International Journal of Research in Engineering and Science (IJRES)
ISSN (Online): 2320-9364, ISSN (Print): 2320-9356
www.ijres.org Volume 10 Issue 5 ǁ 2022 ǁ PP. 190-209

Economics and Risk Assessment of Mirabel Field Offshore Niger Delta

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ABSTRACT
The exploration potential of Mirabel field offshore Niger delta has been carried out using modern technology in 3D seismic data interpretation and supplemented with suite of well data. Seismic data interpretation was done using the petrel 2015 Software while Petrophysical analyses were done using the Techlog and Geolog software. 3D seismic data and well logs were used to define subsurface geometry, structural features and identify hydrocarbon bearing reservoirs. The gamma ray log was used to delineate lithology while the resistivity log was used to differentiate hydrocarbon bearing reservoirs. 5 reservoirs were correlated across 57 wells to delineate lateral reservoir continuity. Fault interpretations and structural analysis show an anticlinal structure with a collapsed crest bounded by major growth faults trending in the North East and South west direction. Time surface maps were generated for each of the reservoirs and a velocity model was used to generate a depth map of each reservoir for the drilling campaign. Structural interpretation showed a two-way anticlinal closure with hydrocarbon accumulation at the crest of rollover anticlines which were compartmentalized. Contacts were based on pressure data from RPM 2016. Petrophysical parameters including porosity, water saturation, NTG, permeability and the thickness of the reservoir were evaluated using the Techlog and Petrel software. Reservoir 4 shows attic oil Updip and good potential for more hydrocarbon production while reservoir 15 should be perforated above the previous perforation to recover more hydrocarbons. The well logs showed no presence of gas indicating that both reservoirs were under saturated. The STOIIP was estimated using both the deterministic and probabilistic methods and compared to determine level of accuracy. Economics and risk assessment carried out on the field showed it has infill well opportunity incremental recovery of 7.8 MMBO.

Date of Submission: 15-05-2022 Date of acceptance: 30-05-2022

I. INTRODUCTION

Petroleum resources still remain very important to many countries‟ economies in the world. The cost of exploring for this important resources are enormous making it necessary that the methods used to identify, locate and quantify them have high levels of precision. The exploration phase is the most risky segment as major uncertainties are associated with locating this resources and quantifying the volume of hydrocarbons in place. As more information is acquired the uncertainties are reduced and the importance of these uncertainties associated with the recovery factor increases. Interest in evaluating the exploration potential of a particular field is channeled towards the need to reduce the uncertainties associated with the geological models employed in quantifying the volume of hydrocarbons in the reservoir. This need is mostly driven by economic realities for better defined reservoirs using the available technology which results in higher drilling successes and fewer development wells. Indeed, in recent years, significant advances in seismic based methods especially in 3D seismic acquisition and processing have increased the possibility of mapping stratigraphic and structural configuration with a higher level of reliability but this still has its challenges. The interpretation of seismic data is one that requires skill and thorough knowledge of geology and geophysics. This involves picking and tracking of consistent seismic reflectors to map and delineate stratigraphic and structural traps containing petroleum reserves that are economically exploitable and delineate their extent for field appraisals and development. These traps, sometimes complex can prove difficult to map with accuracy. Well log data can be used to obtain important information and relevant parameters of a reservoir especially where coring and core analysis of the entire pay zone is not obtainable. Evaluating the Petrophysical properties of a reservoir is a vital element in interpretation. This involves estimation of reservoir properties such as Porosity, Water Saturation and other parameters from seismic and well log data. The integration of seismic and well log data is now widely used in hydrocarbon exploration to map subsurface structures and evaluate the exploration potential of a field. Seismic data can be used to interpolate and extrapolate beyond and between wells. The seismic profile defines subsurface geometry and resolves changes in stratigraphy and structure from the amplitudes and arrival times of subsurface reflections while well logs provides information on the variations of rock properties along the borehole. The information obtained is then complemented to estimate Petrophysical properties and define subsurface geometry. This combination provides a higher level of reliability in evaluating exploration potential and quantifying the hydrocarbon reserves. Risk is reduced as integrating data from both sources helps in discriminating between poor and good reservoirs.

Using new tools in validation of uncertainties in Static and Dynamic model of previous studies reserves estimation and reservoir performance. The current 3D seismic data have made significant improvement from previous datasets in reducing uncertainties associated with seismic imaging. However a good understanding of the variations in seismic imaging and its effects on structural configurations and reservoir properties in depth is required to understand the ranges of volumes in-place, flow properties and exploration potential and infill-drilling strategy. The aim of this study is to evaluate the exploration potential and risk analysis of “Mirabel” field offshore Niger delta using new RPM contact and detailed 3D seismic interpretation. Existing booked hydrocarbon in place and EUR will be validated, while the reservoir will be evaluated for value creation through the identification of Non Rig, Work Over and New Drill opportunities.

THE STUDY AREA

The name of the field was changed as deemed suitable and the exact location is not given for the purpose of confidentiality. Mirabel field lies within northwestern part offshore of the Niger Delta (Figure 1 between latitudes 3° 58’ 48.26’’ N - 4° 01’ 42.54’’N (Northing) and longitudes 2° 28’ 18.26’’ - 2° 30’ 17.95’’E (Easting) . Mirabel field is characterized with rollover structures with multiple growth faults, antithetic and synthetic faults.

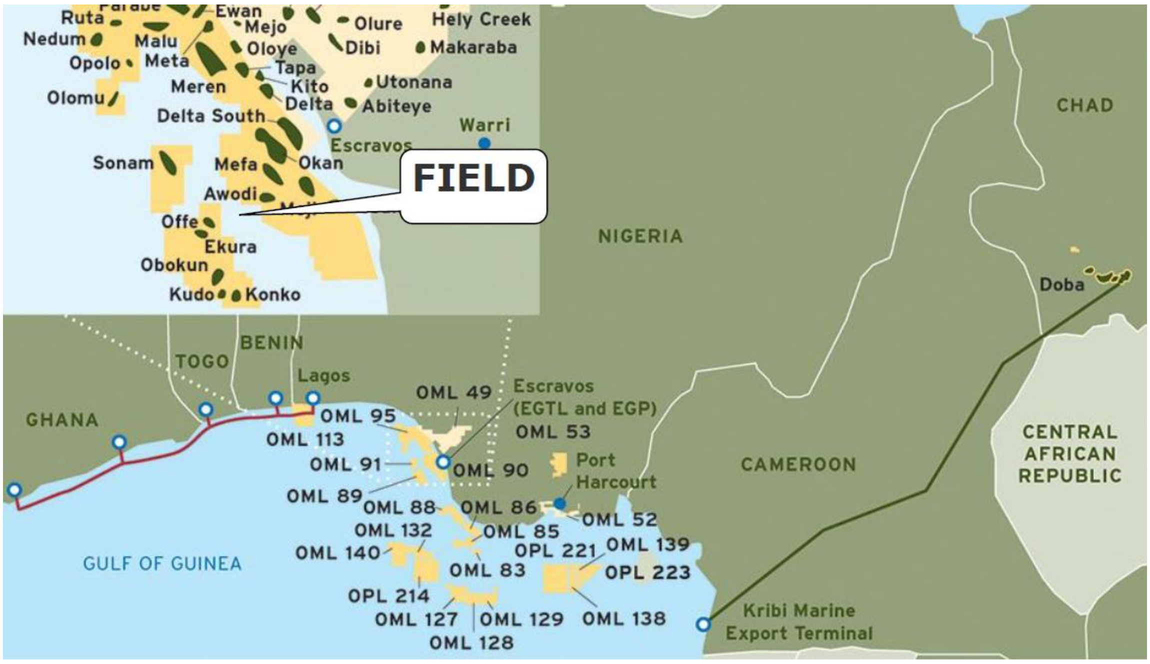


Figure 1: Mirabel Field location Offshore Niger delta

Mirabel Field Overview

Mirabel field was discovered in 1965 at a water depth of approximately 25-30ft and located approximately 25km offshore, with its first production in 1969 and peak production of about 85.4 MBOPD in Feb. 2005, 57 wells drilled to date (including sidetracks) 52 completion strings 36 wells are currently active Cumulative Oil and Gas Prod of 439MMBO and 521BCF till date. Current production is approximately 16 MBOPD till date and its Shallow reservoirs are predominantly water drive and deep reservoirs are predominantly gas cap (figure 2).

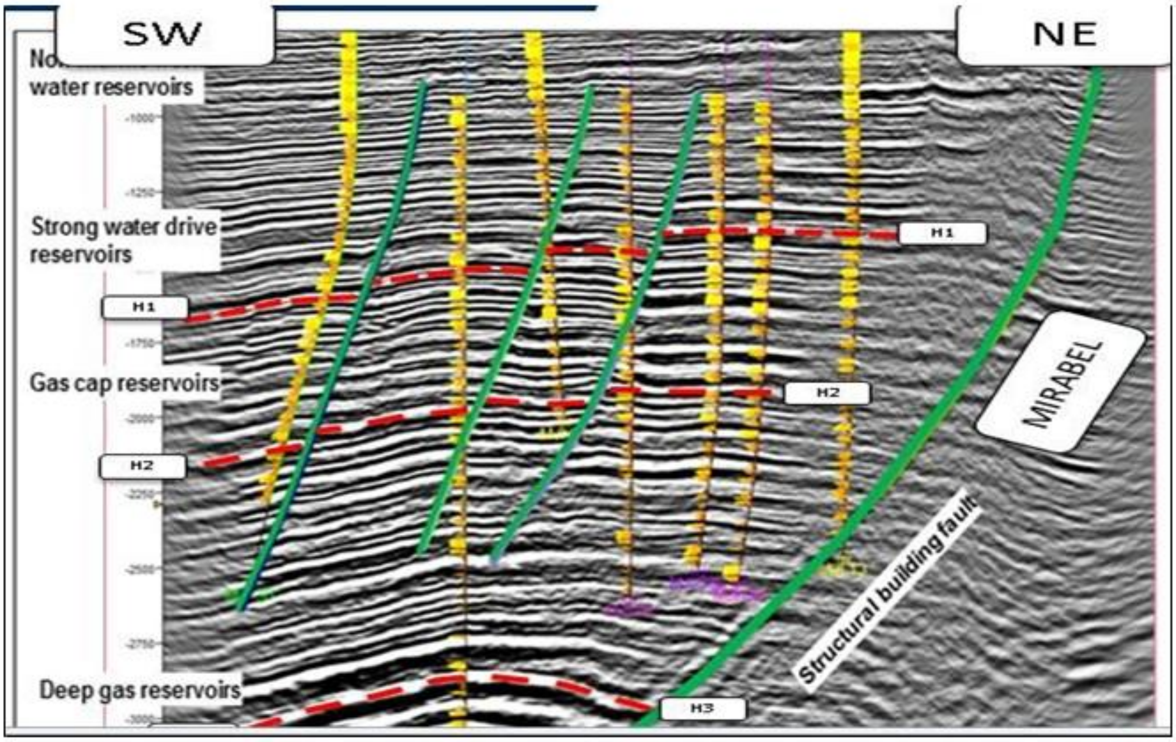


Figure 2: Mirabel Field Overview

Regional Geology of the Niger Delta

The Nigerian Atlantic margin formed from continental separation during the early Cretaceous and Tertiary periods resulting in the opening of the South Atlantic Ocean. The separation resulted in the creation of a three-arm rift system with the Aulacogen; the Benue trough ending up as the main drainage for the future delta. The two other arms of the rift follow the South-Eastern and South Western of Nigeria and Cameroon developing into the passive continental margin of West Africa. Offshore markings of Niger Delta are the Cameroon Volcanic line which stretches far into the Atlantic on the East and the Eastern part of the Dahomey basin on the West. The thickest succession of syn-rift sediments were deposited in a series of transgressive and regressive phases (Doust and Omatsola, 1989). These ended during the Santonian inversion which resulted in a flooding of the Benue Trough. The inversion created the Abakiliki high separating the Niger-Benue river system and the Cross River system which became the two main drainage systems for sediment supply for the formation of the Niger Delta. These two river systems deposited their sediments separately until the Miocene when the Cross river delta merged with those of the Western Delta resulting in a unified enlarged Niger Delta.

During the Late Cretaceous, there were many instances where progress was halted due to transgressions. Volcanic debris from Cameroon's volcanic zone was transported to the Niger River by the Benue River during the Tertiary period, but the Niger River was the primary source of sediment. This upward trend in sediment accumulation continued into the Oligocene. The shape of the basement played a role in the distribution of deposits along early coastlines, which were rounded toward the sea (Doust and Omatsola, 1989). It was at this time that rifting in the area came to an end, and gravity tectonics took over as the dominant mode of change in the region. Shale movement resulted in internal deformation, which was triggered by the convergence of two distinct processes (Michele et al 1999). Shifting from dense delta front sands to overpressed and poorly compacted prodela and dela slope clay (Akata formation) results in the first step in the formation of shales in diapiric settings: (Agbada formation). Second, the delta slope's clays were too loosely packed, resulting in slope instability (Akata Formation). These simple structures like crestal folds and flank folds along individual faults are what contribute to the complexity of the structures in local areas.

Niger Delta Petroleum System

Tertiary Niger Delta (Akata – Agbada) in the province of Niger Delta is home to the only known oil system. At its widest point, it covers an area larger than the entire Niger Delta province. Underwater or on land, oil fields with water depths under 200 meters have large, straightforward structures. Marine shale facies in the upper part of the Akata formation and interbedded marine shale in the lower part of the Agbada formation are its primary source rocks. For offshore oil and gas exploration, the upper part of the Akata formation's turbiditic sands can be found in the Agbada formation's lower facies. Any part of the Agbada formation has the potential to contain oil. Even so, the "oil rich-belt," which has the largest field and the lowest oil-to-gas ratio, is the result of a number of different factors. The authors (Doubt and Omatsola, 1990) argued that an older theory held that the location of hydrocarbons at the time of the formation of landward structures, also known as "traps," was a factor. Oil was already flowing when these structures were constructed, and it had to be halted. Although structural traps predominate in the Niger Delta, stratigraphic traps can also be found. These structural traps developed as a result of the Agbada paralic sequence's synsedimentary deformation (Stacher, 1995). The depobelts that formed later in the south were more complex than those that formed earlier in the north because of the stability of the over-pressed and under-compacted shales. This was caused by the sediment's movement. Some of the trapping elements discovered so far include simple rollover structures as well as structures with antithetic faults, collapsed crests, and numerous growth faults.

II. LITERATURE REVIEW

The need to properly evaluate hydrocarbon prospects in order to determine best production strategy and reduce risk encountered in hydrocarbon exploration has led to the application of several methods which tend to propagate log parameters. One of such techniques is the use of seismic response of subsurface rock strata and corresponding log properties (Moses and Muslim, 2011). Reservoir properties are best estimated from appropriate well log data and the potential of an oil reservoir can be obtained from Petrophysical analysis. Good reservoirs must be porous and permeable, relatively thick with good oil saturation. Thus it is necessary to delineate and rank reservoir sands according to their Petrophysical properties since some reservoirs may not be prolific. A detailed structural analysis will also reveal the trapping mechanism. Seismic section of Niger delta has been known to reveal a number of syn-sedimentary structures from deltaic tectonic activity including rollover anticlines associated with growth faults. These occur when the downdip block is dragged against the fault plane while growth faults are concave shaped normal faults which result from a decrease of dip at depth. 3D seismic data is mostly used in the petroleum industry for exploration, field development and production. It is one of the best methods used in hydrocarbon prospect evaluation due to its ability to properly image subsurface stratigraphy and structures but this must be properly understood in order to effectively delineate structures that are good hydrocarbon prospects.

Hydrocarbons in the Niger Delta are primarily found in geological formations known as "traps." Because these structures make it difficult for oil and gas to move horizontally and vertically, they can accumulate oil and gas. When creating a map of a petroleum reservoir, these structures are taken into consideration. Seismologists use seismic data to pick faults and map horizons with inlines and crosslines in order to find faults and horizons. After creating a time structure map, the data is transformed into a depth map. This information is combined with the well logs to create a time structural map, which estimates the thickness and width of the pay zone. The pay zone thickness and reservoir volume can be estimated using the depth structure map and well logs. Using the well log, one can get a visual representation of the general stratigraphy and the relationships between reservoirs and non-reservoir rock units. This diagram shows the general stratigraphy and the relationship between reservoir and non-reservoir rock units. The characterization signature and patterns in the log set are used to make quantitative interpretations. Using this method, it is possible to determine the depth and width of desirable zones, and the zones that have those properties. Reflection characteristics and stratigraphic indicators can be used to determine where the reservoirs' top and bottom are located in the 3-D seismic volume. It is then possible to compare the logs from each well and to describe the reservoirs according to their petrophysical characteristics. Both methods are used to estimate reserve volumes, which are then combined. As a method for estimating hydrocarbon reserves in the oil and gas industry, well log analysis and three-dimensional seismic interpretation have been viewed as being the most accurate. Because these two methods have been proven to be the most effective, this has occurred (Emujaporue & Ngwueke, 2013).

Well logs and 3-D models will be looked at. The interpretation of seismic data is often one of the most important parts of figuring out how much oil or gas is in a reservoir. In the well log analysis, things like lithological units, gross interval, net-pay thickness, fluid contact, porosity, shale volume, and water saturation are looked at. Seismic data is used to estimate the size of the reservoir. (Ameloko & Owoseni, 2015) In addition, seismic data can be utilized for quantitative reservoir parameter forecasting. To do this, information about the well is compared to the seismic volume at the location of the well. Using density and sonic logs, a synthetic seismogram, which is a model of a seismic track, is made so that the physical properties of subsurface rock units that are important for hydrocarbon exploration can be measured. The seismic volume at the well site is compared to this seismic track model. The goal of this comparison is to find out what kinds of things subsurface rock units have in common. Time contour maps of productive reservoir zones are made by getting the time directly from the tops of the relevant horizons. The measured speeds at regular intervals are used to figure out the average speed. Oil and natural gas are taken out of loose sands and sandstone, most of which come from the Agbada Formation in the Niger Delta. In order to look for and make use of hydrocarbons, it is absolutely necessary to do an accurate assessment of these zones.

III. METHODOLOGY

Soft Ware

The 2015 Schlumberger petrel software was employed to evaluate the exploration potential of Mirabel field using a prescribed workflow. The Excel Microsoft tool was also used in some parts especially in tables while Techlog and Geolog software was used for Petrophysical analysis. The workflow adopted for this project is shown in Figure 3:

Data Inventory

- 3D Seismic data
- Well deviation
- Well header
- Well logs
- Pressure Data
- Velocity Data

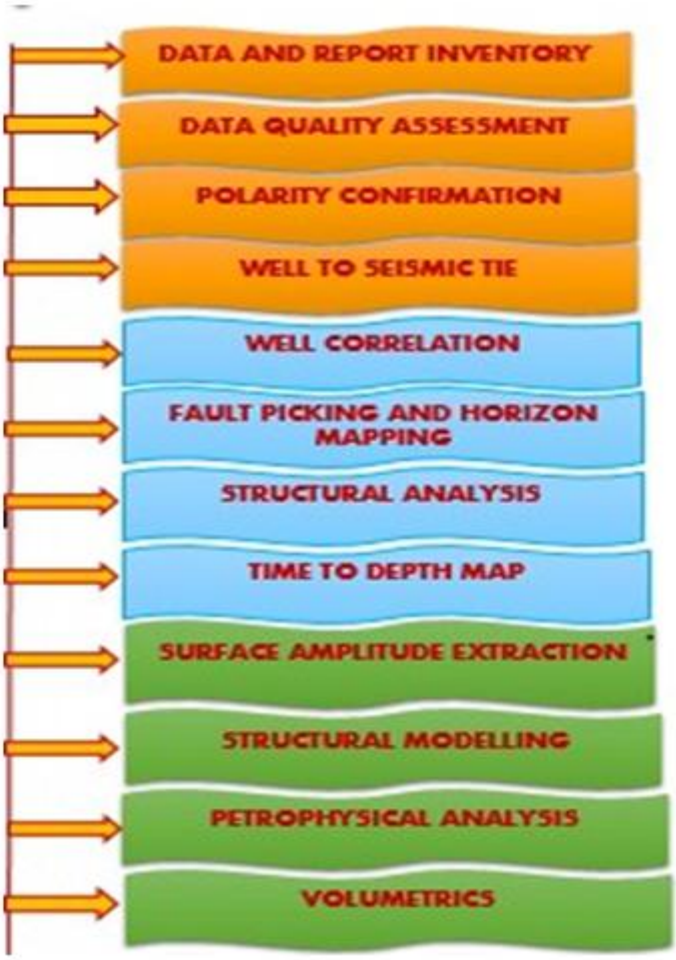


Figure 3: Seismic Interpretation workflow

Data Quality Assessment

The well log data was checked to make sure it was complete and filtered to ensure the readings were not erroneous while irrelevant ones were deleted. The direction of well placement was also checked and arranged in the East-West direction. Some sections of the seismic data were observed to be chaotic while Well log data given was not continuous, some log sections were cut off at some depth while some were noisy

Polarity Confirmation and Data Loading

The seismic data was confirmed to have an SEG polarity with the red reflections displayed as positive loop (peaks) while the red is the negative loop (trough). For SEG Y, change in acoustic impedance from sand to shale represents a trough. Well folder was first created in the input pane, then the well header information was imported using well heads (**).The seismic data was imported using the SEG-Y seismic data format.

Well Log Importation

A new well folder was created in the input pane then the well header was imported using the well heads (**) format. Once this is successfully done the well deviation data for the well logs was also imported. Check shot data were also imported and corrected to two ways travel time (TWT) and converted to measure depth (MD) using Velocity data.

Seismic Data Importation

A folder is created in the input pane and seismic data imported using seismic SEG- Y format. This is allowed to run completely. The seismic SEG-Y data was realized into the ZGY data to help compress the data, increase memory space to ensure that interpretations run faster.

Seismic To Well Tie

A seismic to well tie helped locate the right horizon to match the target reservoir. A process known as "well to seismic tie" is used to convert time-generated seismic data into depths. The check shot data must be used to convert the time-selected horizons from the seismic data to depth because the reservoirs chosen from the well log data are selected by depth. To create a synthetic seismogram, sonic and density logs are used. At control wells, this permits the installation of a time-depth calibration function needed to convert seismic images taken deep underground into the depth necessary for calculating reservoir volume. There was a strong seismic to well connection, with the blue reflection providing negative (trough) bases and the red reflection providing positive (peak) bases. In order to limit the number of reservoir apexes that could be used, the reservoir's apexes were chosen as peaks.

Lithology Delineation and Well Log Correlation

Lithology delineation was carried out using the Gamma Ray and Neutron Density cross over into respective sand and shale sequences. These logs were first displayed on the well section window and limits set as shown in Table 1. The cut off chosen for Gamma ray is 75.

Table 1: Minimum and maximum values defined for logs used in lithology delineation.

LIMITS			
LOGS	MINIMUM	MAXIMUM	CUTOFF
GAMMA RAY	0	150	75
NEUTRON	0	60	
DENSITY	1.70	2.70	

The density/neutron log's behavior has been found to be the most reliable indicator of the reservoir's rock type by researchers. Density logs typically move to the left, which indicates that density is decreasing, and touch or cross the neutron curve in a typical image. The gamma-ray (GR) log typically decreases in clastic reservoirs, but this isn't always the case. Because some reservoirs contain radioactive minerals, the gamma ray log is ineffective at determining whether or not sand is present. Increasing neutron/density crossover improves sand quality in the reservoir. There is a higher crossover for porosity between gas zones and water and oil zones. The resistivity log was used to select fluid contact. Correlation was done from the base upwards since deposition started from the base.

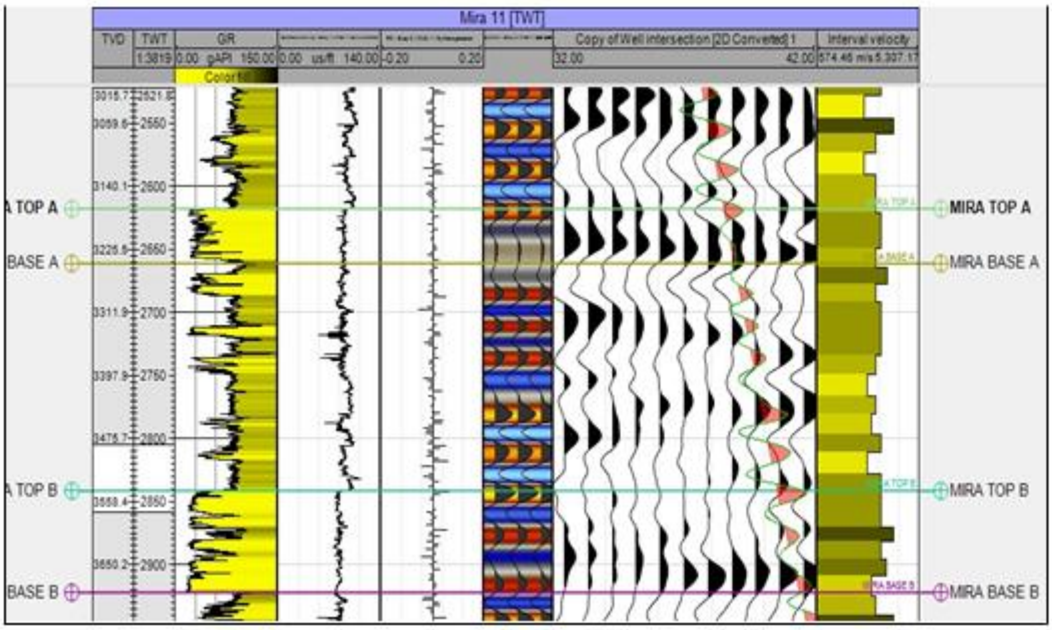


Figure 4: Synthetic seismogram generated from well logs and seismic volume tied to well tops.

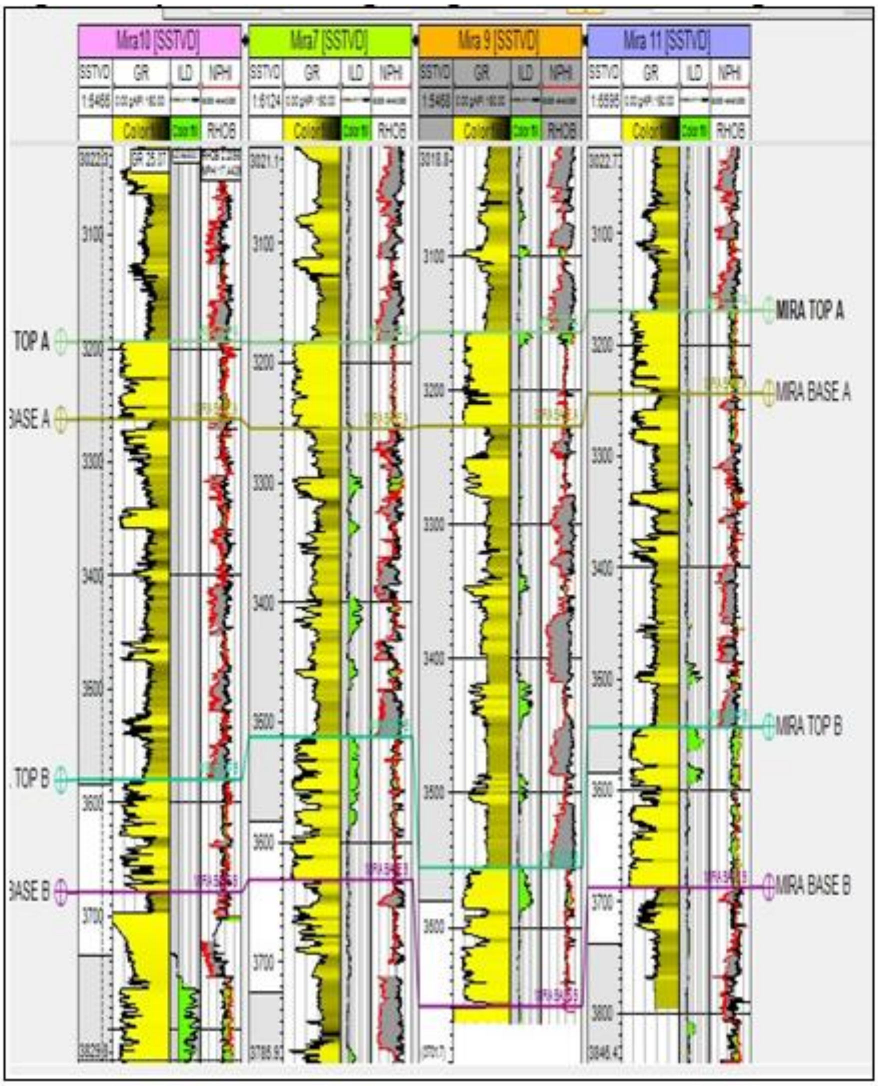


Figure 5: Well log panel showing well correlation having Top and Base.

Fault Interpretation

A fault on a seismic data is an abrupt truncation or termination of seismic events it is shown as a discontinuous displacement of reflection events. They are discontinuities in rock layers due to tectonism. This has a geological significance on the migration of hydrocarbons as they act as pathways or seals to hydrocarbons. It is pertinent to understand the fault locations as this can help in effective planning of well locations. Fault interpretation was carried out by creating a fault folder on the input pane. A particular fault is mapped throughout the seismic volume until it is no longer seen. A new one is created by clicking on the folder to insert a new fault. A total of nineteen 65 faults were mapped throughout the seismic volume. The major boundary faults were mapped first to act as a guide to the other smaller events. A network of both synthetic and antithetic faults trending in the NE – SW direction were identified as associated with the Niger Delta giving rise to a collapsed crest structure. The faults were picked at five (5) line intervals.

Horizon Mapping

A horizon on seismic is the interface between two different rock la yers representing geologic time surface that are mappable on seismic generated from a sequence of events that occur regularly at equal time events otherwise called isochronous surfaces.In this study, two (2) horizons of interest were mapped using as well tops A and B selected. They were manually picked on inlines and crosslines at five (5) line interval on peaks represented by the yellow reflections on figure 8 & 9 below. The faults were respected as the horizons mapped were terminated on them not across them.

Time Map

This is done to convert the picked horizons to surface. Polygons were generated for the horizons using polylines from the polygon editing tool. The make or edit tool under utilities in the process pane was used to generate surfaces. The picked horizons was main input, the polygons picked for the horizon was also an input. The geometry was set to automatic and increment set to 20 to see structures clearly. This process was used to generate time surfaces for both horizons.

Depth Mapping

This process is done to convert the surface generated in time to depth. This is done from the synthetic generation bearing the TDR (time depth relationship). A velocity model is generated in depth and using the Z vs TWT (depth against Two-way Time) relation. The surface generated in time is input in the operation window, the Z vs TWT function created is used as an input in the lookup function, smoothened and run. A surface map is generated. A base surface map is extrapolated from the Top surface depth map generated.

Surface Amplitude Extraction

From the polarity confirmation, the seismic data is in the SEG-Y format. This represents an increase in impedance contrast. The data was also qualitatively checked to ensure it is in the zero phase; at the peak of the waveform. This gives a positive amplitude displayed as the red peak showing an increase in color intensity. Therefore maximum amplitude extraction was carried out due to its high impedance. This was done to determine if amplitude conform to structure.

Structural Modelling

This is done to define the fault pattern and structural frame work using seismic data and well logs. This is done under the corner point grid in the process pane using the following workflow.

- Define a model - a model is created
- Fault modeling - Faults modeled are used to create a boundary with within the structural map. The polylines are selected with the pick tool, converted to selected fault lines and closed to create a boundary
- Pillar Gridding - An exoskeleton is generated on 3D window. This is a 3D grid made up of boxes called grid cells used to properly distribute the Petrophysical parameters of the reservoir taking the reservoir heterogeneities into account. The I and J increment used to define geometry is 50.

Make Horizons - A horizon is built to add more information to the established grid increment and fault definition. The horizons are converted to isochore (a line joining intervals of stratigraphic thickness) points used to make zones.
Make Zones - This is done individually between each stratigraphic interval. Each zone is anticipated to have a Petrophysical parameter similar to those in the zones created.
Layering - this is used to define the variation within individual zones.
Make Contacts – It is used to infer oil-water-contact or gas-oil-contact.

Delineation of Reservoir and Well Log Correlation

Five reservoirs were delineated and correlated across four 57 wells. The type of fluid and contacts present was delineated using the Neutron Density and Resistivity logs. Reservoir 4 was found to be anticlinal separated by a syncline (Figure 23). Reservoir 15 was found to be compartmentalized (Figure 24). The different compartments were segmented and the area calculated. This was later summed up to get the area of the surface showing presence of hydrocarbon

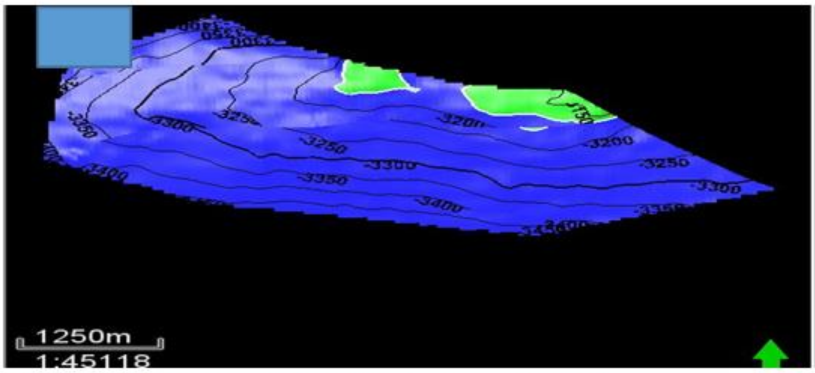


Figure 6: Reservoir 4 showing oil-water contact

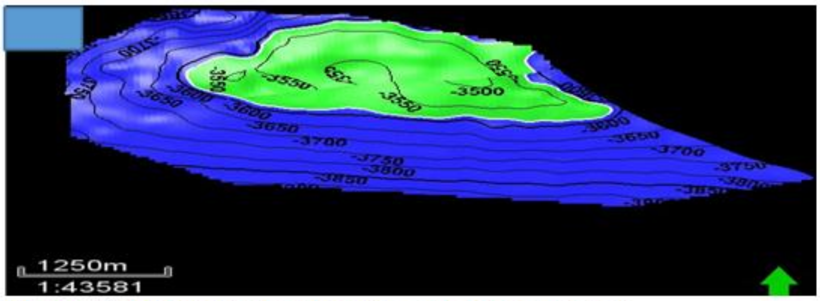


Figure 7: Reservoir 15 showing oil-water contact

Structural Analysis

This evaluates the distribution faults pattern in the study area. It is also used to determine if the faults form a closure or is sealing. The assumption is made that the pressure distribution is same in all parts of the reservoir which in real sense may not be true. A way of determining if the faults are sealing is by taking pressure reading in different parts of the structure to ascertain if same pressure regime is existing throughout the closure.

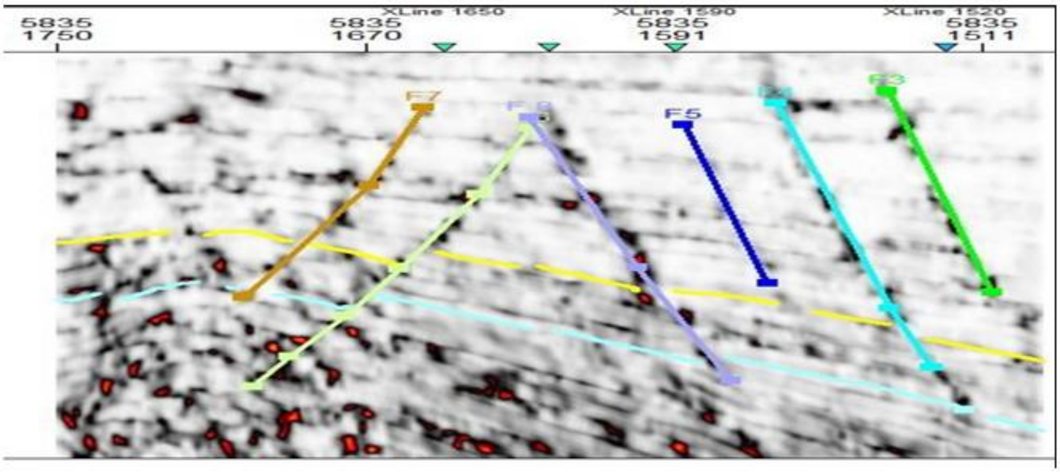


Figure 8: Horizon model for reservoir 4 showing fault patterns

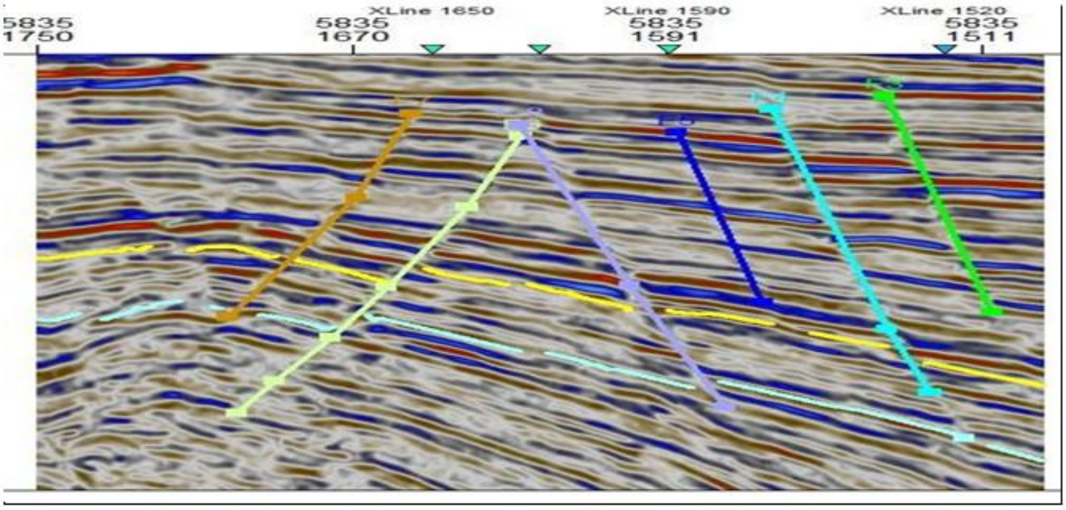


Figure 9: Horizon model for reservoir 15 showing fault patterns within oil water contacts

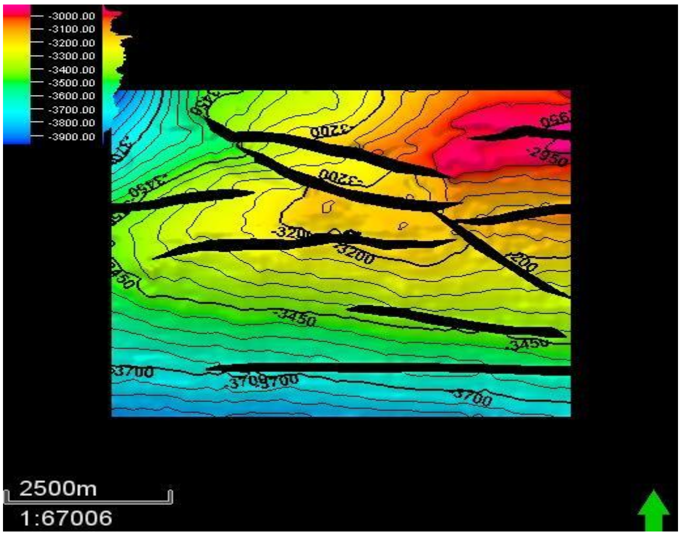


Figure 10: Variance edge attributes

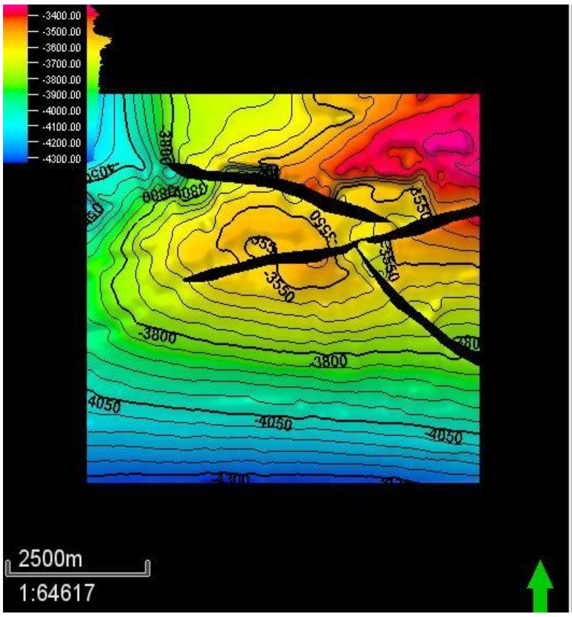


Figure 11: Structural smoothing applied to view structures better

TIME AND DEPTH MAP

The time and depth mapping done to determine the driller's depth shows a lot of similarity showing it was properly done.

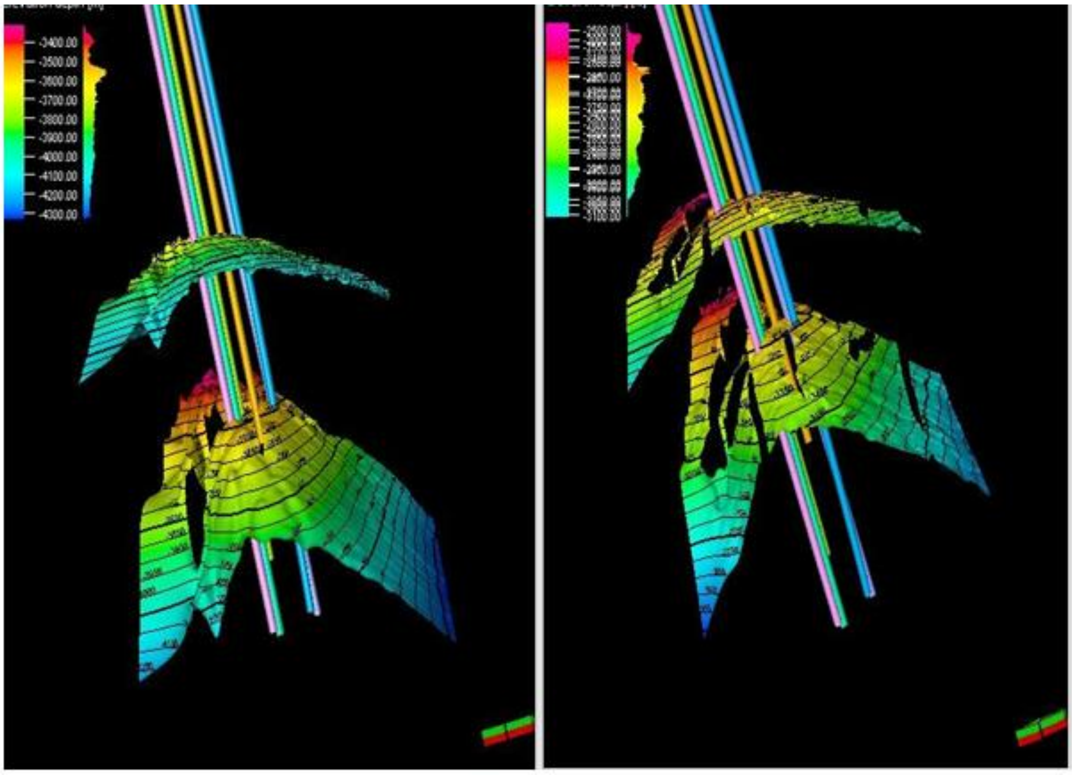


Figure 12: Showing surface maps in time and depth for reservoir 4 and 15 respectively

Petrophysical Analysis

The results of Petrophysical properties employed in STOIIP estimation for each reservoir across well is shown is Table 2. This represents an averaged value of its distribution across wells. The results were generated from Petrel and are presented in a simpler form below:

Table 2: Table of averaged values Petrophysical properties for each reservoir

S /N	PROPERTIES	RESERVOIR 4	RESERVOIR 15
1	IGR (gAPI)	21.80	35.82
2	NTG	87.79	69.21
3	PORO_eff (%)	24.11	18.83
4	Vsh	30.38	18.00
5	PERM	1042	3982
6	Sw	87.60	42.48
7	POROT (%)	26.12	21.15

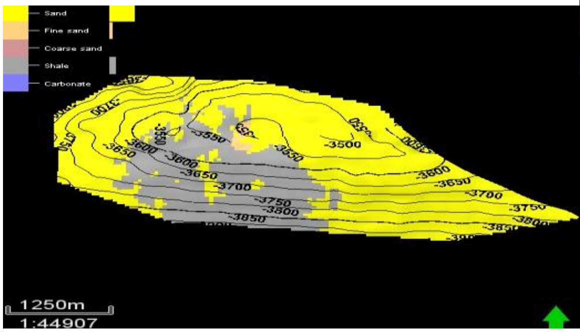


Figure 13: Facies modeling for reservoir 4

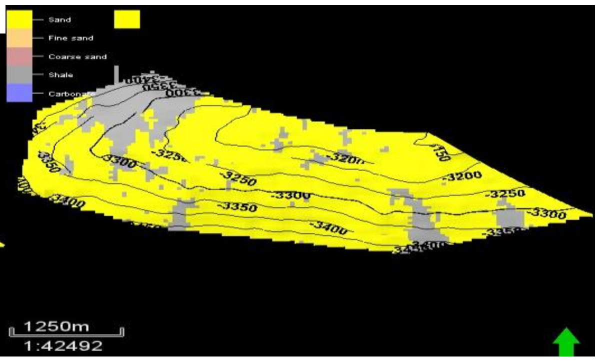


Figure 14: Facies modeling for reservoir 15

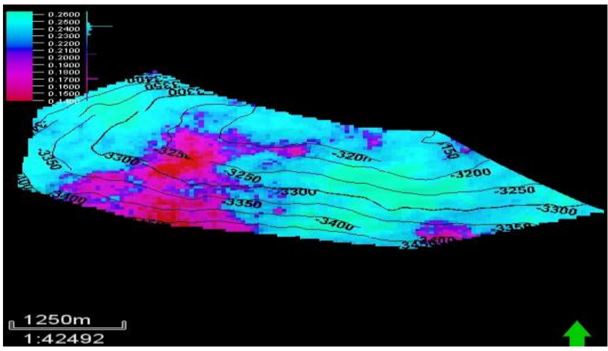


Figure 15: Porosity model for reservoir 4

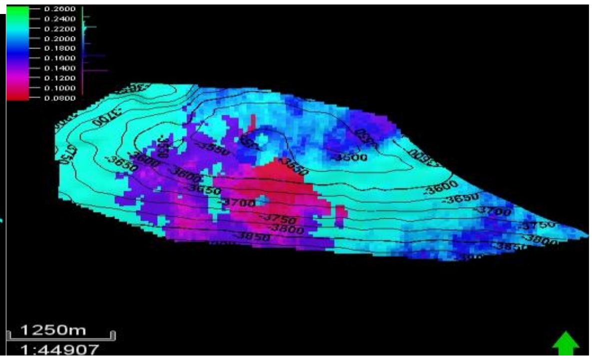


Figure 16: Porosity model for reservoir 15

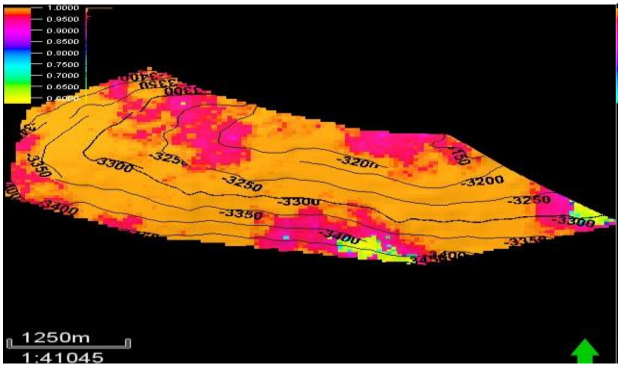


Figure 17: Net to Gross model for reservoir 4

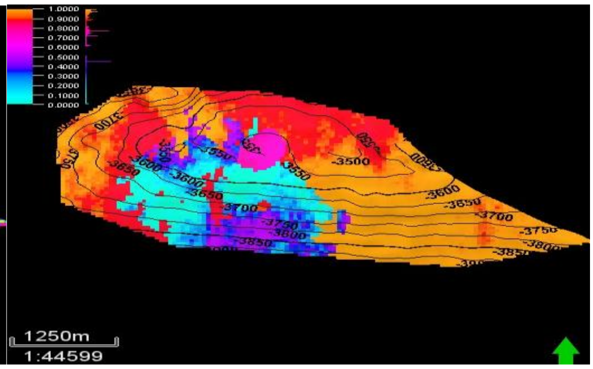


Figure 18: Net to Gross model for reservoir 15

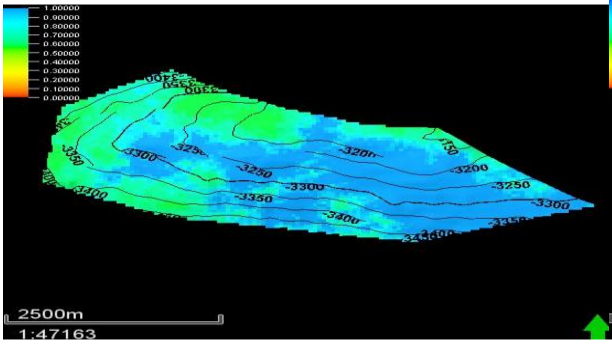


Figure 19: Water Saturation model for reservoir 4

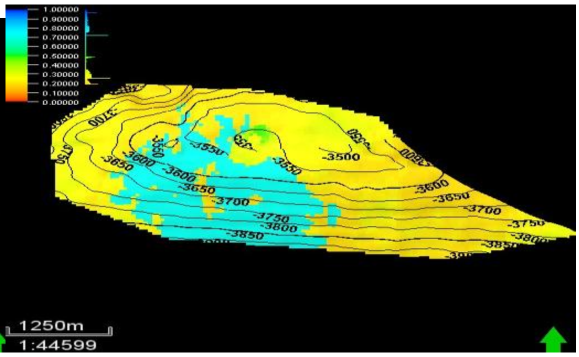


Figure 20: Water Saturation model for reservoir 15

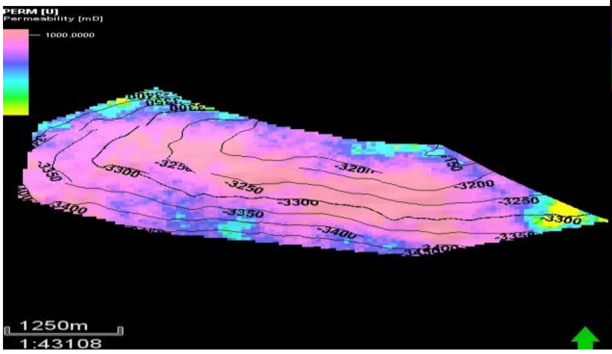


Figure 21: Permeability model for reservoir 4

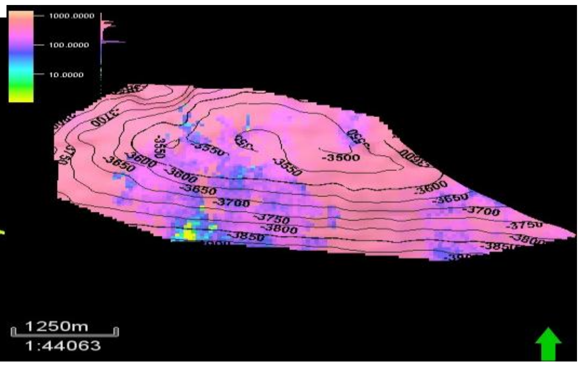


Figure 22: Permeability model for reservoir 15

Petrophysical Analysis

This is analysis is done to determine the relationship between rock properties and its interaction with fluids (water, oil or gas). The rock properties can show the fluid distribution contained in a rock sample. Rock properties include, Permeability, porosity, Net pay thickness, Water/ oil saturation, etc. These properties are evaluated from the integration of well logs, core analysis, PVT and Production data.

The Petrophysical analysis was done using empirical formula to evaluate the Petrophysical properties of Mirabel field. The input in the reservoir model is defined in the log quantitative phase. The Sequential Gaussian Simulator technique was adopted to produce multiple equally probable realizations to give several possible distributions of Petrophysical parameters in the model.

IV. RESULTS AND DISCUSSION

Results

The results obtained from evaluating the exploration potential of the Mirabel shows that previous interpretation is of STOOIP is more optimistic than revised volume by 17 percent and reasons are presented in this chapter and findings discussed according to the seismic interpretation workflow adopted.

Reservoir Initial Condition

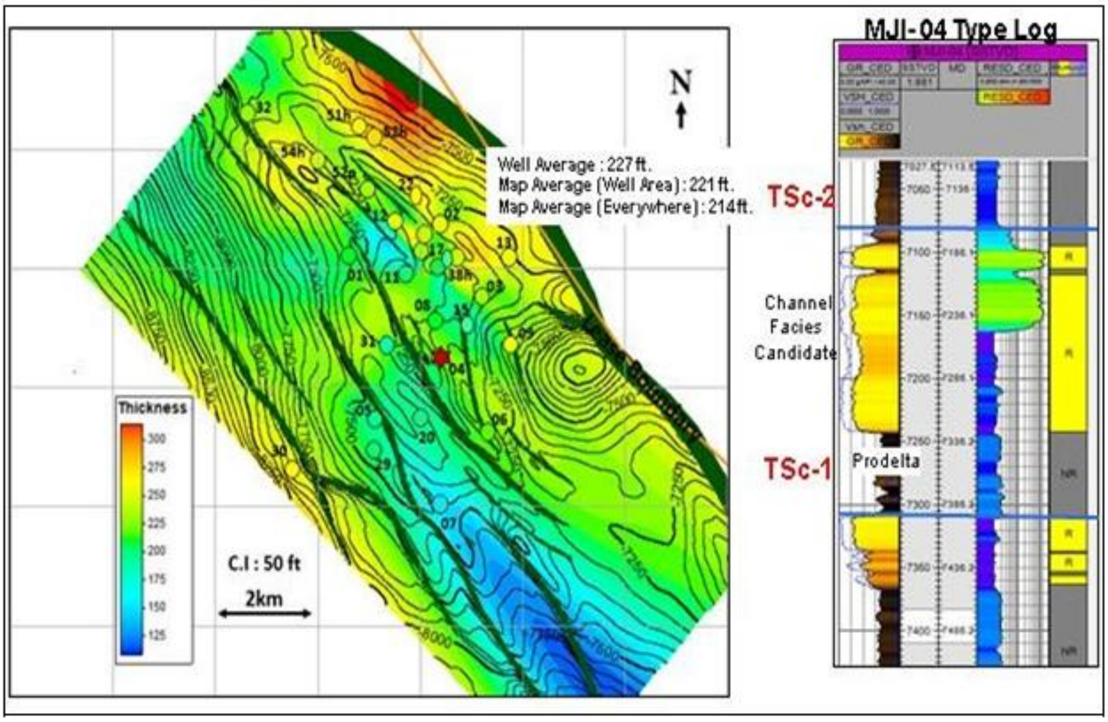


Figure 23: Reservoir Average Gross Thickness Map

Sediment thickening observed towards depocenter of the major and minor synthetic growth structural-building fault. Average property map is consistent with well data values at well location which enhanced confidence in the simple 3D static models

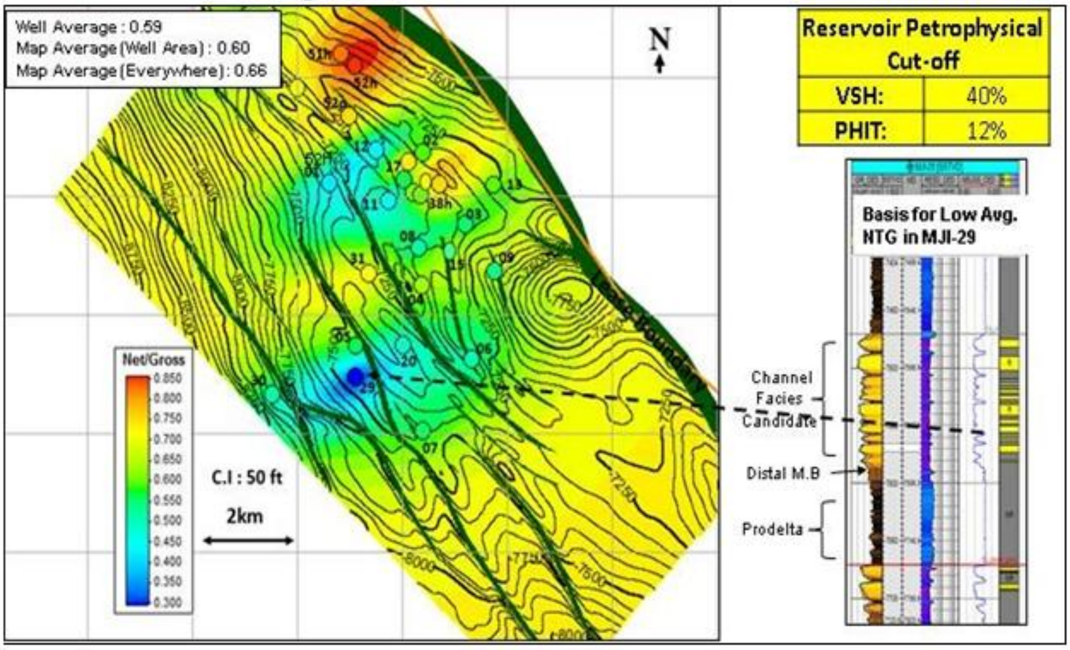


Figure 24: Reservoir Average Net to Gross Map

RNR was based on petrophysical cut-off. High quality reservoir o served towards depocenter of the major synthetic growth structural- building fault. Poor quality around Mira-29 due to underlying potential distal mouth are below the proximal mouth sand bodies. Average property map is consistent with well data values at well location. Impact: Enhanced confidence in the simple 3D static models

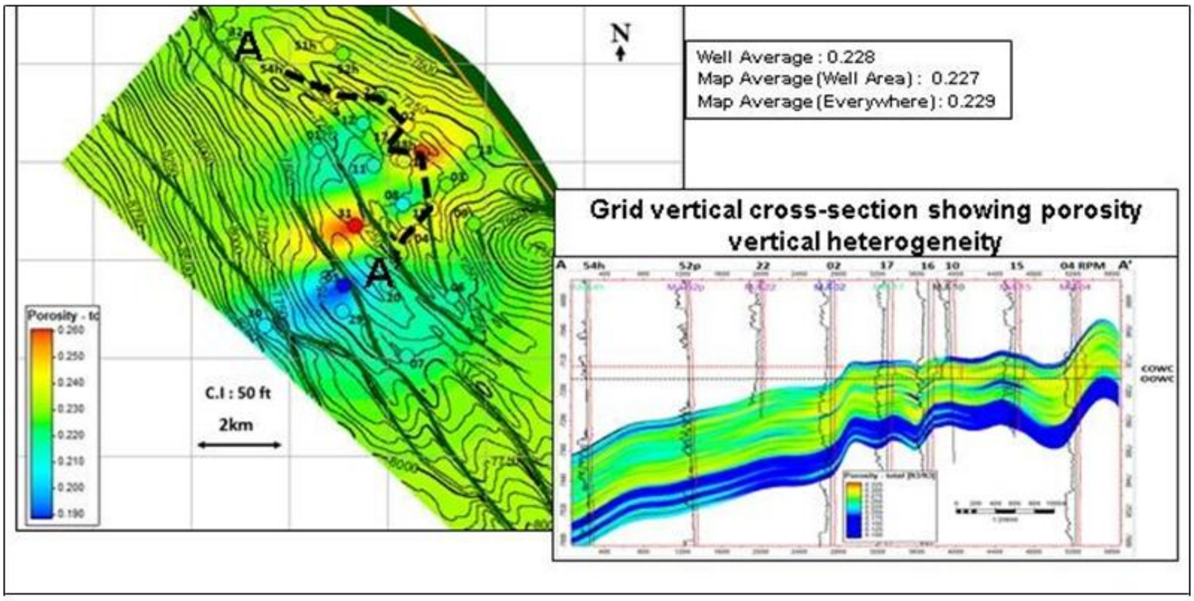


Figure 25: Reservoir Average PHIT Map (in Reservoir)

Porosity trends were characterized laterally and vertically in the model and Average property map is consistent with well data values at well location.
Impact: Enhanced confidence in the simple 3D static models

Comparison of Previous work and Current work

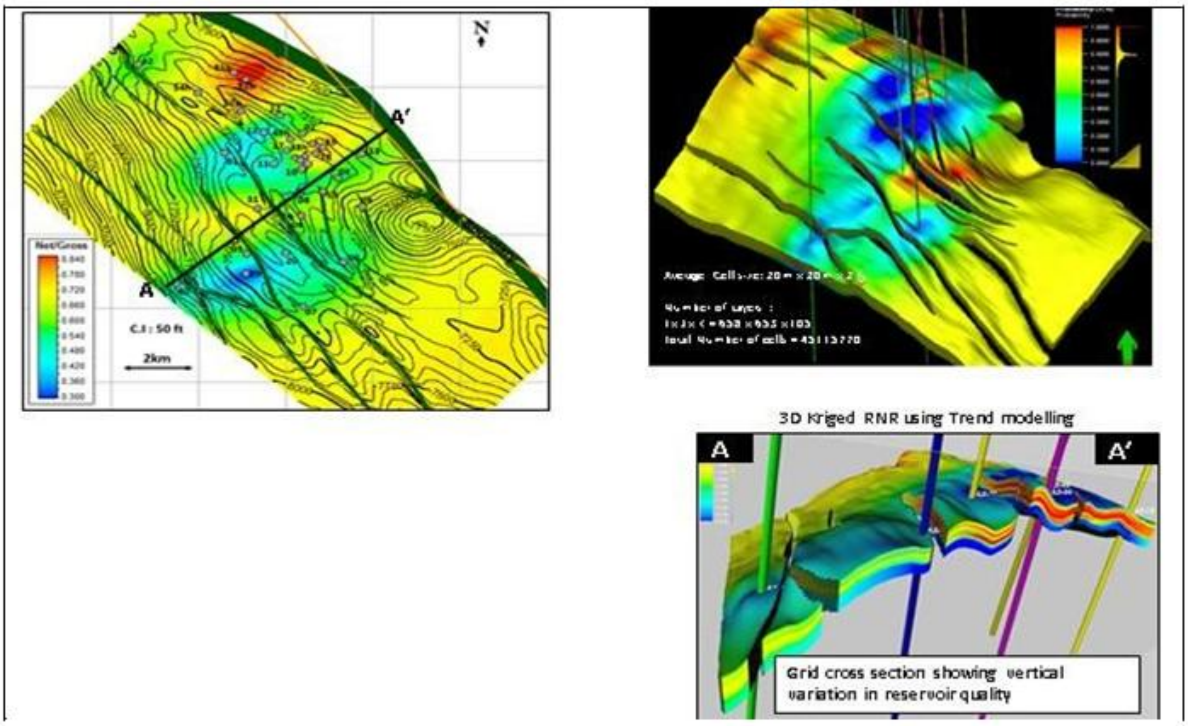
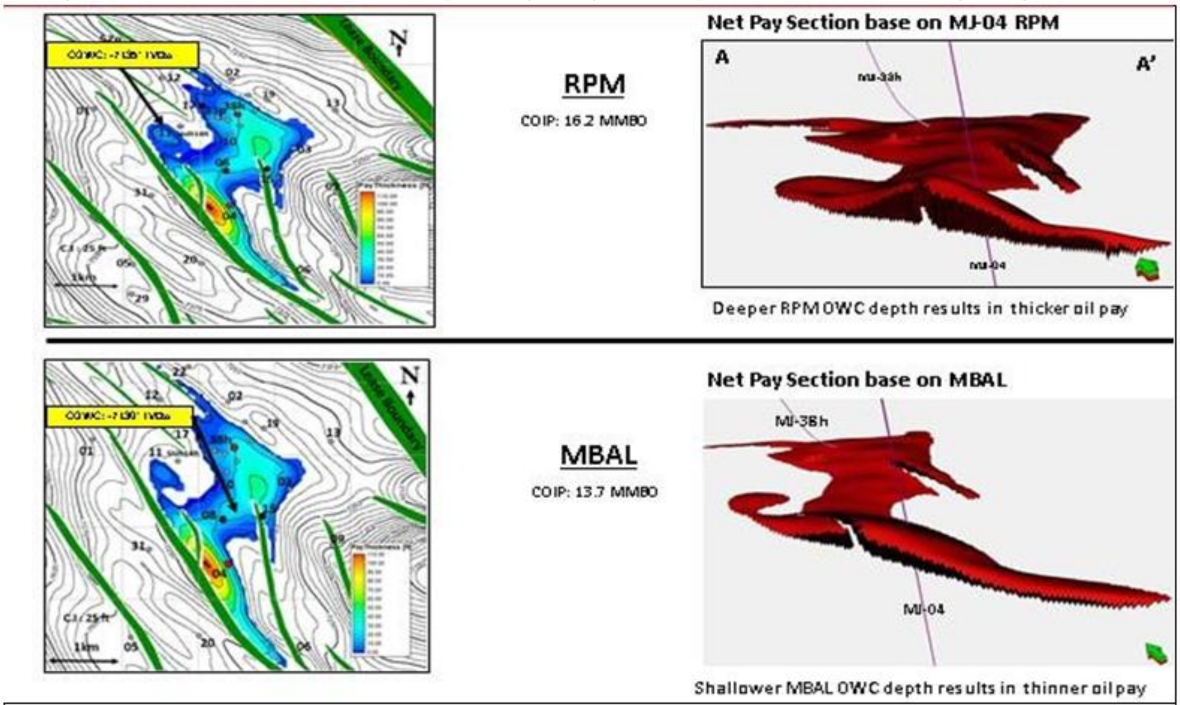


Figure 26: Comparison of NTG distribution for Average Grid Cells vs Simple

Model Extrapolation

Average Grid Cells is consistent with Simple 3D grid layers extrapolation of RNR well log in figure 26.



Original Reservoir Level	AOI	BV	NV	PV	HCPV	OOIP		Avg	Avg	Avg		Avg	
Mirabel well Reservoir level	[acre]	[acre.ft]	[acre.ft]	[acre.ft]	[acre.ft]	[MMSTB]	Diff(%)	Pay Net Thickness [ft]	Pay Poro	Sw	Diff(%)	NTG	Contacts
New Interpretation & 2015 Vel model	[illegible]	55,626	40,959	10,958	8,024	42.0	-17	31.8	0.27	0.27	-16	0.74	OWC-7168'
Reserve Book (1P)	[illegible]	38,983	39,008	12,483	9,612	50.5		42.4	0.32	0.23		1.00	OWC-7169'

Figure 27: Comparison of Previous vs New Interpretations

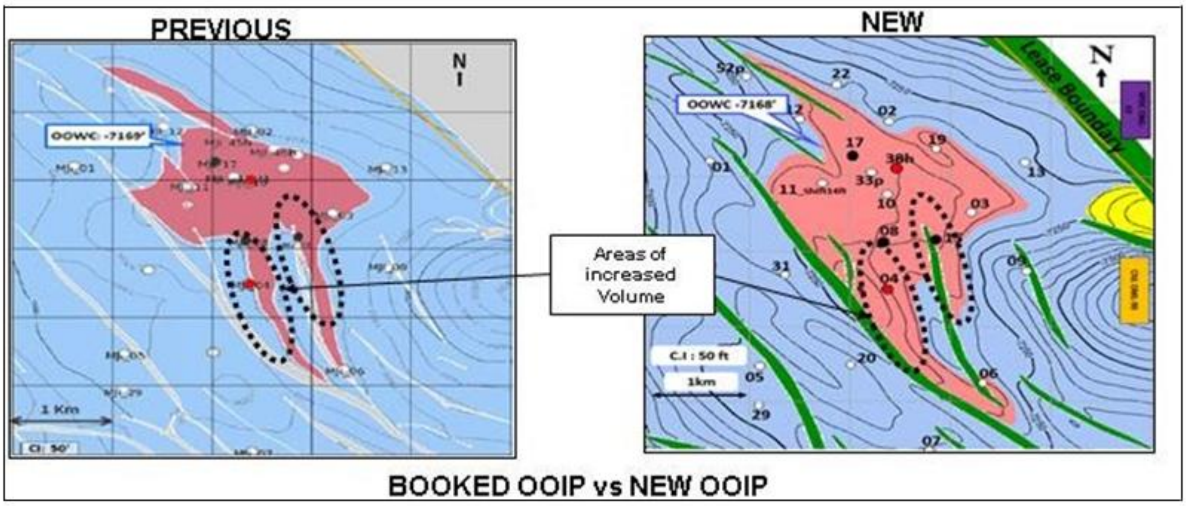


Figure 28: Comparison of RPM and MBAL Current Net Oil Pay Thickness

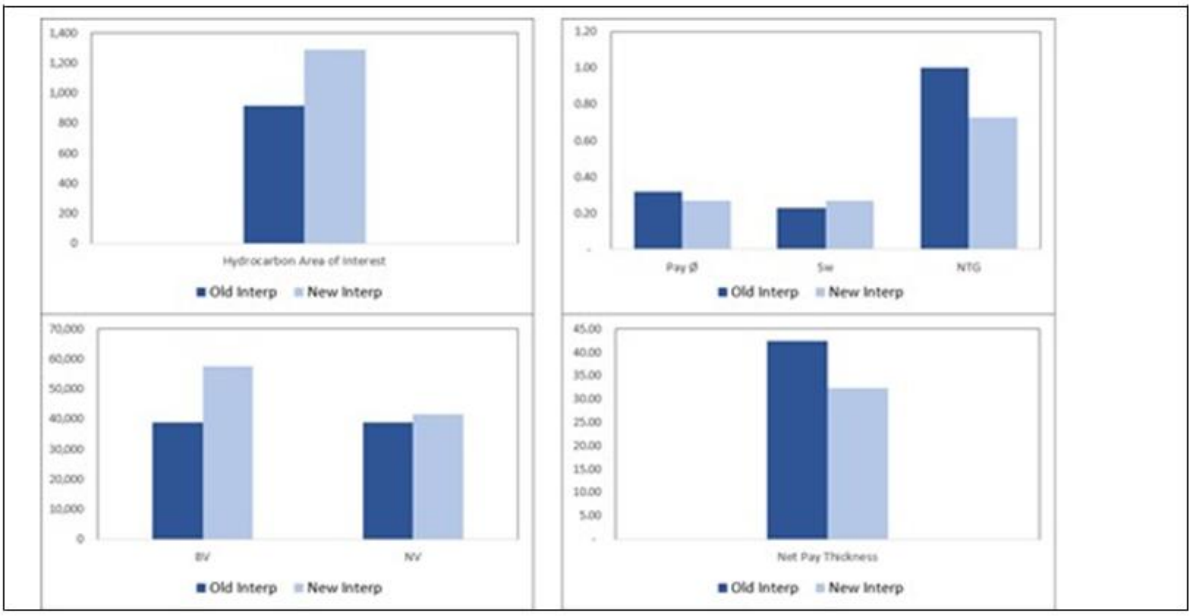


Figure 29: Reservoir Map and Volumetric Change Key Drivers

- Increase in hydrocarbon area of interest is due re-interpretation
- Bulk volume increase is as a result of new picks
- Difference in NTG, Porosity and Water saturation
- 3D Kriging was adopted for distributing RNR discrete logs and petrophysical properties.

Reservoir Geology Current Condition

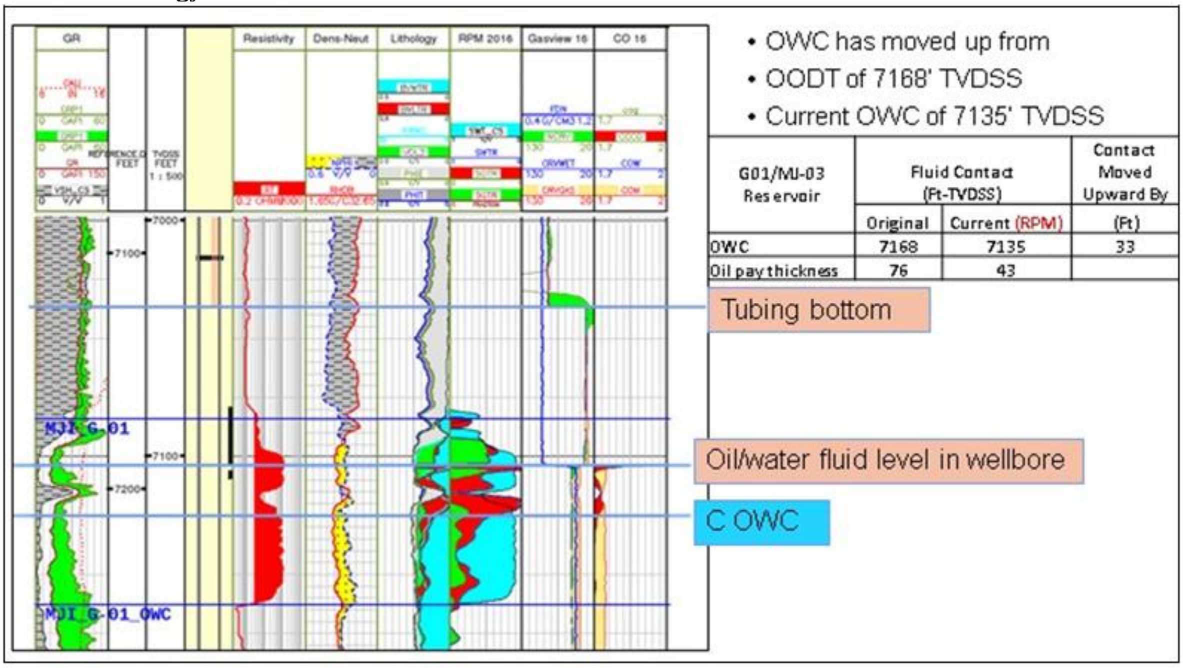


Figure 30: Current Fluid Contacts Interpretation

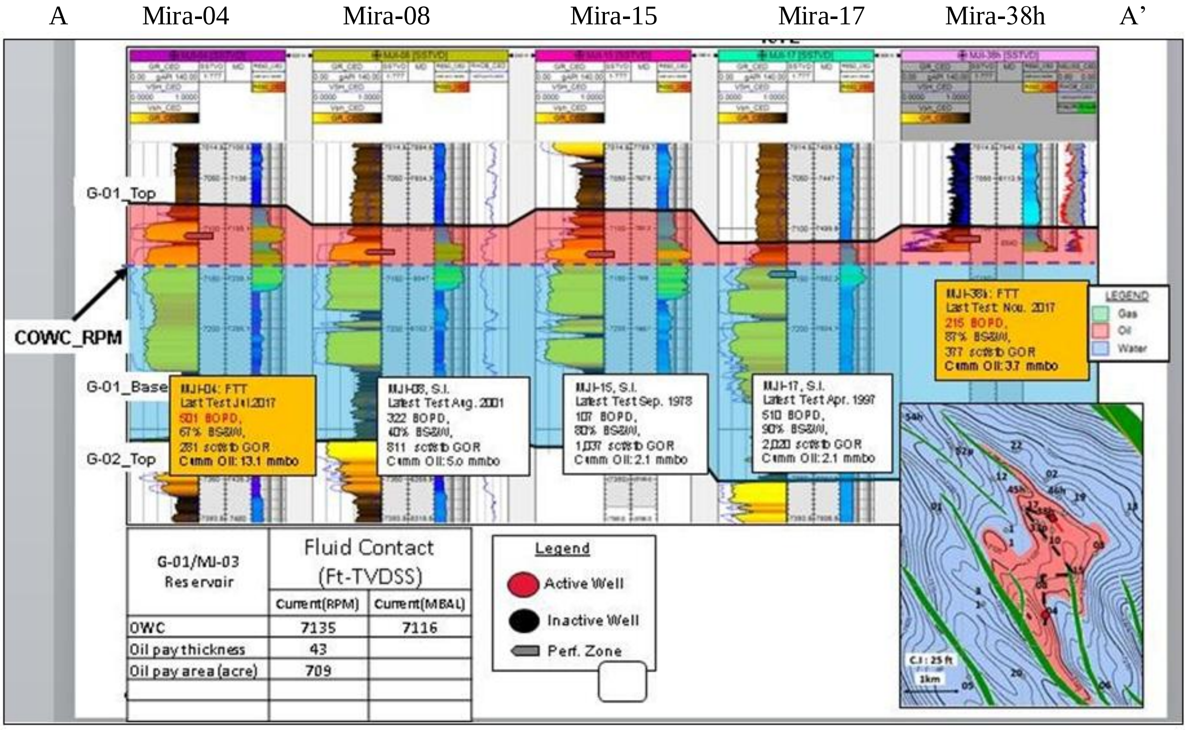


Figure 31: Structural Cross Section (Current Condition)

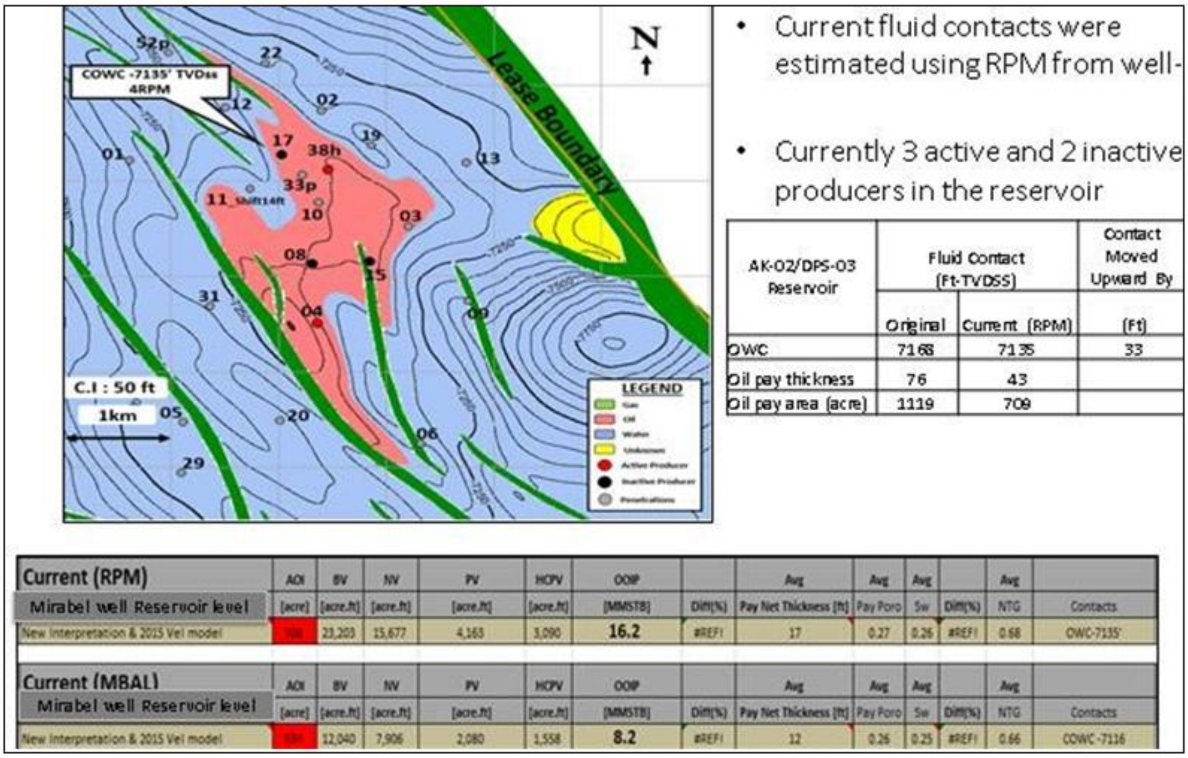


Figure 32: Current Flud Distribution Map

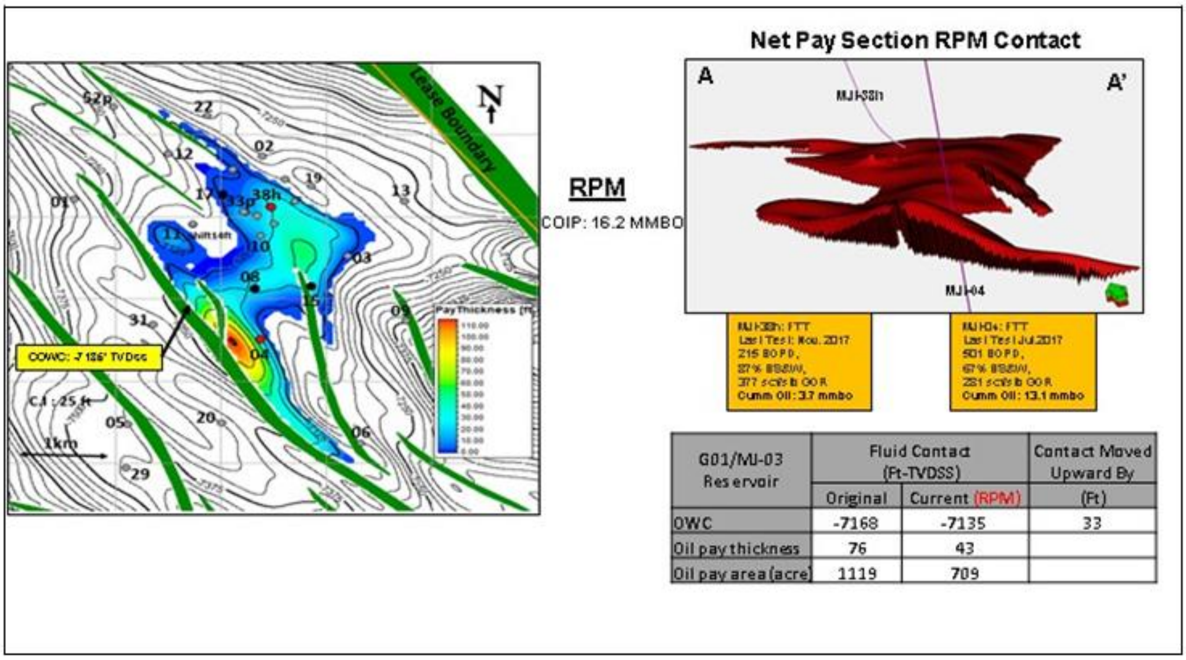


Figure 33: Map Showing Current Net Oil Pay Thickness: (RPM Contacts)

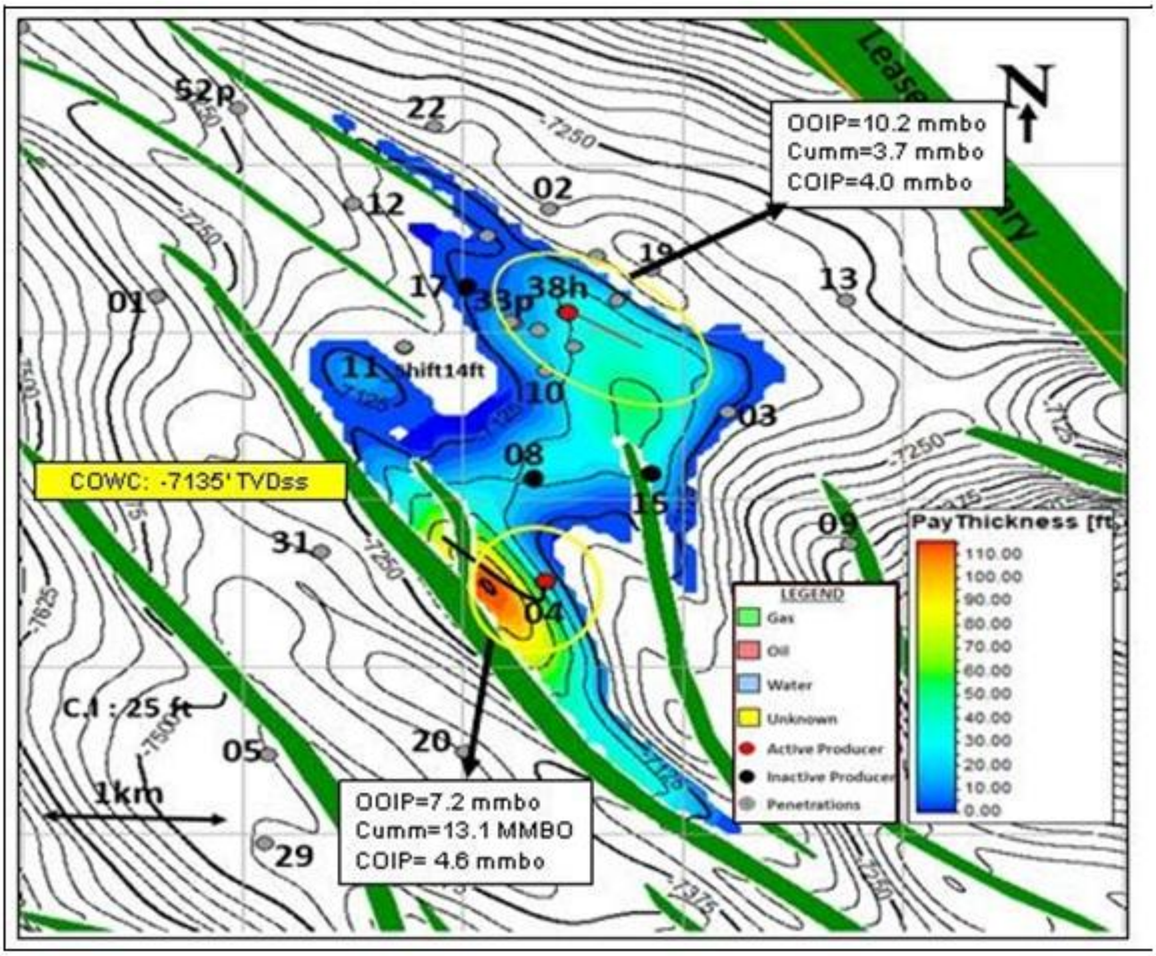


Figure 34 Remaining Average Net Oil Thickness

Figure 34. Above shows a 400 meters radius around well-04 and ellipsoidal around well-38h and volumetric calculated to get OOIP and COIP.

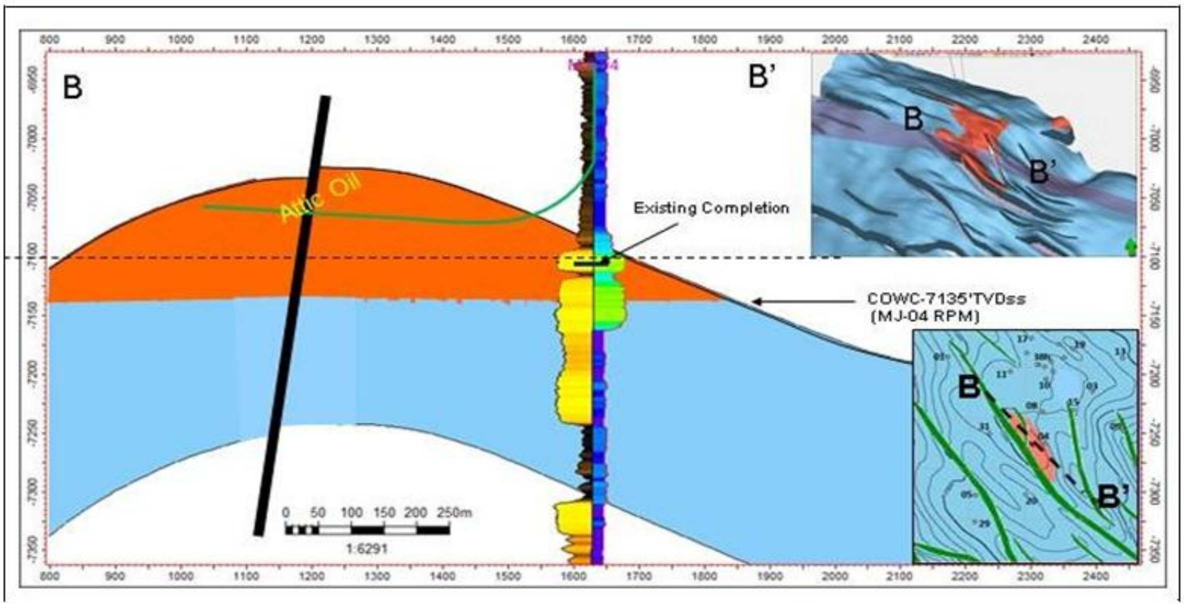


Figure 35: Sgrid Section Showing Attic Oil Updip of well-04

V. Discussion

Evaluation of exploration potential of Mirabel field offshore Niger Delta has been carried out. However, based on the result from current contacts of well-04 RPM, we need to carry out material balance and compare the results for accurate estimation of current fluid contact and also dynamic simulation should be carried out to validate reserves. Also, Fault interpretation shows a dominant subsurface rollover anticlinal structure with collapsed crest bounded by a major growth faults trending in the North East and South west direction. Structural interpretation shows a two-way anticlinal closure with hydrocarbon accumulation at the crest of rollover anticlines which were compartmentalized. Reservoir 4 is identified as a potential target bearing oil, located at the crest, having attic oil saturation. Reservoir 15 shows opportunity for more hydrocarbon drainage base on the petrophysical information, therefore, there is need to perforate above previous perforation to completely drain the reservoir. The STOIIP was estimated using both the deterministic and probabilistic methods and compared to determine level of accuracy. Contacts were taken from the 2016 RPM Fluid contact as I am yet to do MBAL fluid contact.

VI. CONCLUSION

Seismic interpretation using modern technology and supplemented with well data to evaluate Mirabel field, has proved to be a vital tool in evaluating the exploration potential of a well as it is now being used by many professionals in the industry with good success rates. It also lends a hand in reducing uncertainties associated with the Imaging of the subsurface, delineating geological structures and estimating reserves. It's advisable to implement state of the art technology in carrying out interpretation and delineating the extent of a reservoir.

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