Utilising Stratigraphic Driven Approaches and Simulations to Build Robust 3-D Geologic Models for Miocene Reservoirs, “Josh” Field, Niger Delta*

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Abstract

Reservoir properties models that are constrained to facies models and upscaled for dynamic simulation and volumetric estimation are often marred with spurious reservoir properties models, which either underestimate or overestimate the reserves base. Realistic facies models were built for “Josh” field, coastal swamp Depobelt, Niger delta by using integrated core description, 3D seismic, wireline logs, sedimentological and biostratigraphic dataset. Lithofacies identified include shallow shelf sandstones and mudstones, lower to middle Shoreface sandstones, tidal channel sandstones and transgressive marine mudstones while the depositional environment is delta front (inner neritic to middle neritic) as revealed from supervised classification of cored well, biostratigraphic and sedimentological analysis. The depositional units were identified by mapping Maximum flooding Surfaces, Sequence Boundaries and Transgressive Surfaces. For each parasequence, flooding surfaces were correlated; isopach, sandstone-quality trend maps, and mudstone-quality trend maps were constructed to capture the reservoir lithofacies heterogeneities; flow and baffle facies and petrophysical variations within the depositional units. These were upscaled and modeled using modeling algorithms: Truncated Gaussian with Trends (TGT), Truncated Gaussian Simulation (TGS) and Sequential Gaussian Simulation (SGS). Results revealed that the sequence stratigraphic driven approach generated the most geologically reasonable facies model and showed favorable reservoir quality values with the potential for substantial hydrocarbon storage for many lithofacies. This sequence stratigraphic facies model predicted significant vertical compartmentalization identified by the flooding surface mudstones. Petrophysical ranges associated with each facie, as deduced from core and log data, appeared to be clearly related to their respective reservoir qualities. It revealed that this approach to facies model remains a key driver to the understanding of these reservoirs. This will help in placing infill development wells, aiding history-matching and fluid-flow simulations in verifying both the infill targets and reservoir compartments.

Introduction

Geostatically modeled reservoir properties are often not geologically realistic because the degree of heterogeneities of the reservoirs facies that are not well captured. Reservoirs facies heterogeneities often include the facies flow units and mudstones baffles units that are imperative for reservoir management, fluid flow simulation and secondary oil recovery studies. Reservoir are heterogeneous than often thought, with the

Geostatistical models alone not taking into account the compartmentalization inherent in these reservoirs. The two key questions are, how can Sedimentology, Biostratigraphy, Stratigraphy and Seismic be effectively integrated with wireline logs and efficiently incorporated in the 3D geologic (depositional and lithofacies) models? In addition, what is the best approach to predict the heterogeneities and compartmentalization that will drive the properties models?

This studies of the prograding parasequences sets from the Miocene reservoirs in JOSH field answers the questions. The cored intervals from 10580'-10820' MD in JOSH-3 well were integrated and extrapolated to the other wells by neural networking to build the geologic (depositional and lithofacies) models. Realistic sequence stratigraphic driven facies models were built for the Miocene reservoirs by capturing the reservoir's prograding parasequence architecture from the sequence stratigraphic correlation. This helps in constraining the reservoir properties to their respective rock types.

The studies also shows that the sequence stratigraphic driven facies models as the best approach to predict the heterogeneities and significant vertical compartmentalization by the flooding surface mudstones in the Miocene reservoirs. This helps in uncertainties minimisation in well planning, development and Secondary Oil Recovery studies.

Stratigraphy and Facies Description

The middle Miocene shoreface reservoirs in JOSH field within the Agbada Formation located at the Coastal Swamp Depobelt of Niger Delta. It consists of a progradational shoreface (delta front) succession terminated by a minor Sequence Boundary (SB 3) on top and a Maximum Flooding Surface (MFS 2) below which indicates a Highstand Systems Tracts (HST) deposits. JOSH-3 Well core report shows: (i) sidewall core samples descriptions from the cored intervals 10580'-10820' MD (Figure 1) revealed that the Miocene reservoirs are mostly composed of: Sand; Yellowish grey; Upper Fine (fU) to Upper Medium (mU); poorly-moderately sorted; slightly silty; slightly clayey; loosely consolidated while distal portion is shaly, grey and fissile (ii) Depositional facies units include Upper-Middle Shoreface, Lower Shoreface and Transgressive Marine Deposits (iii) Lithofacies identified include Upper-Middle Shoreface Sand, Shallow Shelf Mudstone, Lower Shoreface Sand and Transgressive Marine Mudstone. Depositional environment is delta front (Coastal Deltaic to Inner Neritic) from the Biostratigraphic report.

Parasequences Characterization

The prograding parasequences sets consist of the middle Miocene reservoirs consist of coarsening upward trend intercalated by the mudstones deposited on the flooding surface (Figure 1). Fifteen flooding surfaces were correlated and were constructed for each parasequence and revealed a complex reservoir architecture characterized by shoreface clinoforms. Parasequences consist of relatively conformable successions of strata bound above and below by flooding surfaces and are the building blocks of unconformity bounded sequences (Van Wagoner et al.1990). Each parasequence was correlated (Figure 2) using wireline logs and it is bounded on top by the overlying flooding surface and at the base by the underlying flooding surface. The wireline logs contain limited electrofacie logs: Gamma Ray, Resistivity and Density logs that were used in the correlation studies.

The flooding surfaces bounded on top by each parasequence reveals continuity, shown to be laterally extensive and can be mapped throughout the reservoir (Figure 2). The sand facies identified in the parasequences sets are the reservoir rocks, while the mudstones deposited and occurring above flooding surfaces capping the parasequences represent baffles/seals in the reservoirs. Each of the parasequences is named after the underlying flooding surface.

The oblique section stratigraphic correlation panel (Figure 2) of JOSH-1 ST, 1, 2, 3 and 4 wells consists of the progradational parasequences sets; FS 190, FS 185, FS 180, FS 170, FS 165, FS 160, FS 150, FS 145, FS 140, FS 135, FS 130, FS 125, FS 120, FS 115 and FS 110 being characterized by coarsening-upward successions and generally thickening- upward sand units. The lithofacies (shoreface sands and mudstones) appeared to be laterally correlatable and showed uniform parallelism of flooding surfaces. Mudstone deposits above FS 140 appear to pinch out as observed in the correlation panel.

Supervised Classification of facies in Non-cored Wells (Neural Networking)

Lithofacies identified within the depositional Facies units in JOSH-3 (cored well) was extrapolated vertically to the un-cored interval in the cored well and extrapolated laterally to un-cored wells in the field in a consistent manner. The result (Figure 2) was fine-tuned to reduce training and prediction error. It provides the link, which ensures that the reservoir property data measured from core is properly incorporated into the volume cells used in static reservoir modeling

Conceptual Depositional Geometry and Trend

Vertical facies stacking and profiling of the well log motif from the type well, JOSH-3 were juxtaposed with a conceptual depositional facies model by Van Wagoner et al. (1990) and showed progradational parasequences (Figure 3a). There is a close match of the gamma ray log motif to the Wagoner's 2D conceptual depositional facies model and the 3D analogue depositional model (Figure 3b). This supports our studies of the Miocene reservoir interval as a progradational parasequence set. The mudstones deposited above flooding surfaces can be mapped throughout the reservoirs. It was evident that the mudstones, which are potential seals, have some control on fluid flow in the reservoirs and possibly may affect recovery. The 3D lithofacies model to be generated will be used as input for flow simulation and will characterize the mudstone deposited on flooding surfaces as well as the reservoirs too.

Sandstone Geometry of the Miocene Reservoirs

The sandstone isopach map shows the sandstone thicknesses within each parasequence. It indicates the sand body geometry (spatial continuity) and trend, quality and development within each parasequence (Figure 4a). Each isopach is named after the underlying flooding surface. The gross thickness map from FS 110-190 which shows the total facies (sands and mudstones) geometry (spatial continuity) and trend was used as just only one horizontal variogram (Figure 4c) in building the depositional models in successive facies transition while each of the sandstone and mudstone isopach maps was used as trends for constraining their respective sand facies and mudstone facies in the lithofacies model.

The seismic attributes generated (for example, RMS and Maximum Amplitude) are only conformance to structure and does not truly represent the facies lithological changes/stratigraphic features (Figure 4d) and the inability of the 3D seismic volume to resolve at the parasequence scale. Therefore, it was not used as a constraint for the facies distributions. The sand isopach within each parasequence unit (Figure 4a) exhibits increasing sandstone thickness patterns, from which a generally southward (NNW-SSE) progradational trend is inferred.

Sand isopach 120, 125, 130, 170, 180 and 190 generally pinches out distally (southward) from thickness above 28ft (brighter colours) into a relatively muddier depicted with duller colours (Figure 4a). These were used as trends to constrain the sand lithofacies distributions.

3D Grid Construction

The reservoir's parasequences architectures were captured from the detailed sequence-stratigraphic correlation of gross thickness of the sequence ranging from 222.2ft in JOSH-3 to 259.4ft in JOSH-1 of the FS 110-190 Prograding Parasequences Set. 302 layers (Geological) captured the reservoir architecture and heterogeneities (Figure 5a). FS 110 Top Structure Map was mapped from seismic data and subsequent flooding surfaces structure maps were mapped from their respective well tops. Zones were constructed for each parasequence from the flooding surfaces map and the isopach for each sand facie and mud facie. A geologic model was built using the 3D Grid settings shown in Table 1.

Data Analysis

The Vertical Proportion Curves (VPC) reflects the vertical variations of each lithofacies proportions, and confirms the depositional facies units that governed their distributions (Figure 5b). It allows assessment of reservoir heterogeneities. Local vertical proportion curves (VPC) of the lithofacies were generated using the depositional facies as spatial discriminators. The global VPC gives the proportion of each lithofacies per layer integrated laterally in the Miocene reservoir over the whole field.

Normal score transformations were performed for the porosity distributions for each rock type and distribution curves were fit to the transformed data (Figure 5c). Distribution fit was used instead of a normal or average fit to best characterize the range of porosity values for a given lithofacies.

Depositional Modeling Using Truncated Gaussian with Trends (TGT)

The truncated Gaussian with trends (TGT) was used to model large scale ordered facies, in this case, progradational facies in a shoreface or delta front environment. In this study, the depositional facies transition follows a strict and ordered sequence from upper-medium shoreface, lower shoreface to transgressive marine deposits that defines a broader facies association. These depofacies distributions use only one same variogram. The 3D (spatial) trend is obtained from the geometry tab of the software used by carefully editing and aligning the transition lines (solid and stripped) to capture accurately all depofacies found in all the wells (Figure 6). The azimuth for the geometry (1640) was derived from the horizontal variogram gotten from the depofacies gross isopach map (Figure 4c). The variance decides the degree of interfingering along the transition (trend) lines of the depofacies. It was set for 0.1 to give a moderately better interfingering effect for the depofacies. Residuals between the trend and the upscaled well log data are then distributed, using the Sequential Gaussian algorithm.

Lithofacies Modeling using Truncated Gaussian Simulation (TGS)

In order to honor the particular order of the depofacies model, truncated Gaussian Simulation (TGS) was used to model the lithofacies constrained by the depositional facies model, successively above. It reflects the vertical variations of the proportions, and confirms the depositional process that governed the lithofacies distributions. The shoreface depositional environments have distinct proportions of lithofacies. The trend and variogram from each sandstone and mudstone isopach map were used to constrain the sand facies and mudstone facies respectively in the lithofacies model. This provided a robust framework for porosity distribution within the lithofacies.

Porosity Modeling

The porosity was modeled using Sequential Gaussian Simulation (SGS). Porosity distribution/extrapolation was constrained/biased to the lithofacies model (rock typing) already generated to reflect local porosities ranges.

Results and Discussions

The results of the models (Figure 7a, Figure 7b and Figure 7c) showed that the depositional model revealed the three (3) depositional facies; Upper-Middle Shoreface, Lower Shoreface, and Transgressive Marine Deposits that were identified and modeled. This provided depositional framework and an input for lithofacies distributions. Lithofacies model result revealed shoreface sands flow and mud baffle facies discriminations. The mudstones facies are baffles and are clearly shown in the lithofacies model as vertical compartmentalization. Sand flow facies in the field areas are laterally extensive, and have significant thickness. The baffle facies consist of shallow mudstones and transgressive marine mudstones.

Stratigraphic cross section fence diagrams of the models (Figure 7a) with view from the northwest, the depositional models show that shoreface depofacies (brighter colours) are continuous and prevail in the northwest, updip (Figure 7b) continental portion of the model while the marine deposits (dark colours) dominate the downdip (basinwards). This also applies for the depositional trend cross section.

Lithofacies models show that the reservoir sand quality (brighter colours) is better around northwest updip (Figure 7a, Figure 7b and Figure 7c) and degrades (dark colours) towards the southeast as evident in the isopach trends and vertical facies stacking observed from the well logs correlation (Figure 7b). This reveals the vertical compartmentalization by the mudstone facies. The model is used to constrain porosity distributions and used as an input in the fluid flow simulation.

Porosity models reveal the porosity ranges within each lithofacies. Brighter colours (red and yellow colours) of higher porosity (0.15) are modeled to be found within the better facies towards the northwest, updip while the duller colours (green and blue) of lower porosity are found with the poorer facies dominant downdip towards the basin (Figure 7a, Figure 7b and Figure 7c). An arbitrary line of section (Figure 7c) was taken along the well paths to reveal how the models closely matches the geological and petrophysical information at the well locations along the vertical well bore profiling.

Conclusion and Recommendations

The robust integration of sedimentology and stratigraphy have been captured, characterized, and represented in the sequence stratigraphic-based facies models despite paucity of data. It provided a better understanding of the connectivity potential and heterogeneities of the reservoirs within each depositional facies unit. It is also a major driver to the petrophysical models; porosity model. The lithofacies model allowed reduction in the risks in reserve estimation. The models revealed the vertical compartmentalization that is important to guide new strategies of dynamic stimulation and injection planning, resulting in a secondary oil recovery optimization (better sweep efficiency). It is recommended that Flow Zone Indicator (FZI) Analysis be carried out to further validate the reservoir vertical compartmentalization. Petrographic analysis (Diagenetic studies) may also be carried out to provide a reservoir petrofacies model that may establish the link between the FZI and the stratigraphic framework.

Reference Cited

Van Wagoner, J.C., R.M. Mitchum, K.M. Campion, and V.D. Rahmanian, 1990, Siliciclastic sequence stratigraphy in well logs, cores and outcrops: Concepts for high-resolution correlations of time and facies: AAPG Methods in Exploration Series 7, 55 p.

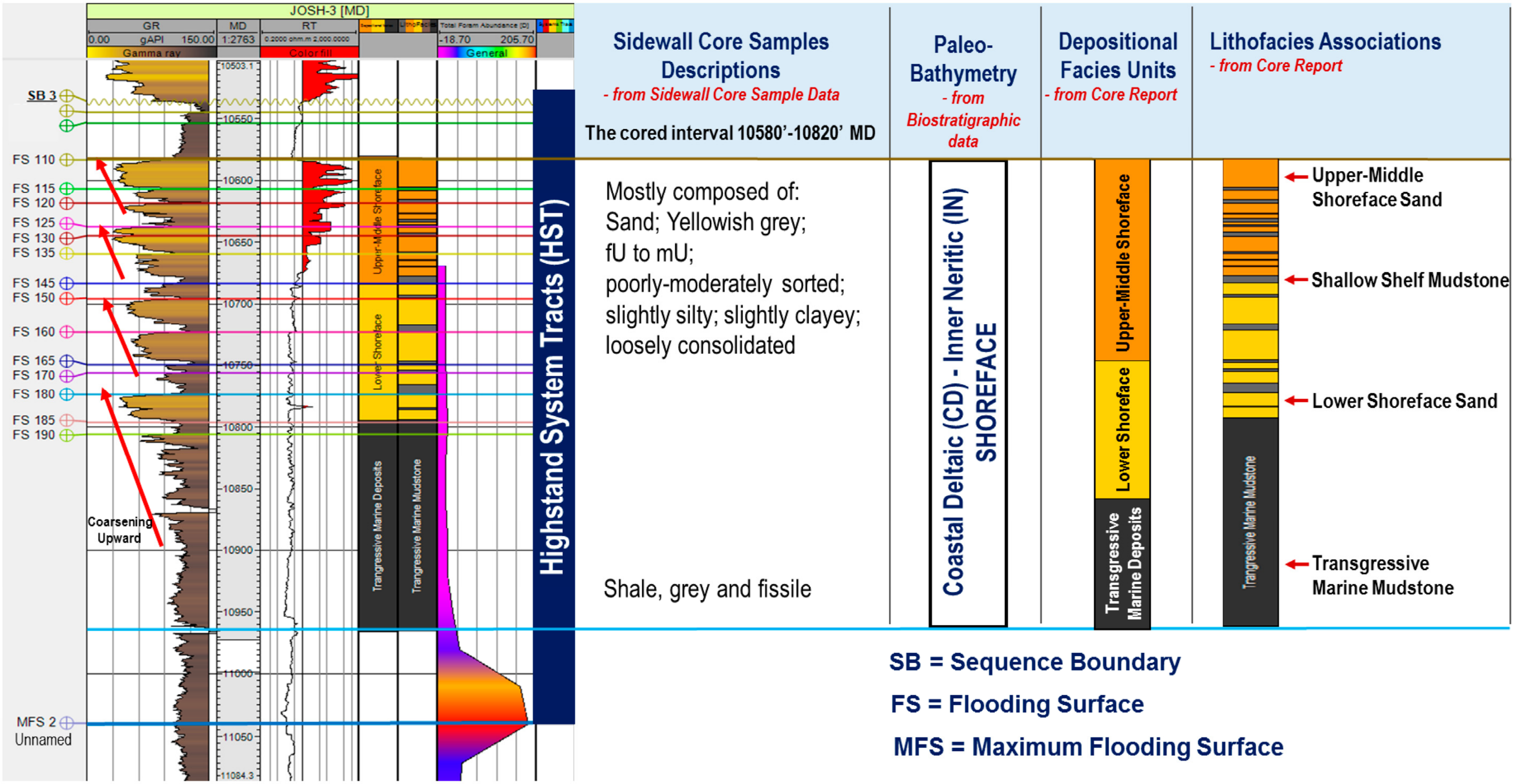

Figure 1. Sequence Stratigraphy of the FS 110-260 Prograding Parasequence Set in JOSH-3 Type well: Integration with the Wireline logs with Sedimentology and Stratigraphy.

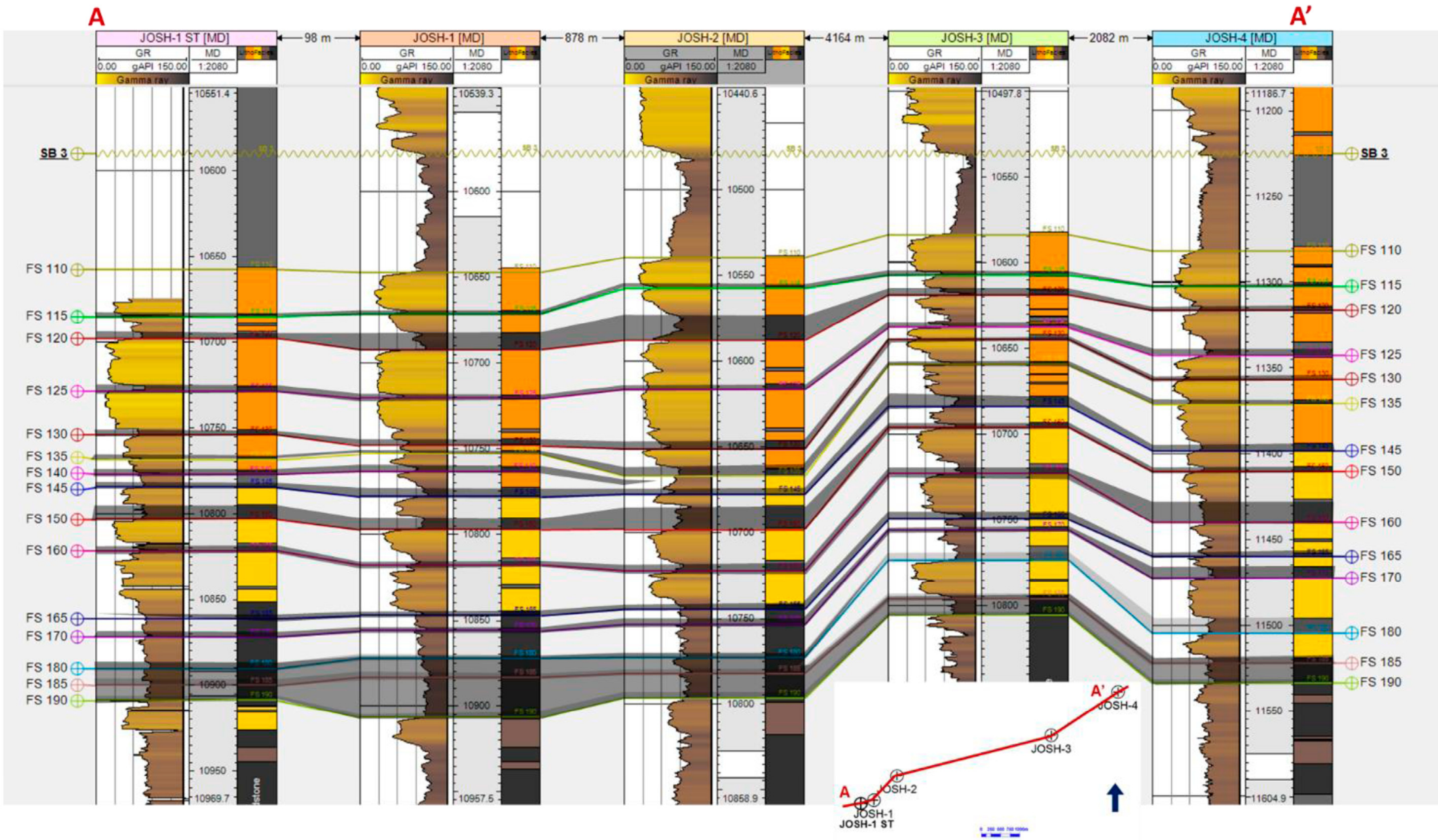

Figure 2. Sequence Stratigraphy Correlation of the FS 110-190 Prograding Parasequence Set. An oblique correlation panel showing the train set from JOSH-3 Type well and result of test by neural networking. Mudstone facies are in dark shaded colours.

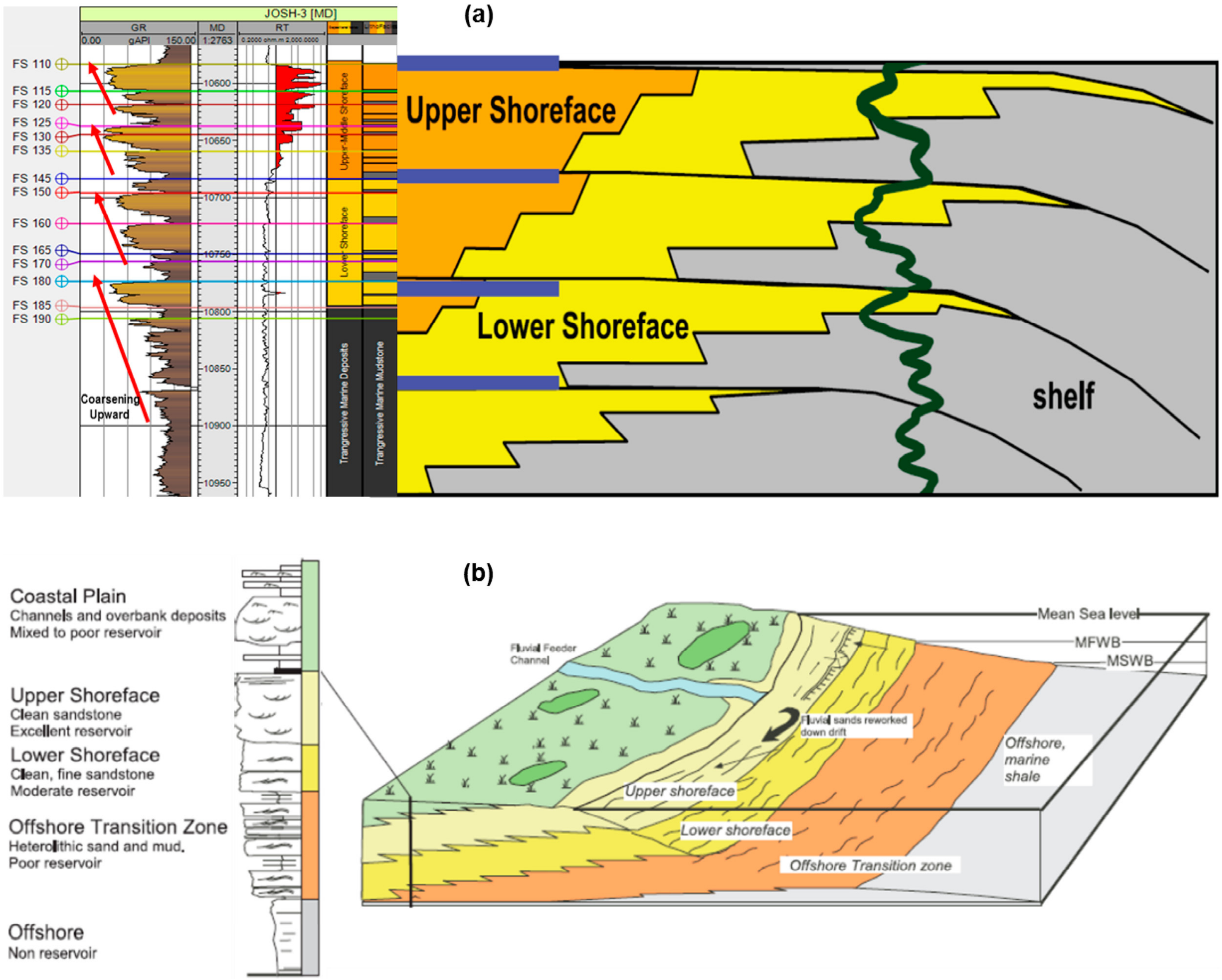

Figure 3. (a) Juxtaposition of the type well log motif with the 2D Conceptual figure by Van Wagoner et al. (1990); (b) 3D Depositional Model for a shoreface and wave-dominated delta.

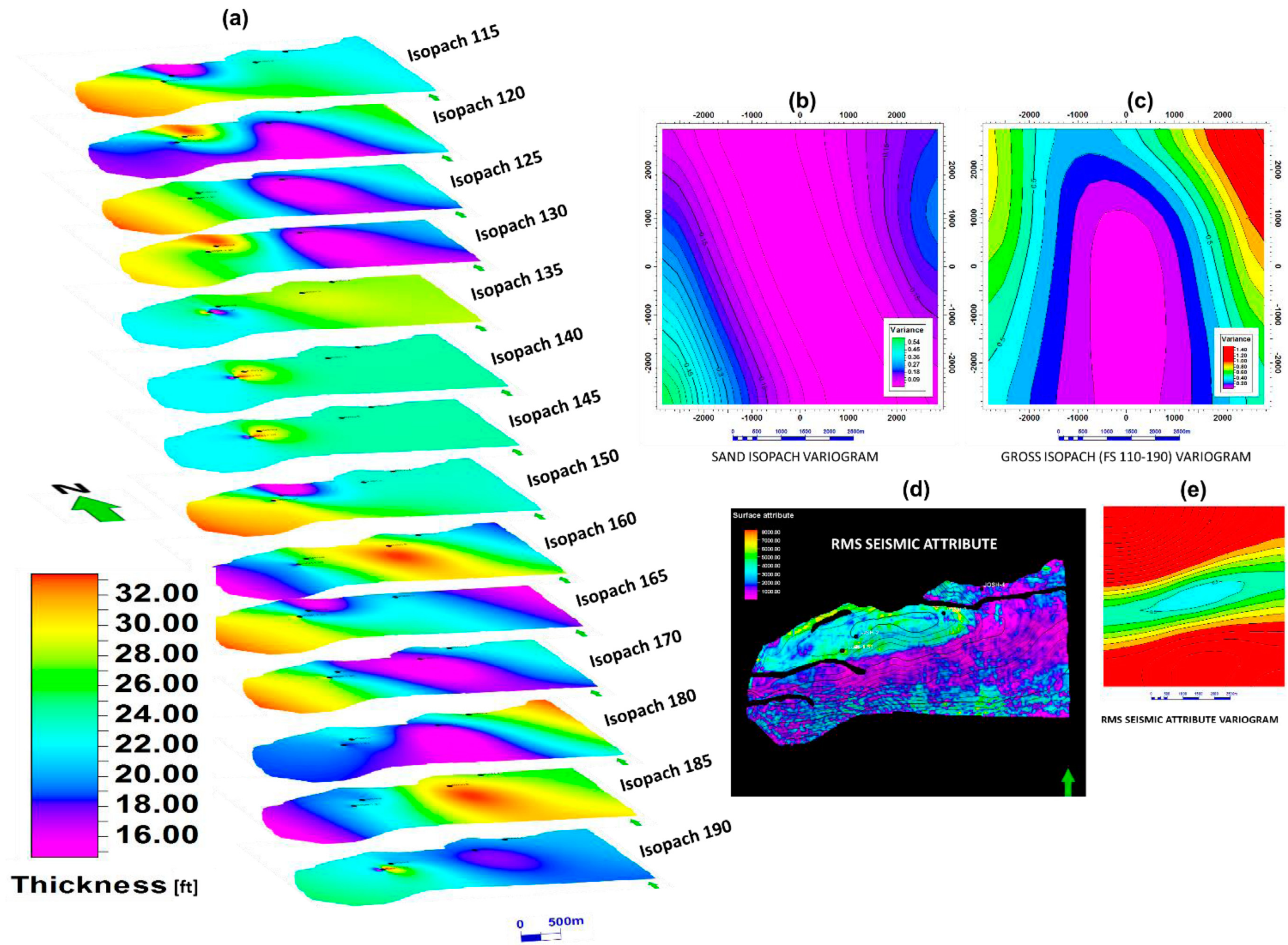

Figure 4. (a) Sandstone isopach map within each parasequence; (b) sand Isopach Variogram; (c) Gross Isopach Variogram; (d) RMS Seismic Attribute on FS110. Note: The black dots represent well positions.

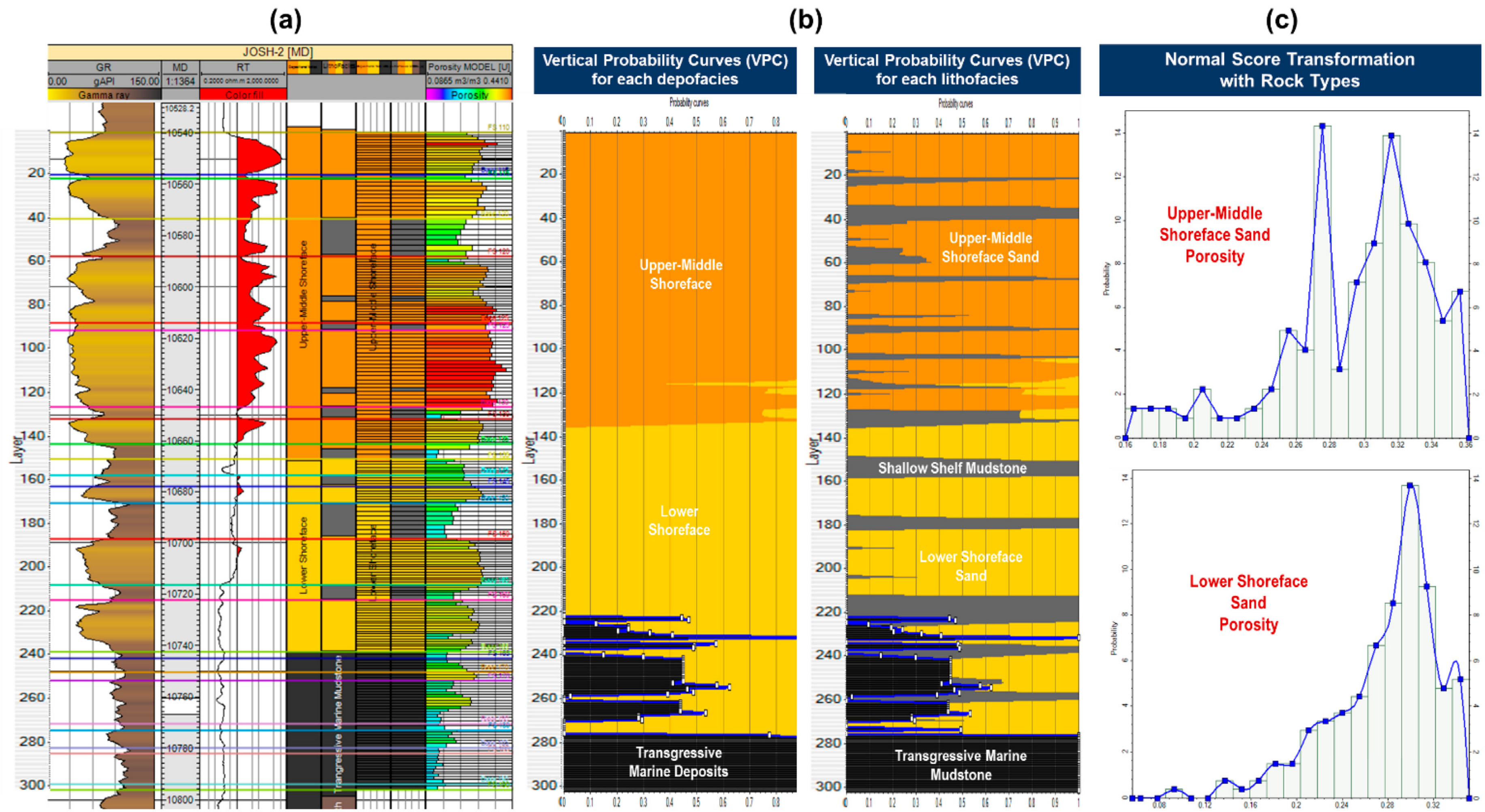

Figure 5. (a) Upscaled properties logs to capture the reservoir heterogeneities; (b) Vertical Proportion Curves for the depofacies and lithofacies; (c) Normal score transformations for the upscaled porosity log.

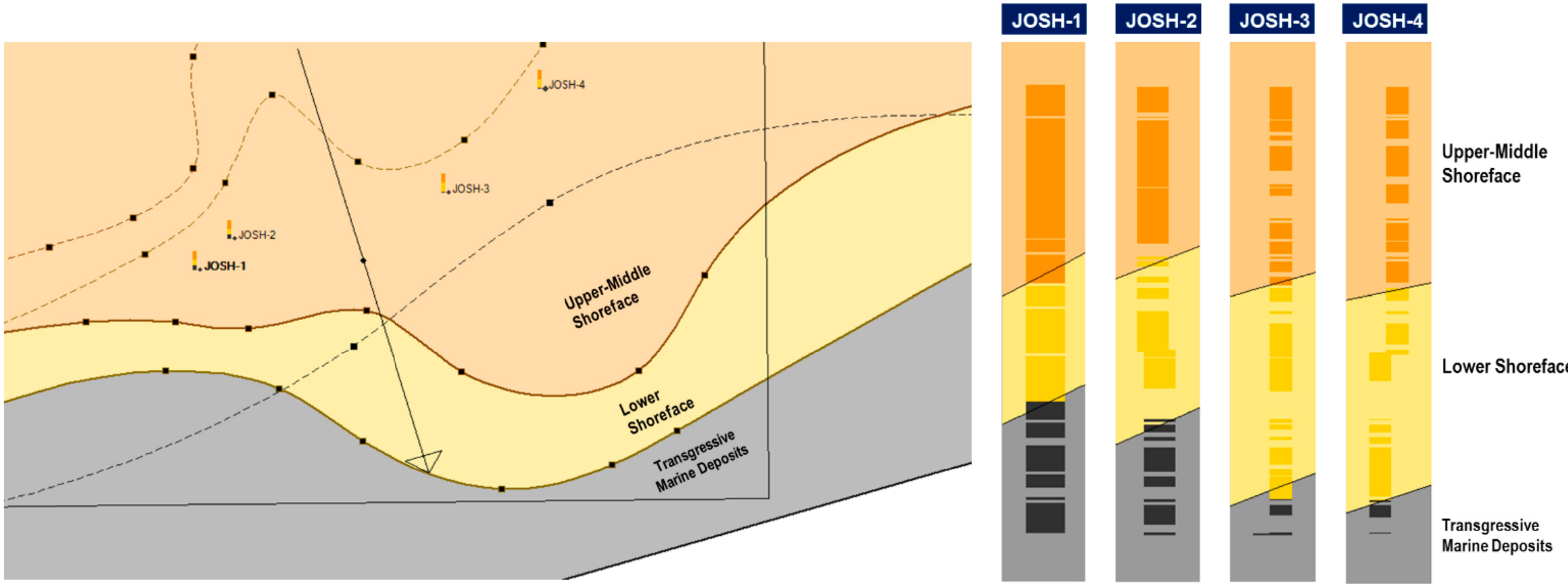

Figure 6. Geometrical trend derivation for the Truncated Gaussian Simulation.

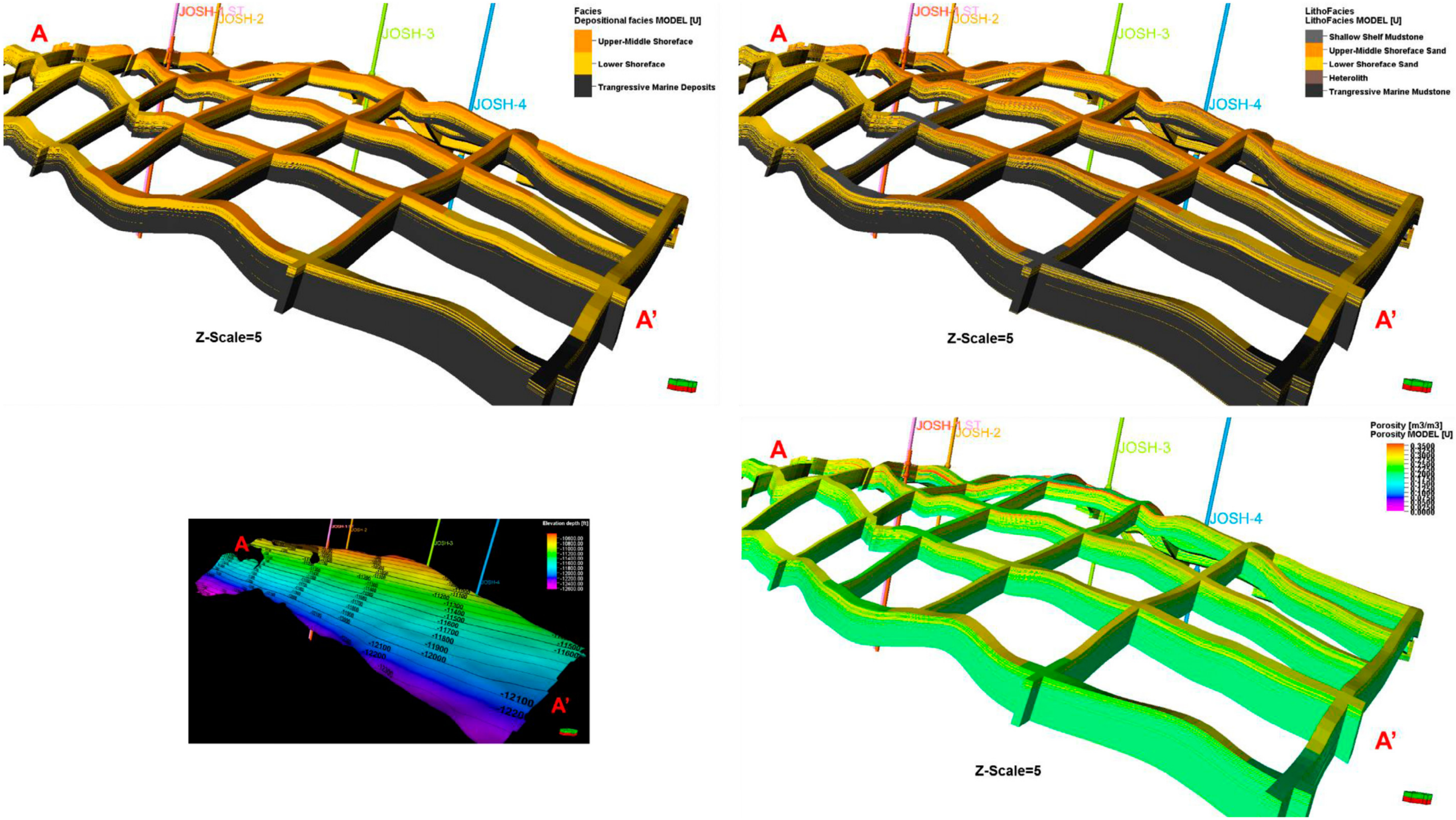

Figure 7a. Stratigraphic cross section fence diagrams of the models with view from the northwest.

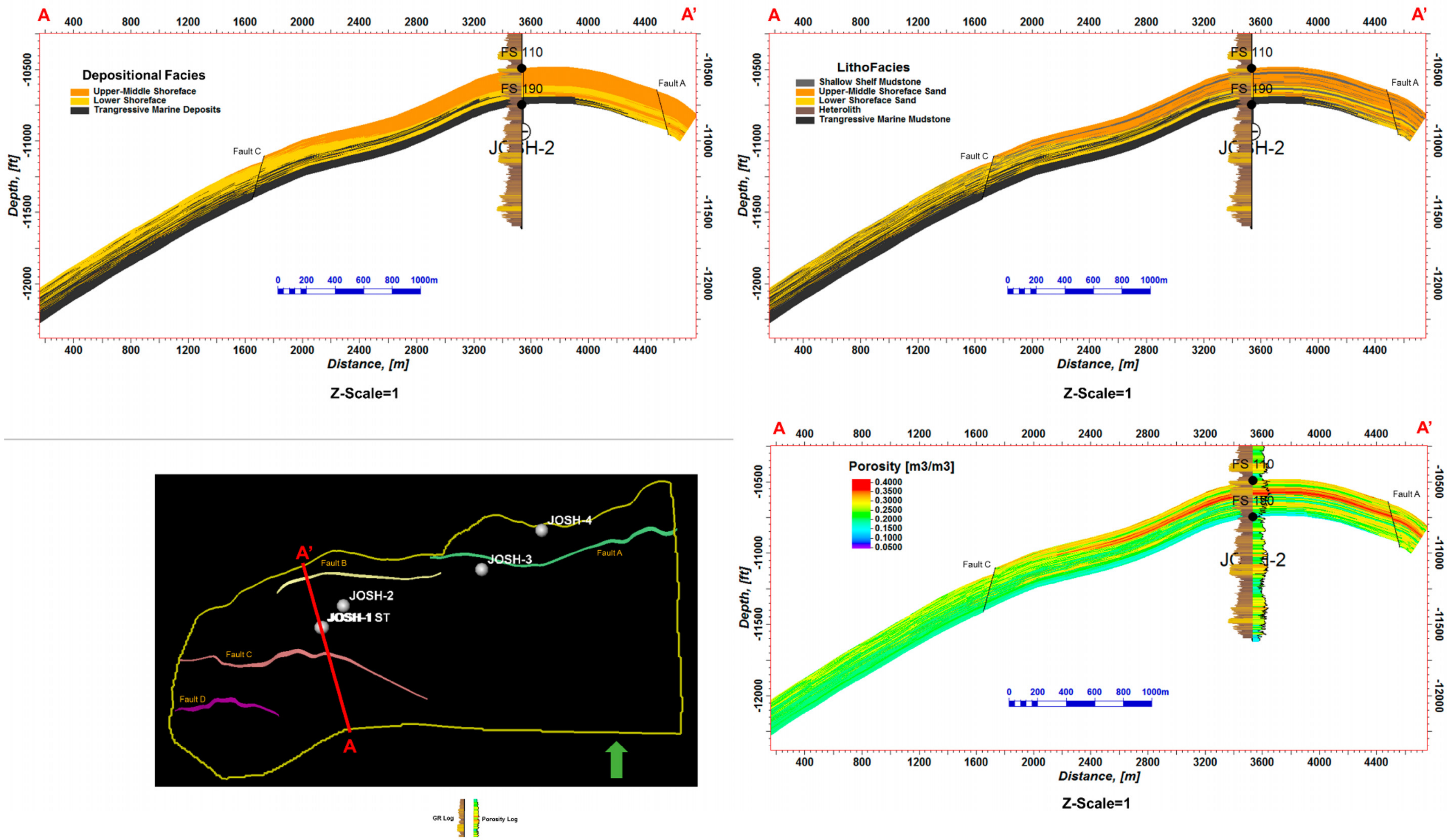

Figure 7b. Depositional trend cross section of the models to reveal the vertical compartmentalization. Note: the black rounded ball indicates the respective Flooding Surfaces (FS) Tops.

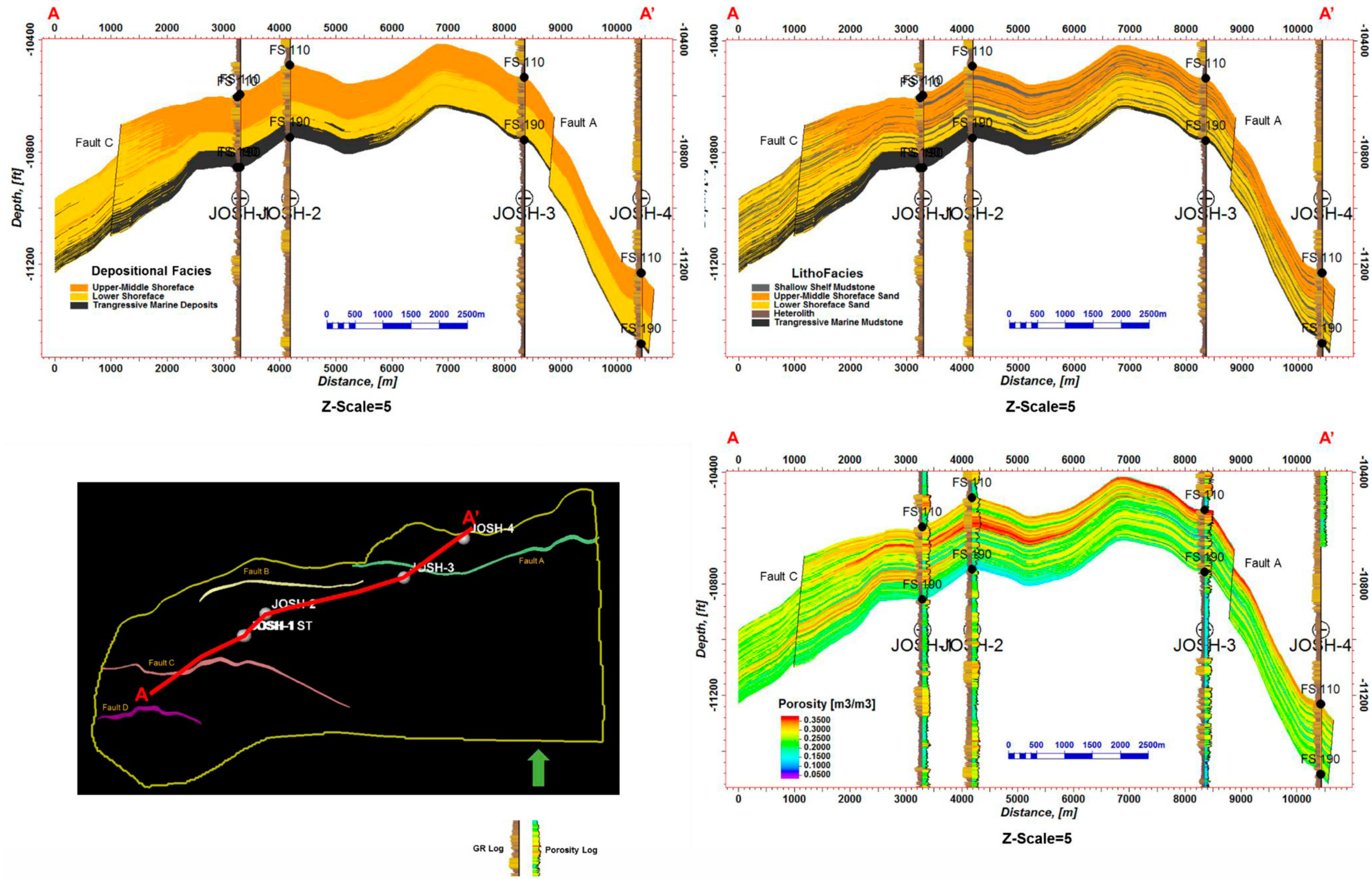

Figure 7c. Arbitrary line of section to indicate the cross section along the well paths revealing a close match of the models with well information along the well bore. Note: the black rounded ball indicates the respective Flooding Surfaces (FS) Tops.

Parasequence Set Interval	Increment	Dimension (nI*nJ*nK)	No Of Layers (K)	Total No Of Cells	Vertical Resolution
FS 110 - FS 190	50 * 50	149 x 94 x 302	302	4,229,812	0.82ft

Table 1. 3D Grid construction for the FS 110-190 Parasequences Sets