

# Predicting Reservoir Performance Through Risk Analysis and Hydrocarbon Prospects Ranking For Improved Economic Recovery in The Eastern Niger Delta

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**Abstract :** This study evaluated reservoir performance, hydrocarbon prospectivity, and economic potential in the Eastern Niger Delta using integrated well-log interpretation, three-dimensional seismic analysis, petrophysical modelling, volumetric estimation, and probabilistic risk analysis. Seven wells and a three-dimensional seismic dataset were analysed to identify and characterize four reservoir units, designated Reservoirs A–D. Reservoir C was selected for detailed evaluation because of its favourable sandstone development, high resistivity response, and relatively good reservoir properties. Its gross thickness ranged from 132 to 267 ft, while net sand thickness varied from 49.30 to 144.23 ft and net-to-gross ratio from 0.40 to 0.91. Mean effective porosity ranged from approximately 0.19 to 0.25, while mean permeability varied from 485 to 1,840 mD. Mean water saturation was approximately 0.29–0.33 in the evaluated wells, indicating generally favourable hydrocarbon saturation in selected intervals. Seismic interpretation identified several faults and structural closures that may influence reservoir compartmentalization and hydrocarbon accumulation. Deterministic and probabilistic volumetric analyses were performed to quantify hydrocarbon potential and uncertainty associated with reservoir geometry, petrophysical properties, and fluid-contact depth. Economic screening ranked Prospect B first, with a reported P50 economic value of approximately US\$1,349.2 million, followed by Prospect C at US\$1,343.2 million and Prospect A at US\$1,243.8 million. The findings indicate that Prospects B and C are the

most attractive targets for further appraisal. However, additional well data, oil–water contact confirmation, fault-seal analysis, dynamic simulation, and detailed economic evaluation are required before development decisions are made.

**Keywords:** *reservoir modeling, risk analysis, STOIP, prospect ranking, petrophysics, Niger Delta, Petrel*

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## 1.0 Introduction

The Niger Delta Basin is one of the world's major hydrocarbon-producing provinces, with substantial accumulations of oil and natural gas hosted predominantly within Tertiary siliciclastic formations. The basin's petroleum system is characterized by complex depositional architectures, heterogeneous reservoir properties, growth-fault systems, and structurally controlled hydrocarbon traps. These geological characteristics influence reservoir continuity, fluid distribution, hydrocarbon accumulation, and the reliability of volumetric estimates. As exploration and field development extend into structurally and stratigraphically complex settings, uncertainties associated with subsurface interpretation, reservoir characterization, and economic evaluation become increasingly important. Reliable prediction of reservoir properties and hydrocarbon potential is therefore essential for reducing exploration risk, improving field development planning, and supporting efficient allocation of investment in petroleum resources.

The structural complexity of the Niger Delta is strongly associated with the development of growth faults, rollover anticlines, fault-bounded compartments, and stratigraphic variations within deltaic depositional systems. These geological features influence the geometry of reservoirs and the distribution of hydrocarbon accumulations. In particular, faults may act as seals that preserve hydrocarbon accumulations or as conduits that facilitate fluid migration and leakage. Adagunodo et al. (2017) demonstrated the importance of fault-seal evaluation in the Jemir Field, Niger Delta, through the integration of three-dimensional (3-D) seismic and well-log data. Their study reported porosity values ranging from 0.20 to 0.29 and stock tank original oil in place (STOIIP) estimates between 5.5 and 173.4 Mbbl. The reported

shale gouge ratio (SGR) values ranged from less than 20% to greater than 60%, indicating variations in fault-sealing potential from leaking to sealing conditions. These findings demonstrate that structural interpretation and petrophysical evaluation alone may not adequately describe hydrocarbon trapping and reserve distribution where faults control reservoir compartmentalization.

Three-dimensional seismic interpretation provides an important means of delineating subsurface geological structures, reservoir horizons, faults, and potential hydrocarbon traps. When integrated with wireline-log data, seismic interpretation facilitates the construction of a geological framework that connects the structural geometry observed in seismic sections with the lithological and petrophysical information obtained from wells. The application of this integrated approach is particularly relevant in the Niger Delta, where fault-controlled structural closures and laterally variable deltaic reservoir facies are common. Ogbe et al. (2021) integrated modern 3-D seismic data, composite well logs, and petrophysical analysis to re-evaluate the hydrocarbon prospectivity of the S-600 and S-700 reservoirs in the Fega Field, onshore Niger Delta. Their structural interpretation identified synthetic and antithetic growth faults that compartmentalized the reservoirs into blocks, while structural surface maps revealed fault-dependent closures and possible hydrocarbon prospects in previously unpenetrated reservoir blocks. The study further showed that reprocessing seismic data and updating reservoir information can improve the identification of exploration opportunities in structurally complex settings.

The interpretation of seismic data is complemented by petrophysical evaluation of wireline logs, which provides information on lithology, reservoir thickness, porosity, permeability-related characteristics, and fluid



saturation. These parameters are essential for identifying hydrocarbon-bearing intervals and estimating the volume of oil and gas contained within a reservoir. Horsfall and Akpan (2024) evaluated reservoir quality and performance in a producing Niger Delta field using gamma ray, resistivity, caliper, density, and compressional-wave logs. Their analysis reported gross reservoir thicknesses of 50–329 ft, net thicknesses of 40–213 ft, net-to-gross ratios of 0.496–0.924, effective porosities of 0.202–0.404, water saturations of 0.036–0.431, and permeability values of 2108–4932 mD. The authors concluded that the reservoirs exhibited fair-to-good porosity, exceptional permeability, and good-to-excellent net-to-gross characteristics. These results illustrate the importance of detailed well-log interpretation and petrophysical analysis in assessing reservoir quality and improving confidence in hydrocarbon evaluation.

Recent studies have further demonstrated the value of integrating petrophysical parameters with reservoir ranking and field development decisions. Maju-Oyovwikowhe et al. (2026) evaluated five wells from Agbeju Field, Niger Delta Basin, using well-log interpretation and Schlumberger Petrel software. Three major reservoirs were identified and ranked according to their petrophysical properties. Sand C was considered the most promising reservoir because of its relatively high hydrocarbon saturation and favourable net-to-gross ratio, whereas Sand B, despite its higher permeability and net-to-gross ratio, was considered less viable for immediate production because of its higher water saturation. The study illustrates that reservoir quality cannot be assessed using a single petrophysical parameter. Rather, the integration of porosity, permeability, net-to-gross ratio, and fluid saturation provides a more comprehensive basis for reservoir evaluation and ranking. Static reservoir modelling

provides a framework for integrating structural interpretation, stratigraphic correlation, and petrophysical data into a three-dimensional representation of reservoir properties. The process involves the construction of structural surfaces, fault frameworks, reservoir zones, and spatial distributions of properties such as porosity, permeability, and water saturation. These models are useful for estimating hydrocarbon volumes in place and evaluating the influence of reservoir heterogeneity and structural compartmentalization on hydrocarbon prospectivity. However, the reliability of static reservoir models depends on the quality and distribution of available data, the accuracy of structural interpretation, the assumptions adopted in petrophysical modelling, and the methods used to represent subsurface uncertainty.

The integration of seismic interpretation, well-log analysis, and stratigraphic interpretation has been shown to improve reservoir continuity and hydrocarbon prediction in complex deltaic systems. Ekiliwo and Ekot (2026) conducted an integrated qualitative and quantitative evaluation of depositional environment and hydrocarbon prospectivity in the QX Field, southeastern Niger Delta. Their study combined seismic data, well logs, and sequence stratigraphic analysis to characterize three reservoirs and establish their depositional architecture. The identified reservoirs exhibited net-to-gross values of 69.25–84.75%, porosity of 19.50–25%, shale volume of 12.20–30.75%, water saturation of 27.94–41.75%, and permeability of 59.68–152.51 mD. Deterministic and simplified probabilistic volumetric analyses yielded a P50 STOIP of 6.13 MMSTB for RES1 and 58.27 MMSTB for RES3, while the total estimated oil and gas resources of the field were approximately 64.40 MMSTB and 12.20 BCF, respectively. The study demonstrated that integrating depositional architecture with quantitative



petrophysical evaluation can improve confidence in reservoir continuity, fluid prediction, volumetric estimation, and field development planning.

Uncertainty in reservoir characterization arises from variations in reservoir geometry, net-to-gross ratio, porosity, water saturation, fluid contacts, and other geological and engineering parameters. Consequently, hydrocarbon volume estimates should be treated as uncertain quantities rather than as single deterministic values. Probabilistic methods, such as Monte Carlo simulation, provide a means of generating a range of possible hydrocarbon volumes by varying uncertain input parameters according to specified distributions. The resulting P10, P50, and P90 estimates can be used to evaluate the range of potential hydrocarbon accumulation and support risk-informed exploration decisions. However, the interpretation of these percentiles depends on the convention adopted and should be stated clearly when presenting volumetric results.

The application of probabilistic volumetric estimation is particularly relevant to hydrocarbon prospect ranking, where competing prospects may differ in geological size, reservoir quality, structural closure, uncertainty, and economic potential. Ogbe et al. (2021) demonstrated that integrated structural, petrophysical, and volumetric analysis can identify commercially viable hydrocarbon prospects and support the evaluation of additional oil production opportunities in the Fega Field. Their findings emphasize the importance of updating reservoir information when new geological and geophysical data become available. Similarly, Ekiliwo & Ekot (2026) showed that deterministic and simplified probabilistic volumetric approaches provide complementary information for assessing uncertainty in complex Niger Delta reservoirs. These studies support the use of integrated geological and

quantitative workflows in improving prospect evaluation and development planning.

Structural interpretation remains a critical component of prospect delineation because the geometry and continuity of faults and horizons influence the size and integrity of potential hydrocarbon traps. Abbey et al. (2026) investigated structural controls and hydrocarbon prospectivity in a Niger Delta field using 3-D seismic reflection data. Their interpretation identified nine faults, comprising seven synthetic growth faults and two antithetic faults, together with three seismic horizons delineated from reflection continuity, amplitude, strength, and configuration. The study highlights the importance of seismic reflection characteristics and fault interpretation in defining subsurface structural architecture and identifying potential hydrocarbon-bearing intervals. In structurally complex reservoirs, such interpretation provides an essential basis for constructing reliable reservoir frameworks and assessing the spatial distribution of prospective closures.

The increasing application of advanced data-driven methods has also expanded the scope of reservoir characterization. Bakry et al. (2026) developed a machine-learning and rock-physics workflow for reservoir characterization in the West Offshore Nile Delta, Egypt. Using conventional well logs and measured shear-wave velocity data, their categorical boosting model achieved an  $R^2$  of 0.912 for testing and 0.904 for blind validation. The predicted elastic properties were integrated with seismic-derived structural surfaces and three-dimensional geostatistical modelling to generate volumetric distributions of porosity, acoustic impedance, and Lambda-Rho across the reservoir. The study demonstrated the potential of combining well-log analysis, machine learning, rock physics, and geostatistical modelling to improve reservoir characterization where direct measurements



are limited. Although the present study does not employ machine-learning or rock-physics prediction, these developments emphasize the broader importance of integrating complementary datasets to reduce uncertainty in subsurface interpretation.

Reservoir heterogeneity is another important factor affecting the reliability of reservoir models and hydrocarbon recovery predictions. Ngu et al. (2026) investigated multi-scale heterogeneity and explainable artificial intelligence for reservoir rock typing in the Southern Niger Delta Basin. Their analysis showed that global heterogeneity measures could mask localized baffles and cyclicity within the reservoir. The application of a supervised Random Forest model achieved 91% accuracy in predicting rock types in uncored intervals, while unsupervised clustering identified transition zones not captured by conventional three-rock-type models. These findings indicate that reservoir heterogeneity may occur at different spatial scales and that its representation can influence the interpretation of reservoir quality and flow behaviour. For conventional static modelling studies, this reinforces the need to recognize the limitations of available data and to consider the uncertainty associated with property distribution.

Despite these advances, the evaluation of hydrocarbon prospects in structurally complex Niger Delta reservoirs remains challenging because geological interpretation, petrophysical characterization, volumetric estimation, and economic assessment are often treated as separate components of the exploration workflow. Existing studies have demonstrated the value of seismic interpretation, fault analysis, well-log evaluation, depositional modelling, and reservoir ranking. However, further field-based application of an integrated workflow that combines static reservoir modelling,

probabilistic STOIP estimation, and economic prospect ranking is required to improve the consistency of prospect prioritization in structurally complex settings. In particular, the relationship between uncertainty in reservoir properties and structural configuration and the resulting ranking of competing prospects in the Eastern Niger Delta requires further investigation.

The present study addresses this need through the integration of 3-D post-stack migrated seismic data and wireline-log data from seven wells in the X-Field, Eastern Niger Delta. Reservoir C is evaluated through well-log analysis, stratigraphic correlation, well-to-seismic ties, seismic horizon interpretation, fault mapping, and petrophysical modelling. The integrated data are used to construct a static reservoir model and estimate STOIP for three identified structural prospects. Monte Carlo simulation is applied to quantify volumetric uncertainty, while economic screening is used to evaluate the relative potential of the prospects for hydrocarbon recovery and development.

## 2.0 Geologic Setting and Location of the Study Area

The study area, designated as X-Field in this study, is located in the eastern part of the Niger Delta Basin, Nigeria. The field lies between latitudes  $4^{\circ}28'21.68''\text{N}$  and  $4^{\circ}34'8.69''\text{N}$  and longitudes  $6^{\circ}57'4.99''\text{E}$  and  $7^{\circ}06'11.36''\text{E}$  (Fig. 1). The Niger Delta Basin is one of the major sedimentary basins of the Gulf of Guinea and contains a thick regressive siliciclastic succession deposited through the progradation of sediments into the Atlantic Ocean. The basin extends over a broad area of the continental margin and is characterized by complex depositional architectures, variable reservoir properties, growth faulting, and structural deformation. These geological characteristics have contributed to the development of significant hydrocarbon accumulations and a



variety of structural and stratigraphic traps within the basin (Evamy et al., 1978; Doust & Omatsola, 1990).

The regional stratigraphy of the Niger Delta is commonly subdivided into three major diachronous lithostratigraphic units: the Akata, Agbada, and Benin Formations. These formations represent a progressive transition from marine and prodeltaic environments to deltaic and continental depositional systems. Their lithological characteristics and depositional relationships have played important roles in the development of the basin's petroleum system, particularly in the generation, migration, accumulation, and trapping of hydrocarbons (Doust & Omatsola, 1990).

The Akata Formation constitutes the basal, predominantly marine unit of the Niger Delta stratigraphic succession. It consists mainly of prodeltaic and marine shales with subordinate siltstone and claystone intervals. The formation is widely regarded as the principal source-rock interval of the basin because of its organic-rich shale units. The Akata Formation underlies the Agbada Formation and provides the geological foundation for the overlying reservoir and seal succession. Its thickness and stratigraphic extent vary across the basin in response to depositional and tectonic processes (Doust & Omatsola, 1990).

The Agbada Formation overlies the Akata Formation and consists predominantly of interbedded sandstone, siltstone, and shale deposited within a deltaic to fluvio-marine depositional system. The sandstone intervals constitute important reservoir units in the Niger Delta, while the interbedded shale units may function as seals and contribute to reservoir compartmentalization. The formation contains numerous hydrocarbon-bearing reservoirs whose distribution and continuity are influenced by depositional processes, sedimentary facies variations, and structural

deformation. Hydrocarbon accumulations within the Agbada Formation are commonly associated with structural traps, including rollover anticlines and fault-bounded closures developed in relation to growth faulting (Doust & Omatsola, 1989, 1990).

The Benin Formation is the uppermost major lithostratigraphic unit of the Niger Delta. It consists predominantly of continental sands, gravels, and subordinate clay intervals deposited mainly in fluvial and alluvial environments. The formation generally constitutes the shallowest part of the basin's sedimentary succession and overlies the Agbada Formation. Its relatively coarse-grained sediments reflect the influence of continental depositional processes in the upper part of the Niger Delta succession (Avbovbo, 1978).

The Eastern Niger Delta is characterized by a complex structural framework dominated by growth faults, rollover anticlines, antithetic faults, and associated fault-bounded compartments. These structures developed largely in response to gravitational deformation, differential sediment loading, and shale mobility within the deltaic sedimentary succession. Growth faults may influence the geometry of reservoir closures, the lateral continuity of reservoir units, and the compartmentalization of hydrocarbon accumulations. The sealing capacity of individual faults may also affect hydrocarbon retention, migration, and the distribution of recoverable volumes within a field. Consequently, structural interpretation is essential for evaluating hydrocarbon prospectivity in the region.

Previous studies have demonstrated the importance of integrating seismic interpretation, well-log analysis, and petrophysical evaluation in Niger Delta reservoir characterization. Adagunodo et al. (2017) investigated reservoir characterization



and fault-seal integrity in the Jemir Field using 3-D seismic and well-log data. Their findings showed that variations in fault-sealing potential could influence hydrocarbon trapping and the distribution of reserves within structurally controlled reservoirs. Ogbe *et al.* (2021) integrated modern 3-D seismic data, composite well logs, and petrophysical analysis to evaluate the hydrocarbon prospectivity of the S-600 and S-700 reservoirs in the Fega Field. Their study identified synthetic and antithetic growth faults, fault-dependent structural closures, and variations in reservoir quality, demonstrating the value of integrated subsurface interpretation for identifying additional hydrocarbon opportunities in structurally complex settings.

Further investigations have emphasized the role of petrophysical and depositional analysis in improving reservoir evaluation. Horsfall & Akpan (2024) demonstrated the usefulness of gamma ray, resistivity, density, and other wireline logs for determining reservoir thickness, porosity, permeability, and water saturation in a producing Niger Delta field. Ekiliwo & Ekot (2026) integrated seismic data, well logs, and sequence stratigraphic analysis to characterize reservoirs and evaluate hydrocarbon prospectivity in the QX Field, southeastern Niger Delta. Their findings showed that combining depositional architecture with quantitative petrophysical analysis can improve confidence in reservoir continuity, fluid prediction, and volumetric estimation. These studies provide a relevant geological and methodological context for the present investigation.

The present study focuses on Reservoir C in the X-Field, Eastern Niger Delta, using 3-D post-stack migrated seismic data and wireline-log data from seven wells. The reservoir is evaluated through well-log interpretation, stratigraphic correlation, well-to-seismic ties, seismic horizon interpretation, fault mapping,

and petrophysical modelling. The integrated interpretation is used to establish the structural and geological framework of Reservoir C and to identify potential hydrocarbon-bearing closures within the field. The resulting reservoir framework provides the basis for static reservoir modelling, probabilistic STOIP estimation, and economic ranking of the identified prospects.

The geological and structural characteristics of the study area are therefore important for understanding the distribution of reservoir properties and hydrocarbon accumulations within Reservoir C. Variations in reservoir thickness, lithology, porosity, permeability, water saturation, and fault geometry may influence the size and uncertainty of hydrocarbon volumes estimated for individual prospects. Accordingly, the integration of seismic and well-log data provides a suitable approach for evaluating reservoir architecture, quantifying volumetric uncertainty, and supporting the ranking of hydrocarbon prospects in the X-Field (Fig. 1).

### 3.0 Materials and Methods

#### 3.1 Data

The seismic data, well log data and checkshot data used in this study were provided by a multinational Oil company and were analysed using Schlumberger Petrel 2014. The seismic dataset is a rectangular grid of 3-D post-stack migrated data covering an area of 178 square kilometres, comprising 673 north–south oriented inlines and 425 east–west oriented crosslines, both spaced at 25 m intervals, with inline and crossline lengths of 10.6 km and 16.8 km respectively and a vertical trace length of six seconds (Table 1). Well log data from seven wells (A–G) were used, comprising gamma ray, density, neutron, induction and caliper logs (Table 2); a single well (Well C) had checkshot data. Data quality checks were carried out on both datasets before interpretation. For the



seismic volume, survey orientation, inline/crossline numbering, time-slice character, acquisition footprint, amplitude spectra, amplitude histograms and horizon phase were all examined, and no clipping, irregular spiking, or departure from a near-Laplacian amplitude distribution was found (Hart, 2000). For the well logs, unrealistic

values at the top of logging runs, single-point spikes, and washout effects were edited or despiked, checkshot-derived synthetic seismograms were correlated with the seismic data, and well tops, deviation data and log scales were validated and reconciled across wells.

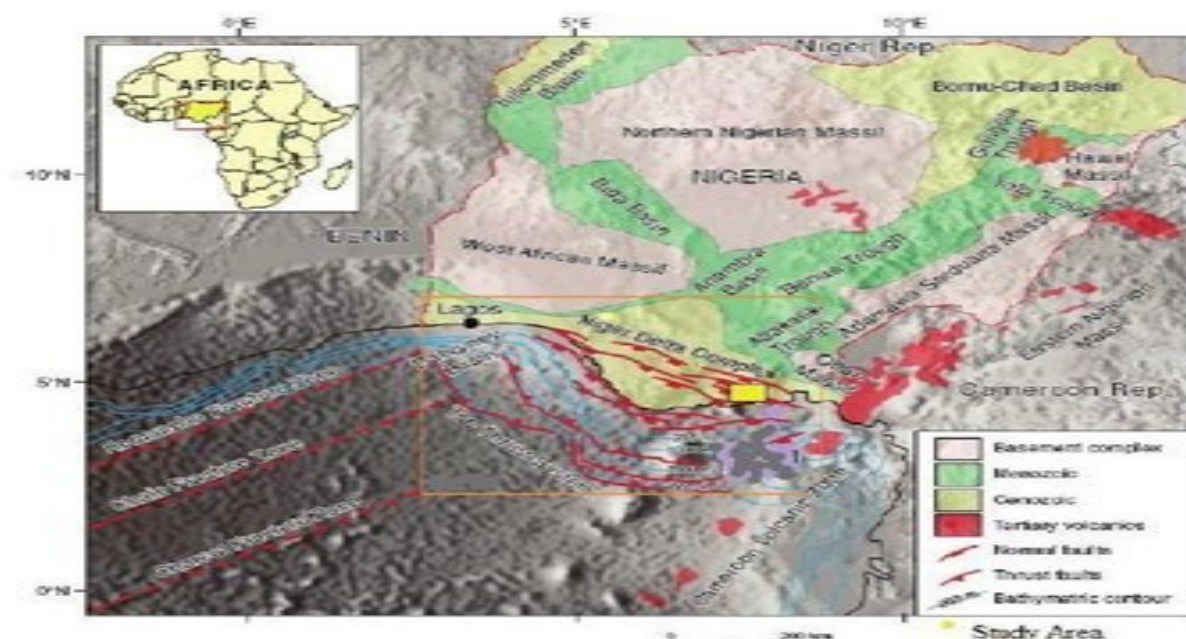


**Fig. 1: Location map of the onshore region of the Eastern Niger Delta where the X-Field is located (After Corredor et al., 2005)**

### 3.2 Petrophysical Evaluation

Shale volume ( $V_{sh}$ ) was estimated from the gamma ray index using the linear method and, for the Tertiary reservoirs typical of the study area, using the Larionov (1969) non-linear relation. Total porosity was computed from the density and sonic logs following Wyllie & Rose (1950), with neutron and density logs corrected for shale effect before effective porosity was derived. Water saturation was evaluated using Archie's (1942) equation in clean sand intervals and, because Niger Delta sands are typically shaly, using the Indonesian equation (Poupon & Leveaux, 1971) and the modified Simandoux (1963) equation, with  $a = 1$ ,  $m = 2.01$  and  $n = 2$ . Permeability was

estimated using the Owolabi et al. (1994), Coates & Denoo (1981), and Wyllie & Rose (1950) empirical relations. Reservoir quality was qualitatively ranked against the porosity-permeability classification of Levorsen (1967), reproduced in Table 3. Reservoir identification was carried out using a cross-plot of gamma ray against density log response, from which a cut-off value of 75 API was chosen as the midpoint between the clean sand and shale baselines to separate net sand from non-net sand. Fluid type was determined from the separation ("cross-over") between the neutron and density logs, with a large cross-over taken to indicate gas and a small cross-over taken to indicate oil (Asquith & Krygowski, 2004).



### 3.3 Seismic Interpretation and Structural Modeling

A seismic-to-well tie was performed using the post-stack migrated seismic volume, the checkshot data from Well C, and mapped well tops, in which the reflectivity series (derived from sonic and density logs) is convolved with an extracted wavelet to produce a synthetic seismogram (Fig. 2). A Ricker wavelet of 128 ms length, 2 ms sample rate and 25 Hz frequency was used, and a bulk shift of 2 milliseconds was applied to achieve a satisfactory tie, with the top of Reservoir C corresponding to a seismic peak and its base to a trough.

**Table 1: Principal shooting and recording parameters of the seismic dataset**

| Parameter         | Value |
|-------------------|-------|
| Number of inlines | 673   |

| Parameter                 | Value                      |
|---------------------------|----------------------------|
| Number of crosslines      | 425                        |
| Inline interval/length    | 25 m / 10,600 m            |
| Crossline interval/length | 25 m / 16,800 m            |
| Vintage/seismic type      | Time 1 / 3-D               |
| Samples per trace         | 1,501                      |
| Sample interval           | 4 ms                       |
| Storage type              | ZGY seismic bricked format |

Faults were interpreted on an amplitude-gain-corrected, structurally smoothed and dip-guided edge-enhanced seismic volume, on which variance (edge-method) and ant-tracking attributes were successively applied to sharpen fault visibility (Fig. 3). Faults were mapped on inlines at 10-slice intervals, with major faults also mapped on crosslines.

**Table 2: Availability of well log data by well**

| Well | GR | CALI | RHOB | ILD | NPHI | Checkshot | DT |
|------|----|------|------|-----|------|-----------|----|
| A    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✓  |
| B    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✓  |
| C    | ✓  | ✗    | ✓    | ✓   | ✓    | ✓         | ✓  |
| D    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✓  |
| E    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✗  |
| F    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✓  |
| G    | ✓  | ✓    | ✓    | ✓   | ✓    | ✗         | ✓  |

**Table 3: Qualitative evaluation of porosity and permeability (After Levorsen, 1967).**

| Porosity (%) | Evaluation | Permeability (mD) | Evaluation |
|--------------|------------|-------------------|------------|
| 0–5          | Negligible | < 10.5            | Poor       |
| 5–10         | Poor       | 15–50             | Moderate   |
| 10–15        | Fair       | 50–250            | Good       |
| 15–20        | Good       | 250–1000          | Very Good  |
| 20–25        | Very Good  | > 1000            | Excellent  |



Horizons corresponding to the top and base of Reservoir C were similarly mapped at 10-slice intervals in both inline and crossline directions, gridded into time surfaces using the convergent interpolation algorithm, and converted to depth using the time–depth relationship derived from the Well C seismic tie. Fluid contacts were determined from resistivity log character, and, because no gas was encountered, only oil–water contacts (OWC) were used to constrain the volumetric calculation; where no OWC was penetrated, an oil-down-to (ODT) value was used instead. Structural modelling proceeded from the depth-converted fault sticks and horizon maps through fault modelling (using a listric pillar type, consistent with the listric geometry of faults in the study area), pillar gridding to build the 3-D skeletal framework, zonation, layering, and contact making, following the general workflow described by Cosentino (2001).

### 3.4 Reservoir Modeling

Lithofacies were distributed stochastically across the modelled grid using Sequential Indicator Simulation, constrained by the upscaled facies log. Petrophysical properties (net-to-gross, effective porosity, permeability and water saturation) were then modelled using Sequential Gaussian Simulation, conditioned to the facies model, with a spherical variogram and major and minor anisotropy ranges of 6,400 m and 5,000 m respectively, derived from the mapped reservoir surface. Facies models were built before petrophysical models so that they could be used to constrain the distribution of porosity, permeability and water saturation.

**3.5 Volumetric Estimation and Risk Analysis**  
Structural and petrophysical property models, together with the interpreted oil–water contact, were input into Petrel's model-based volume calculation workflow to estimate the STOIP deterministically and probabilistically for each of the three identified prospects.

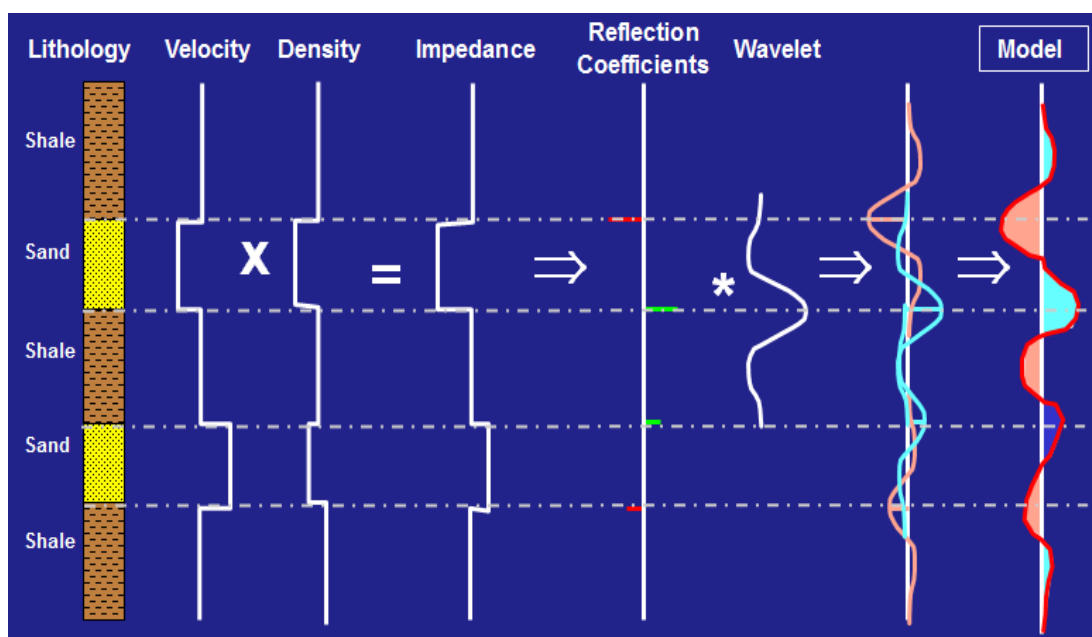


Fig. 2: Schematic showing the seismic-to-well tie process (After Peterson et al., 1995).



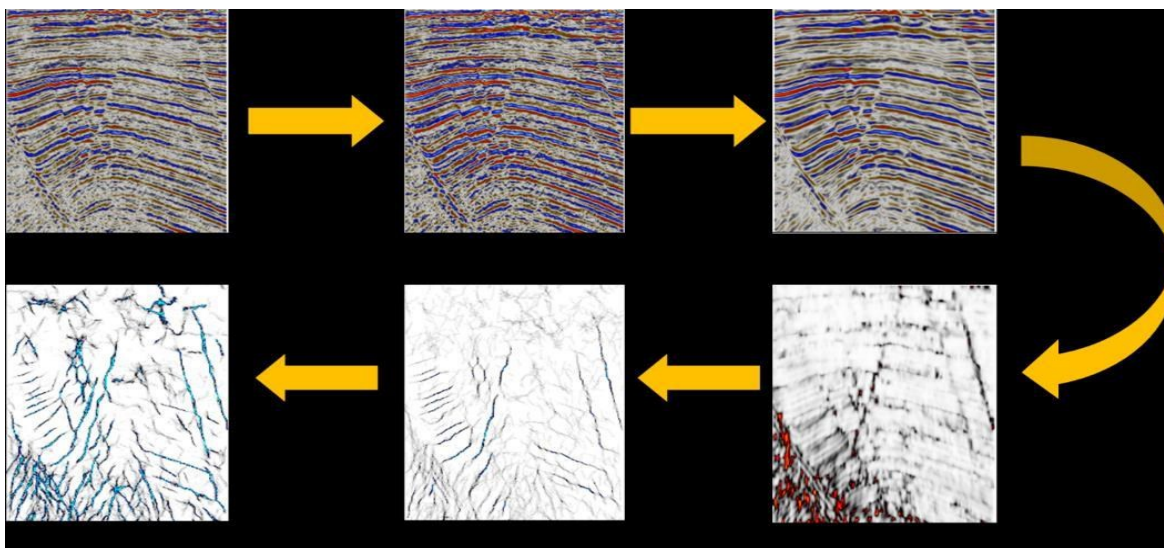


**Fig. 3: Procedure for fault identification and mapping (After Schlumberger PETREL, 2014).**

A Monte Carlo approach was used to generate 1,000 realisations for the probabilistic assessment, from which the P10 (low case), P50 (most-likely case) and P90 (best case) STOIP values were extracted for each prospect. Uncertainty in the petrophysical inputs (net-to-gross, water saturation and porosity), and in the position of the oil–water contact — constrained only by Well C on the up-dip rollover anticline — was explicitly carried through the probabilistic assessment rather than being absorbed into a single deterministic figure.

### 3.6 Economic Analysis

Economic screening of the three prospects was carried out using the relation: Profit = (Volume × Oil/Gas Price) – Production Cost, applying an oil price of US\$53.76 per barrel (rigzone.com, September 2017), a production cost of US\$23 per barrel for onshore Nigeria (nnpcgroup.com), and a recovery factor of 35% typical of the Niger Delta. A risk factor of 20% was subsequently applied to the projected profit to obtain the ultimate recoverable value for each prospect at its P10, P50 and P90 case.

## 4.0 Results and Discussion

### 4.1 Well Log Correlation and Reservoir Zonation

The interpretation of the gamma-ray and deep-resistivity logs from the seven wells enabled the identification and correlation of four principal sandstone reservoirs, designated Reservoirs A, B, C and D. The gamma-ray logs were used to distinguish relatively clean sandstone intervals from shale-dominated units, whereas the deep-resistivity logs assisted in identifying intervals with probable hydrocarbon saturation. The combined use of gamma-ray and resistivity responses is appropriate for reservoir delineation because clean, porous sandstone commonly exhibits relatively low gamma-ray values, while hydrocarbon-bearing intervals may display elevated resistivity compared with adjacent water-bearing or shale-rich intervals (Asquith & Krygowski, 2004; Cosentino, 2001).

Reservoir C was selected as the principal reservoir of interest because it exhibited a relatively clean gamma-ray response and a pronounced deep-resistivity anomaly across the evaluated wells. The continuity of the reservoir was established by correlating the tops and bases of the sandstone interval using the characteristic log motifs and the continuity of the intervening shale markers. This approach is consistent with established reservoir-



characterization workflows in the Niger Delta, where well-log correlation is used to establish lateral reservoir continuity, identify fault-related offsets and define the geometry of hydrocarbon-bearing sand bodies (Doust & Omatsola, 1990; Ogbe *et al.*, 2021).

The top of Reservoir C was picked at the transition from the overlying shale-dominated interval to the cleaner sandstone response, characterized by a decrease in gamma-ray values and an associated increase in resistivity. The base of the reservoir was identified from the reverse change in the gamma-ray and resistivity responses. The resulting correlation panel demonstrates that Reservoir C occurs at different measured depths across the wells, indicating structural relief and possible fault-related displacement. The correlated reservoir interval is presented in Fig. 4.

The correlation of Reservoir C also revealed internal vertical variability within the sandstone package. Based on the gamma-ray character, resistivity response and the SML plots derived from the petrophysical logs, Reservoir C was subdivided into three flow zones. Zone 1 represents the upper part of the reservoir and is characterized by relatively favourable sandstone development. Zone 2 contains a more heterogeneous interval with relatively higher shale content and poorer reservoir properties, while Zone 3 represents the lower part of the reservoir and displays the most favourable reservoir characteristics. The identification of internal flow zones is important because vertical variations in shale content, porosity and permeability may produce baffles or barriers to vertical fluid movement, even where the reservoir appears to be laterally continuous.

The SML plots were used to support the subdivision of Reservoir C into flow units by examining changes in the relationship between storage and flow properties. The three flow zones identified from the log responses and

SML interpretation are shown in Fig. 5. Zone 1, Zone 2 and Zone 3 were subsequently treated as separate modelling units during the reservoir-property distribution and volumetric calculations.

The same correlation procedure was applied to the other identified sandstone bodies. Fig. 6 presents the correlation of Reservoir A, while Fig. 7 shows the correlation of Reservoir B across the study wells. The correlation of Reservoir D is presented in Fig. 8. These correlations demonstrate the vertical and lateral variability of the sandstone packages within the field. Such variability is characteristic of Niger Delta reservoirs, where changes in depositional energy, channel migration, mouth-bar development and shale intercalation may produce heterogeneous reservoir architectures (Doust & Omatsola, 1990; Ekiliwo & Ekot, 2026).

The correlation results provide the stratigraphic framework for the subsequent petrophysical evaluation and three-dimensional reservoir modelling. In particular, the subdivision of Reservoir C into three flow zones allows the spatial distribution of porosity, permeability, net-to-gross and water saturation to be modelled more realistically than would be possible if the reservoir were treated as a single homogeneous unit. Similar integrated use of well-log correlation, seismic interpretation and petrophysical modelling has been shown to improve the understanding of reservoir continuity and hydrocarbon distribution in the Niger Delta (Ogbe *et al.*, 2021).

#### 4.2 Petrophysical Results

The petrophysical evaluation of Reservoir C was based on the integrated interpretation of gamma-ray, deep-resistivity, density and neutron logs. The gamma-ray response was used to estimate shale content and identify relatively clean sandstone intervals, while the density–neutron and resistivity responses were used to assess porosity and fluid saturation. The



representative petrophysical interpretation for Well A is presented in Fig. 9.

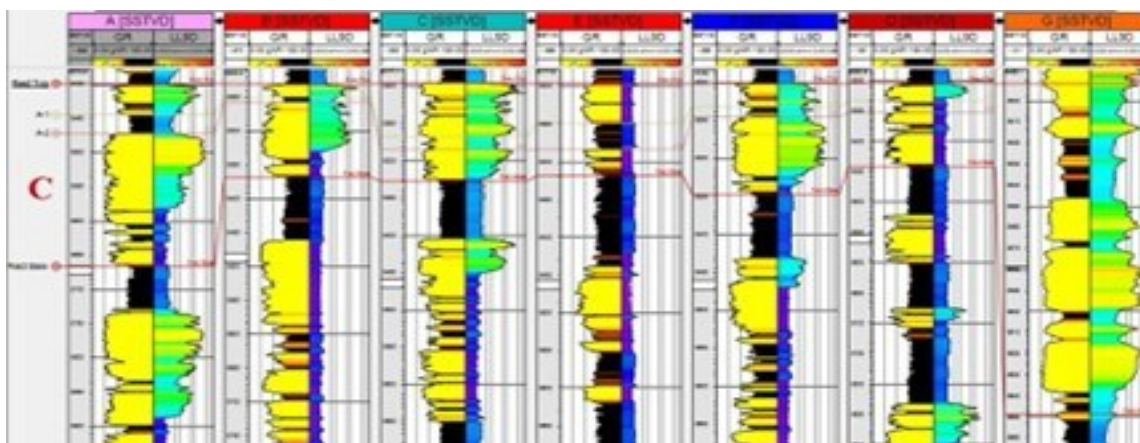


Fig. 4: Well section window showing correlation of Reservoir C across the field

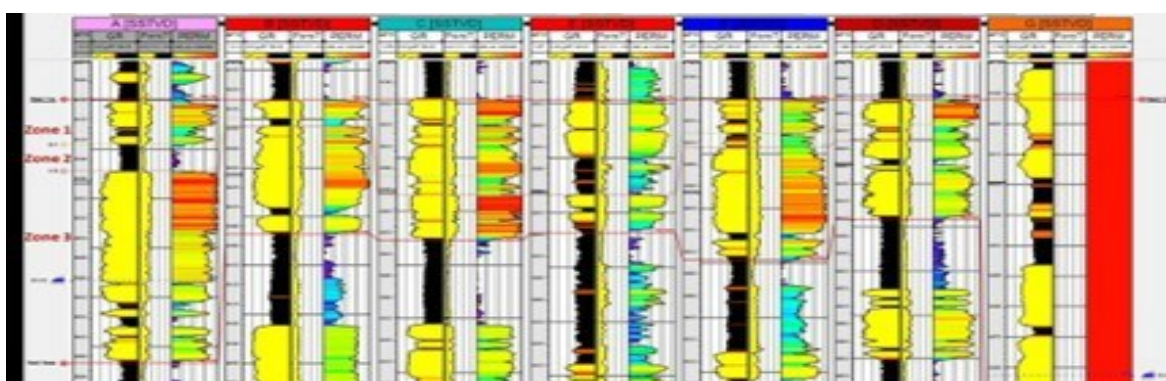


Fig. 5: Three reservoir flow zones identified within Reservoir C based on visual examination and SML plots

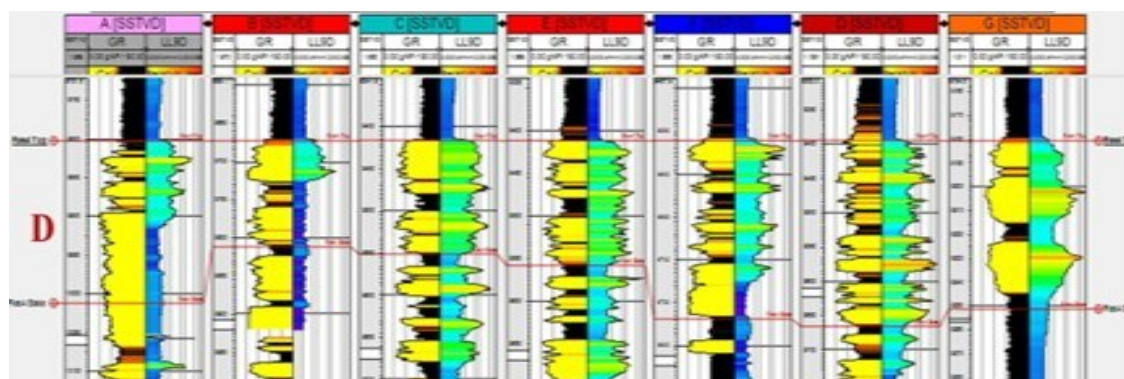


Fig. 5: Three reservoir flow zones identified within Reservoir C based on visual examination and SML plots



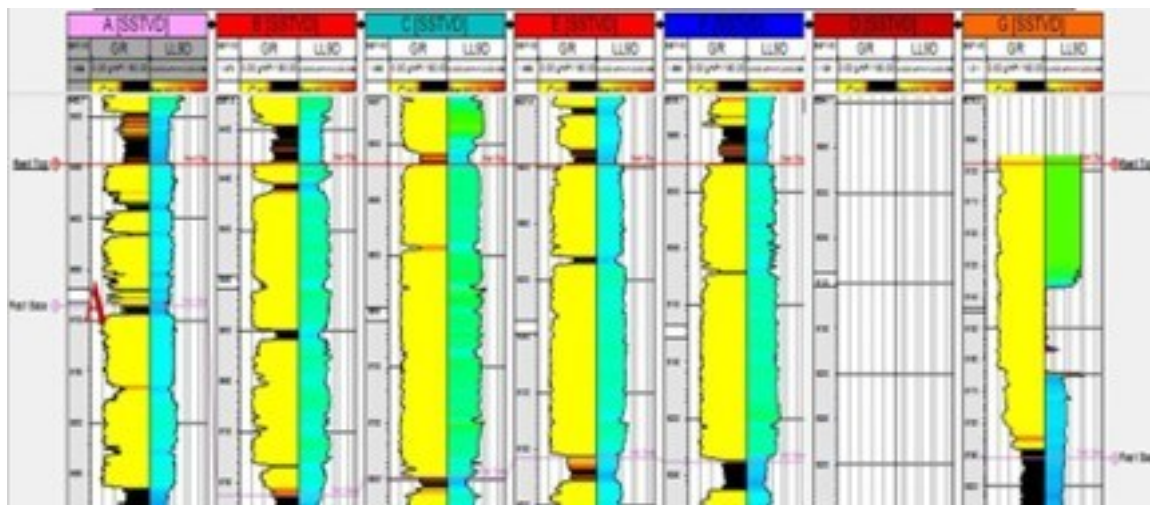


**Fig. 6:** Well section window showing correlation of sand body A (Reservoir A) across the field

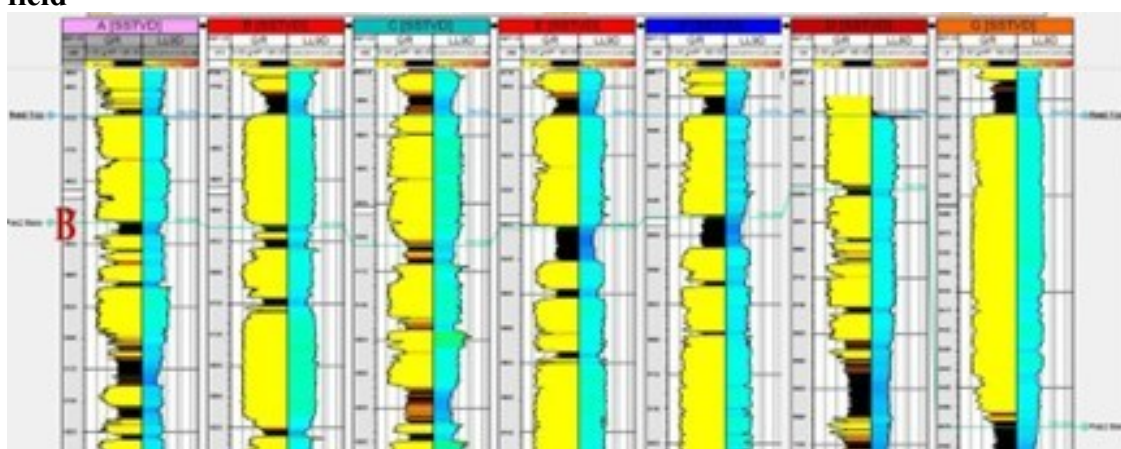


**Fig.7:** Well section window showing correlation of sand body B (Reservoir B) across the field.

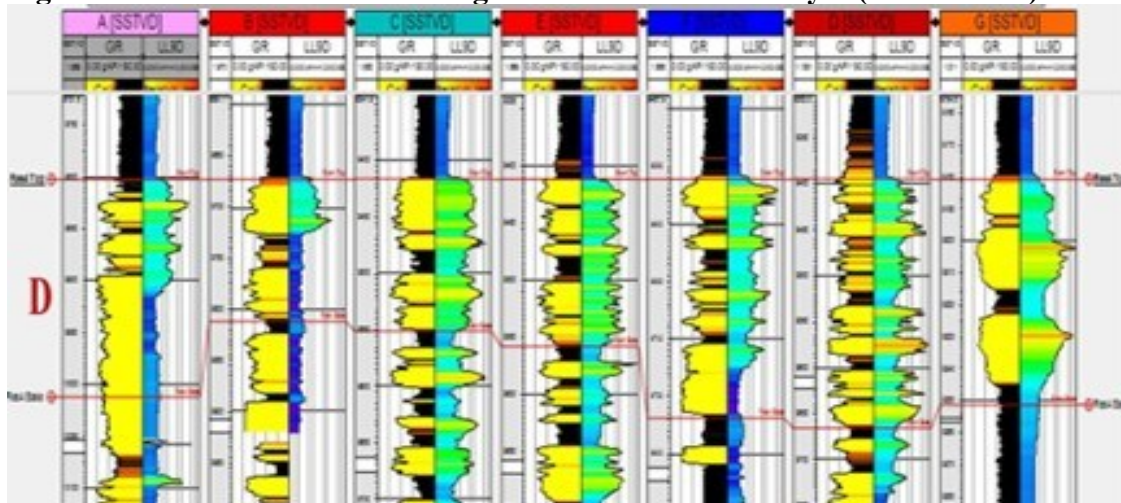


**Fig. 8:** Well section window showing correlation of sand body C (Reservoir D) across the field



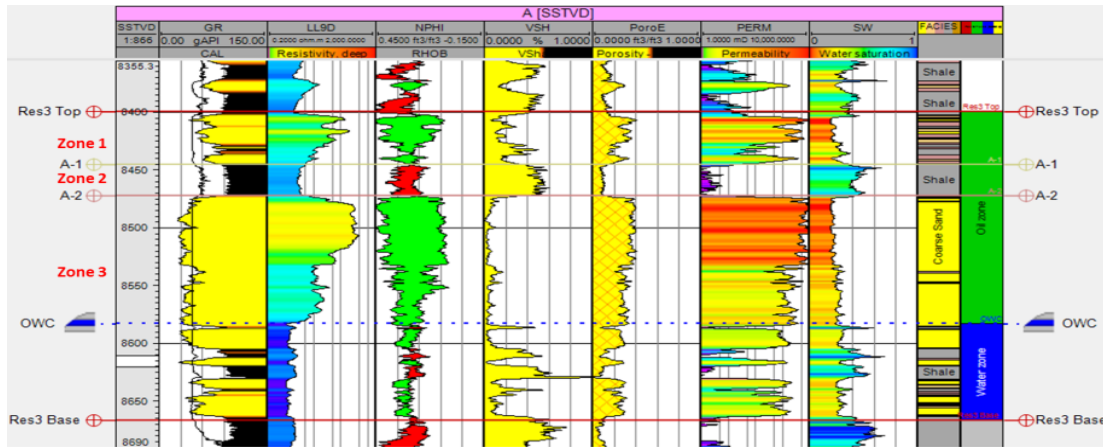


**Fig. 9: Petrophysical log derived for Well A within Reservoir C.**

The log response in Well A indicates that Reservoir C is predominantly a clean to moderately shaly sandstone containing hydrocarbon-bearing intervals. The reservoir is characterized by relatively low gamma-ray values, comparatively high deep-resistivity readings and a favourable neutron–density response. These characteristics suggest the presence of porous sandstone with hydrocarbon saturation. The transition from the oil-bearing interval to the water-bearing interval is associated with a reduction in resistivity, which was used together with the other log responses to identify the approximate oil–water contact.

The gross thickness of Reservoir C varies from 132 ft in Well C to 267 ft in Well A. The net-to-gross ratio ranges from 0.40 in Well E to 0.91 in Well D, indicating substantial lateral variation in the proportion of reservoir-quality sandstone. The corresponding net-sand thickness ranges from 49.30 ft in Well E to 144.23 ft in Well A, as shown in Table 4. The relatively high net-to-gross values observed in Wells B, C, D and F indicate that Reservoir C is well developed in these locations, whereas the lower value in Well E suggests a more shale-rich or poorly developed reservoir interval.

The fluid interpretation in Table 4 indicates that Wells A, B, C, D, F and G encountered

intervals interpreted as containing both oil and water. Well E was interpreted as water-bearing within the evaluated interval. The water-bearing response in Well E may reflect a structurally lower position, local variation in reservoir quality or lateral changes in the oil–water contact. However, the fluid interpretation should be considered alongside the structural maps and contact analysis because log responses alone may not fully define the lateral extent of the fluid contacts.

The water-saturation results are summarized in Table 5. The mean water saturation values for Wells A–F range from approximately 0.29 to 0.33, corresponding to 29–33% when expressed as percentages. These mean values indicate relatively high hydrocarbon saturation within the evaluated reservoir intervals. Nevertheless, the minimum and maximum values show a broader range, reflecting vertical variations in saturation within the reservoir. The maximum water-saturation values reach approximately 0.51–0.63 in some wells, indicating that individual intervals may contain significant water saturation even where the overall reservoir average is favourable.

The effective-porosity results in Table 5 also demonstrate vertical and lateral heterogeneity. The reported minimum porosity values range from approximately 0.05 to 0.08, whereas the maximum values range from approximately



0.31 to 0.39. The mean effective porosity values for Wells A–F range from approximately 0.19 to 0.25. These mean values indicate generally good reservoir storage capacity, although the lower minimum values suggest the presence of tighter or more shale-rich intervals within the reservoir package.

The permeability values show considerable variability between and within the wells. The reported mean permeability values range from approximately 485 mD in Well A to 1,840 mD in Well B. The maximum values are substantially higher in some wells, reaching more than 8,000 mD in Wells B and F. Such variability may reflect changes in grain size, sorting, cementation, shale content and depositional facies. The permeability distribution should therefore be interpreted as heterogeneous rather than uniform across Reservoir C. The large difference between minimum and maximum permeability also indicates that the arithmetic mean may be strongly influenced by high-permeability intervals. For reservoir modelling, the use of logarithmic permeability statistics or geometric means should be considered.

Using the qualitative porosity–permeability classification presented in Table 3, the mean porosity and permeability values indicate that most of Reservoir C falls within the good to very-good reservoir-quality categories. The

favourable reservoir quality is particularly evident in Wells B, D and F, where relatively high net-to-gross, porosity and permeability values occur together. These intervals are likely to provide better storage and flow capacity than the more heterogeneous portions of the reservoir.

The petrophysical results are generally consistent with previous studies of Niger Delta reservoirs. For example, Horsfall & Akpan (2024) reported substantial variations in reservoir thickness, net-to-gross, porosity, permeability and water saturation within a producing Niger Delta field. Similarly, Ogbe et al. (2021) demonstrated that the integration of well-log interpretation and seismic mapping provides an effective basis for evaluating reservoir continuity, structural position and hydrocarbon prospectivity. The observed variation in Reservoir C is also consistent with the heterogeneous reservoir architecture described by Ekiliwo & Ekot (2026), where changes in depositional setting and structural position influenced the distribution of reservoir-quality properties.

Well G could not be fully evaluated because of the incomplete log suite, as indicated in Table 2 and Table 5. Consequently, the absence of petrophysical values for Well G should not be interpreted as evidence of poor reservoir quality. Instead, it represents a data limitation.

**Table 4: Petrophysical properties of Reservoir C by well — interval, fluid type, OWC and thickness.**

| Well | Interval (SSTVD ft) | Fluid Type    | OWC (ft) | Gross Thick. (ft) | NTG (%) | Net Sand (ft) |
|------|---------------------|---------------|----------|-------------------|---------|---------------|
| A    | 8399–8666           | Water and oil | 8580     | 267               | 0.54    | 144.23        |
| B    | 8230–8368           | Water and oil | 8329     | 138               | 0.66    | 91.17         |
| C    | 8195–8327           | Water and oil | 8323     | 132               | 0.67    | 88.66         |
| D    | 8304–8441           | Water and oil | 8326     | 137               | 0.91    | 124.55        |
| E    | 8196–8319           | Water         | WUT      | 123               | 0.40    | 49.30         |
| F    | 8200–8347           | Water and oil | 8321     | 147               | 0.58    | 84.71         |



| Well | Interval (SSTVD ft) | Fluid Type    | OWC (ft) | Gross Thick. (ft) | NTG (%) | Net Sand (ft) |
|------|---------------------|---------------|----------|-------------------|---------|---------------|
| G    | 8473–8648           | Water and oil | 8636     | 175               | –       | –             |

**Table 5: Petrophysical properties of Reservoir C by well — water saturation, porosity and permeability**

| Well | Sw Min | Sw Max | Sw Mean | Poro Min | Poro Max | Poro Mean | Perm Min (mD) | Perm Max (mD) | Perm Mean (mD) |
|------|--------|--------|---------|----------|----------|-----------|---------------|---------------|----------------|
| A    | 0.24   | 0.57   | 0.33    | 0.05     | 0.32     | 0.19      | 0.05          | 3134.16       | 485.26         |
| B    | 0.20   | 0.63   | 0.32    | 0.06     | 0.39     | 0.23      | 0.12          | 9377.02       | 1840.05        |
| C    | 0.24   | 0.56   | 0.30    | 0.08     | 0.31     | 0.22      | 0.75          | 2588.28       | 714.36         |
| D    | 0.24   | 0.55   | 0.29    | 0.06     | 0.32     | 0.25      | 0.19          | 2941.37       | 1051.71        |
| E    | 0.16   | 0.51   | 0.30    | 0.07     | 0.33     | 0.20      | 0.30          | 3356.72       | 559.19         |
| F    | 0.20   | 0.51   | 0.31    | 0.06     | 0.38     | 0.22      | 0.11          | 8427.44       | 1748.62        |
| G    | –      | –      | –       | –        | –        | –         | –             | –             | –              |

The missing log information introduces uncertainty into the spatial interpolation of reservoir properties, particularly in the vicinity of Well G. Additional log acquisition, reprocessing or the use of calibrated seismic-derived property information would improve the reliability of the model in this area.

Overall, Reservoir C exhibits favourable reservoir characteristics, including relatively high net-to-gross, moderate-to-high effective porosity, high permeability in selected intervals and generally low mean water saturation. However, the wide range of petrophysical values indicates that the reservoir is heterogeneous. The most favourable reservoir intervals are expected to occur where high net-to-gross, high porosity and high permeability coincide with relatively low water saturation. These observations provide the basis for the subsequent structural interpretation, reservoir-property modelling and prospect volumetric evaluation.

#### 4.3 Well-to-Seismic Tie and Structural Framework

The well-to-seismic tie was performed to establish a reliable relationship between the stratigraphic information obtained from the well logs and the seismic reflection data. This integration is essential for transferring the reservoir tops, bases, and fluid-contact interpretations from the wells into the three-dimensional seismic volume. The synthetic seismogram generated for Well C was matched with the corresponding seismic trace using the available sonic and density-log information. A time adjustment of approximately 2 ms was applied to improve the alignment between the synthetic and observed seismic reflections. However, the polarity convention and the specific wavelet parameters used for the tie should be stated clearly in the final manuscript because the identification of peaks and troughs depends on the adopted seismic polarity.

The top and base of Reservoir C were identified on the seismic section and correlated with the corresponding well-log markers. The top of the reservoir was associated with a distinct seismic reflection generated by the contrast between the overlying shale and the reservoir sandstone,



whereas the reservoir base was interpreted from the reflection corresponding to the transition from the reservoir interval to the underlying formation. The well-to-seismic tie

is presented in *Fig. 10*. The agreement between the synthetic seismogram and the seismic trace provided the basis for extending the reservoir horizons away from the control well.

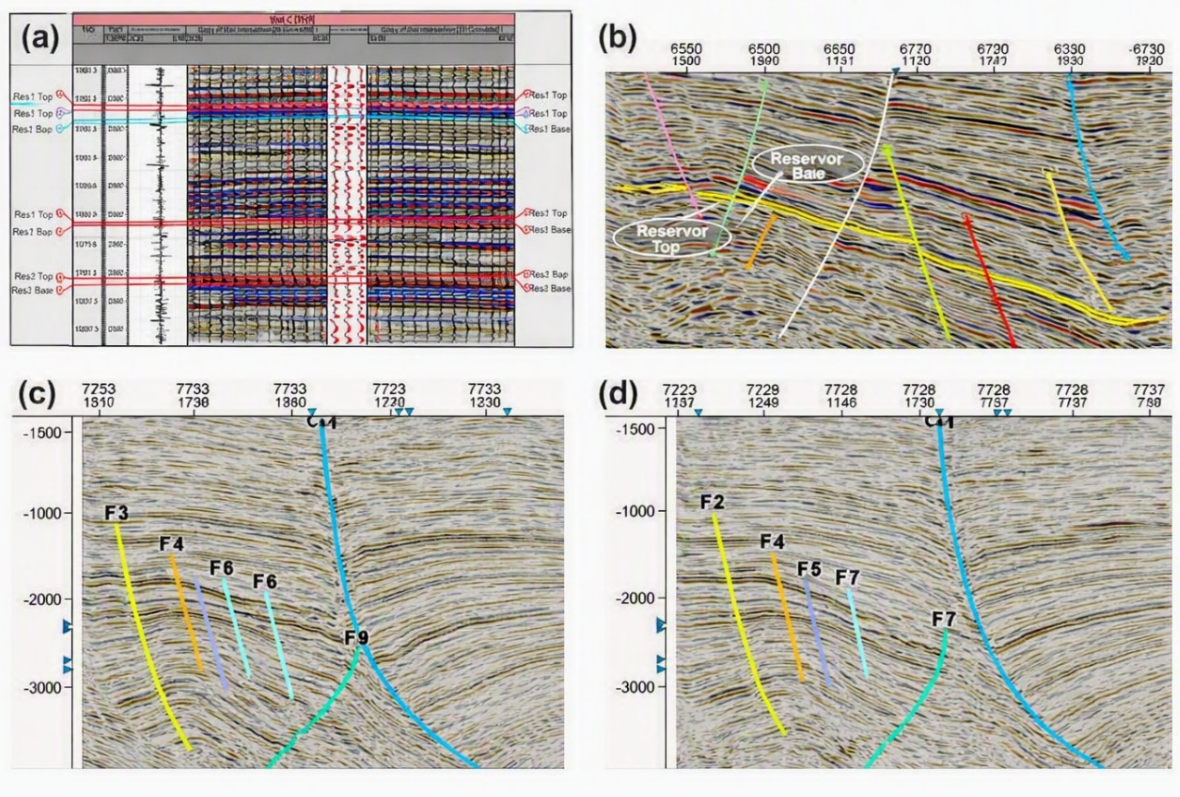


**Fig. 10:** Well-to-seismic tie for Well C, (b) **Fig. 11:** Inline 6940 and crossline 1349 showing the mapped horizons and faults in the study area (c) **Fig. 12:** Fault mapping on representative seismic inlines 7253 (a) and 7228 (b) showing interpreted fault sticks F1–F9

The structural interpretation was conducted using the available three-dimensional seismic volume. The interpreted horizons were tracked along the inlines and crosslines to identify lateral changes in reflection continuity, structural relief, and fault displacement. The interpreted seismic volume was used to map the reservoir horizons and establish the structural framework of the field. The inline and crossline ranges reported in the manuscript should be checked against the actual seismic survey dimensions before publication. In particular, the reported line numbers should be

consistent with the inline and crossline limits presented in Table 1.

Several normal faults were identified from discontinuities and vertical offsets in the seismic reflections. These faults were designated F1–F9 and were incorporated into the structural interpretation. The interpreted faults and fault sticks are shown in Figs. 11 and 12, respectively. The fault pattern indicates that the reservoir is structurally compartmentalized, with the degree of compartmentalization controlled by fault orientation, displacement, and continuity. Nevertheless, the faults should



not automatically be classified as sealing faults solely on the basis of their seismic expression. Fault-sealing behaviour requires additional evidence, such as juxtaposition analysis, shale-gouge assessment, fault-rock properties, pressure data, or production interference information.

The interpreted horizon and fault framework was subsequently used to generate the structural grid. The seed grid and the resulting structural framework are presented in *Fig. 13*. The grid provides the geometric foundation for the subsequent facies, petrophysical, and volumetric models. Accurate structural gridding is particularly important because small variations in structural elevation can significantly influence the calculated gross rock volume, fluid-contact position, and hydrocarbon volume.

Depth-converted structural maps were generated for the reservoir horizons to evaluate the spatial distribution of structural highs, lows, and possible closures. The depth structure maps are shown in *Figs. 14 and 15*. The maps reveal the structural configuration of the reservoir and indicate areas where closure may be developed. Structural highs are considered prospective where they coincide with favourable reservoir properties and are located above the interpreted oil–water contact. However, structural closure alone does not confirm the presence of commercially recoverable hydrocarbons. Prospectivity also depends on reservoir continuity, porosity, permeability, hydrocarbon saturation, seal integrity, charge, and the effectiveness of the trapping configuration.

The interpreted prospects are presented in *Fig. 16*. Prospect delineation was based on the integration of mapped structural closures, reservoir distribution, petrophysical quality, and the interpreted fluid-contact level. The three-dimensional structural skeleton shown in *Fig. 17* provides an integrated view of the

interpreted horizons and faults. This representation assists in visualizing the relationship between the reservoir surfaces and the fault framework and supports the identification of structurally distinct compartments.

The oil–water contact used in the model is shown in *Fig. 18*. The position of the contact is a major uncertainty in the volumetric assessment because even a small vertical change can produce a considerable difference in the estimated hydrocarbon pore volume. The interpreted contact should therefore be supported by the available resistivity responses, pressure data, fluid samples, or other direct and indirect evidence. Where such evidence is unavailable, the contact should be treated as an uncertain modelling parameter rather than a fixed geological boundary.

The structural interpretation is consistent with the commonly described fault-controlled framework of the Niger Delta, where growth faults, rollover structures, and associated closures provide important hydrocarbon-trapping configurations (Doust & Omatsola, 1989; Doust & Omatsola, 1990). Similar integrated well-log and three-dimensional seismic studies have demonstrated that structural interpretation improves reservoir correlation, prospect identification, and hydrocarbon-volume estimation in Niger Delta fields (Adagunodo et al., 2017; Ogbe et al., 2021). The present interpretation therefore provides the structural basis for the reservoir property modelling and probabilistic volumetric evaluation discussed in the subsequent sections.

#### 4.4 Reservoir Property Models

The reservoir property models were developed by integrating the interpreted structural framework with the available well-log-derived petrophysical parameters. The principal properties modelled were facies, net-to-gross ratio, effective porosity, permeability, and

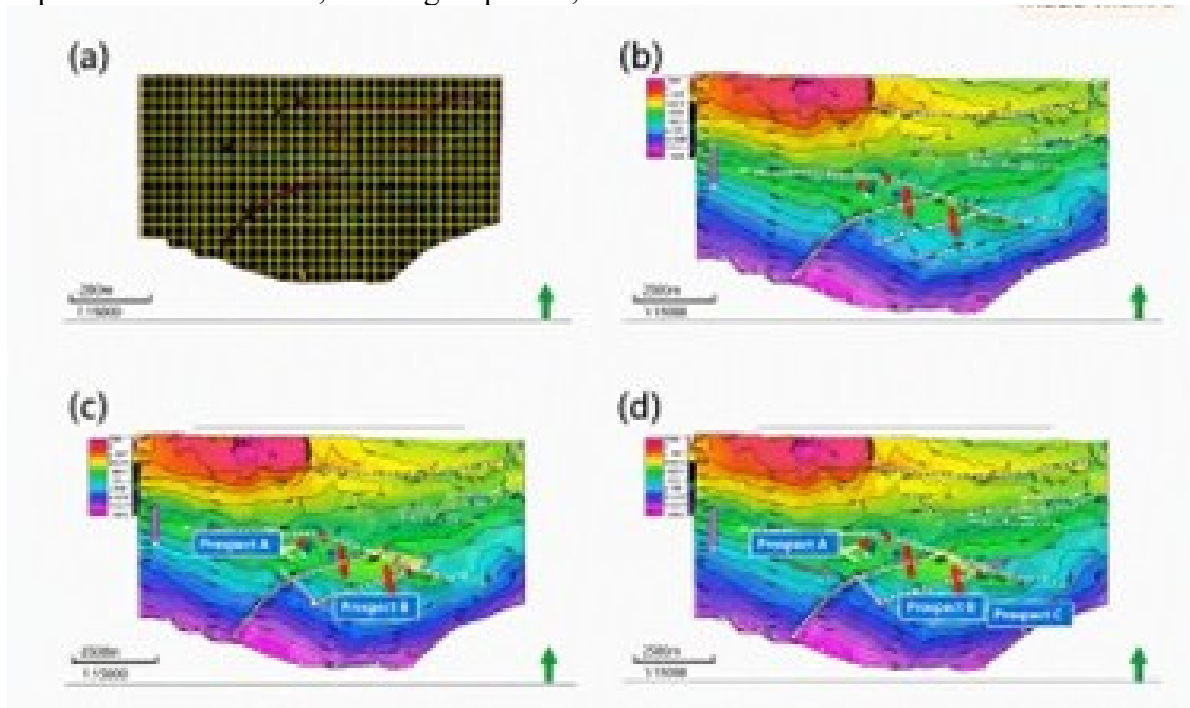


water saturation. These properties control the distribution of reservoir pore volume, fluid storage capacity, fluid transmissibility, and hydrocarbon saturation. The modelling workflow therefore provided the link between the geological interpretation and the subsequent volumetric and economic evaluations.

#### 4.4.1 Facies Model

The facies model was generated using the interpreted reservoir zones, well-log responses,

and the structural framework established from the seismic interpretation. The model was designed to distribute reservoir and non-reservoir facies between the wells while maintaining consistency with the observed vertical succession and lateral continuity of the reservoir units. The resulting facies distribution is presented in Fig. 19.



(a) Fig.11: Grid overlay map showing the spatial framework of Reservoir C, (b) Fig. 12: Time-structure map for the top of Reservoir C with color-coded depth contours, (c) Fig. 3: Top-structure map of Reservoir C highlighting fault contours and prospect zones, and (d) Fig. 14: Reservoir C top-structure map showing the three identified prospects A, B, and C

The model indicates that the reservoir is dominated by sandstone facies, with shale or shaly-sand intervals occurring locally within the reservoir succession. The sandstone-dominated intervals correspond to the cleaner gamma-ray responses and relatively higher resistivity values observed in the wells, whereas the shaly intervals are associated with

higher gamma-ray readings and comparatively less favourable petrophysical characteristics. The distribution of shale within the reservoir is important because it may reduce effective reservoir thickness, interrupt vertical communication, and produce local heterogeneity in fluid flow.



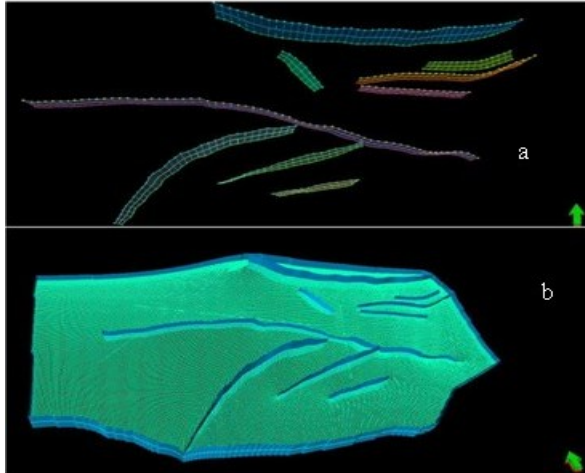


**Fig. 17: (a) Fault modeling for Reservoir C  
(b) 3-D skeleton generated from the top and base of Reservoir C**

The facies model also suggests that reservoir quality is not uniform throughout the field. Some parts of the reservoir show relatively continuous sandstone development, while other areas contain more frequent shale intercalations. Such heterogeneity may influence the distribution of movable hydrocarbons and may create preferential flow paths during production. The facies model should therefore be regarded as a geological representation of reservoir architecture rather than a direct prediction of production performance.

The use of well data to constrain facies distribution is consistent with integrated reservoir-modelling practices, in which geological interpretation, well-log analysis, and seismic structure are combined to generate a spatially coherent reservoir model (Cosentino, 2001; Ogbe et al., 2021). However, the reliability of the facies model depends on the number and spatial distribution of wells, the variogram parameters, the selected facies proportions, and the assumptions used during interpolation or stochastic simulation.

#### 4.4.2 Net-to-Gross Model

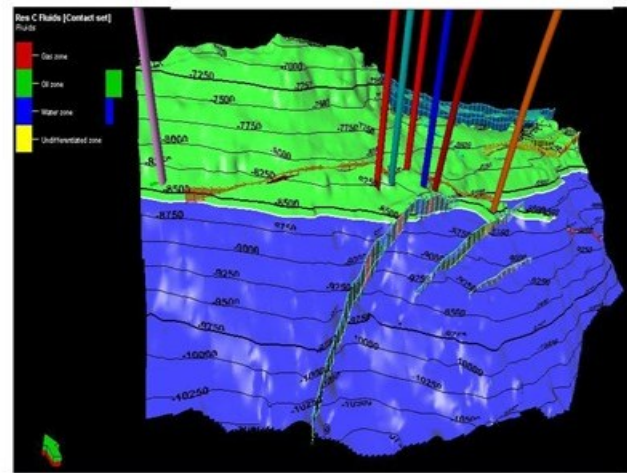


**Fig. 18: 3-D view showing the oil–water contact (OWC) across the X-Field (red: gas zone; green: oil zone; blue: water zone; yellow: undifferentiated zone)**

The net-to-gross model was generated to estimate the proportion of reservoir-quality rock within the gross geological volume. The resulting distribution is shown in Fig. 20. Net-to-gross is a critical parameter in volumetric evaluation because it accounts for the effect of shale and other non-reservoir intervals on the effective thickness of the reservoir.

The model shows that the net-to-gross ratio varies spatially across the field. Higher values are associated with cleaner sandstone-dominated intervals, whereas lower values occur in areas containing a greater proportion of shale or shaly sandstone. This variation agrees with the well-log interpretation, which identified changes in gamma-ray response and reservoir quality between the wells. The net-to-gross distribution therefore reflects the heterogeneous nature of the reservoir and provides a basis for estimating the effective reservoir volume.

The net-to-gross values reported in Table 4 should be presented consistently either as fractions or percentages. For example, a value of 0.40 should be reported as 0.40 when the model uses fractional values or as 40% when percentages are used. Mixing both conventions



within the same section may lead to incorrect interpretation and errors in the volumetric calculations.

The spatial distribution of net-to-gross is particularly important in areas where the reservoir is affected by shale breaks or fault-related compartmentalization. A high gross thickness does not necessarily indicate a high hydrocarbon storage capacity if the corresponding net-to-gross ratio is low. Consequently, net-to-gross should be interpreted together with porosity, permeability, and water saturation rather than as an isolated measure of reservoir quality.

#### 4.4.3 Effective Porosity Model

The effective porosity model is presented in Fig. 21. Effective porosity represents the interconnected pore space available for storing and transmitting fluids. The model was generated from the well-log-derived porosity values and distributed throughout the reservoir framework using the adopted geostatistical procedure.

The model indicates that effective porosity varies across the reservoir, reflecting differences in grain packing, shale content, diagenetic modification, and depositional texture. Areas with relatively higher porosity are expected to possess greater fluid-storage capacity, whereas zones with lower porosity may have reduced hydrocarbon pore volume. The well-log results presented in Table 5 show that the evaluated wells generally possess moderate to high effective porosity, although the minimum and maximum values demonstrate considerable vertical and lateral variability.

The porosity distribution should be interpreted in relation to the facies model. Cleaner sandstone intervals generally provide more favourable conditions for pore preservation and fluid storage, while shaly or tightly compacted intervals may show lower effective porosity. The relationship between porosity and facies is

therefore important for ensuring that the property model remains geologically realistic. The mean porosity values should also be distinguished from the extreme values. Maximum porosity values may occur over short intervals and should not be used to represent the entire reservoir. For volumetric purposes, the average effective porosity within the net reservoir interval is more appropriate than isolated maximum values. In addition, the averaging method used—arithmetic, thickness-weighted, or facies-weighted—should be stated clearly.

#### 4.4.4 Permeability Model

The permeability model is shown in Fig. 22. Permeability determines the ability of the reservoir rock to transmit fluids and is therefore a major control on well productivity, pressure communication, and sweep efficiency. Because direct permeability measurements were not reported for all model cells, the permeability distribution was derived from the available well-log relationships and the adopted petrophysical modelling procedure.

The model displays substantial permeability variation across the reservoir. Higher permeability values are associated with cleaner and more porous sandstone intervals, while lower values occur in shaly, compacted, or otherwise less connected portions of the reservoir. The well results in Table 5 indicate that the reservoir generally falls within the good-to-very-good permeability classes defined in Table 3, although the wide range between minimum, mean, and maximum values indicates significant heterogeneity.

The presence of high-permeability zones may support relatively strong fluid deliverability; however, these intervals may also become preferential flow paths during production or water displacement. Conversely, low-permeability intervals may retain hydrocarbons but contribute less effectively to production. This contrast is particularly important for



reservoir development because high average permeability does not necessarily guarantee uniform sweep or efficient recovery.

The permeability model should be checked against the porosity model to ensure that the predicted relationship between the two properties is physically reasonable. A positive relationship is generally expected in clean clastic reservoirs, but the relationship may weaken in intervals affected by shale, cementation, compaction, or diagenesis. Any permeability transform used in the modelling should therefore be reported, including the equation, calibration data, correlation coefficient, and applicable porosity range.

#### 4.4.5 Water Saturation Model

The water saturation model is presented in *Fig. 23*. Water saturation represents the fraction of the effective pore space occupied by formation water. It is a key parameter in determining hydrocarbon saturation and, consequently, the hydrocarbon pore volume used in the volumetric assessment.

The model indicates that water saturation varies across the reservoir. Lower water-saturation values are generally associated with intervals interpreted as hydrocarbon-bearing, particularly where the resistivity response is relatively high and the gamma-ray response indicates cleaner sandstone. Higher water saturation occurs in water-bearing or more shaly intervals. The well-log-derived values in Table 5 indicate that the mean water saturation values are relatively similar across several wells, although the wider minimum and maximum ranges show that saturation changes vertically within the reservoir.

The relationship between water saturation and reservoir quality is important. A zone may possess high porosity and permeability but still have limited hydrocarbon potential if its water saturation is high. Similarly, a zone with moderate porosity may contain a meaningful

hydrocarbon volume if its water saturation is sufficiently low. Therefore, hydrocarbon prospectivity should be assessed using the combined effect of net-to-gross, porosity, permeability, and water saturation.

The water-saturation calculation should be described explicitly in the methodology and linked to the appropriate petrophysical model. If Archie's equation was used, the values adopted for formation-water resistivity, cementation exponent, saturation exponent, and tortuosity factor should be reported. Where shale is present, a shaly-sand model such as the Simandoux, Indonesian, or Poupon–Leveaux model may be more appropriate than a simple Archie model, depending on the available data (Archie, 1942; Poupon & Leveaux, 1971). The selected model should be applied consistently to all wells and reservoir zones.

#### 4.4.6 Integrated Interpretation of the Property Models

The integrated property models show that Reservoir C is heterogeneous in terms of facies, net-to-gross, porosity, permeability, and water saturation. The most prospective intervals are those where clean sandstone facies coincide with relatively high net-to-gross, favourable effective porosity, high permeability, and low water saturation. Conversely, intervals containing shale or elevated water saturation are expected to contribute less to effective hydrocarbon storage and flow.

The property models also demonstrate why reservoir evaluation should not rely on a single petrophysical parameter. High porosity without adequate permeability may indicate poor fluid transmissibility, while high permeability with high water saturation may provide limited hydrocarbon value. Similarly, a thick reservoir interval may contain only a small proportion of effective reservoir rock if the net-to-gross ratio is low. The combined interpretation of the models is therefore more reliable for prospect ranking than the use of any individual property.



The spatial variability observed in the models is consistent with the heterogeneous depositional and structural framework of the Niger Delta. Variations in sandstone distribution, shale intercalation, fault displacement, and reservoir continuity can produce substantial changes in reservoir performance across relatively short distances (Doust & Omatsola, 1989; Cosentino, 2001). Comparable integrated studies in the Niger Delta have also shown that combining well-log-derived properties with seismic interpretation improves the identification of reservoir-quality zones and supports more reliable hydrocarbon evaluation (Adagunodo et al., 2017; Ogbe et al., 2021).

The STOIIP calculation may be expressed generally as:

$$N = \frac{7758AhNTC\phi(1-S_w)}{B_{oi}} \quad (1)$$

where N is the stock-tank oil initially in place in stock-tank barrels, A is the reservoir area in acres, h is the gross reservoir thickness in feet, NTGNTG is the net-to-gross ratio,  $\phi$  is effective porosity,  $S_w$  is water saturation, and  $B_{oi}$  is the initial oil formation volume factor in reservoir barrels per stock-tank barrel. If metric units or a different volumetric convention was used, the corresponding conversion factor should be stated in the methodology.

The calculated values should be interpreted as in-place hydrocarbon volumes rather than recoverable reserves. STOIIP does not account directly for recovery efficiency, well deliverability, pressure support, reservoir compartmentalization, operating constraints, or economic limitations. Consequently, the deterministic estimates provide an indication of the size of the prospects but do not, by themselves, establish commercial viability.

The accuracy of the volumetric estimates is strongly dependent on the quality of the structural and petrophysical models. Uncertainty in the oil–water contact, reservoir

boundaries, fault interpretation, net-to-gross distribution, porosity, and water saturation may produce significant changes in the calculated hydrocarbon volume. Integrated reservoir studies therefore recommend that deterministic estimates be supplemented with uncertainty analysis and multiple geological realizations (Cosentino, 2001; Ogbe et al., 2021).

#### 4.5.2 Probabilistic Volumetric Analysis

Probabilistic analysis was conducted to quantify the effect of geological and petrophysical uncertainty on the estimated hydrocarbon volumes. The principal uncertain parameters included reservoir area, gross thickness, net-to-gross ratio, effective porosity, water saturation, and fluid-contact depth. These parameters were varied within their specified uncertainty ranges to generate a distribution of possible STOIIP outcomes.

The probabilistic results are summarized in Table 7. The distribution of outcomes demonstrates that the estimated hydrocarbon volume is not a single fixed value but a range of possible values resulting from uncertainty in the input parameters. The lower-end outcomes represent combinations of less favourable geological and petrophysical conditions, whereas the higher-end outcomes represent more favourable combinations of reservoir extent, quality, and hydrocarbon saturation.

The percentile terminology used in Table 7 must be defined carefully. In petroleum risk analysis, the conventional probability-of-exceedance terminology is generally:

- (i) P90: low case; there is a 90% probability that the actual volume will equal or exceed the estimate.
- (ii) P50: median case; there is a 50% probability that the actual volume will equal or exceed the estimate.
- (iii) P10: high case; there is a 10% probability that the actual volume will equal or exceed the estimate.



The values in Table 7 should therefore be checked to ensure that their labels agree with the adopted convention. If the values are arranged in ascending order as  $P10 < P50 < P90$ , they may represent ordinary cumulative percentiles rather than petroleum probability-of-exceedance estimates. The final manuscript should use one convention consistently and explain it in the table caption and methodology. The P50 value should be described as the median estimate, rather than the “most-likely” value. The median is not necessarily the mode or the most frequently occurring outcome. Likewise, P10 and P90 should not be interpreted as absolute minimum and maximum values; they represent selected points within the probability distribution.

The probabilistic analysis is useful because it identifies the range of possible outcomes and highlights the parameters that contribute most strongly to volumetric uncertainty. For example, uncertainty in the oil–water contact may have a major influence on the hydrocarbon column and pore volume, while uncertainty in net-to-gross and porosity directly affects the effective reservoir volume. Structural uncertainty may also influence the calculated closure area and the continuity of the reservoir across faults.

#### **4.5.3 Interpretation of the Risk Distribution**

The spread between the low, median, and high cases provides an indication of the uncertainty associated with each prospect. A narrow distribution suggests relatively consistent geological and petrophysical predictions, whereas a wide distribution indicates greater uncertainty in the reservoir description. The uncertainty may result from limited well control, incomplete log suites, ambiguous fluid contacts, structural complexity, or variability in reservoir properties.

The probabilistic estimates should be compared with the deterministic results in Table 6. Any difference between the

deterministic and probabilistic values should be explained by the assumptions used in each calculation. A deterministic estimate normally uses a single selected value for each input parameter, whereas probabilistic analysis combines multiple possible values and accounts for their distributions. The deterministic result may therefore fall near, above, or below the probabilistic median depending on the selected input assumptions.

The number of realizations used in the analysis should also be reported clearly. If 1,000 realizations were generated, the manuscript should state that the reported P10, P50, and P90 values were derived from the complete set of 1,000 outcomes. Where only ten cases are displayed in the table, these should be described as representative realizations rather than as the complete probability distribution.

The reliability of the probabilistic results depends on the distributions assigned to the input variables and on whether correlations between variables were considered. For example, porosity and permeability may be positively related, while net-to-gross and water saturation may vary systematically with facies. Treating all variables as independent when they are geologically related may overestimate or underestimate the uncertainty. The modelling procedure should therefore state the distribution type, minimum, most likely, maximum, standard deviation, and correlation assumptions for each uncertain parameter.

#### **4.5.4 Geological Significance of the Volumetric Results**

The volumetric results indicate that the prospects differ in their hydrocarbon potential because of variations in structural closure and reservoir quality. Prospects with favourable structural position, greater effective reservoir thickness, higher porosity, and lower water saturation are expected to possess greater hydrocarbon storage capacity. However, the



presence of a large calculated STOIP does not automatically imply high recoverability.

Fault compartmentalization may restrict pressure communication and reduce the effective drainage area of individual wells. Similarly, shale intercalations may create vertical barriers or baffles that limit sweep efficiency. High-permeability streaks may improve initial productivity but can also encourage early water breakthrough or uneven displacement. These factors should be considered when converting in-place volumes into recoverable volumes.

The results are consistent with the principle that reliable reservoir evaluation requires the integration of structural interpretation, facies distribution, petrophysical properties, fluid contacts, and uncertainty analysis (Cosentino, 2001). Studies from the Niger Delta have

similarly shown that reservoir volume estimates are strongly influenced by the combined effects of structural closure, reservoir continuity, porosity, permeability, and water saturation (Adagunodo et al., 2017; Ogbe et al., 2021).

Overall, the probabilistic analysis provides a more realistic representation of prospect uncertainty than a single deterministic estimate. It supports the ranking of the prospects by showing not only their central volume estimates but also the degree of confidence associated with those estimates. Nevertheless, the results should be regarded as screening-level estimates until they are supported by additional well data, improved seismic interpretation, pressure information, fluid-property measurements, and dynamic reservoir simulation.

**Table 6: Deterministic STOIP by prospect and zone**

| Prospect | Zone  | Bulk Volume (m <sup>3</sup> ) | Net Volume (m <sup>3</sup> ) | STOIP (MMSTB) |
|----------|-------|-------------------------------|------------------------------|---------------|
| A        | 1     | 3,264,159                     | 2,801,801                    | 3             |
| A        | 2     | 9,251,952                     | 5,968,617                    | 6             |
| A        | 3     | 166,491,322                   | 153,167,112                  | 147           |
| A        | Total | 179,007,434                   | 161,937,531                  | 155           |
| B        | 1     | 34,068,449                    | 31,411,747                   | 33            |
| B        | 2     | 25,405,784                    | 20,126,942                   | 20            |
| B        | 3     | 116,998,482                   | 103,904,276                  | 103           |
| B        | Total | 176,472,715                   | 155,442,965                  | 157           |
| C        | 1     | 25,873,659                    | 20,629,497                   | 26            |
| C        | 2     | 26,795,646                    | 24,946,740                   | 26            |
| C        | 3     | 144,702,561                   | 115,790,696                  | 95            |
| C        | Total | 197,371,867                   | 161,366,933                  | 146           |

## 4.6 Prospect Ranking and Economic Evaluation

### 4.6.1 Basis for Prospect Ranking

Prospect ranking was performed by integrating the structural, petrophysical, volumetric, and economic characteristics of the identified prospects. The main parameters considered were estimated STOIP, reservoir quality, structural closure, hydrocarbon saturation,

uncertainty range, and projected economic value. This integrated approach is more appropriate than ranking the prospects solely according to their gross rock volume because a large structure may contain limited recoverable hydrocarbons if reservoir quality or hydrocarbon saturation is poor.

The economic and ranking results are presented in Table 8. The table compares the identified



prospects using their estimated hydrocarbon volumes and associated economic indicators. The ranking provides a basis for prioritizing prospects for further appraisal and possible development. However, the ranking should be considered preliminary because the analysis is based on static geological and petrophysical information rather than a fully calibrated dynamic reservoir model.

The P50 value should be interpreted as the median estimate of the predicted economic outcome. It should not be described as the “most-likely” value unless a probability-density analysis has demonstrated that it represents the mode of the distribution. Similarly, the risk-adjusted economic value should be distinguished from ultimate recovery or recoverable reserves.

#### 4.6.2 Comparison of Prospect Values

Based on the values reported in Table 8, Prospect B has the highest P50 economic value of approximately US\$1,349.2 million, followed by Prospect C with approximately US\$1,343.2 million and Prospect A with approximately US\$1,243.8 million. Therefore, the correct P50 ranking is:

1. Prospect B – highest P50 economic value.
2. Prospect C – second-highest P50 economic value.
3. Prospect A – third-highest P50 economic value.

The difference between Prospects B and C is relatively small, indicating that both prospects may warrant further consideration. Although Prospect B has the highest median economic value, Prospect C may remain attractive if it exhibits better structural definition, more favourable uncertainty characteristics, lower development complexity, or superior reservoir continuity. Consequently, the final ranking should consider both economic magnitude and confidence in the underlying geological model.

Prospect A also displays substantial economic potential, but its lower P50 value suggests that it may be less attractive than Prospects B and C under the assumptions used in the present analysis. This does not necessarily imply that Prospect A should be abandoned. A prospect with a lower median value may still be selected if it has a lower risk profile, lower development cost, better access to existing infrastructure, or more favourable production characteristics.

#### 4.6.3 Risk-Adjusted Economic Value

The risk-adjusted economic values were calculated by applying a risk factor to the projected economic values. The manuscript currently describes this adjustment as a 20% risk factor. If the calculation involved multiplying the projected value by 0.80, the procedure represents a 20% reduction or discount, rather than a complete probabilistic risk analysis.

The calculation can be expressed as:

$$V_{risk-adjusted} = V_{projected} (1 - r)$$

where  $V_{risk-adjusted}$  is the risk-adjusted economic value,  $V_{projected}$  is the unadjusted projected value, and  $r$  is the assumed risk discount. For a 20% discount:

$V_{risk-adjusted} = 0.80$ ,  $V_{projected} = -0.80 V$ . This approach provides a simple screening adjustment for uncertainty, but it does not replace a full economic-risk model. A rigorous economic evaluation would incorporate the probability of geological success, development costs, operating costs, oil price uncertainty, production profiles, taxes, royalties, abandonment costs, and discounting over time.

**Table 7: Probabilistic STOHP (P10–P50–P90) by prospect**

| Prospect | P10<br>(MMSTB) | P50<br>(MMSTB) | P90<br>(MMSTB) |
|----------|----------------|----------------|----------------|
| A        | 131.69         | 144.32         | 154.33         |
| B        | 154.10         | 156.65         | 160.52         |
| C        | 146.15         | 155.96         | 167.96         |



**Table 8: Economic analysis of Prospects A, B and C.**

| Prospect | Case | Projected Profit (US\$M) | Risk Factor 20% (US\$M) | Ultimate Recovery (US\$M) |
|----------|------|--------------------------|-------------------------|---------------------------|
| A        | P10  | 1417.7                   | 283.5                   | 1134.2                    |
| A        | P50  | 1553.8                   | 310.0                   | 1243.8                    |
| A        | P90  | 1664.8                   | 332.9                   | 1331.9                    |
| B        | P10  | 1659.0                   | 331.8                   | 1327.2                    |
| B        | P50  | 1686.5                   | 337.3                   | 1349.2                    |
| B        | P90  | 1728.2                   | 345.6                   | 1382.6                    |
| C        | P10  | 1573.4                   | 314.6                   | 1258.8                    |
| C        | P50  | 1679.1                   | 335.8                   | 1343.2                    |
| C        | P90  | 1808.3                   | 361.6                   | 1446.7                    |

The term “risk-adjusted economic value” is therefore more appropriate than “ultimate recovery” for the values calculated using the 20% adjustment. Ultimate recovery refers to the total quantity of hydrocarbons expected to be recovered over the productive life of a reservoir, whereas the values in Table 8 represent monetary estimates adjusted using an assumed risk discount.

#### ***4.6.4 Economic Implications for Prospect Selection***

The economic results suggest that Prospects B and C should receive higher priority for additional technical investigation because they possess the highest median economic values. Nevertheless, the selection of a preferred prospect should not be based only on the P50 value. The P10 and P90 outcomes, the spread of the probability distribution, the estimated STOIP, reservoir continuity, and structural uncertainty should also be considered.

A prospect with a high P50 value but a very wide uncertainty range may be less attractive than a prospect with a slightly lower P50 value and a narrower range of outcomes. Similarly, a prospect with high in-place volume may have limited economic value if it contains significant

shale barriers, high water saturation, poor vertical communication, or complex fault compartmentalization.

The results therefore support a staged prospect-evaluation strategy. Prospects with the highest combined economic value and geological confidence should be prioritized for further evaluation. The next stage should include improved seismic interpretation, additional petrophysical analysis, pressure and fluid-property data acquisition, and, where appropriate, dynamic reservoir simulation. These activities would help reduce uncertainty and determine whether the static model predictions can be translated into sustainable production performance.

Based on the integrated interpretation, the following preliminary priorities are proposed:

1. Prospect B should be considered the first-ranked prospect based on its highest P50 economic value.
2. Prospect C should be considered a close alternative because its P50 value is only slightly lower than that of Prospect B.
3. Prospect A should be retained as a secondary prospect and evaluated further if additional data reduce its uncertainty or improve its economic outlook.
4. Additional appraisal should focus on confirming the oil–water contact, reservoir continuity, fault behaviour, and the distribution of high-quality sandstone.
5. Final development decisions should be deferred until dynamic simulation and a more complete economic evaluation have been performed.

The ranking is consistent with the principle that prospect selection should integrate geological probability, reservoir quality, hydrocarbon volume, and economic attractiveness rather than relying on a single parameter (Cosentino, 2001; Adagunodo et al., 2017; Ogbe et al.,



2021). Integrated reservoir characterization studies have shown that the combination of structural interpretation, petrophysical modelling, volumetric estimation, and uncertainty analysis provides a more reliable basis for prospect prioritization than isolated structural or log-based interpretation.

#### 4.6.6 Limitations of the Economic Assessment

The economic evaluation should be regarded as a preliminary screening analysis because several important economic and engineering parameters have not been fully documented. The manuscript should clearly state the oil-price assumption, price date, production forecast, recovery factor, capital expenditure, operating expenditure, fiscal terms, discount rate, inflation treatment, and project life. It should also explain whether the projected values represent gross field value, net present value, discounted cash flow, or an undiscounted revenue estimate.

In addition, the economic analysis should distinguish between STOIP, technically recoverable resources, economically recoverable reserves, and projected monetary value. STOIP represents the volume of oil initially present in the reservoir, whereas recoverable reserves depend on the recovery mechanism, well configuration, pressure support, production constraints, and economic conditions. Without these additional considerations, the calculated economic values should not be presented as proven reserves or guaranteed project returns.

Overall, the integrated results identify Prospect B as the highest-ranked prospect based on the reported P50 economic value, with Prospect C closely following. Prospect A remains potentially attractive but requires further evaluation. The ranking provides a useful basis for directing future appraisal activities, but additional geological, petrophysical, engineering, and economic investigations are

required before any final development decision is made.

#### 4.7 Discussion of Findings

The integrated results demonstrate that the hydrocarbon potential of the studied field is controlled by the combined effects of reservoir architecture, petrophysical quality, structural closure, fluid distribution, and economic uncertainty. The well-log interpretation identified four principal reservoirs, designated Reservoirs A–D, while Reservoir C was selected for detailed evaluation because it displayed a comparatively favourable combination of sandstone development, resistivity response, reservoir thickness, and petrophysical characteristics. The identification of multiple reservoir units indicates vertical stratigraphic variability, while the differences observed between wells suggest lateral heterogeneity within the field.

The gamma-ray and resistivity responses were particularly useful for distinguishing cleaner sandstone intervals from shale-rich sections and for identifying possible hydrocarbon-bearing zones. Cleaner intervals generally exhibited lower gamma-ray readings and higher deep-resistivity responses, whereas shaly and water-bearing intervals displayed less favourable log signatures. This interpretation agrees with the established use of gamma-ray, resistivity, density, and neutron logs in reservoir identification and fluid evaluation (Asquith & Krygowski, 2004). However, resistivity response alone is insufficient to confirm hydrocarbon presence because formation-water salinity, shale content, invasion, and lithological variation may also affect the measured values.

The subdivision of Reservoir C into three flow zones indicates that the reservoir is internally heterogeneous. Variations in gamma-ray response, resistivity, and shale-related indicators suggest changes in sand quality and possible differences in vertical fluid



communication. The flow-zone interpretation is important because the reservoir may not behave as a single homogeneous unit during production. High-quality sandstone intervals may act as preferential flow paths, whereas shale intercalations may create baffles or barriers to vertical flow. This type of heterogeneity can influence pressure communication, water movement, sweep efficiency, and the distribution of remaining hydrocarbons.

The petrophysical results indicate that Reservoir C possesses generally favourable reservoir characteristics, although the properties vary between wells and across individual intervals. The effective porosity and permeability values suggest that several zones may have adequate storage capacity and fluid transmissibility. Nevertheless, the observed range between minimum, mean, and maximum values confirms that reservoir quality is not uniform. The highest permeability intervals may contribute disproportionately to production, while lower-permeability intervals may contain hydrocarbons that are less readily drained. Similar relationships between porosity, permeability, shale content, and reservoir performance have been reported in integrated Niger Delta reservoir studies (Horsfall & Akpan, 2024; Ogbe et al., 2021).

The water-saturation results provide an additional basis for evaluating hydrocarbon prospectivity. Zones with relatively low water saturation and favourable porosity are expected to contribute more significantly to hydrocarbon pore volume. However, high porosity and permeability do not necessarily indicate high hydrocarbon potential when water saturation is elevated. The most prospective intervals are therefore those in which low water saturation coincides with sufficient net-to-gross, effective porosity, and permeability. This integrated interpretation is preferable to ranking intervals using any single petrophysical parameter.

The seismic interpretation established the structural framework of the field and identified several faults and possible structural closures. The mapped faults may have influenced reservoir compartmentalization, migration pathways, and fluid distribution. The structural highs identified from the depth maps provide potential trapping configurations, particularly where they occur above the interpreted oil–water contact. However, the presence of a structural closure does not independently confirm a commercial accumulation. Charge, seal integrity, reservoir continuity, hydrocarbon saturation, and development feasibility must also be demonstrated.

The integration of well data and seismic interpretation improved the spatial understanding of the reservoir. Well logs provide detailed vertical information at discrete locations, whereas seismic data provide broader structural and stratigraphic continuity between wells. Combining both datasets therefore reduces some of the limitations associated with using either dataset independently. This integrated approach is consistent with reservoir-characterization workflows in which seismic horizons, faults, well markers, and petrophysical properties are combined to build a three-dimensional geological model (Cosentino, 2001; Adagunodo et al., 2017).

The facies and petrophysical models further demonstrate that reservoir quality varies spatially. Sandstone-dominated areas generally correspond to higher net-to-gross and more favourable porosity and permeability, while shale-rich intervals display reduced effective reservoir quality. The spatial distribution of water saturation also indicates that hydrocarbon saturation is not uniform throughout the model. These results support the interpretation that the field contains zones of contrasting storage and flow capacity and



should therefore be evaluated using a heterogeneous reservoir model.

The deterministic volumetric estimates provide an initial indication of the hydrocarbon storage capacity of the prospects. However, the probabilistic analysis demonstrates that the calculated volumes are subject to uncertainty associated with structural area, reservoir thickness, net-to-gross ratio, porosity, water saturation, and fluid-contact depth. The probabilistic results are therefore more informative than a single deterministic value because they show the range of possible outcomes. The P50 value should be interpreted as the median estimate, while the P10 and P90 values should be defined according to the selected percentile convention.

The uncertainty analysis also highlights the importance of the oil–water contact. A small vertical change in the contact can significantly alter the hydrocarbon column and the calculated hydrocarbon pore volume. Similar uncertainty may arise from the interpretation of fault boundaries and the lateral extent of reservoir-quality sandstone. These uncertainties should be incorporated into future model updates and reduced through additional well control, pressure data, fluid sampling, and improved seismic interpretation.

The prospect-ranking results indicate that Prospect B has the highest reported P50 economic value, followed closely by Prospect C and then Prospect A. The close values for Prospects B and C suggest that the difference in economic attractiveness may be sensitive to the assumptions used in the volumetric and economic models. Prospect B may be prioritized on the basis of its higher median value, but Prospect C should remain a strong candidate if it has better geological confidence, lower uncertainty, or easier development conditions. Prospect A may also warrant further consideration where additional data improve its estimated volume or reduce its risk.

The economic results should be interpreted as preliminary risk-adjusted economic estimates rather than ultimate recovery or proven reserves. The application of a 20% reduction to projected values represents a simplified risk discount and does not constitute a complete probabilistic economic evaluation. A more rigorous assessment should incorporate production forecasting, recovery factor, capital and operating costs, fiscal terms, oil-price uncertainty, discount rate, abandonment costs, and the probability of geological success.

Overall, the findings indicate that the field contains potentially attractive hydrocarbon accumulations, but the degree of heterogeneity and uncertainty requires careful appraisal. The study demonstrates the value of integrating well-log analysis, seismic interpretation, three-dimensional property modelling, volumetric estimation, and economic screening for prospect evaluation in the Niger Delta. The results provide a basis for prioritizing Prospects B and C for further investigation, while emphasizing that final development decisions should be supported by additional geological, petrophysical, engineering, and economic analyses.

## 5.0 Conclusion

This study assessed hydrocarbon prospects in the Eastern Niger Delta using integrated well-log analysis, seismic interpretation, reservoir modelling, volumetric estimation, and risk analysis. Four reservoirs were identified, with Reservoir C selected for detailed evaluation because of its favourable sandstone development, thickness, resistivity, porosity, and permeability.

The results revealed significant reservoir heterogeneity and structural compartmentalization. The most promising intervals were characterized by higher net-to-gross, favourable porosity and permeability, and relatively low water saturation. The volumetric results also showed that uncertainty



in reservoir geometry, petrophysical properties, and oil–water contact strongly influences estimated hydrocarbon volumes.

Based on the reported P50 economic values, Prospect B ranked first (US\$1,349.2 million), followed by Prospect C (US\$1,343.2 million) and Prospect A (US\$1,243.8 million). Prospects B and C are therefore recommended for further appraisal, while Prospect A remains a secondary opportunity.

The economic estimates are preliminary risk-adjusted values and should not be interpreted as proven reserves or ultimate recovery. Further studies should include confirmation of the oil–water contact, fault-seal analysis, additional well data, dynamic reservoir simulation, production forecasting, and detailed economic evaluation before development decisions are made.

## 6.0 References

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#### Declaration

#### Conflict of Interest

The authors declare that there is no known conflict of interest or personal relationships that have influenced the work reported in this paper.

#### Ethical Consideration

Not applicable

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#### Author Contributions

Selong Unanaonwi Edem conceptualized the study, conducted data analysis, interpreted well-log and seismic data, and drafted the manuscript. Enah Asinya Asinya contributed to geological interpretation and manuscript development. Samuel Izama Ugar supported petrophysical analysis and data interpretation. Godwin Terwase Kave contributed to reservoir characterization and technical review. Philip



Asuquo Edem contributed to data analysis, validation, manuscript review, and editing. All authors approved the final manuscript.

