Reservoir Characterization using Genetic Inversion and Seismic attributes of Block 1 Orange Basin, Offshore South Africa

A mini thesis in Petroleum Geoscience

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Submitted in partial fulfillment of the requirements for the degree of Magister Scientiae (MSc) in the Faculty of Science, Earth Sciences Department University of the Western Cape, Bellville, South Africa.

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Abstract

Block 1, Orange Basin is located offshore west coast South Africa. This study is focused on providing a solution to performing reservoir characterization in areas where well data is scanty by generating reservoir models using genetic inversion. The study area is represented by the extent of a 1500km^2 3D seismic survey which is intersected by one well.

Petrophysical analysis of Well A-F delineated a reservoir interval of Lower Cretaceous age between 2140- 2509m and which comprised of two individual reservoir zones reservoir A and B respectively. Seismic attribute analysis provided strong evidence that the reservoir interval was deposited in a transitional depositional environment with channels and channel complexes being delineated. Reservoir models showed a distinct variation between Reservoir zone A and Reservoir zone B in terms of distribution of favourable reservoir properties (Porosity > 22% & Vsh <50%) as Reservoir zone A was interpreted as a upper fan depositional setting displaying favourable reservoir properties (Porosity > 22% and Vsh < 50%) in the more proximal portion of the reservoir related to channel complexes comprising of relatively thin but numerous channels which are not extensive throughout the reservoir zone and Reservoir zone B interpreted as a middle to lower fan depositional setting showing favourable reservoir properties (Porosity > 22% and Vsh < 50%) in the proximal and distal portion of the reservoir confined mostly to the sinuosity of a single large and extensive channel which splays out into a lobe structure with favourable reservoir properties into the distal portion of the reservoir zone.

Declaration

I declare that **"Reservoir characterization using genetic inversion and seismic attributes of Block 1 Orange Basin, Offshore South Africa"** 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.

Reagan Africa **October 2016**

Signature

Dedication

This project is dedicated to my mother Sunette Africa, my father Lesley Africa, my brother Ryan Africa and my grandmother Cate Petersen as without their constant motivation and support, completing this project would not have been possible.

Acknowledgement

I would like to show appreciation to my supervisor Dr M Opuwari, as without his guidance and commitment this project would not have been completed. Thanks also to Professor T Chatterjee for his input and knowledge he has given to me.

I would like to thank the Petroleum Agency of South Africa (PASA) for providing me with the necessary data I required to carry out and complete my project. I would also like to thank the staff of Schlumberger for their excellent petrotechnical support.

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Thank you to all my family and friends who has supplied me with endless motivation, prayers, encouragement and belief during this period.

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Chapter 1: Introduction

The problem of predicting reservoir properties away from and between well bores is one of the main challenges faced by Petroleum Geoscientists in reservoir characterization, this problem is intensified in exploration areas where relatively few wells have been drilled and well data is very limited. A relatively new exploration technique called Genetic inversion provides a solution to predicting reservoir properties away from the well bore in areas where well data is limited.

The Orange Basin is located on the West coast of Southern Africa and exhibits proven petroleum plays within the basin. The area of interest regarding this study is represented by the extent of the 3D seismic survey present in Block 1 of the Northern Orange Basin, the seismic survey covers an area of approximately 1500km^2 (Figure 1.1).

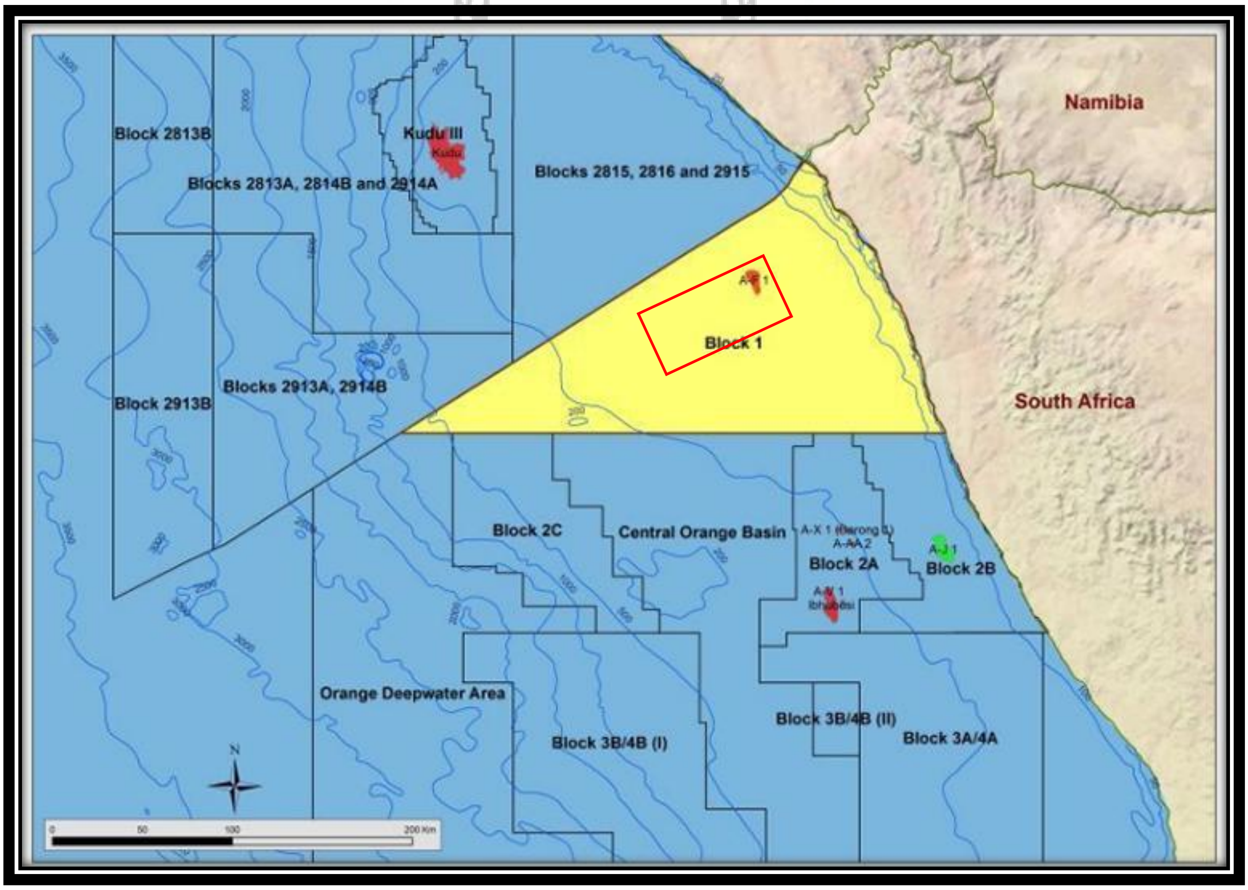


Figure 1.1: Map of Block 1, Orange Basin modified from www.1Derrick.com (1Derrick, 2012)

One well has been drilled within block 1, Well A-F1. The limited Well data within the seismic survey of Block 1 creates a problem in determining and predicting hydrocarbon reservoir distribution and the quality of reservoir properties throughout the extent of the seismic survey away from the well.

The problem of performing reservoir characterization in Block 1 related to limited well data can be addressed with the use of Genetic Inversion and seismic attributes. The aim of this study is to delineate potential hydrocarbon reservoirs within the seismic survey in Block 1 of the Orange Basin and determining the reservoir properties through petrophysical analysis. Once reservoir properties have been calculated Genetic inversion and seismic attributes will be used to determine the quality of the reservoir away from the well bore based on the selected reservoir properties as well as determining the depositional environment of these reservoirs. The end goal is to determine which areas of the reservoir are best in terms of future exploration, as well as determining the depositional environments of potential reservoirs to create an understanding of reservoir distribution throughout Block 1 outside the extent of the 3D seismic survey.

Well A-F1 will form the core of the petrophysical analysis as it is the only well drilled within the post stack seismic survey and will be used to delineate potential hydrocarbon reservoirs and to calculate desired reservoir properties. For the purpose of this study the petrophysical properties used for determining quality of the potential reservoirs will be Porosity and Volume of shale. The post stack 3D Seismic survey situated in Block 1 will form the core of the geophysical analysis.

Block 1(Figure 1.2): The specific study area is located within Block 1 of the Orange Basin, where 3 Wells have been drilled one of which resulted in a gas discovery. The seismic survey which was conducted in 2009 covers an area of 1500km^2 and is only intersected by Well A-F1.

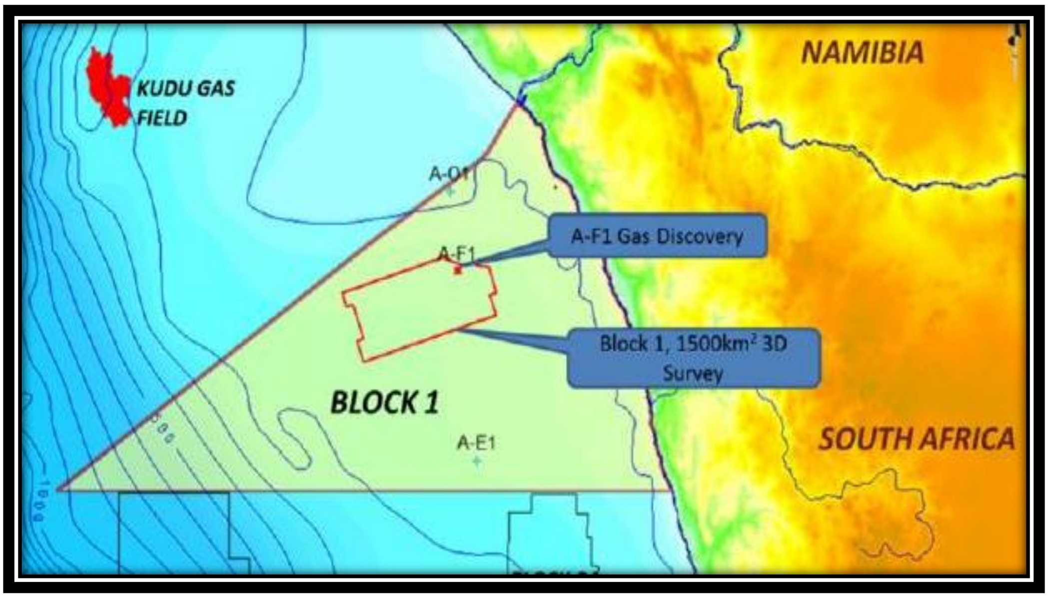


Figure 1. 2: Map Block 1 and extent of seismic survey modified from Offshore Engineer (Offshore Engineer, 2014)

3D seismic data adds valuable information to the hydrocarbon evaluation chain (Ampilov 2009). A 3D seismic trend provides a more trustworthy reservoir property forecast for modelling purposes (Veeken and DaSilva 2004).

A 3D structural model of the reservoir is created and then 3D petrophysical models for the respective attributes will be created using Geometrical modelling taking into account various inverted 3D reservoir attributes. Geometrical modelling uses the seismic sampling method to populate the 3D model with seismic values derived from genetic inversion. The problem of finding clear relation between seismic data and elastic/petrophysical properties of overburdened rocks is solved by Genetic inversion (M.Nooraiepoor 2014)

Genetic Inversion (GI) is a novel technique that determines a non-linear operator for transforming the seismic cube into reservoir properties, like for instance porosity or volume of shale. The process does not rely on conventional wavelet derivation. By using a non-linear operator it is possible to determine various reservoir properties. Genetic inversion is based on the artificial neural networks with the enhancement of genetic algorithm to determine a single non-linear operator that produces an inversion result. This operator produced by training a sub volume of seismic data against well logs to determine a logical relationship between seismic wave and reservoir properties.

Although the current approaches resulting from deterministic and stochastic models of seismic data provide quite reliable estimation of petrophysical properties they are reasonably ineffective with limited well data. Therefore Genetic inversion and seismic attributes will be used in Block 1 of the Orange Basin to carry out reservoir characterisation in terms Porosity, Volume of Shale as well as determining the depositional environment of these potential hydrocarbon reservoirs

1.1 Problem statement

The Orange basin overall is a reasonably under explored basin with very few wells being drilled in comparison to its size, this is especially true in the case of Block 1 of the Orange basin where a $1500km^2$ 3D seismic survey has been carried out and only one well intersects it. With only one well intersecting the seismic cube it creates a serious challenge regarding estimating reservoir properties throughout the area.

Therefore the technique of genetic inversion is used to build 3D petrophysical mode to perform reservoir characterization in the field to estimate the distribution of reservoir properties throughout the area and determine which parts of the reservoir are most desirable or optimum.

By performing a petrophysical evaluation on Well AF-1 which is intersecting the seismic survey and determining the desired reservoir attributes (Porosity, Vsh etc) it is possible to "train" the genetic inversion through neural networks in order to populate the seismic volume with the before mentioned reservoir attributes. From these properties petrophysical models of the reservoir interval will be built.

By populating the seismic volume with reservoir properties such as porosity and volume of shale it is possible to determine which areas of the field represent optimum areas for drilling in terms of reservoir quality.

Therefore the problem of performing reservoir characterization with limited well data is addressed by using genetic inversion and seismic attributes to build 3D petrophysical reservoir models to exhibit where reservoir quality is best within the reservoir interval.

1.2 Objectives

- Delineate potential hydrocarbon reservoirs.
- Carry out petrophysical evaluation of the reservoir zones determining reservoir attributes.
- Perform genetic inversion with desired reservoir attributes.
- Apply desired Seismic attributes to Seismic cube.
- Perform seismic interpretation.
- Construct 3D petrophysical models of reservoir interval exhibiting reservoir property distribution.
- Construct Common Risk Segment model exhibiting areas optimum reservoir property distribution.
- Relate reservoir property distribution to depositional environment, structural and stratigraphic setting.

1.3 Regional Geology

1.3.1 1.3.1 Study Area

The Orange Basin is located offshore of western South Africa and Namibia and forms part of the South Africa coastal basin (Figure 1.3). The South African coastal basin extends from the Northern Walvis ridge to the southerly situated Agulhas Falkland Fracture Zone. The Orange Basin represents the largest of South Africa's offshore basins both in terms of area and volume.

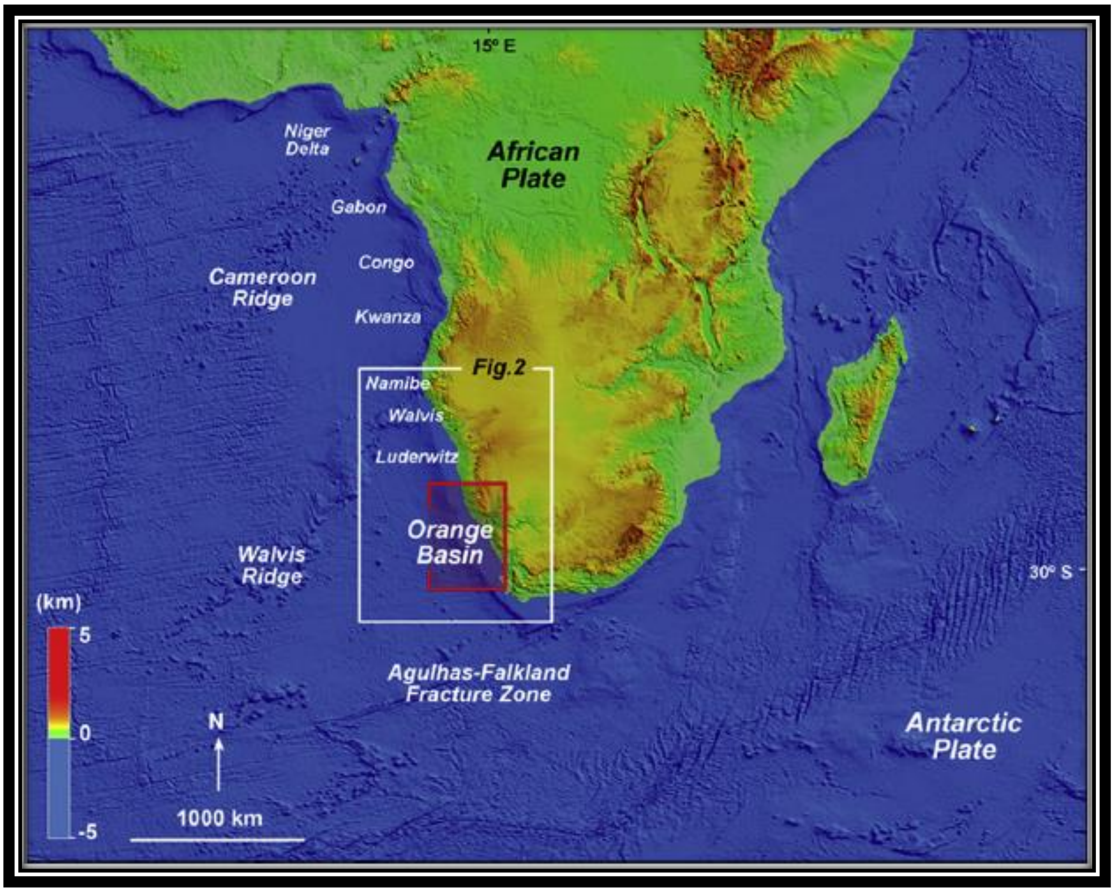


Figure 1.3: Location map of Orange Basin, South Africa (PASA, 2012)

3 recognisable depocentres comprise the region, namely the Walvis, Luderitz and Orange sub-basins (Figure 1.4). The Orange Basin covers an area of 160 000 km^2 and is the largest of the 3 depocentres and its extent is defined by the infill of post rift sediments in the area.

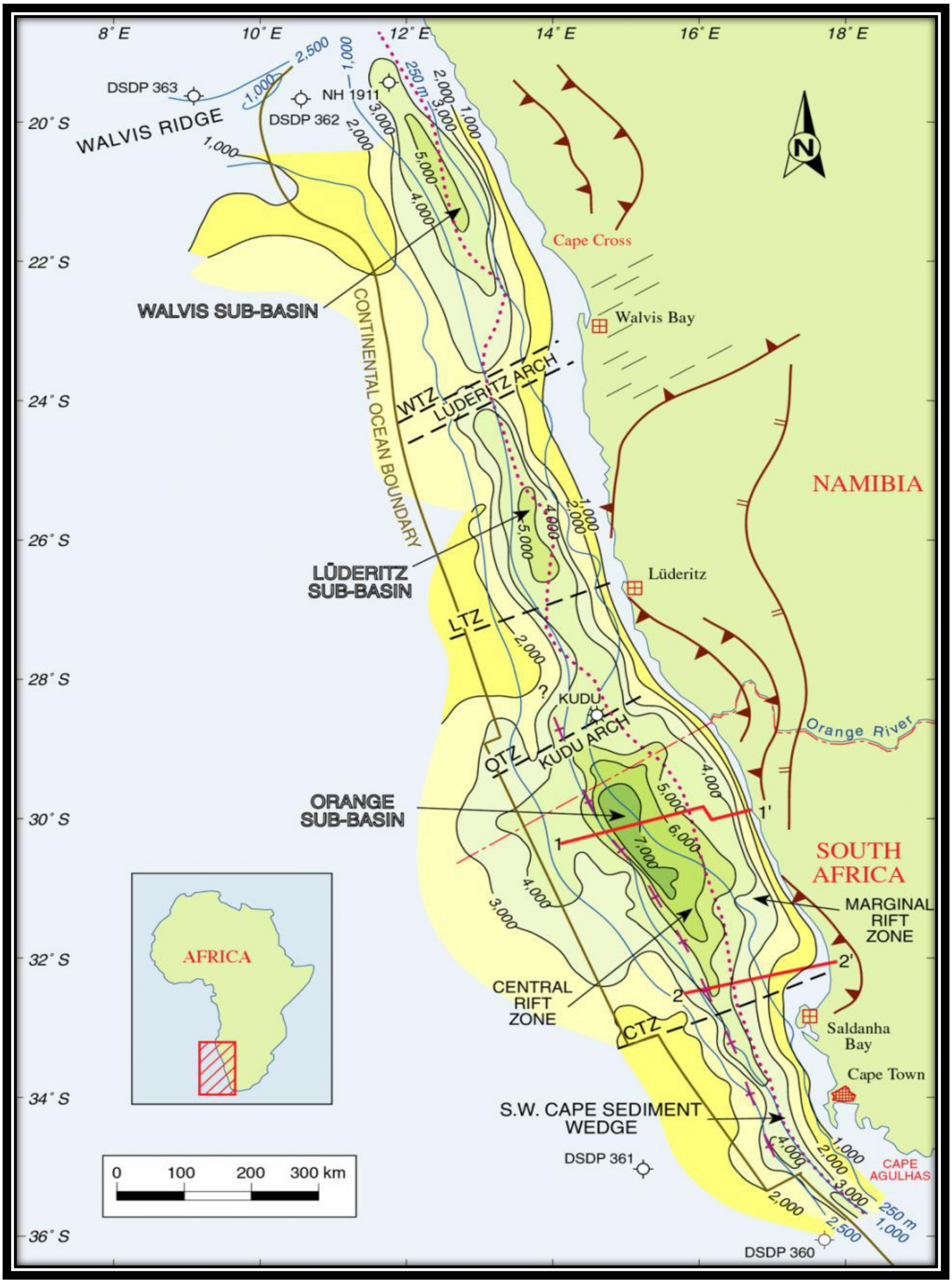


Figure 1. 4: Structural framework and main depocentres of the Orange Basin (Salomo, 2009)

1.3.2 Basin Geology

The Orange Basin formed as a result of the fragmentation of Western Gondwanaland and the opening of the South Atlantic Ocean. The geological succession displays a typical two-fold subdivision of an older synrift unit with a younger post rift unit overlaying it. The rifted plate margin that is underlain by pre rift and synrift grabens is covered by post-rift sediments. (Salomo,2012).

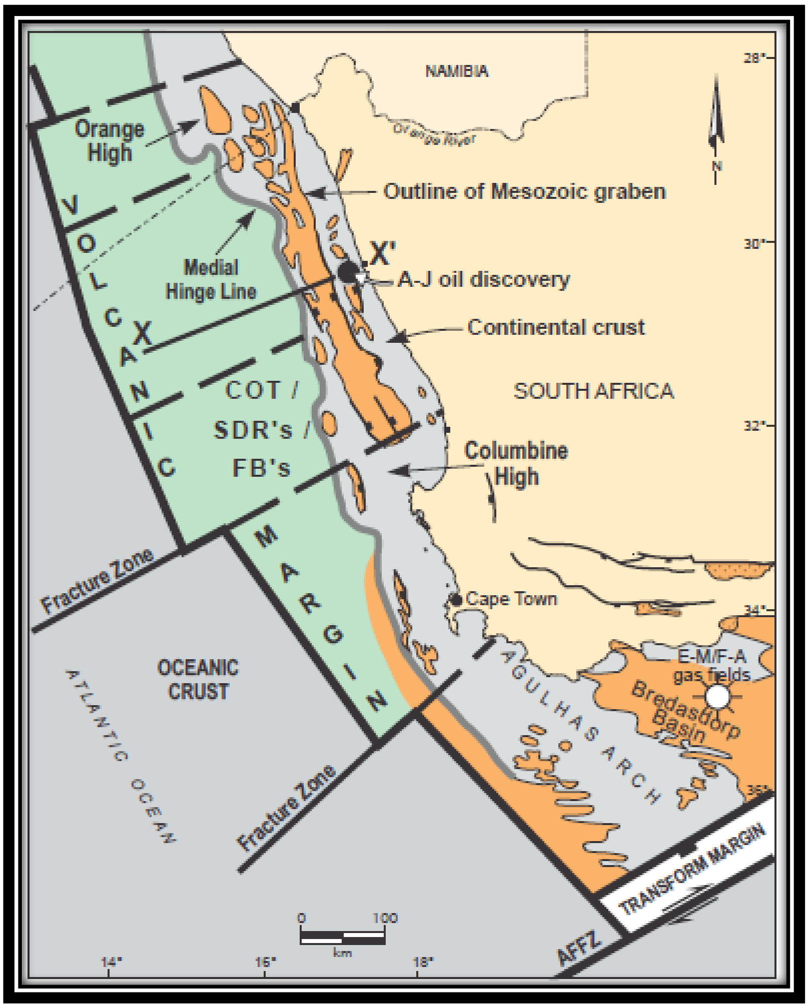


Figure 1. 5: Major tectonic elements and crustal segments of the rifted volcanic margin (Jungslager, 1999)

The tectno-stratigraphic sequences are represented by four major phases, namely the Synrift, Post rift (Transitional), Drift and Post- drift (Crataceous and tertiary).

Synrift: During the Middle to Late Jurassic, the extensional stress associated with the breakup, caused the formation of a series of coast-parallel N-S trending graben systems. These graben systems are separated laterally from an outbound synrift wedge by a flexural high which is known as the Medial Hinge. The graben-fill comprises Lower Cretaceous siliclastic sand volcanics, the former including fluvio-lacustrine sediments and coarse continental clastics.

Post rift/drift: A thick post-rift seaward and landward thinning sedimentary wedge overlies the rift basins. The volume of sediments was mainly supplied by the Orange and Olifants rivers. Flanking basement highs represent the depocenter in a strike sense.

Cretaceous: Rifting terminated resulting in the onset of drift at about 117.5 Ma with permanent marine influence. Five major super-sequences bounded by major sequence boundaries, a shallow and restricted margin during the initial phase represented by a transitional environment, a poorly developed ramp-like shelf/slope, a restricted marine, deltaic and coastal plain settings. Major marine flooding was established at 112Ma marking onset of passive margin drifting and subsidence, mainly deltaic to shelfal. Sediment input prolonged during the Mid-to late Cretaceous in the north explains the position of the main depocenter

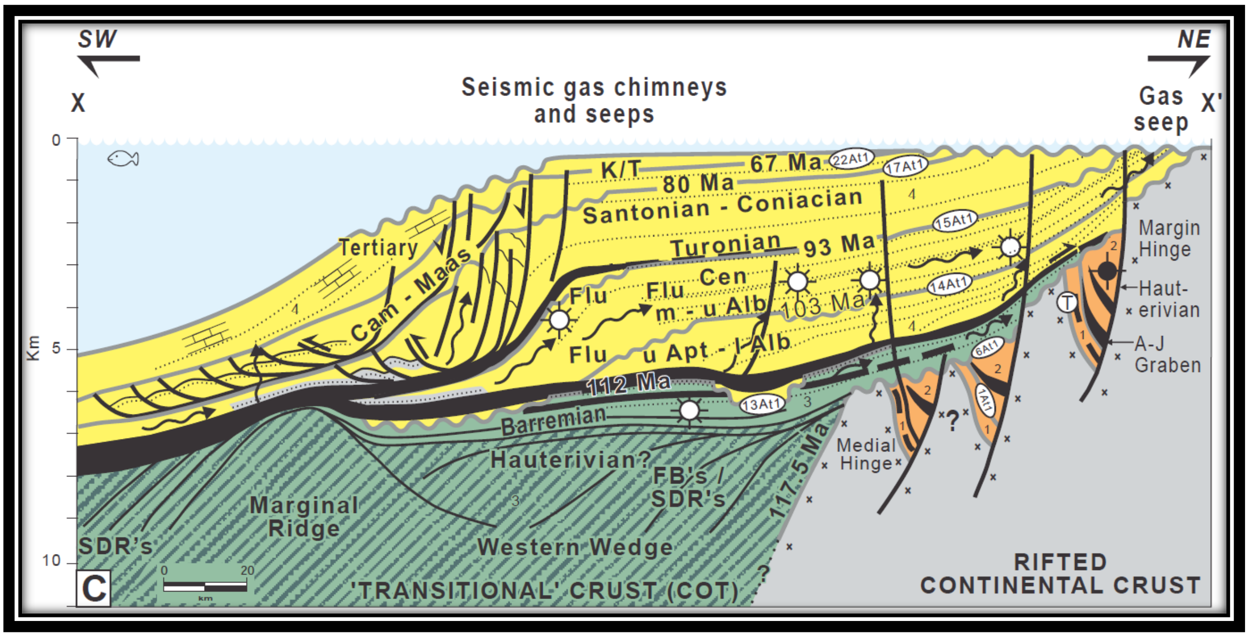


Figure 1. 6: Geologic cross section across Orange Basin (Jungslager, 1999)

Tertiary: Subsidence rates were slowed down by the onset of the Tertiary which caused a stable underlying Cretaceous platform. Sediment depocenters shift basinward resulting in slope setting sedimentation. The vertical slope stacking during aggradation causing spectacular gravity faulting (Salomo, 2012)

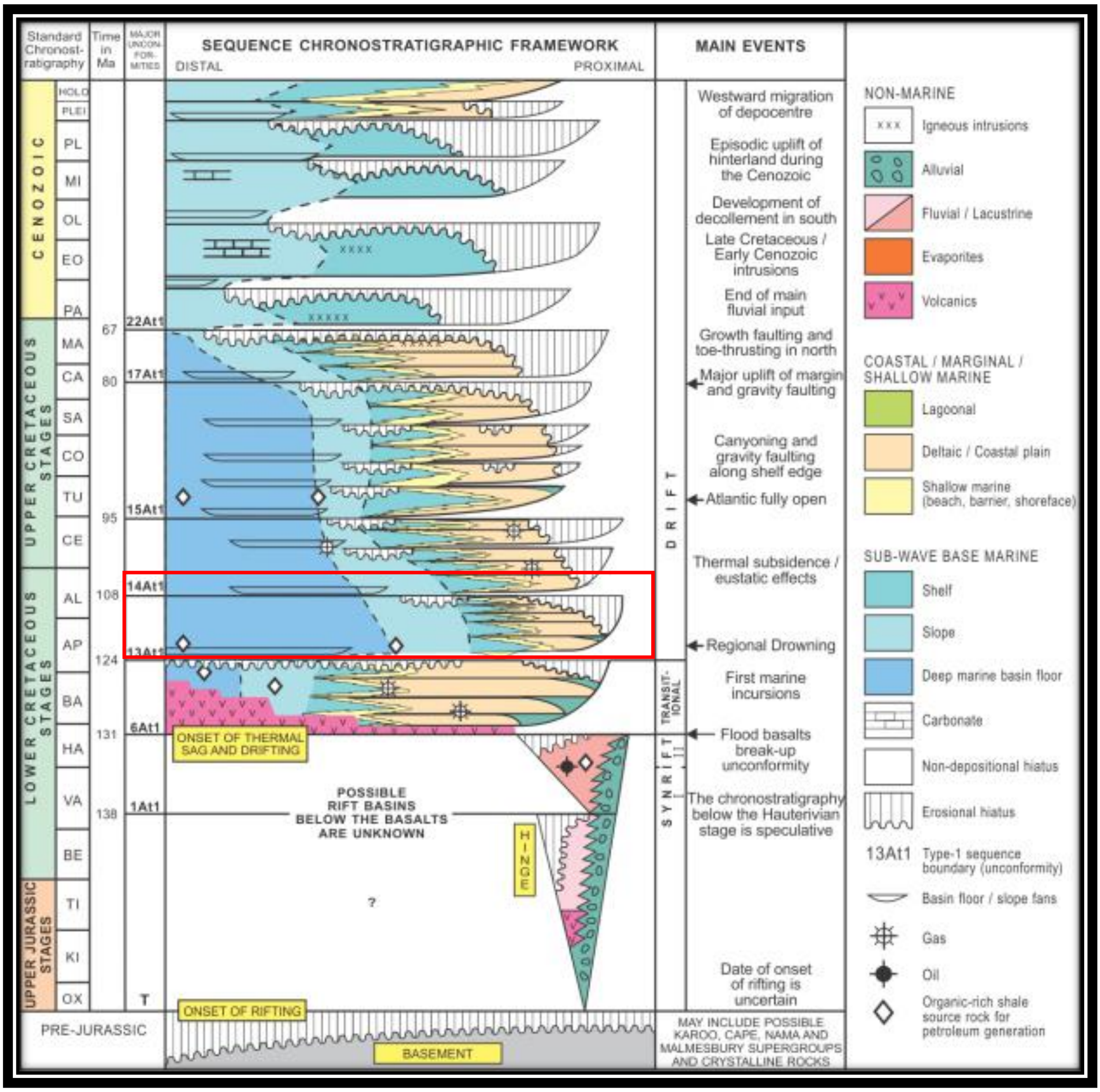


Figure 1. 7: Chronostratigraphic column Orange Basin (PASA, 2012)

1.3.3 Petroleum system elements

1.3.3.1 Source rocks

There are three source rock intervals within the Cretaceous synrift and drift sediments of the Orange Basin: A Hauterivian oil-prone lacustrine shale found in the synrift sediments of the isolated A-J Graben (Jungslager, 1999, Petroleum Agency SA, 2012). Jungslager (1999) suggests that similar organic-rich shale intervals may be present in other rift grabens along the continental margin.

Barremian to early Albian aged black shales, which represent the main source rock interval, deposited in anoxic marine environments of the nascent South Atlantic (Van der Spuy, 2003, Hartwig et al, 2012). Anoxia was most severe during the first marine incursion lasting from Barremian to early Aptian times. This transitional sequence contains oil and gas prone organic-rich marine shales. During the late Aptian and early Albian bottom water ventilation increased due to the widening of the South Atlantic. The early drift deposits contain intercalated wet-gas and gas-prone marine shales known from exploration wells and DSDP site 361 (Adekola et al, 2012, Akinlua et al, 2010, Hartwig et al, 2012, Van der Spuy, 2003).

A Cenomanian/Turonian-aged marine condensed section, which contains oil- and gas-prone organic-rich shales (Aldrich et al, 2003; Adekola et al., 2012). Similar time-equivalent source rocks deposited during the Oceanic Anoxic Event (OAE) are known to occur throughout the South Atlantic (Herbin et al, 1987, Bray et al, 1998, Burwood, 1999, Hartwig et al, 2012)

1.3.3.2 Reservoir and seal rocks

Continental sandstones of the synrift sequence provide potential reservoirs for structural and stratigraphic traps in the rift grabens. In the A-J1 well, oil shows were encountered in sandstones interbedded with Hauterivian-aged lacustrine source rocks (Jungslager, 1999). Aeolian sandstones of the transitional phase, such as the Barremian sandstones of the Kudu gas field, may occur regionally in the northern Orange Basin (van der Spuy, 2003, Petroleum Agency SA, 2012). In the Kudu field, they form a stratigraphic trap at the featheredge of the SDR sequence, consisting of medium-grained aeolian and fine- to medium- grained fluvial sandstones intercalated with basalts and volcaniclastics (Wickens and McLachlan, 1990).

The Albian and Cenomanian succession contains extensive (up to 1500m thick) fluvio-deltaic sandstones and incised-valley fill sandstones (McMillan, 2003), which account for the majority of gas shows in exploration wells located in the Cretaceous depocenter, although the sandstone reservoir quality is often reduced by silica and chlorite cementation (Fadipe et al., 2011). Potential traps are stratigraphic with low relief and sometimes fault-bounded. Up to date, the best reservoir properties and gas flow rates are found in Middle Albian to Cenomanian aged fluvial channel sandstones of the Ibhubesi gas/condensate field (Jungslager, 1999; Petroleum Agency SA, 2012). Constraining petroleum generation and migration in the Orange Basin, South Africa

Futher reservoir potential may exist in sand-rich deepwater turbidite channel/lobe deposts of the Upper Createaceous succession, either in the form of stratigraphic or structural traps in the extensional growth-fault and compressional toe-thrust dmain if the slope (Jungslager, 1999).

Regional sealing rocks are generally Lower and Upper Cretaceous transgressive shales and thick claystone sequence of middle Turonian to late Coniacian age.

Chapter 2: Literature review

2.1 Previous studies

2.1.1 Paper 1: "Predicting Effective Porosity by Genetic Inversion of Seismic Data in Zechstein Carbonates, North Sea" (M.Nooraipour et al 2014)

The goal of this paper was to determine a new approach for efficient reservoir characterisation by predicting dynamic petrophysical properties. Effective porosity was calculated for the reservoir interval through petrophysical analysis.

The variation between effective porosity and acoustic impedance was used as the bridge between seismic surveying and petrophysical properties.

A meaningful trend between these properties were observed and by applying genetic inversion the trend was extended to the volume of seismic data and the result of the procedure was confirmed by seismic attribute analysis.

The effective porosity cube truly showed anomaly in areas represented in dark colours (High effective porosity), which is supposed to be gas-bearing zone Seismic attenuation attribute also confirms possibility of gas accumulation in this area. (Figure 2.1)

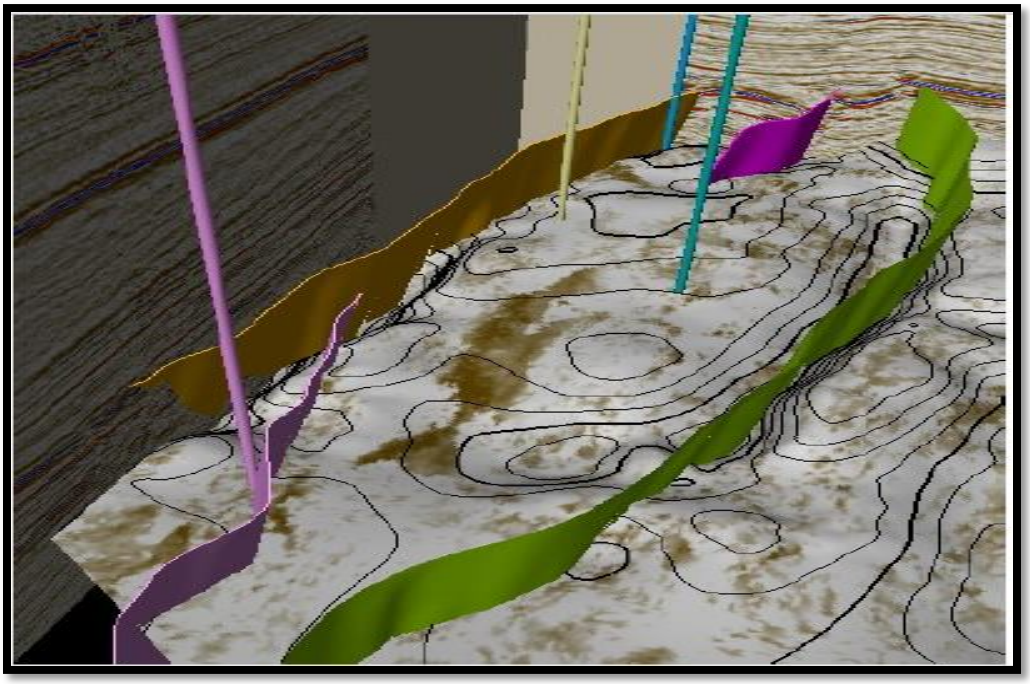


Figure 2.1: Effective porosity genetic inversion model (M.Nooraipour, 2012)

Based on the inverted effective porosity cube and results from seismic attribute analysis, a location for next well was determined. The calculated effective porosity cube has also provided insights into the distribution of effective porosity for reservoir modelling and future scenarios of production and injection.

2.1.2 Paper 2: "Genetic Inversion for Reservoir Modelling in the Shtokman Field, Offshore Northern Russia" (I.Priezhev & P.Veeken, 2009)

A semi-automated 3D genetic inversion has been used for reservoir property prediction in the Shtokman gas/condensate field. The basic input requirements for the workflow are a post-stack seismic cube and relevant logs at some control wells.

Reservoir parameters like density, hydrocarbon saturation and gamma-ray have also been genetically inverted. The results are compared with the conventional geological model, as accepted by the Russian State Committee for Reserves. The latter is based on interpreted seismic horizons and data obtained from conventional attribute analysis.

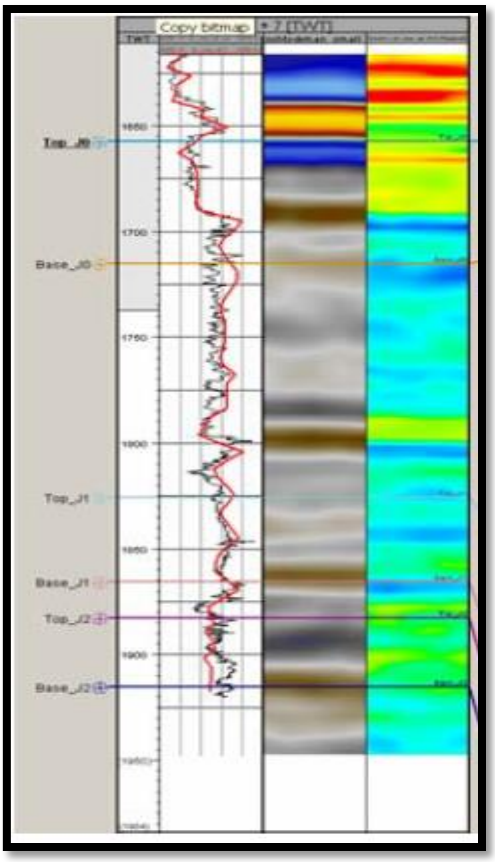


Figure 2.2: Training genetic inversion with well logs (I.Priezhev & P.Veeken, 2009)

Figure (2.2) shows how the genetic inversion is trained and how well it correlates with the seismic and acoustic impedance. A reasonably good match is evident here.

Figure (2.3) is a genetic inversion cube representing acoustic impedance and a clear anomalous bright spot is exhibited which is indicative of the presence of a gas accumulation.

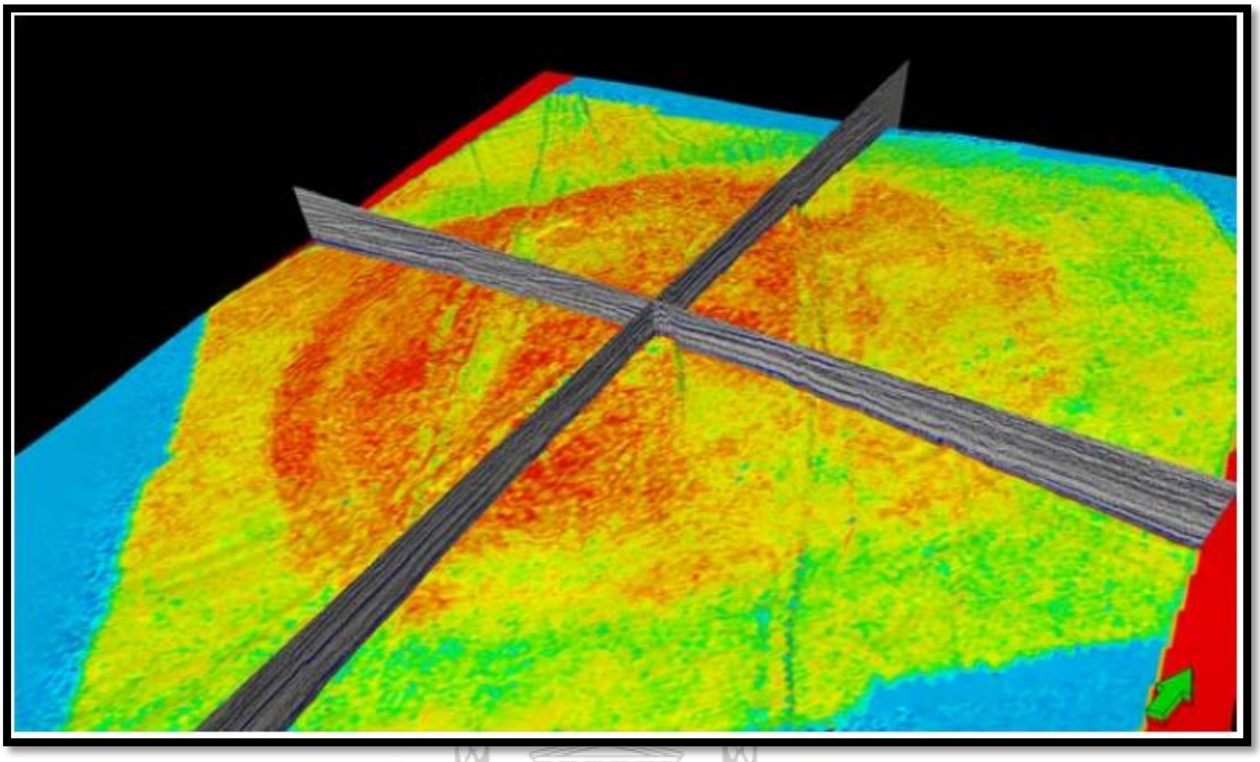


Figure 2.3: Genetic inversion model (I.Priezhev & P.Veeken, 2009)

Figure (2.4) exhibits pay zones with net to gross properties derived from genetic inversion. The genetic inversion earth model for the Shtokman field has a higher resolution and hence is considered of better quality than the existing field reservoir model; it can be used in the further field development planning efforts.

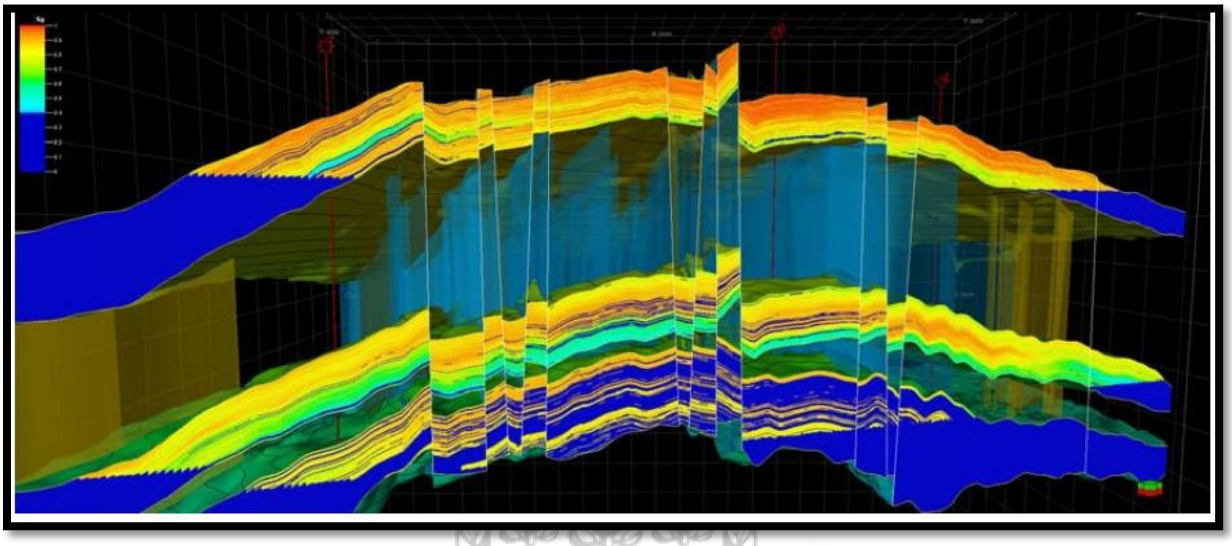


Figure 2.4: Pay zones with NTG property based of genetic inversion (I.Priezhev & P.Veeken, 2009)

Genetic inversion workflow proved a robust analysis tool for modelling an existing gas condensate field, adding valuable details to the reservoir model. The neural network method produces convenient and fast results for distribution of reservoir attributes, suitable as input for the earth model building task. The robustness of the algorithm, the non-biased and user friendly approach are important advantages of the proposed work procedure.

2.2 Exploration History

Exploration to date has confirmed that several petroleum systems are present in the Orange Basin and are sourced from known source rocks. Van der Spuy (2003) has compiled evidencve for source rocks of Aptian age. There is also evidence for Cenomanian/ Turonian source rocks being active in the area (Aldrich et al, 2003).

These Oil and gas systems contain a number of exploration plays and prospects which are currently being pursued. The Orange Basin is relatively under explored with only 38 exploration wells being drilled in the area. The main play elements are represented in Figure (2.5)

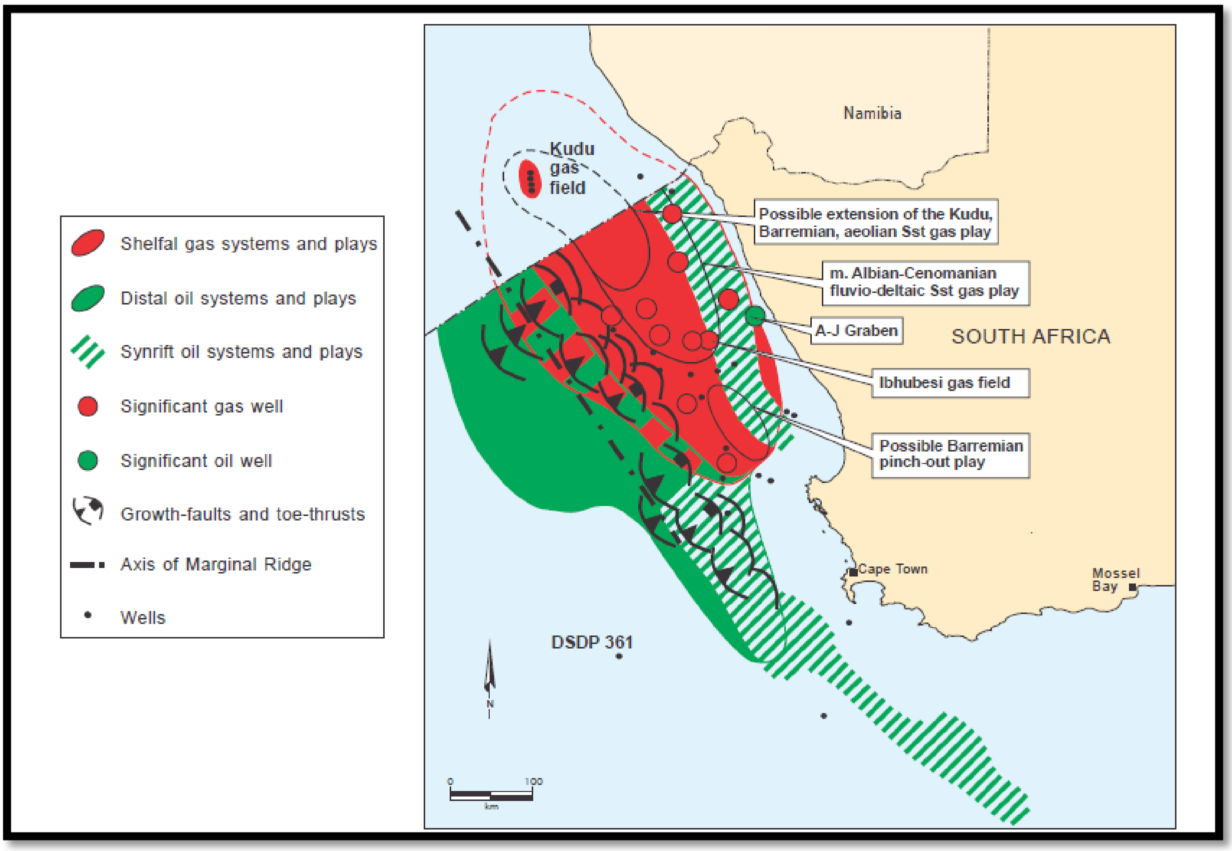


Figure 2.5: Predicted extent of Oil and Gas play systems (PASA, 2012)

The company Forest Exploration is pursuing the Albanian Gas Play which is represented by the Upper Cretaceous Shallow Gas Play and the Barremian Deep Gas Play in the shelfal portion of Blocks 1 and 2A, as well as the Upper Creataceous Deep water slope turbidite

Oil/Gas play in block 2C. BHP Billiton are pursuing the Albanian Gas Play in block 3A/4A and the Upper Cretaceous Deep water turbidite Oil Play in block 3B/4B.

The petroleum system which is most well documented discovery to date is the natural gas system sourced from the lower Aptian and Barremian source shales located in the depocentre of the Orange Basin. The Albian Gas Play within this system has led to the Ibhusbesi gas field currently being appraised by Forest Exploration. The reservoirs are stratigraphically trapped fluvial channel fill sandstones, which yielded 68MMscfg/d and 340 bbl of condensate per day during the testing of the A-K1 discovery well by Soekor in 1987.

Forest Exploration has drilled a further 8 wells during subsequent appraisal of the field and combined tests yield 221 MMscfg/d. Forest exploration and its partners have been granted a production right over this field. Bright spots and seismic gas chimneys are common occurrences in the play fairway. The Barremian Deep Gas Play has yielded the Kudu gas field in the Orange Basin off southern Namibia. The reservoirs are stratigraphically trapped Aeolian sandstones with good gas deliverability. Both the Ibhubesi and Kudu plays are regarded as having the potential for the multi-TCF reserves of natural gas.

Within the synrift succession, the only oil system confirmed to date occurs in the isolated A-J half graben. The oil is sourced from typically rich Hauterivian lacustrine shales within the half graben and is trapped stratigraphically within lake shore line sandstones interbedded with the source shales. The Maximum flow rate reached whilst testing is about 200 barrels per day of viscous oil. This geological success has shown the potential of the Synrift Oil Play. Several speculative petroleum systems and plays are also prognosed in the undrilled parts of the basin, notably in the deep water areas (Figure 2.5 & 2.6)

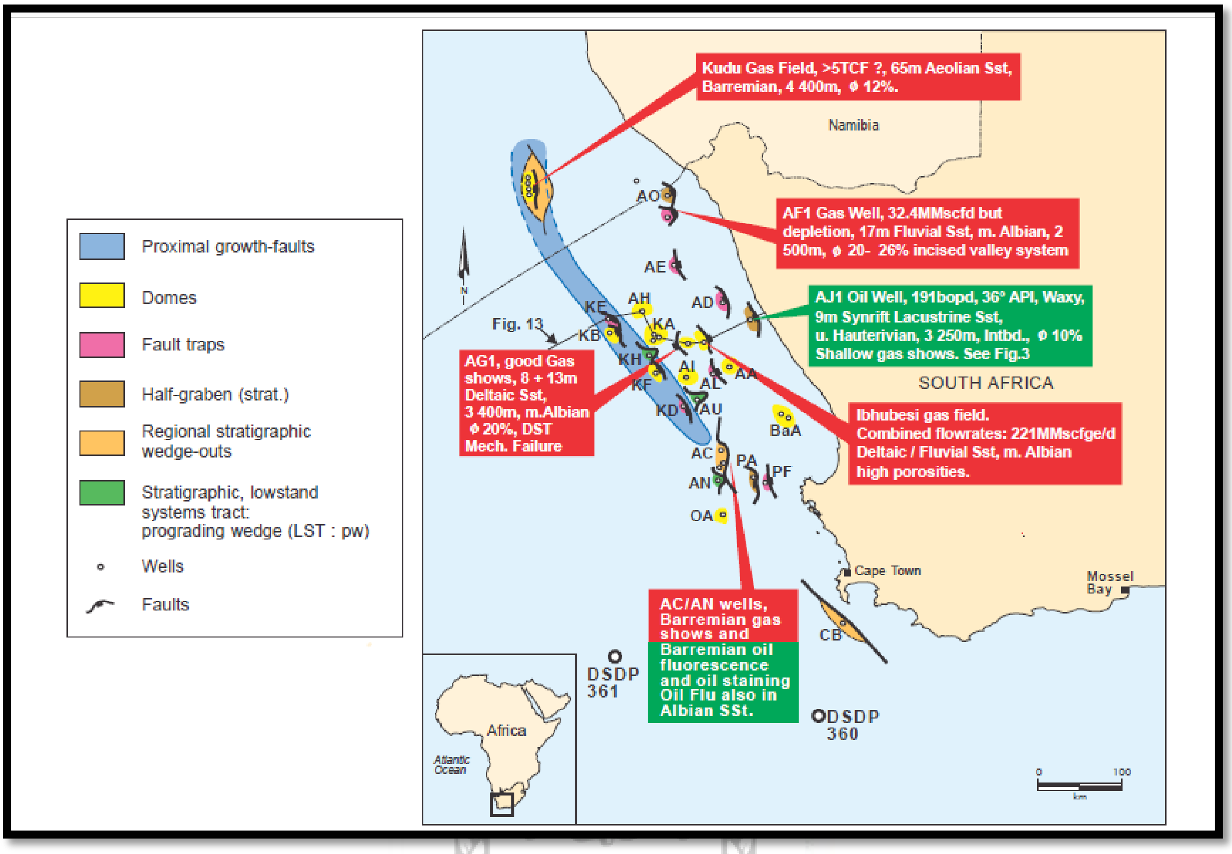


Figure 2.6: Main discoveries and shows in the Orange Basin (Jungslager, 1999)

The known Aptian Barremian source rocks are postulated to become increasingly oil-prone westward on the basis of evidence from the more distal wells. A Turonian oil source rock is envisaged as a possibility based on intersections in the distal pat of the Bredasdorp Basin, in Namibia's Walvis Basin, evidence of a wet-gas source shale in some of the Orange Basin wells, seismic character and possible organically rich, climatically driven upwelling zones in the Late Cretaceous (Aldrich et al, 2003)

During the Late Cretaceous, shelfal sand supply was ample and several canyons have been identified whereby sand could be supplied to the slope and basined domains providing reservoirs for vertically migrating hydrocarbons. Trapping is visualized against the flanks of the structures in the form of ponded and channelized turbidite sandstones.

These deep-water plays remain high risk but are believed to be attractive targets for future exploration. Based on evaluation of a regional non-exclusive seismic survey acquired by PGS in 2002.

The Orange Basin is an under explored area with a sizeable potential for both oil and gas. The oil potential may be greatest beyond the present day shelf, but the gas potential may be the greatest on the shelf.

2.3 Previous exploration history Well A-F1, block 1 Orange Basin

Borehole A-F1 is located on the north eastern margin of the Orange Basin off the West Coast of South Africa and was drilled in order to test for hydrocarbons on the downthrow side of the fault controlled structure associated with stacked vertical closures several stratigraphic levels.

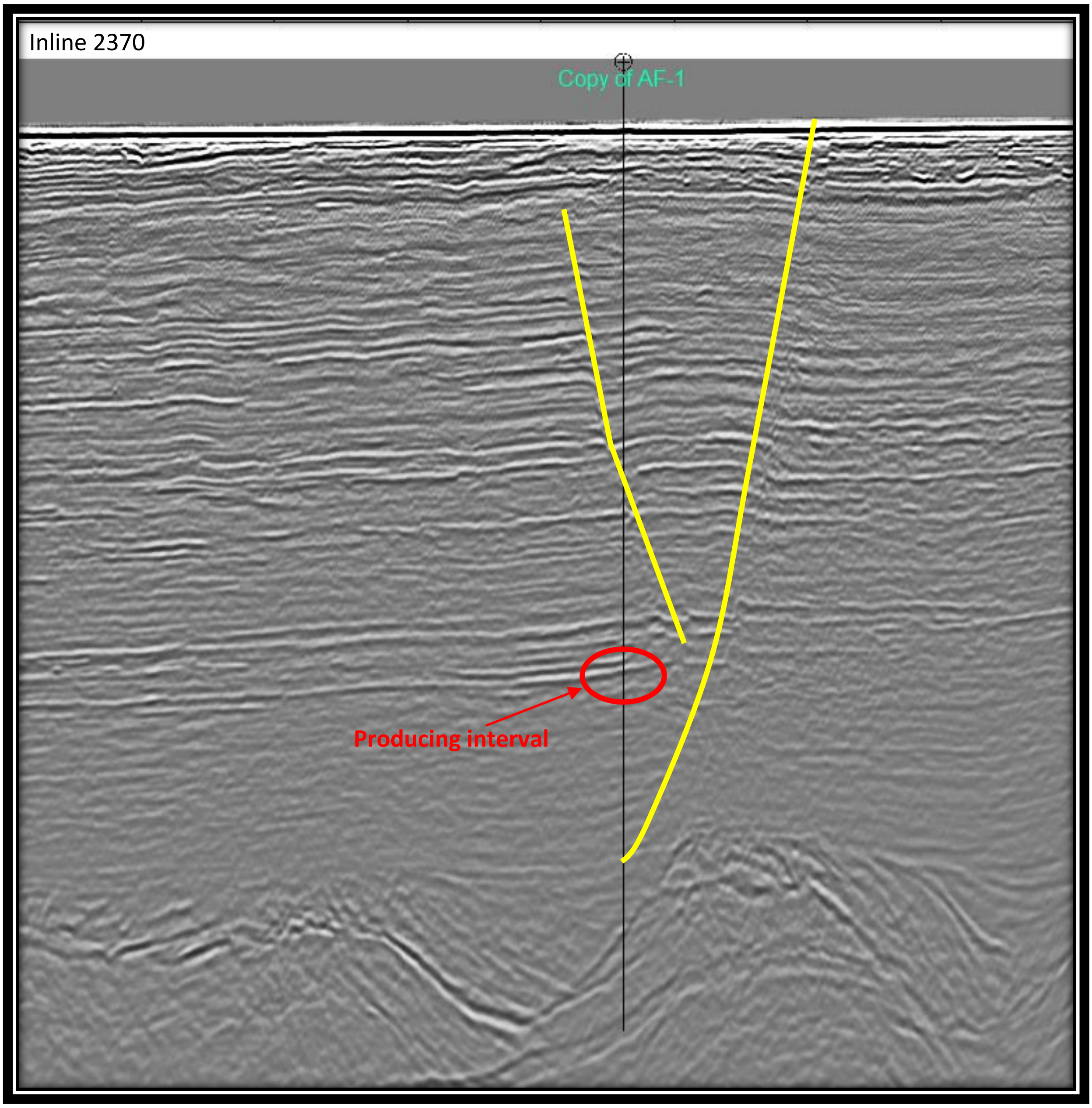


Figure 2.7: Position of Well A-F1 related to major faults

The sediments in the area were interpreted as being deposited in a marine environment. Only after drilling the borehole and examining core samples was it inferred that the depositional environment exhibited characteristics of a much more proximal setting. The proximal depositional environment related to the study area was initially undetected from seismic interpretation and drilling location was chosen due to positioning of fault related closure.

Despite the prognosis of a marine depositional environment well A-F1 struck hydrocarbons in the form of gas at a depth of 2509-2526m where a drill stem test was performed. During this test the reservoir flowed at a maximum rate of 868 013 cubic metres (32.4 MMscf/d) of gas per day. The reservoir however did show signs of depletion during testing.

Also it is necessary to note from the Well Completion Report that low resistivity values are attributed to the presence of chlorite coating the sand grains, which increases the conductivity of the formation. This would affect the water saturation calculations over hydrocarbon zones.

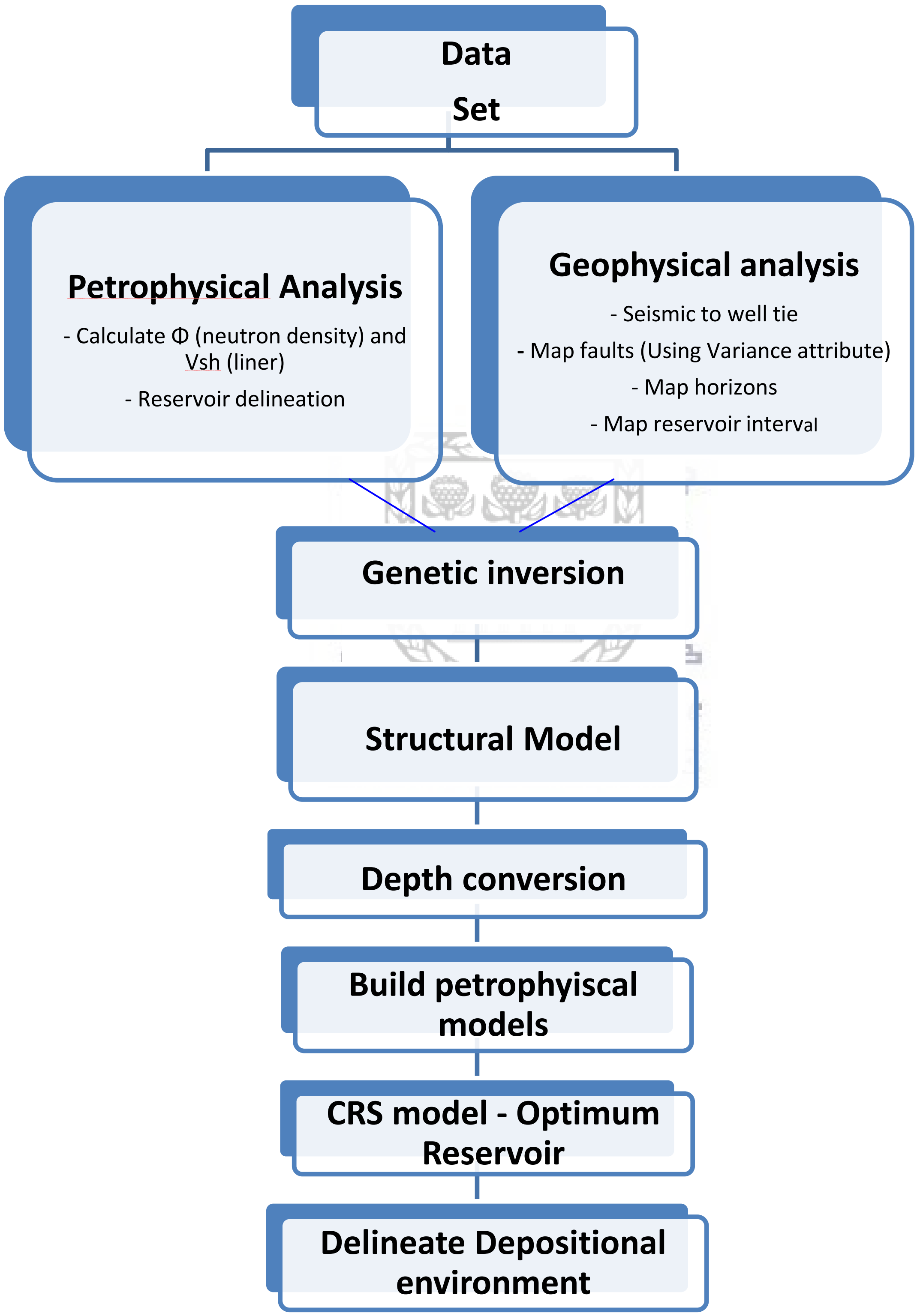
Drill Stem Test

Table 2.1: Drill Stem Test Well A-F1

No.	Interval (m)	WHPP (MPa)	Choke (in)	Qgas (MMscfd)	Qngl (BPD)
1	**2509 -2526**	**6.4**	**2 x 1.25**	**32.4**	**0**

A drill stem test was performed and flowed at a maximum rate of 888 013 cubic meters or 33.4 MMscf per day and showed signs of depletion at 60 psi.

Chapter 3: Methodology



3.1 Research Methods

Table 3.1: Data and Software used

3-D Seismic cube (Post Stack)
Well Completion reports
Check shots
Well logs (LAS)
Core Data
SOFTWARE:
Petrel 2015
Interactive Petrophysics

3.2 Preamble

3.2.1 Gamma Ray Log shapes related to depositional environment

K Futalan et al describe how the shape of gamma ray logs can be used in determining the depositional environment of potential hydrocarbon reservoirs. He used four basic shapes of gamma ray logs to determine depositional environment (Figure 3.1)

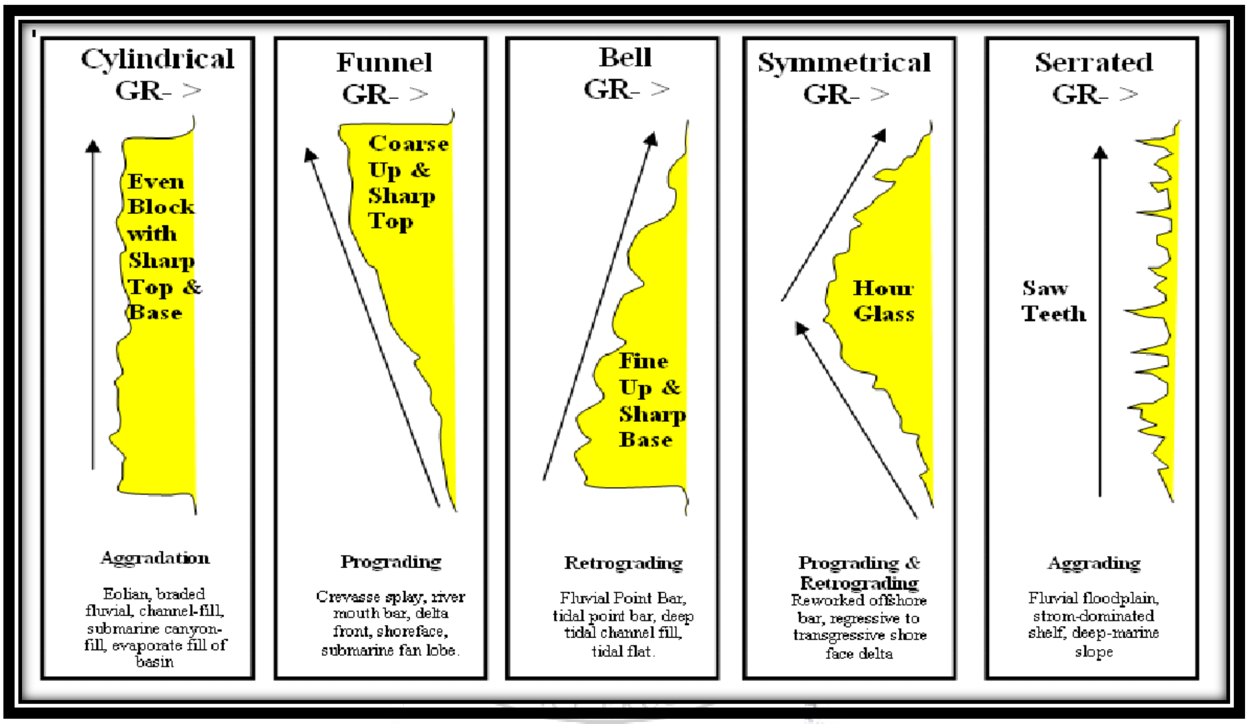


Figure 3.1: Gamma ray log shapes in relation to depositionl environment (K. Futalan, 2011)

Gamma ray log profiles/shapes and relation to depositional environments are basically described by the characteristics of how the sediments fine and coarsen.

Fining upward is the most common log profile for channel deposits (point bar, distributary channel, longitudinal bar) and is an indication of rapid initial deposition followed by gradual deposition abandonment. The best hydrocarbon reservoirs are formed in the lower half of this depositional sequence.

Coarsening upward is the typical log profile for marine bars (delta front, detached bars and shoreline deposits e.g. shoreface) and occurs due to a shallowing depositional environment. Deposition is a result of vertical accretion, transition and lower bar facies initially deposited in deeper water and overlain by cleaner, thicker and coarser sandstone comprising upper bar facies. The best hydrocarbon reservoirs are formed in the upper half of this depositional sequence.

A Cylindrical profile is indicative of abundant sediment supply, rapid high energy deposition and rapid abandonment. It is characteristic of shallow marine detached bars and distributary channels. Thinner profiles are representative of splays and turbidites. Good reservoirs are found throughout this depositional sequence

These descriptions are courtesy of (Rider, 1986)

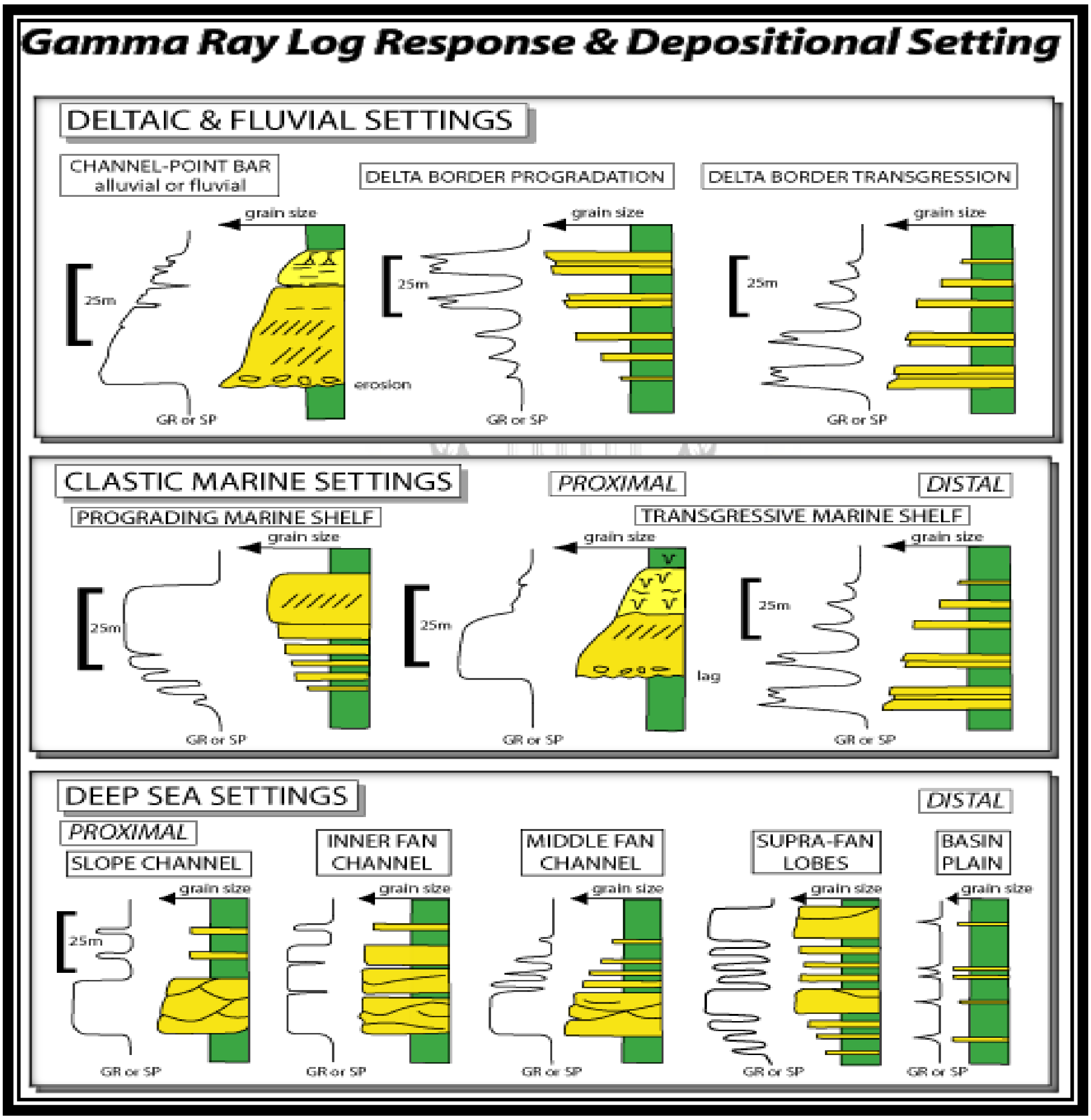


Figure 3.2: Gamma ray log shapes relating to depositional envionments (Malcom Rider, 1999)

3.2.2 Petrophysical concepts

3.2.2.1 Wireline Logs

Wireline logs provide a record of a specific attribute (Gamma ray, Density, Resistivity etc) throughout the depth of the well. They are obtained in LAS format and loaded into Petroleum software to perform necessary analysis. They are used to calculate necessary petrophysical parameters (Porosity, Sw etc)

3.2.2.2 Porosity

Defined as the fraction of the bulk volume of the reservoir rock that is not occupied by the solid framework of the reservoir. It is also interpreted as the void space within the reservoir. It is also defined mathematically as:

$$\Phi = \frac{Vb - Vgr}{Vb} = \frac{Vp}{Vb}$$

Where: Φ – Porosity

V – Bulk volume

Vgr – Grain volume

Vp – Pore Volume

3.2.2.3 Volume of Shale

The Vclay/Vshale analysis was done using the Interactive Petrophysics software for the evaluation of clay in the sandstone reservoirs. It was calculated based on the linear method using the natural gamma ray log using the Vclay/Vshale steiber equation to calculate Vclay.

3.2.2.4 Temperature Gradient

Obtained from the well completion report.

3.2.3 Geophysical concepts

3.2.3.1 Seismic to well tie

Well Seismic ties allow well data measured in unites of depth to be compared to seismic data measured in units of time. The process of creating a well tie involves seismic image processing, wavelet creation, estimation of the time-depth curve, geologic interpretation and manual corrections. Each step in generating a well tie may require quantitative analysis, but ultimately creating a well tie is a lengthy and interpretive process with possibility for significant human error. Integrating well logs and seismic data is crucial when estimating subsurface properties. It allows us to relate horizon tops identified in a well with specific reflections on the seismic section. We use sonic and density well logs to generated a synthetic trace and compare the synthetic trace to real seismic data collected near the well location. (A. Munoz)

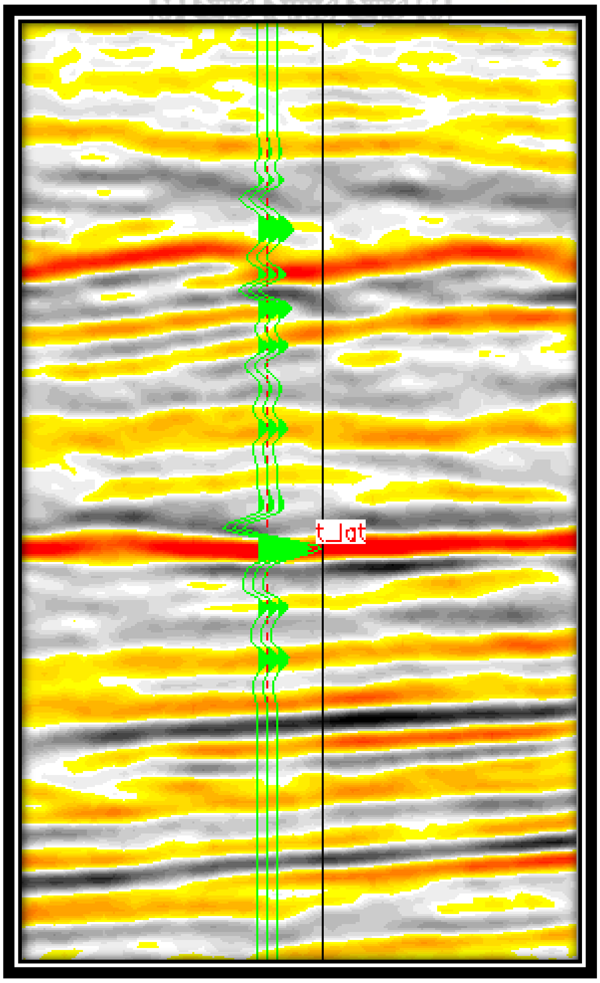


Figure 3.3: Example of a seismic-well tie (Fred W.Schroeder, AAPG)

3.2.4 Genetic Inversion Theory

Seismic data is widely used to aid hydrocarbon exploration by providing in-fill data on the rock properties between wells. Many inversion techniques are available that use seismic for property prediction based on the correlation between the property (e.g., acoustic impedance, porosity, Poisson's ratio) and the seismic.

Genetic inversion is a new algorithm which was initially incorporated into Petrel 2009.1 seismic to simulation software. Specifically it does not require an input wavelet or initial model like many other currently available poststack inversion methods. It also allows getting results quicker compared to the traditional methods. Genetic inversion is based on the neural network process but with the addition of the genetic algorithm which together generate a nonlinear multitrace operator.

This multitrace operator is produced as a result of training a seismic subvolume against well data. And it is used to invert the seismic data into the desired well log response producing a best fit to the given well data (Figures. 3.4, 3.5) (Veeken et al, 2009).

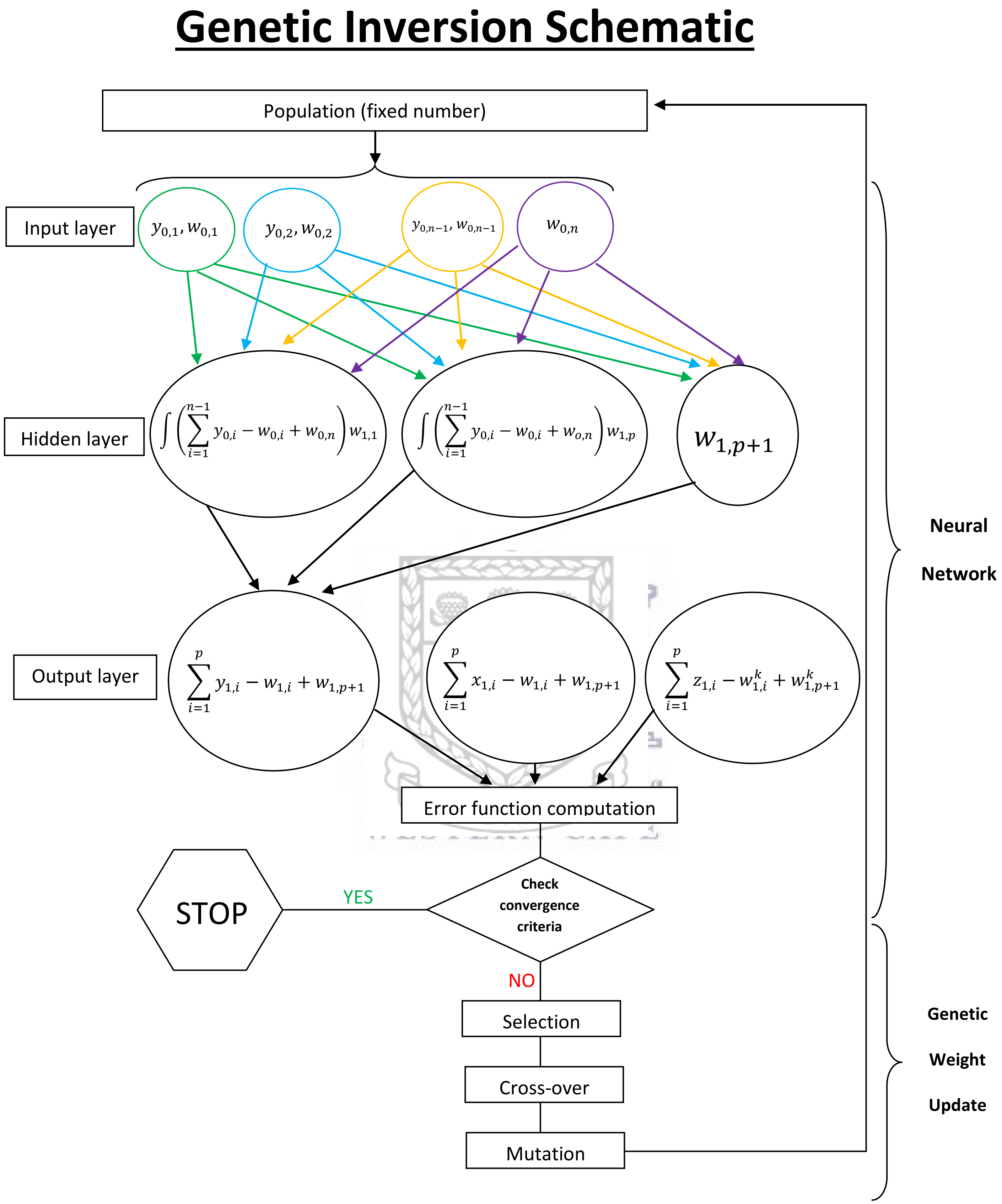


Figure 3.4: Genetic Inversion Schematic adapted from (Daber et al, 2011)

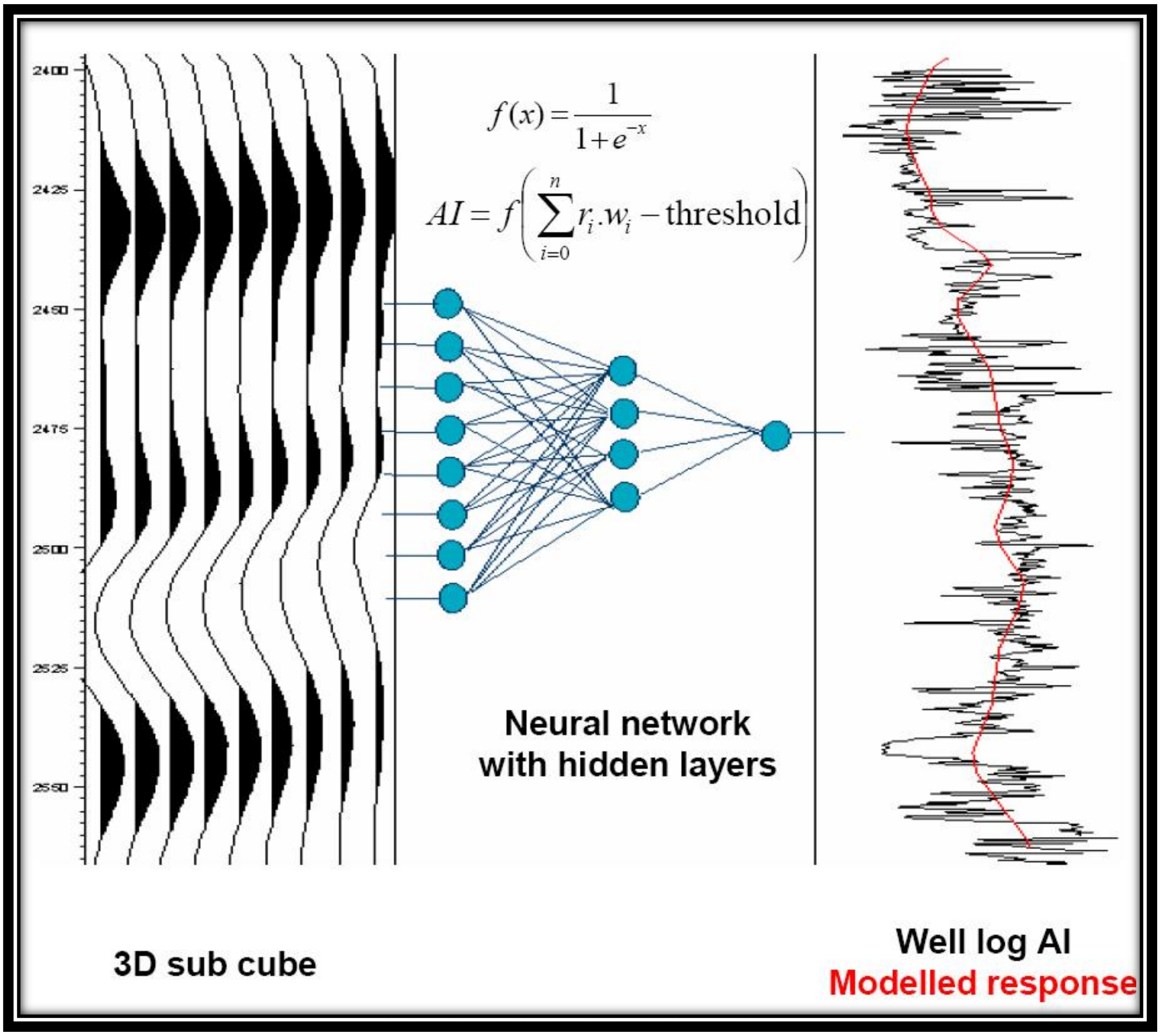


Figure 3.5: Petrel workflow (Daber R et al, 2011)

The nonlinear genetic inversion can be distantly compared to the "colored inversion", which uses a linear algorithm (Lancaster and Whitcombe 2000, Veeken 2007). The linear mode computes a series of weights derived by a curve fitting procedure that utilizes a least-squares minimization, while in the non-linear mode a neural network is trained, using the selected attributes as inputs (Figures 3.4 & 3.5). The more complex genetic inversion scheme generates improved results, because it better honours subtle changes in the input dataset (Veeken et al, 2009).

This phenomenon has been demonstrated already by Hampson et al. (2001), who pioneered the neural network application for seismic reservoir characterization purposes. Hampson et al (2001) shows how a combination of seismic attributes is used to create a function that links the seismic to the petrophysical property in order to match the given well data (e.g, Hampson et al., 2001, Boult and Donley, 2001).

The complexity of this multi-attribute method is that it is difficult to define attributes that should be used and the combination varies from volume to volume. It is also difficult to control the prediction quality and there is a chance of neural net overtraining (Priezzhev et al, 2009) and especially overfitting when the training set is “memorized” in the network (Van der Baan and Jutten,2000).

Genetic inversion requires a single seismic cube (e.g., poststack migrated true amplitude or acoustic impedance) and a set of wells with a petrophysical property which has some relation to seismic (e.g., porosity, velocity, bulk modulus). During the learning phase of the neural net instead of the back propagating the error (standard neural net algorithm) the genetic algorithm is used. This algorithm updates the weights for the neural network using the Evolutionary approach (i.e., Selection, Cross-over and Mutation). The use of the genetic learning algorithm allows the Neural Net to find the global error minimum of the function and therefore an optimal solution, while standard Neural Net algorithms generally reach the local minimum error of the function (Veeken et al., 2009).

As mentioned earlier the unknown weights in the Neural network are updated by the genetic algorithm. Initially 50 weight combinations are chosen at random, which all pass through the first iteration of the Neural network. The output result is then compared with the observed datasets (i.e. well logs) by calculating an error function. As soon as an error value is computed for each of the 50 input weight combinations the process enters into the Genetic part of the algorithm: Selection, Crossover and Mutation (Klinger et al, 2008).

Selection – weight combinations with the smallest error are selected. In analogy to the natural selection hypothesis of Charles Darwin which favours only the best adapted individuals to survive; in this case the survival criteria is given by the individual with the smallest error.

Cross-over – weight combinations are exchanging single weights from one combination to another (the number of exchanged weights can be singular or multiple). This crossover phenomenon occurs with a given probability after and within each iteration.

Mutation – as in evolution single weights are exchanged randomly from one weight combination to another. This ensures that the process does not converge to a local minimum. The mutation event occurs with a higher probability as soon as the error function starts to stabilize (i.e. reach a minimum).

It is important that a population has a constant number (e.g., 50) at each iteration of the inversion. Thus, even if selection reduces the size of the population by taking, for example, the 10 best weights, applying “cross-over” and “mutation” to those selected combinations of weights will recreate a full set of 50 “chromosomes” in the population. The output of this workflow is a nonlinear multitrace operator which is applied to the whole seismic dataset, and transforms it into the property described by the logs used during the training phase (Klinger et al., 2008). Seismic subcubes represent the operator structure (i.e. multi-trace or 3D) and are utilized during the training and the modelling phase (Figure 3.6)

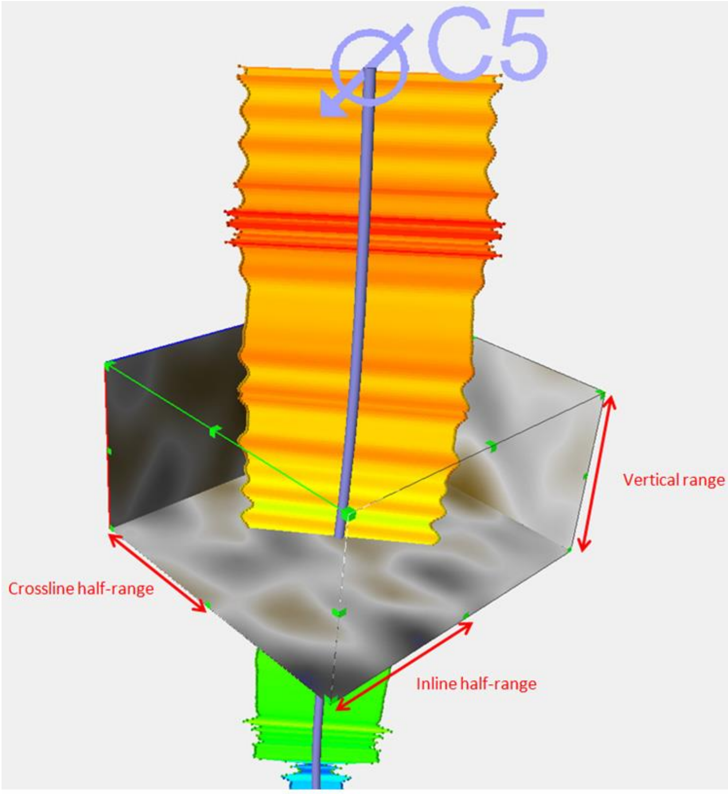


Figure 3.6: Illustration of subcube used for neural network (Daber R et al, 2011)

The middle trace passes through the well and the number of surrounding traces can be set from 0 to 21 in InLine and Xline directions. The vertical range can be 10–200 ms. Vertical as well as lateral components are taken into account to establish the operator. The program allows input of the top and bottom surfaces between which the inversion is run. Computation of the derived neural network operator is made step by step from top surface down to the bottom surface, each step being equal to the seismic sample interval (e.g. 1 to 4 ms) (Veeken et al., 2009).

3.2.5 Genetic theory application

<u>**Genetic inversion input and parameters**</u>

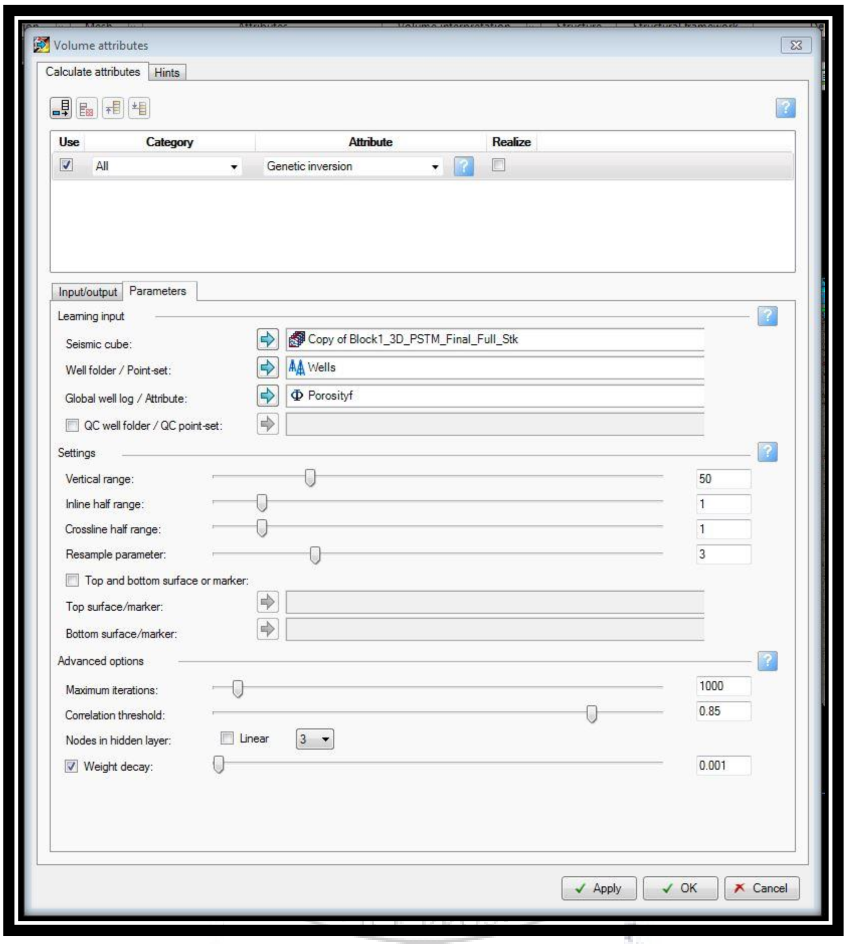


Figure 3.7: Genetic inversion input parameters

3.2.5.1 Learning in put

Seismic cube

User will drop in the 3D volume he wants to use for the learning step, as well for the inversion itself

Well folder/Point-set

Select the point set global well folder or any sub folder, containing the point-set/ well which will be used for the learning process

Settings

Vertical range

Vertical half extension of the seismic sub-volume which is dependent on the resolution of the seismic

Inline half range

Horizontal half extension of the seismic sub-volume with respect to the inline direction.

Crossline half range

Horizontal half extension of the seismic sub-volume with respect to the crossline direction,

Resample parameter

Defines the sample increment within the seismic around the well sample in order to create the input vector containing the seismic amplitudes for which the learning process is computated. The higher the resample parameters the more important the concentration of samples per volume unit.

Advanced options

Maximum iterations

Defines the maximum number of learning iterations allowed for computing the neural network derived operator.

Correlation threshold

Converging criteria set to 0.85 by default, if the correlation is reduced before the maximum number of iterations, the learning process will stop.

Nodes in the hidden layer

Number of cells in the hidden layer to use for the hidden layer to use for computing the inversion operator.

Linear

When toggled off deactivates the neural network

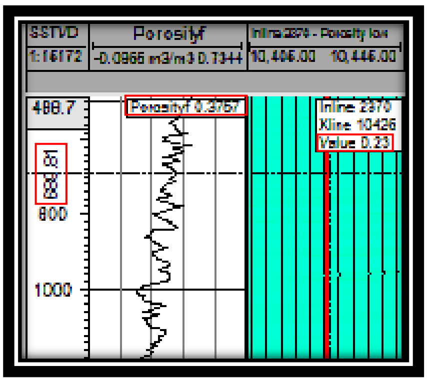
Weight decay

Neural network smoother and overlifting prevention parameter. Once this parameter is set larger than 0, it will contain the neural network fitting process. The result is smoother output data. Correlation on training data will generally decrease when increasing the weight decay parameters.

3.2.5.2 Genetic Inversion Calibration

Well logs from the respective Genetic inversion petrophysical cubes. Genetic inversion is then calibrated by comparing the respective well logs generated from the Genetic inversion seismic cubes are to the well log calculated from petrophysical analysis. Readings are gathered by placing cursor at various depths of the well logs and values noted.

E.g



Depth: 689m

Porosity

Well log: 37%

Genetic inversion: 23%

3.2.6 Seismic attributes

A seismic attribute is any measure of seismic data that helps us better visualize or quantify features of interpretation interest. It could be described as powerful aid to improve accuracy of interpretations and predictions in hydrocarbon exploration and development (Oyeyemi KD, 2015). Seismic attributes allow the geoscientists to interpret faults and channels, recognize depo-sitional environments, and unravel structural deformation history more rapidly.

Seismic attributes can be used for both quantitative and qualitative purposes. Quantitative uses include prediction of physical properties such as porosity or lithology (Leiphart and Hart, 2001; Sagan and Hart, 2006). Qualitative uses include detection of stratigraphic or structural features.

Variance

The Variance attribute is a method in petrel which can be used to isolate edges from the input data set, where "edge" refers to discontinuities in the horizontal continuity of amplitude. The method computes a normalised population variance with an optional weighted vertical smoothing.

Sweetness

The Sweetness attribute is the envelope (reflection strength) divided by the square root of the Instantaneous Frequency can sometimes help in delineating subtle discontinuities.

Root Mean Square Amplitude (RMS)

RMS amplitude is defined as the square root of the sum of the squared amplitudes, divided by the number of live samples. Where "k" is the number of live samples.

$$\sqrt{\frac{(\sum_i^n amp^2)}{k}}$$

RMS amplitude is known to be a successful tool in predicting sand bodies i.e. areas of high porosity and low volume of shale and is often used as a tool in predicting reservoir distribution, as sand bodies are isolated from the background shales. High RMS amplitude values indicate reservoir sands and low RMS amplitude values indicate non-sands (Figure 21).

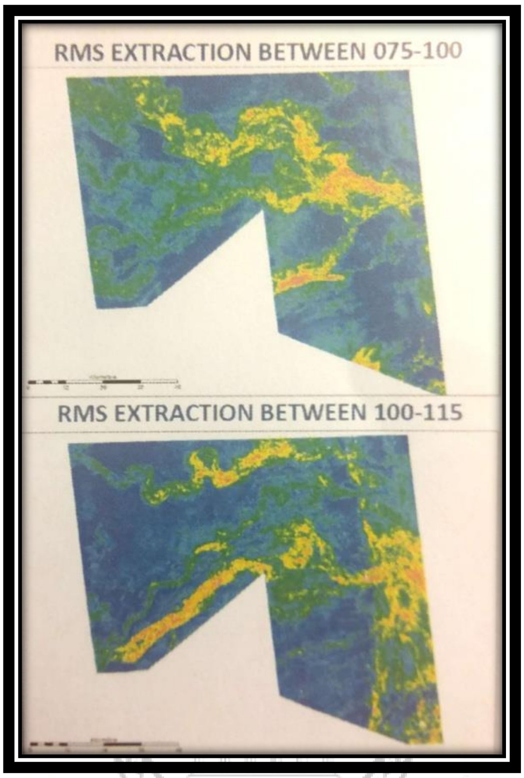


Figure 3.8: Application of RMS in delineating sand bodies (Chariot Oil & Gas)

Chapter 4: Data analysis and results

4.1 Seismic to Well Tie

Seismic to well tie was performed for Well AF-1 using the sonic log and check shot data. The synthetic trace was generated using the Ricker method. Image below shows the synthetic trace and well tie throughout the well. With figure showing the synthetic trace calibration within the reservoir interval (Figure 4.1 & 4.2).

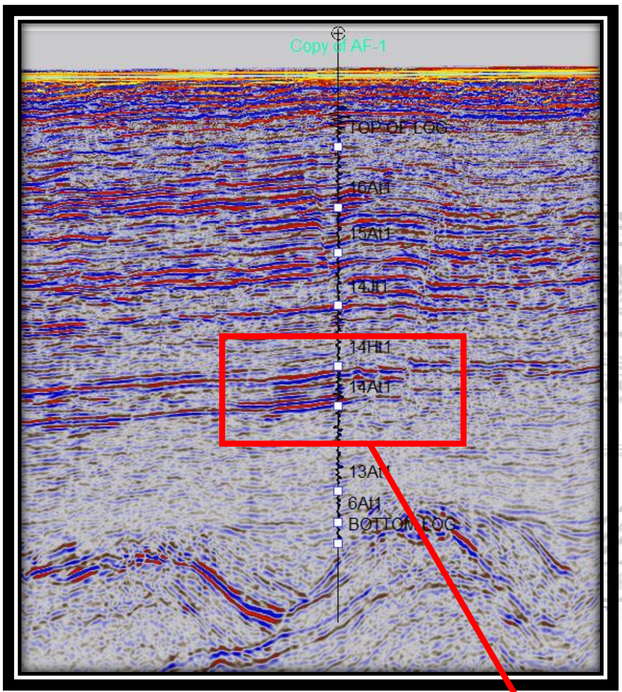


Figure 4.1: Image of Seismic to Well tie

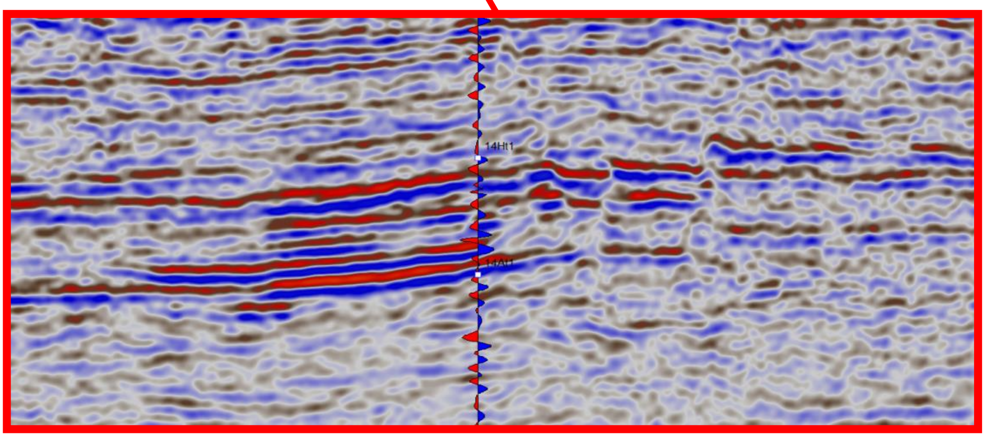


Figure 4.2: Seismic to Well tie within reservoir interval

4.2 Petrophysical analysis

4.2.1 Reservoir delineation

Reservoir delineation was carried out in Well A-F1 and a prospective reservoir interval was delineated between the 14Ht and 14Jt unconformity. The reservoir interval was further comprised of two relatively thick reservoir zones (Reservoir A and Reservoir B) which separated by an approximately 25m thick layer of shale. This reservoir interval was chosen due to its adequate porosity, volume of shale and considerable thickness (369m). The upward coarsening GR log shape for both reservoir zones is also considered as a desirable reservoir characteristic.

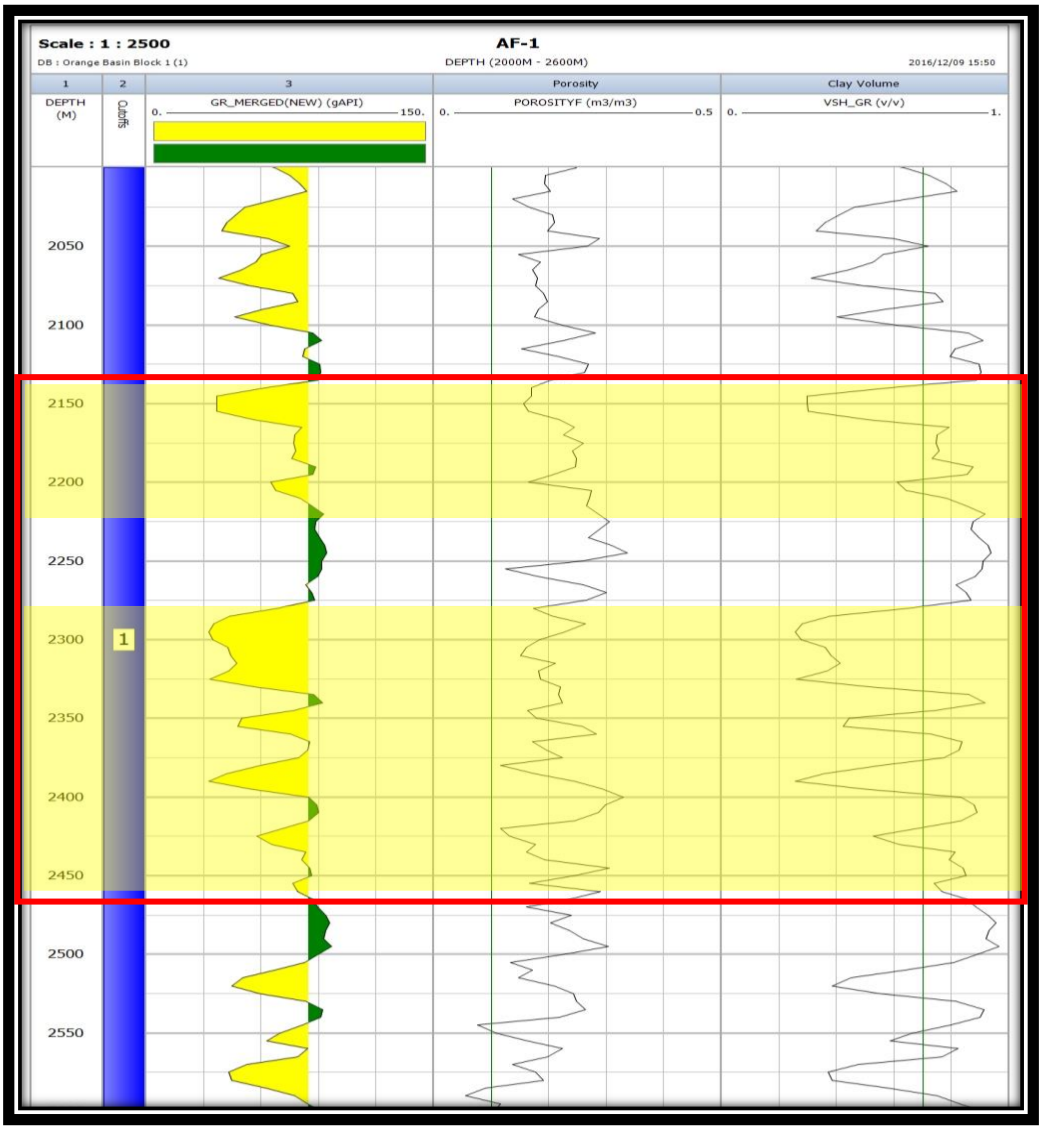


Figure 4.3: Reservoir delineation with Porosity and Volume of shale logs

Conventionally potential hydrocarbon reservoirs would be delineated with the aid of the resistivity logs, however literature and previous exploration history at similar depths within the Orange Basin indicates that Chlorite coating of sand grains result in inaccurate resistivity readings due to the conductive nature of Chlorite. This also has a direct effect on water saturation calculations as it limits its accuracy.

Reservoir zone B exhibited more desirable reservoir characteristics in terms of porosity, volume of shale and thickness. Reservoir Zone B or the lower half of the reservoir interval displays more promising hydrocarbon reservoir potential relative to Reservoir Zone A as even though they exhibited similar good reservoir properties in terms of porosity and Volume of shale, Reservoir Zone B is considerably thicker and represented by a more desirable compartmentalised reservoir.

Reservoir Zone A

Reservoir zone A is represented by an upward coarsening approximately 60m thick sandstone reservoir exhibiting an average porosity of 19% and an average volume shale or NTG of 40%.

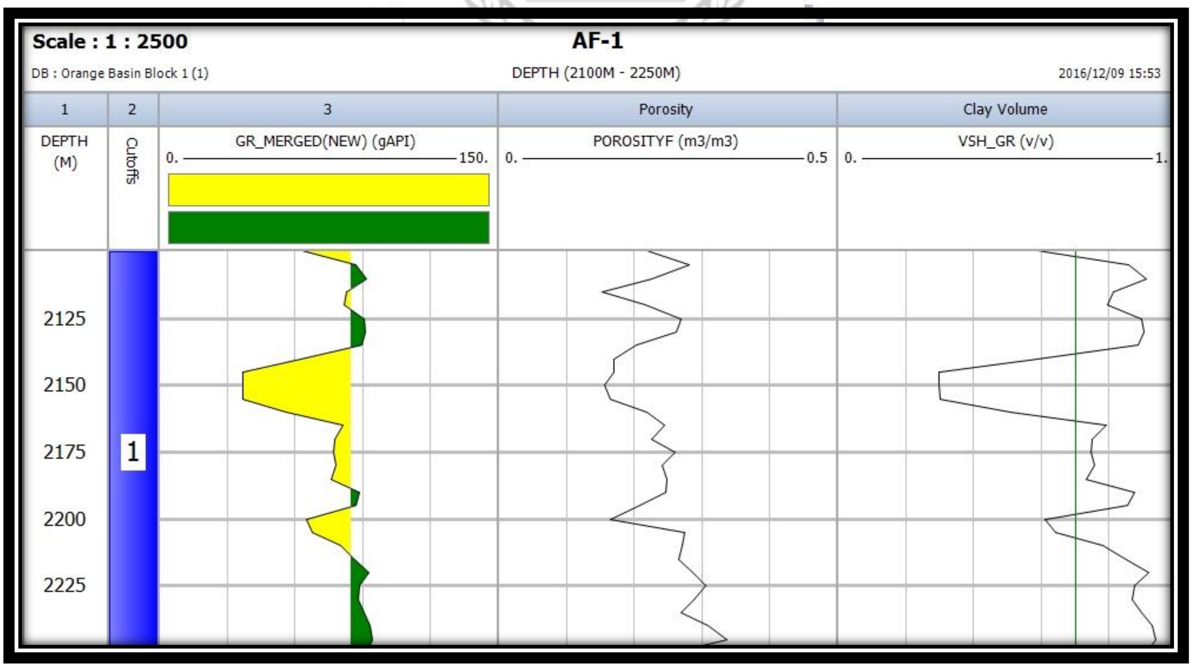
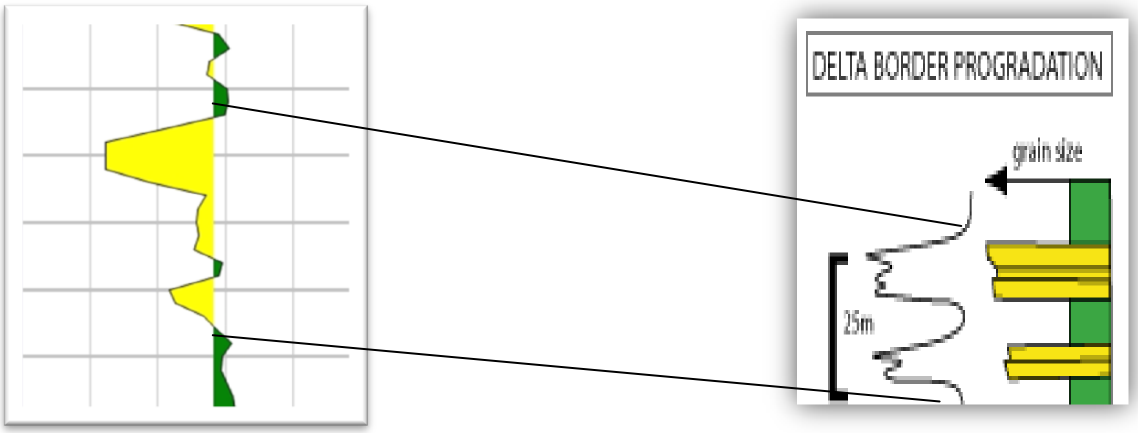


Figure 4.4: Reservoir Zone A

Gamma Ray Log shape



The gamma ray log shape exhibited by Reservoir Zone A is representative of a Delta Border Progradation environment and this upward coarsening funnel shape is closely related to a delta front, crevasse splay or a lobe depositional environment.

Reservoir Zone B

Reservoir zone B is represented by an upward coarsening 150m compartmentalised sandstone reservoir. With an average porosity of 19% and average volume of shale of 35%

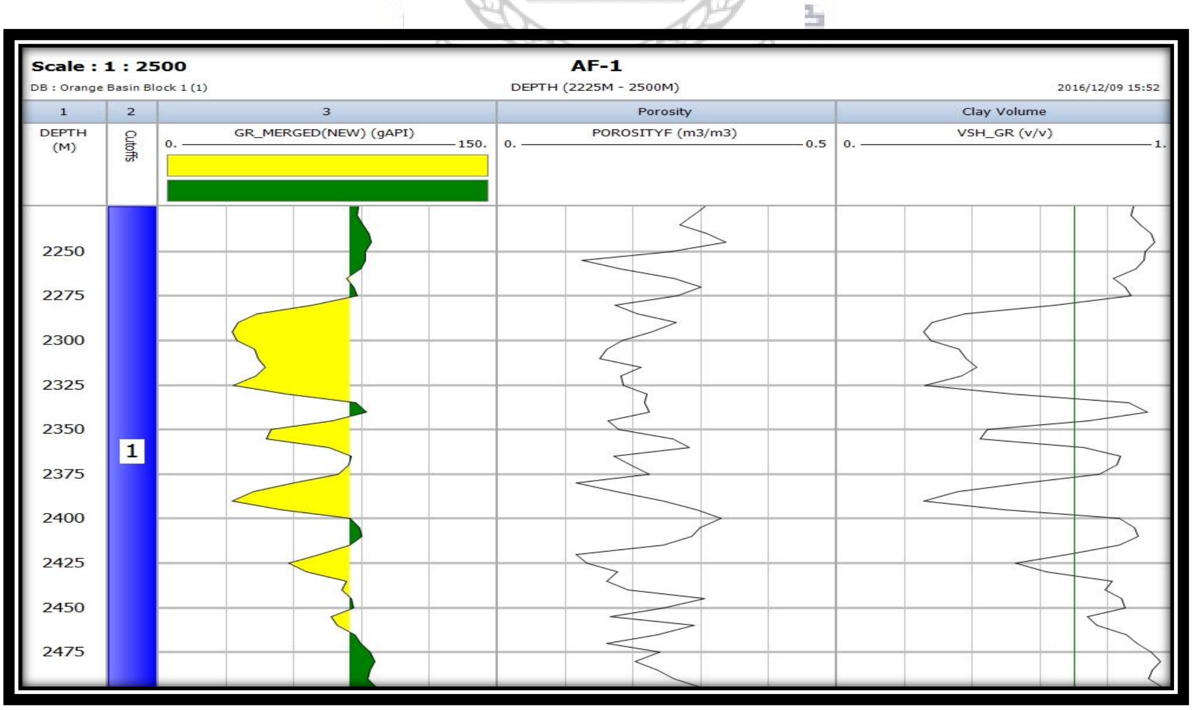


Figure 4.5: Reservoir Zone B

Gamma Ray Log Shape

The gamma ray log shape exhibited by Reservoir B is representative of a Progradational Delta Border environment and this upward coarsening “funnel” shape is closely related to a delta front, crevasse splay or a lobe depositional environment. The gamma log shape is also indicative of a more proximal depositional environment instead of a distal deep marine setting.

4.2.2 Vsh calculation

Volume of shale was calculated using the Basic log analysis function of the Interactive petrophysics software using the Linear method.

4.2.3 Porosity Calculation

Porosity was also calculated using basic log analysis using the Neu Den method which matched up the most accurately with Core Porosity measurements.

4.2.4 Net Reservoir flag

Cut-offs were set for Porosity and Volume of shale at 10% and 40% respectively and the areas within the reservoir where porosity is greater than 10% and Volume of Shale is greater than 40% is displayed on the log by the green “Reservoir flag”.

4.3 Geophysical Analysis and seismic interpretation

4.3.1 Seismic Interpretation

Seismic interpretation was carried out and major faults were delineated and the reservoir interval of interest was mapped out along with two other unconformities. The reservoir interval of interest was mapped out between horizon 14Ht1 and horizon 14At1.

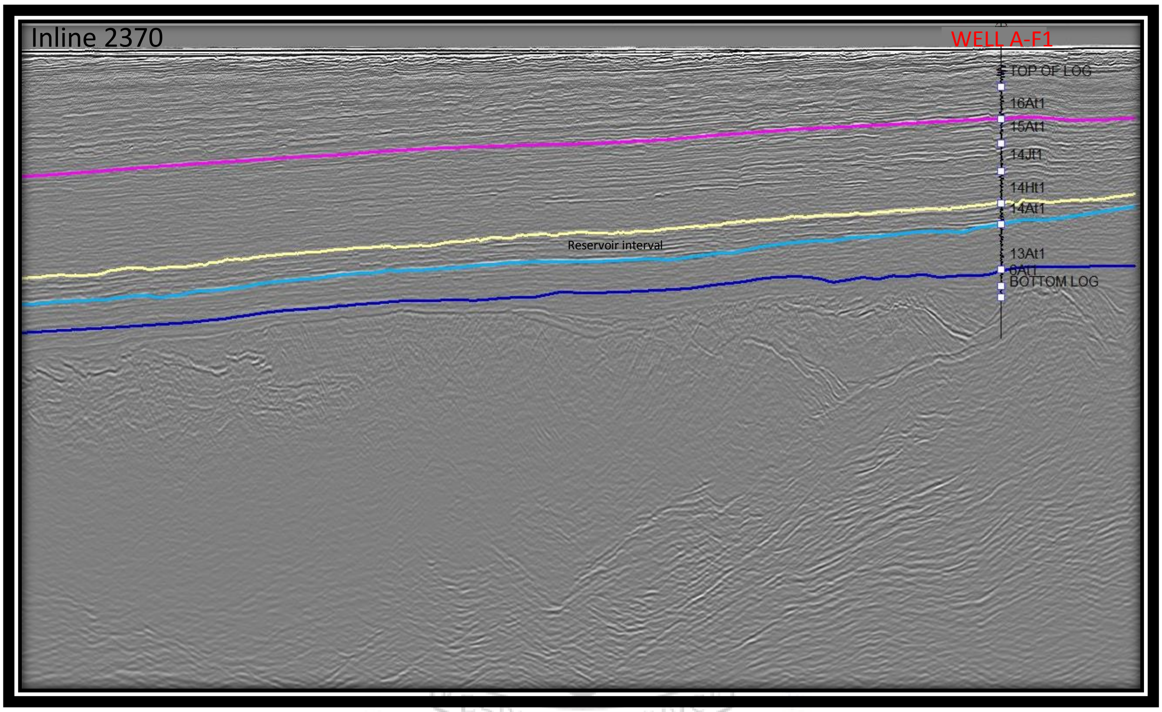


Figure 4.6: Significant seismic horizons mapped

The seismic survey showed that the reservoir interval was laterally quite extensive and relatively thick (Figure 4.6). The reservoir interval is dipping towards the distal region of the basin.

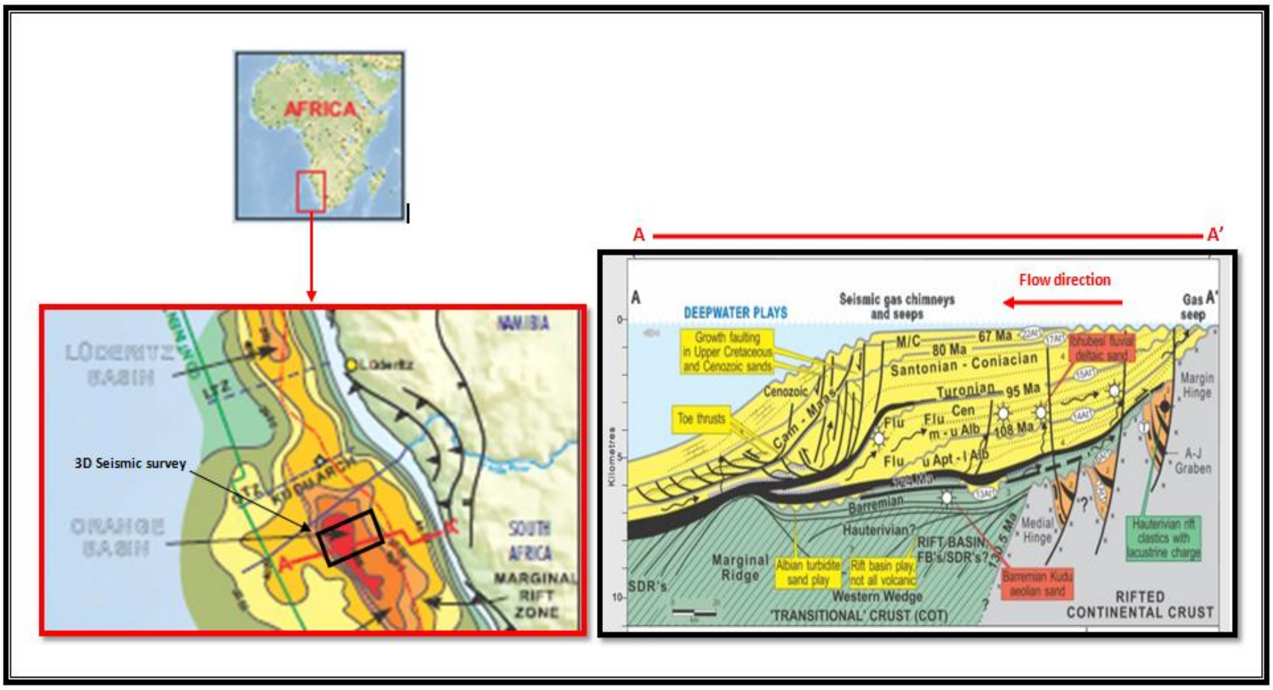


Figure 4.7: Position of 3D seismic survey relative to flow direction

Figure 4.7 provides the necessary evidence that the location of the study area represented by the extent of the 3D seismic survey is positioned parallel to the coast with sediments dipping perpendicular to the coast. What is evident from this that the strike of the 3D survey is perpendicular to the direction of flow of the Oliphants and Orange rivers which supplied the sediments for the drift succession as mentioned. This is further justified by the evidence produced by seismic attribute analysis and allows us to place areas of distal and proximal setting within the study area.

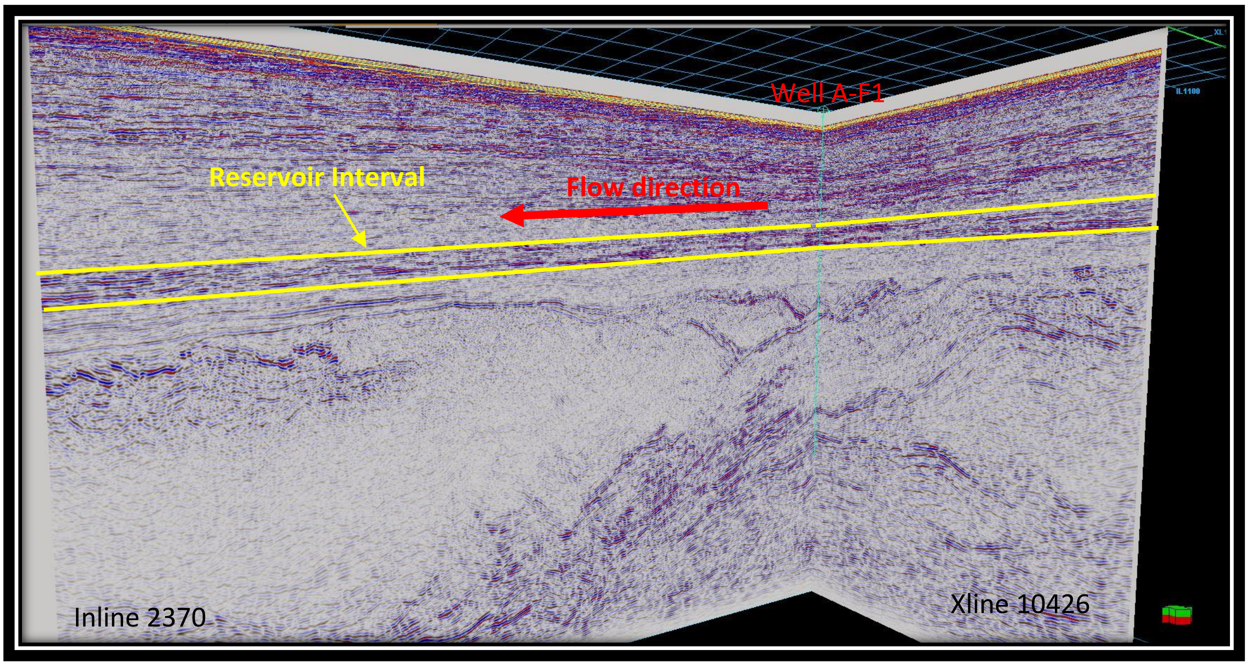


Figure 4.8: Inline 2370 and Xline 10402 exhibiting lateral extent of reservoir interval

As previously mentioned Well A-F1 was drilled with the initial prognosis that sediments in Block 1 was deposited in a deep marine depositional setting and was only determined to be of a more proximal environment once core analysis was carried out. The initial prognosis was a result of preliminary seismic interpretation which exhibited no clear evidence of a proximal depositional environment.

Characteristics of a proximal depositional environment could not be delineated from default seismic which is also related to the dipping orientation of the depositional setting.

Core analysis exhibited a depositional environment of a transitional nature as a presumed channel was intersected. Once again interpretation of the default seismic showed little to no evidence of channels or a transitional deposition environment.

4.3.2 Sweetness seismic attribute

To assist the problem of being unable to delineate channels the seismic attribute "Sweetness" was applied to the seismic survey to highlight channel complexes. This however did not provide a complete solution due to the dipping nature of the environment as a conventional "Time slice" intersection could not represent an entire depositional interval. Therefore using the "Horizontal/Stratal slice" tool in Petrel 2015 it was possible to create an intersection which followed the dip angle of the environment.

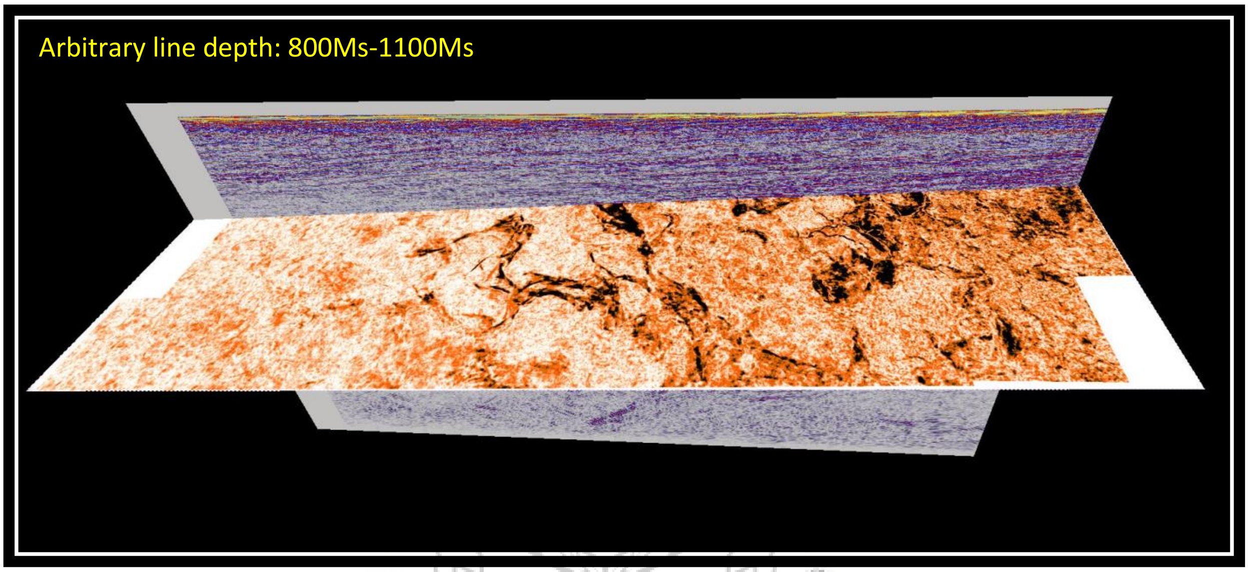


Figure 4.9: Sweetness attribute dip seismic intersection displaying channels

The combination of the Sweetness seismic attribute and horizon dip intersection proved an imperative tool in delineating the channels complexes and the transitional environments was clearly exhibited. The dark/black colours are representative of sand bodies and with clear sinuosity present they are interpreted as channels.

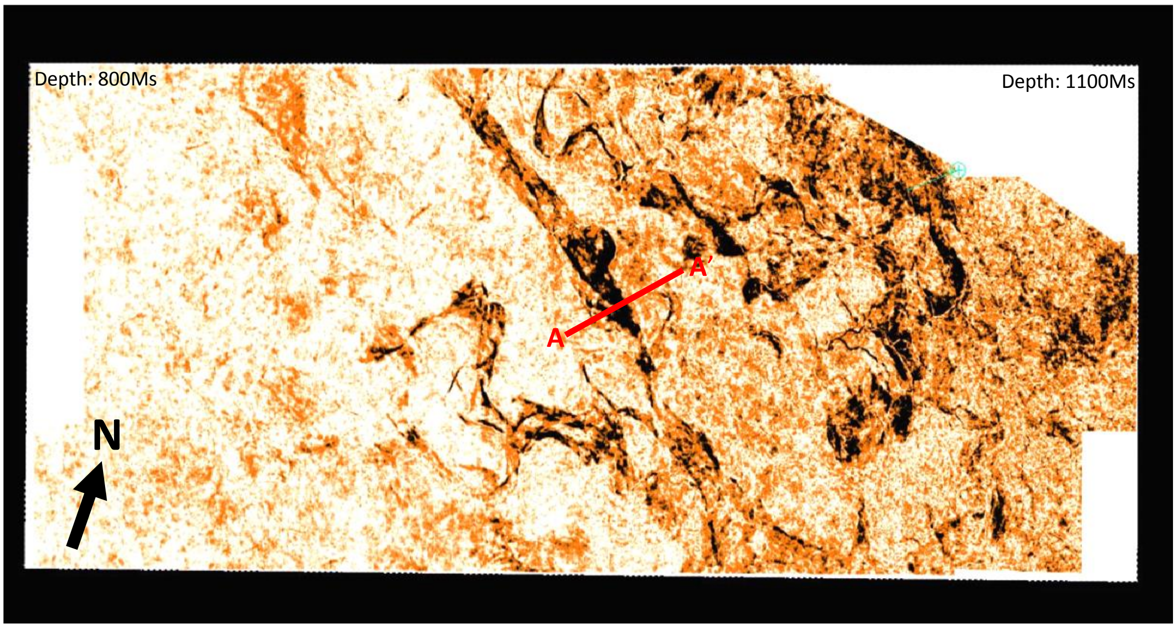


Figure 4.10: Sweetness attribute dip seismic intersection top view

As can be seen from the figure 4.10, channels are clearly exhibited and confirmation of a transitional depositional environment is evident.

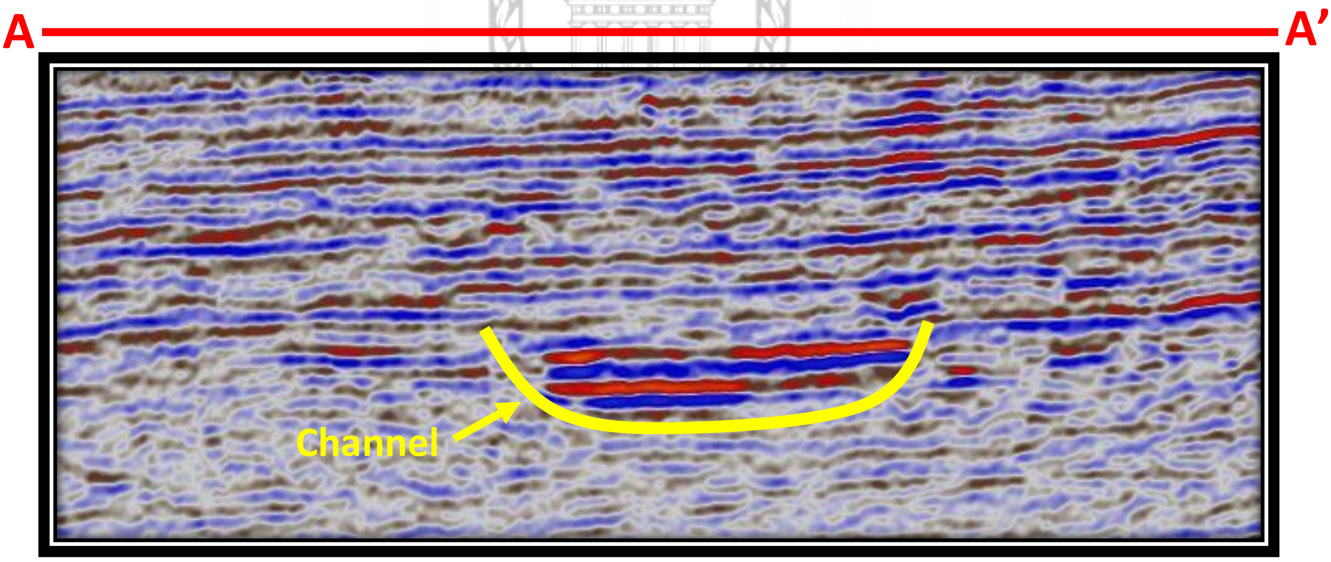


Figure 4.11: Seismic cross section (Channel)

When different seismic attributes are compared to default/original seismic it is clear that seismic attributes provide an imperative tool in seismic interpretation. Represented below is the default seismic (Figure 4.12) compared to two different seismic attribute Sweetness (Figure 4.13) respectively. The comparison clearly exhibits structural and depositional systems which can be seen on the seismic attributes especially the sweetness attribute which are not clearly delineable on original seismic.

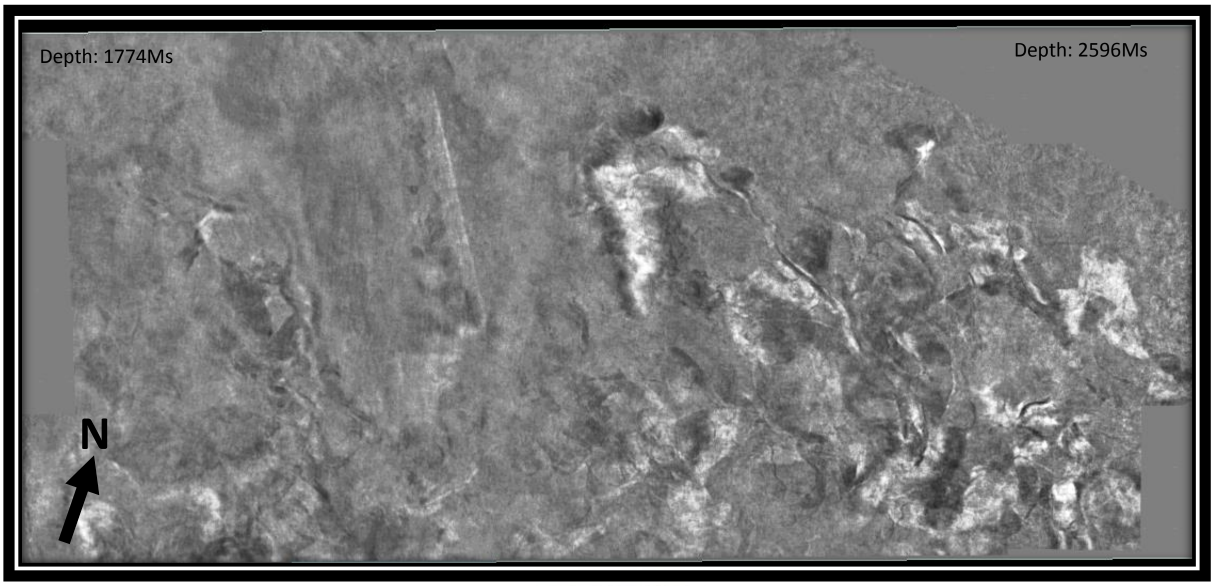


Figure 4.12: Reservoir interval default seismic intersection

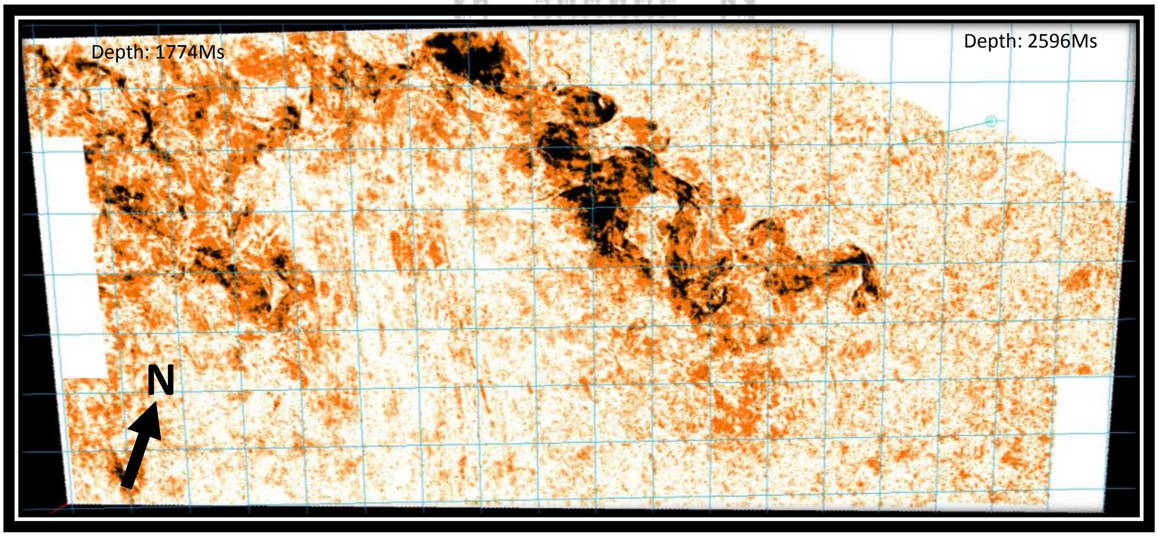


Figure 4.13: Reservoir interval sweetness attribute intersection

4.4 Genetic inversion calibration

Genetic inversion vs Well logs with lower range parameters

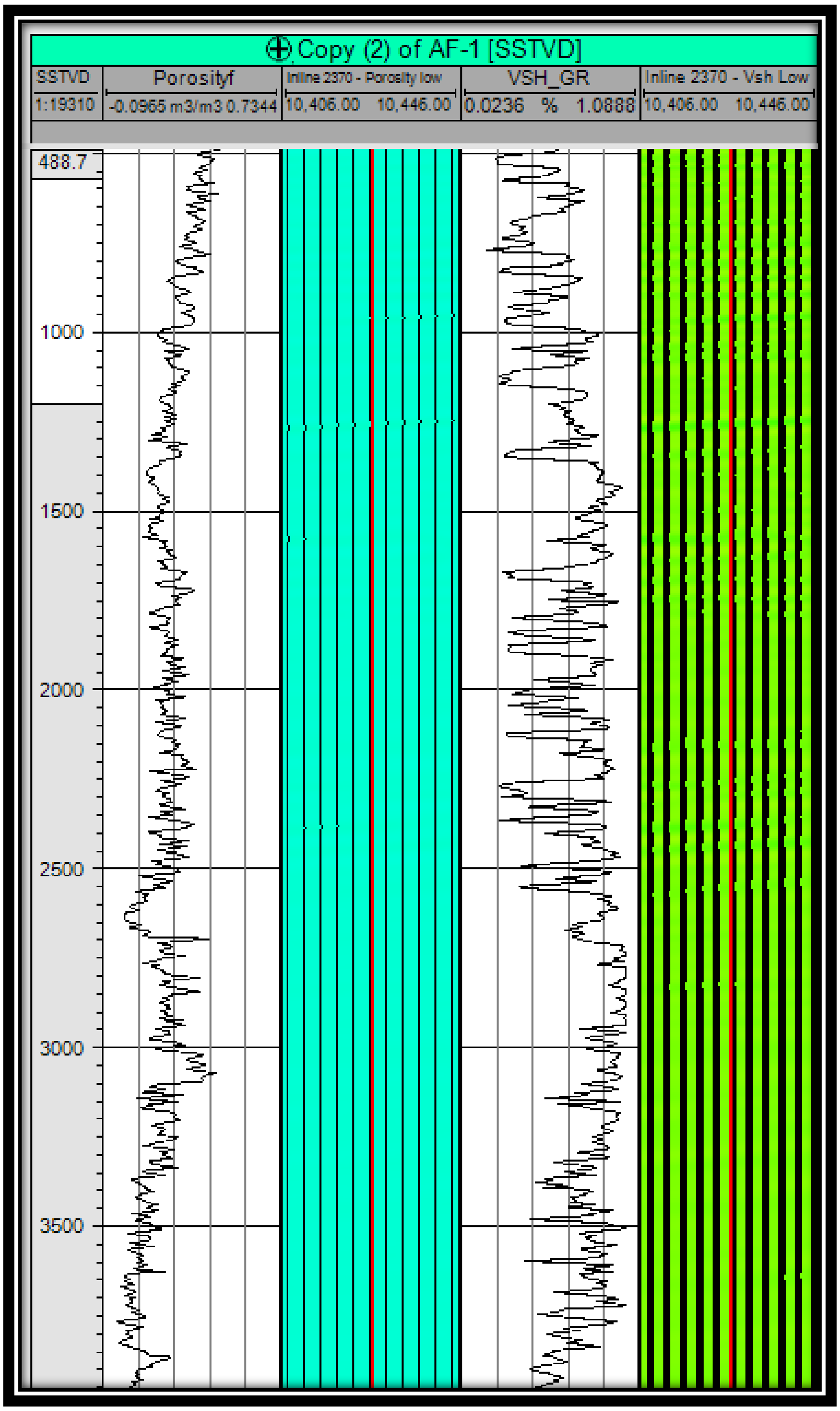


Figure 4.14: Genetic inversion, low range setings

Table 4.1: Porosity log vs Genetic inversion log (Low range)

Porosity

Depth (m)	Well Log (m/m3)	Genetic Inversion Log
689	37%	23%
1250	12%	24%
2000	31%	22%
2600	9%	23%

Table 4.2: Vsh log vs Genetic inversion (Low range)

Volume of Shale

Depth (m)	Well Log	Genetic Inversion Log
488	34%	66%
1350	33%	47%
2000	74%	54%
2600	48%	41%

When genetic inversion is run with the input parameters and settings set at a low range the readings for both porosity and volume of shale cubes are considerably inaccurate with values deviating from the well logs data by more than 10-20% and given locations throughout the well log (Figure 4.12)

Genetic inversion vs Well Logs with higher range input parameters

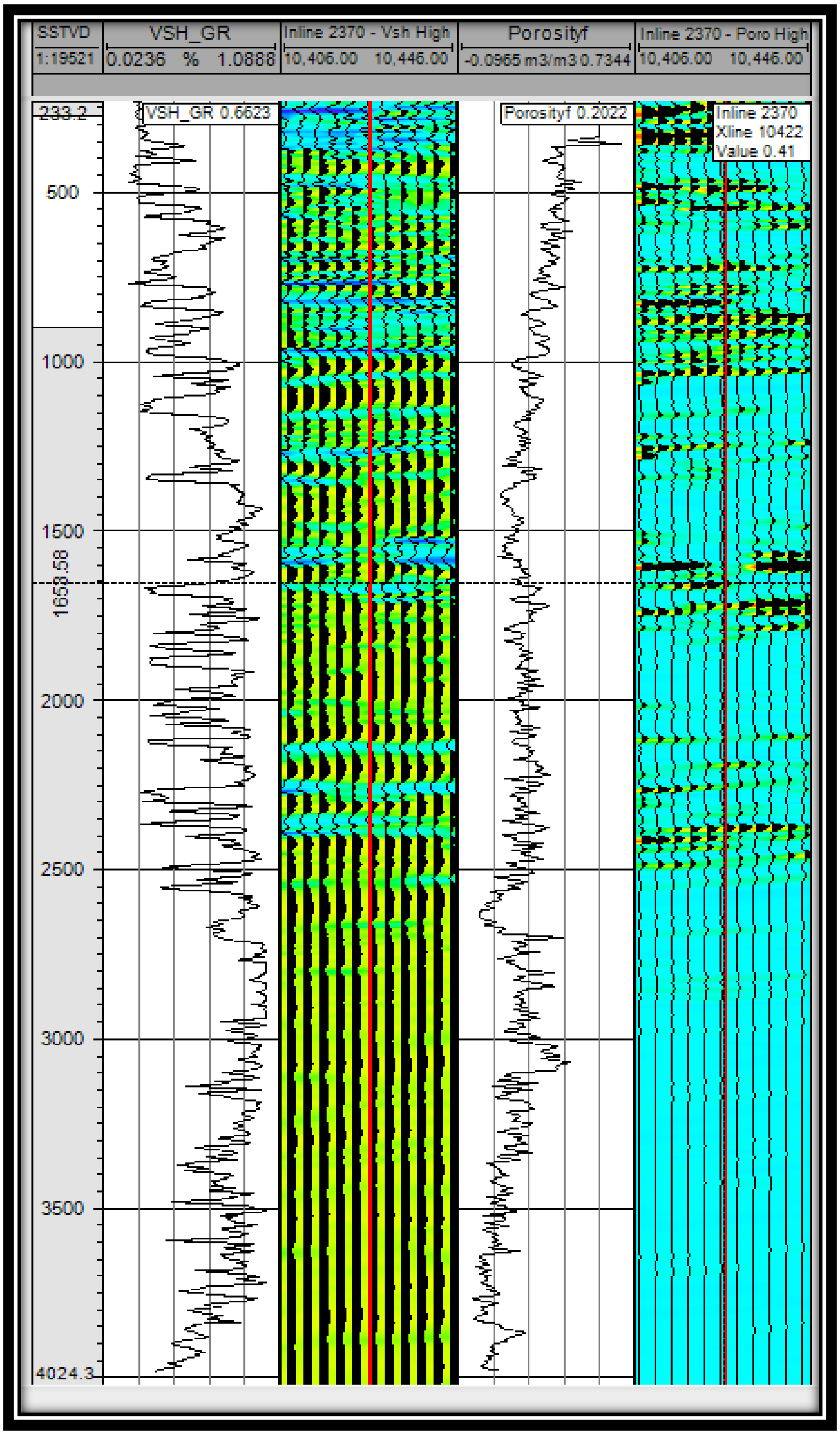


Figure 4.15: Genetic inversion with high input settings

Table 4.3: Porosity log vs Genetic inversion log (High range)

Porosity

Depth (m)	Well Log (m/m3)	Genetic Inversion Log
233	20%	41%
1250	12%	43%
2000	31%	39%
2600	9%	41%

Table 4.4: Vsh log vs Genetic inversion log (High range)

Volume of Shale

Depth (m)	Well Log	Genetic Inversion Log
1350	33%	77%
1653	66%	88%
2000	74%	62%
2600	48%	71%

With the genetic inversion input parameters and settings set at relatively high values the same inaccuracy noticed with the lower input parameters and settings is exhibited here with values for porosity and volume of shale deviating from the well logs by more than 20% in given locations (Figure 4.15).

Genetic inversion vs Well Logs with intermediate/default parameters

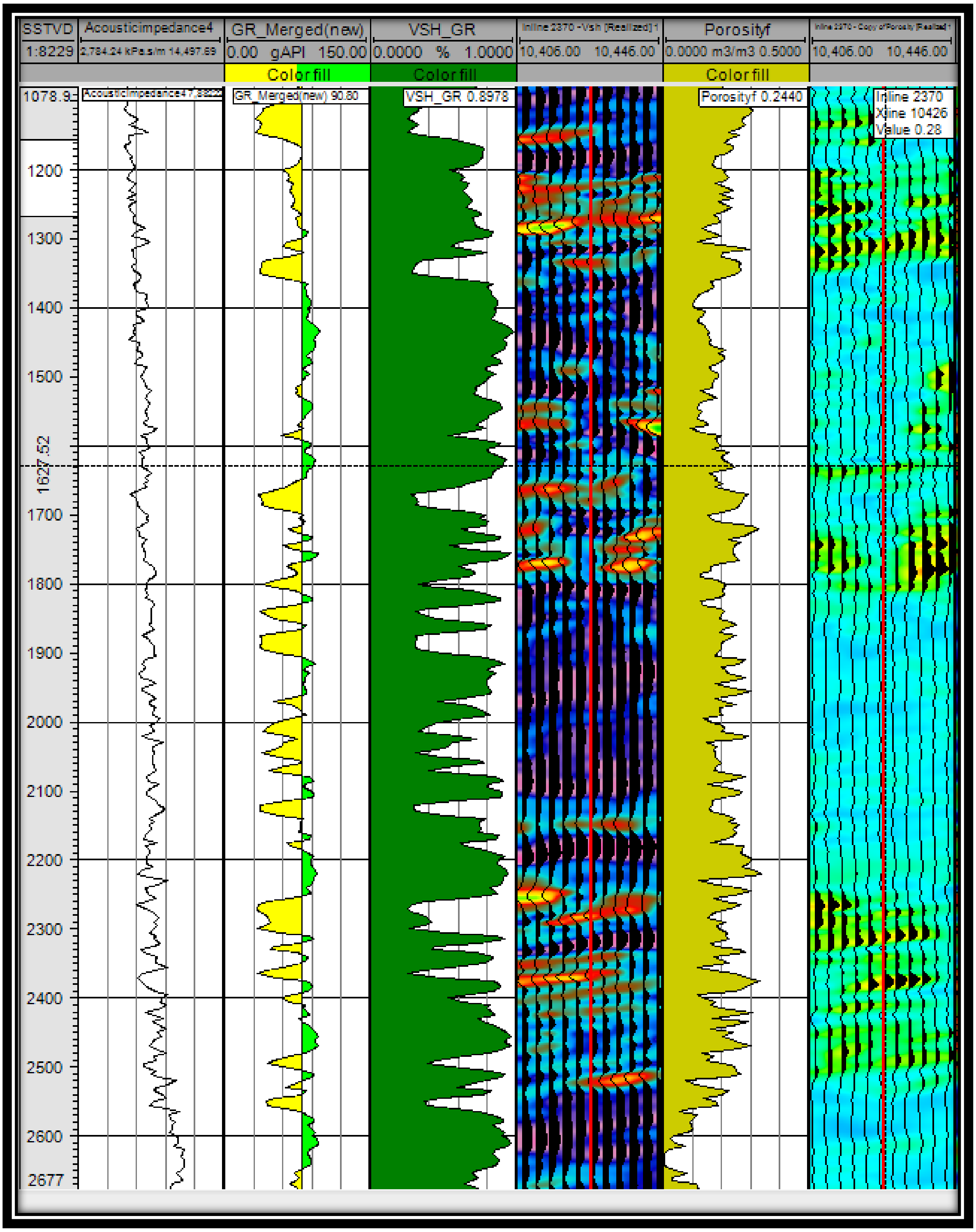


Figure 4.16: Genetic inversion default settings

Table 4.5: Porosity log vs Genetic inversion log (Default range)

Porosity

Depth (m)	Well Log	Genetic Inversion Log
1250	12%	13%
1627	24%	28%
2000	31%	38%
2600	9%	14%

)

Table 4.6: Vsh vs Genetic inversion log (Default range)

Volume of Shale

Depth (m)	Well Log	Genetic Inversion Log
1350	33%	28%
1550	77%	72%
2000	74%	77%
2600	48%	54%

With the genetic inversion parameters and settings set at intermediate/default values the respective property cubes for both Porosity and Volume of shale exhibited an exceptional match with the well logs where the values of the genetically inverted cube do not deviate by more than 5% for Volume of shale and porosity at any location throughout the well logs (Figure 4.16).

4.5 Genetic inversion property cubes

With the intermediate/default genetic inversion parameters and input settings exhibiting a relatively good match to the well logs compared the low and high settings which was to be expected as "Default settings have been set-up to fit the best, to most data sets"(Schlumberger, Petrel 2009) and it was used to carry out the study further. The resultant Volume of shale and Porosity cube are exhibited below (Figures 4.17 & 4.18). These cubes show distinct variation throughout the Volume of shale and Porosity cubes respectively.

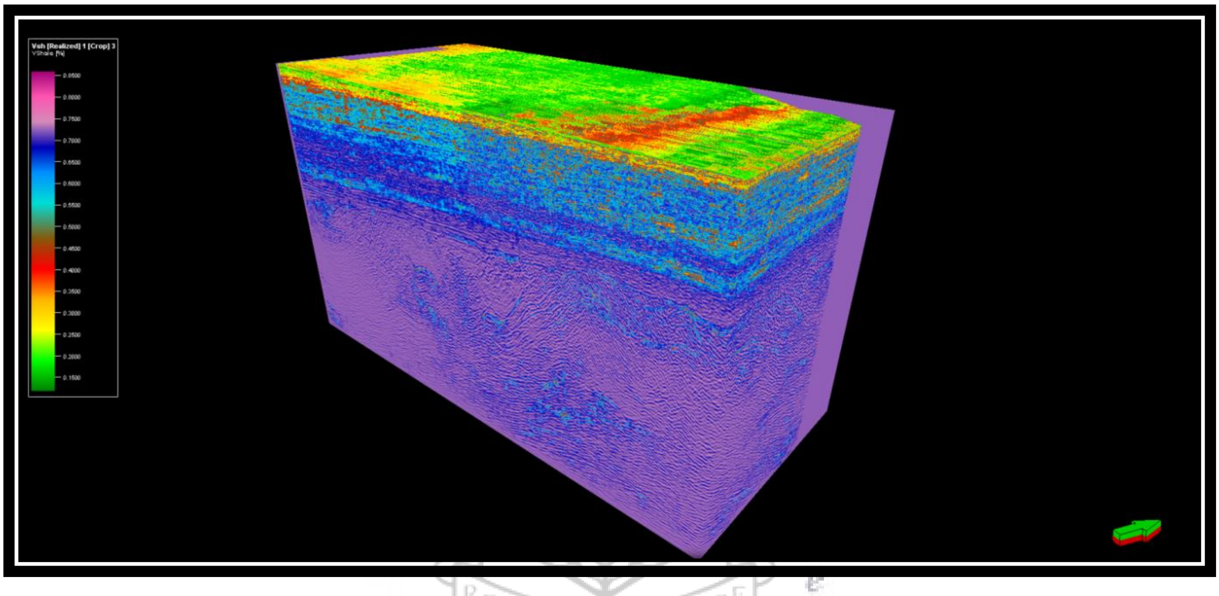


Figure 4.17: Volume of shale cube

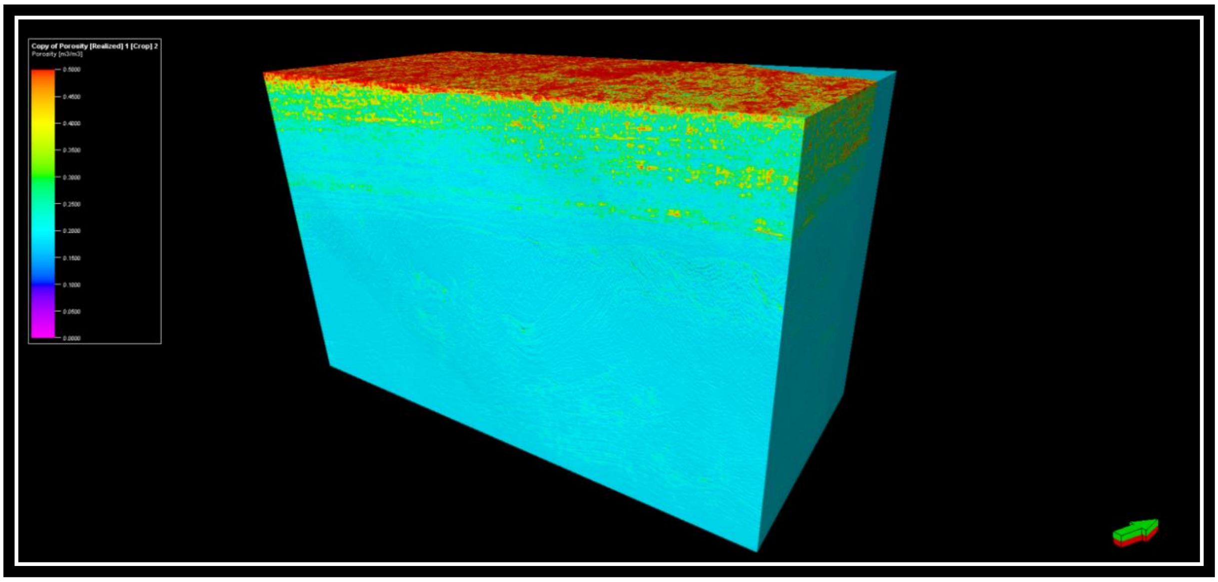


Figure 4.18: Porosity cube

Figures 4.19 & 4.20 exhibit the volume of shale and porosity cubes once an opacity filter has been applied where the undesirable values for volume of shale and porosity respectively have been filtered out. This allows for a clearer visualisation of areas within the cube which are considered desirable in terms of reservoir properties.

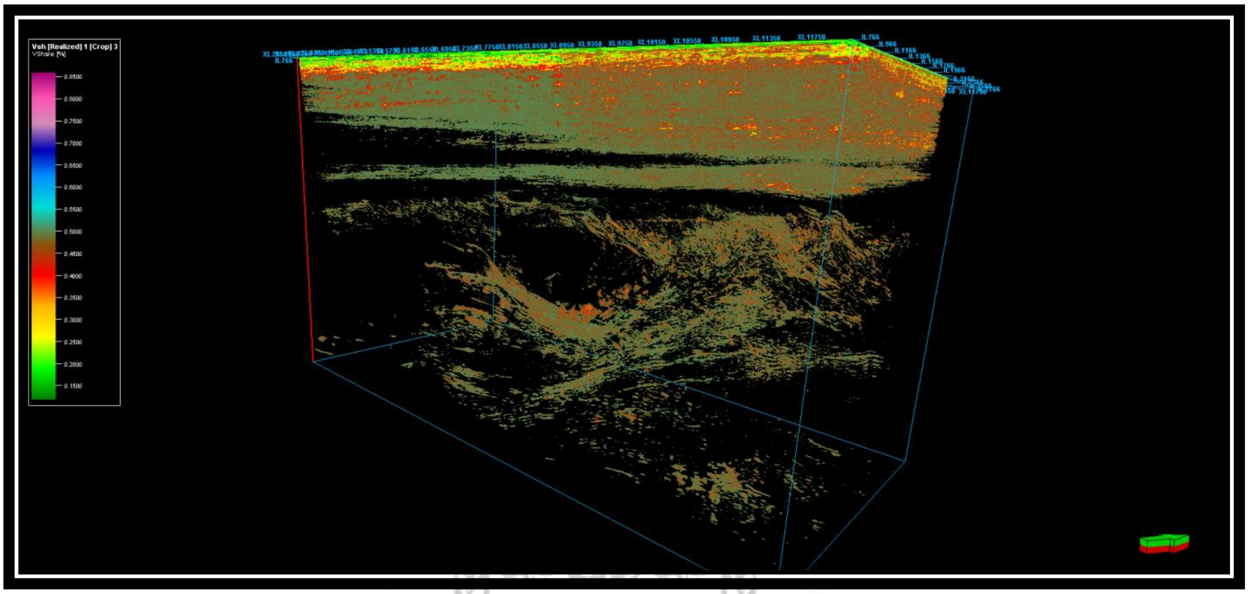


Figure 4.19: Filtered Volume of shale cube

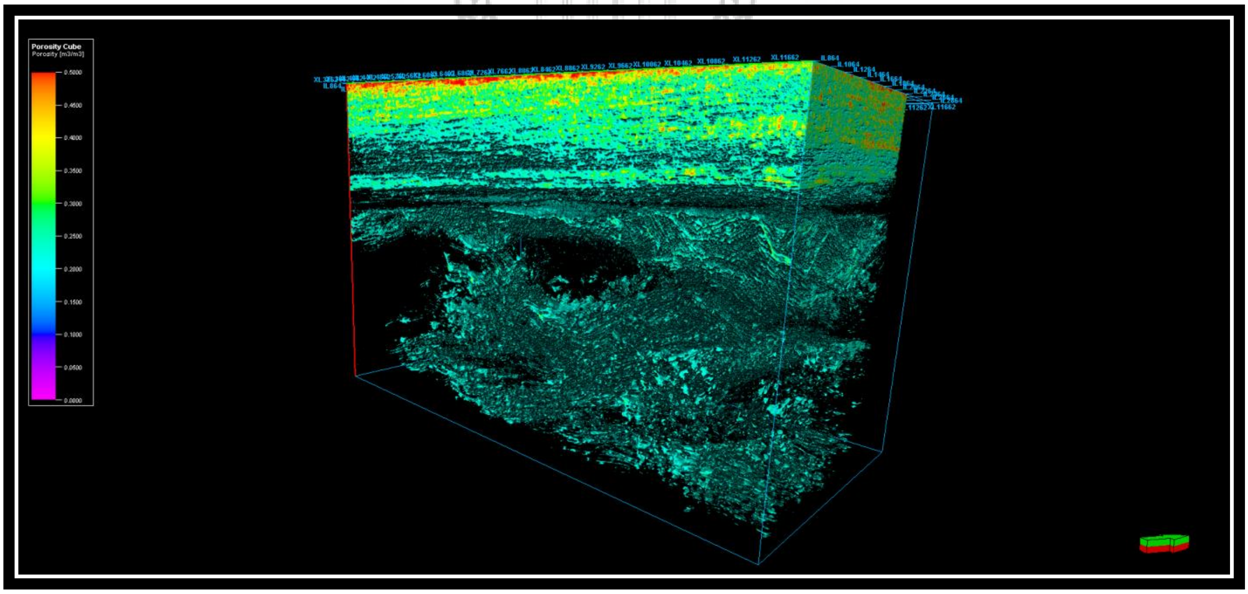


Figure 4.20: Filtered Porosity cube

4.6 Geometrical Modelling

Geometrical modelling is used to provide a solution related to only one well being drilled within the seismic survey, as the conventional method of upscaling well logs as the initial step of petrophysical modelling wouldn't be considered as a useful method as upscaling is used to predict reservoir properties between wells and this is redundant with only 1 well being used.

Geometrical modelling with the use of the Seismic Resampling method was used to populate the structural model with reservoir properties derived from the genetically inverted seismic property cubes therefore creating Petrophysical models of the desired reservoir properties

4.7 Property Modelling

4.7.1 Porosity

The colour scale red indicates areas of low porosity, yellow and orange indicate areas of intermediate porosity and areas represented by blue to purple exhibit high porosity.

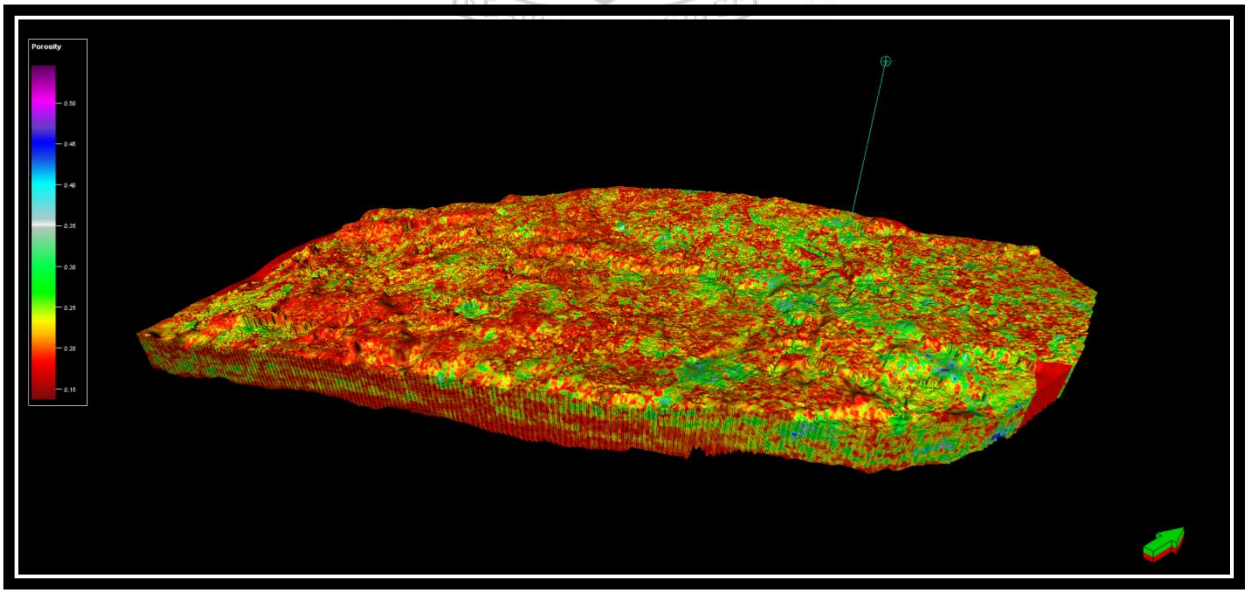


Figure 4.21: Porosity model

This Petrophysical model (Figure 4.21) exhibits porosity distribution throughout the reservoir interval. As can be seen areas of high porosity are concentrated in the more proximal portion of the study area which is related to channel complexes where coarser/ cleaner sand sediments were deposited.

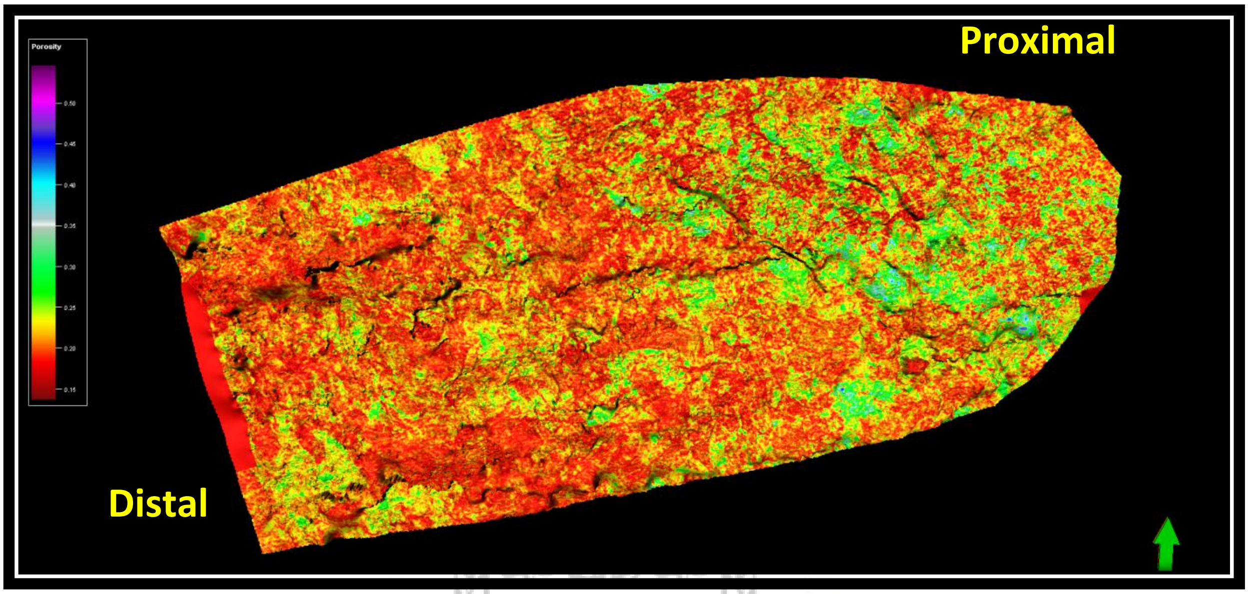


Figure 4.22: Porosity model (Top view)

From the resulting petrophysical model (Figure 4.22) and observation of the upper reservoir zone A, it is evident that coarser sediments resulting in high porosity was deposited in the more proximal setting of the study area which is interpreted as the higher energy transport system s as high depositional rates would be present in the proximal setting.

However what is also clearly exhibited by the Porosity model is that high porosity is not strictly defined to the more proximal setting of the reservoir interval as clear variation in porosity distribution is evident at different depths, which is related to the flow and sinuosity of the various channel complexes.

4.7.2 Volume of shale

Regarding the Volume of shale model (Figure 4.23), the colour scale shows that areas represented by green to yellow exhibit high volume of shale, red indicates intermediate volume of shale and blue represents low volume of shale

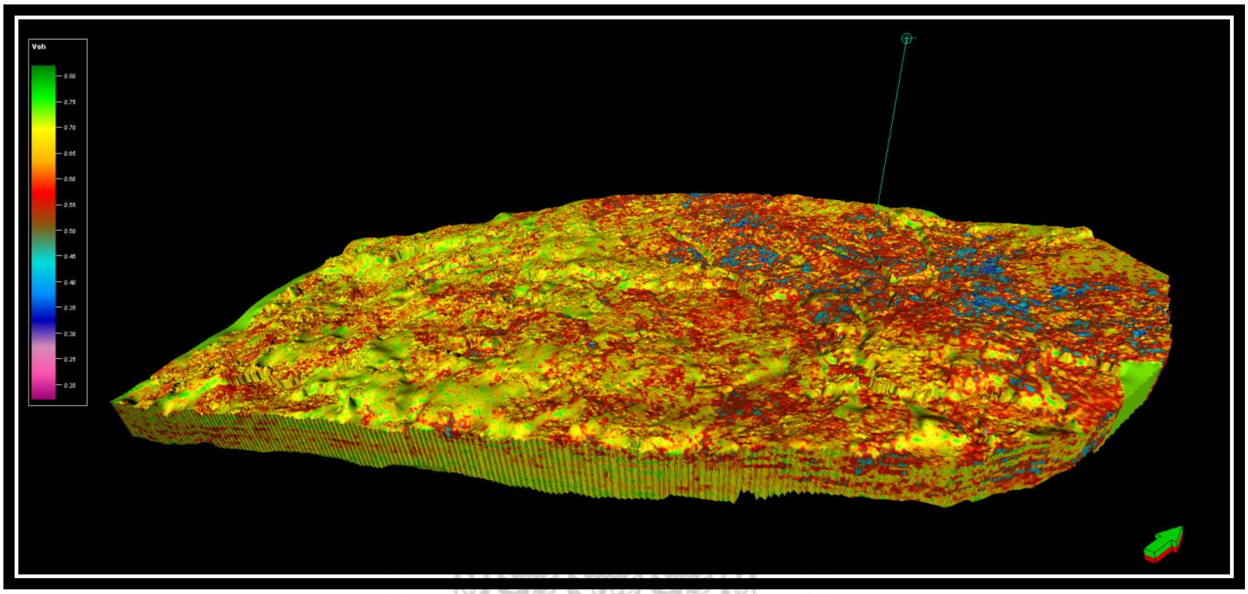


Figure 4.23: Volume of shale model

The Volume of shale model exhibits shale distribution which directly relates to the distribution of high porosity values as high volume of shale would relate to low porosity and low volume of shale would relate to low porosity areas. The volume of shale model (Figure 4.24) exhibits low volume of shale distribution in the more proximal setting with higher volume of shale distribution occurring in the more distal portion of the model, which is characteristic of a transitional environment and not a marine setting which was the initial prognosis, as sediment distribution is directly related to the energy of transport of the sediments which dissipates from the proximal setting to the distal setting.

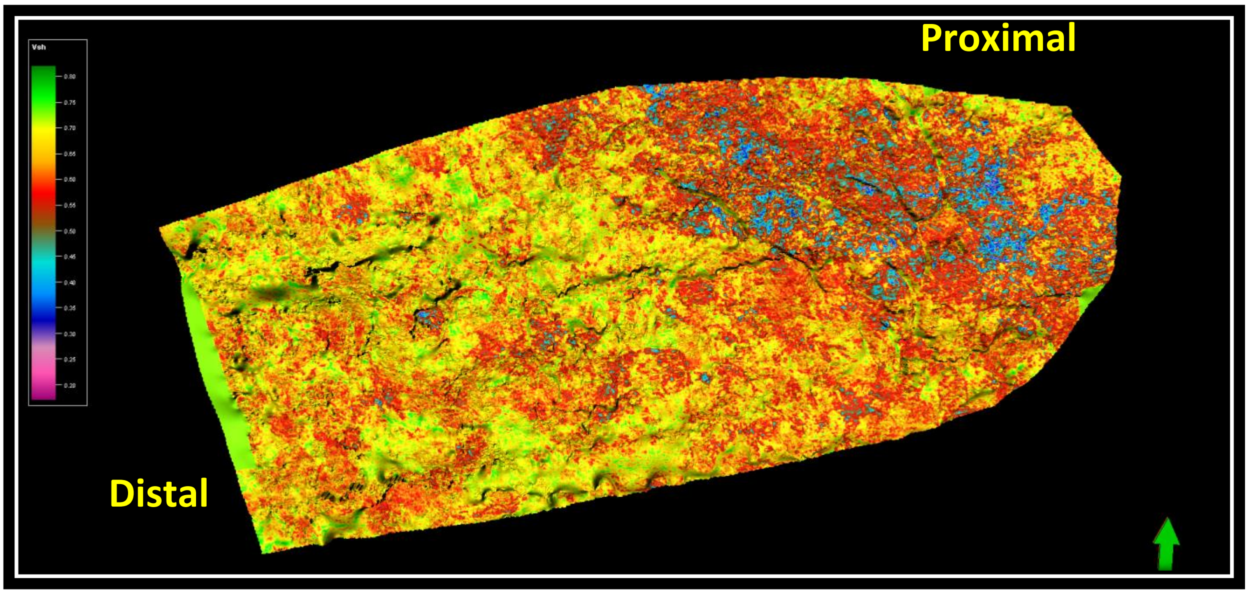


Figure 4.24: Volume of shale model (top view)

4.7.3 Common Risk Segment/ Optimum reservoir model

By using the seismic calculator in Petrel it was possible to create a Common Risk Segment/Optimum Reservoir model (Figure 4.25 & 4.26) based on the classifying the combination porosity and volume of shale to determine areas of optimum reservoir.

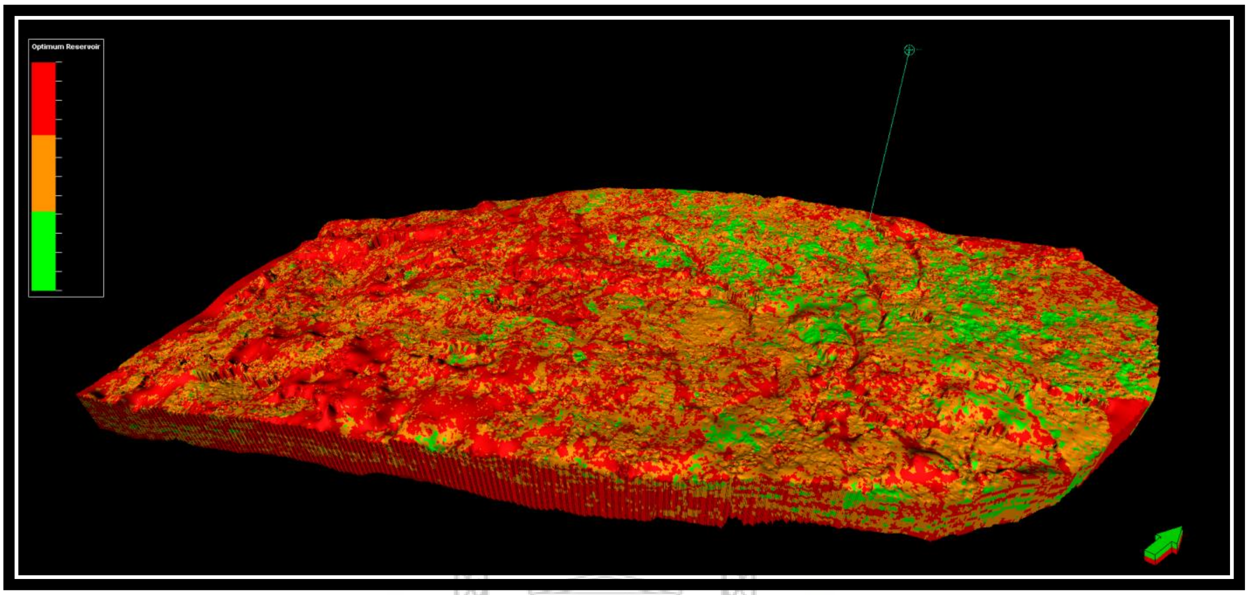


Figure 4.25: Optimum reservoir model

The model is categorized into 3 different classes Green, Orange and Red. Green areas represent the most optimum reservoir characteristics in terms of high porosity and low volume of shale. Orange represents intermediate reservoir quality in terms of intermediate porosity and volume of shale. Red represents the least optimum reservoir potential as it represents areas where porosity is lowest and volume of shale is highest.

Green represents all are areas where porosity is greater than 22% and Volume of shale is less than 50%, Orange represents areas where Porosity is between 14% - 22% and Volume of shale is between 50% - 70%. Red indicates areas where porosity is less than 14% and Volume of Shale is greater than 70%. Even though these categories might not be representative of good or bad reservoir qualities in terms of porosity and volume of shales relative to other basin, it is specific to the study area.

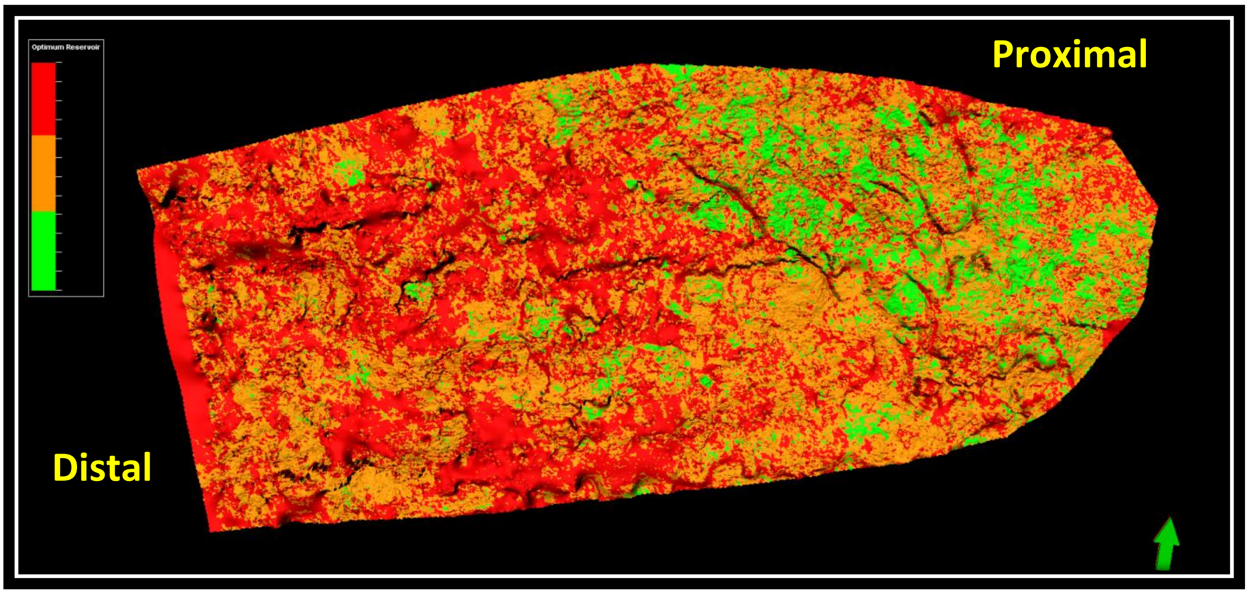


Figure 4.26: Optimum reservoir model (Top view)

It is important to view the Optimum reservoir model at different depths to have an understanding of the lateral and vertical variation of the reservoir interval at different depths.

Figure (4.27) represents the reservoir interval at a depth of 2200m at the base of reservoir zone A, examining reservoir zone A at different depths in the model showed a relatively consistent reservoir distribution both laterally and vertically.

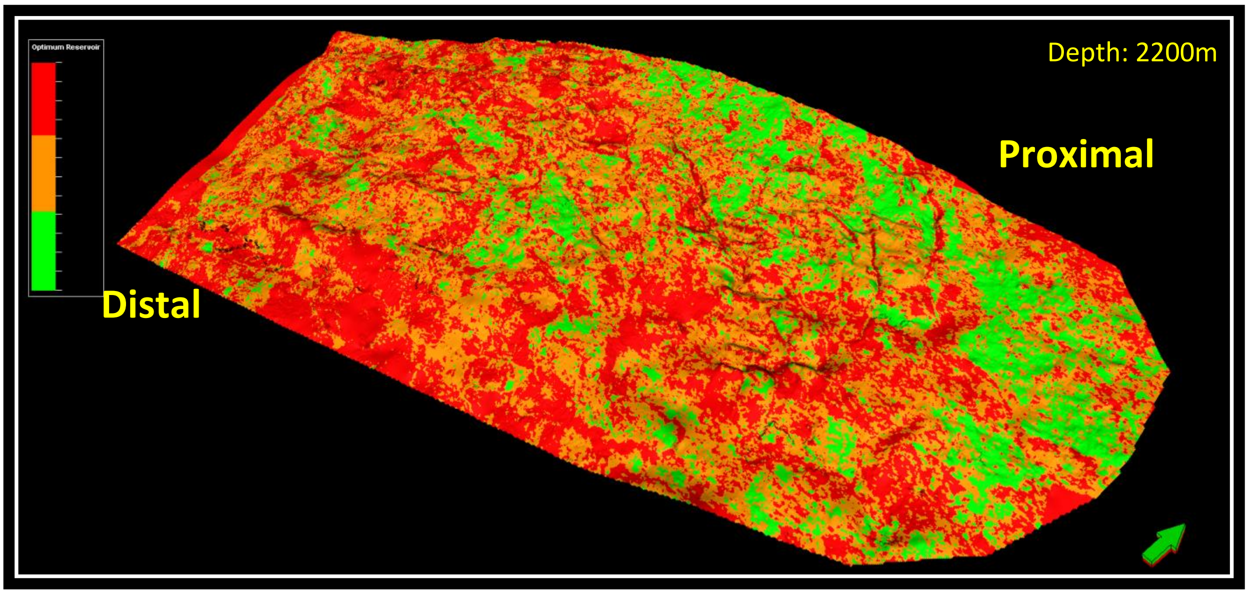


Figure 4.27: Optimum reservoir model Reservoir Zone A

Figure (4.28) represents the reservoir interval at a depth of 2460m at the base of reservoir zone B, examination of reservoir zone B at different depths showed clear variation in reservoir distribution both laterally and vertical.

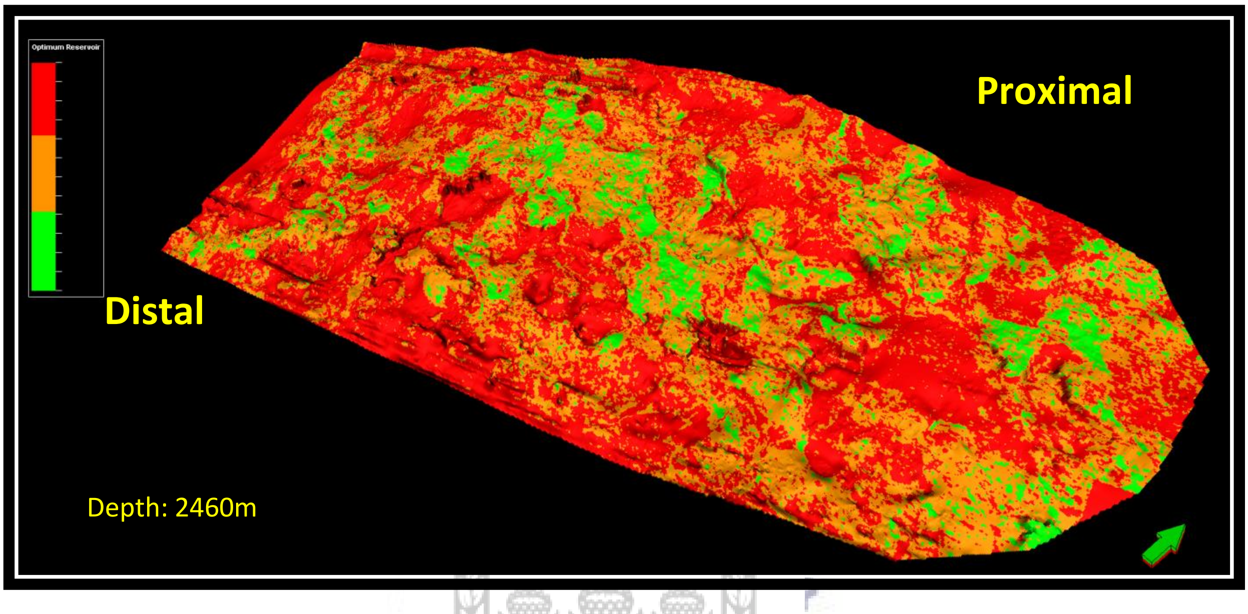


Figure 4.28: Optimum reservoir model Reservoir Zone B

The channels in the upper portion of the reservoir interval seems to be smaller in width as well as length however seem to exhibit a stacking or channel complex structure which relates to the concentration of optimum reservoir properties being concentrated in the proximal setting of the basin. This observation is presumed due to the optimum reservoir properties not being confined to the sinuosity of a single channel which suggests multiple channels are present i.e. channel complex.

It is clear that the optimum reservoir distribution is related to the sinuosity of the channels present in the area. This mostly evident in reservoir zone B as the channels are much larger in relation to the channels in the upper interval of the reservoir. What is also evident from examining the optimum reservoir model at different depths, within the reservoir zone B is a splay/lobe type structure (Figure 4.29 & 4.30) exhibiting good reservoir properties. This observation from the optimum reservoir model is also consistent with seismic interpretation.

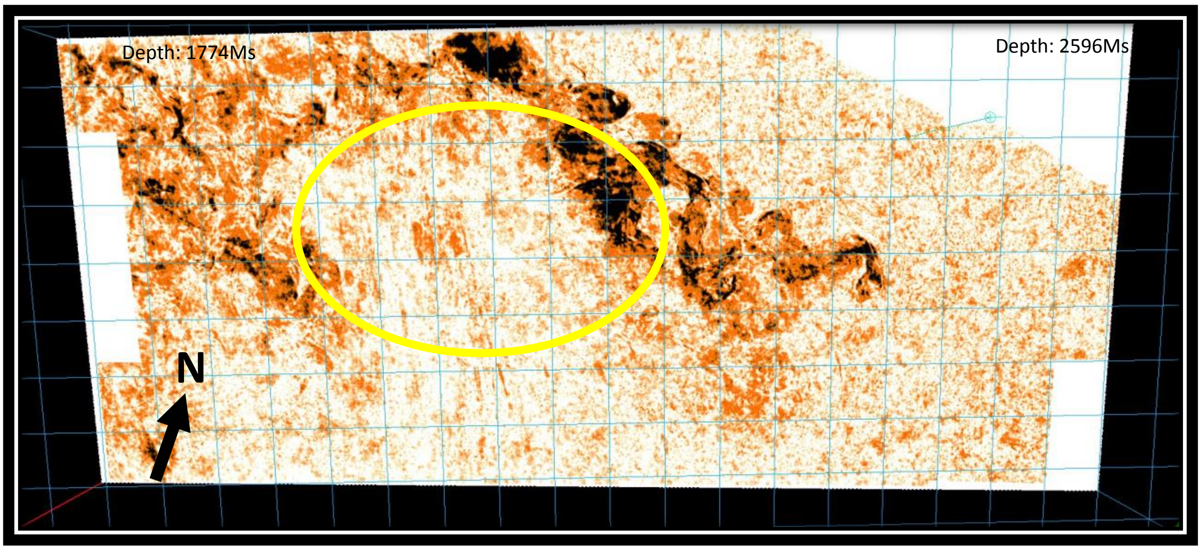


Figure 4.29: Sweetness attribute Reservoir Zone B intersection

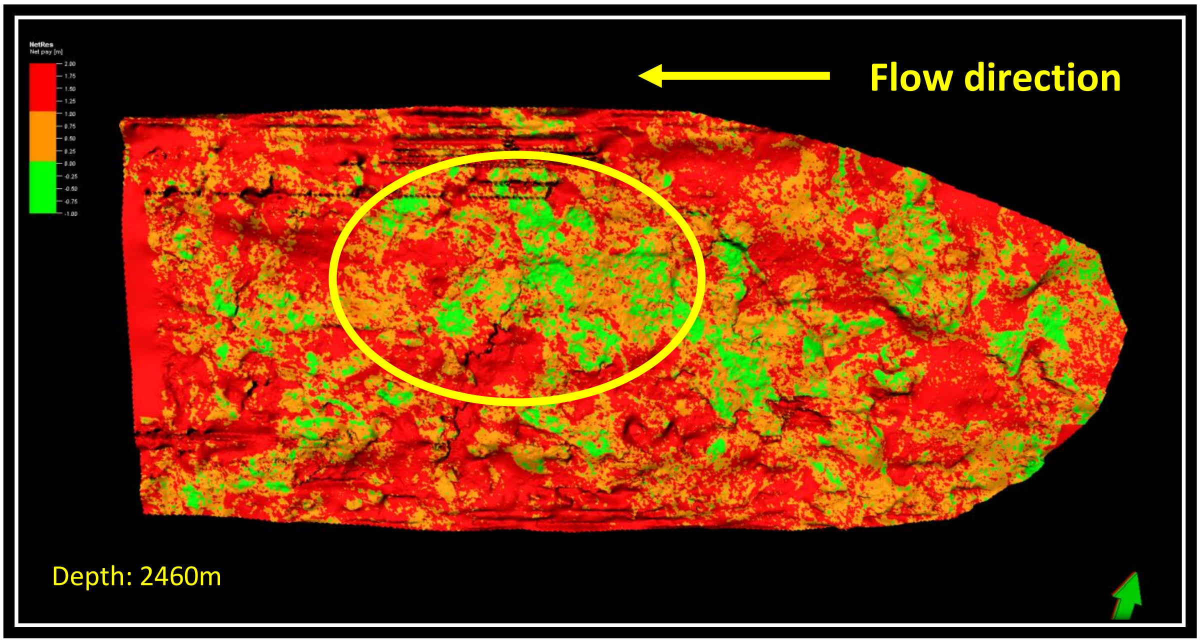


Figure 4.30: Optimum reservoir model Reservoir Zone B

4.7.4 Root Mean Square Amplitude

RMS amplitude is a common tool used in exploration to determine areas and the distribution of “Clean sand” i.e. High porosity and low volume of shale. Figure (4.31) represents the Seismic cube populated with RMS amplitude values.

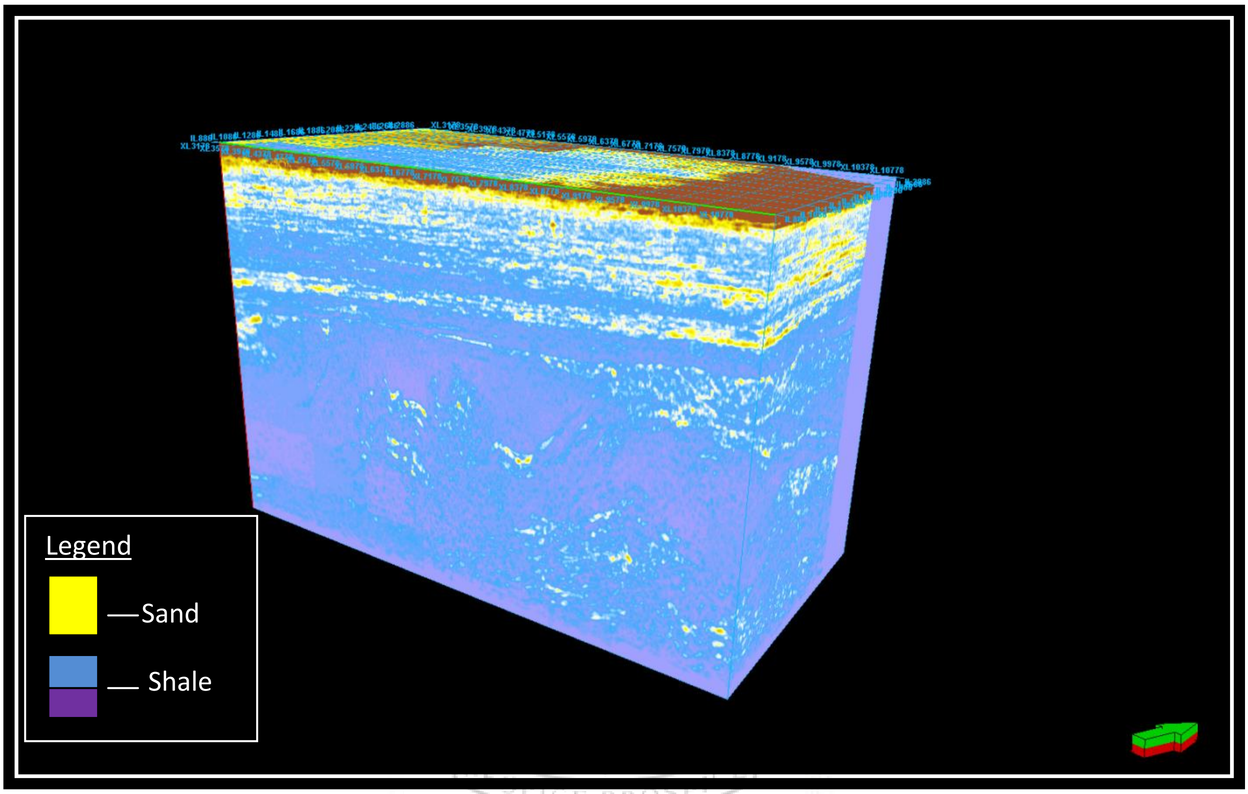


Figure 4.31: Root Mean Square Amplitude cube

Figure (4.32) represents the RMS amplitude cube after the undesirable low RMS amplitude values are filtered out. The low RMS amplitudes values represent areas of high volume of shale and low porosity and therefore area considered undesirable in terms of reservoir characterization.

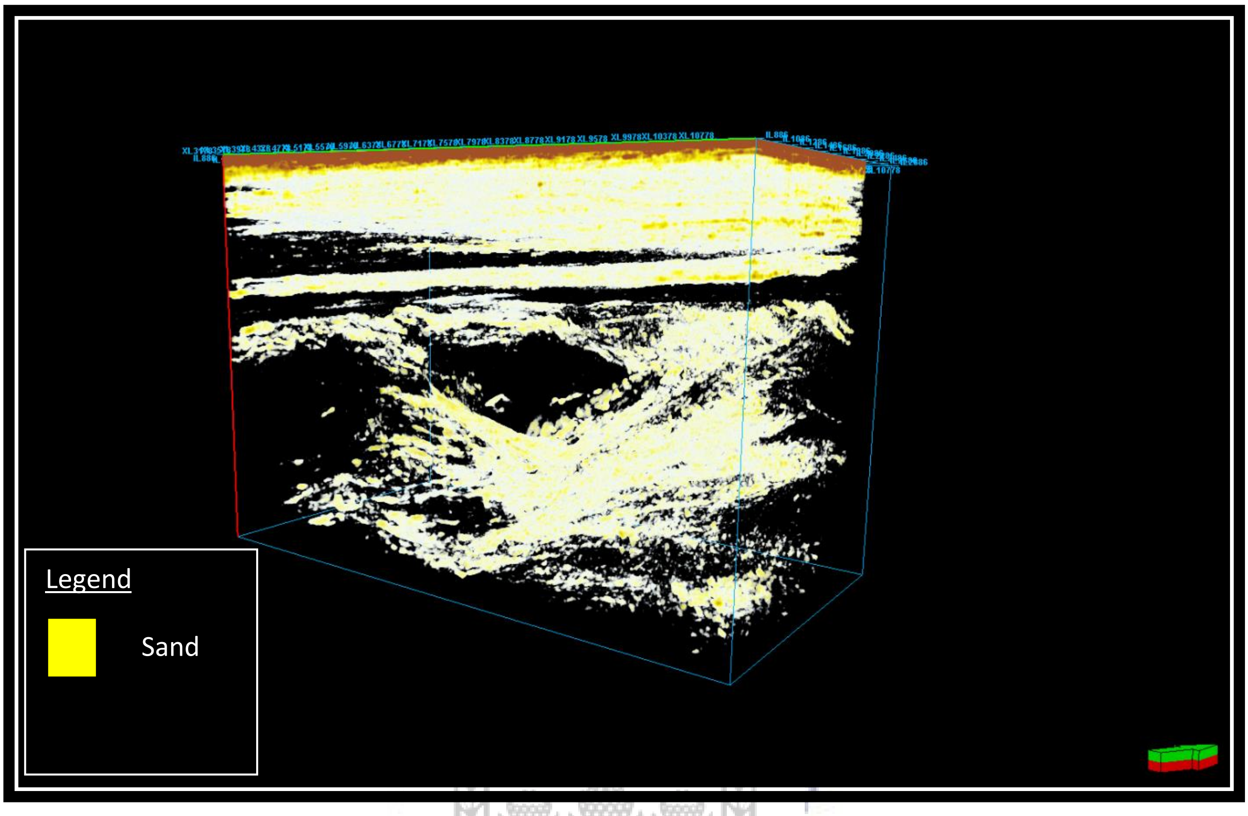


Figure 4.32: Filtered RMS amplitude cube

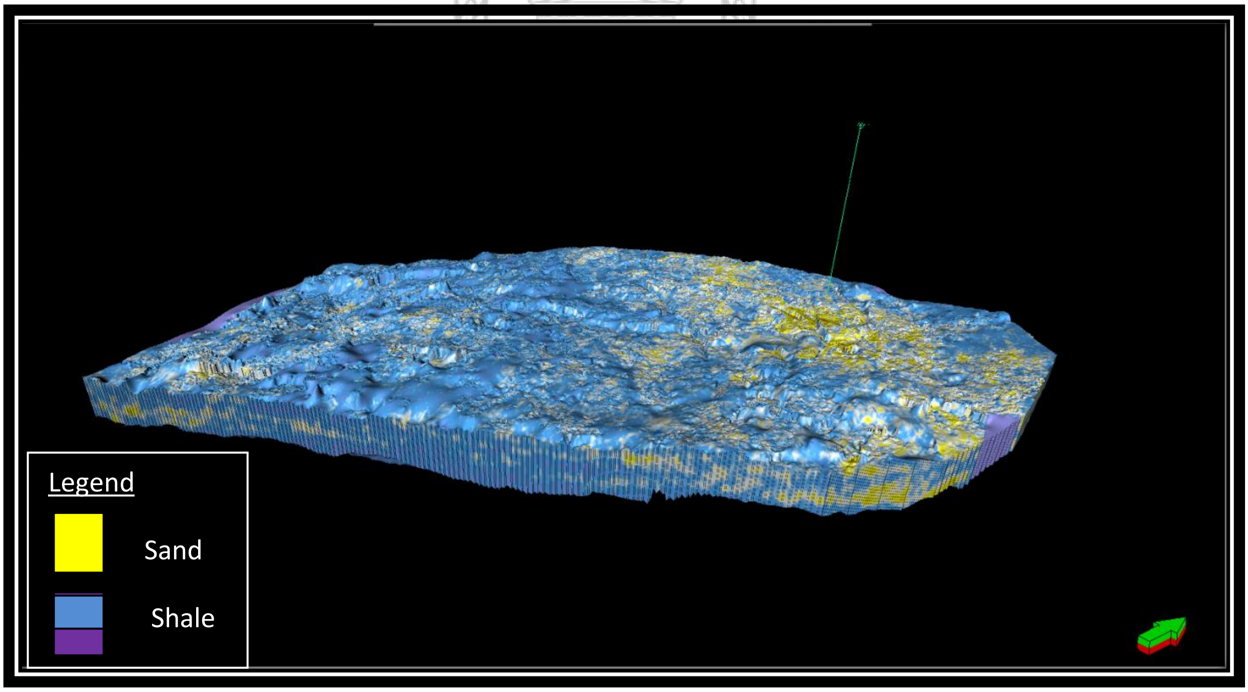


Figure 4.33: RMS amp reservoir model

By creating a RMS amplitude model (Figure 4.33) and comparing it to the Petrophysical models and Commons Risk segment (Optimum Reservoir) model a clear correlation can be seen regarding high porosity and low volume of shale i.e. clean sands which provides solid evidence regarding the accuracy of the petrophysical models.

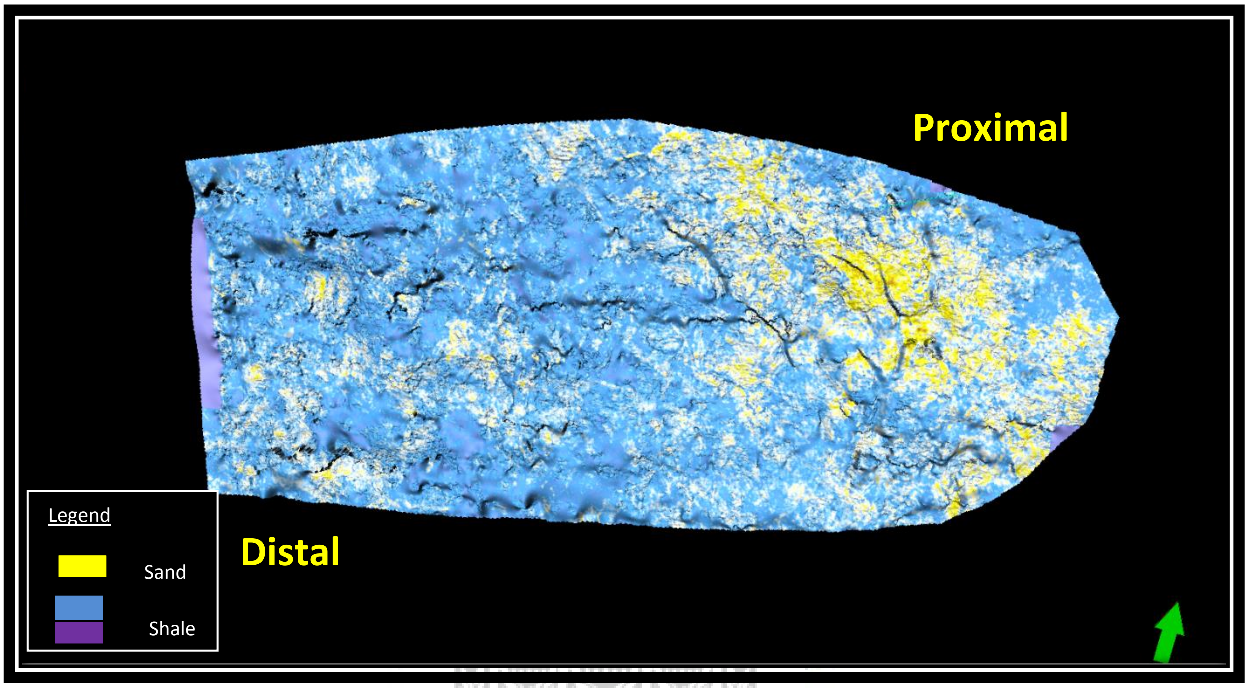


Figure 4.34: RMS amp reservoir model (Top view)

When the Net Reservoir model is compared to the RMS amplitude model (Figure 4.34) the correlation between areas of optimum reservoir conditions and high RMS amplitudes is excellent. This comparison further justifies the accuracy of the petrophysical models derived from genetic inversion.

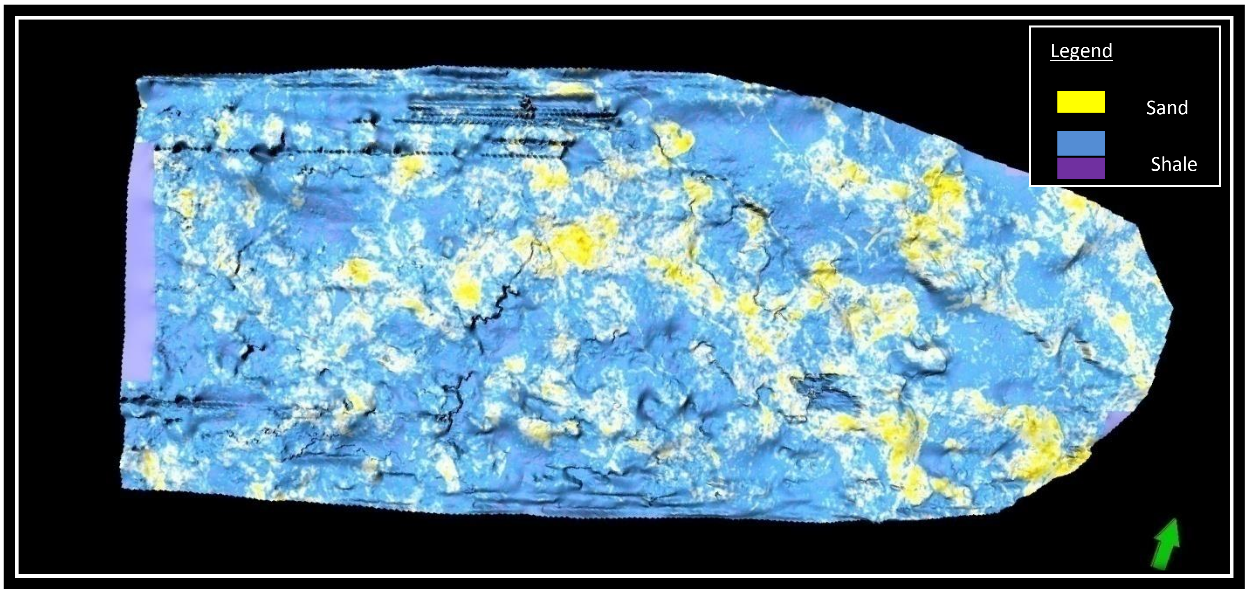


Figure 4.35: RMS amplitude model Reservoir Zone B

When the RMS amplitude model (Figure 4.35) is examined at a depth of 2460m (Base of reservoir zone B), the sinuosity of the inferred channels and splay/lobe structure is excellently exhibited.

All though the RMS amplitude model provides justification if the accuracy of the petrophysical and net Reservoir models the major benefit and difference between the petrophysical and RMS amplitude model is that Porosity and Volume of Shale distribution can be quantified in terms of knowing what the porosity and volume of shale values are in certain area. Therefore the RMS amplitude model can be seen as a qualitative model and the Petrophysical models derived from genetic inversion can be seen as a Qualitative and Quantitative model.

4.7.5 Producing interval

As previously mentioned Well A-F1 produced gas, however the reservoir showed signs of depletion. Due to the initial prognosis of a marine depositional environment of the area the well was not expected to intersect any channel reservoirs. However core analysis of the producing interval exhibited lithology characteristics of a channel depositional environment.

By using the combination of the Sweetness seismic attribute and horizontal slice tool. A seismic intersection was created at the producing interval depth. (Figure 4.36. 4.37 & 4.38)

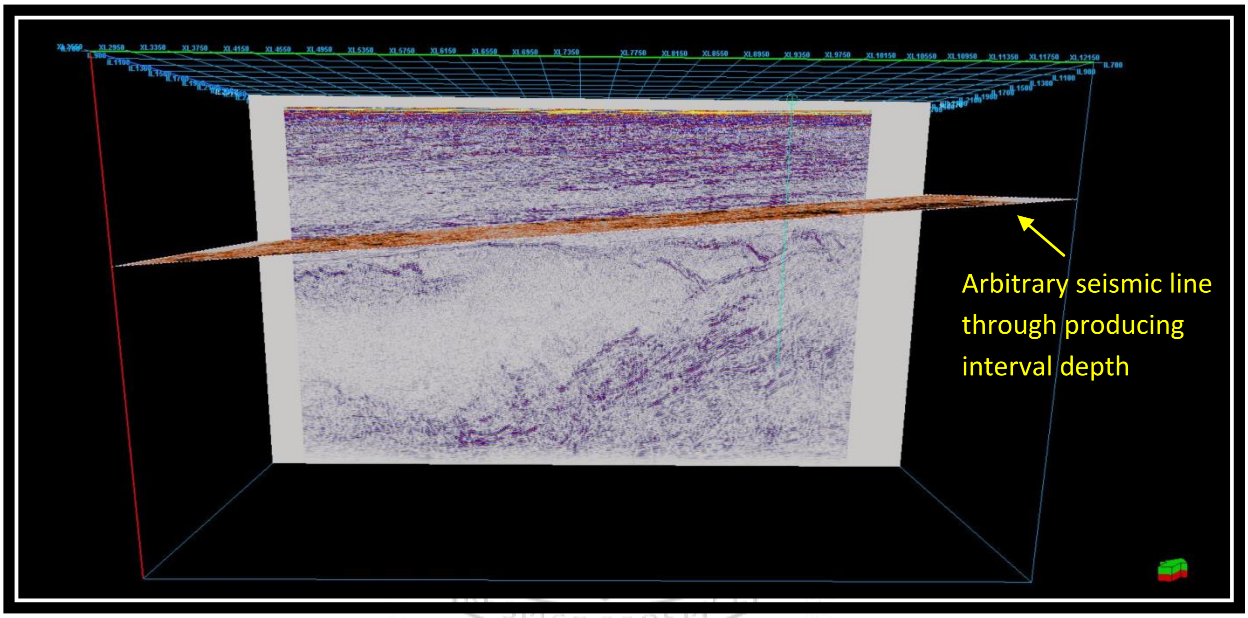


Figure 4.36: Sweetness attribute intersection at producing interval depth

This seismic intersection (Figure 4.37 & 4.38) clearly highlighted the channel which was intersected by the wellbore which resulted in the hydrocarbon gas discovery. However more detailed seismic interpretation showed that the well actually intersected an Ox box lake/ Meandering scar deposit which would exhibit the same depositional characteristics as a channel.

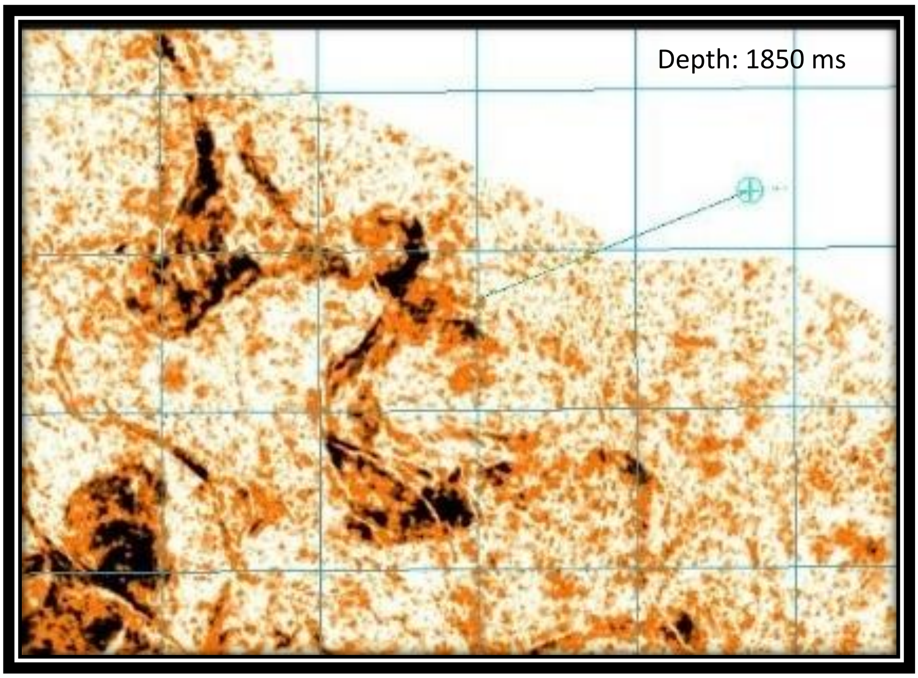


Figure 4.37: Sweetness attribute at producing interval (Top view)

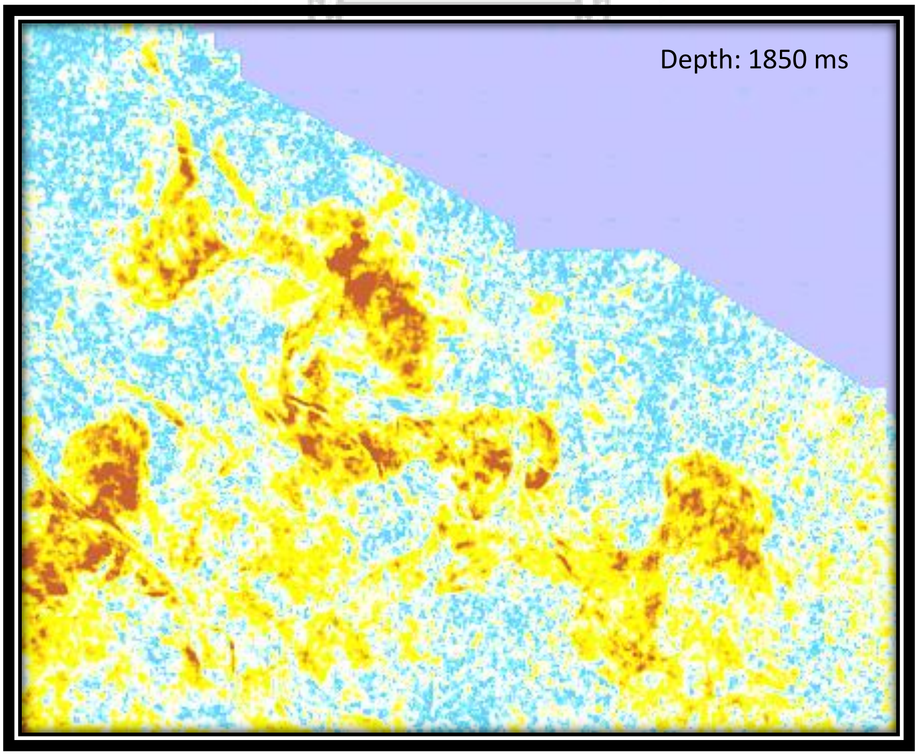


Figure 4.38: RMS amplitude intersection producing inteval

The signs of reservoir depletion can also be related to the well bore intersecting a ox bow lake/ meandering scar deposit as the potential reservoir volume would be significantly less as the channel deposit located just East of where the well bore intersected

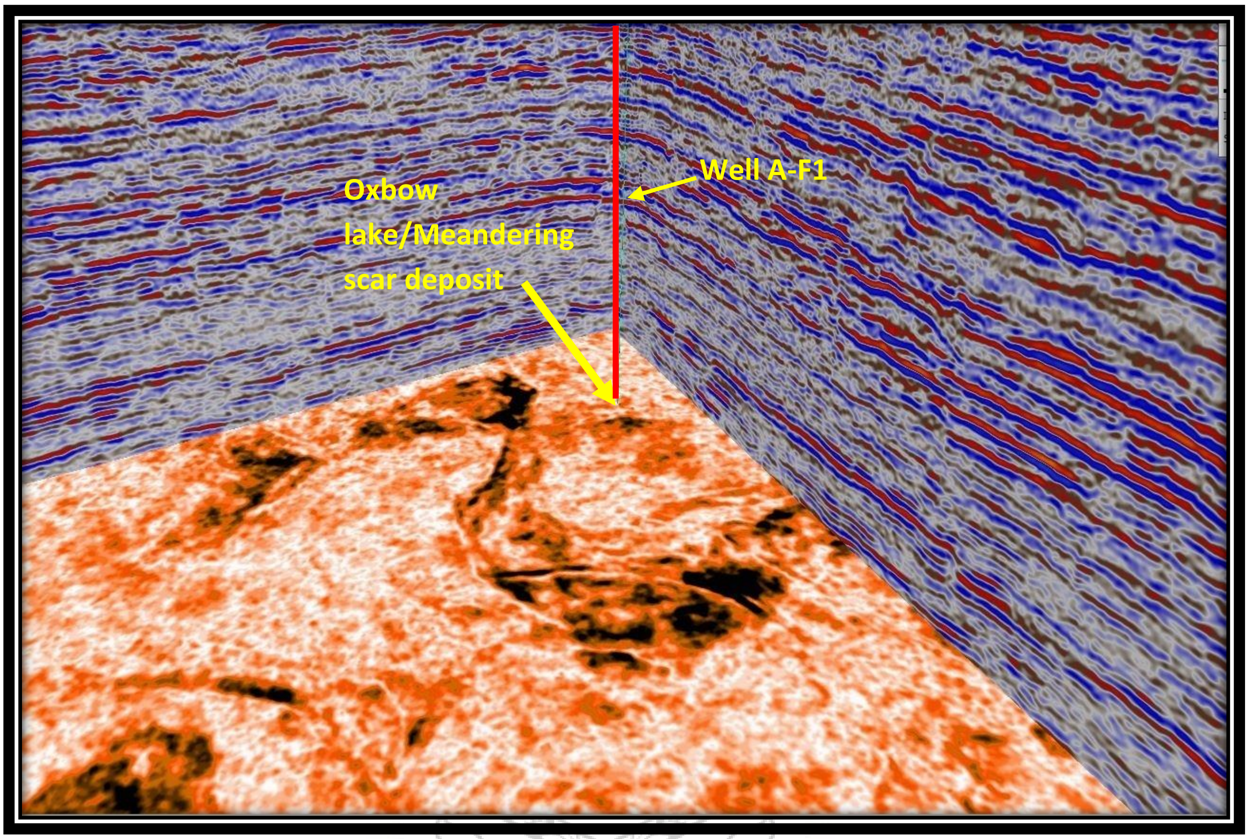


Figure 4.39: Well intersection of producing interval (Sweetness attribute)

Figure (4.39) shows that the well bore intersected an ox box lake/ meandering scar deposit which would also exhibt good reservoir properties as a channel would. However relatively large channel East of where the well bore was drilled could represent a potential hydrocarbon reservoir due to it volume and good reservoir properties which should be similar to the producing interval intersected by the well bore location. The relativly small volume of the ox bow lake/meandering scar reservoir deposit can explain why the reservoir showed signs of depletion relatively quickly.

Figure (4.40) represents a conceptual model of the presumed deopitional environment of the producing interval reservoir

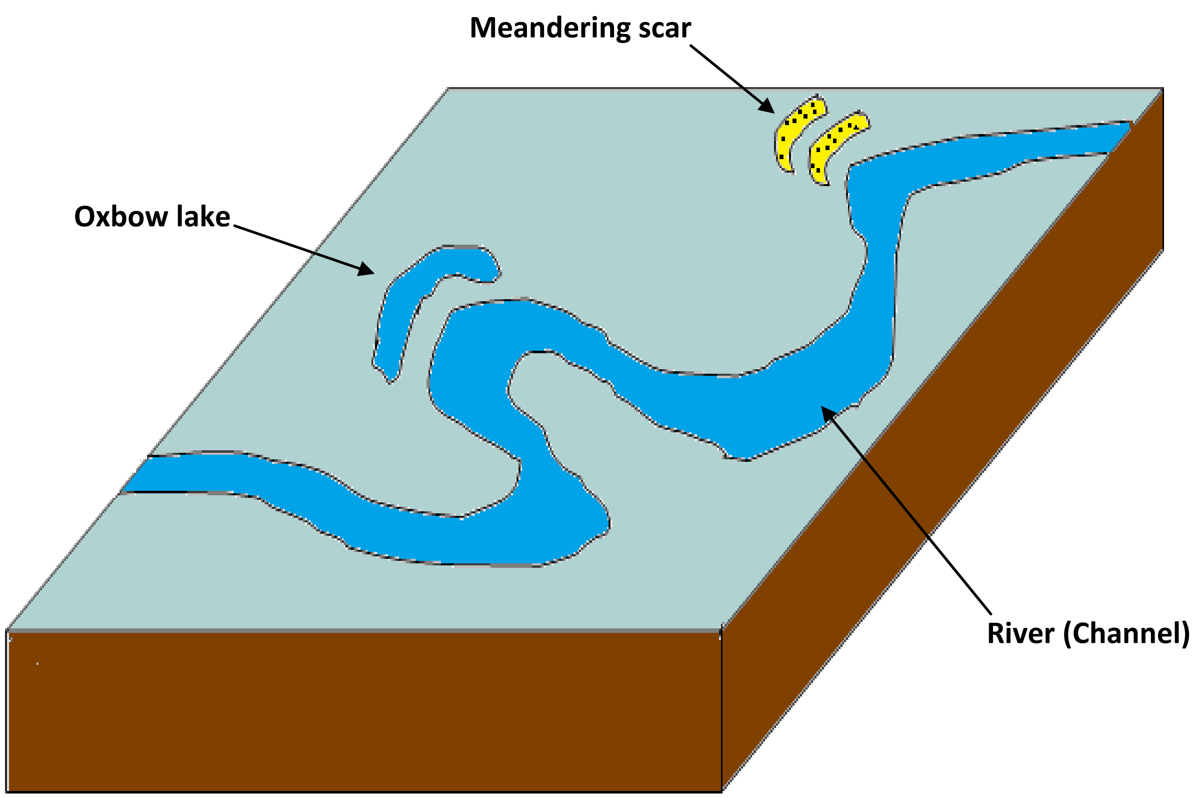


Figure 4.40: Conceptual model of depositonal environment producing interval

4.8 Depositional environment

It is evident from seismic interpretation with the aid of the horizontal slice tool and Sweetness seismic attribute that the depositional environment for the delineated reservoir interval is related to a transitional setting, with numerous and large channel complexes present in the study area. Also evident was a distinct difference of deposition between reservoir zone A and reservoir zone B.

The transitional depositional environment is further justified by the Petrophysical model, as the model exhibits high porosity in the more proximal portion of the study area and lower porosity in the more distal portion of the study area which is consistent to a transitional setting as coarser heavier sediments would be deposited in an high energy environment related to proximal portion of the study area and as the deposition energy dissipates moving towards the distal portion of the study area finer and therefore less porous sediments would be deposited there.

More evidence relating to a transitional depositional setting is exhibited by the Petrophysical porosity model by high porosity values forming a Splay structure exhibited in reservoir zone B and due to its relative size it most likely a Lobe deposit where a channel splayed its coarse sediments. It is possible that this splay structure exhibiting high porosity values could also be related to a Crevasse splay but conventionally Crevasse splay deposits are not of such a large size. This large lobe deposit would place the deposition of reservoir zone B much closer to a lower fan depositional setting.

By examining a horizontal time slice following the dip of the reservoir model even more justification of the depositional setting is found as with the aid of the "Sweetness" seismic attribute a large channel is displayed exhibiting mouth region of a splay deposit.

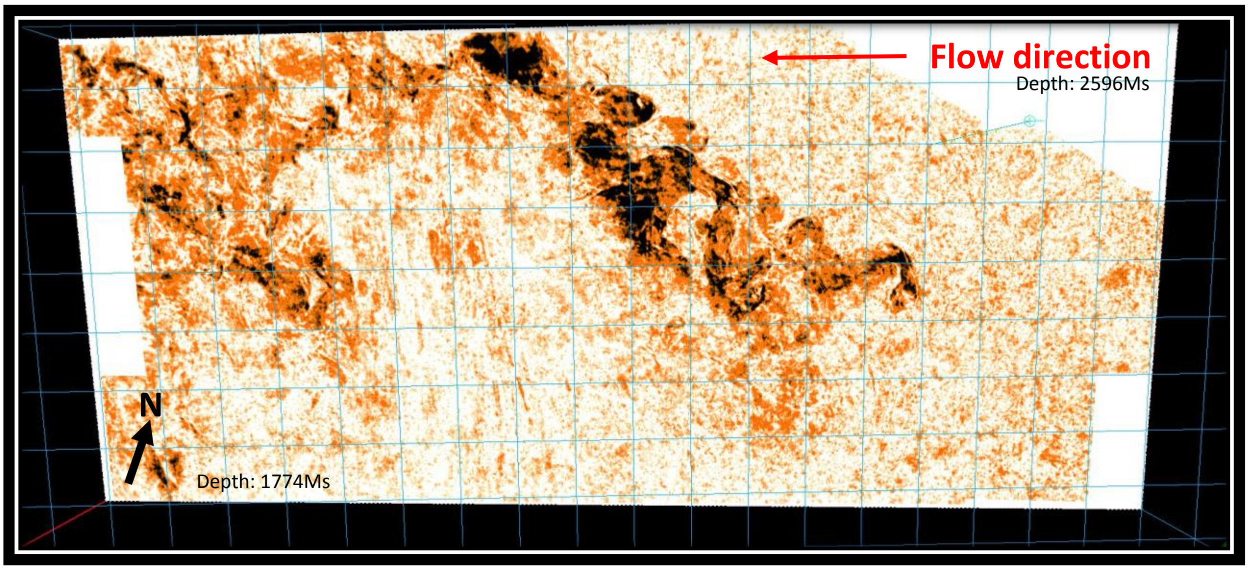


Figure 4.41: Sweetness attribute interection

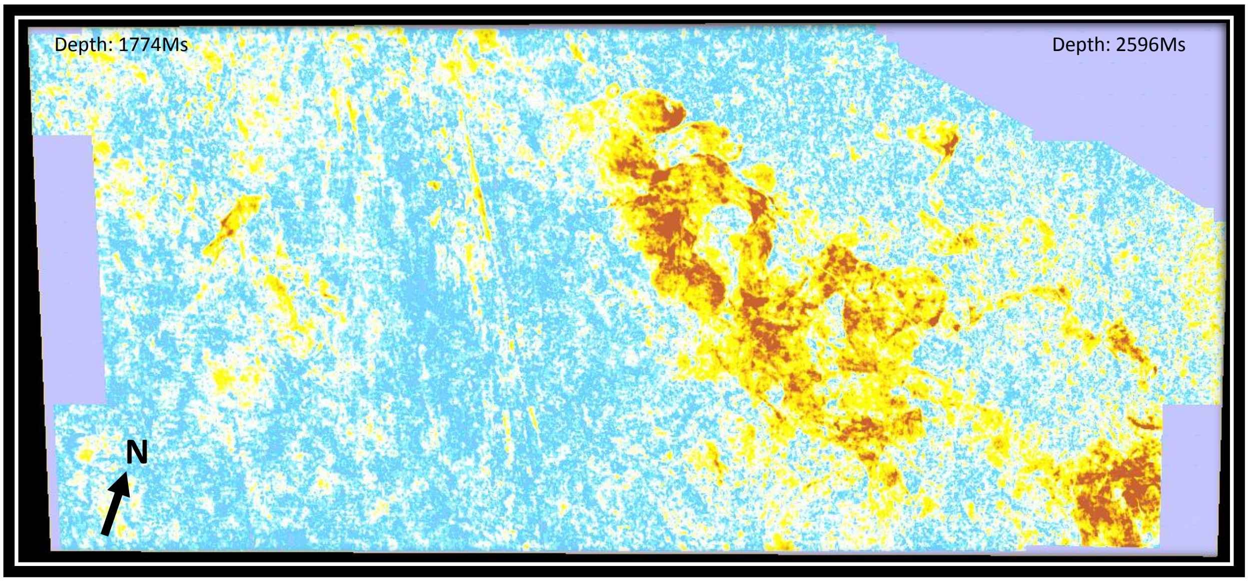


Figure 4.42: RMS amplitude intersection

The Seismic intersection (Figure 4.41 & 4.42) through the reservoir zone displays a channel flowing from the proximal portion towards the distal portion of the study area as well as the mouth of a splay structure which is consistent with the Petrophysical porosity model.

From interpretation of the Petrophysical model and seismic intersection it clear that a Transitional setting is found in the study area and not a Marine setting as which was initially prognosed. The high porosity values found in the high energy proximal portion of the study area is related to Channel complexes and low porosity values is related to the distal setting where lower depositional energy would have deposited finer sediments.

From the Petrophysical models for porosity and volume of shale the depositional environment for this reservoir interval is interpreted to be a classic fan depositional environment with reservoir zone A being concentrated in the more upper to middle fan environment of the slope and Reservoir zone B being more concentrated in the Lower fan portion of the fan environment (Figure 4.43).

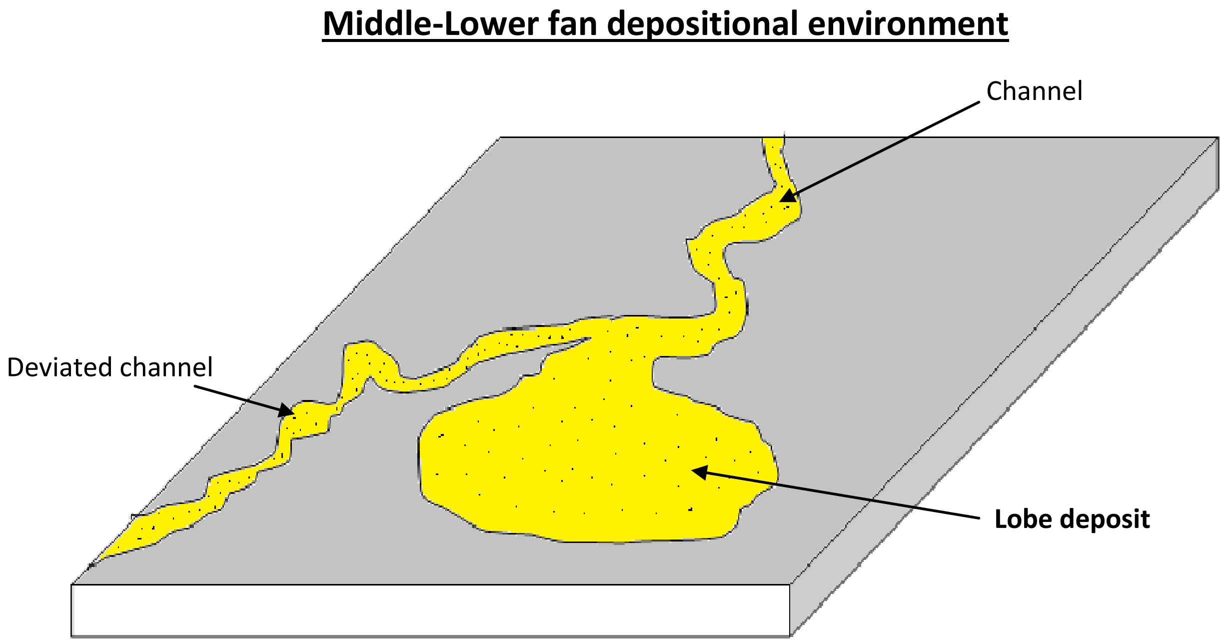


Figure 4.43: Conceptual model of depositional environment of reservoir interval

Chapter 5: Discussion

An approximately 369m thick reservoir interval was delineated at 2140m from petrophysical analysis of Well A-F1 and exhibited good reservoir properties in terms of porosity and volume of shale. The reservoir interval was comprised of two individual reservoir zones, namely reservoir zone A and reservoir zone B.

Genetic inversion proved to be an effective tool in the prediction of reservoir properties throughout the 3D seismic survey, by exhibiting the distribution of favourable reservoir properties where porosity is greater than 22% and volume of shale is less than 50%. The optimum reservoir model for the reservoir interval based on porosity and volume of shale showed a distinct variation between reservoir zone A and Reservoir zone B in terms of distribution of favourable reservoir properties. With reservoir zone A displaying favourable reservoir properties (porosity > 22% and Vsh < 50%) in the more proximal part of the reservoir which is related to channels complexes comprising of relatively thin but numerous channels which are not extensive throughout the reservoir interval and reservoir zone B showing favourable reservoir properties (porosity > 22% and Vsh < 50%) in the distal and proximal portion of the reservoir confined mostly to the sinuosity of a single large and laterally extensive channel which splays out into a lobe structure with favourable reservoir properties into the distal portion of the reservoir zone .

Areas classified as having favourable reservoir conditions based on the optimum reservoir model exhibit porosity values greater than 22% and Volume of shale values of less than 50%. Areas with no relation to the sinuosity of channels or channel complexes tend to exhibit poor (porosity < 14% and Vsh >70%) reservoir properties represented in red by the optimum reservoir model. It is evident that Reservoir zone A and Reservoir zone B are both related to a transitional depositional environment with the variation of distribution of favourable reservoir properties being related to their respective locations within the transitional depositional environment, with Reservoir Zone A being interpreted as being in the proximal portion of the reservoir interval due to favourable reservoir conditions being related to channel complexes and Reservoir Zone B being interpreted as being in the more distal portion of the reservoir interval as favourable reservoir conditions are related to a single large channel and lobe deposit.

Seismic attribute analysis justified that the two reservoir zones within the reservoir interval exhibits distinct differences regarding its depositional location in terms of the transitional environment. The Sweetness seismic attribute was imperative in delineating channel structures and once compared to the reservoir models showed that the favourable reservoir properties were confined to channel complexes and sedimentary structures characteristic of a transitional depositional environment.

The upper portion of the reservoir interval sediments are seemingly deposited within the upper to middle fan represented by reservoir zone A and the middle to lower fan region of the depositional environment representing reservoir zone B. The placement of the depositional environment for the respective reservoir zones within the reservoir interval is evident by the channel complexes in the more proximal region of the study area which becomes less evident towards the distal region of the area for reservoir zone A. Whereas reservoir zone B exhibits clear lower fan depositonal characteristics with large distributary channel with a clear lobe depositional structure being present. Both reservoir zones exhibit favourable reservoir properties however Reservoir zone B is considered a more favourable prospective hydrocarbon reservoir due to its considerable thickness relative to reservoir zone A and extensiveness.

The use of RMS amplitude further justified and supported the accuracy of the reservoir models by showing consistency in the prediction of “Clean Sand” distribution within the reservoir interval.

This study has made it clear that genetic inversion is an excellent tool to use for quantifying and predicting reservoir properties away from and between wells. Genetic inversion can be a useful tool in numerous exploration basins where well data is limited or as a quality control method for more conventional petrophysical models derived from upscaling. The application of genetic inversion on unconventional hydrocarbon resources such as shale gas should also be considered.

Chapter 6: Consclusion

Genetic inversion and seismic attributes provided an excellent method in predicting the distribution of reservoir properties in areas where limited well data is present. In Block 1 of the Orange Basin only one well is drilled intersecting the 1500 $\mathbf{km^2}$ seismic survey and not only did the use of genetic inversion and seismic attributes assist greatly in the prediction of reservoir properties away from the wellbore in providing a critical component as the link between the structural model and petrophysical model with the lack of upsclaing, it also gave imperative insight into the depositional environment for which initial well reports demonstrated significant uncertainty.

Genetic inversion used with the combination of seismic attributes proved to be an excellent tool in terms of exploration and future drilling opportunities.

Chapter 7: Recommendations

7.1 Recommended drilling target

At the base of reservoir zone B a large channel was delineated using the Sweetness seismic attribute and Horizon slice tool (Figure 7.1). The seismic intersection exhibits a large and relatively wide channel

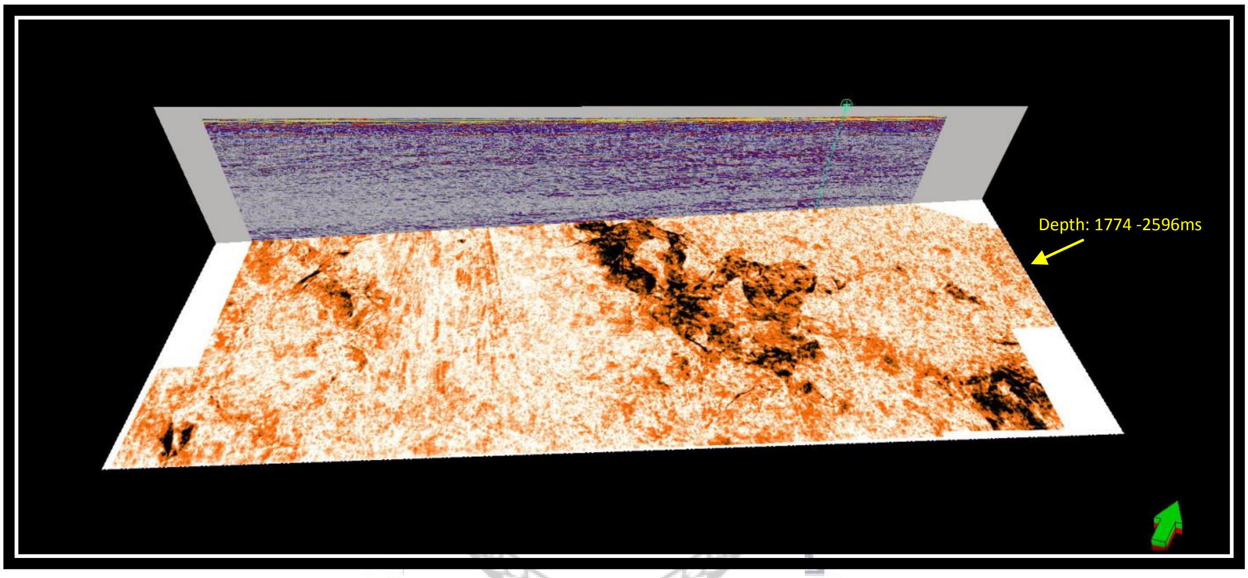
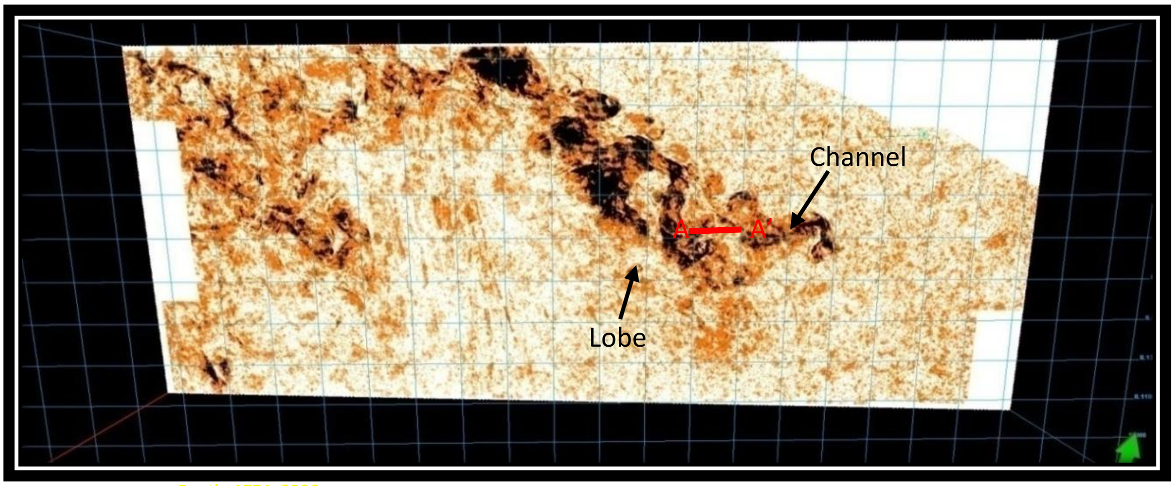


Figure 7.1: Sweetness attribute intersection Base of reservoir interval

The sinuosity of this large channel is clearly displayed by the seismic intersection (Figure 7.2) as is the direction of flow from the proximal West direction towards the distal East direction.



Depth: 1774 -2596ms

Figure 7.2: Seismic attribute intersection (Top view)

Viewing the seismic horizon from above it is apparent that this large channel of interest begins exhibits and area where it splays.

An ariel view show that this channel is lasrge and quite extensive, originating from the proximal portion of the study area.

An cross section of this large channel shows that is exhibits substantial thickness (Figure 7.3)

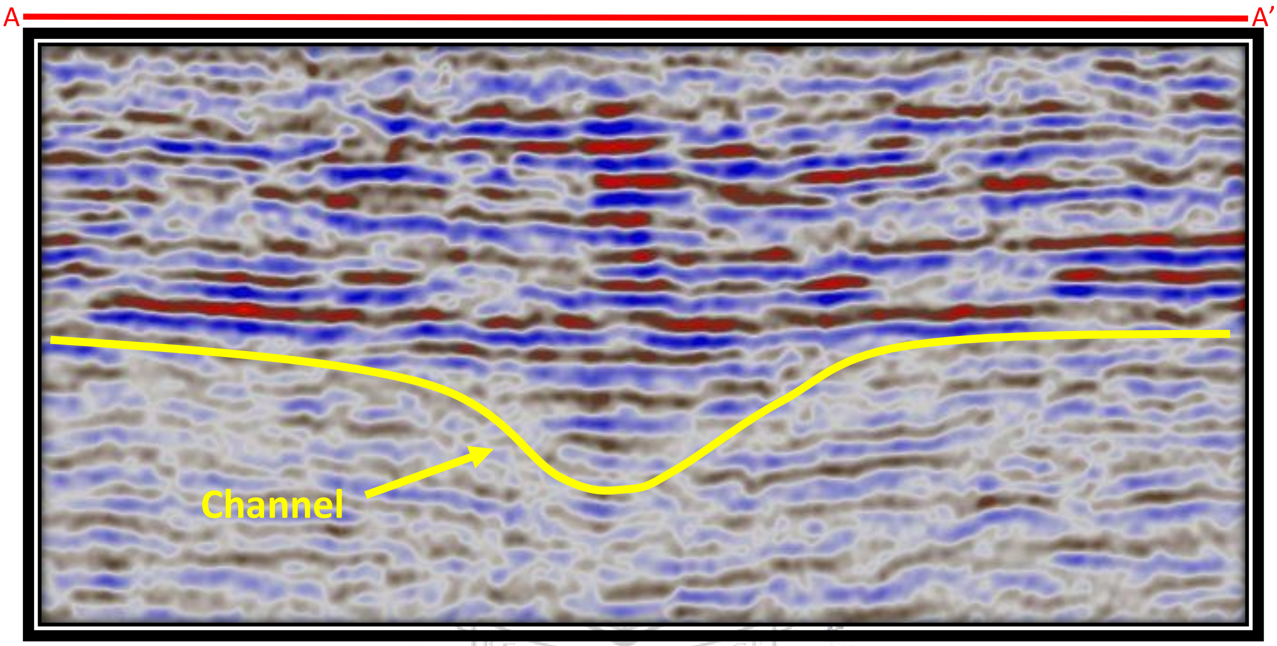


Figure 7.3: Seismic cross section (Channel)

This channel could represent an excellent potential hydrocarbon reservoir and it is recommended that it should be drilled into at the more proximal portion within close proximity to a potentially sealing fault.

7.2 Prospective areas relating to faulting

Its is evident that major faults are concetrated in the proximal portion of the study area (Figure 7.4). In the upper portion of the reservoir interval in reservoir zone A optimum reservoir properties are also concentrated in the proximal portion of the study area.

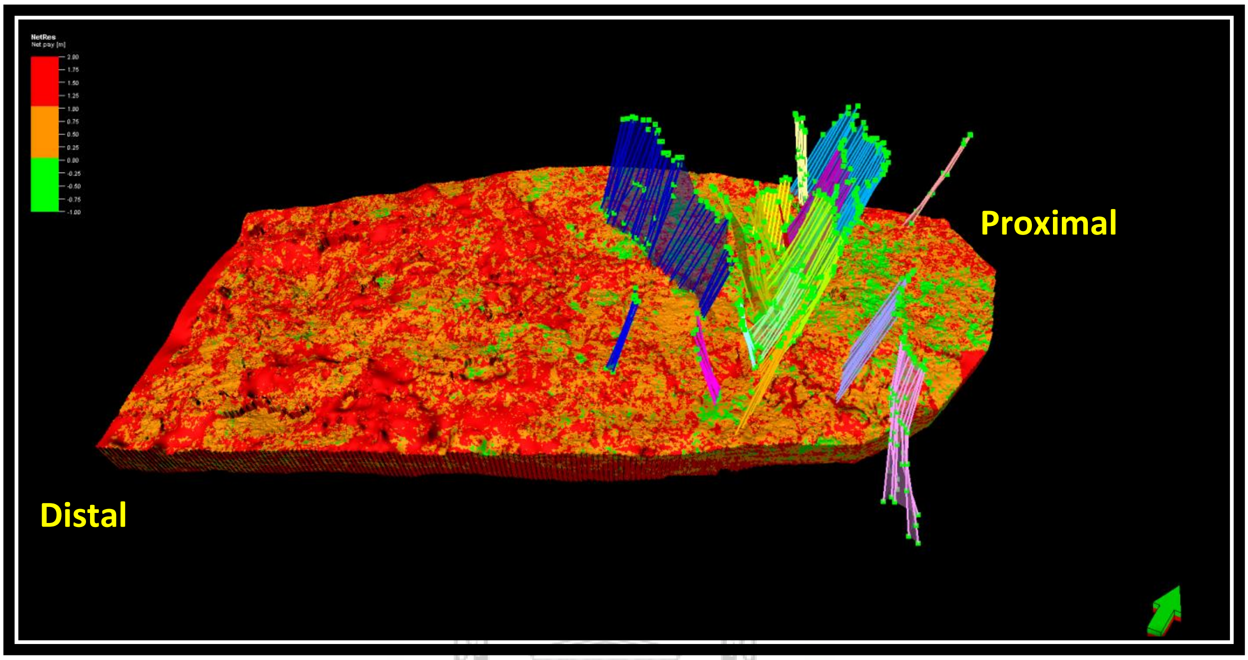


Figure 7.4: Optimum reservoir model and fault distribution

It is possible that these faults in the proximal portion of the study area can act as potential traps for hydrocarbons in the area. Especially as the faults are positioned on either side of reservoir zone A, where reservoir properties are optimum (Figure 7.5). These faults are vertically extensive throughout the reservoir interval and if they are sealing in nature they would act as adequate hydrocarbon traps.

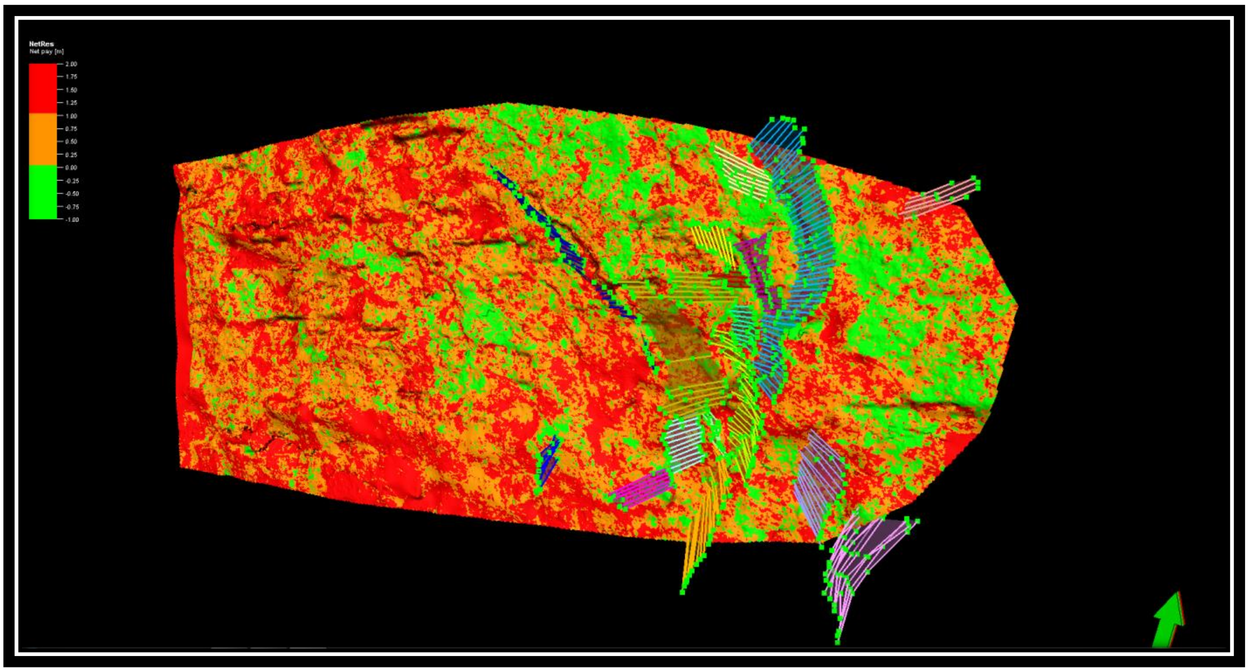


Figure 7.5: Optimum reservoir model and fault distribution (Top view)

Figure (7.6) represents fault distribution through the base of reservoir zone B. The positioning of a major fault in relation to the lobe structure provides an area of interest regarding prospective drilling opportunities, as this fault is well positioned to act as a hydrocarbon trap in relation to the optimum reservoir properties represented by the Lobe/Splay deposit.

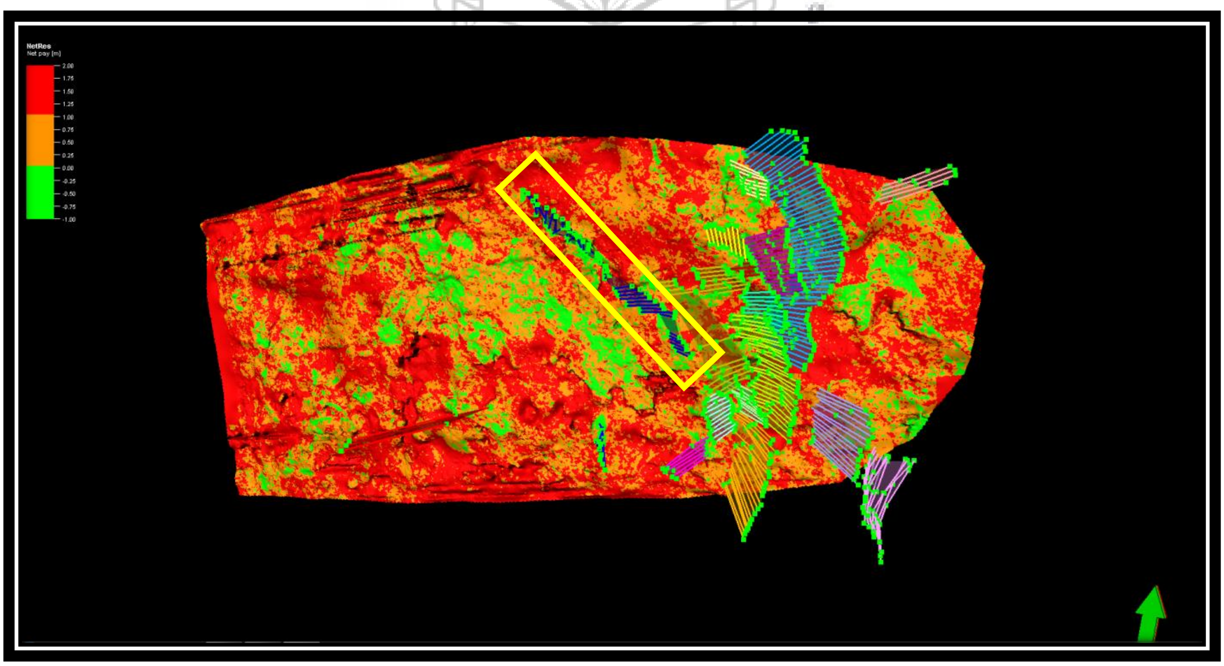


Figure 7.6: Optimum reservoir model Reservoir Zone B and fault distribution

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