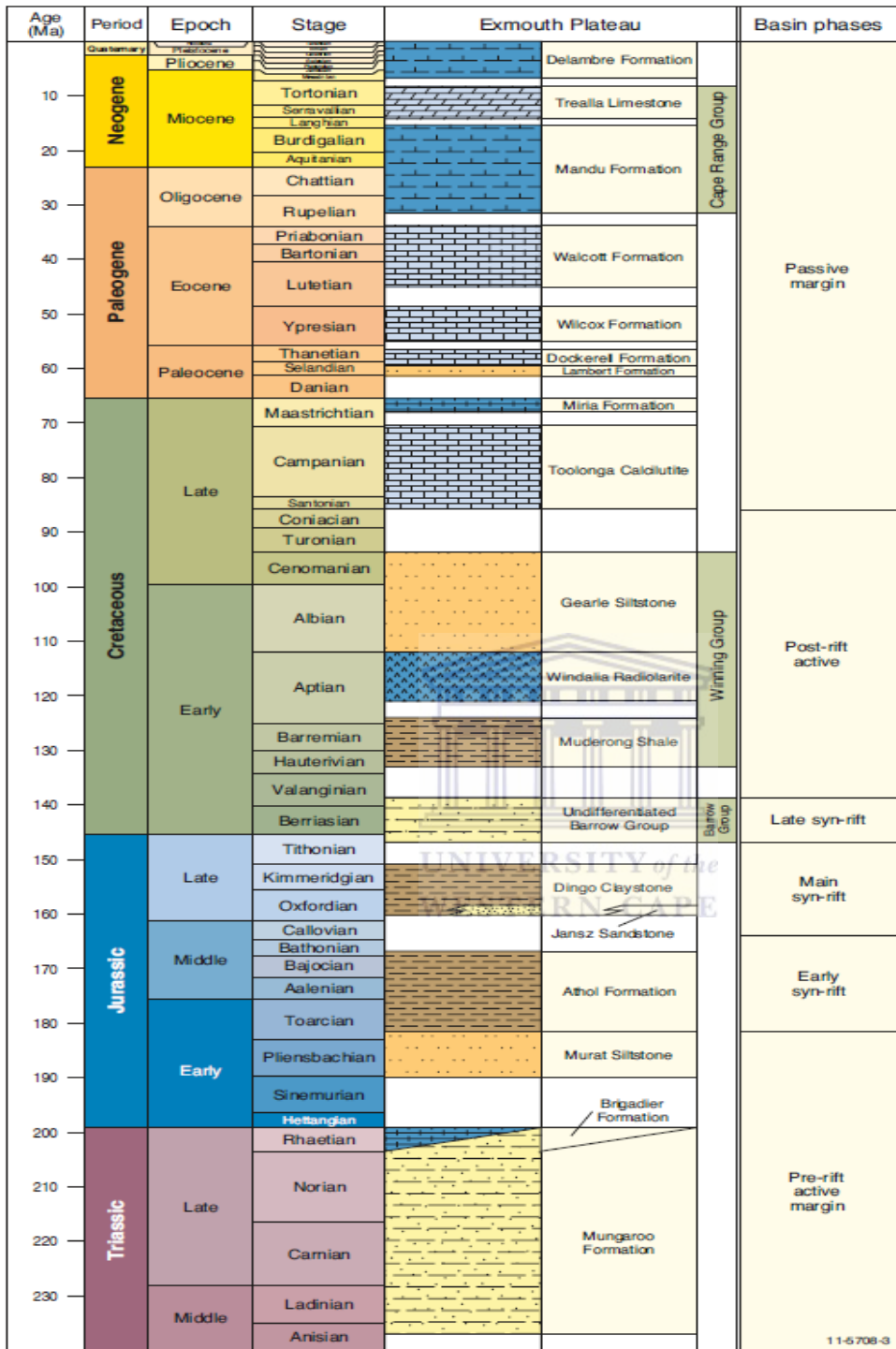
Figure 2.5. Stratigraphic column of the Exmouth Plateau (Geoscience Australia, 2012)

2.4. Petroleum Elements

2.4.1. Introduction to petroleum elements:

The most important petroleum elements are source rocks, reservoirs, seals and traps.

Source Rocks

A source rock is a sedimentary rock that consists of enough organic matter so that when it undergoes burial and heating it will produce oil and gas (petroleum) *(Gluyas et al.., 2004)*.

Reservoir

A reservoir rock is a rock that has adequate porosity and permeability to hold economic quantities of petroleum *(Bailey, 2009)*. The most common reservoir rocks are coarse-grained sandstones and carbonates.

Trap.

A trap is described as a part of the reservoir that holds sufficient quantities of petroleum for it to be economically viable. The most common traps found are structural traps and stratigraphic traps.

Seal

The seal is a moderately impermeable layer that is situated above the trap *(Bailey, 2009)*. Seals are typically fine-grained or crystalline, low permeability rocks. Seals are commonly evaporites and shales *(Gluyas et al.., 2004)*.

Petroleum system

"A petroleum system is defined as a system that encompasses a pod of active source rocks and all genetically related petroleum accumulations. It includes all the geologic elements and processes that are essential if an oil and gas accumulation is to exist" *(Magoon et al.., 2003)*.

2.4.2. Petroleum elements of the Exmouth Plateau

Source rocks:

The rocks with the greatest potential for mature sources are the thick Triassic and older sedimentary sections on the Exmouth Plateau. There are possible organic rich units in the Lower Triassic (marine Locker Shale) and Upper Triassic deltaic Mungaroo Formation facies and marine equivalents. From these Triassic source rocks peak gas generation is interpreted to occur at depths greater than 5km *(Australian Government, 2010)*.

Reservoir rocks:

On the Exmouth Plateau the fluvio-deltiac sandstones of the Upper Triassic Mungaroo Formation and the basin-floor fan and turbidite sandstones of the Lower Cretaceous Barrow Group act as good quality reservoirs *(Australian Government, 2010)*.

Seals:

The Muderong Shale provides the regional seal across the Exmouth Plateau. Within the deltaic sequences of the Upper Triassic Mungaroo Formation there are intra-formational seals. When preserved the Rhaetian marl and Dingo Claystone equivalents also provide a seal to Triassic reservoirs *(Australian Government, 2012)*.

Traps:

On the Exmouth Plateau the main traps are provided by high relief top Triassic fault blocks with associated drape features. A number of potential structural traps are provided by deep intra-Triassic cross fault traps *(Australian Government, 2010)*.

Chapter 3: Data and Methodology

3.1. The Carnarvon Basin

3.2. The Northern Carnarvon Basin

3.3. The Exmouth Plateau

3.4. Petroleum elements

3.5. Petroleum elements of the Exmouth Plateau

3. Data and Methodology

The data used for this research study was supplied by Sasol Petroleum International.

The methodology followed is represented graphically in the form of a flow chart (Refer to flow chart below). A discussion on each of the processes followed is presented below.

```
┌─────────────────┐        ┌─────────────────┐
│                 │        │                 │
│  Seismic Data   │        │   Well Data     │
│                 │        │                 │
└────────┬────────┘        └────────┬────────┘
         └──────────────┬───────────┘
                ┌────────▼────────┐
                │                 │
                │ Well to Seismic │
                │      ties       │
                └────────┬────────┘
                ┌────────▼────────┐
                │    Seismic      │
                │ Interpretation  │
                └────────┬────────┘
                ┌────────▼────────┐
                │ Construction of │
                │ twt maps and    │
                │ average         │
                │ velocity maps in│
                │ Surfer 10       │
                └────────┬────────┘
                ┌────────▼────────┐
                │ Depth Conversion│
                └────────┬────────┘
                ┌────────▼────────┐
                │ Construction of │
                │  depth map.     │
                └────────┬────────┘
                ┌────────▼────────┐
                │    Volume       │
                │  Calculation    │
                └─────────────────┘
```
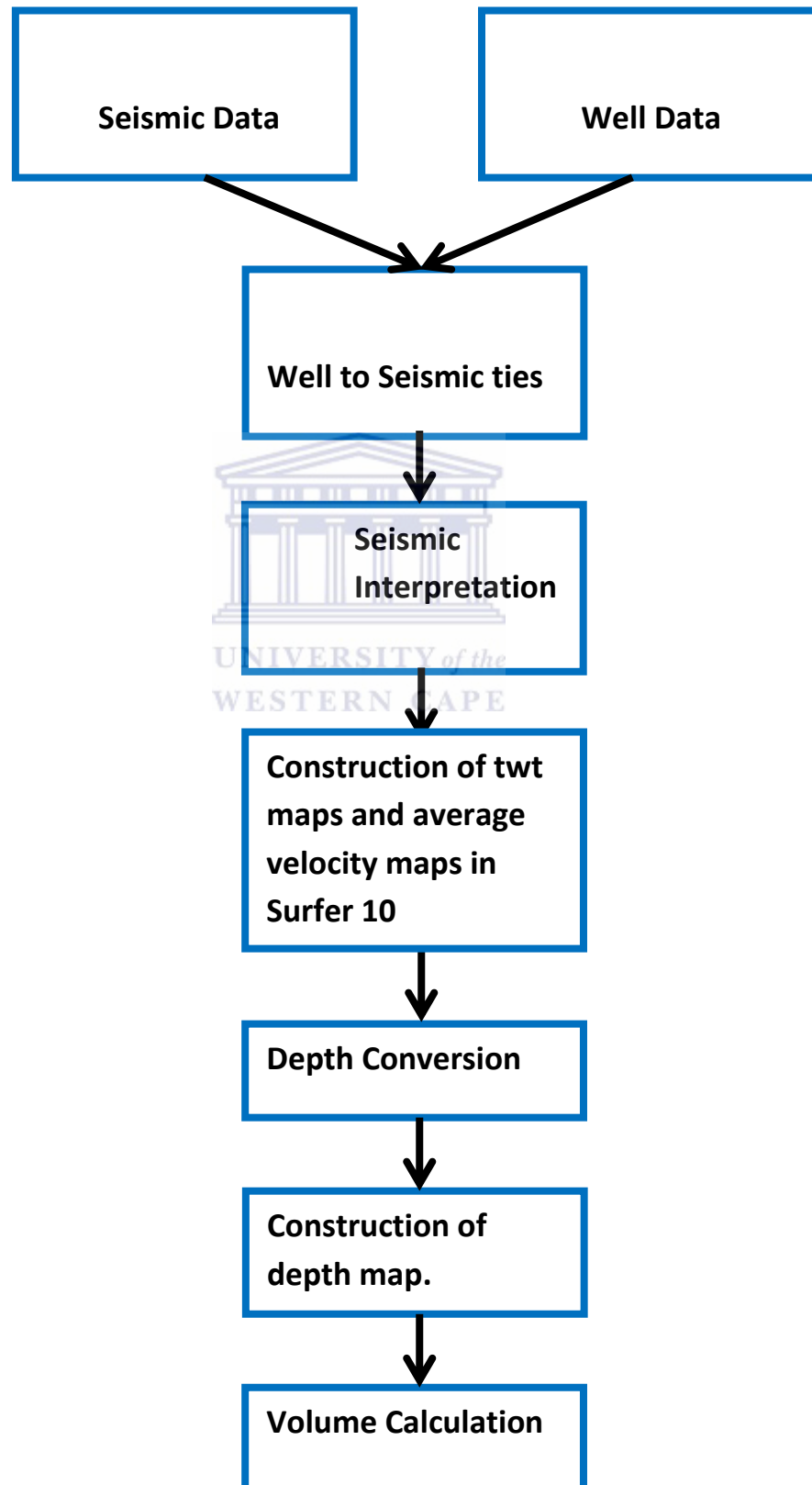
3.1. Seismic Data

The seismic data used for this study is the HEX07B 3D survey which was conducted in 2007 over the prospect known as Thebe, Western Australia, North West Shelf. The Thebe survey area is an 1197.987 km^2 survey block with water depths ranging from 900 to 1200m. The Thebe survey (HEX07B 3D survey) is located in WA-346-P permit area.
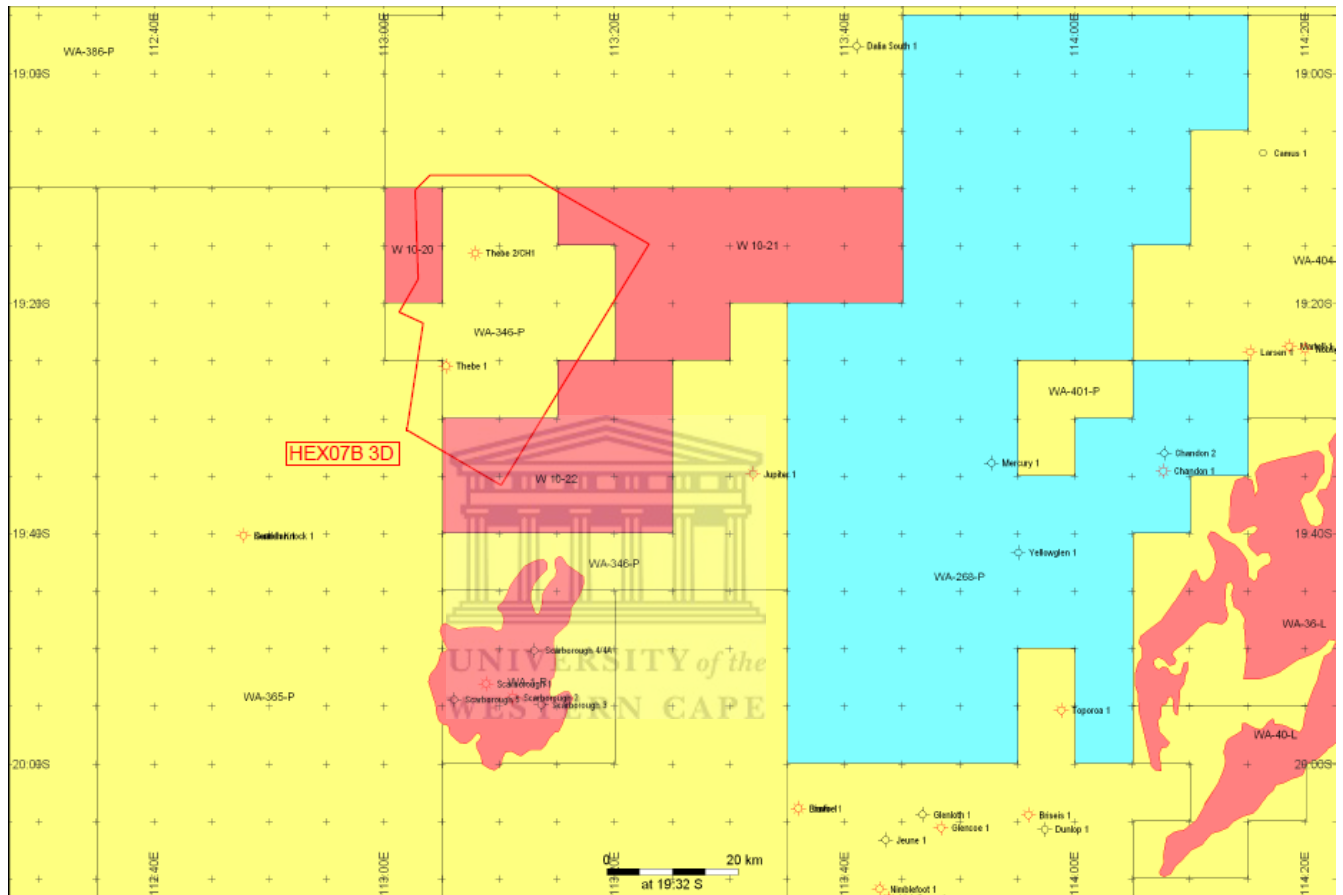
Figure 3.1. Map showing the location of the seismic dataset HEX07B 3D. *(WesternGeco. 2007)*

3.2. Wireline Logging

Wireline logging is the practice within the oil and gas industry whereby a logging device is attached to a wireline is lowered into a borehole or oil well to measure the properties of the rock and fluids of the formation. Once the measurements have been obtained they are interpreted and the findings are used to determine the depths and zones where potential hydrocarbons can be found *(Robinson, 2009).* The following logs were used in this study; gamma ray, deep and shallow resistivity, caliper log, density log and the neutron log.

3.3. Well Data

Well data from four wells were provided for this research project, namely Thebe 1, Thebe 2, Jupiter 1 and Scarborough 4. The well data from the wells located within the study area, Thebe 1 and Thebe 2, were used for the well to seismic ties.

Thebe 1 was drilled in 2007 by BHB Biliton in 1173m water depth about 50km north of the Scarborough gas field. Thebe 1 was drilled to a depth of 2510m. Thebe 1 discovered a 73m gas column in a Triassic fault block that may contain 2-3 Trillion cubic feet (Tcf) of gas.

Thebe 2 was drilled in 2008 by BHB Billiton *(Australian Government, 2012)*

3.4. Well to seismic ties

Due to the lack of data available, the well to seismic ties were done by the process of identifying the main horizons from the wireline logs (gamma ray) in depth and comparing it to the main events on the seismic line which is in two-way-time and by so doing time-depth charts were created in order to determine the precise location of the main horizons.

3.5. Seismic interpretation

Seismic interpretation involves the process of developing a geologic model that coincides with the seismic data observed *(Sheriff, 1992).*

In 3D seismic surveys, the seismic lines shot during the seismic survey are called inline sections or rows and the vertical sections which are perpendicular to the inlines are called cross line sections or columns *(James et al.., 1994).*

For this research project, six horizons were interpreted which were identified using the time-depth charts. The software used to interpret the seismic data was SMT Kingdom 8.6.
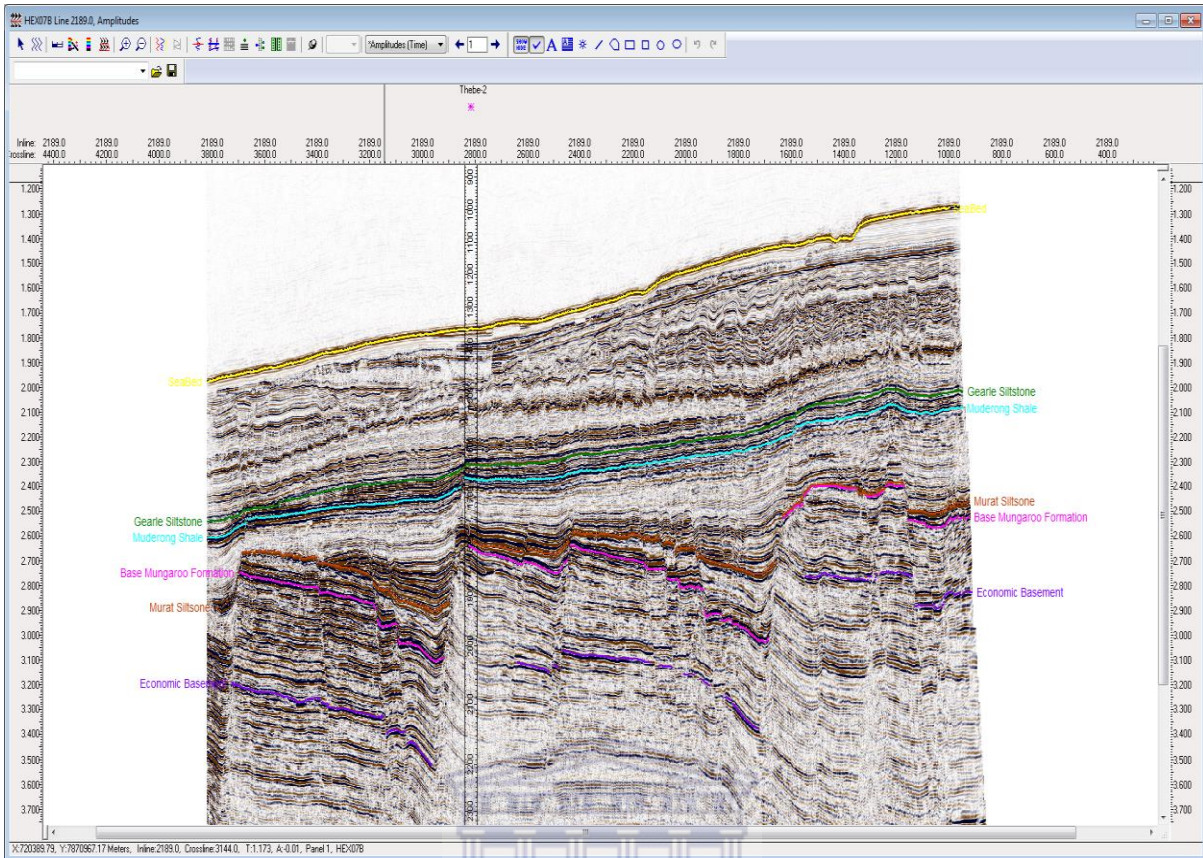
Figure 3.2. Seismic section showing the six horizons picked

The six horizons interpreted were the Sea Bed, Gearle Siltstone, Muderong Shale, Murat Siltstone, Mungaroo Sandstone and the Economic Basement which could possibly be the Locker Shale. The base of the Mungaroo Formation was picked because it was the strongest event (Refer to Figure 3.2.).

.

3.6. Depth Conversion.

Depth conversion is the process whereby the two-way-time of various horizons and the average velocities between the formations are multiplied by one another in order to get the correct depth. Once the depth values have been obtained they can be posted and contoured in the same way as the two-way-time values *(McQuillin et al.., 1984).*

Thebe 1 and Thebe 2 are the wells of interest in the study. The data from Thebe 2 was very unreliable and therefore only the data from Thebe 1 was used for the depth conversion. The other wells were not used in determining the depth conversion equation because they do not

fall within the area of interest, the data from those wells were used to compare against the data of Thebe 1. The average velocity was derived by the following equation:

$$\text{average velocity} = (\text{depth})/ (\text{TWT}/2)$$

The depth conversion equation was derived from plotting the Average Velocity against the Two-Way-Time (TWT) from Thebe1. A polynomial trend line was applied to the plotted data and this was used to get the equation as presented in Figure 3.3.
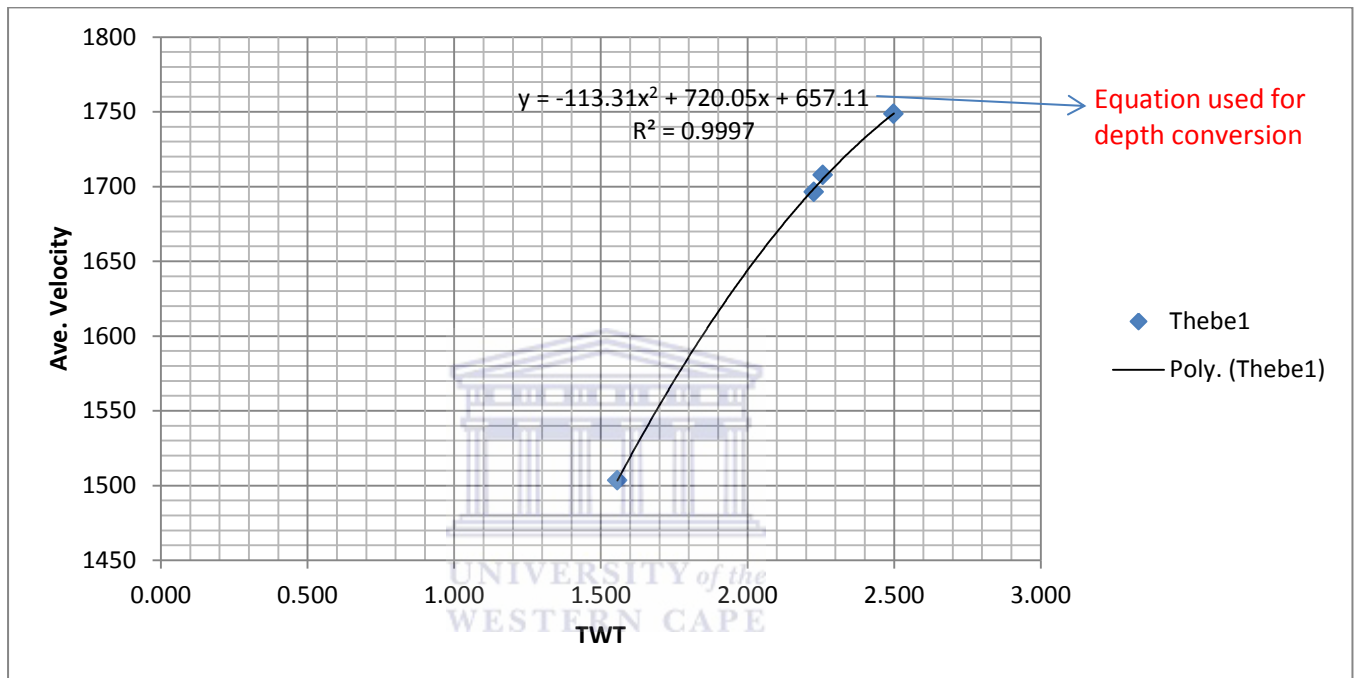
Figure 3.3. Figure showing average velocity vs. twt and the equation used for depth conversion.

3.7. <u>**Average velocity map, two-way-time maps, and depth structure maps.**</u>

The average velocity maps, two-way-time maps, depth structure maps and isopach maps were all created using Surfer 10.

Average velocity maps:

The velocity distribution over a given area must be known in order to convert a two-way-time map into a depth map. The velocity data can be from the well sonic logs or from the seismic stacking velocities. The velocity needed in order to convert two-way-time into depth is the average velocity (McQuillin et al.., 1984).

The velocity of an area is mainly controlled by the mineral content of the rock, the pore fluid, porosity fabric and the state of cementation. The seismic velocity in limestones and dolomite is greater compared to the velocities in sandstones. The velocities in sediments such as muds and coals are particularly slow. The presence of petroleum in pores results in the reduction of the velocity. The presence of gas causes the velocity to decrease dramatically (Gluyas et al.., 2004).

Two-way-time (Structure) and Depth structure maps:

Time and depth structure maps are the most important elements of a seismic interpretation study. The completed time or depth structure maps provide a basis for reconstructing the temporal and spatial evolution of a sedimentary basin of interest.

Time structure maps are represented in two-way-time (TWT) and depth structure maps are represented in meters (m) for this study. The depth structure maps are created by multiplying the two-way-time by the average velocity.

3.8. Repeat Formation Testing (RFT).

Repeat Formation Tester (RFT) is the most common tool used to measure the formation pressure at numerous points from a well. The fluid phase can also be sampled using the Repeat Formation Tester tool. The pressure data collected from a well can be used to identify important information relating to the depletion of the reservoir and cross-flow between reservoir intervals (Gluyas et al.., 2004).

In this research project,the RFT data was used to identify the fluid contacts, namely the gas-water-contact based on pressure gradient differences.

Chapter 4: Results

4.1. Seismic interpretation

4.2. Two-way-time structure maps

4.3. Average Velocity map

4.4. Depth Maps

4.5. Petrophysical results

     4.5.1. Wireline logs

     4.5.2. Repeat Formation Testing

4. Results

In this section all the seismic lines, two-way-time maps, velocity maps and depth maps of each horizon will be presented and discussed.

4.1. Geophysical Interpretation.

The horizons will be discussed from oldest to youngest.

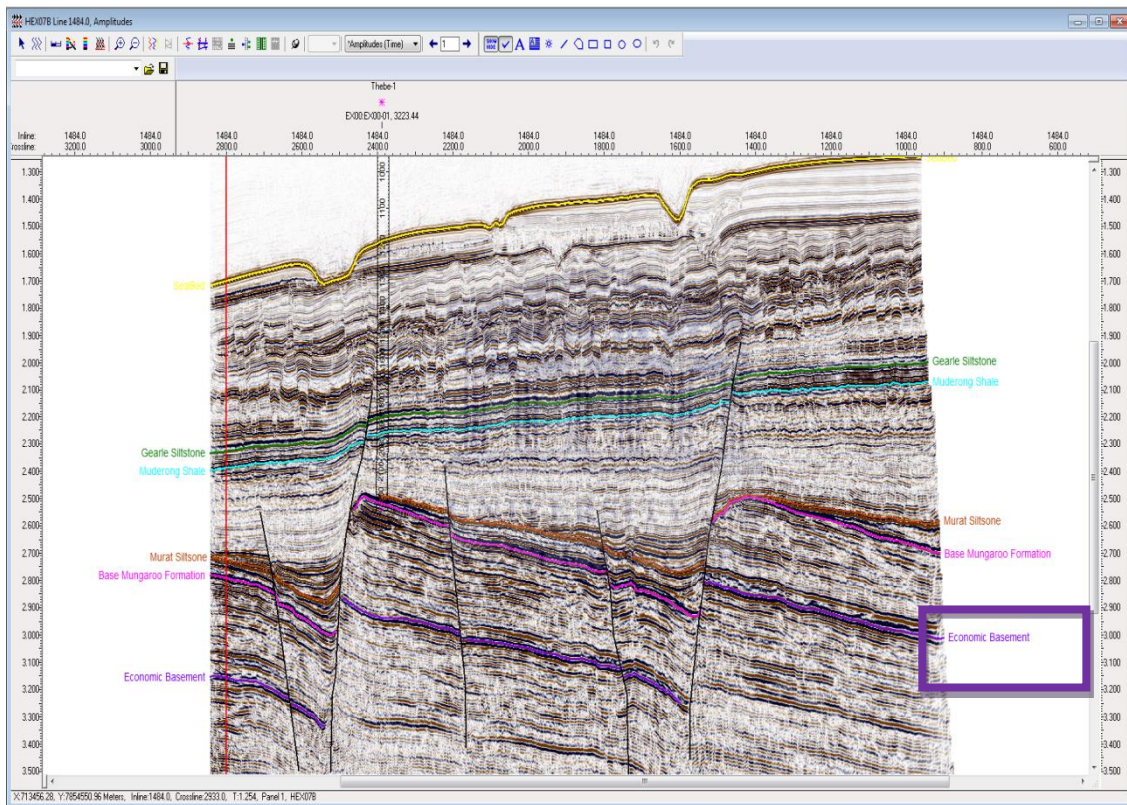### 4.1.1. Economic basement.

Figure 4.1: Seismic section of the economic basement at Thebe 1.
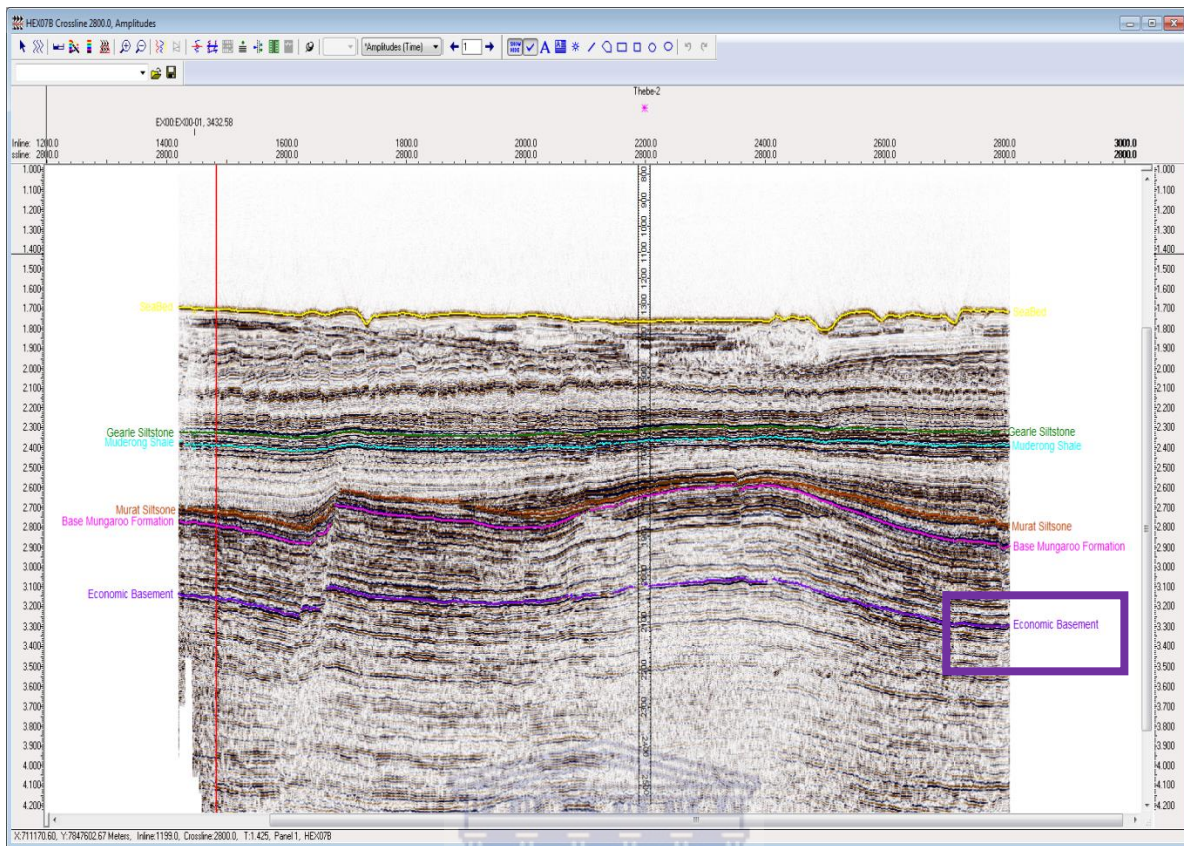
Figure 4.2: Seismic section showing the economic basement at Thebe 2

The economic basement is the oldest horizon interpreted in this project and is represented by the purple rectangle as shown in Figure 4.2. This horizon could possibly be the Locker Shale but this could not be proven because the wireline logs did not penetrate to its depth. At Thebe 1 on inline 1484 the Economic Basement is present at 3050 milliseconds and intersected by five major faults. At Thebe 2 on crossline 2800 the Economic Basement is present at 3050 milliseconds and it is intersected by three major faults.

4.1.2. Mungaroo Formation

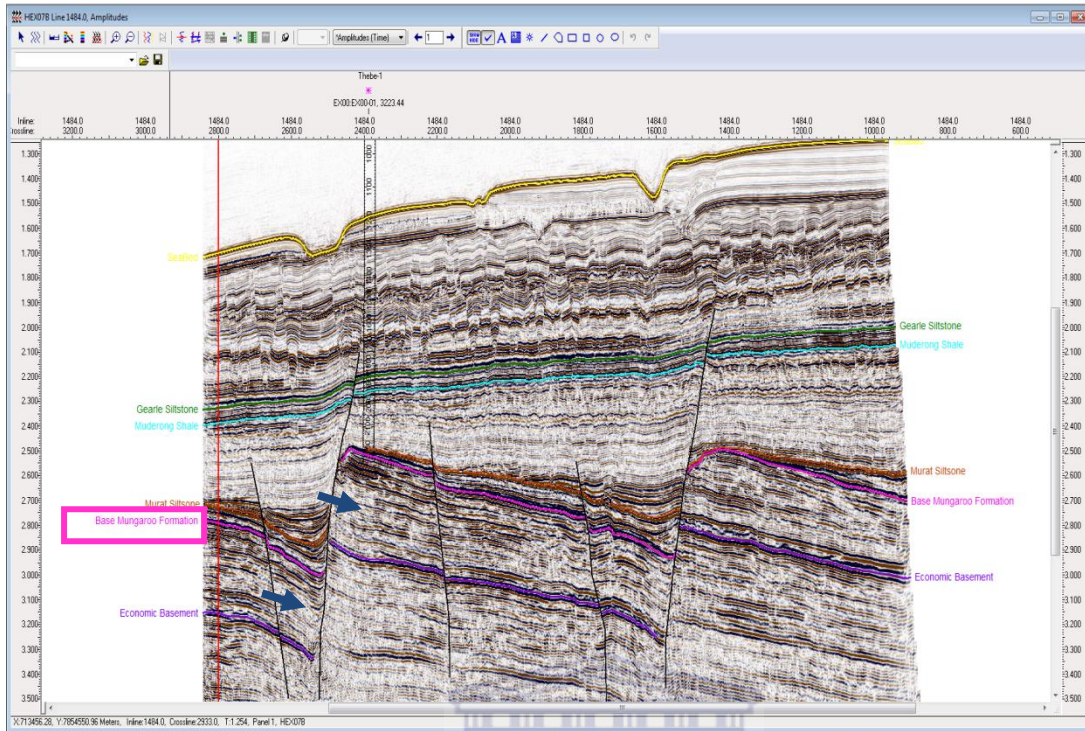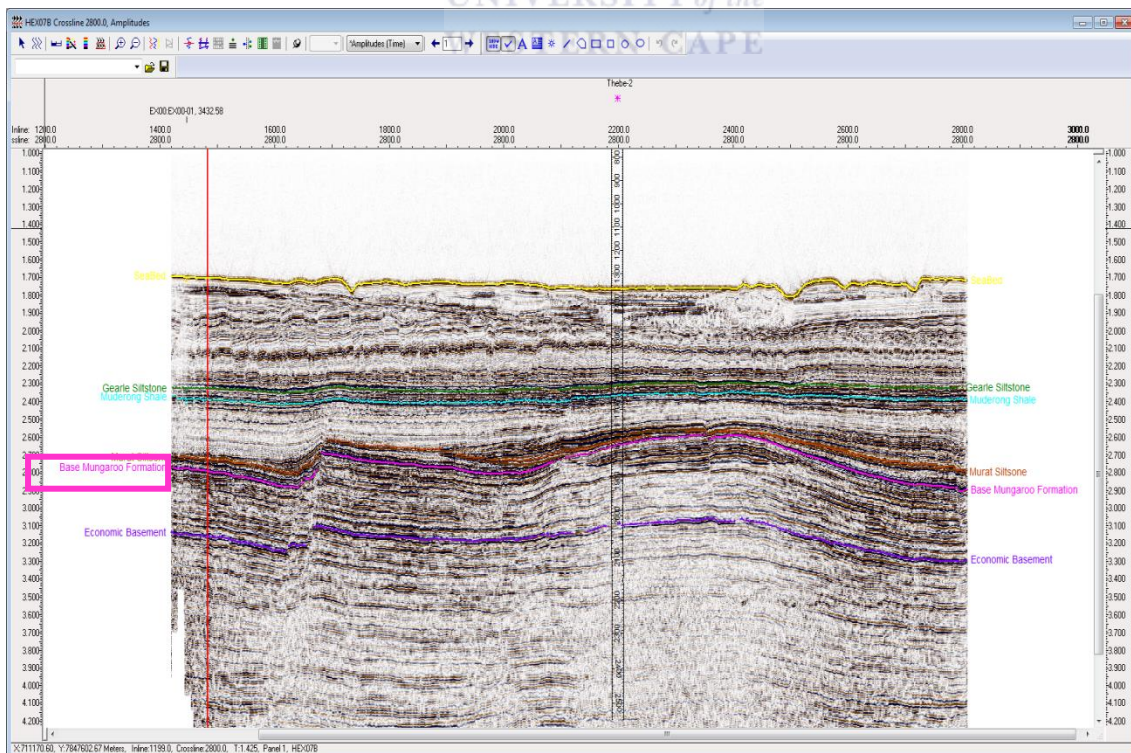Figure4.3: Seismic section showing the Mungaroo Formation at Thebe 1

Figure 4.4: Seismic section showing the Mungaroo Formation Base at Thebe 2

The Mungaroo Formation is the horizon of interest and it is represented by the pink rectangle. The Mungaroo Formation was deposited during the Middle to Late Triassic and the depositional environment is fluvial to marine.

At Thebe 1 on inline 1484 the Mungaroo Formation occurs between twt 2750 milliseconds to 3050 milliseconds (Refer to Figure 4.3). It is intersected by five major faults. The continuity of the Mungaroo Formation is excellent and it is visible throughout the seismic data. At Thebe 2 on crossline 2800 the Mungaroo Formation occurs between 2750 milliseconds to 3050 milliseconds and it is intersected by three faults. The formation increases in thickness at the well and then decreases towards the southeast (Refer to Figure 4.4).

According to Hocking, (1988) "fluvio-deltaic distributaries prograded northwards into most parts of the Northern Carnarvon Basin in the Ansian, these distributaries avoided areas where shale deposition continues until the Norian". This shale deposition is indicated on the seismic section by the blue arrows.
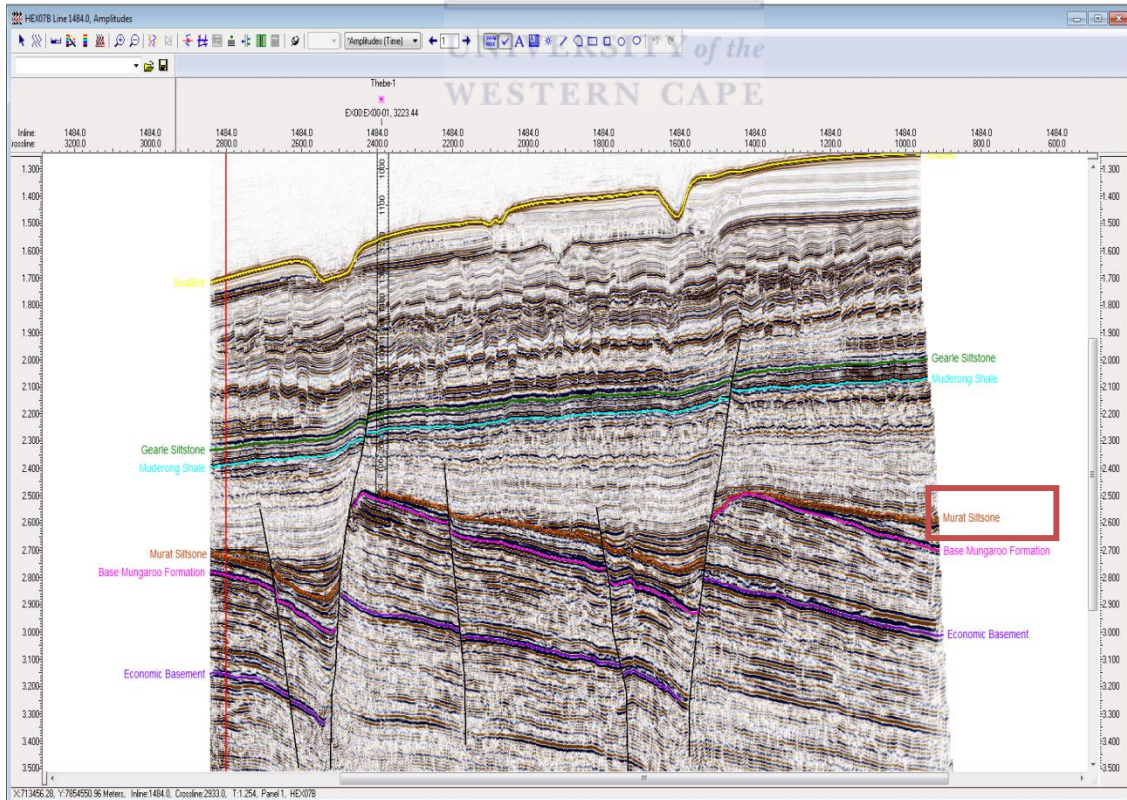
4.1.3. Murat Siltstone

Figure 4.5: Seismic section showing the Murat Siltstone at Thebe 1
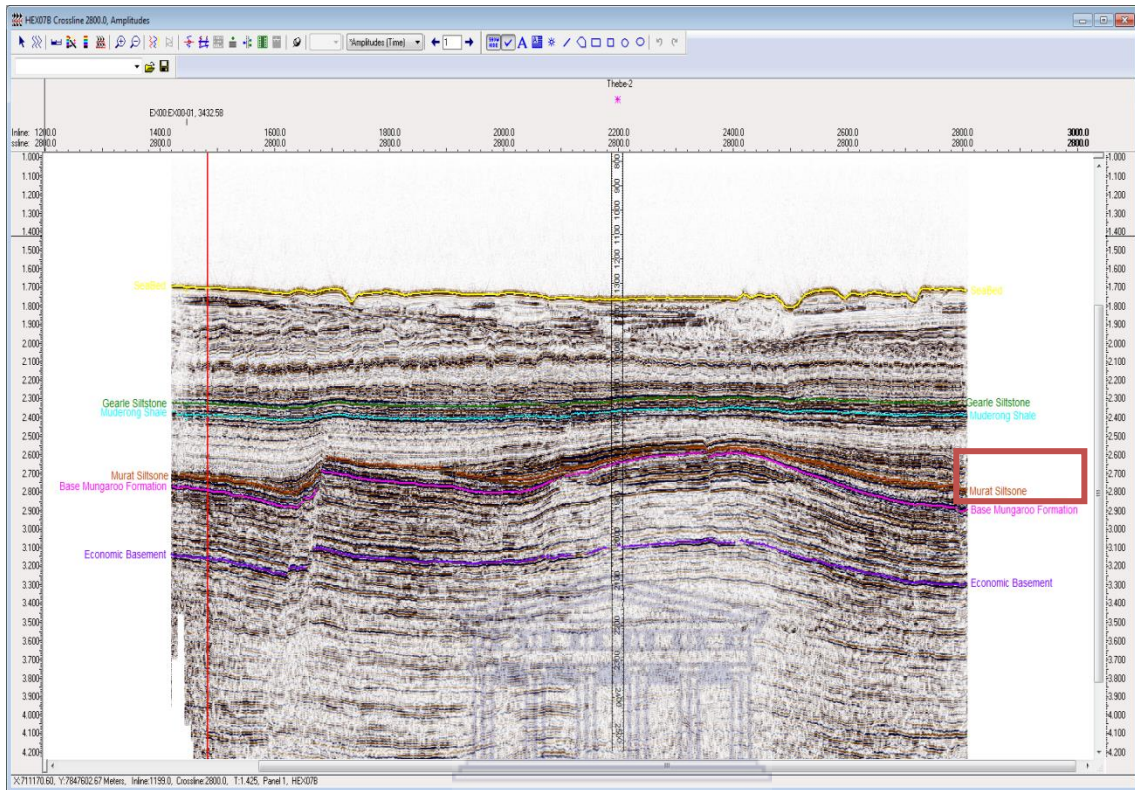
Figure 4.6: Seismic section showing the Murat Siltstone at Thebe 2

The Murat Siltstone is represented by the brown rectangle. It was deposited during the Early Jurassic and the depositional environment is marine. It could possibly be the seal of the petroleum system.

At Thebe 1 on inline 1484 the Murat siltstone is found between 2700 milliseconds and 2750 milliseconds. The Murat Siltstone increases in thickness towards the southeast and it is intersected by five major faults. The continuity of the seismic event is good but in some areas of the seismic data it is eroded (Refer to Figure 4.5) . At Thebe 2 on crossline 2800 it occurs between 2700 milliseconds and 2750 milliseconds. At the well the Murat Siltstone thins out and onlaps against the Mungaroo Formation. It is intersected by three major faults (Refer to Figure 4.6).

4.1.4. Muderong Shale
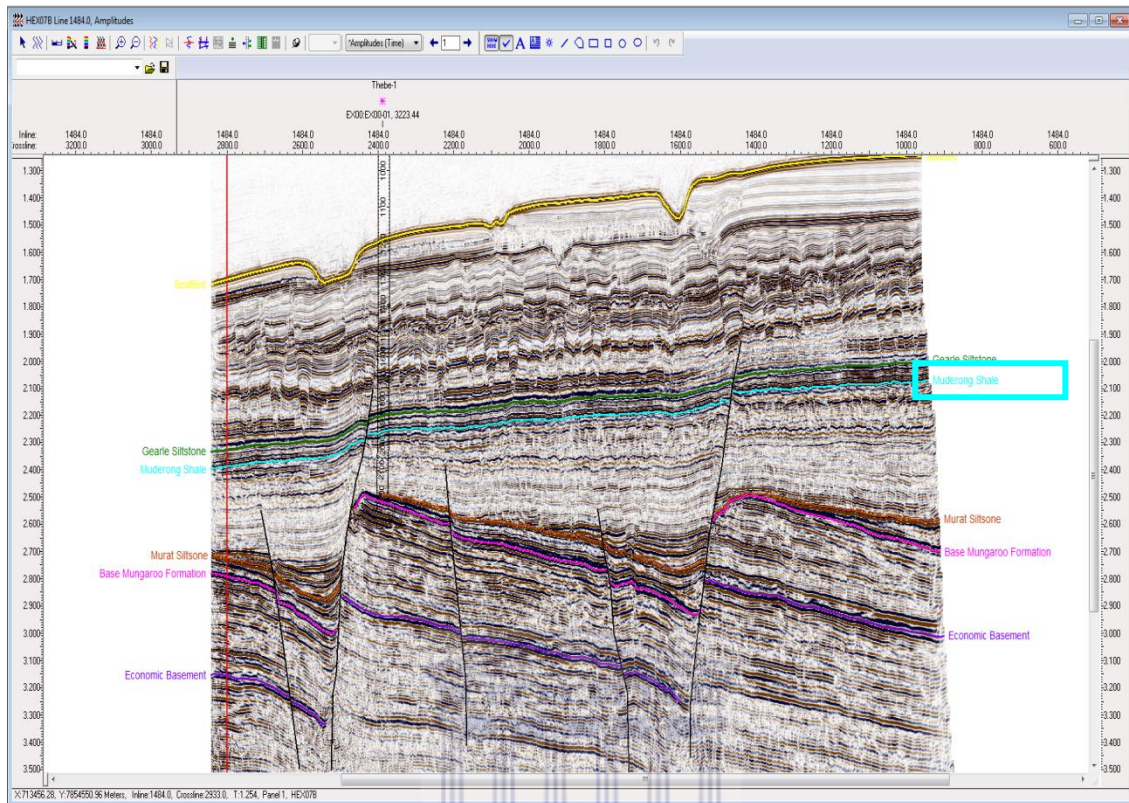
Figure 4.7: Sesimic section showing the Muderong Shale at Thebe 1
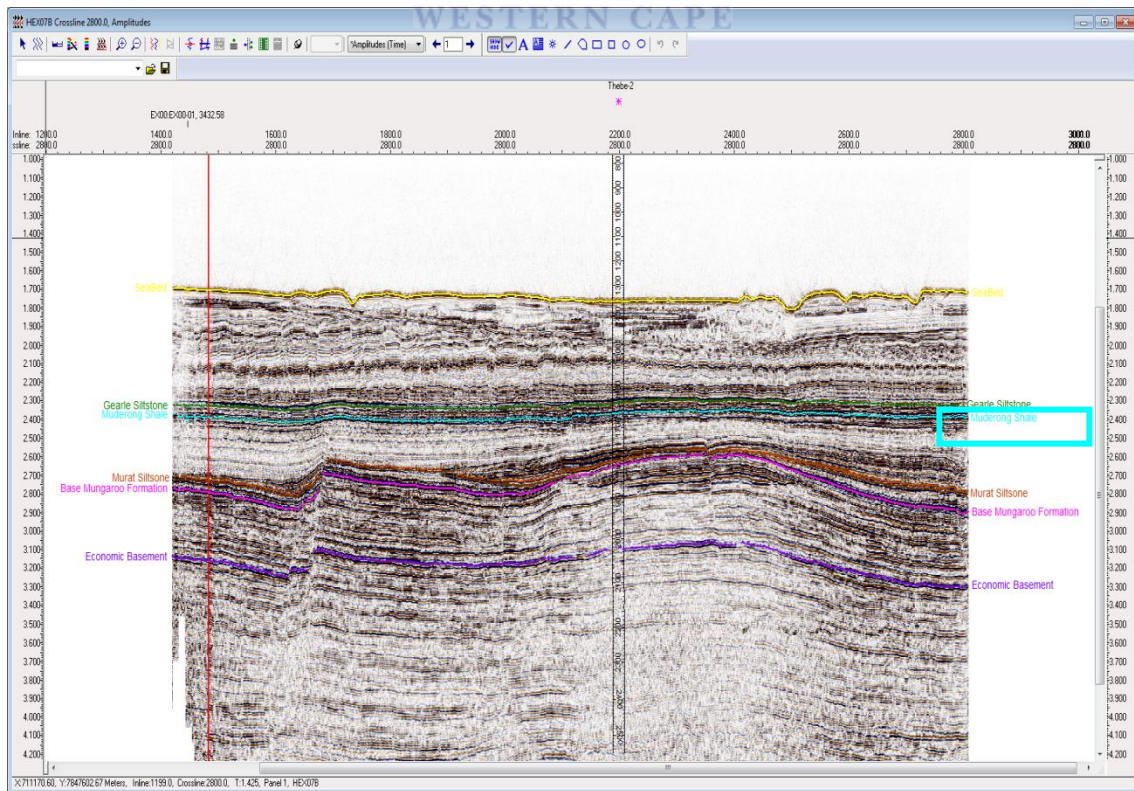
Figure 4.8: Seismic section showing the Muderong Shale at Thebe 2

The Muderong Shale is represented by the cyan rectangle. It was deposited during the Early Cretaceous and it was deposited in a marine environment. The continuity of the event is excellent and no problems were encountered while interpreting. The Muderong Shale is thought to be the regional seal across the Northern Carnarvon Basin

At Thebe 1 on inline 1484 the Muderong Shale occurs at 2400 milliseconds. The formation increases in thickness towards the southeast and it is intersected by two major faults. At Thebe 2 on crossline 2800 it occurs at 2400 milliseconds. The formation increases in thickness away from the well and it is intersected by three major faults.

4.1.5 Gearle Siltstone
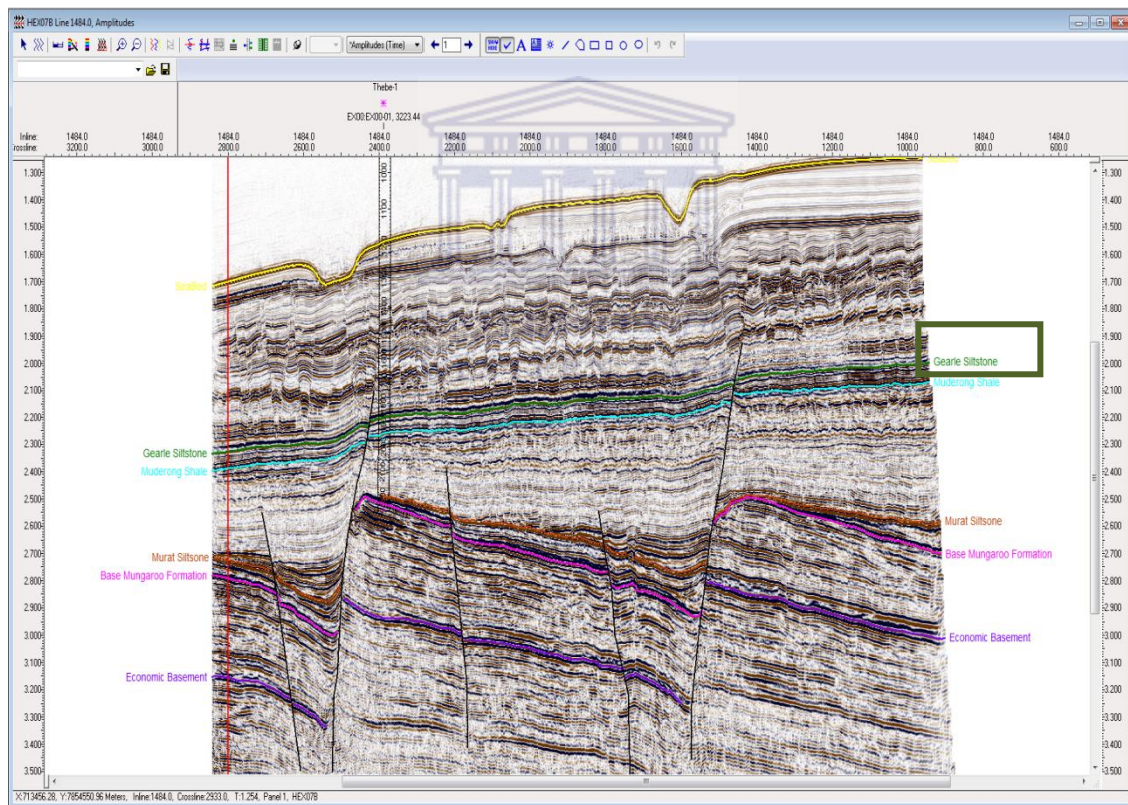
Figure 4.9: Seismic section showing the Gearle Siltstone at Thebe 1
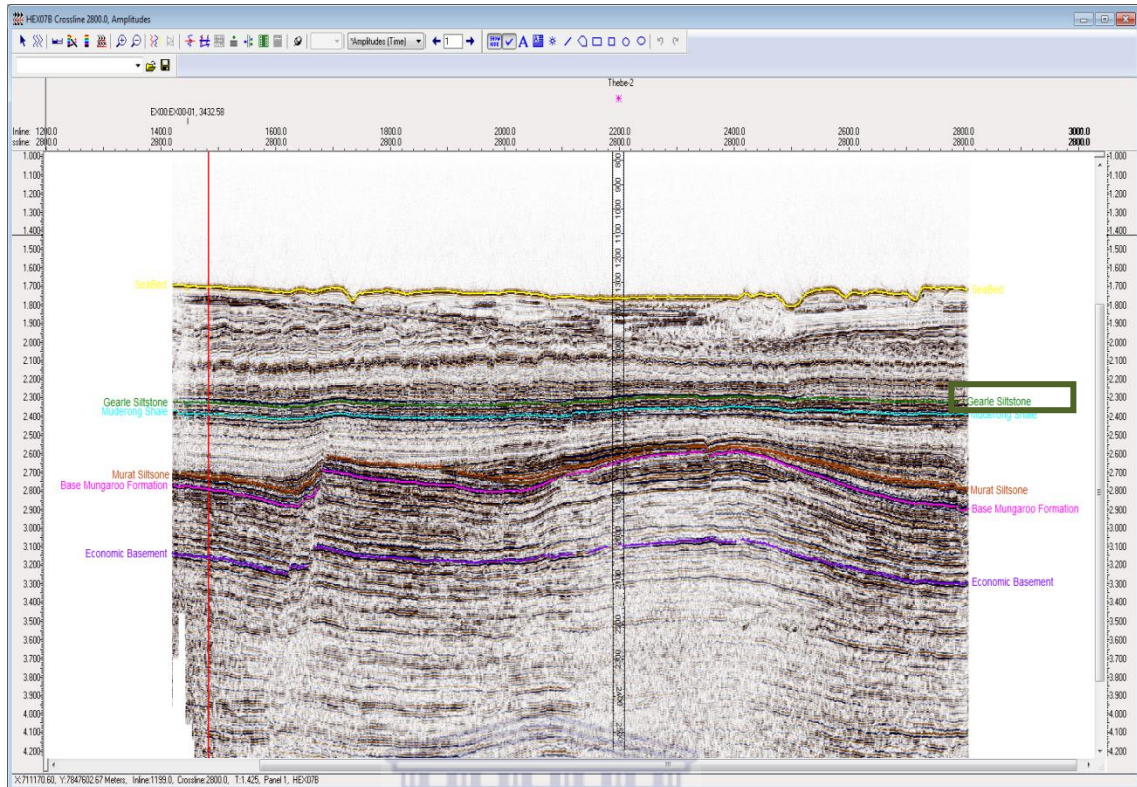
Figure 4.10: Seismic section showing the Gearle Siltstone at Thebe 2

The Gearle Siltstone is represented by the green rectangle. It was deposited during the Early to Late Cretaceous and it was deposited in a marine environment.

At Thebe 1 on inline 1484 the Gearle Siltstone occurs between 2340 milliseconds and 2400 milliseconds. The thickness of the formation remains fairly constant and it is intersected by two major faults (Refer to Figure 4.10). At Thebe 2 on crossline 2800 it occurs between 2340 milliseconds. The formation remains fairly constant in thickness and two faults intersect it (Refer to Figure 4.10).

4.1.6. Sea Bed
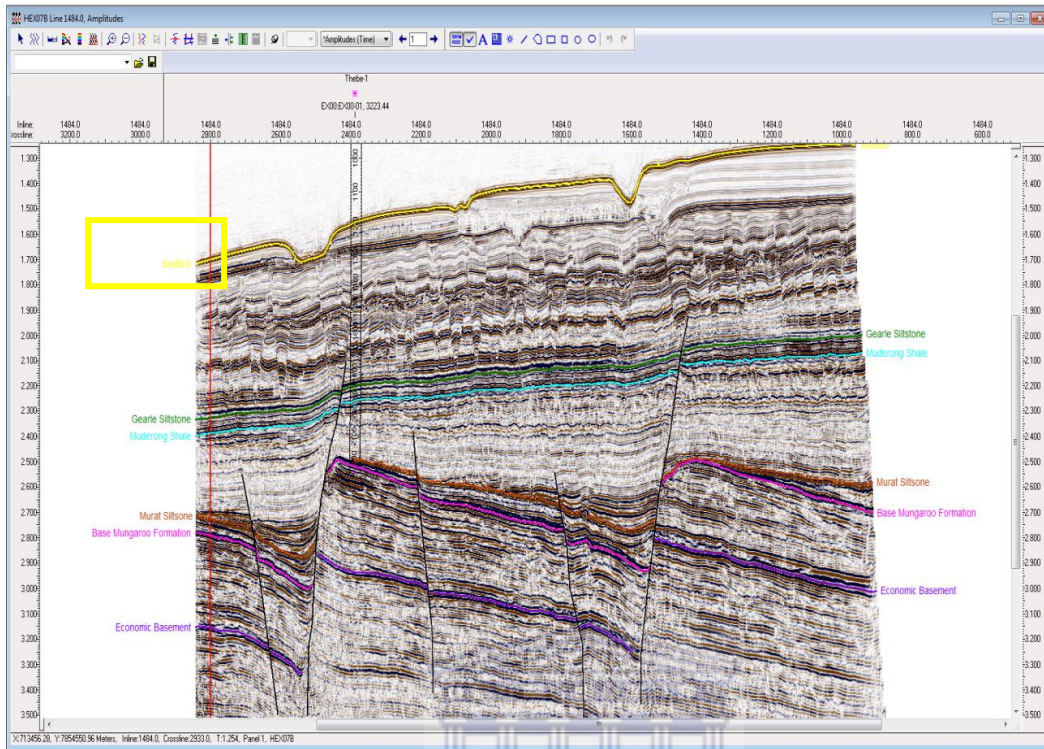
Figure 4.11: Seismic section showing the Sea Bed at Thebe 1
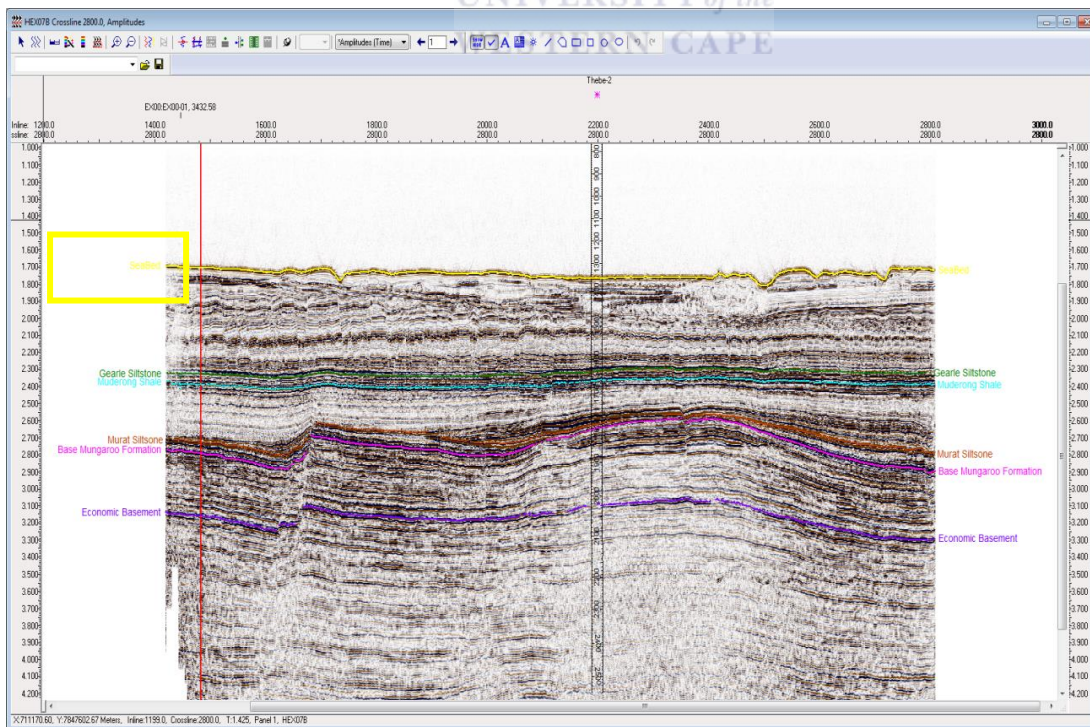
Figure 4.12: Seismic section showing the Sea Bed at Thebe 2

The Sea Bed is represented by the yellow rectangle. It occurs at 1700 milliseconds at both Thebe 1 and Thebe 2 (Refer to Figures 4.11 and 4.12). The continuity of the seismic event is excellent throughout the seismic dataset.

4.2 Two-Way-Time Structure Maps

4.2.1. Economic Basement
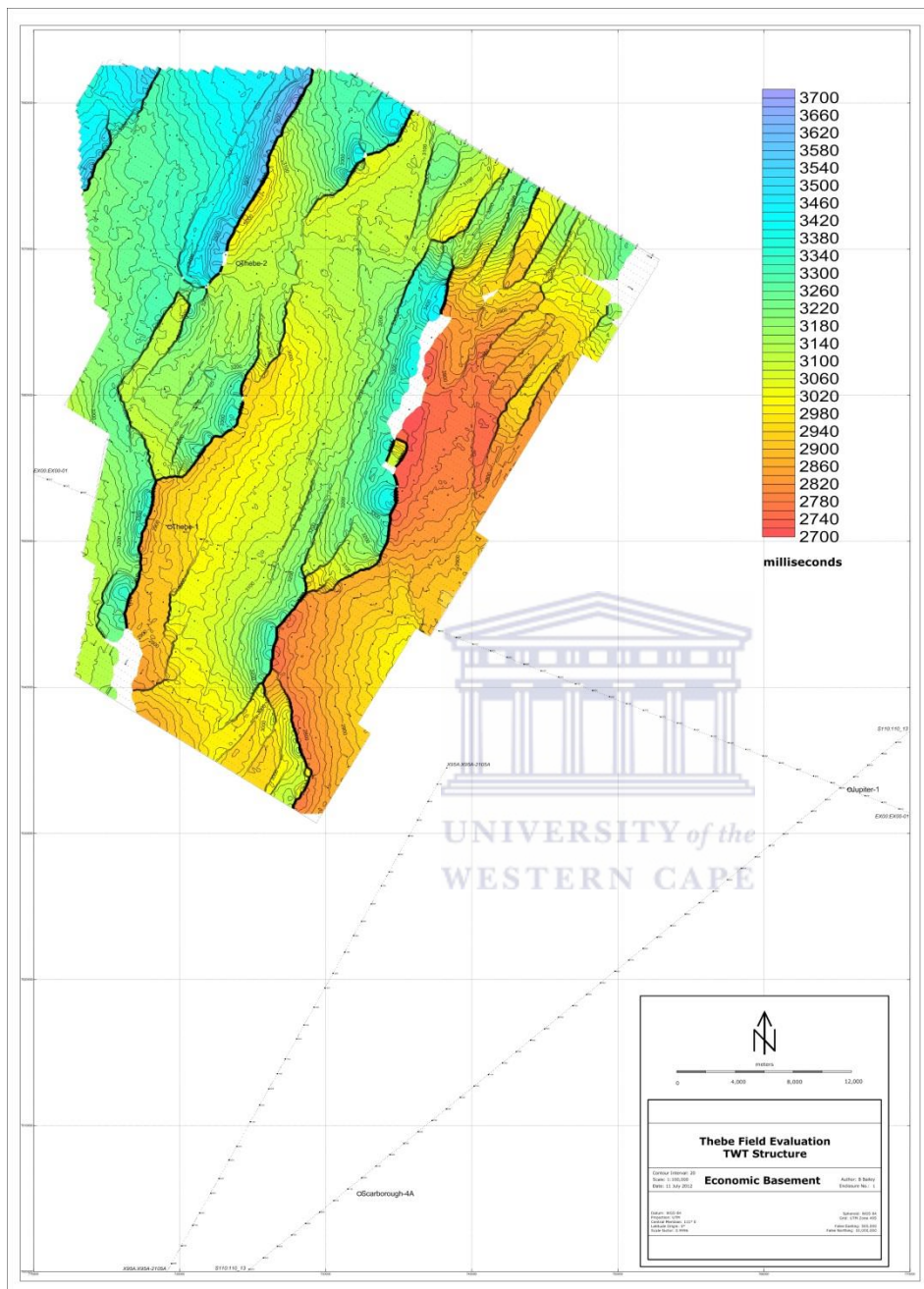
 Figure 4.13: Two-way-time structure map of the Economic Basement.

The two-way-time increases from southeast to northwest. At Thebe 1 the two-way-time ranges between 2800 milliseconds to 2900 milliseconds and at Thebe 2 it ranges between 3060 milliseconds to 3180 milliseconds. The dominant fault trend is northeast to southwest across the area. The two-way-time on the up-thrown side of the fault ranges between 2700

milliseconds to 2940 milliseconds and this indicates that it is shallow. On the down-thrown side of the fault the two-way-time ranges between 3180 milliseconds to 3700 milliseconds and this indicates that the down-thrown side is deep and this can be due to an increase in sediment supply. Both Thebe 1 and Thebe 2 are situated on the up thrown side of the respective faults (Refer to Figure 4.13).

4.2.2. Mungaroo Formation
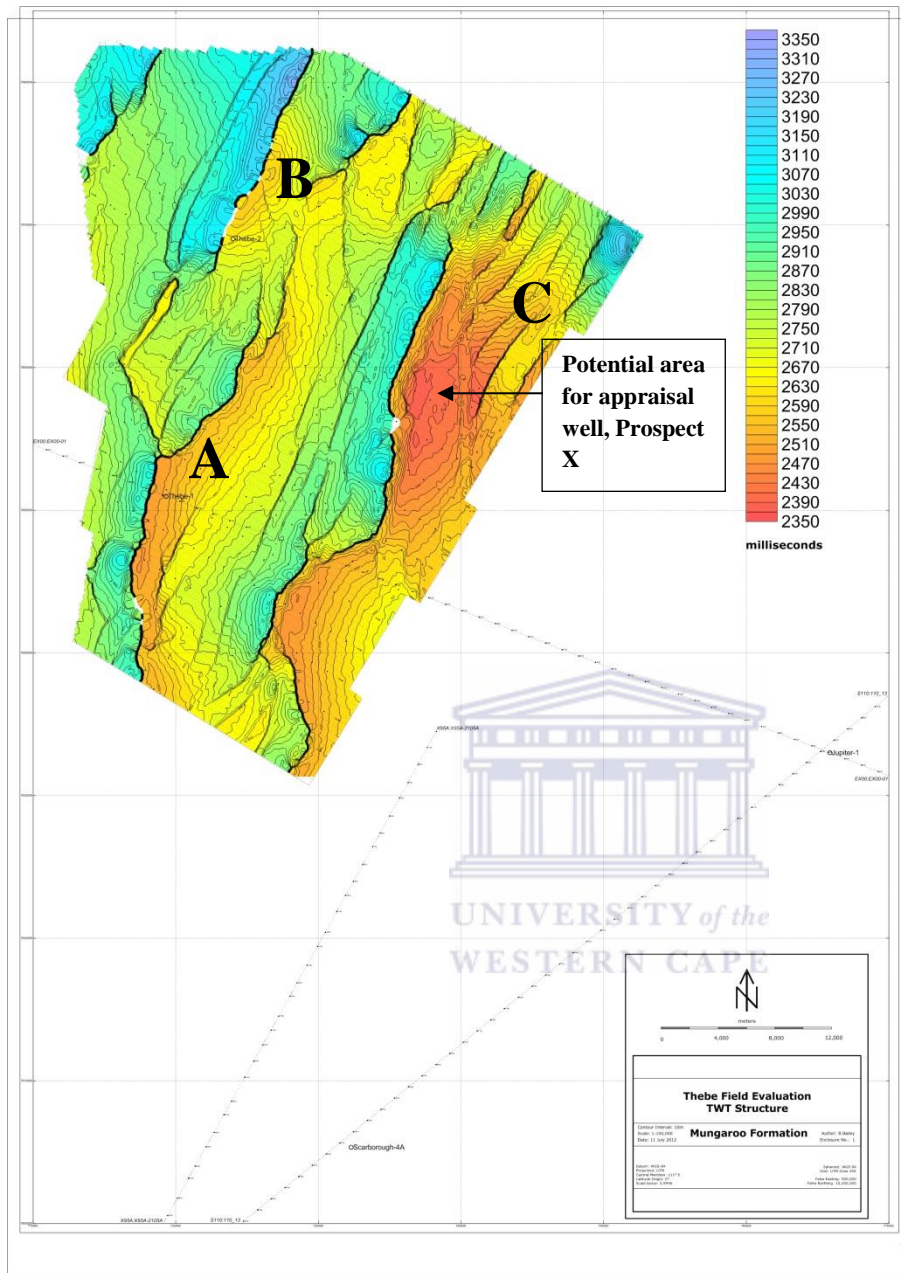
Figure 4.14: Two-way-time structure map of the Mungaroo Formation.

The two-way-time increases from southeast to northwest. At Thebe 1, which is located on the upthrown side of fault block A, the two-way-time ranges between 2470-2510 milliseconds and at Thebe 2, which is located on the upthrown side of fault block B, it ranges between 2590-2670 milliseconds. The dominant fault trend is northeast to southwest across the area. The two-way-time on the upthrown side of the fault ranges between 2350-2630 milliseconds and this indicates that it is shallow. On the down-thrown side of the fault the two-way-time

ranges between 2670-3350 milliseconds and this indicates that the down-thrown side is deep and this can be due to an increase in sediment supply (Refer to Figure 4.14).

Area C which is on the eastern side of the Thebe Field will be discussed in detail at a later stage as it is the area of interest in the project.

4.2.3. Murat Siltstone
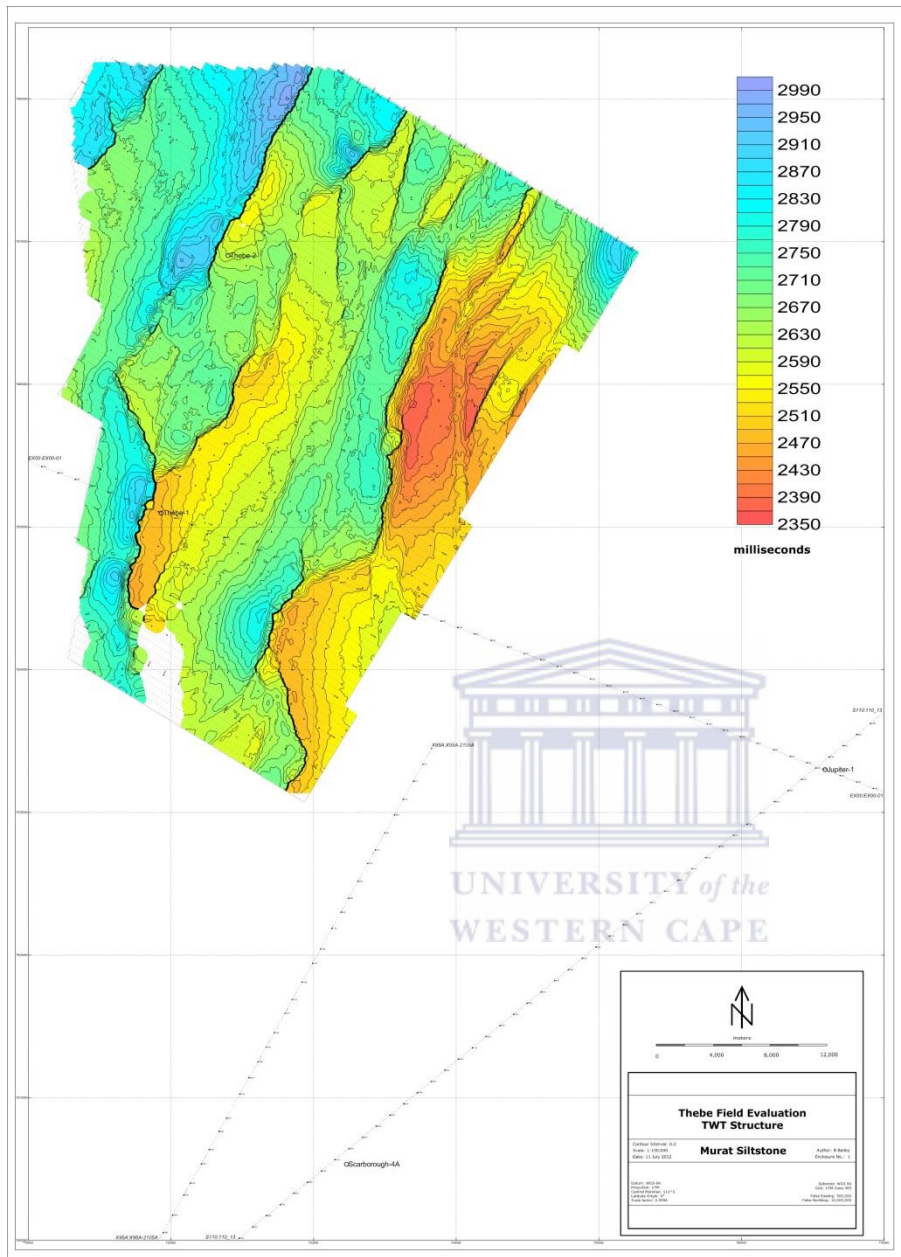
Figure 4.15: Two-way-time structure map of the Murat Siltstone

The two-way-time of the Murat Siltstone increases from southeast to northwest. The two-way-time at Thebe 1 ranges between 2430 milliseconds to 2470 milliseconds. The two-way-time at Thebe 2 ranges between 2590 milliseconds to 2630 milliseconds. The dominant fault trend is northeast to southwest with minor faults trending in a northwest-southeast direction.

The two-way-time on the upthrown side of the faults range between 2350 milliseconds to 2630 milliseconds and this indicates that the up thrown side is shallow. The two-way-time on the down thrown side of the fault ranges between 2670 milliseconds to 2990 milliseconds and

this indicates that the down thrown side of the fault is much deeper than the up thrown side of the fault(Refer to Figure 4.15).

4.2.4. Muderong Shale
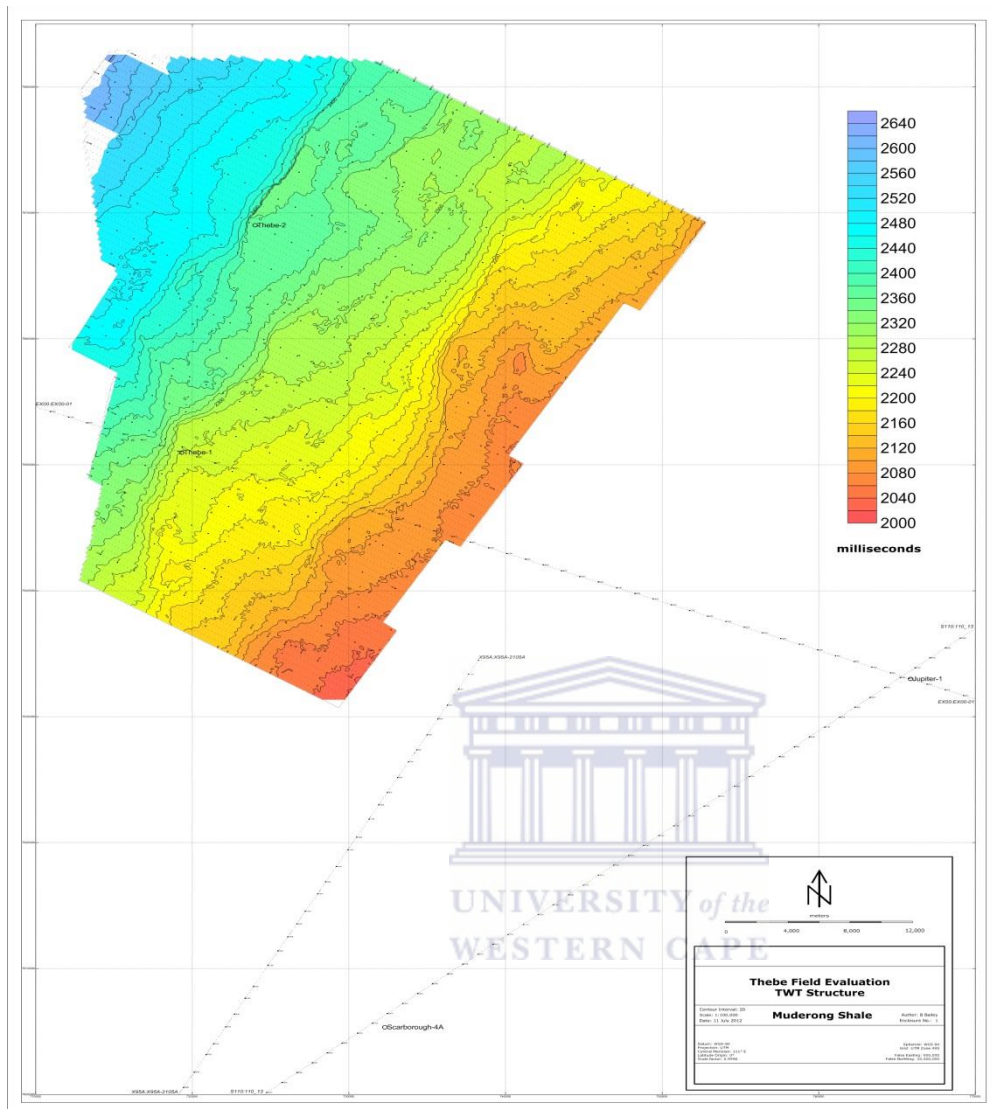
Figure 4.16: Two-way-time structure map of the Muderong Shale

The two-way-time of the Muderong Shale gradually increases from southeast to northwest.

There are no major faults but there are minor faults present and this is evident where the contours are close together. The two way time at Thebe 1 ranges between 2240 milliseconds to 2280 milliseconds. The two-way-time at Thebe 2 ranges between 2320 milliseconds to 2400 milliseconds (Refer to Figure 4.16).

4.2.5. Gearle Siltstone
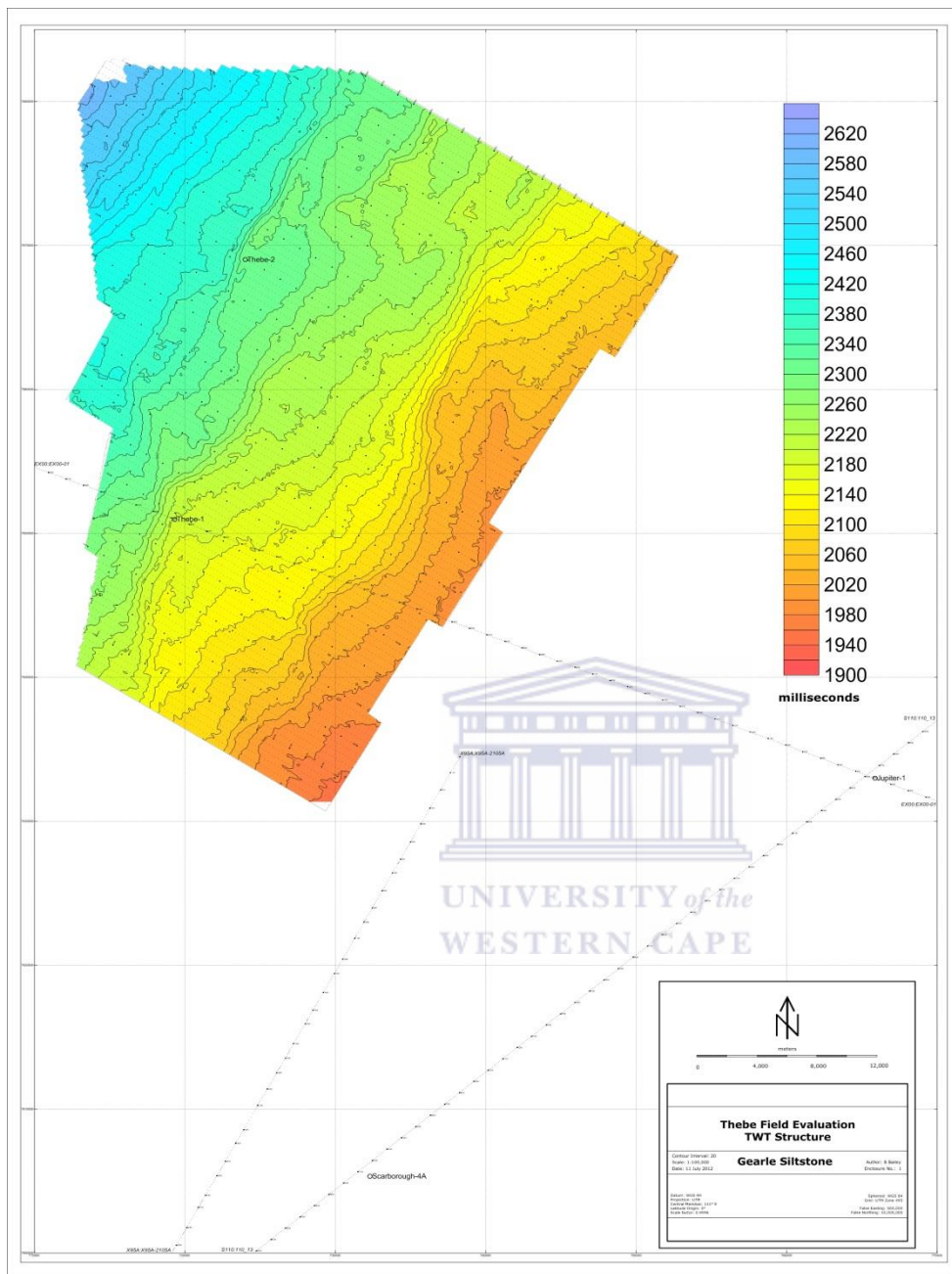
Figure 4.17: Two-way-time structure map of the Gearle Siltstone

The two-way-time of the Gearle Siltstone gradually increases from southeast to northwest. As with the Muderong Shale there are no major faults present for the Gearle Siltstone. The two-way-time at Thebe 1 ranges between 2180 milliseconds to 2220 milliseconds. The two-way-time at Thebe 2 ranges between 2300 milliseconds to 2340 milliseconds (Refer to Figure 4.17).

4.2.6. Sea Bed
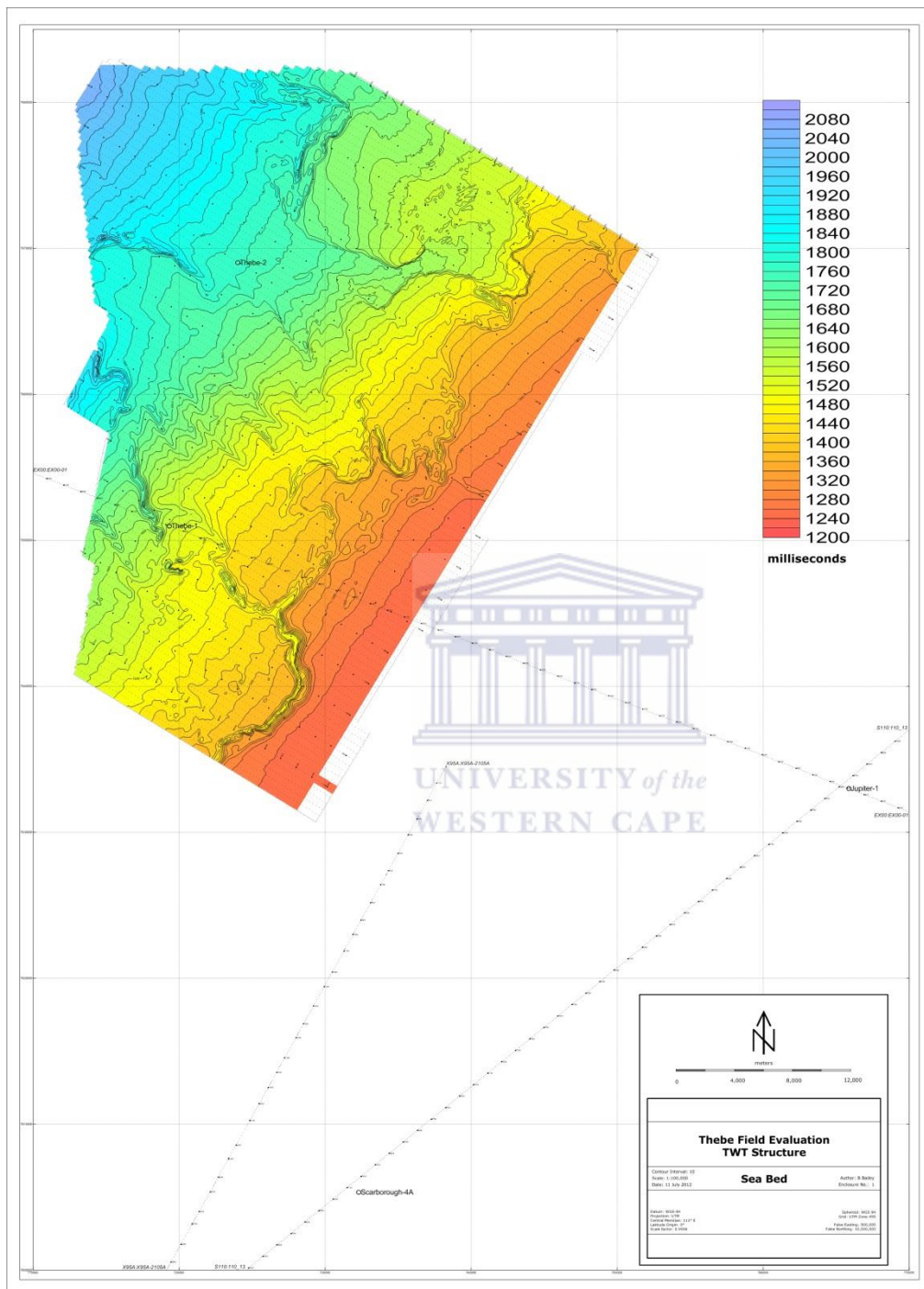
Figure 4.18: Two-way-time structure map of the Sea Bed

The two-way-time increases from southeast to northwest. The two-way-time at Thebe 1 ranges between 1520 milliseconds to 1680 milliseconds and the two-way-time at Thebe 2 ranges between 1800 milliseconds to 1840 milliseconds(Refer to Figure 4.18).

4.3 Average Velocity Map

4.3.1 Mungaroo Formation
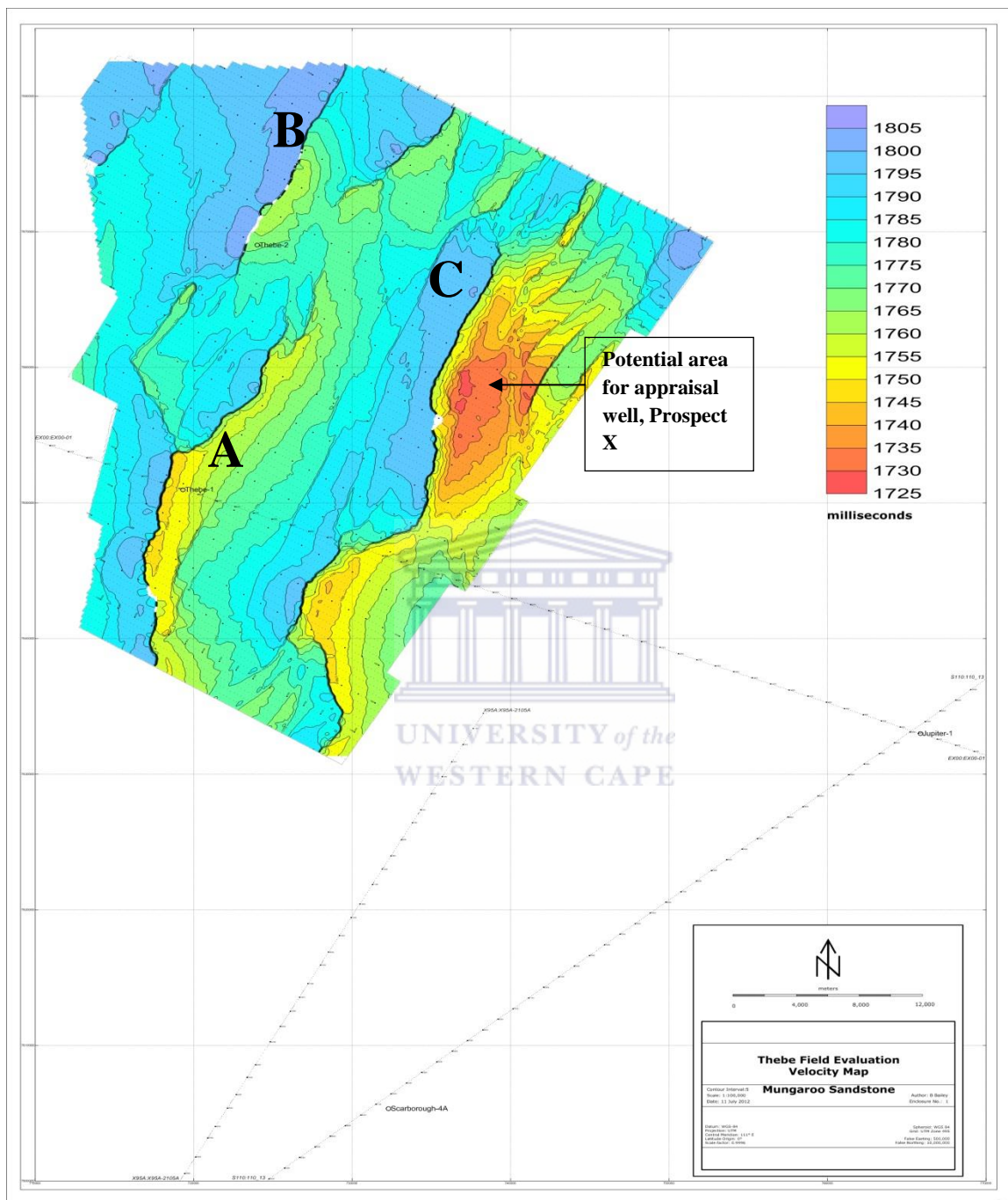
Figure 4.19: Average velocity map of the Mungaroo Formation.

The average velocity increases from southeast to northwest. The average velocity at Thebe 1, which is located on the upthrown side of fault block A, ranges between 1740 milliseconds to 1755 milliseconds and at Thebe 2, which is located on the upthrown side of fault block B, the average velocity ranges between 1760 milliseconds to 1770 milliseconds. The average

velocity on the up thrown side of the faults ranges between 1725 milliseconds to 1760 milliseconds and on the down thrown side of the fault the average velocity ranges between 1780 milliseconds to 1805 milliseconds. Thebe 1 and Thebe 2 are situated on the up thrown side of the respective faults. Area C which is on the eastern side of the Thebe Field will be discussed in detail at a later stage as it is the area of interest in the project(Refer to Figure 4.19).

4.4. Depth Structure map

4.4.1. Mungaroo Formation
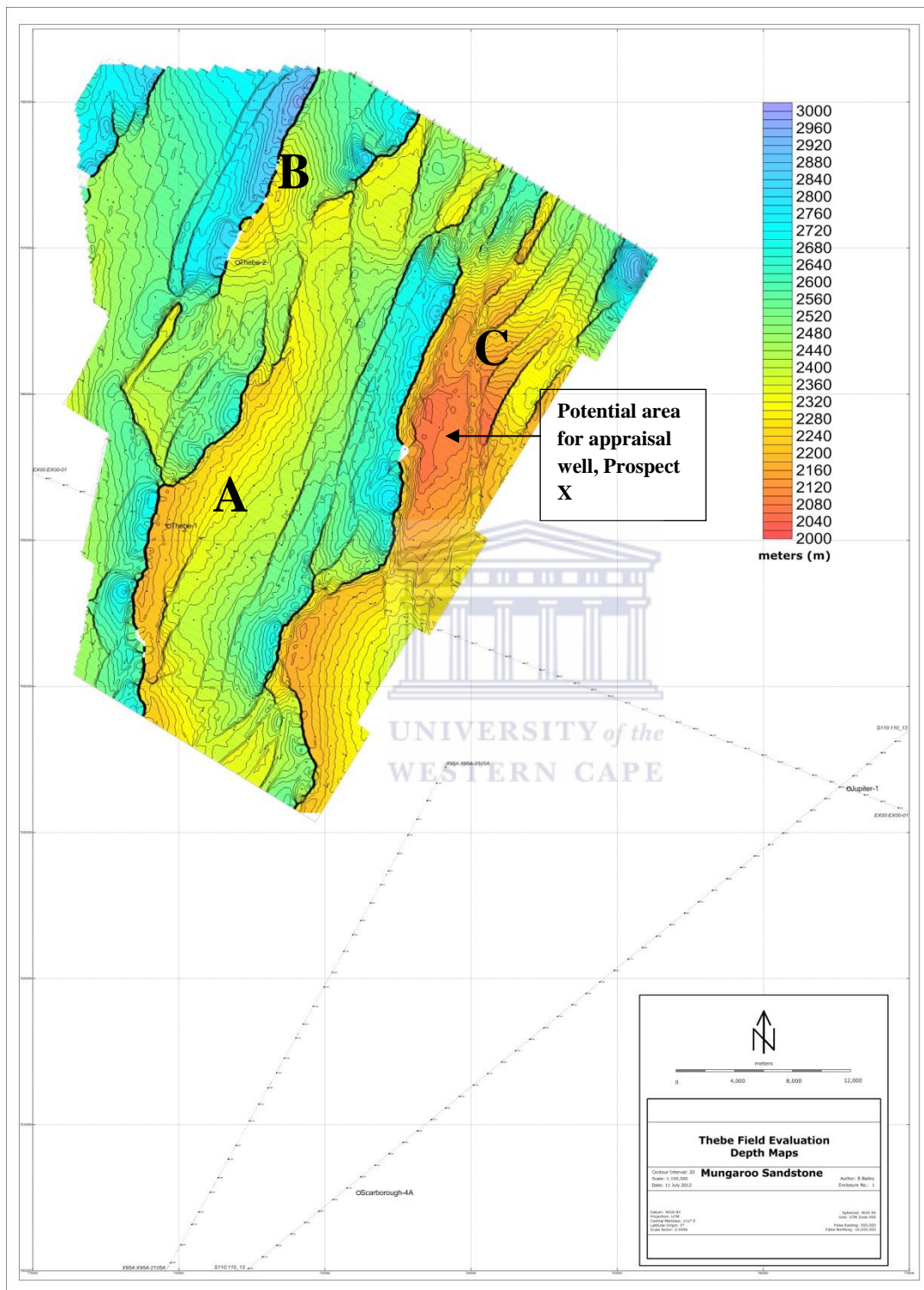
Figure 4.20: Depth structure map of the Mungaroo Formation.

The depth map of the Mungaroo Formation, from southeast to northwest, does not show any gradual increase in depth and this is due to the presence of faults. The dominant fault trend is

in the northeast to southwest direction. The depth in the area of Thebe 1, which is located on the upthrown side of fault block A, ranges between 2120 meters to 2220 meters and the depth in the area of Thebe 2, which is located on the upthrown side of fault block B, ranges between 2280 meters to 2400 meters. On the up thrown sides of the faults the depth ranges between 2000 meters to 2400 meters. On the down thrown sides of the faults the depth ranges between 2520 meters to 3000 meters and this indicates that the down thrown sides of the faults are deeper than the up thrown sides of the faults. Thebe 1 and Thebe 2 are both situate on the up thrown sides of the faults (Refer to Figure 4.20).

Area C which is on the eastern side of the Thebe Field will be discussed in detail at a later stage as it is the area of interest in the project

4.4.2. Muderong Shale
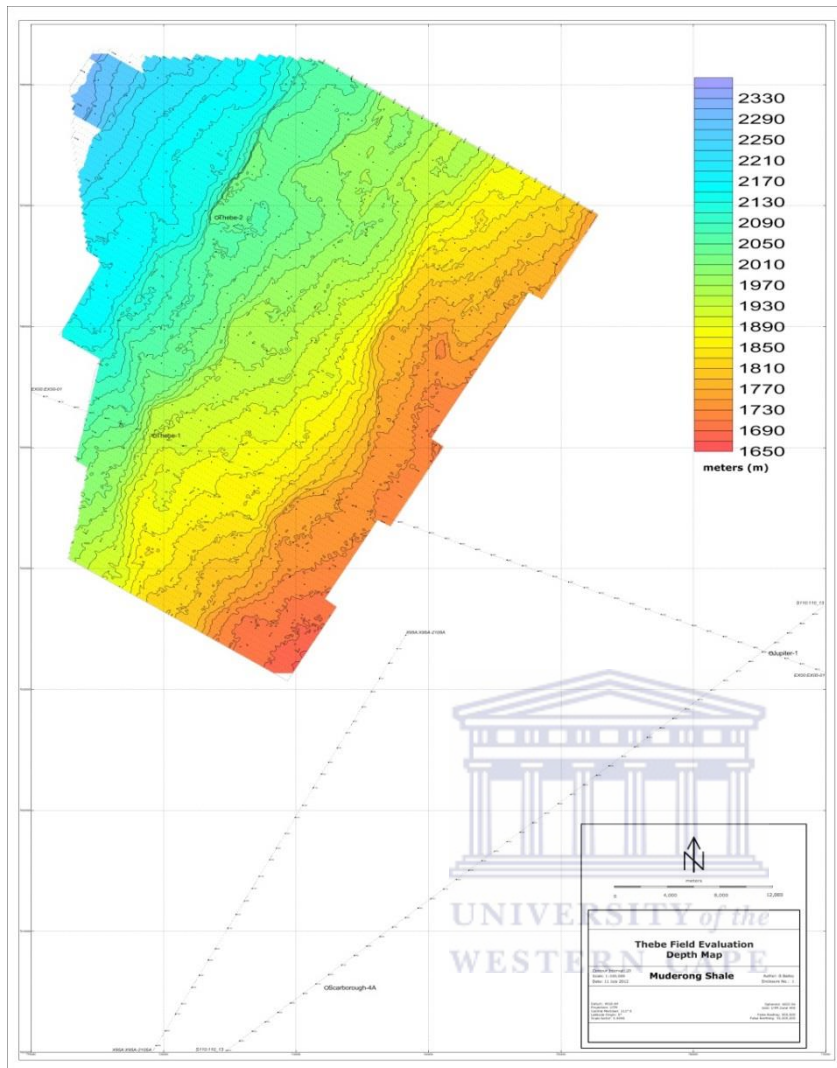
Figure 4.21 Depth structure map of the Muderong Shale

No depth map was created for the Murat Siltstone because its thickness was of no significance.

The depth of the Muderong Shale gradually increases form southeast to northwest. On major fault is present at Thebe 2. The Depth in the area of Thebe 1 ranges between 1890 meters to 1930 meters. The Depth in the area of Thebe 2 ranges between 1970 meters to 2010 meters. The minor faults are present where the contours are close together (Refer to Figure 4.21).

4.4.3. Gearle Siltstone
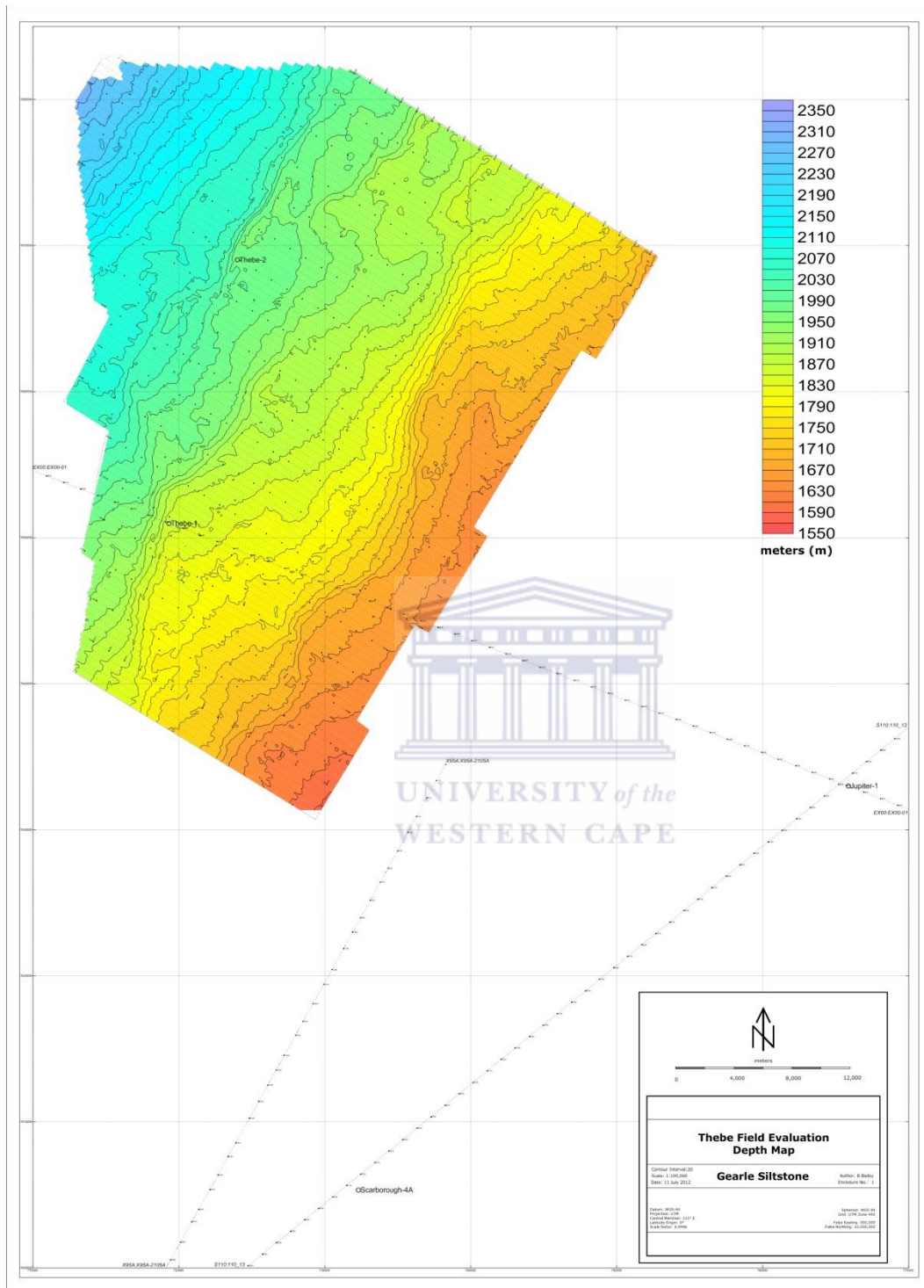
Figure 4.22 Depth structure map of the Gearle Siltstone

The depth of the Gearle Siltstone gradually increases from southeast to northwest. The depth in the area of Thebe 1 ranges between 1830 meters to 1870 meters and the depth in the area of Thebe 2 ranges between 1950 meters to 19990 meters. There are only minor faults present (Refer to Figure 4.22).

4.4.4. Sea Bed
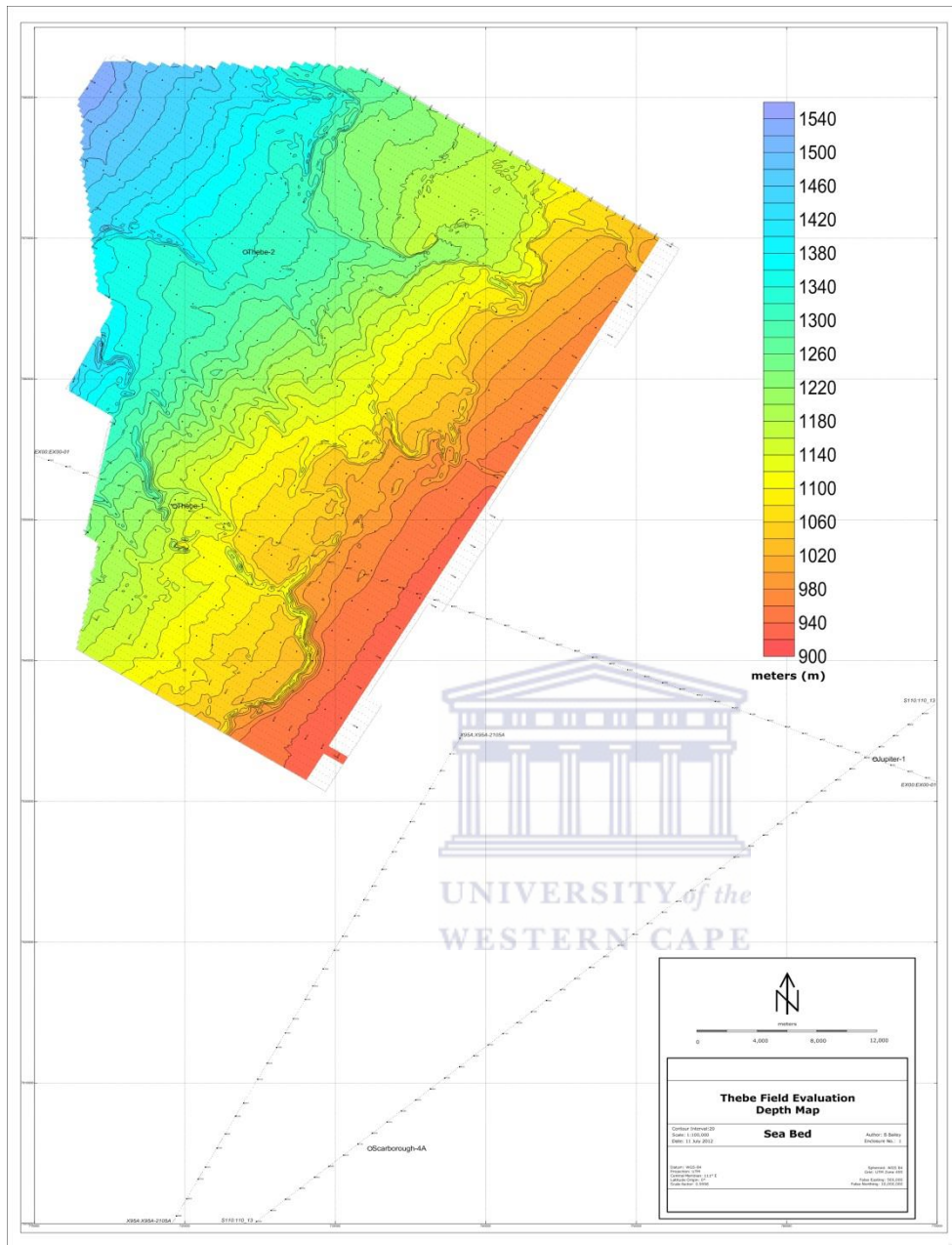
Figure 4.23 Depth structure map of the Sea Bed

The depth of the Sea Bed increases from southeast to northwest. In the area of Thebe 1 the depth ranges between 1140 meters to 1220 meters and the depth in the area of Thebe 2 ranges between 1300 meters to 1380 meters (Refer to Figure 4.23).

.

4.5 Petrophysical Interpretation.

4.5.1 Wireline logs.

4.5.1.1. Wireline Log of Thebe 1

The figure 4.24 below presents some of the wireline logs run in Thebe 1 well. Track one is the Gamma-Ray log (green colour), track 3 is the deep resistivity (red colour) and shallow resistivity (blue) and track 4 is the caliper log and track 5 is the density log (red) and neutron log (green) plotted on a linear scale.
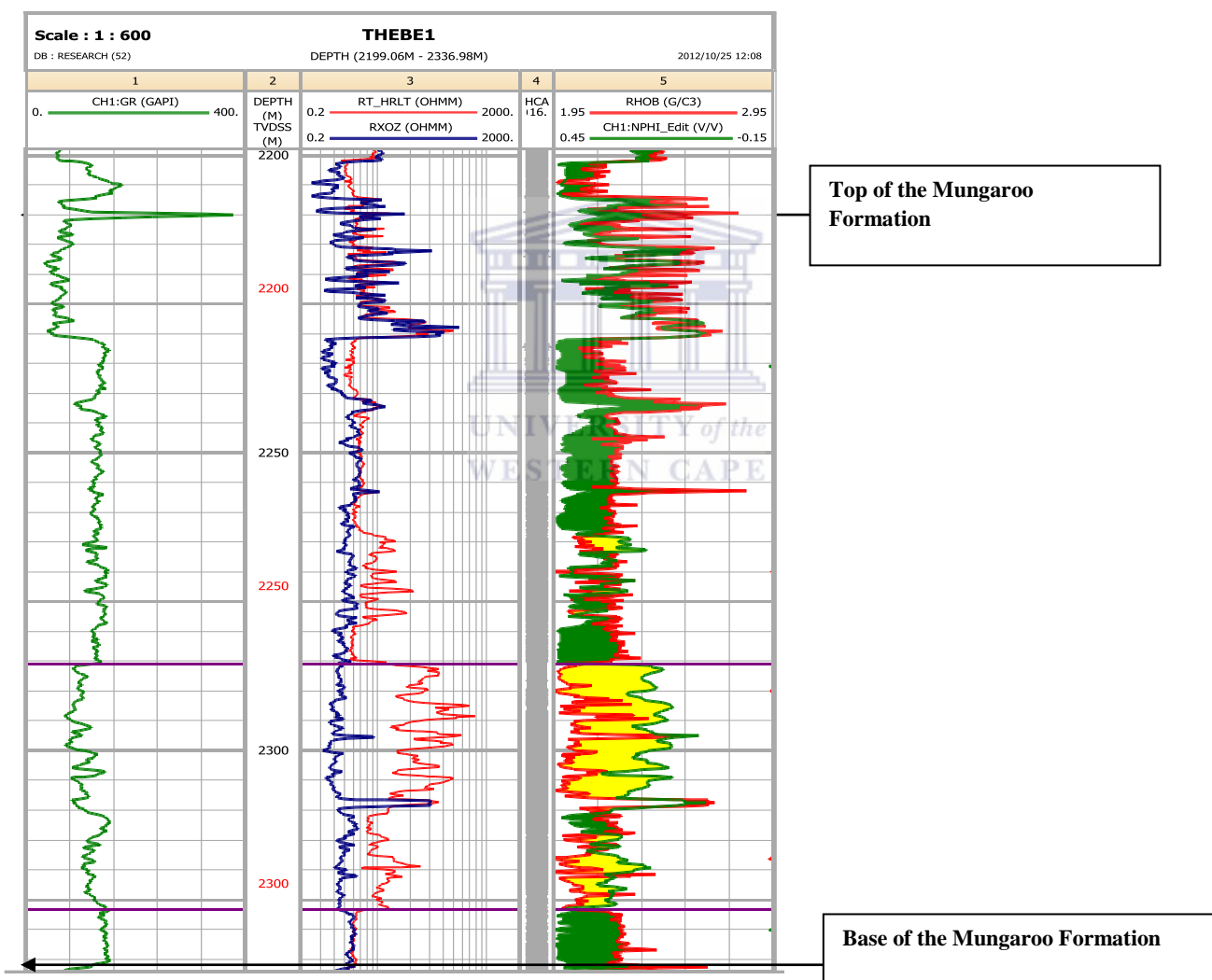
Figure 4.24: Wireline log of Mungaroo Formation at Thebe 1

The top of the Mungaroo Formation starts at 2211 m and the base is at 2336.8 m. From the log it shows that the Mungaroo is composed mainly of sandstone and shale. The measured depth is shown in black and the TVD is shown in red.
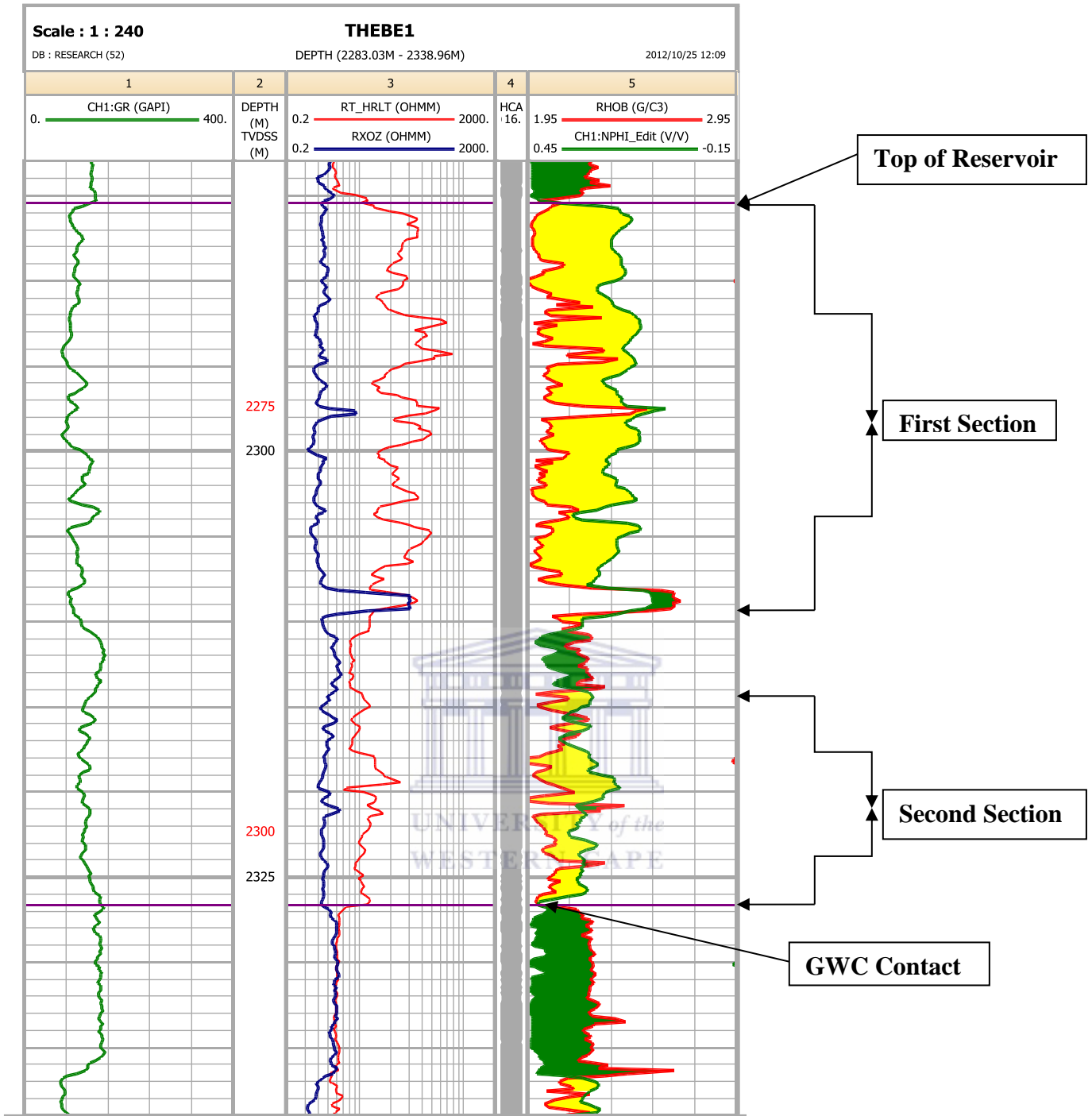
Figure 4.25: Reservoir section of Thebe 1.

The wireline log shows the reservoir section of the Mungaroo Formation at Thebe 1. The top of the reservoir occurs at a depth of 2285.5m and the base occurs at a depth of 2326.6m. The gas-water-contact (GWC) occurs at depth of 2326.5 meters. The reservoir section is separated into two sections by shale unit which is approximately 5 meters thick. The entire section is approximately 41 meters thick. The first section is approximately 24.5 meters thick and the second section is approximately 16.5 meters thick.

4.5.1.2. Wireline log of Thebe 2
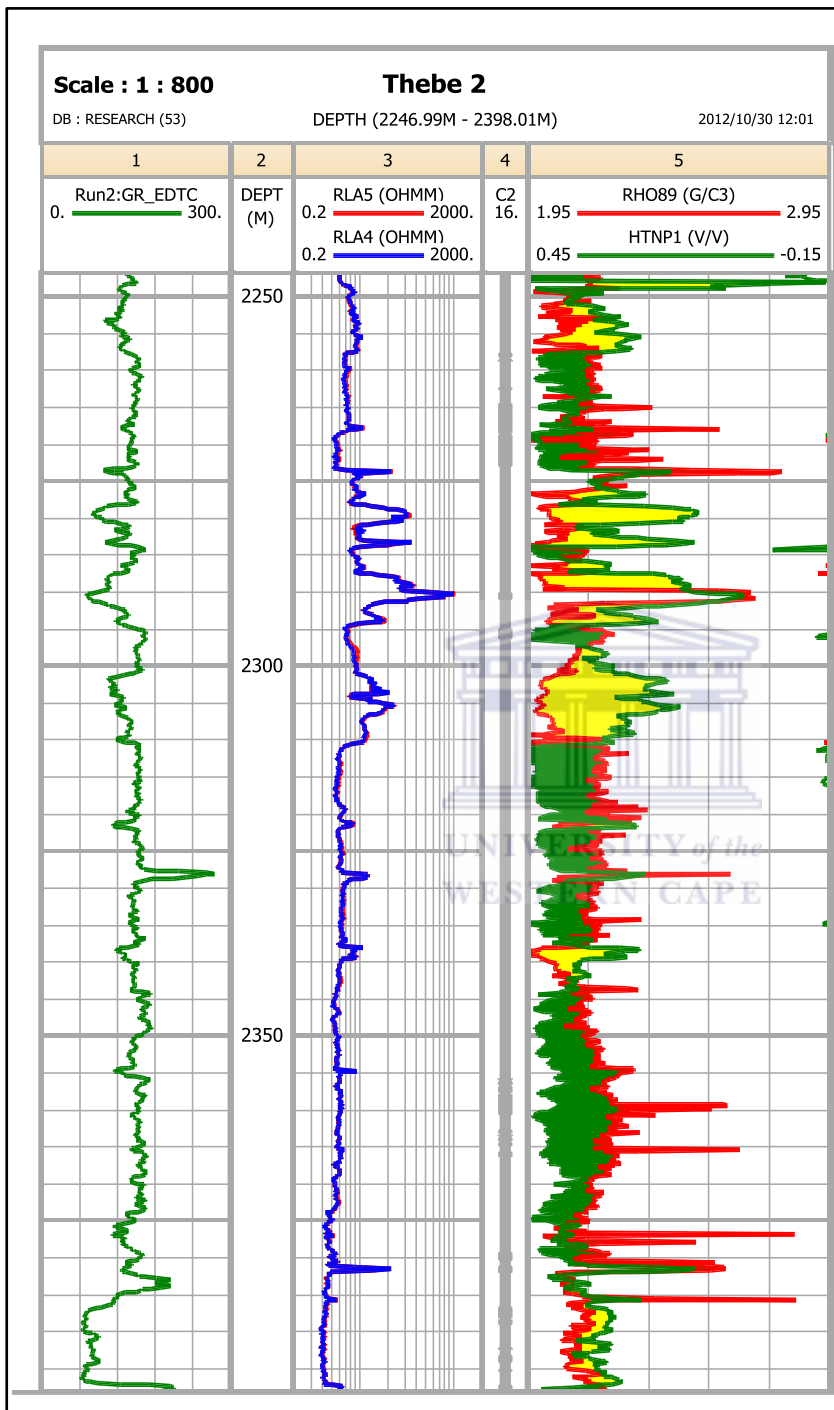
Figure 4.26: wireline log of the Mungaroo Formation at Thebe 2

The wireline log section above occurs between 2246.99 – 2398.01 meters which is possibly the top and base of the Mungaroo Formation respectively. From the log it shows that the Mungaroo is composed mainly of sandstone and shale. The measured depth is shown in black

and the TVD is shown in red. The gas-water-contact at Thebe 2 occurs at a depth of 2342.1 meters.
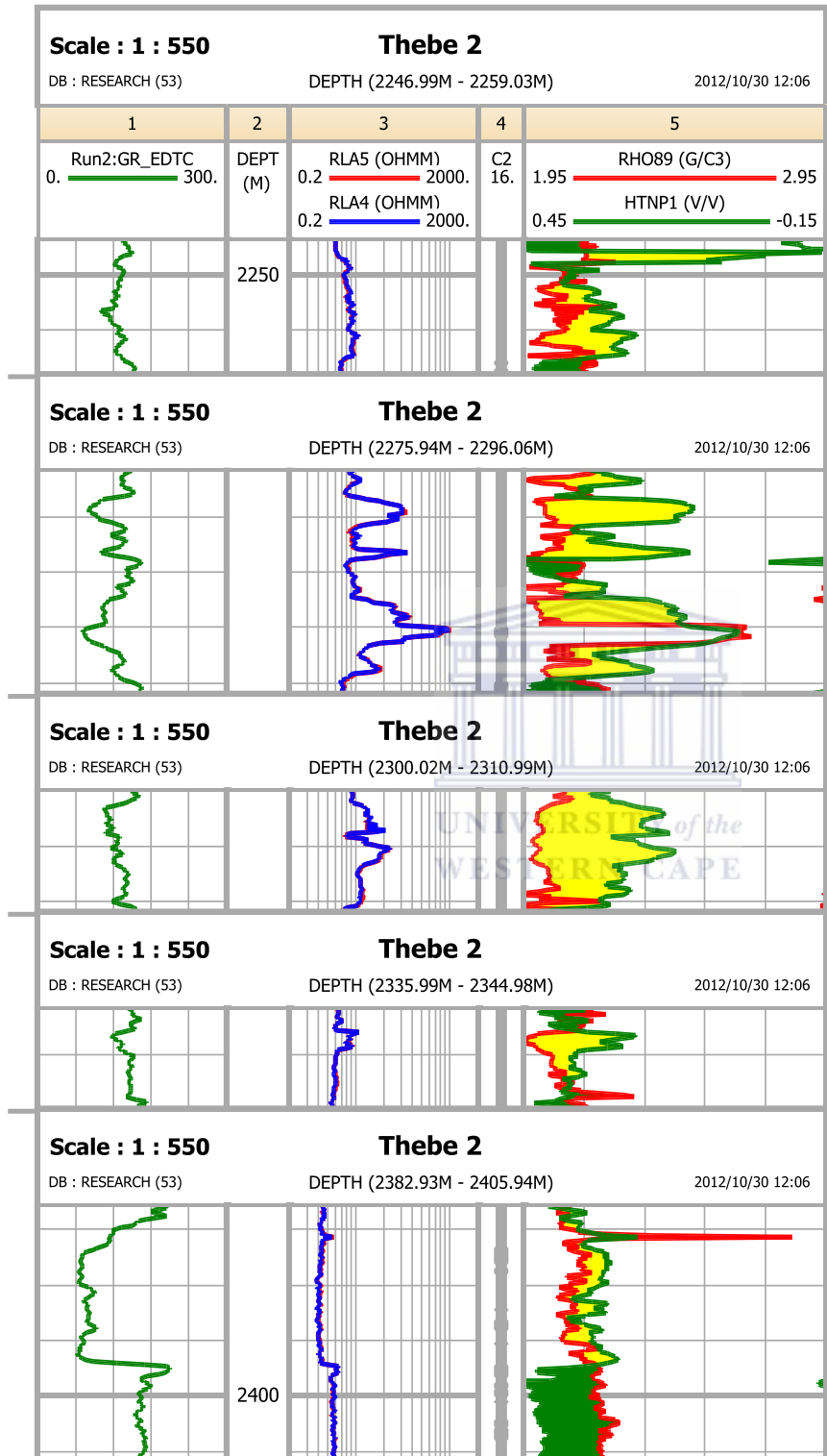
Figure 4.27: Wireline logs showing the reservoir sections at Thebe 2.

The wireline log section above represents all the possible reservoir sections present at Thebe 2. There are five possible reservoir sections ranging between 2246.99 – 2405.94 meters. The last section which occurs between 2382 – 2405.94 meters is mainly water saturated and this is shown by the low resistivity values.

4.5.2 Repeat Formation Testing (RFT)

4.5.2.1. Repeat formation testing at Thebe 1

The scatter plot below represents the RFT analysis for the fluid contact for the reservoir of Thebe 1. The red line represents the gas and the blue line represents the water. The gas gradient 0.24 psi/m and the water gradient is 1.40 psi/m. The gas-water-contact (GWC) is indicated where the gas line and water line intersect and from the graph below it occurs at a depth of 2326.5 meters. This is then compared to the wireline log to confirm this finding (Refer to Figure 4.28)
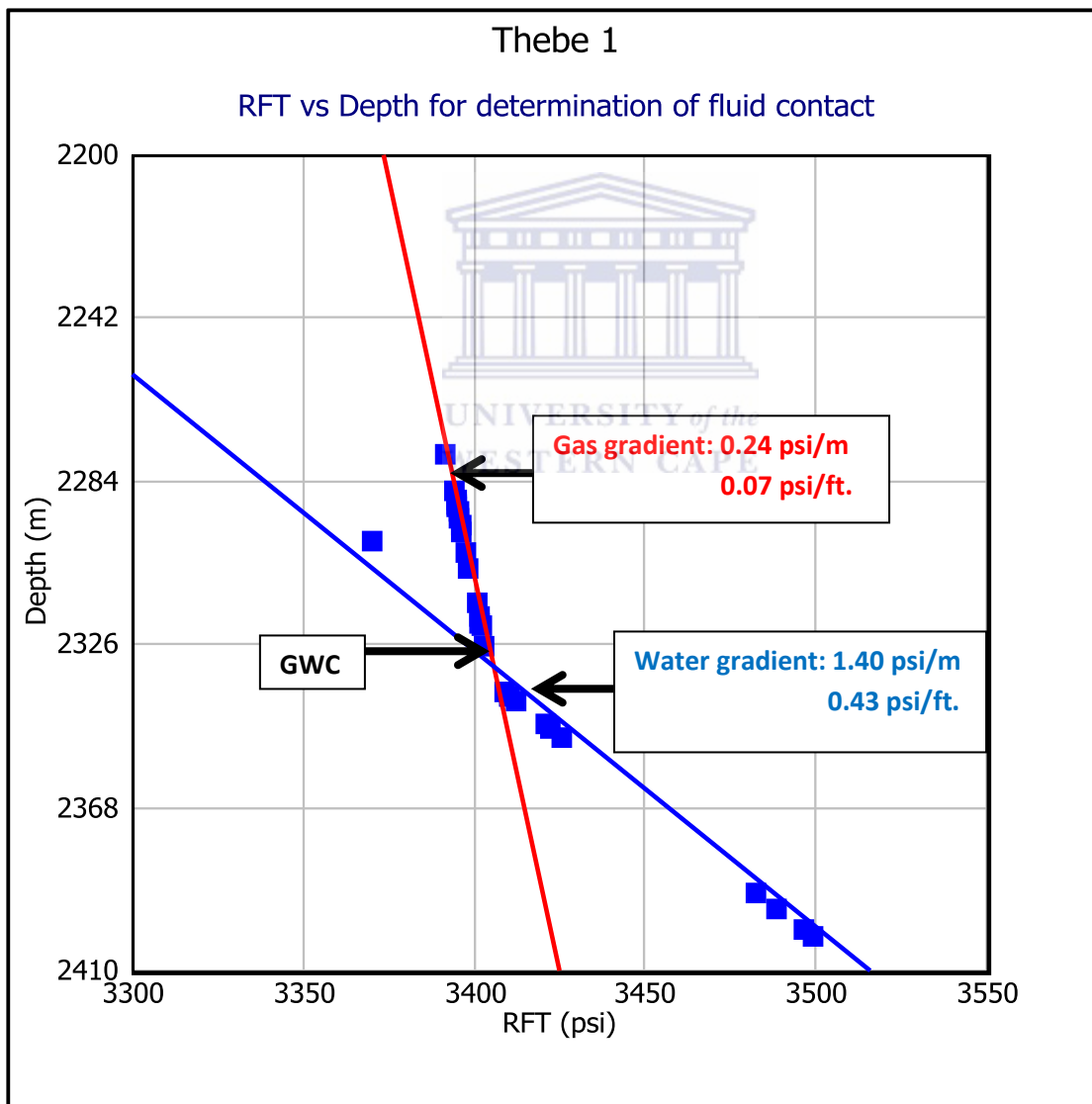
Figure.4.28: RFT vs. Depth for determination of fluid contact for reservoir of Thebe 1.

4.5.2.2. Repeat formation testing at Thebe 2
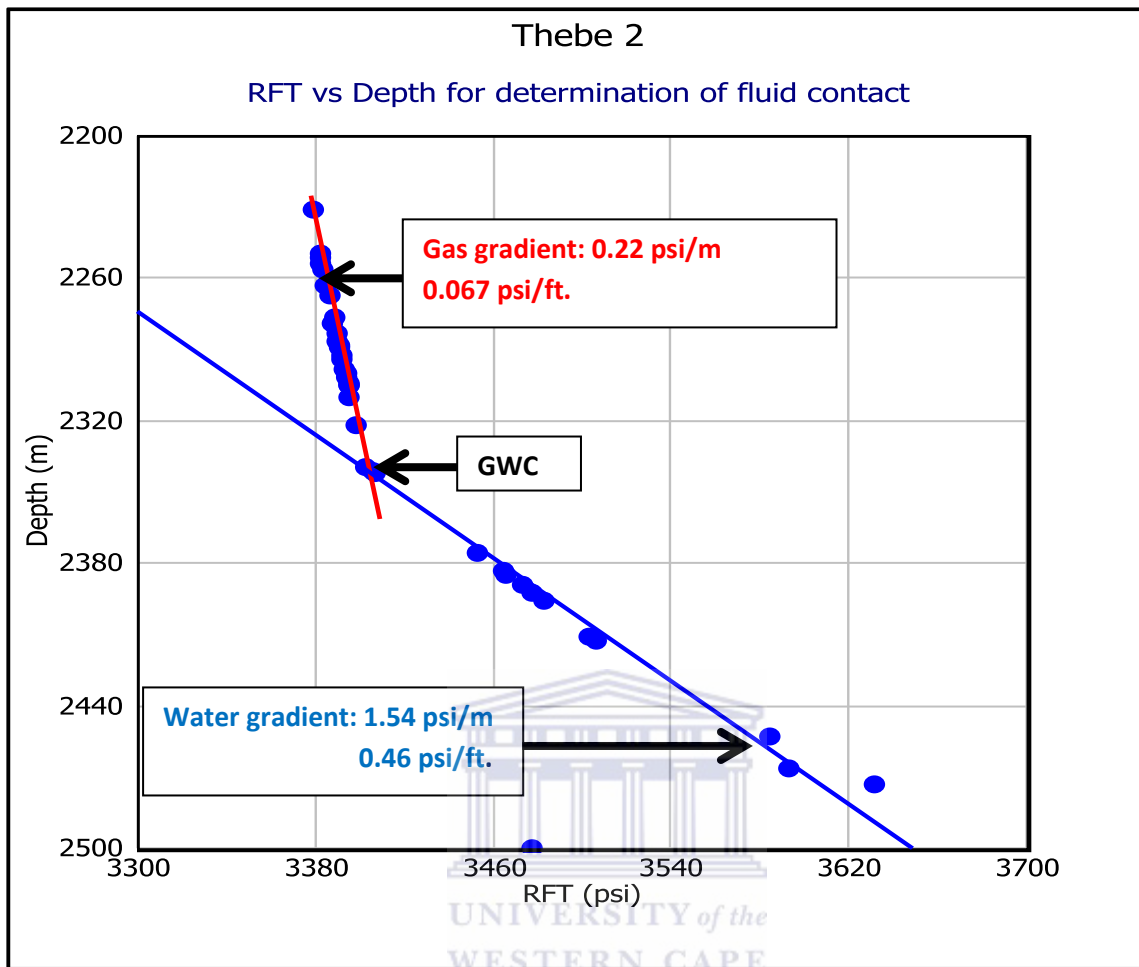
Figure.4.29: RFT vs. Depth for determination of fluid contact at Thebe 2.

The scatter plot above represents the RFT analysis for the fluid contact for the reservoir of Thebe 2. The red line represents the gas and the blue line represents the water. The gas gradient is 0.22 psi/m and the water gradient is 1.54 psi/m. The gas-water-contact (GWC) is indicated where the gas line and water line intersect and from the above graph it occurs at a depth of 2326.5 meters. This is then compared to the wireline log to confirm this finding.

Chapter 5: Discussion

5.1. Mungaroo Formation

5.2. Muderong Shale

5.3. Volumetrics

5.4. Geological Success

5.5. Summary of Prospect X

5. **Discussion**

In this chapter the economic basement, Murat Siltstone and the Gearle Siltstone will not be discussed as these formations have no significance within the petroleum system discussed. Only the Mungaroo Formation and Muderong Shale will be discussed, starting with the Mungaroo Formation. Only seismic sections and geophysical maps will be discussed as the main objective of this study is finding a location for an appraisal well to be drilled.

5. 1. **Mungaroo Formation.**

The Mungaroo Formation is the primary reservoir present in the study area.

From figure 4.14 (two-way-time map) and figure 4.20 (depth map) it can be seen that there is no gradual increase in two-way-time or depth.

The high and low areas present are defined by the fault trend and the dominant fault trend is NE to SW. On both the two-way-time and depth maps there are three major fault blocks present, A, B and C, defined by faults A, B and C (refer to figures 4.14 and 4.20).

On the western side of the maps, Thebe 1 was drilled on the upthrown side of fault block A, along fault A. The structure upon which Thebe 1 was drilled is formed by the contour closing against fault A. The throw present between the upthrown and downthrown sides of fault A 520 milliseconds from the two-way-time map (figure 4.14) and 560 meters from the depth map (figure 4.20). The closing contour at Thebe 1 is contour 2550 on the two-way-time map and contour 2240 on the depth map. Thebe 2 which is present in the north western part of the area was drilled on the upthrown side of fault block B. The structure upon which Thebe was drilled was identified by the closing of the contour against fault B. The closing contour at Thebe 2 is contour 2670 on the two-way-time map and contour 2380 on the depth map. The throw present between the upthrown and downthrown sides of fault block B is about 560 milliseconds on the two-way-time map and about 560 meters on the depth map. The throw between the upthrown and downthrown sides of fault block A and B appears to be consistent.

Prospect X

On the eastern side of the area, on the upthrown side of fault block C, multiple potential for structural closure exists. This is the site for prospect X. Four way dip closure at fault block C is evident on both two-way-time and depth maps and because the structure is present on both structure maps it indicates that the evidence that the structure exists is extremely good. The closing contour at fault block C is contour 2410 on the two-way-time map and contour 2100 on the depth map. The maximum area for closure on fault block C is contour 2430 on the two-way-time maps and contour 2120 on the depth map. These contours present on the structure maps could possibly represent the spill point at the potential area on fault block C.

The average velocity map of the Mungaroo Formation, figure 4.19 shows that the average velocity at Thebe 1 and Thebe 2 is lower than the average velocity on the downthrown sides of the respective fault blocks. A low average velocity is an excellent indication of the presence of gas, when gas is present the average velocity of a particular formation drops. On the upthrown side of fault block C extremely low average velocities are present which could possibly be due the presence of gas. The average velocity on the upthrown side of fault block C ranges between 1725 milliseconds and 1755 milliseconds.
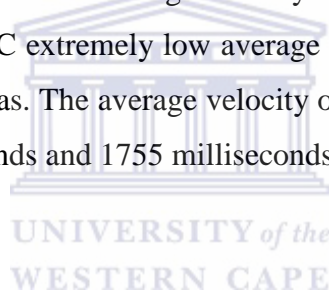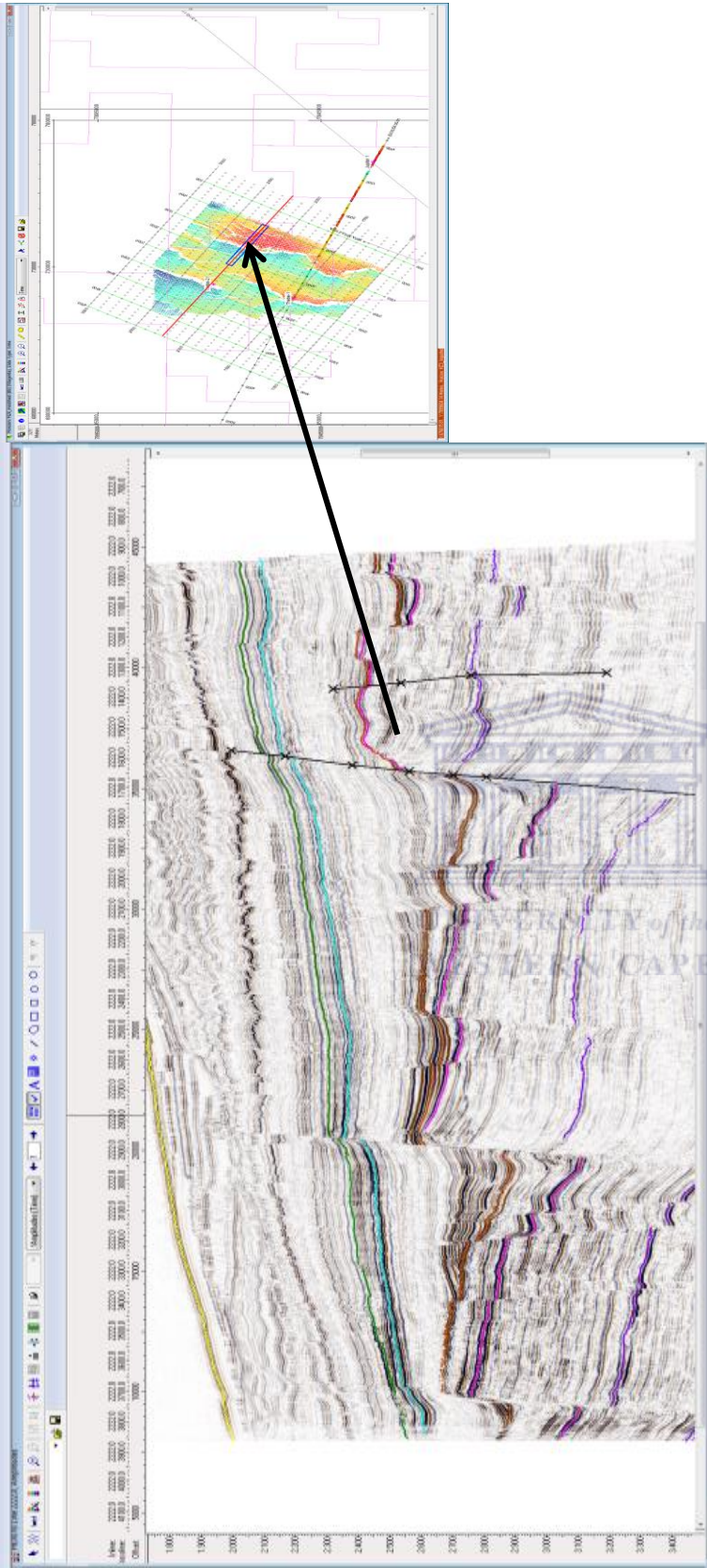
Figure. 5.1: Inline 2222 showing the location of prospect X.
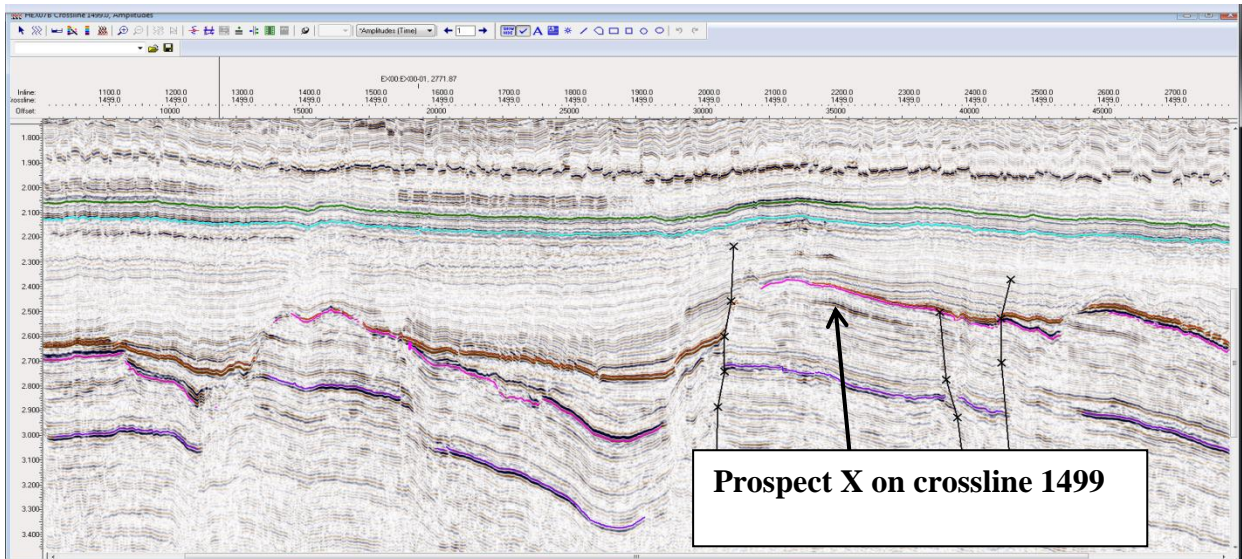
Figure. 5.2: Crosssline 1499 showing the location of Prospect X.

The sands of the Mungaroo Formation are described as being fluvial-deltaic. The sandstones of the Triassic Mungaroo Formation are also described as being very fine to fine grained. *Rek et al, 2003* describes the reservoirs of the Triassic Mungaroo Formation as having good to excellent reservoir characteristics, with porosities ranging between 20% to 30%. It is dominated by fluvial meandering and braided stream sequences with the upper section being dominated by marine conditions. West of Jupiter 1 the possibility exists of encountering pro-delta deposits and beach-barrier sandstones.

In summary, there is a very high possibility of encountering reservoir within prospect X since prospect X is located west of Jupiter 1.

From the seismic section below, figure 5.3, a thick transparent package assumed to be shale exists. Previous analysis of the potential source rocks of the Mungaroo Formation have indicated that the source rocks are gas prone and reflects source rocks which are typical of fluvial-deltaic depositional settings (Jong, 1996).

The Triassic Mungaroo has been described by *Scott, 1994*, as having source rock potential. In summary this could thus be the source feeding the reservoir.
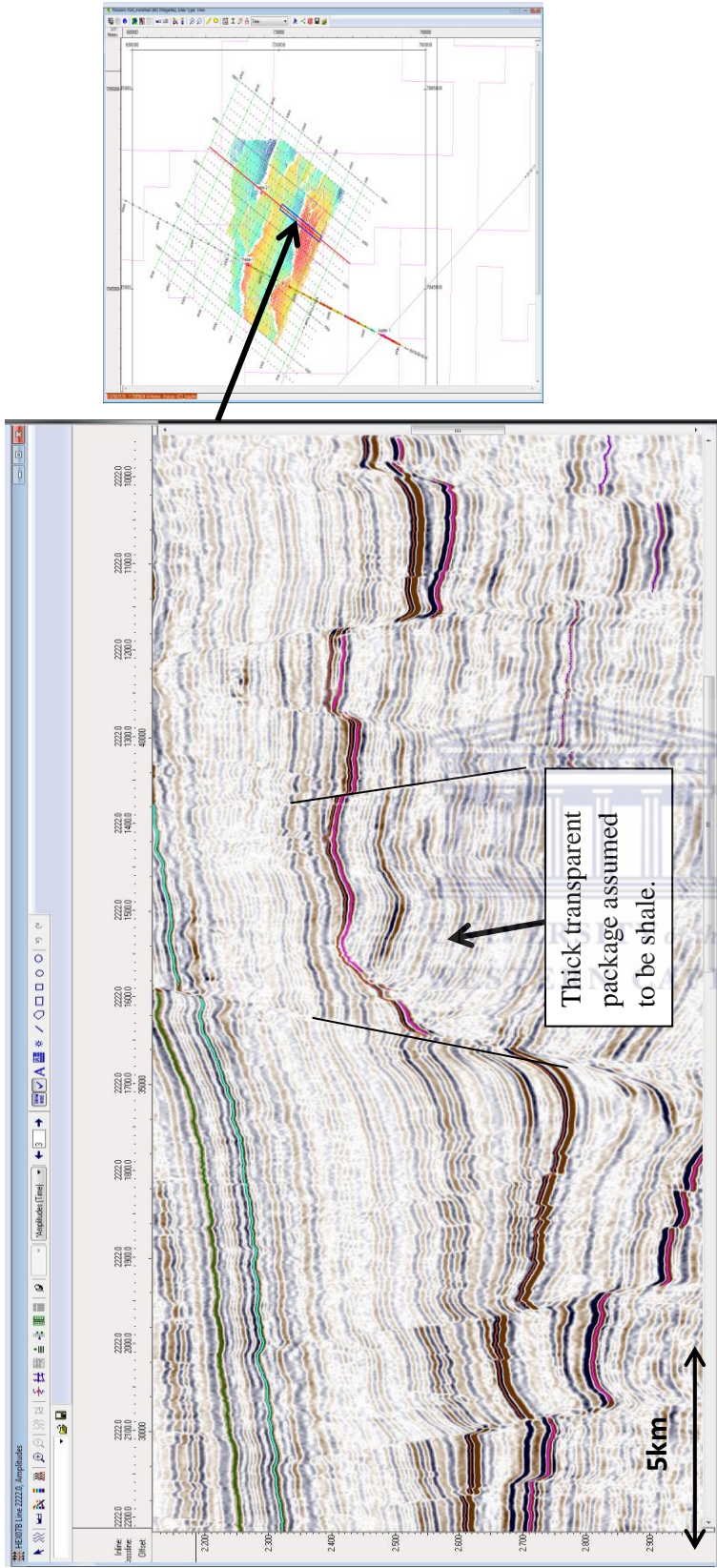
Figure.5.3. Seismic section showing the transparent package assumed to be shale at prospect X.

Thick transparent package assumed to be shale.

5km

The trapping style within the Triassic Mungaroo is said to be structural traps. Fault controlled structural traps are the dominant play types within the Triassic play types. This has also been discussed by *Rek et al, 2003*. Migration pathways have possibly been provided by the faults present. Migration pathways are indicated on figure 5.4.

Possible migration pathways indicated by black arrows.

5km
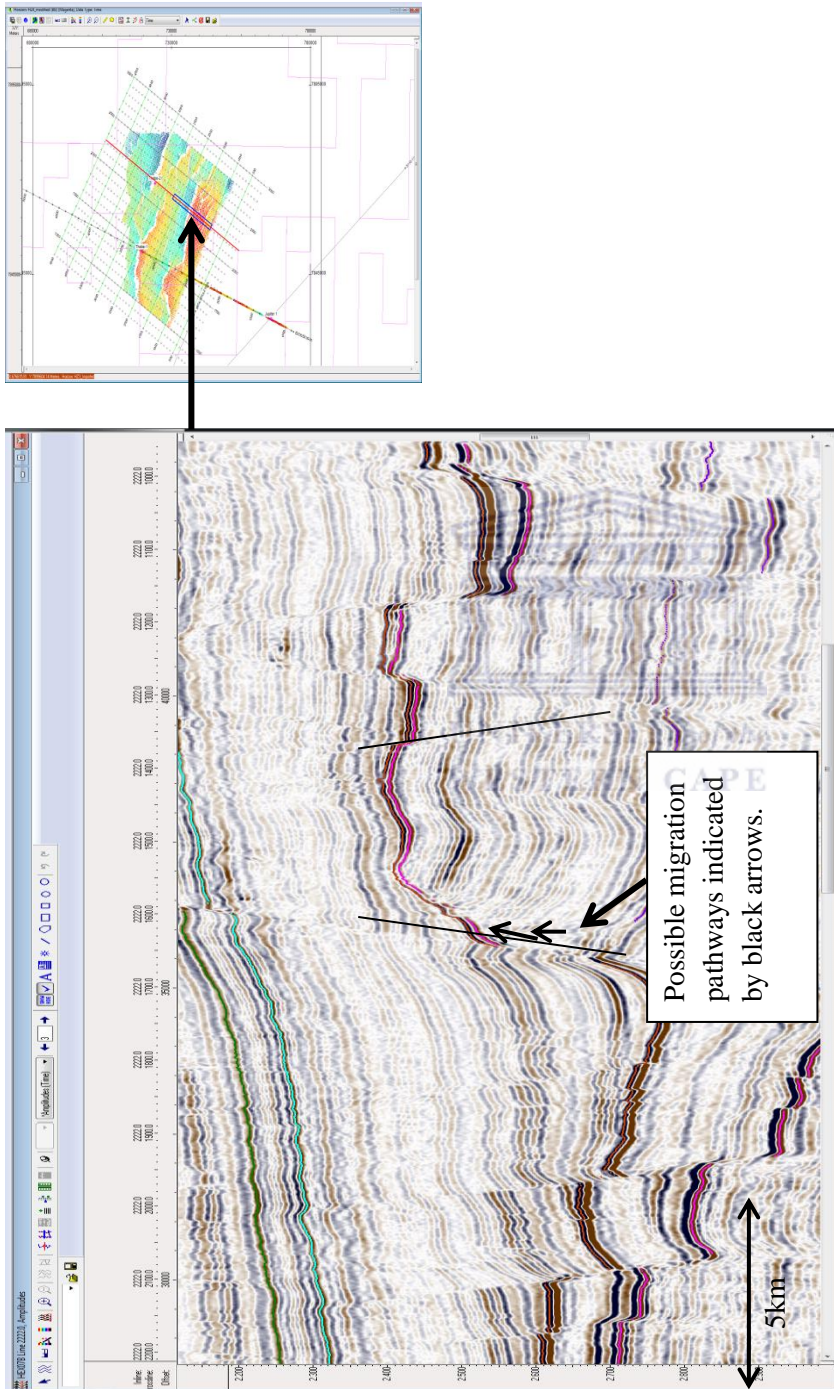
Figure.5.4: Seismic section showing possible migration pathways at prospect X.

From the seismic section below it can be seen that there are high amplitudes present at the prospect on fault block C. Amplitudes were also present at Thebe 1 and Thebe 1 is a producing well. This amplitude could be a possible indication of gas. The faults on either side of the upthrown side will possibly prevent the gas from leaking.
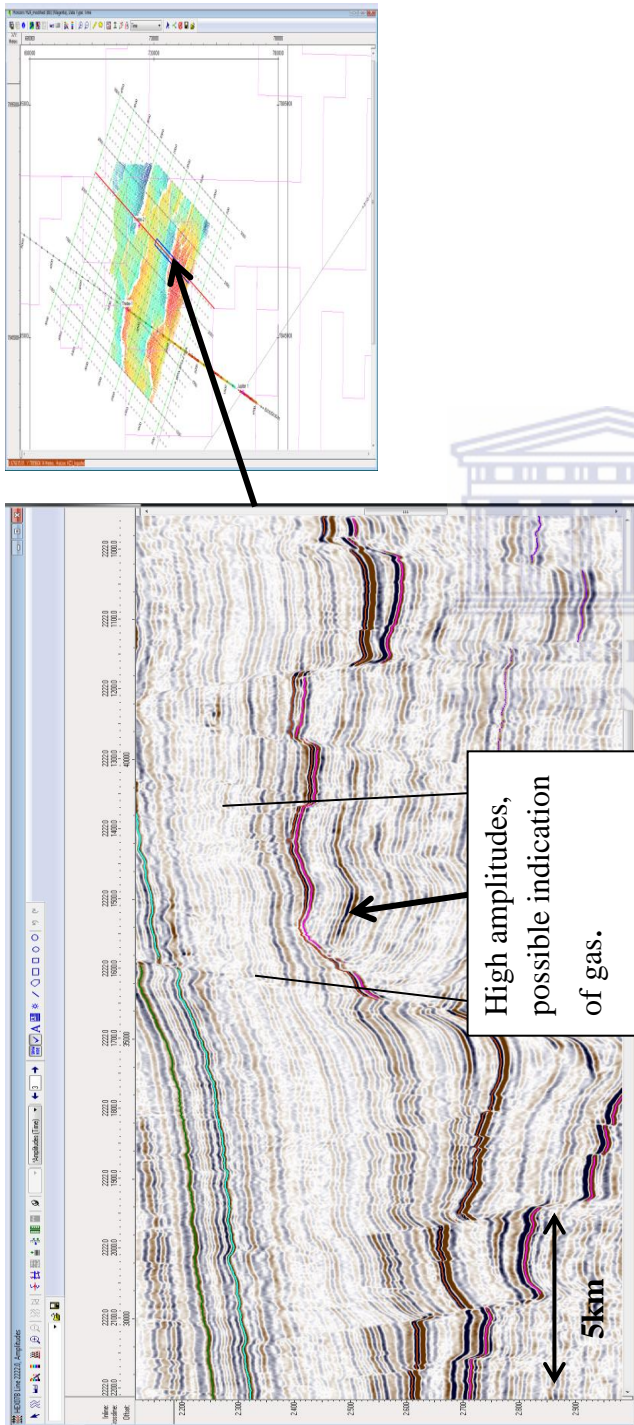
Figure.5.5: Seismic section of the proposed location (Prospect X) Area C, showing the high amplitudes present

5.2. Muderong Shale

The Muderong Shale could be mapped over the entire area of interest. The lateral extent as well as the thickness of the Muderong Shale implies that it could possibly provide relatively good sealing qualities.

At prospect X, the seal is relatively thick and could possibly provide good sealing qualities (figure 5.6).

Thickness and lateral extent of the Muderong Shale

5km
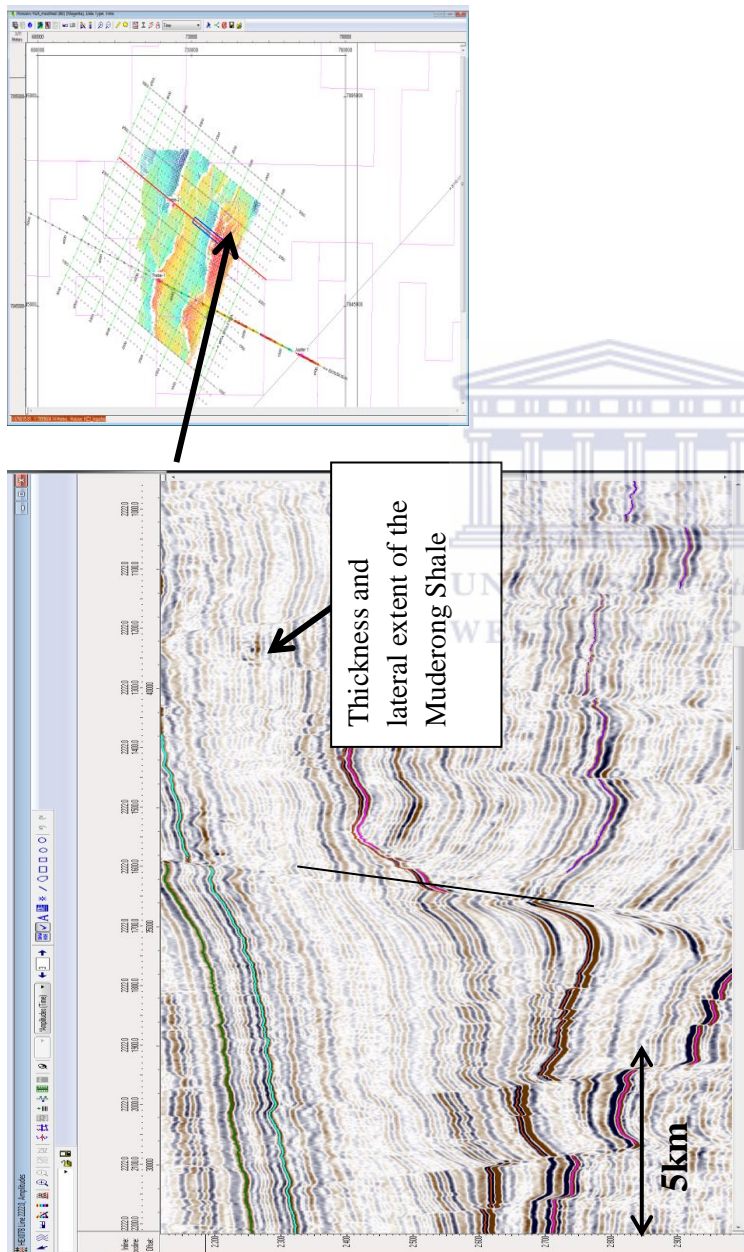
Figure.5.6: Seismic section showing the lateral extent and thickness of the Muderong Shale at prospect X

5.3. Volumetrics.

The volumes were calculated using the Monte-Carlo simulation.

A Monte-Carlo simulation involves a process whereby thousands of calculations are performed, the input parameters are chosen at random from the defined distribution for that parameter. This allows the output distribution to be calculated from which the statistical measures can be determined *(Gluyas et al.., 2004).*

The volumetrics were calculated using three depth contours namely; P90, P50, P10, These will be defined below:

P90: The P90 is defined as the amount of reserves where there is a 90% chance that the reserves present will be greater *(Hefner et al.., 1996).* The P90 is defined by the closing contour 2080 on the depth map (refer to figure 5.7below).
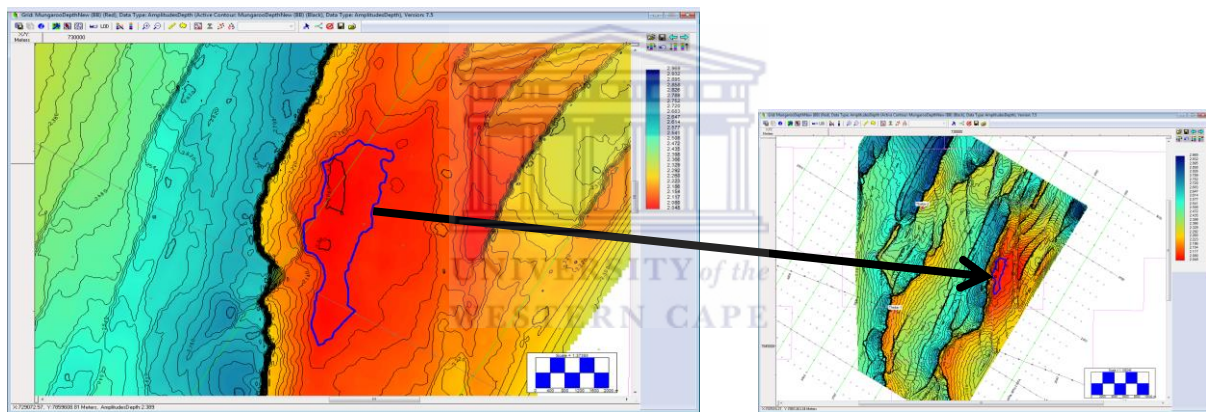
Figure 5.7: P90 location and closing contour 2080.

P50: The P50 is defined as the amount of reserves where there is a 50% chance the reserves present will be greater (*Hefner et al.., 1996).* The P50 is represented by the closing contour 2100 on the depth map (refer to figure 5.7 below).
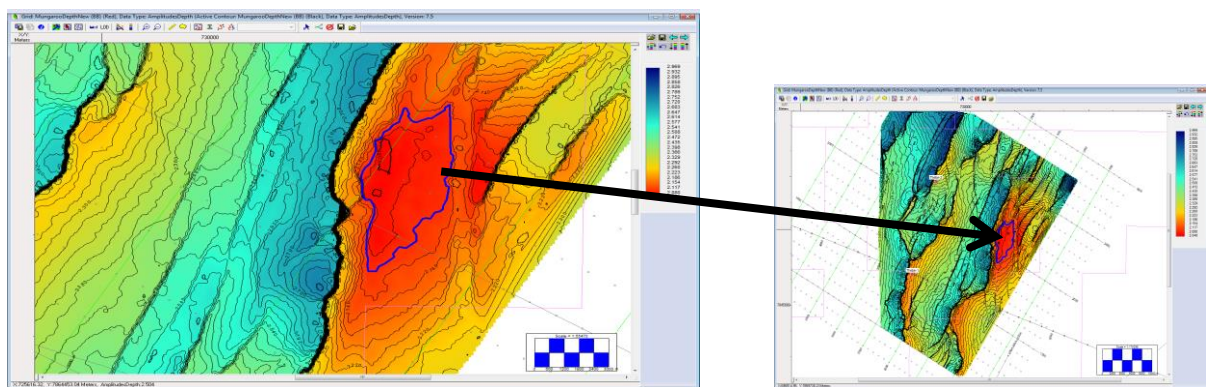
Figure 5.8: P50 location and closing contour 2100.

P10: The P10 is defined as the amount of reserves where there is a 10% chance the reserves present will be greater (*Hefner et al.., 1996).* The P10 is represented by the closing contour 2120 on the depth map (refer to figure 5.8 below)
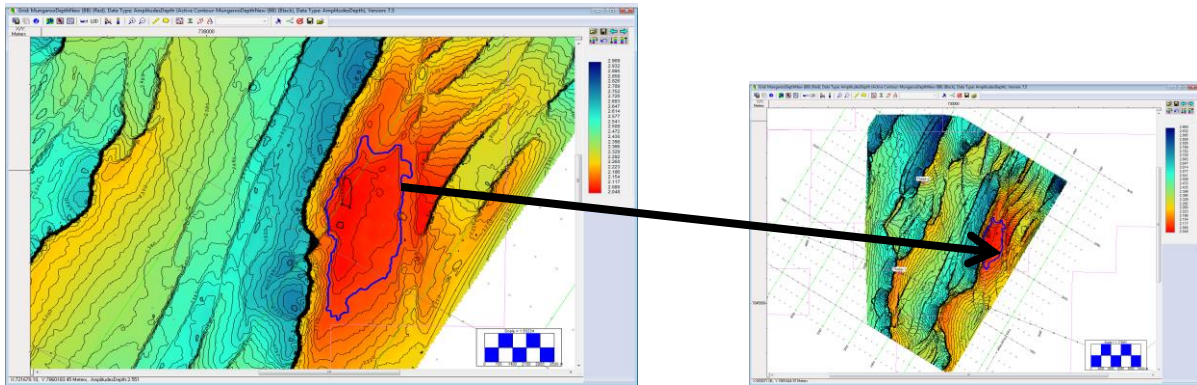
Figure 5.9: P10 location and closing contour 2120.

The table below shows the parameters used for the volume calculations.

Common Assumption			
	P90	**P50**	**P10**
Porosity %	15	25	35
Water Saturation %	27.8	27.8	27.8
Net/Gross %	30	40	60

Table 2. Parameters used in the calculation of volumes.

The table below shows the volumes for the gas-in-place calculated from the above parameters.

Gas in place (GIP)	
P90	893 Bcf (0.9Tcf)
P50	1128 bcf (1.1 Tcf)
P10	1367 Bcf (1.4Tcf)

Table 3. Gas-in-place volumes calculated from the parameters in Table 2.

5.4. Geological Success.

The geological probability of success of the prospect has been calculated to be 20%. Below is a table showing the various elements contributing to the geological success.

Elements	Pros	Cons	COS
Reservoir	• Extensively mapped • Proven reservoir in control wells • Relatively clean Sandstone • Good reservoir qualities	• Small quantities of shale present	80%
Trap	• Structural traps • Extensive 3D • Structure holds in both time and depth domain	• Faults may cut through to surface	70%
Seal	• Extensive 3D seismic • Proven regional seal • Thick shale package	• Internal seals unidentified	70%
Source	• Lower Triassic Mungaroo source rocks • Proven source in producing wells	• Not as thick as Locker Shale • Locker Shale acts as a better source rock.	65%
Migration	• Large scale faults provide migration pathways. • Extensive 3D seismic	• Faults may cut through to surface	80%

Table 4. Table showing the elements contributing to the geological success of Prospect X.

The geological risk was calculated as follows using the percentages of the above elements:

Probability of Success= 0.8 x 0.7 x 0.7 x 0.65 x 0.8

$$= 0.20384 \text{ x } 100$$

$$= 20\%.$$

5.5. Summary of Prospect X

Below is a table summarizing the various aspects of Prospect X.

| Prospect X	
Reservoir	The sandstones of the Triassic Mungaroo Formation.
Trap	Structural traps created by large fault blocks.
Seal	The Muderong Shale provides the sealing qualities, which is also the regional seal.
Source	The Lower Triassic Mungaroo Formation is the possible source to the petroleum system.
Migration	Primary migration along faults from the source to the reservoir.
Volumes (GIP)	P90 893 Bcf (0.9Tcf)
	P50 1128 bcf (1.1 Tcf)
	P10 1367 Bcf (1.4Tcf)
Geological Success	20%

Table 5. Table showing a summary of Prospect X.

From table 5 it can be seen that Prospect X has all the necessary elements required for a petroleum system to exist.

Chapter 6: Conclusion and Recommendation

6.1. Conclusion

6.2. Recommendation
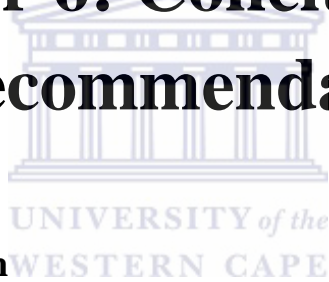
6.1. Conclusion.

The Thebe gas field is under explored and from the available seismic data the best possible location for gas was identified.

The use of seismic interpretation in the search for hydrocarbons is one of the most important processes in any exploration project.

Seismic interpretation was used in order to identify horizons and faults and in the interpretation thereof. From the interpreted seismic lines time structure maps, depth structure maps and an average velocity maps were constructed and used in conjunction with the seismic lines in order to identify possible locations for the presence of hydrocarbons.

Prospect X was identified on the basis of the presence of amplitudes on the seismic sections, which is an indication of possible hydrocarbons. The structure which is present in both time and depth domain and this is usually a good indication that the structure does indeed exist. The low average velocities observed at Prospect X is an indication of the presence of hydrocarbons, the low average velocities is a good hydrocarbon indicator.

The Mungaroo Formation has been identified in many petroleum systems on the Exmouth Plateau as being the primary reservoir with excellent reservoir qualities and it is thus the primary reservoir at Prospect X. The big fault blocks present provide excellent opportunities for structural traps and at prospect X this is the main trapping style, with the faults providing migration pathways from the source to the reservoir. From the volumes of estimated gas-in-place it shows that there is enough gas in place for it to be considered for future exploration.

In conclusion it can be said that Prospect X shows good reservoir qualities and has all the characteristics that make it a good exploration opportunity, the aims and objectives listed in chapter 1 were achieved.

6.2. Recommendation

The gas dominated Exmouth Plateau provides numerous opportunities for the exploration of gas.

Based on the interpretation of the available data drilling should take place at Prospect X but to ensure the best results a technical recommendation would be to calculate the recoverable volumes and petrophysical analysis should be done at the prospect. The petrophysical analysis for future prospects in the field should include among others, production test (RFT), wireline logging (NMR), etc. AVO analysis should be carried out in order to identify whether the amplitudes present are an indication of gas or if it is an indication of lithology.

An economical evaluation should be carried out in order to determine if Prospect X would be economically viable to explore.

References:

1. Baber, P.M., 1988, The Exmouth Plateau Deep Water Frontier: A Case Study, in Purcell, P.G and R.R., (Eds), The North West Shelf, Australia: Proceedings of Petroleum Exploration Society Australia Symposium, Perth, 1988. 173 – 187.

2. Bailey, C., 2009, Comparative Study of the Chemostratigraphic and Petrophysical characteristics of wells A-A1, A-L1, A-Ui and A-I1 in the Orange Basin, South Atlantic Margin, Offshore South Africa. Master's Thesis. University of the Western Cape.

3. Baillie, P.W., Powell, C.McA., Li, Z.X., Ryall, A.M., 1994, The Tectonic Framework of Western Ausrtalia's Neoproterozoic to Recent Sedimentary Basins, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Sympossium, Perth, 1994. 45 – 62.

4. Barber, P.M., 1982, Palaeotectonic evolution and hydrocarbon genesis of the central Exmouth Plateau, APEA Journal, 22(1), 131-144.

5. Barber, P., 2004, Sequence Stratigraphy and Petroleum Potential of Upper Jurassic – Lower Cretaceous Depositional Systems in the Dampier Sub-basin, North West Shelf, Australia, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Sympossium, Perth, 1994. 525 – 542.

6. Condon, M.A., 1954, Geological Significance of Discovery of Oil at Rough Range. Western Australia. Bulletin of the American Association of Petroleum Geologist, 38 (10), 2110-2118.

7. Edwards, D., Boreham, C., Hope, J., Hong, Z., LePoidevin, S., Buckler, T., 2005, Sourcing WA's offshore natural gases. AusGeo news, 82, 1-3.

8. Exon, N.F., Von Rad, U., Von Stackelberg, U. 1982, The geological development of the passive margins of the Exmouth Plateau off northwest Australia. Marine Geology (47) 1-2. 131-152.

9. Exon, N.F., von Rad, U., 1994, The Mesozoic and Cainozoic Sequences of the Northwest Australian Margin, as revealed by ODP Core Drilling and Related Studies, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth, 1994. 181 – 199.

10. Explorer's Guide, Petroleum and Geothermal Energy, Western Australia, 2009, Government of Western Australia, Department of Mines and Petroleum, 27-33.

11. Eyles, C.H., Mory, A.J., Eyles, N., 2003, Carboniferous-Permian facies and tectono-stratigraphic successions of the glacially influenced and rifted Carnarvon Basin, Western Australia, Sedimentary Geology 155(1-2), 63-68.

12. Fugro, 2006, Report for the Thebe Gas Field and Proposed Pipeline Routes Multibeam Surveys, Survey Operations and Results. Volume 1- Text, Appendices and Drawings, 1-2.

13. Geoscience Australia, 2010, Regional Geology of the Northern Carnarvon Basin. Offshore Petroleum Exploration and Acreage Release. Australian Government, Department of Resources, Energy and Tourism. 3-8.

14. Geoscience Australia, 2012, Petroleum Geological Summary, Release Areas W 12-10, W 12-11, W 12-12, W 12-13, W12-14 Exmouth Plateau, Northern Carnarvon Basin, Western Australia. Australian Government, Department of Resources, Energy and Tourism. 4-13.

15. Geoscience Australia, 2012, Regional Geology of the Northern Carnarvon Basin. Offshore Petroleum Exploration and Acreage Release. Australian Government, Department of Resources, Energy and Tourism. 2-21.

16. Gluyass, J.G., Swarbrick, R., 2004, Petroleum Geoscience. Blackwell Science Ltd.

17. He, S., Middleton, M., Kaiko, A., Jiang, C., Li, M., 2002, Two case studies of thermal maturity and thermal modelling within the overpressured Jurassic rocks of the Barrow Sub-basin, North West Shelf of Australia. Marine and Petroleum Geology 19, 143-159.

18. Hocking, R.M., 1988, Regional Geology of the Northern Carnarvon Basin, in Purcell, P.G and R.R., (Eds), The North West Shelf, Australia: Proceedings of Petroleum Exploration Society Australia Symposium, Perth, 1988. 97 - 114.

19. Hocking, R.M., 1990, Carnarvon Basin, in: Geology and Mineral Resources of Western Australia, Western Australia Geological Survey, Memoir 3, 457-495.

20. Hocking, R.M., Mory, A.J., Williams, I.R., 1994, An Atlas of Neoproterozoic and Phanerozoic Basins of Western Australia, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth, 1994. 21 – 43.

21. Jablonski, D., 1997, Recent Advances in the sequence stratigraphy of the Triassic to Lower Cretaceous successions in the Northern Carnarvon Basin, Australia. The APPEA Journal, 37 (1), 429-454.

22. James, H., Tellez, M., Schaetzlein, G., Stark, T., 1994. Geophysical Interpretation: From Bits and Bytes to the Big Picture. 24-25.

23. Jenkins, C.C., Maughan, D.M., Acton, J.H., Duckett, A., Korn, B.E., Teakle, R.P., 2003, The Jansz gas field, Carnarvon Basin, Australia. The APPEA Journal, 43 (1), 303-324.

24. Jong, J.T-S., 1996, Sedimentary History, Diagenesis and Organic Facies of the Triassic Mungaroo Formation, Barrow Sub-basin, Western Australia. Master's Thesis. University of Adelaide.

25. King, R.C., Neubauer, M., Hillis, R.R., Reynolds, S.D., 2010, Variation of vertical stress in the Carnarvon Basin, NW Shelf, Australia. Tectonophysics 428 (2010), 73-81.

26. Kopsen, E., 1994, Northern Carnarvon Basin Hydrocarbon Distribution and Future Petroleum Potential, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth, 1994. 127 – 139.

27. Kopsen, E., McGann, G.J., 1985, A review of the Hydrocarbon habitat of the eastern and central Barrow-Dampier Sub-basin, Western Australia: APEA Journal, 25(1), 154-176.

28. Longley, I.M., Buessenschuett, C., Clydsdale, L., Cubitt, C.J., Davis, C.J., Johnson, R.C., Marshall, M.K., Murray, M.N., Somerville, A.P., Spry, R., T.B and Thompson, N.B. Woodside Energy Ltd. 2002, The North West Shelf of Australia – A Woodside Perspective, (Electronic Version) Petroleum Exploration Society of Australia Symposium, Perth.

29. Magoon, L.B., Beaumont, E.A., 2003, Petroleum Systems. Search and Discovery Article #40068.

30. McQuillin, R., Bacon, M., Barclay, W., 1984, An Introduction to Seismic Interpretation.

31. Purcell, P.G., Purcell, R.R., 1988, The North West Shelf, Australia – An Introduction, in Purcell, P.G and R.R., (Eds), The North West Shelf, Australia: Proceedings of Petroleum Exploration Society Australia Symposium, Perth, 1988. 3 - 15.

32. Rek, A., Kleffmann, S., Khan, S., 2003. Petroleum Prospectivity of the Northern Exmouth Plateau, Technical Focus.

33. Robinson, D.A., 2009, The History of Wireline Logging in a Nutshell.

34. Ross, M.I., Vail, P.R., 1994, Sequence Stratigraphy of the Lower Neocomian Barrow-Delta, Exmouth Plateau, Exmouth Plateau, Northwestern Australia, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Sympossium, Perth, 1994. 435 – 447.

35. Scott, J., 1994, Source Rocks of West Australian Basins – Distribution, Character and Models, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia: Proceedings of Petroleum Exploration Society of Australia Sympossium, Perth, 1994. 141 – 155.

36. Sheriff, R.E., ed, 1992, Reservoir Geophysics. Society of Exploration Geophysics.

37. Sinhabaedya, P., 2011, Seismic Stratigraphy and Geomorphology of the Exmouth Plateau, North-Western Shelf, Australia, Maters Thesis, 5-18.

38. Tearpock, D.J., Bishcke, R.E, 1991, Applied Subsurface Geological Mapping. Prentice Hall.

39. Tindale, K., Newell, N., Keall, J., Smith, N., 1998, Structural Evolution and charge history of the Exmouth Sub-basin, Northern Carnarvon Basin, Western Australia, in: Purcell, P.G. and R.R. (Eds), The Sedimentary Basins of Western Australia 2: Proceedings of Petroleum Exploration Society of Australia Symposium, Perth, 1998. 447-442.

40. WesternGeco Australia Australia Pty.Ltd. 2007, Processing Report, Hex07b Thebe 3D MSS. North West Shelf Australia.

Appendix A: Data Used for Depth Conversion

		Vinck	Kentish Knock	Eendracht	Thebe 1	Thebe 2	Jupiter 1
Depth	Sea Floor	1372.6	1228.0	1343.6	1170.0	1303	950
	Gearle_1	1818.6	1967.7	2114.6	1889	1948	1522
	Muderong_2	1923.6	2054.7	2173.6	1928	1960	1610
	Tr Mung_4	2716.6	2229.7	2408.6	2185	2169	1836
TWT	Sea Floor	1.830	1.637	1.791	1.556	1.71	1.280
	Gearle_1	2.317	2.391	2.541	2.227	2.313	1.842
	Muderong_2	2.422	2.469	2.588	2.258	2.369	1.945
	Tr Mung_4	3.126	2.628	2.796	2.499	2.638	2.198
Ave. Velocity	Sea Floor	1500	1500	1500	1503.383	1523.977	1484.375
	Gearle_1	1569.692	1645.747	1664.161	1696.453	1684.393	1652.552
	Muderong_2	1588.331	1664.568	1679.609	1707.706	1654.707	1655.527
	Tr Mung_4	1737.885	1696.674	1722.837	1748.699	1644.428	1670.61
V-INTERVAL	Sea Floor- Gearle	1831.590	1962.275	2056.345	2144.636	2139.303	2035.587
	Gearle-Muderong	1999.562	2245.335	2517.011	2516.129	428.571	1708.738
	Muderong-Mungaroo	2252.319	2193.381	2261.094	2132.780	1553.903	1786.561

y = 8E-06x² - 0.0223x + 16.916
R² = 0.9993
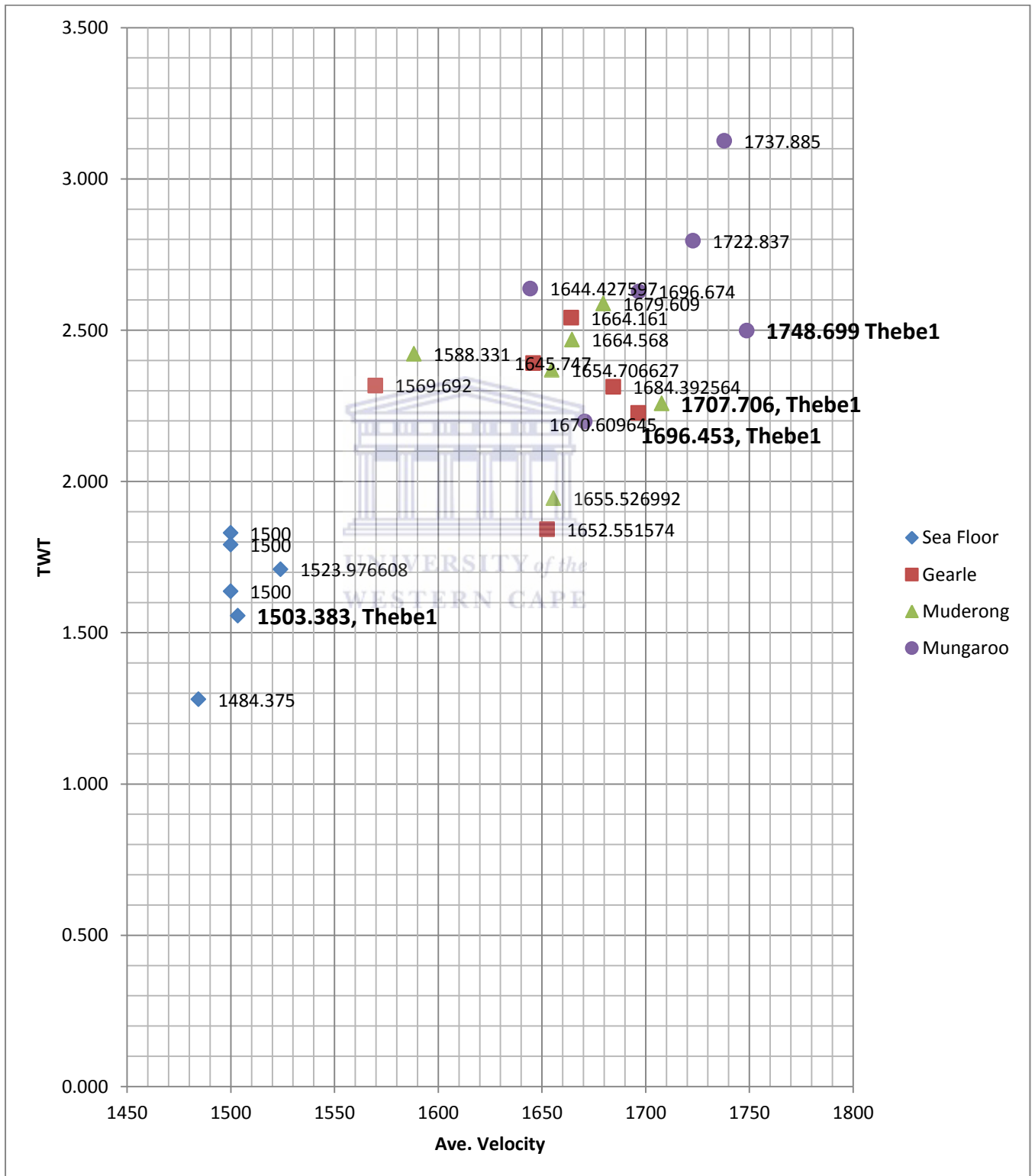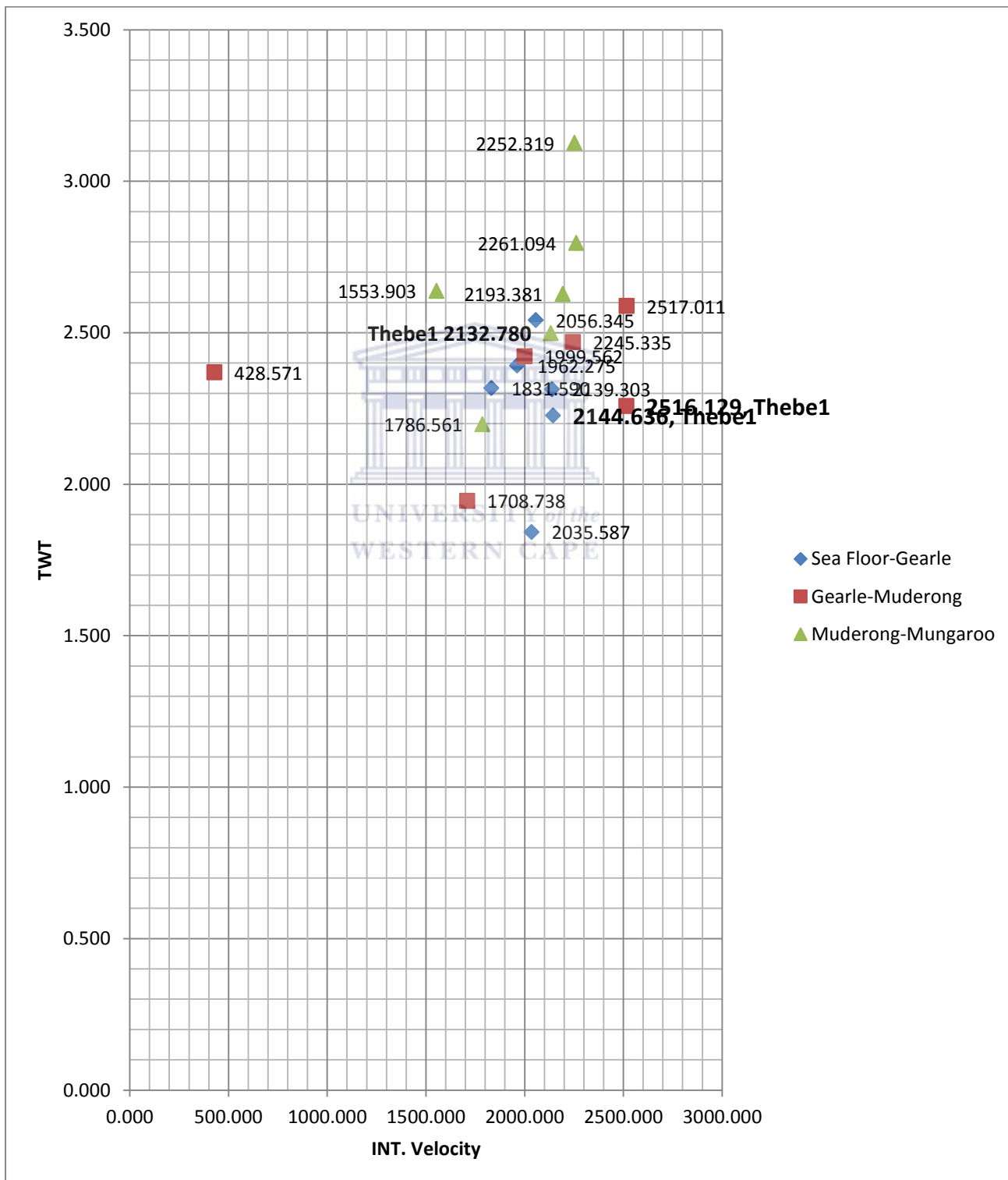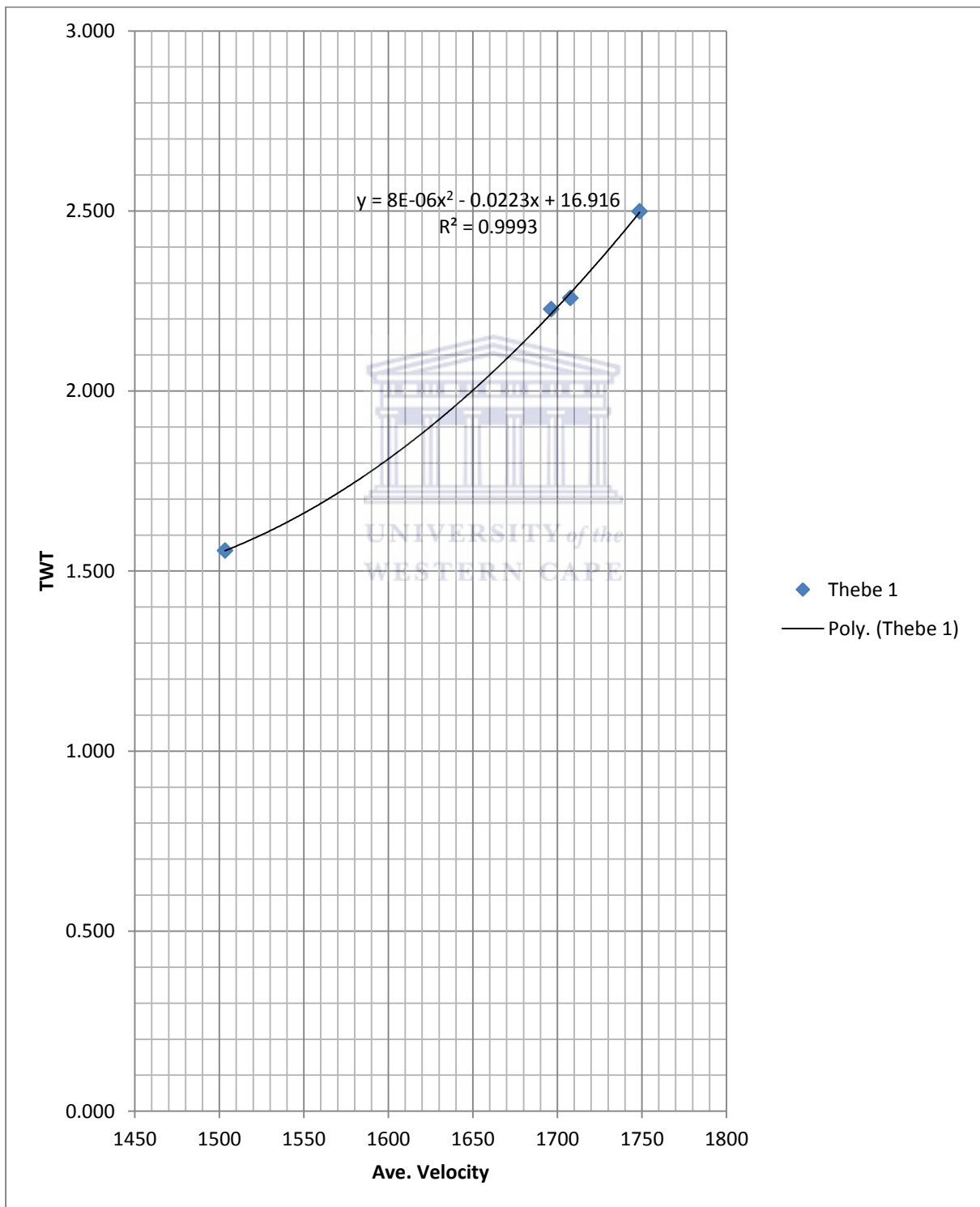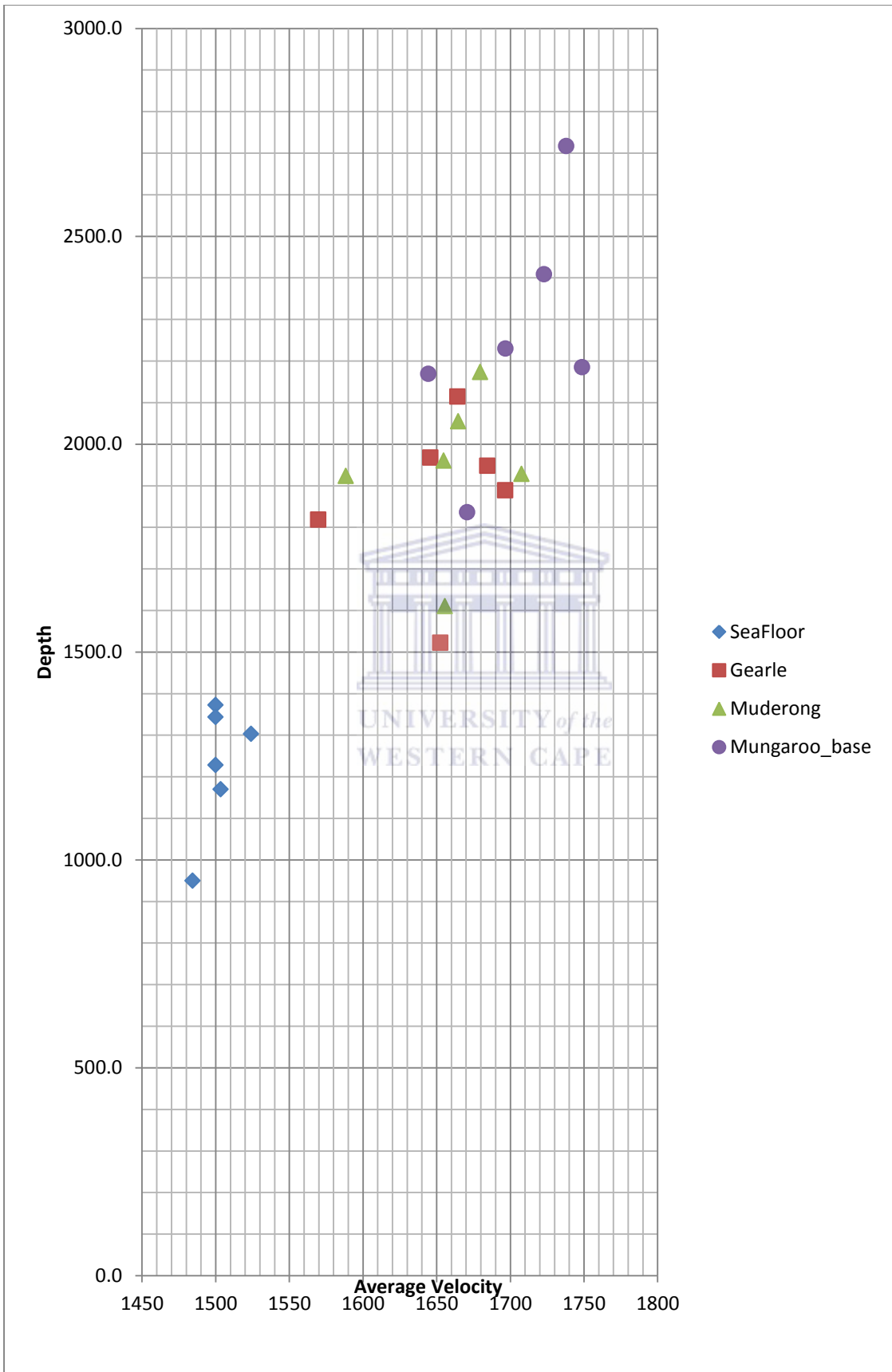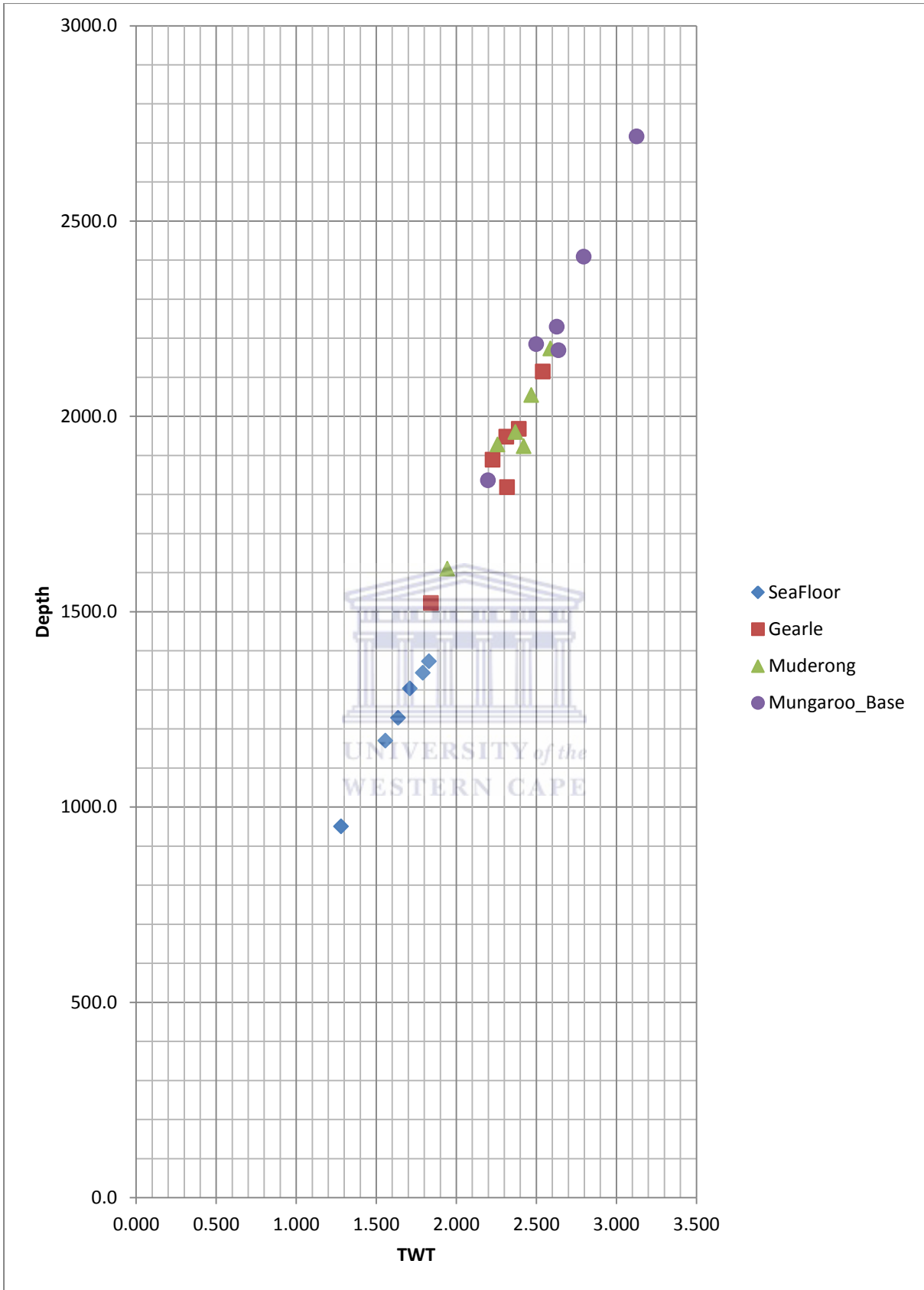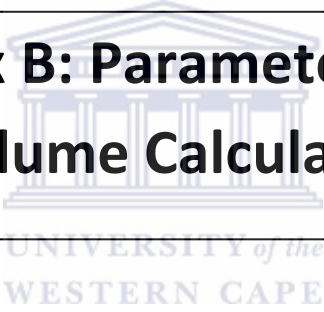
Appendix B: Parameters Used for Volume Calculations

	Depth (m)	Area (m²)	Area (km²)	Spill Point (m)	2115
P90	2080	7, 355, 161.025	7.355		
P50	2100	18, 934, 573.109	18.935	Hydrocarbon Contact (m)	2115
P10	2120	26, 837, 875.505	26.838		
	Gross (m)			Reservoir Depth (m)	2040
Min	55				
Mean	107			Water Saturation (%)	27.8
Max	150				
	Nett (m)				
Min	35				
Mean	42				
Max	50				
	Net/Gross Ratio				
Min	0.6				
Mean	0.4				
Max	0.3				
	Porosity (%)				
Min	15				
Mean	25				
Max	35				