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Optimizing Reservoir Uncertainty Parameterization in Deltaic Environments with Production Performance data Using Experimental Design Process

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Abstract:

Reservoir-X is one of 22 reservoirs modelled in a field re-development study in the Niger Delta. The reservoir has substantial production history and serves as a good candidate for the characterization of the remaining reservoirs in the stack. The initial static model for reservoir X was built by integrating all the available static data from various sources including seismic, well logs, biofacies. Various subsurface model realizations reflecting the full envelope of uncertainties were developed including uncertainties in structure, reservoir architecture, rock properties, fluid properties, and fluid contacts. The various model realizations were fed into the Experimental Designed (ED) Production History Matching Iterative Process. The analysis of the ED history-matching process clearly highlighted some of the static and dynamic parameters realization, which were less probable. These insights were then fed back into the model updates. The updated reservoir models were then fed back into the final history matching of the model to underpin the development planning and reserves estimation. This workflow, leading to a robust model for reservoir X also provided a geologically and logically consistent basis as a suitable analogue for the modelling of other reservoirs in the field that has little or no production. The paper discusses the details of the initial modelling and uncertainty definition; the process of "listening to the production performance" through Experimentally Designed History Matching, and the eventual recalibration of the model to underpin the field development planning and reserves booking. IT highlights the ED workflow as a robust subsurface uncertainty estimation and management methodology.

Keywords **—Reservoir Characterization, Uncertainty, Realization, Experimental Design, History Matching, Development Planning, Niger Delta.**

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I. INTRODUCTION

The central role of reservoir characterization as a robust tool for understanding the geological basis of the dynamic performance of hydrocarbon fields has been highlighted by several authors ([1], [2], [3], [4]). According to [2], reservoir characterization as a veritable discipline emerged out of the recognition that more oil and gas could be extracted from reservoirs if the geology of the reservoir was understood. He argued that a key component of reservoir characterization is an understanding of the range of potential depositional settings in which a reservoir could have been deposited. As a process, reservoir characterization is undertaken to describe the characteristics and properties of reservoirs using available data from varied sources. Such descriptions when applied to parameterize subsurface uncertainties with the aid of geostatistical routines result in a reliable 3D reservoir model that can be used to evaluate reservoir development, manage existing fields, and make reservoir performance predictions ([5]).

For a long time, reservoir characterization and 3D modelling were challenges in the oil and gas industry ([6])

owing mainly to the difficulty in accurately representing detailed reservoir architecture (including structural, and stratigraphic frameworks) in their true subsurface complexities ([7]). As a result, the scale of 3D static models was historically restricted by computational limitations. A traditional starting point in the description of the reservoir is the determination of the shape and size of the subsurface hydrocarbon accumulation, more commonly referred to in the industry as defining "the size of the tank". Structural interpretation with its resulting structural model or its more simplified presentation in a depth-structure map provides a foundational component for the reservoir characterization process. It presents the configuration of the hydrocarbon and aquifer compartments in the reservoir including its associated faults. Faults signify reservoir heterogeneities that delineate controlling first-order features that influence the dynamics of in-place hydrocarbon during production ([8]). The scales and sizes of the faults in the reservoir determine their impact on flow dynamics.

A pertinent question that is central to any reservoir modelling effort is therefore "at what degree of detail must the reservoir be characterized to ensure its heterogeneity is adequately captured and dynamic connectivity assumptions are representative to enable realistic recovery predictions?"Reference [1] focused on this question in their work on "Geological Modelling for Simulation Studies". In their attempt to resolve the question, they indicated that reservoir heterogeneity is hierarchical in nature and different levels of reservoir heterogeneity needed to be quantified by the reservoir geologist for numerical simulation. At the largest scale (field scale), they argued that sand-body continuity and interconnectedness including the impact of faulting are the most important parameters. At the reservoir or genetic sand-body scale, they contended that attributes of permeability contrast including areal permeability trends, presence, and distribution of permeability baffles, vertical profiles of permeability, and presence of directional permeability within a sand body are the most important parameters. At a smaller scale, the influence of sedimentary structures is shown to be significant in displacement processes ([1]).

Empirical evidence suggests that interrogating the reservoir at the right rate to gain requisite insights needed to manage a range of subsurface uncertainties and optimize field development requires a sophisticated multi-scenario modelling workflow anchored on multiple subsurface realizations ([9]). With current advancements in computing capabilities, the potential to bridge the gap between geological and computational requirements to make 3D models more realistic continues to grow. Currently, it is possible to build extremely detailed static models which attempt to emulate geological features such as bedding laminations, sub-seismic faults, and small geo-bodies, potentially improving the modelling of oil recovery via waterflood schemes or the location of by-passed oil arising from water over-rides or channelling effects ([10]). There is no doubt that the available computing ability affords geoscientists the latitude to investigate the reservoir at several scales to gain empowering insights and propose reliable predictions. For example, we are presently able to run reservoir simulations on many 3D models with different sand-body connectivity and/or permeability distribution profiles, potentially improving the understanding associated with the models and their predictions ([11], [12], [13]). Added to this advantage of advancement in computing power are improvements in dynamic simulation workflows including Experimental Design (ED).

Experimental design is a technique that enables scientists and engineers to efficiently assess the effect of multiple inputs and/or factors on measures of performance and/or responses. This approach, when compared to one-factor-at-a-time, trial-and-error approaches, highlights that a well-designed experiment can provide clear results while dramatically reducing the required amount of testing ([14]). The concept of ED as applied in this study affords the ability to simultaneously evaluate several subsurface variables including multiple subsurface realizations and their interrelated dependencies. The approach offers a veritable means to evaluate multiple subsurface uncertainties at the same time while providing a platform to manage them ([15]). With this workflow, it is now possible to implicitly factor in analogue data to calibrate models, include actual field performance data, and constrain them while evaluating the realism of model predicted structure, facies, permeability, Kv/Kh, hydrocarbon contact, PVT, Relperm, etc with actual production data. This methodology results in more representative models with far more robust predictions, especially in situations of limited data availability or poor data resolution.

The case presented here involves reservoir X with hydrocarbon accumulation in two blocks (main and west) with production from both blocks. This sand has good well control with 27 wells, 21 of which are in the main block while 6 penetrated the western block. This reservoir was studied for reserves estimation and further development assessment. The main block is a saturated reservoir with a large condensate-gas cap and a very thin (20 feet) but well-defined oil rim, two wells (M1 & M2) have been completed in this block The western block on the other hand is an under-saturated oil reservoir and two wells (W1 & W2) have also been completed in this block. While all previous developments have been for oil, the current study was to assess the viability of developing the large gas cap of the main block. Pressure evidence indicated that the long period of sustained (large volume) oil production in the western block had caused pressure depletion in the main block, so this study modelled the two blocks together to see what the mutual effect of their productions would be on each other. In addition, there was a plan to put well W1 back into production while the study also tries to assess how much more oil that could be recovered from it, where or not the gas cap of the main block was developed, and to use the integrity of the long production history of the western block to characterize the main block.

II. MATERIALS AND METHODS

A. Materials

There is the availability of good seismic coverage of the area processed to post-stack depth migration (PSDM). Soft copies of the top and bottom depth horizon grids and their associated fault polygons calibrated to the 27 wells drilled in the field (Figs. 1,2 & 4) including their suite of wireline logs, well trajectories, and a full suite of production data from the four wells were used for the study. The suite of wireline logs comprised calliper, resistivity, density, gamma ray, neutron, spontaneous potential, sonic, and porosity-derived permeability logs. Gamma-ray, resistivity, spontaneous potential, density, and neutron logs were employed in the delineation of lithologies, correlation, and interpretation of depositional facies augmented by side wall samples.

B. Methods

The reservoir thickness varied from about 100ft in the east to about 80ft in the west. Genetic units were interpreted for the field based on the available datasets (SWS and wireline logs). Using the side-wall samples together with the relevant wireline logs, petrophysical property evaluation was completed. The availability of a relatively high density of wells to the study, and their spread enabled closely spaced well correlation in a bid to assess gross reservoir geometry and sand development trend in the field.

1). Structure: The top and base of the sequences of each well were selected to build the 3D structural framework. The interpreted top horizon showed good amplitude expression that conformed to the structure with the outlines of the amplitude consistent with the hydrocarbon contacts identified by the wells in the main block (Figs. 1 and 2).

a) Structural Depth Uncertainty Estimation

The structural depth uncertainty was estimated based on the quality of the seismic data, and the velocity model used for the depth conversion. The uncertainty estimation applied a depth calibration workflow to generate low and high-case structural realizations. In the workflow, the maximum uncertainty estimate used for the structure was (+/-) 25ft, consistent with the spread of residuals obtained from seismic horizon interpretation of the reservoir structure when tied to well tops with zero uncertainty at the well location (Fig 3). The workflow created an uncertainty grid with zero difference at the well locations, which gradually increased away from the well to a maximum of 25ft as a function of a pre-defined well influence radius. The low and high-case structures were then generated respectively by combining the base case grid with the uncertainty grid.

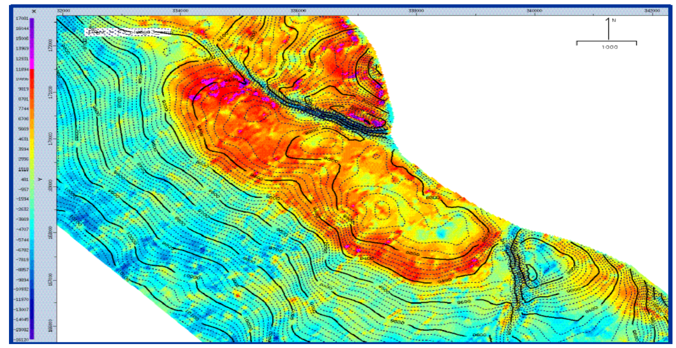


Figure 1: Top structure map, showing depth contours along with amplitude

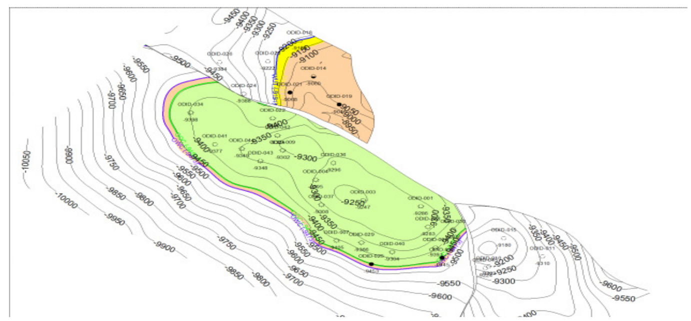


Figure 2: Base Case Depth Structure Map of the Reservoir, showing two blocks with hydrocarbon accumulation

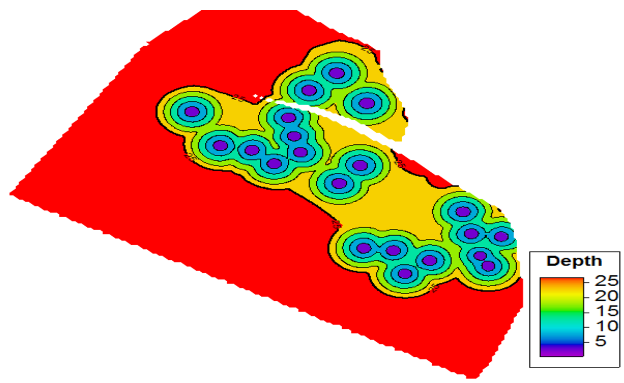


Figure 3. Structural Uncertainty difference map

b) Oil-Water Contact Uncertainty Estimation

Several wells have been drilled in the structure in the main and western blocks. An average Gas-Oil Contact is estimated in the main block at 9453ftss with an average Oil-Water Contact at 9473ftss (Fig. 4). None of the wells drilled to date in the western block has encountered a clear oil-water-contact (OWC). However, an oil-down-to (ODT) and a water-up-to (WUT) had been encountered in the block. The ODT and the WUT defined the block's fluid contact uncertainty band. The fluid contacts were set to define low, mid, and high in the field as follows:
Low-contact case = ODT.
Mid-contact case = Midway between ODT &WUT.
High-contact case = WUT.

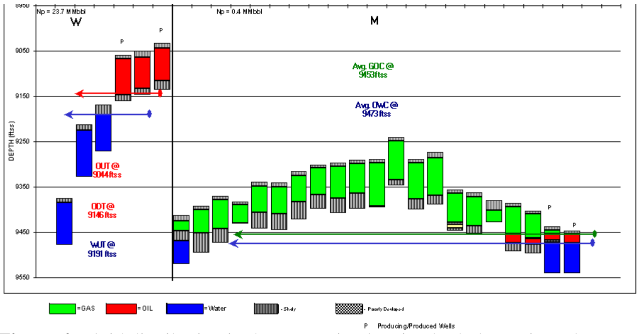


Figure 4: Fluid distribution in the reservoir, showing both the Main and Western blocks.

2) Reservoir Architecture and Rock Properties: A critical first step in the estimation of hydrocarbon reservoir thickness is the definition of the sand top. This is complicated in situations where the lithology change is transitional as inmost Niger Delta reservoirs where sand tops are transgressive, tight, radioactive, or any combination of these. This transitional boundary effect gives rise to some uncertainty in selecting the effective top of the reservoir from electrical logs alone. The reservoir under study has a wide range of derived porosity (0.05 to 0.24) and permeability (800 to > 4000 mD) with no core data. The static model employed a simple layer-cake methodology for the facies modelling in which sand-shale layers were defined based on varying Vsh values to obtain the low, base, and high cases respectively.

a) Shale Volume (Vsh)

Shale volume (Vsh) was determined linearly using normalized gamma-ray curves. Endpoint values were chosen to represent both 100% clean sand and 100% shale. A cut-off of 23 gAPI was used for sand while 116 gAPI was applied for Shale. Integrated comparison of Gamma Ray, Resistivity, Density and Compensated Neutron logs indicated the absence of radioactive sands in the study interval and gave confidence for the use of a Gamma-Ray log for Vsh estimation. The evaluation was validated using density and neutron logs. The integrated log result was used to define Low, Base and High-Case Vsh cut-off (Fig.5).

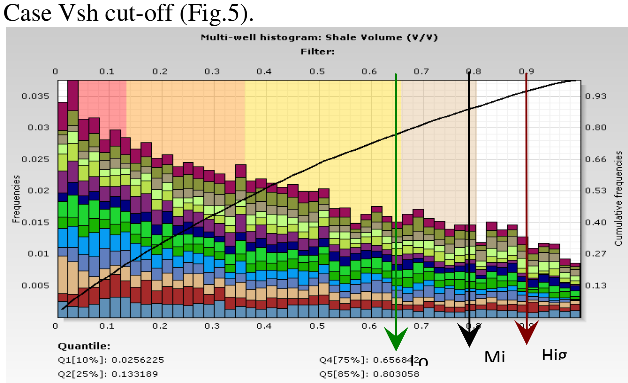


Figure 5: Low, Medium, and High Vsh cut-off used to define respective Net Sand realizations

b) Net Sand

Net-to-gross was determined from the final Vsh curves by applying appropriate cut-offs to define reservoir and non-reservoir sections. Based on Vsh sensitivity carried out, cut-offs of 0.65 for the low case, 0.79 for the medium case, and 0.90 for the high case were defined and used to derive the net sand intervals

3) Other Key Uncertainty Parameters: Estimatesfor the other key reservoir parameters with uncertainties such as Kv/Kh, relative permeability, and PVT were set using analogue field data. The ranges of the dynamic parameters were evaluated during the dynamic simulation. Table 1 presents a summary of the key uncertainties considered and their low, base, and high-case deterministic ranges as defined for experimental design simulation evaluation.

TABLE 1: SUMMARY OF UNCERTAINTY IN RESERVOIR PROPERTIES

Parameter	Low case	Mid case	High case
Structure	Low case interpretation (-25ft uncertainty)	Mid case interpretation	High case interpretation (+25ft uncertainty)
Facies	0.65 V-shale cut-off	0.8 V-shale cut-off	0.9 V-shale cut-off
Permeability	Low case por-perm transform	Mid case por-perm transform	High-casepor-perm transform
KvKh	0.001	0.01	0.1
Original OWC in Western block	Oil-Down-To (ODT)	Mid-way between ODT & WUT	Water-Up-To
Relative Permeability	Low case rel-perm correlation	Mid-caserel-perm correlation	High-case rel-perm correlation
PVT	Dindoruk-Christman PVT correlation	Peng-Robinson EOS	Niger Delta Correlations

III.RESULTS AND DISCUSSION

A. Results

1) Stratigraphic Modelling: Three lithofacies models were built using the v-shale cut-off to categorize the variously identified facies into reservoir and non-reservoir (Fig. 6).

Low lithofacies Model

- V- shale cut off: 0.65
- Reservoir: Upper Shoreface, Channels, and part of Lower Shoreface (ca. 50 %)
- Non-Reservoir: Shale, Channel Heterolithics, and part of Lower shoreface (ca. 50 %)

Mid lithofacies Model

- V- shale cut off: 0.79
- Reservoir: Upper Shoreface, Channels, and part of Lower Shoreface (ca. 80 %)
- Non-Reservoir: Shale, Channel Heterolithics, and part of Lower shoreface (ca. 20 %)

High lithofacies Model

- V- shale cut off: 0.9
- Reservoir: Upper Shoreface, Lower Shoreface Channels, and Channel Heterolithics
- Non-Reservoir: Shale

Using the three lithofacies models as described above, three tops were defined for the reservoir of interest buttressing the transitional nature of the interval. These tops were designated to correspond as follows:

High case = Stratigraphic top (ST)
Mid case = Reference top (RT) - historical top in database
Low case = Effective top (ET) - where reservoir quality sand begins based on integrated evidence from wireline logs.

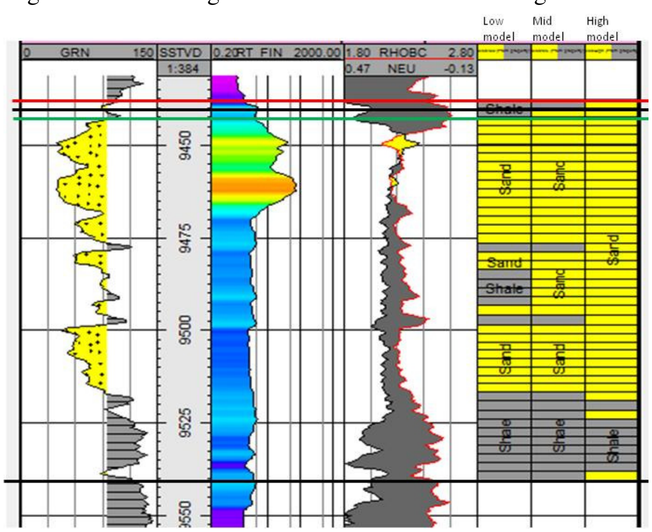


Figure 6: Well Panel, showing Low, Mid, and High facies model

***2). Reservoir Property Modelling*:** These lithofacies models which were already constrained by the palinspastically reconstructed structural models were then used to calibrate the porosity and permeability models giving rise to low, mid, and high property models (Figs. 7a, 7b and 7c) which were used for dynamic simulation.

Low Case Model

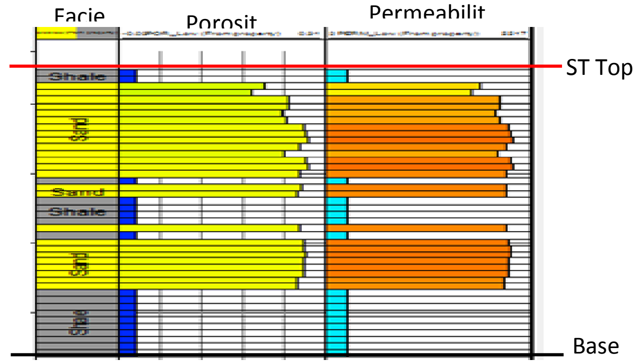


Figure 7a: Low, mid, and high properties at the well level

Mid Case Model

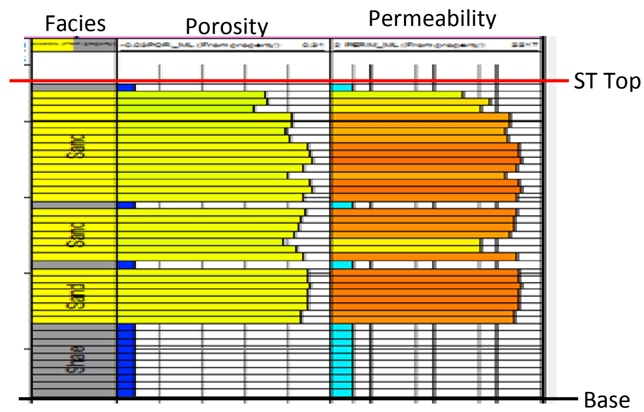


Figure 7b: Low, mid, and high properties at the well level

High Case Model

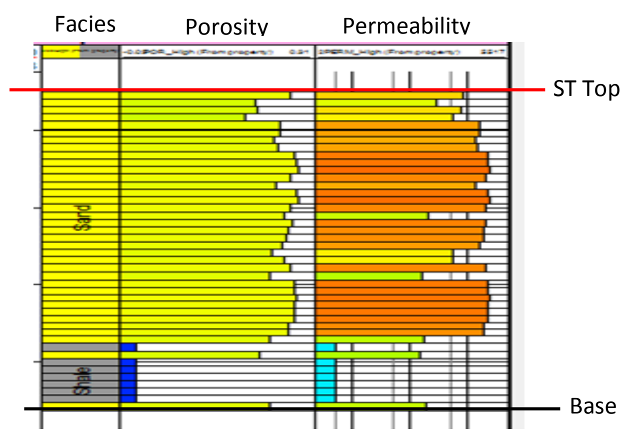
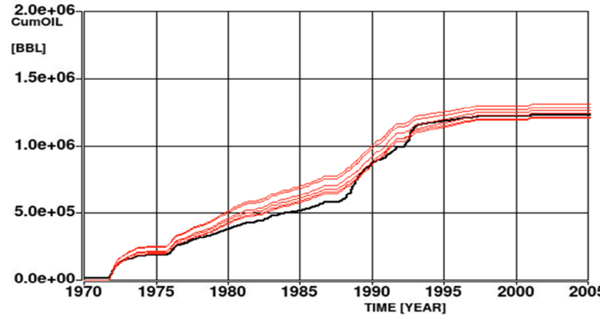


Figure 7c: Low, mid, and high properties at the well level

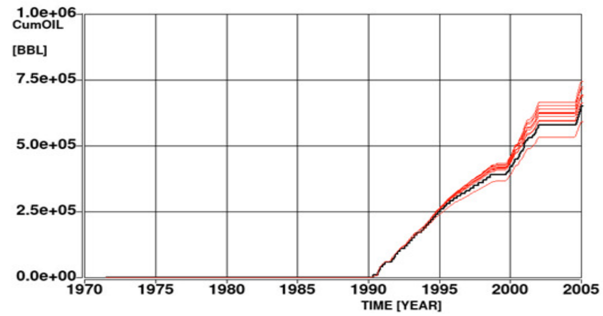
3). Constraining the Model with Production Data - Listening through ED History Match: With the defined ranges of uncertainty parameters, history matching was done with the liquid product from each of the four well completions as the match parameter. Experimental Design (ED) as applied in the history matching of historical production from hydrocarbon reservoirs is a technique that allows an unbiased assessment of all possible combinations of reservoir parameters which can result in the historical fact (production). The process is a five-step approach as outlined below.

1. Determine all uncertainties and define realistic ranges,
2. Build a few simulation models from a small combination of uncertainty parameters,
3. Statistically analyse the results of these simulation models to determine objective function outcome (e.g., cumulative oil production) for all other combinations of these uncertainties,
4. Rank the results based on a minimum error from actual data, and
5. Select a manageable number of these combinations and build simulation models for these.

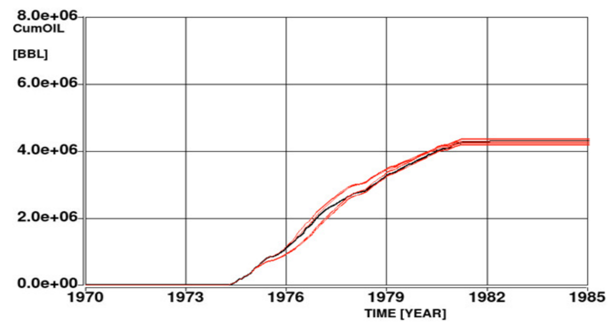
The experimental approach was applied in this case to determine which property variations affected recovery the most and determine as many combinations as possible could be used to achieve a history match within a defined error margin (5% of historical oil production). At the end of the history match, very good matches (+/- 2.5% error) were obtained on the reservoir level with the reservoir oil production. The quality of the cumulative gas production match was lower but there was a good spread around historical cumulative gas production. To manage the number of actual simulation models that will be built, nine statistical combinations were selected to reflect the P90, P50 & P10 cases (three models per case). The history matches of the four wells in these nine models are presented below.



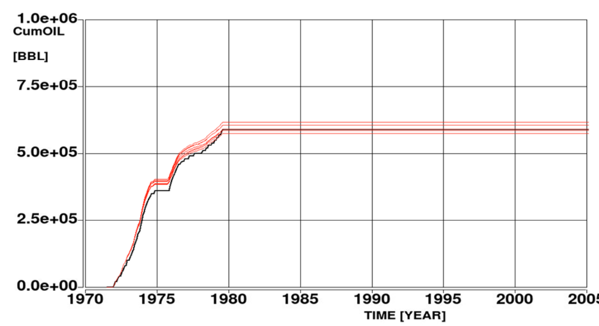
History Match of W1 Oil Production



History Match of W2 Oil Production



History Match of M1 Oil Production



History Match of M2 Oil Production

Figure 8: History match (nine cases) for four wells in the reservoir

B. Discussion

*1). **Inferences from Listening to the Production Data:*** With 7 uncertainties (Table 1), there were 2187 possible models (i.e., possible combinations of these uncertainties). From these, all the 'models' which passed the 2.5% error test (i.e., cumulative oil production from all reservoirs was within a 2.5% error) were extracted and from these, further filtering (again, a 2.5% error tolerance) was done to give a higher weighting to well M1 (the highest producer in the main block). After this filtering, only 186 models passed the history match quality test out of the total. An analysis of these models is presented below.

Table 2: SUMMARY OF HISTORY MATCH CASES OF UNCERTAINTY PARAMETERS USED TO ACHIEVE HISTORY MATCH

	Structure	Facies	Perm	KvKh	West Block OWC	RelPerm	PVT
	F_1	F_2	F_3	F_4	F_5	F_6	F_7
Low case	3	16	53	75	7	22	56
Mid case	94	64	59	57	60	75	67
High case	89	106	74	54	119	89	63
Low case	2%	9%	28%	40%	4%	12%	30%
Mid case	51%	34%	32%	31%	32%	40%	36%
High case	48%	57%	40%	29%	64%	48%	34%
	-0.88	-0.68	-0.32	-0.62	-0.86	-0.94	0.24

a) Structural Interpretation

Only 2% of the history-matched models support the low-case interpretation of the structure. This implies that the low-case structural interpretation was not supported by field performance. The mid and high-case structural interpretations showed significant agreement with dynamic performance with support percentages at 51 and 48% respectively. These were more reflective of the subsurface conditions than the low-case interpretation. Nevertheless, the low-case structural interpretation was adjudged as too pessimistic and unrealistic.

b) Reservoir Architecture (facies distribution)

The low-case facies interpretation could only reproduce history in 9% of the cases. This implied that with a low-case model, the V-shale cut-off of 0.65 was too severe as too much reservoir sand was discounted as non-reservoir.Figure 9 shows a slice from a key layer of the dynamic model highlighting the non-reservoir portions as red and reservoir sections as sky blue.

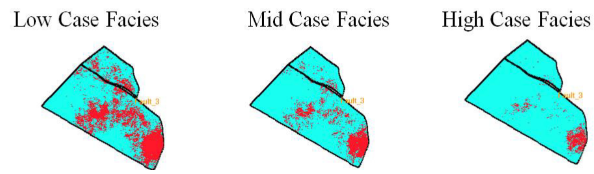


Figure 9: Difference between low, mid, and high case facies interpretation, showing the gradation in shale occurrence in the reservoir, (Note: Red Spots are non-sand, blue area is sand).

c) Original Oil-Water-Contact (OWC) in the Western Block

Only in 4% of the cases does the history match to support the low-case OWC interpretation (i.e., ODT as fluid contact). The history match supports the WUT as the fluid contact in the block in 64% of all the cases. This was the highest support obtained for any of the three cases as the mid-point between the ODT and WUT was supported only in 32% of the cases. This implied that the original fluid contact in the western block was more likely to be close to the WUT than to any other (ODT or mid-point between ODT and WUT). The deeper contact implied more initial oil in place in the western block which is consistent with field performance given the high production from that block to date.

*2). **Recalibrating the Static Model***

a) Structure

The history match result indicated that the low-case structure was unrealistic; therefore, it was re-evaluated with a structural uncertainty estimate of -15ft using all the available seismic and well data.

b) Reservoir Top and Facies Distribution

With only 9% history match models supporting the low case facies interpretation, it is evident that the reservoir top and sand distribution were not as poor as envisaged by the low facies model. Hence the reservoir top was most likely to correspond to "ST" followed by 'RT'. The ED result suggests that the zone between 'RT' and 'ET' was contributing to the production (Figures 6 & 7). Therefore, the model carried forward retained the top at 'ST'. The spectrum of the v-shale cut-off used in the ***lithofacies Modes*** was also reduced from 0.65 – 0.9 to 0.8 – 0.9 because of the above indications from the ED results. ED results suggested that heterolithic facies contributed to the flow in the reservoir. This indicated that the facies that contributed to the hydrocarbon production were Upper Shoreface, Lower Shoreface, Channels, and Channel Heterolithics; these were then classified as reservoir sand units.

All other uncertainty factor estimates (permeability, anisotropy, relative permeability, and fluid properties) passed the 10% (see, table 2) cut-off criterion for uncertainty estimate validity and were not modified in any way. The updated uncertainty parameters estimate resulting from the modifications as described above (Table 3) were then fed into the ED process, which now gave a result of 30%, 25%, and 20%

of history-matched models supporting the low-case structure, facies, and OWC realizations respectively.

Table 3: RE-CALIBRATED TABLE OF UNCERTAINTY RESPECTING PRODUCTION

	Low case	**Mid case**	**High case**
Structure	Low case interpretation (-15ft uncertainty)	Mid case interpretation	High case interpretation (+25ft uncertainty)
Facies	0.8V-shale cut-off	0.85V-shale cut-off	0.9 V-shale cut-off
Permeability	Low case por-perm transform	Mid case por-perm transform	High-casepor-perm transform
KvKh	0.001	0.01	0.1
Original OWC in Western block	Midway between ODT & WUT	Midway between ODT & WUT	Water-Up-To
Relative Permeability	Low case rel-perm correlation	Mid-caserel-perm correlation	High-case the rel-perm correlation
PVT	Dindoruk-Christman PVT correlation	Peng-Robinson EOS	Niger Delta Correlations

3). Application to Other Reservoirs

The study of this reservoir was part of a larger study involving 22 reservoirs in the same field. Previous developments in the field had been for oil, but the current study was for the assessments of free gas accumulations (and associated oil rim in cases where they existed). Given the initial field development strategy and production philosophy which focused oil, the gas reservoirs (NAG and AG with big gas cap reservoirs) mostly had no production and therefore no means to calibrate models built for these reservoirs by history matching.

The geological information including structural and stratigraphic insights (with respect to structure, lithology cut-offs, and selection of sand tops) gleaned from this analysis was used to apply auditable realism to the definition of the uncertainty range for the various parameters that went into the building of the static models of these other reservoirs. This approach resulted in improved robustness of the models based on in-field analogue calibration. It also facilitated significant savings in modelling time, acceleration of milestone decision gates with huge benefits to project schedule and cost savings.

IV. CONCLUSIONS AND RECOMMENDATIONS

The main genetic units identified in the field included upper shoreface, lower shoreface, channels, channel heterolithics, and shale. In the reservoir, the best quality sand unit was of about 24% porosity with over 4 Darcy permeability. The best sands in the field lie along the NE-SW trend near the central part of the field in what approximated a channel axis. The reservoir showed an overall shaling direction to the east, but all the units appeared to be in communication with one another.

The definition and management of uncertainties remain key objectives of 3D reservoir modelling. The identification of the key uncertainties and the estimation of the ranges should form the focus of any robust modelling effort. In reality, it is always a challenge to evaluate the statistical full range of possible uncertainty combinations for any reservoir. Ingenious means should therefore always be explored to focus only on those uncertainties, which control the performance of the field. The use of Experimental Design portends a fit-for-purpose tool for addressing this objective.

This study showed that by carefully “listening to the reservoir” through ED, modelling efforts can be properly guided and focused on key field performance-driving uncertainties. This resulted in the generation of models which were more representative of the reservoir and more effective as tools for development and field management. While Experimental Design is readily applicable in the dynamic reservoir simulation with a reverse engineering approach, it can as well be used in static modelling as demonstrated above.

For this study, experimental design has been used to test the boundaries of the key subsurface uncertainties (by application of stringent history criteria) and enabled the determination of the most likely range of each parameter assessed. For the other reservoirs in this field with no production history, the findings from the study provided an auditable means for calibrating the range of ‘static’ uncertainty used in modelling the reservoirs.

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