Resolving Subsurface Geological Complexities for Improved Production through Optimal Wellbore Placement using Integrated Approach

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ABSTRACT

Subsurface geological complexities (reservoir discontinuity, variable stratigraphy, compartmentalization, formation instability and so on) are some of the major factors impacting the optimal recovery of the remaining oil in place to meet and sustain the ever-increasing demand of energy at affordable cost. This paper demonstrates a streamlined integrated approach used in delineating the best region in a target reservoir with high quantity and quality of sand to maximize reserves to production via optimal wellbore placement. We first conducted detailed petrophysical analysis of all wells that penetrated the target reservoir, identified key stratigraphic surfaces using Biostrat data, coupled with stratal geometries and facies relationships, and assigned numbers based on depositional patterns and sediment supply. The methodology deployed incorporates quantitative stratigraphic (Qstrat) analysis, which utilizes numerical and statistical approaches to analyze and interpret the characteristics and relationship of rock types within a reservoir into reservoir characterization. These were used to build efficient structural and stratigraphic frameworks utilized in constructing reliable static model output. Some lateral heterogeneity and the quality of sand variations within the target reservoir were identified. This led to optimal wellbore placement that accommodated identified structural and drillability constraints. The results of the optimized wellbore Well X selected through this study delivered consistent production performance greater than 1,700 barrels of oil per day over the past two years. This aligned with the predrill forecast of 1,500 BOPD. Lessons learned includes, Qstrat should be utilized during Reservoir Characterization prior to static modelling. Also, one team approach aided the timely attainment of the project objectives.

Keywords: : Wellbore Placement, Reservoir quality, Lithofacies, Maximize production, Qstrat, Facies, Hydrocarbon Pore Volume, Pressure Maintenance, Geological complexities, Static modeling and Drillability, Quantitative stratigraphic.

INTRODUCTION

It has been observed that optimal wellbore placement is vital for improved oil and gas production. Thus, subsurface geological complexities such as reservoir discontinuity, variable stratigraphy, compartmentalization, formation instability and so on must be resolved to optimally recover or drain the remaining oil in place to meet and sustain the ever-increasing demand of energy at affordable cost. However, the challenge becomes how to properly resolve the above-mentioned subsurface geological complexities knowing that access to reliable and affordable energy services remains a vital catalyst to the improvements of human development including productivity, health and safety, gender equality and education (Alstone *et al* 2015). In this paper, we share the detailed integrated approach applied to resolve subsurface complexities encountered in Gig field.

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Field Overview

The Gig field is situated in the swamp region, within the NW-SE oriented Oligocene-Miocene depocenter in the wave and tidal dominated western part of the Niger Delta oil field (Fig.1). It was discovered in 1973 and appraised with a total of seven wells from 1991 until 1996, while first production started in 1997. Pressure maintenance in the field is by gas and water injection which began in 2000 across the main reservoir units.

Structurally, the fault framework is comprised of NW-SE trending normal structure-building faults, along with several smaller fault splays, dipping basin-ward towards the SW. Rapid sediment supply rates in a large-scale deltaic system resulted in the formation of structure-building growth faults and rollover anticlines in the Agbada Formation (Weber, 1972. Doust and Omatsola,

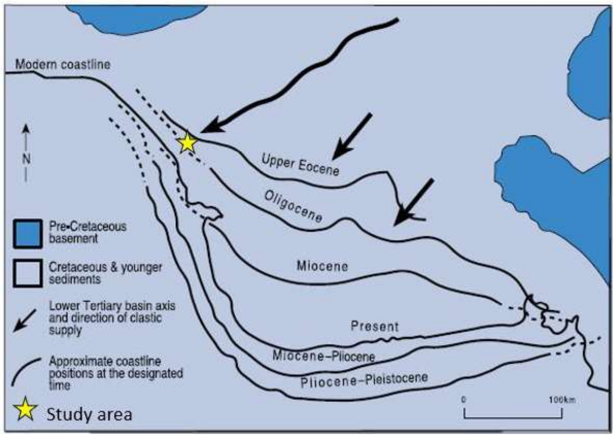


Figure 1: Study location (after Whiteman, 1982, and Orajaka *et al.*, 2015).

1990). The rollover anticlines and the listric faults serve as primary hydrocarbon traps mechanism and migration pathways respectively. Stratigraphically, the field is consistent with the typical Niger Delta stratigraphy; Continental Benin, Paralic Agbada and Akata Formations. The basal deep seated Akata Formation, which is mainly of marine shale deposits provide hydrocarbon source for the overlaying Agbada Formation. The Paralic Agbada Formation contains the Niger Delta reservoir intervals (Ejedawe, 1981, Reijiers *et al,* 1997). The paralic sequence consists of shore face, beach and tidal channels sandstones interbedded with marine and interdistributary-bay shales. The system is overlain by continental to shallow marine sandstones of the Benin Formation. All the wells drilled in the studied field to date have only penetrated the top of Continental Benin and Paralic Agbada Formations, with all hydrocarbon pool discovered, restricted to the Paralic Agbada Formation.

Target Reservoir

The target reservoir was saturated at initial conditions when it was discovered in 1997. It has no completion prior to the drilling of #-82h well. The structural trapping mechanism of the reservoir is formed by a combination of rollover, stratigraphy, and fault closure against the main structure building growth fault. The reservoir strikes northwest to southeast; and is bounded by canyon to the north-west and an internal fault to the east, which separates fault block from the adjacent reservoir. There are no internal faults present within the reservoir. Stratigraphically, the reservoir consists predominantly of wave dominated, and tidal-influenced shoreface sandstone deposits. The tidal and fluvio-deltaic deposits are predominant towards the northwest, whereas shoreface deposits are more prominent towards the southeast where this reservoir lies. The reservoir interval is Miocene in age.

Fluid Contacts: The reservoir was interpreted to be saturated at the pre-production condition with an original gas oil contact (OGOC) at -4,990 feet (ft) true vertical depth subsea (TVDSS). Well, #-10 pilot which is located at the crest of the reservoir logged the OGOC, Well # -82 pilot logged the lowest known oil (LKO) at -5,096 ft, while highest known water was encountered at -5247 ft TVDSS by water injection well (well #--8i) which is in the water-leg of the reservoir (Fig. 2). Area of unknown fluid exists within the lowest known oil and the highest known water contacts.

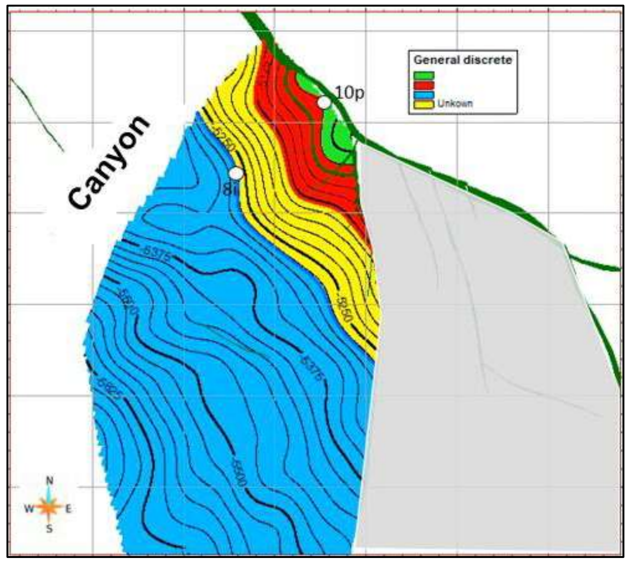


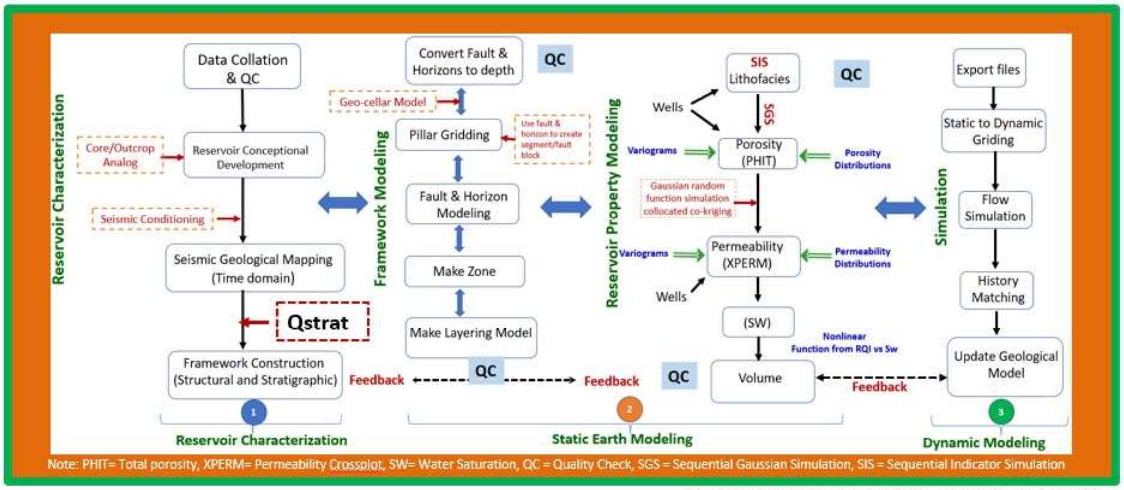
Figure 2: Structural map showing fluid distribution of the target reservoir.

To drain the hydrocarbon underlying in the target reservoir, optimal wellbore placement is required to maximize production for energy accessibility and affordability. Hence, this paper's objective is to share the streamlined systematic workflow used in delineating the rock properties quality of different regions of the target reservoir for optimal wellbore placement.

RESEARCH OBJECTIVE/ METHODOLOGY

The methodology deployed involved looking beyond the bright spot in the seismic volume, with a deep dive into petrophysical parameters of the existing wells, reservoir characterization, utilizing high resolution sequence stratigraphical approach, static modeling, and reservoir simulation.

In general, the methodology is broadly categorized into three namely, (1) Reservoir characterization (RC), (2) Static Modeling (Earth Model) and (3) Dynamic Modeling (Reservoir Simulation) see figure 3.



Modified from Bassey et al (2015 and Jiajie Chen (2017)

Figure 3: Integrated and iterative workflow utilized for Reservoir Characterization to build Earth Model (Static and Dynamic).

It is important to point out that Reservoir Characterization involves cross functional analysis of a reservoir to enable reasonable understanding of the reservoirs. The analysis is not limited to geomechanics- tectonic and structural background, basin setting, geological evolution, petrophysics, seismic characters, reservoir properties, biostratigraphy, depositional environment, sequences stratigraphy, lithofacies, flow units, and fluid contacts. Modeling (Static or Dynamic) is a simplified process to represent the subsurface reservoir or complex interior of the earth in 3-dimensional space, based on certain physical and numerical process, using either static or dynamic approaches (Jiajie Chen, 2017). However, the main reason for reservoir modeling is to gain an insight about the reservoirs architecture and predict or forecast its performance.

The streamlined systematic approach deployed involves comprehensive and iterative data integration from multi-functional teams of geoscientists and petroleum/reservoir engineers. The study commenced with deep dive into petrophysical features of the existing wells, large scale 3D seismic interpretation and sequence stratigraphic assessment to characterize the reservoir. After closing out the action items from the constructive feedback received during peer review, the team built geo-cellular model using the geologic framework constructed.

Integrated Reservoir Characterization (IRC)

The integrated reservoir characterization was carried out to understand the reservoir characteristics from various perspectives and to enable the building of the reservoir representation in 3-dimension, using available high technological tools and applications. It involves data collection and Quality Check, Petrophysical Analysis of the offset well, development of reservoir conceptional model using cores/outcrop analog, geochemical, biostratigraphy data, Seismic Interpretation, Seismic-to-well-tie, structural and stratigraphic framework construction, as well as seismic attribute analysis as shown in figure 3 above.

Geo-cellular Model Generation: This involves the construction of fault and horizon framework in depth domain, distribution of reservoir physical properties (Net-to -Gross, Porosity, Water Saturation, Permeability, Shale volume), Production data, Upscaling of the well logs within the grid, Volumetric computation, Risk Analysis and Uncertainty Management. The processes used in building G-09 reservoir geo-cellular model involved 3 major steps as outlined in the workflow, namely (1) Earth model Framework Construction (3D structural and 3D stratigraphic grids), (2) Property Modeling (PKS) and (3) Simulation. The Earth model framework construction began with depth conversion of the time-interpreted horizons and faults.

Fault and Horizon Modelling: The fault interpreted along the strike and dip lines of PSTM seismic time volume were depth converted. A total of 13 faults identified were incorporated into the structural framework. The faults were generated with the assumption they were linear faults. Framework grids were constructed with 50m x 50m lateral spacing to adequately include the stratigraphic details. In all, the 3 identified compartments were integrated into the framework gris as areal segments using a combination of faults, “no throw” faults and trends (Fig. 4). The compartments, as grid segments, give the flexibility to use any portion of the models at ease.

The interpreted horizon-fault lines were extracted from the model for all faults and were edited on each fault pillar, this is to ensure consistency with seismic interpretation. The

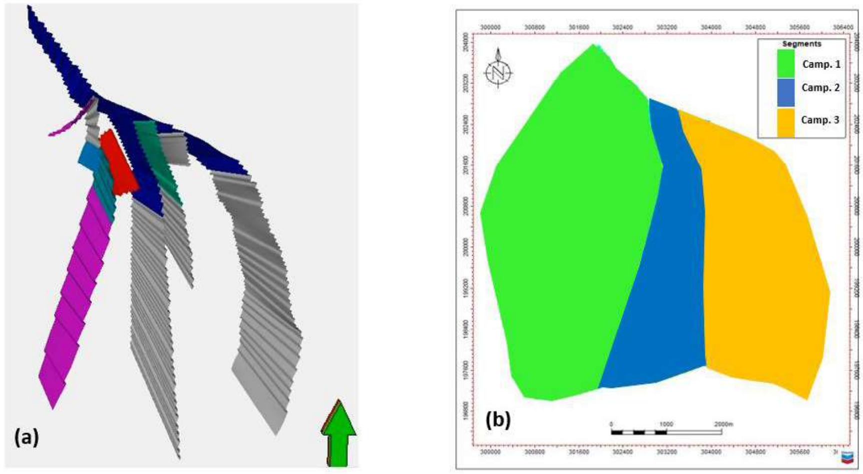


Figure 4: Fault model showing (a) Mapped faults, and (b) Three compartments identified.

horizon-fault lines were fed back into the horizon modelling process to ensure a consistent geologic framework. Three vertical zones were defined based on isochores created from four interpreted horizons (flooding surface (FS), Transgressive surface (TS), G-09, and G-09 base) on seismic and tied to well tops (Fig. 5). Proportional layering and average thickness were adopted for the three zones. However, the key depth converted horizons modelled into the model frameworks have stratigraphic and production significance to allow for ease of replication of flow behaviour in the simulator.

grid, following data analysis carried [variogram, vertical proportion curves and estimated facies] out on the G-09 reservoirs zone. These were used to build geologic reasonable EOD boundaries.

Reservoir Property Modelling:

Facies Distribution- Based on interpretation from seismic extraction, amplitude analysis, the use of spectral decomposition technique, and data analysis, the G-09 lithofacies were modelled by zones and distributed, using

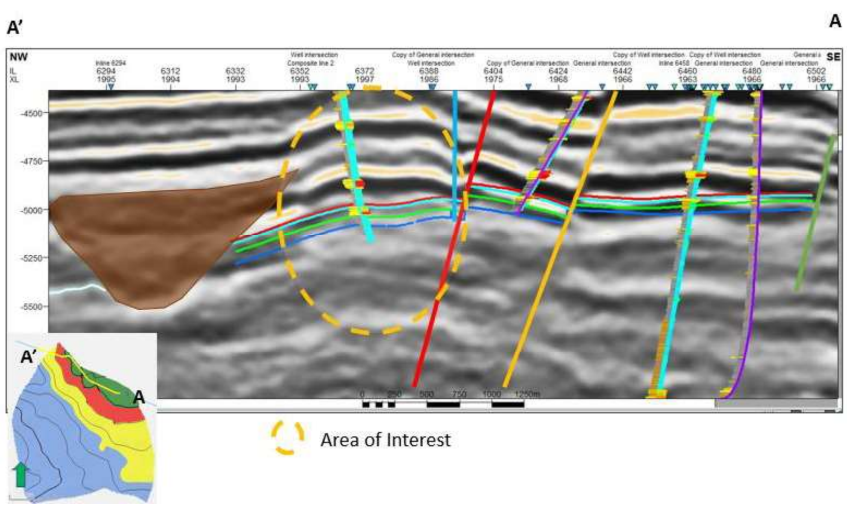


Figure 5: Strike-oriented seismic cross section showing interpreted horizons and faults.

Environment of Deposition (EOD) properties were introduced into the model using the Truncated Gaussian Simulation (TGSim) algorithm. The G-09 reservoirs are primarily classified as channel systems deposit. The EOD was generated using the EOD interpreted from the wells and seismic, using areal EOD polygons. The EOD interpreted at well locations were then upscaled in the

Sequential Indicator Simulation method.

Porosity- Sequential Gaussian Simulation approach was utilized to model the upscaled compaction -corrected total porosity (PHIT) trained to the lithofacies model property. During the process, the PHIT logs were upscaled and populated by zones and by lithofacies using variograms and distributions from data analysis.

Permeability- Porosity-permeability transforms derived from the core data obtained in the field were utilized to build permeability model, using Gaussian simulation approach and porosity as soft constraint. During the process, data scatter was incorporated around the best-fit line in the porosity-permeability cross plot to create a geologically consistent permeability model.

Water saturation (Sw)- This was derived from a transform generated from core Water Saturation (Sw) vs Rock Quality Index (RQI) cross plot.

RESULT AND DISCUSSIONS

Static Earth model.

In recent times, the E&P industry has become more competitive in meeting and sustaining the ever-increasing demand for energy at affordable cost. This requires- useful subsurface models, efficient operations cost, appropriate operating system, ideal projects, and having a multi-talent workforce.

Though no model is perfect, ("Every model is wrong, but some are useful"), the team ensured that the target reservoir was properly modelled to better understand the architecture of the container (the reservoir), the distribution and stacking relationship of the reservoir zones, the reservoir property ranges, the combinations of these properties and their likely outcome. Thus, a depth structural map, geologically realistic representation of the reservoir architecture which allowed for 3D visualization of the reservoir stratigraphic architecture, reservoir properties and fluid distribution were generated.

Facies Classification

Depo-facies and Lithofacies classification were guided by detailed log analysis and analog. No core data exist within the interval of interest, however, linear transform was generated, using core data from the shallow reservoir. The defined depo-facies and lithofacies using Vshale (VSH)) and Gamma Ray (GR) logs were reconciled with porosity, permeability data, and overall log character. Lithofacies cutoffs were tied to observed trends in the histogram distributions of the VSH and Gamma Ray and qualitative replication of well logs (Table 1).

Four depo-facies corresponding to (1) the transgressive lag (Calcite), (2) the upper delta front (clean sand), (3) the lower delta front (shaley sand), and (4) the shelf (shale) were identified, based on the geologic concept interpreted from seismic and well log character.

Four lithofacies were identified; (1) High quality sand, (2) Mid quality sand, (3) Low quality sand, and (4) non-reservoir (Fig. 6).

Table 1: Reservoir Property Cut-off.

Cut-offs	VSH	PHIT	SWT
SNS	<0.4		
RNR	<0.4	>0.12	
PNP	<0.4	>0.12	<0.7

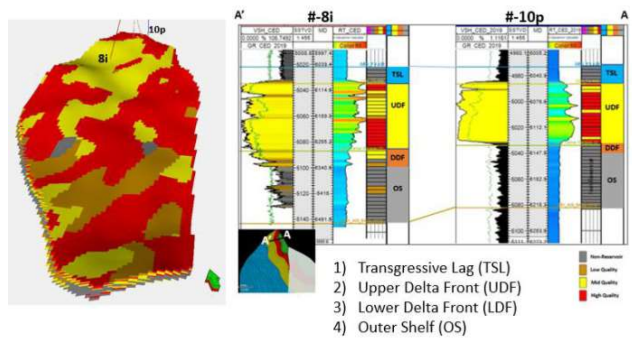


Figure 6: (a) 3-D Map showing Lithofacies model, and (b) Stratigraphic cross section.

Stratigraphic and Structural Framework:

Typically, vertical stratigraphic sequence depicts marine regressions and transgressions; this was observed in the G-09 reservoir. The gross thickness of the sand package in the well that served as type log is about 121ft. Its overall look from the well gamma ray (GR) log motif is funnel shaped (Fig. 7). The shape portrays a Fluvial- Deltaic progradation with a coarsening-upward parasequence architecture (Selley 1978, Rider 1990). Coarse up and shape top is likely characteristics of river mouth bar, delta front, shoreface and submarine fan lobes. However, prograding parasequence is believed to be deposited during a drop in sea level. The sand is laterally extensive across the field via seismic-view and across wells that penetrated this interval.

A stratigraphic cross section through the interval of interest shows overall variation in thickness. The sand is laterally continuous and extensive across the field, as seen on seismic and across the well penetrations. Although, some variability is obvious in #-10p; the base is highly eroded when compared with #-8i and #-82p see figure 8.

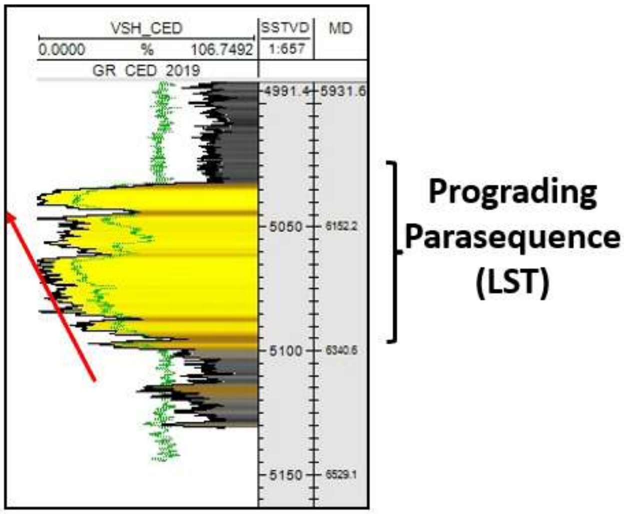


Figure 7: G-09 reservoir typlog.

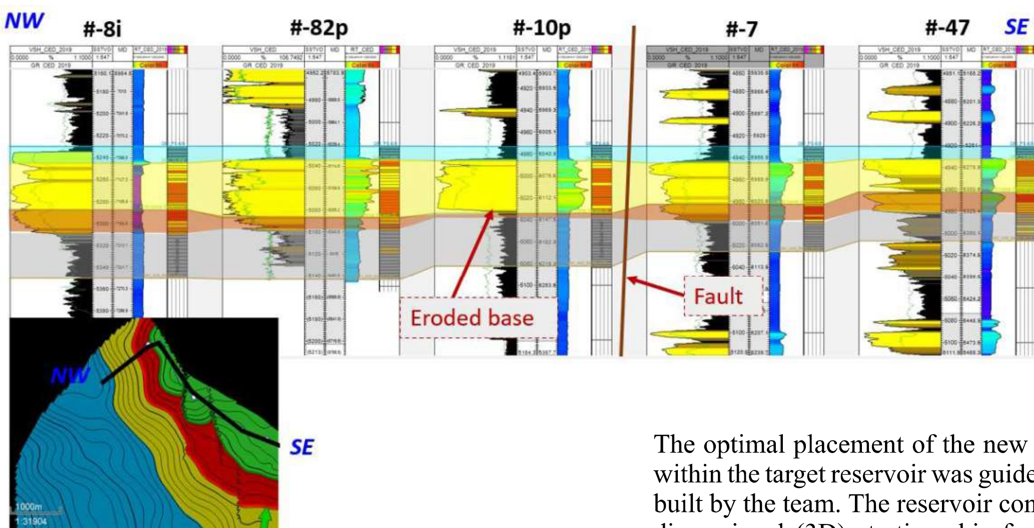


Figure 7: Strike-oriented Stratigraphic Cross Section.

A coarsening prograding parasequence set (likely LST tracts) is observed across the reservoirs, using stacking pattern method. The gamma ray log and seismic signature give a likely indication of an incipient river mouth bar progradation associated with a reduced fluvial.

Structural Framework: The depth structural map generated shows geologically realistic representation of the subsurface reservoir architecture. The structural trend is Northwest Southeast, while the dip direction is towards the Southwest. The reservoir's structural trapping mechanism is formed by rollover, stratigraphy and fault closure against the main structure building growth fault. The reservoir strikes northwest to southeast; and is bounded by the Opuama canyon to the north-west and an internal fault to the east, which separates the fault block of interest from the adjacent reservoir. The structural cross section shows the fluid types logged in the wells that penetrated the reservoir (Fig. 8).

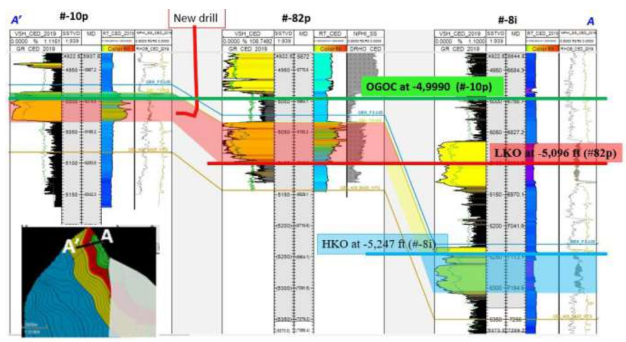


Figure 8: Structural Cross Section.

The optimal placement of the new planned well (#-82h) within the target reservoir was guided by the useful model built by the team. The reservoir conceptual model and 3-dimensional (3D) stratigraphic framework aided in the delineation of the environment of deposition. The improved understanding of the depositional environment gave insights on how the sand was distributed across the field, as well as the sand fair way (Fig. 9).

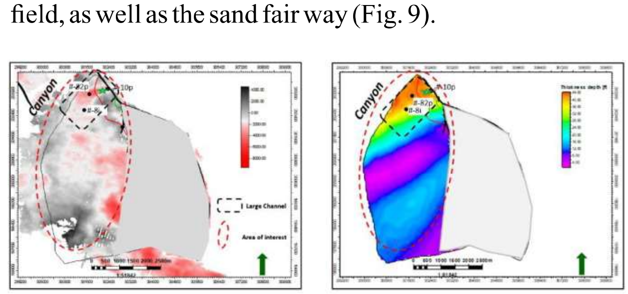


Figure 9: Notional Paleogeographic Maps showing (a) Seismic attribute (Exact Value Amplitude Extraction, and (b) Depofacies Trend.

The seismic attribute extraction revealed large channel around well #-10p, this agrees with the depo-facies trend and stratigraphic framework as shown on the maps. As a result of the interpretation, the new well was positioned at the crest close to #-10p area which is sand-rich.

Some other factors considered while choosing the well location prior to drilling include, reservoir continuity, structure, reservoir properties (PKS), lithofacies, and the drainage area. These considerations enabled the successful and cost-efficient drilling of the well. Fluid contact uncertainties, resulted in a 10ft-below-contact encounter in Well #-10, which saw the GOC. Wells #-10p and #-82p were used as the offset wells while drilling the wellbore. Although the new well encountered GOC 10ft deeper, which was attributed to depth issue, other properties prognosed by the model matched closely as shown on figures 9A to 9C.

The new well (#-82h) wellbore was placed at the sweetest portion of the reservoir with the following characteristics: water saturation (Sw) = 23%, porosity = 33%, permeability = 800md, hydrocarbon pore volume (HPV) = 10 feet, net hydrocarbon thickness volume (NHPV) = 23 feet, and lithofacies is within high quality range. The well production performance has been consistent with over 1,700 barrels of oil per day (BOPD) over the past two years, thus. maximizing production.

Lessons Learned: The optimal wellbore placement in the sweet spot of any reservoir requires the efforts of multi-disciplinary team and reasonable quality data set. Lithofacies analysis and dynamic modeling were useful. These remain valuable for reservoir management, while maximizing reserves to production. One team approach also aided the timely attainment of the project objectives.

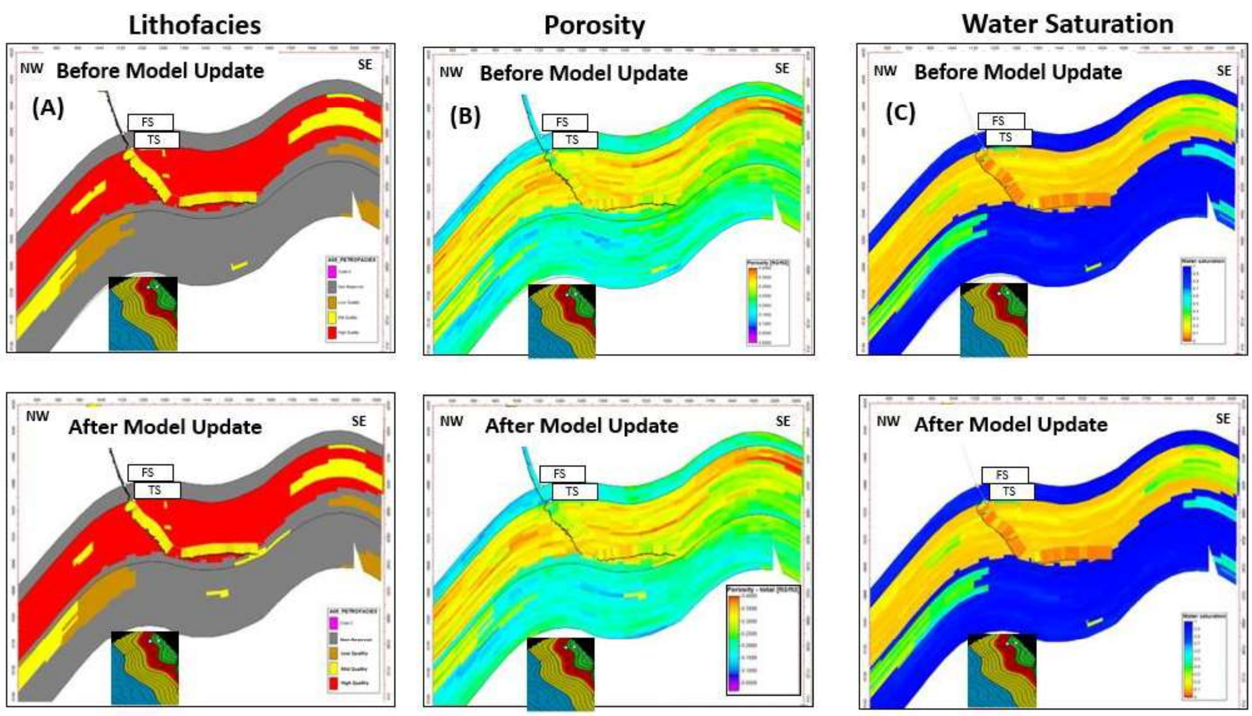


Figure 9: Cross section through new well showing (A) Lithofacies, (B) Porosity, and (C) Water saturation.

The Best Practice: The best practice would be to integrate reliable datasets, such as pressure information, fluid rates, well logs, 3D/4D seismic volumes and attributes, to generate representative geologic and simulation models that best depict and predict subsurface 'architectural` behaviours.

CONCLUSIONS AND RECOMMENDATIONS

The systematic approach utilized in this study, aided in the realistic delineation of the rock properties quality of different regions of the reservoir. A series of sensitivity tests enabled the selection of a lateral length of 1200 feet to accommodate identified structural and drill-ability constraints. #-82h wellbore was placed at the sweetest portion of the reservoir, which led to production maximization in the field.

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