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Facies and Petrophysical Modelling of Sand R700, 'Sigma Field', Onshore Niger Delta: Implication on in-fill well placement

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ABSTRACT

This study was designed to evaluate the facies and petrophysical models of a reservoir interval, R700, within the Sigma Field, Onshore Niger Delta with a view to understanding the reservoir property distribution which could help in in-fill well placement. Well tops from well logs were interpreted by variations in depositional characteristics and were tied to seismic surfaces in order to construct the stratigraphic framework. Well data including facies, porosity, volume of shale and hydrocarbon saturation were scaled-up to geological grids. The pixel-based facies model was built based on normal distribution of the facies using Sequential Indicator Simulation algorithm. Petrophysical models were constrained to the facies models using Sequential Gaussian simulation algorithm. The average petrophysical parameters of the three reservoir intervals penetrated by the wells revealed the reservoirs to be of good quality with porosity ranging from 22.2-32.4%, net-to-gross; 51.9-80.3% and water saturation; 23.3-27.1%. The generated fault model of the field showed a dominant East-West trend with good connectivity/linkage. From the analysis of the structural maps and positions of existing wells, the faults can be said to play a major role in aiding accumulation and as such can be used as a guide/control in delineating other areas where accumulation can be favoured. The facies interpretation from well log and analysis of the isochore maps helped in delineating the direction of sand development and helped in constraining the facies model. The facies model captured the heterogeneity in the reservoir interval. Cross section drawn across positions of existing wells showed the location of the wells on structural highs while those drawn across other areas of the field away from existing wells but through areas of structural high revealed areas of good reservoir quality for sitting new wells for optimum recovery of hydrocarbon from the field.

Introduction

Nigeria has the largest oil reserve in Sub-Sahara Africa with over 30Bbl recoverable reserve of oil (Petroconsultants Inc., 1996a). This has made the area receive serious exploration attention for several decades. However, despite this concerted exploration effort, investors and exploration companies still drill many unproductive wells. This is attributed to the complexity of the delta itself in terms of structure, facies changes, among others. It is therefore important to approach the existing problems in the basin from modelling point of view in order to reduce exploration risk. The Agbada Formation, which consists of paralic siliciclastics, is the main hydrocarbon producing formation within the Niger Delta. The Niger Delta has been divided into five (5) structural belts otherwise referred to as depobelts. These depobelts are defined by synsedimentary faulting that occurred in response to variable rates of subsidence and sediment supply (Doust and Omatsola, 1990). The paralic nature of the Agbada Formation and the complexity in the structural style often time lead to great heterogeneity in reservoir properties and structural development. Therefore, a detailed knowledge of variation in reservoir properties and structure is essential in development planning of any field.

The Dataset used for this research include 3-D Seismic (with 868 lines and 910 traces), suite of digitised well data from three (3) wells and a Checkshot data for one of the wells. Since the development of a reservoir requires a detailed knowledge of both reservoir structure and the spatial and temporal variation in reservoir properties, this work utilised the application of 3D characterization techniques in interpretation, modelling and evaluation of a reservoir. Studies of this nature are becoming increasingly important in the petroleum industry as the emphasis on optimizing recovery from existing reservoirs increases. A similar approach can also be used for regional scale oil field evaluation. The study is aimed at producing facies and petrophysical models of the reservoir interval, generating a structural (fault) model of the Field as well as using a combination of these models to delineate areas suitable for development well planning.

Geology of the Niger Delta

Niger Delta is situated at the apex of the Gulf of Guinea on the West African Coast, covering a total area of about 75 000 km2 (Short and Stauble, 1967). The tectonic setting of this basin has been attributed to the divergence of the African and South American Plates and creation of Southern Atlantic.

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The sediments of the delta show an upward transition from marine pro-delta shales through a paralic interval to a continental sequence (Fig. 1). These three sedimentary environments, typical of most deltaic environments, extend across the whole delta and ranges in age from Early Tertiary to Recent and are thus named Akata, Agbada, and Benin Formation respectively (Fig. 1). The pro-deltatic shales, Akata Formation are medium to dark grey, fairly hard, or at places soft, gumbo-like, and sandy or silty. The shales are undercompacted and may contain lenses of abnormally high-pressured siltstone or fine-grained sandstone. The known age of the formation ranges from Eocene to Recent.

Agbada Formation consists of an alternating sequence of sandstones and shales of delta-front, distributary channel, and deltaic plain origin. This alternation was shown by Weber (1971) to be cyclic sequence of marine and fluvial deposits. The sandstones are medium to fine-grained, fairly clean and locally calcareous, glauconitic, and shelly. The shales are medium to dark grey, fairly consolidated, and silty with local glauconite. The formation ranges in age from Eocene to Recent.

However, the Benin Formation consists of predominantly massive, highly porous, freshwater–bearing sandstones, with local thin shale interbeds which are considered to be of braided-stream origin. The age of the formation varies from Oligocene (or earlier) to Recent. In the subsurface of the eastern part of the Niger delta, a clay section, the "Afam Clay Member" is locally recognized.

Synsedimentary faulting and folding is believed to be the cause of sequence deformation in the Niger Delta. The most common of the subsurface structural phenomena on seismic reflection profiles is the growth fault, which often offsets an active surface of deposition. It is characterized by thicker deposits in the downthrown block relative to the upthrown block. It has been demonstrated that the Niger Delta growth faults have curved, concave-upward fault planes. Movement along these fault planes results in warping of the sediments in the downthrown block in the fashion of a reversed drag along an axis parallel to the fault (Ekweozor, 1994; Michele at al., 1999; Uko, 1996). This creates a so-called "rollover structure", i.e. dip into the fault.

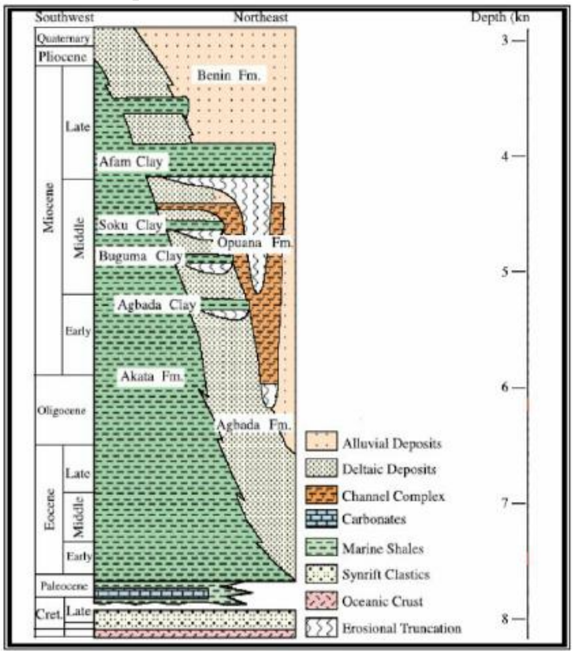


Figure. 1: Stratigraphic column showing formations of the Niger Delta (Doust and Omatsola, 1990).

Methodology

Well log Correlation and seismic-well caliberation

The quality-checked dataset were loaded into Petrel™ software. Potential hydrocarbon-bearing zones within the Agbada Formation were delineated using a combination of Gamma Ray (GR) and Resistivity logs (after identifying the Benin-Agbada transition zone), in which zones with low GR readings that correspond with high resistivity log reading were identified as a potential hydrocarbon zone. These zones were correlated in the three (3) wells available for this study, SM-001, SM-002 and SM-003. The correlation line was carefully selected such that it followed an E-W Trend (Figure 2) for better imaging of the depositional trend.

Three potential hydrocarbon bearing zones, designated R500, R600 and R700 were identified and their continuity established by marking their extents (tops and bases) as shown in Figure 3.

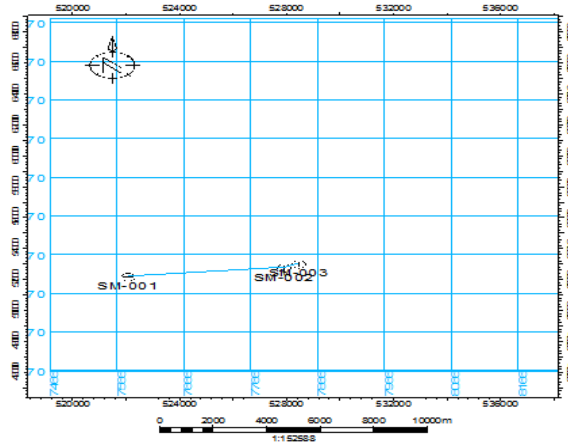


Figure 2. Basemap of Sigma field showing the E-W line of Correlation.

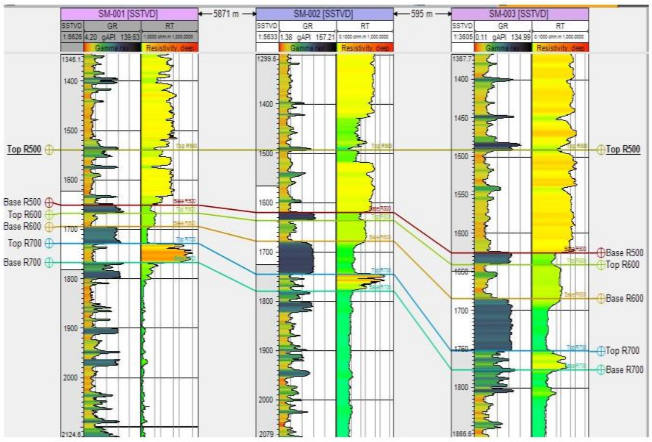


Figure 3: Well section showing the three (3) potential hydrocarbon-bearing zones correlated across the three wells.

The identified zones were then caliberated to the seismic data using the time-depth (t-z) relationship provided by the checkshot data. The density and sonic logs were also utilised for the generation of acoustic impedance log. A good match was observed between the generated synthetic seismogram and the original seismic data. With success at this stage, the well tops as identified on the wells were then posted on the seismic section for horizon interpretation.

Seismic Interpretation

The realized seismic data was structurally smoothened to allow for better reflection quality. The seismic data was then subjected to two types of interpretation-fault interpretation and horizon interpretation.

Thirty four (34) fault sets (Labelled F1-F34) were interpreted through the seismic volume of which only seven (7) were major faults.

These faults were interpreted on the Traces (cross-lines) on an increment of 10. The interpreted faults were the main input for generating the fault model of the field. The corresponding events of the earlier marked well tops were properly interpreted throughout the seismic volume paying attention to reflection continuity and amplitude both on inlines(lines) and crosslines (traces) using an increment of 5.

The resulting horizons were then used in the generation of time structure maps. Using the function generated from the checkshot data, $Y=1.42362*X + 490.87$, the time structure maps were converted to depth structure maps (Figures 11a-c) and these served as important inputs for the construction of the 3D grid.

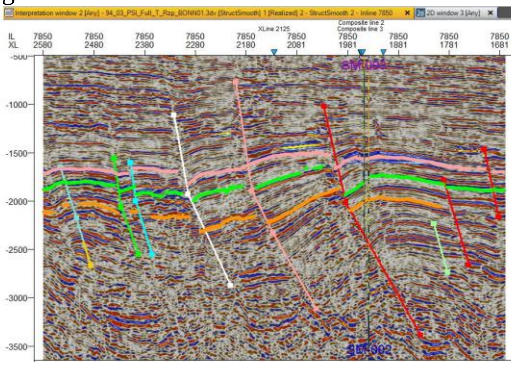


Figure 4. Seismic section across Inline-7770 showing the reservoir intervals and some of the interpreted faults.

Lithofacies Interpretation from Well log

The sand and shale baselines were established using the GR log. Sandy lithology was assigned a yellow colour and a code "0", shale was assigned a black colour and a code "1".

The Lithofacies analysis was performed using the calculator mode of Petrel™ based on the following equation:

Facies=if(GR<60,0,1)

Results and Discussion

Petrophysical Estimate

The result of the petrophysical evaluation (Table 1) shows an expected decrease of porosity values with depth, with reservoir R500 having the highest porosity value of 31% while reservoir R700 has the least value, 26.3%. Based on the estimation of the gross thickness, the reservoirs were observed to become thinner with depth. Shaliness increases from reservoir R500 to R700. The net pay thickness (the actual hydrocarbon-containing thickness within the reservoir) was determined through the multiplication of the net sand with the hydrocarbon saturation.

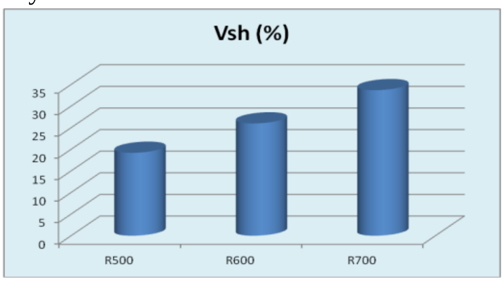


Figure 5:Plot of average Volume of shale values across the three reservoirs.

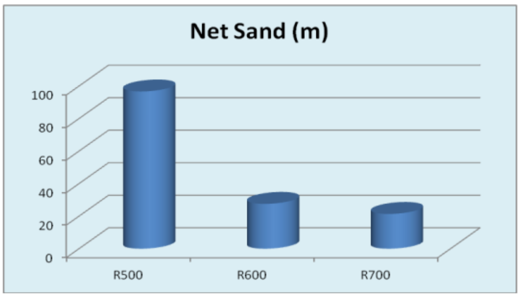


Figure 6: Plot of average net sand across the reservoirs.

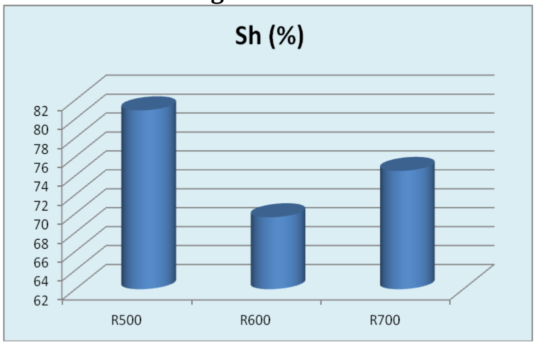


Figure 7: Plot of average hydrocarbon saturation across the reservoirs.

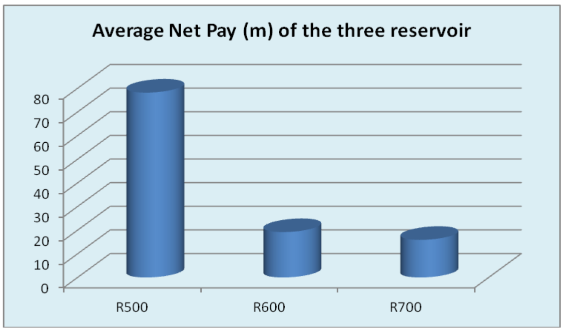
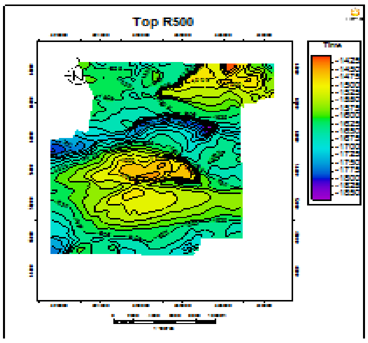


Figure 8: Plot of the average Net pay thickness across the reservoir.

Figures 5-8 puts in pictorial view, the variation in the averages of volume of shale, net sand thickness, hydrocarbon saturation and net pay thickness across reservoirs R500, R600 and R700.

Seismic Interpretation

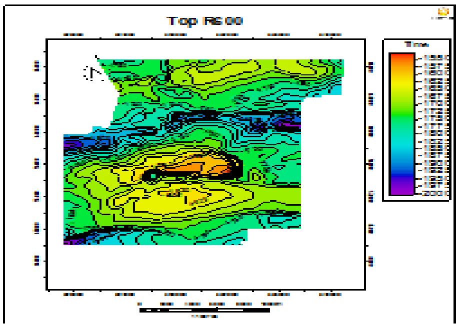
The time and depth structure maps generated from the interpreted horizons are displayed in Figures 9(a-c) and 10 (a-c). The areas shown in bright colours are areas of structural highs (anticlines) while structural lows (synclines are shown in cool colours-blue and purple.



a)

Table 1: Average Petrophysical values for important reservoir parameters across the three reservoirs

Reservoir	Gross thickness (m)	NTG (%)	Vsh (%)	Net sand (m)	Por (%)	Sh (%)	Net Pay (m)
R500	119.7	80.8	19.2	96.7	31.0	80.9	78.2
R600	37.3	74.0	26.0	27.6	29.5	69.6	19.2
R700	32.3	66.3	33.7	21.4	26.3	74.5	15.9



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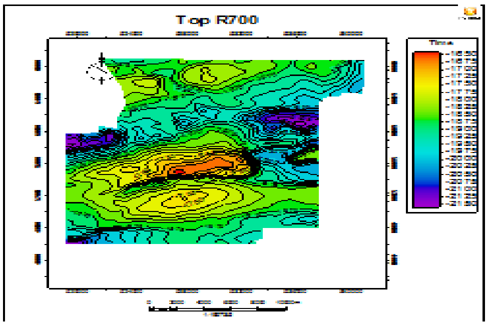
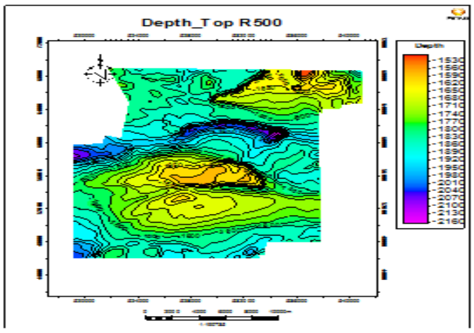
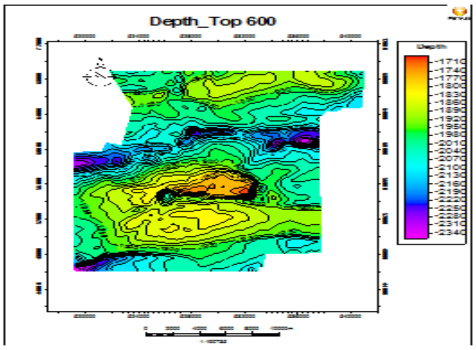


c)

Figure 9 a-c: Time structure maps of the interpreted horizons.



a)



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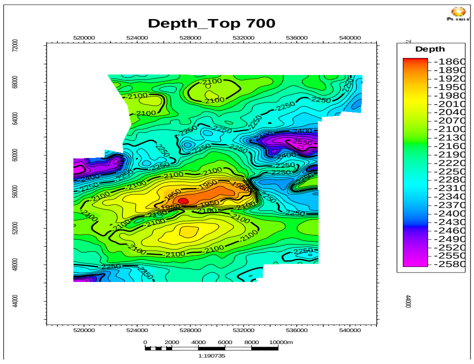

Figure 10 a-c: Depth structure maps of the interpreted horizons

Figures 11 -14 show the result of upscaled facies log and other computed parameters petrophysical parameters. Each of these properties have been made into ten layers to capture the heterogeneity of the reservoir and to allow for the study of the properties in slices

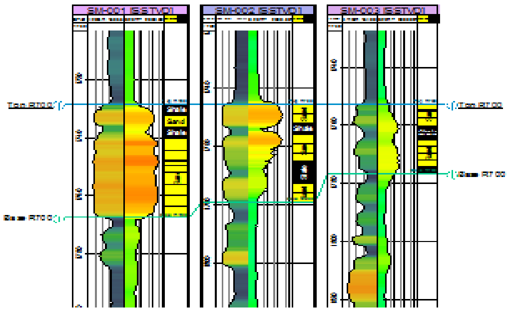

Figure 11: Upscaled Facies log of R700.

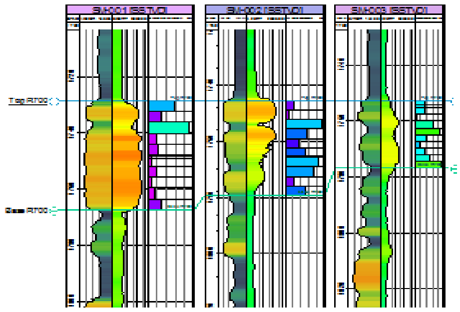

Fig.12:Upscaled Vsh log for R700.

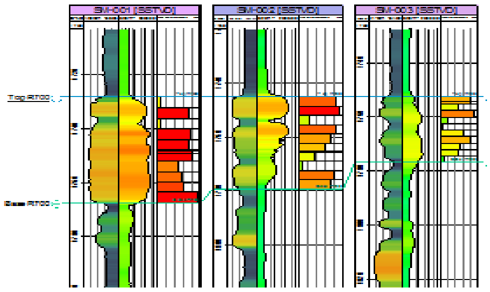

Figure 13: Upscaled porosity log .

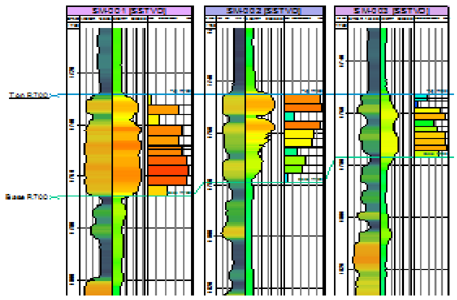

Figure 14: Upscaled Sh log .

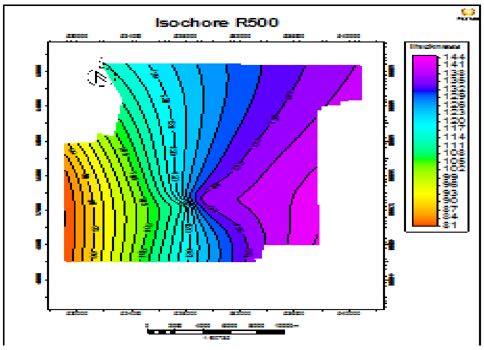

Figure 15:Thickness map of R500 .

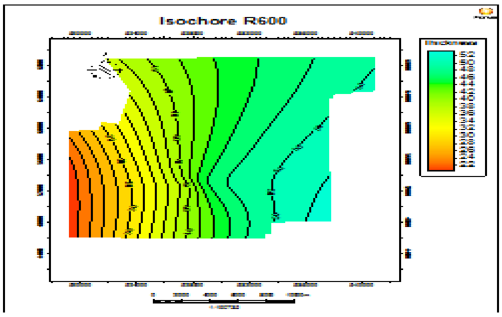

Figure 16:Thickness map of R600.

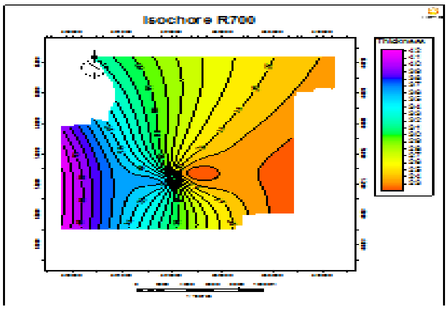

Figure 17: Thickness map of R700.

3D Grid Construction

The interpreted fault sticks, depth structure maps and thickness maps were used as input at different stages for the construction of the 3D framework of Sigma field. The fault model consists of key pillars that define the fault planes. The skeleton grid consists of the top, mid and base skeleton, representing the top, mid and base shape points respectively. The fault showed a dominant E-W orientation (Fig. 18).

Reservoir R700 was then used as a case study in in populating the facies and property models

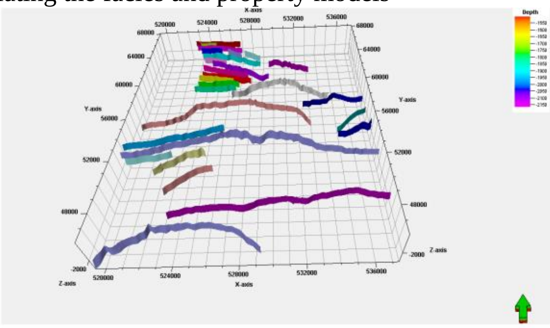

Figure 18: Structural (fault) model of Sigma field.

Property modeling

The upscaled logs were used as the main inputs for the generation of facies and petrophysical models across the field. The upscaled facie log (using an average method of 'most of'; being a discrete log) was modelled using the sequential indicator simulation algorithm.

The result (Figure 19) showed a dominance of sandstone facies and a 'random' shale distribution.

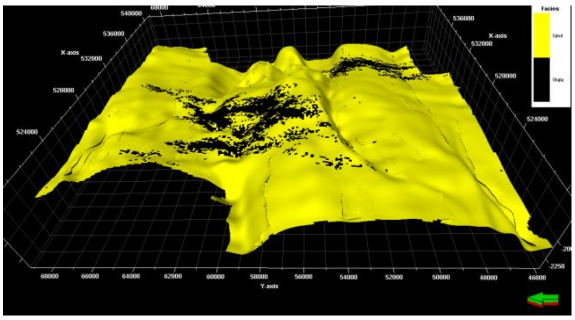

Figure 19: Facies model of R700.

Other properties' models (volume of shale, porosity, hydrocarbon saturation) were then populated biased to the facies. The results (Figures 20-22) reveal the distribution of the properties across the reaservoir. The hydrocarbon saturation model revealed areas of higher hydrocarbon saturation and they conform to structure (observed on the depth maps). Based on this, other areas with good potential for well development were delineated

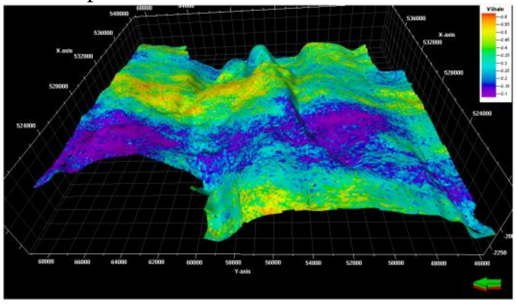

Figure 20: Volume of shale model of R700.

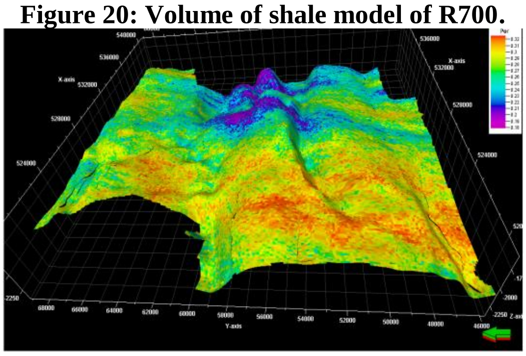

Figure 21: Porosity model of R700 Field.

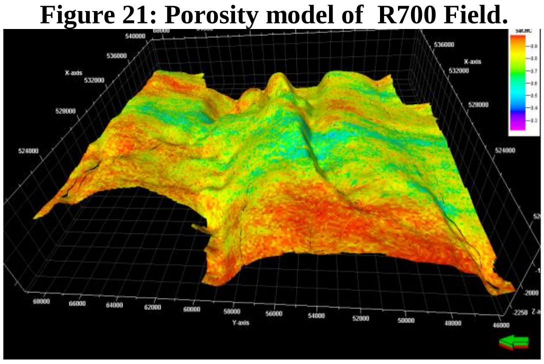

Figure 22: Hydrocarbon saturation model of R700.

Conclusion

Development planning

The 3D models of reservoir structure and the spatial variations of properties which can be viewed on sections at any spatial orientation, or as 3D perspective displays leads to an enhanced appreciation of reservoir complexity, which is invaluable in the planning of development drilling and enhanced recovery activities.

The facie model of Sigma Field clearly showed that sand dominates the reservoir interval of R700, which exhibits 4-way closure believed to have trapped the hydrocarbon from further migration. Based on interpreted depositional facie modeling, structural model and the position of the existing wells, it is recommended that such location that posesses good petrophysical characteristics could be exploited.

The 3D grid data structures of reservoir properties can also be exported to provide primary data for production simulation studies. Since the models are in 3D coordinate space, plotting a proposed drilling profile can be interactively achieved. Figure 23 shows the recommended locations on the fault model based on a combination of the facies and other models for development consideration.

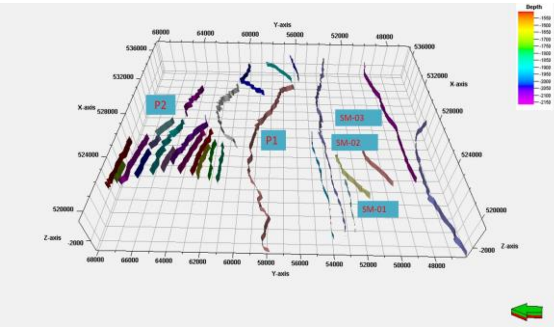

Figure 23: Proposed well locations for development planning as shown on the fault model.

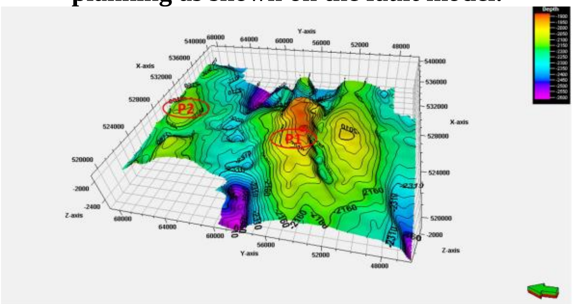

Figure 24: Proposed well locations for development planning as shown on depth structure map.

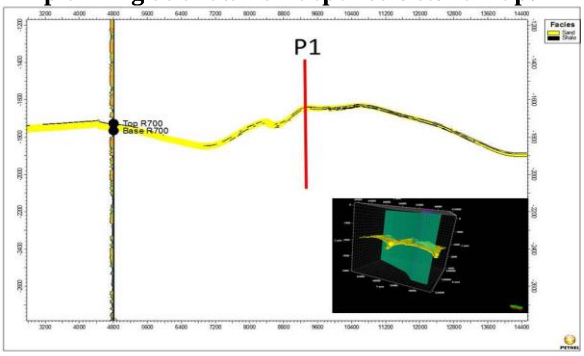

Figure 25: Cross section through the facies model showing the position of Proposed Well 1 (Inset shows the line of cross section through the facies model).

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