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Managing Uncertainties in Hydrocarbon-in-Place Volumes in a Northern Depobelt Field, Niger Delta, Nigeria

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Abstract: The construction of 3-D static reservoir models based on the understanding of facies and their relationships, through the integration of all available data have been used to enhance the understanding and qualification of the uncertainties. Standard evaluation of uncertainties in the spread of petrophysical parameters like porosity, hydrocarbon saturation and Net-to-Gross ratio was carried out and compared with the multiscenrio concepts incorporated in the geological models. Pressure, Volume and Temperature (PVT) parameters were derived for the reservoir based on analogy and correlations constrained with production and test data. An attempt has also been made in comparing results from the probabilistic volumetric evaluation of this reservoir and the deterministic (best estimate) method.

Key words: Seismic, sands, reservoir, hydrocarbon, porosity

INTRODUCTION

In field development planning, it is routine to identify and quantify the impact of major subsurface uncertainties such as, the oil in place volumes and their distribution (Egwebe, 2003; Ayoola, 2004). Often times at the discovery of a new field or extension of an existing field, there are uncertainties associated with quantifying the amount of hydrocarbon (HC) in-place (Ayoola, 2004). This study presents the methodology and results of an integrated disciplinary effort at translating uncertainties into a range of static (in-place) volumes for the purpose of field development.

This study intends to build two deterministic models on different possible interpretations of the same data set. The two models can be used to evaluate some of the uncertainties in the volumetric parameters.

Erratic sand development paucity of biostratigrahic control coupled with a complex structure make the G1 sand complex of the field of study one of the least understood hydrocarbon reservoirs of the Northern depobelt onshore of the Niger Delta, Nigeria.

The field of study is located some 100,000 m North-West of Port Harcourt in the Niger Delta land area of Southern Nigeria (Fig. 1). The field was discovered by

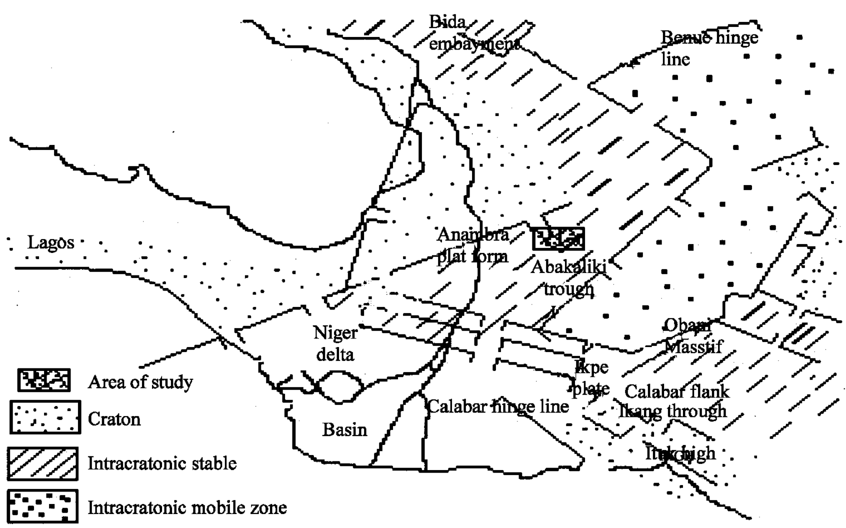

Fig. 1: Map of Niger delta land area of southern Nigeria

exploration well 1 in 1960 and covers an area of approximately 24,000 sq. m (5, 500×4,000 m), oriented East-West. It came on stream in 1970, but was latter abandoned.

The field is a sample fault-bound rollover structure with dip closure located to the south of the growth fault that defines the northern limit of the field. Hydrocarbon occurrences in the field of study are located within a coastal plain/fluvio-deltaic sequence. Hydrocarbons were encountered between 1,067 and 2,438 m in 8 intervals, including the G sands (Fig. 2). The individual reservoir units are difficult to correlate throughout the field. Gross thickness range from 46 to over 107 m. The field produces oil from six hydrocarbon reservoirs. Nine exploratory wells have been drilled to date, eight of which penetrated the G1.0 complex, hence this study. The G1.0, which was found to be one of the main oil-bearing sands in the field of study, is some 98 m thick. Four wells (wells 2, 3, 7 and 8) were completed on the G1.0 complex although nearly all production (about 98%) emanated from well 3 alone. The G1.0 has a strongly varying sand development. Vertical communication between the various layers is uncertain. This probably explains why the other 3 wells had productivity problems. It is possible that the sands in which these other wells were completed on two intervals in the reservoir. The higher interval was produced via the short string, the lower interval via the long string. The study by Ayoola (2004) concluded amongst other things that the G-reservoir complex is a deep-water re-sedimented sand body characterized by the chaotic sand development usually associated with slumped sediments. Estimates of hydrocarbon (HC) volumes were based on 2-D seismic interpretation. Initial-oil-in-place was estimated as 34.2 MMstb. The recently acquired 3-D seismic data in 1994/95 was processed in 2000. This data was interpreted and the result of that interpretation formed the basis for this new study whose results on the volumetrics aspects are being presented in this study. The study was initiated to address the negative volumes carried in the article of Ayoola (2004). Previous estimates (based on 2D seismic data) carried an oil recovery of about 21.7 MMstb. The results from the new 3D seismic interpretation confirms a larger volume of hydrocarbon in place due mainly to a larger structure (Table 2). There were a lot of uncertainties in the structure due mainly to the poor quality of the seismic data at the G1 level. Other uncertainties include the Petrophysical parameters (Porosity, Net-to-gross and HC saturation) and the fluid parameters (due to the non-availability of fluid sample analysis).

MATERIALS AND METHODS

Uncertainty handling methodology: For the purpose of defining arrange of static hydrocarbon volumes, two approaches were used.

Deterministic evaluation: The deterministic approach was based on the use of static and dynamic model

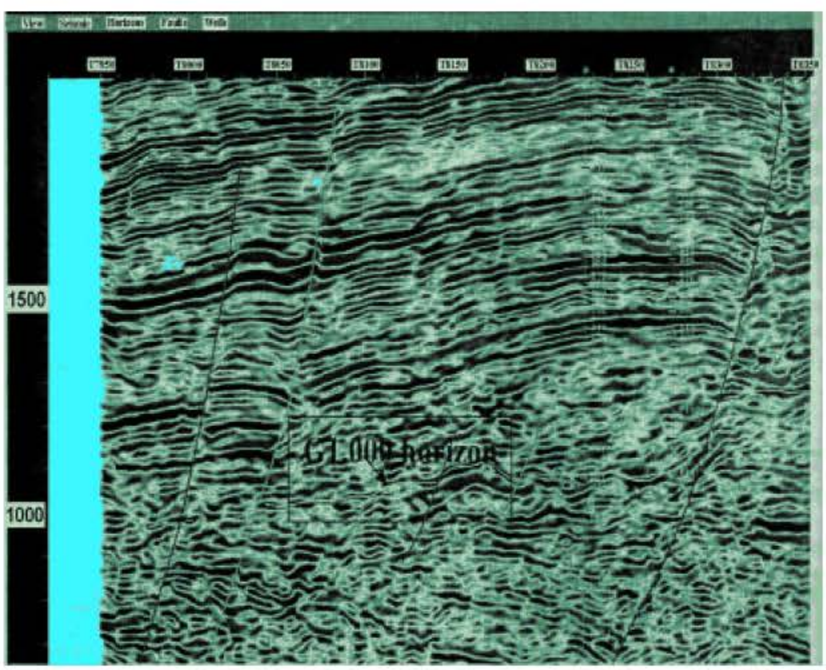

Fig. 2: Seismic cross-section showing poor data at the G 1.0 horizon

realizations to quantify the uncertainty. Each scenario was based on a possible interpretation of the available data.

Probabilistic evaluation: The common method for calculating statistical uncertainty in the Oil Initially In Place (OIIP) is to generate Probability Distribution Functions (PDFs) for each volumetric parameter (Gross Rock Volume, porosity, Net-To-Gross, hydrocarbon saturation and formation volume factor). These PDFs are then combined statistically with each OIIP PDF constructed to define the uncertainty in a particular parameter.

This study was conducted in the North-West of Port Harcourt in the Niger Delta land area of Southern Nigeria. Furthermore, due to the lack of well coverage to the west and south of the structure and the complex internal architecture, the model was subdivided into three main blocks mainly for the volumetric exercise. The three blocks were named firm, probable and remote blocks.

The firm block covers the area around the wells which have proven hydrocarbon existence and from which production has been obtained. The probable block is to the west of the structure where the probability of hydrocarbon (HC) occurrence is least likely.

The reservoir subdivision into the firm, probable and remote blocks is the foundation for the estimation of the deterministic volumes. Several combinations of the blocks were attempted namely;

- Firm block only
- Firm+probable
- Firm+probable+possible

Main uncertainties affecting OIIP: The main uncertainties affecting the evaluation of oil initially in place (OIIP) for the G1.0 reservoir as seen in this study are;

- Gross rock volume
- Porosity
- Hydrocarbon saturation-HC (capillary pressure curves)
- Net-to-gross ratio
- Formation volume factor

Uncertainties in each of these parameters are discussed in the following sections while the combination of all these uncertainties to yield a range of OIIP values for the reservoir will be discussed afterward.

Gross Rock Volume (GRV): An exhaustive discourse of the structural and sedimentological settings and evaluation is given by Efeotor (1999) and Arochukwu, 2005. The main uncertainties associated with the structure included horizon picking and correlation, fault plane definition and time to depth conversion (velocity variations).

Horizon picking: This data quality of Fig. 2 may have been impacted by the geology of the area, which indicated high level of slumping, soft sediment deformation and channeling activates. This has generally resulted in very poor, unstable, discontinuous and complex loops at the G-Sands level. This situation was further compounded by the paucity of checkshot data, which constrained well-to-seismic tie and consequently loop identification. These limitations resulted in enormous uncertainties in the accuracy of the horizon interpretation and thus form the largest source of uncertainty in this interpretation. A regular grid of every 8th inline/trace has been interpreted. This grid spacing was reduced to 4×4 in some areas, which required closer interpretation. To ensure consistency in the interpretation, several geological conclusion panels of the top G1.0 complex were generated to guide seismic correlation. Several seismic arbitrary lines were taken along the lines of the geological correlation panels to enable loop correlations and tie the G1.0 complex on seismic across the field.

Fault plane definition: The field is characterized by the presence of a major synthetic bounding fault to the north and a smaller synthetic fault to the south of the field. Generally, fault segment interpretation was done every 8th line. This was reduced to every 4th line area of complex fault geometry. The fault interpretation was quality-checked using SEMBLENCE time slices. While the fault planes of the major faults were fairly easy to draw, recognizing the minor faults was difficult especially around the G-levels (beyond 1.8 sec). Given the quality of the seismic data, the uncertainties in the current interpretation are related to the presence of the minor faults, the lateral continuity of the faults, their position and the number identified. Indeed, the faults could be more extensive than they have been mapped and in addition, several of these faults may not have been identified and interpreted. These minor faults generally have very low throws of less than 15 m, are non-sealing and rarely coalesce. The faults are thus not interpreted to compartmentalize the reservoir complex into fault blocks. These faults whilst not affecting overall hydrocarbon volumes may be important in fluid dynamics and field development, especially during drilling of horizontal wells.

Time to depth conversion (velocity variations): A major uncertainty is related to the velocities used for the depth conversion. Several depth conversion methods have been applied, each resulted in varying residuals between the calculated and actual well depths. The choice of the combined velocity model based on time depth (TZ) and Migration velocity as the most-likely model was based on the fact that it provided the platform for the integration of all available data. Given the paucity of TZ data and the limited sample points in the only available one, the TZ models were considered sub-optimal. The instability associated with the interpreted loop rendered the application of psuedovelocities calculated from the time grid a sub-optimal means of carrying out the depth conversion. A Quality Check (QC) of the migration velocity grid and contacts indicated that the extracted migration velocity grid is good and useable. The single TZ, Migration velocity and Migration velocity+TZ models were the three depth conversion scenario generated for each of the two interpretation cases highlighted earlier.

Fluid contacts: Only well 7 logged an Oil-Water-Contact (OWC) of 2,424 m at the flank. The uncertainty in the contact has been determined at +1.5 and 3 m to account for the possible variation across the shaly intervals and the effect of this on the OWC. The most crestal well (well-3) did not encounter any gas. This investigation concluded that it is unlikely for a primary gas cap to be present. Therefore, no Gas-Oil-Contact (GOC) was assumed present in the reservoir.

Combination of uncertainties to yield a GRV PDF: Two-time interpretation scenarios, three time to depth conversion scenarios and three OWCs were carried out in this study. The combination of these will yield eighteen different scenarios. Probabilities were assigned to each interpretation case (case 1-40%, case 2-60%) and to each depth conversion case. Each of the resulting combination was further combined with the three different oil water contacts on an equal weighing. The assigned probabilities were then combined in a scenario tree to get an expectation curve (PDF) for use in the probabilistic volumetric evaluation with the other parameter. Table 1 details the probabilistic combination while Fig. 3 show the expectation curve (PDF) for the GRV.

Porosity: Porosities are evaluated from porosity logs at the well positions across the vertical interval of the reservoir. Several techniques for determining the distribution of porosity in the interwell areas exist

Table 1: Probabilistic distribution of OIIP

OIIP (MMstb)			
Low (P85)	Med (P50)	High (P15)	Exp
156.2	197.5	205.0	180.3

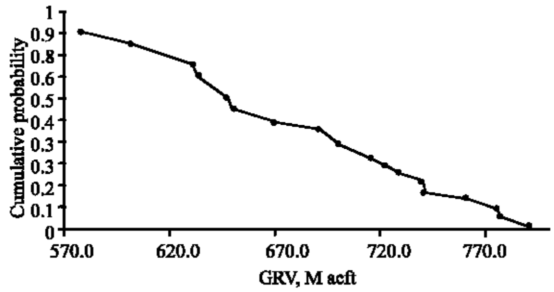

Fig. 3: GRV Expectation (PDF) Curv

including interpolation between well positions, krigging based on geological facies-based modeling and the use of seismic attributes of porosity to constrain the distribution in the interwell areas (Schlumberger, 1985; Aigbedion, 2003). Each of these methods has implications for static volumes calculation and flow behaviour.

Porosity measurements were carried out on the core plugs from well 8 G sand complex and were compared with the porosity results from other sources in the same reservoir for validation of the result from deterministic approach and parameters used in FLAME (a porosity evaluation tool) (Schlumberger, 1985). The maximum change in pore volume recorded for porosity values between (0.19-0.27) BV ranged from (2-6)% or (0.5-1) p.u. This evaluation was carried out for individual wells with adequate porosity logs. There was good correlation between the Flame derived porosity and core porosity measurements. (In the range of 1 p.u).

Wells are concentrated to the North Eastern part of the structure. Porosity modeling relied heavily on facies-based modeling and kriging of the porosity curves at the well locations to the interwell and extra well areas. Based on available data, two likely geological models were generated for G 1.0 complex. The first model is based on earlier studies (Ayoola, 2004), which relied heavily on the core interpretation well 8. This study interpreted the G1.000X as deep-water resedimented deposits characterized by the chaotic sand development usually found associated with slumped sediments. A cross-section of the facies model is given in Fig. 2. In the alternate model, the channels in the G-reservoir complex is interpreted as estuarine/incised valley system. This interpretation is supported by the series of incisions seen on the seismic data around the G1.0 level. The chanelised deposits are seen to juxtapose/interfinger with the re-worked mouth bar and coastal plain deposits. Channel and re-worked mouth bar deposits from the bulk of the G1.0 sand reservoirs. Each model generated its own porosity distribution and averages, which were used in the probabilistic estimates. Seismically constrained distributions were not reliable due to the poor quality of the seismic data.

Net to gross ratio: The methodology adopted for the porosity spread was also adopted for the N/G parameter. The density neutron log separation DNS adequately identifies the shale from sands over most of the intervals more especially in radioactive sand, where shale was separated based on the fact that neutron lies to the left of the density in shale. The DNS curve was also used as input for estimating the shale volume in the reservoir. Based on the sensitivity that was carried out on the cut-off for the Vsh, net/gross was computed and plotted against varying Vsh, net/gross was computed and plotted against varying Vsh cut-off values. The result shows a trend with an asymptote at Vsh cut-off 70%. The tight formation, which was identified from the density-neutron logs and the microsperical logs were also cutoff as non-reservoir. For wells that have no neutron, GR and density were used for a first pass net sands determination via the CLUSTER electrofacies grouping (Schlumberger, 1985). The result was further refined based on the Caliper and SP logs. The multiwell approach to CLUSTER on LOGIC (Schlumberger, 1985) was used to recognized common log properties across well, which improved the identification of shale from sand.

The Gross Hydrocarbon Rock Volumes (GHRVs) were calculated for the various fault sub blocks by summing the volume of all voxels within the hydrocarbon column. The reservoir facies are flood plain, estuarine-fill heterolothics, channel, mouth bar and crevasse splay were defined. The mud-dominated coastal plain shales and overbank deposits, which have very poor flow properties, were considered as non-reservoir. Volume weighted net-to-gross ratios were calculated as the quotient of GHRV and the Net Hydrocarbon Rock Volumes (NHRV). The volume-weighted average net-to-gross calculated for the G1.000X is 40% in one of the cases. This value highlights the overall poor quality of the G1.000 reservoir complex.

Hydrocarbon saturation (Capillary pressure curves): Saturations were modeled using capillary pressure curves generated from a log derived saturation height function calibrated against nearby field cores analysis (including capillary pressure measurements) was carried out on the acquired core. Height Above Free Water Level (HAFWL) was established from the log of well 7, which was the only well that saw an OWC. Because of the uncertainties associated the log-derived function, saturation exponent and the inadequate water column in well 7, several functions were derived within the band of the aforementioned uncertainties. These functions were applied to the geological models to extract average HC saturations for use in the probabilistic estimate.

Formation volume factor: No fluid samples were taken in the G1,000X complex for Pressure, Volume and Temperature (PVT) analysis. Two method were therefore used to estimate and generate PVT data for use in the study.

- Use of establishment Correlation
- Enriched reservoir fluid from EGBM E1,000X (directly above GI).

Established correlations: A number of correlations were considered namely the Nigerian, Standing, Lasater and vasques-Beggs correlations (Egwebe, 2003; Verbruggen *et al*., 2002). One of these correlations was eventually used after determining its suitability for the G1 reservoir (and advisably, the other reservoir in the field without PVT samples).

PVT samples and reports from reservoirs in the field and nearby fields were validated and characterized. Subsequently, correlations were tested against results of the characterized fluids and the Standing correlation was found to be the most consistent with experimental data.

Figure 4 shows that comparison of different correlations with the characterized fluids from field above sand G1,000X. From the comparison, the Standing's

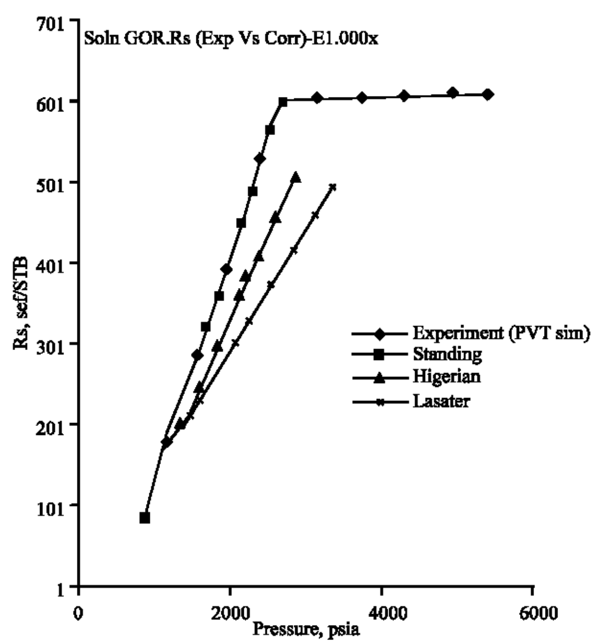

Fig. 4: Comparison of different PVT correlation

correlation was best suited to fluids neighbouring reservoirs and fields hence its choice for this study.
The basic variables required for the correlation included;

- Initial reservoir pressure from early pressure build-up and Bottom Hole Pressure (BHP) surveys
- Reservoir temperature from the formation temperature Vs depth trend established from maximum-recorded temperature from drilling and BHP surveys.
- Oil density/API data from early field production tests and data.
- Gas gravity from a general separator gas density Vs depth trend for Nigerian reservoirs.

Although, most of the correlation inputs were obtained from early production data (Ayoola, 2004), there still exists some uncertainty in their accuracies. There was more confidence in early solution Gas-Oil-Ratio (GOR) and American Petroleum Institute (API) measurements, as these were consistent over several measurements. The uncertainty in the bubble point pressure was estimated to be about 400 psi (3300-2900 psi). Production data suggests a value between 29000 and 3100 psi. Results from PVT correlations suggest a higher value of 3300 psi. This range has been accounted for in the uncertainty analysis pertaining to PVT data and the adequately capture in the calculations of the bubble point of the GI reservoir.

RESULTS

The shell group probabilistic volumetries software-PROTEUS (Aigbedion, 2003), was used in combining the PDFs to yield a distribution of Oil Initially in Place (OIIP). The range in OIIP enables a judgment to be made on the observed reservoir performance and the appropriateness of the use of the static and dynamic models to further investigate past and future field performance, respectively.

Table 1 and 2 show the OIIP probabilistic distribution and the deterministic evaluation results, respectively.

Material balance estimates agree with the firm block results. This shows that the present wells are only connected to volumes in the firm block area. Volumes outside this block may not exits or may be unconnected to the firm block area. As no strong evidence exists to support either of the two possibilities exclusively, they are both carried forward into the dynamic simulation phase of the study. These volumes in the probable and possible blocks can be treated as possible upsides subject to appraisal.

Table 2: Deterministic estimates of OIIP

Block	OIIP (MMstb)
Firm	55.3
Probable	89.0
Possible	24.8
Total	169.1

The P50 value of OIIP (from the probabilistic method) agree to within 6% of that obtained deterministically.

From the foregoing, a statistical approach to the determination of a range of statics hydrocarbon volumes based on the uncertainty range of each parameter is adequate for reporting static volumes. However, a more rigorous approached to determine low and high case for investment decisions is required. Multi-scenario static and dynamic modeling will be required to quantify the impact of these uncertainties not only on the static volumes, but also on the other parameters needed for a robust field development.

CONCLUSIONS

The main uncertainties for the G1.0 sand complex have been identified and evaluated via a thorough statistical uncertainty analysis. i.e. the uncertainty identification and quantification exercise will help to improve the reserve estimates and ultimately support field development. The key uncertainties impacting the statics OIIP include the Gross Rock Volume (GRV), Porosity and the Net to Gross ratio.

Two determines models based in different possible interpretations of the same data set have been built. These were used to evaluate some of the uncertainties in the volumetric parameters for use in probabilistic volumetrics. The statistical method used is a pragmatic approach to quantify the uncertainty ranges in reservoir parameters and their impact on the statics volumes as well as recovery.

The results from the new 3D seismic interpretation from this study confirms a larger volume of hydrocarbon in place due mainly to a larger structure (Table 2). There were a lot of uncertainties in the structure due mainly to the poor quality of the seismic data at the G1 level. Other uncertainties include the Petrophysical parameters (Porosity, Net-to-gross and HC saturation) and the fluid parameters (due to the non-availability of fluid sample analysis).

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