Reservoir Characterization and Volumetric Analysis of Roan Field, Niger Delta, Nigeria

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ABSTRACT

This study focuses on the effective integration of interpreted 3D seismic and well log data to build static geological models which were used to estimate the Stock Tank Oil initially In Place (STOIIP) volumes of two sandstones reservoirs in the Roan Field, Niger Delta, Nigeria. The data available for this study included two (2) 3D interpreted horizons for Reservoirs X and Y, interpreted fault data and well logs. The method adopted for the study involved the determination of log derived petrophysical parameters (Vshale, porosity and water saturation). This was later followed by fault modeling, pillar gridding and upscaling to quantify the spatial heterogeneity in the reservoirs prior to the distribution of petrophysical properties across the 3D grid. The reservoir structural model showed a common major growth fault defining the boundary of the structure. A rollover anticline formed as a result of deformation of sediments deposited on the downthrown block of the major growth fault in the field. Hence, the trapping mechanism is a fault assisted anticlinal closure. The STOIIP volumes of 2.6 MMSTB and 20.45 MMSTB were estimated for Reservoirs X and Y respectively, as against 2.4 MMSTB and 26.87 MMSTB that were initially estimated using 2D seismic data. These discrepancies can be attributed to overestimation and underestimation of the Gross Rock Volumes (GRVs) of the respective reservoirs from 2D seismic data. Smoothed and well-corrected top reservoir surface for Reservoir X increased GRV and therefore STOIIP while lower range in reservoir thickness for Reservoir Y reduced GRV and STOIIP estimate. Thus reliance on 2D seismic data for accurate estimation of STOIIP volumes comes with lots of uncertainties and consequently, considerable care needs to be taken.
INTRODUCTION

The quest for optimum method of hydrocarbon production has been an issue which many oil and gas companies are interested in (Kramers, 1994). Considering the conventional production technique, it has been observed that we can only produce one-third of the oil in place. For the unrecovered oil, estimation shows that it varies according to the depositional environment. This hitch needs to be proffered with a sustainable solution. One of the major ways of resolving this issue is through hydrocarbon reservoir properties modeling. This will buttress our idea on how petrophysical properties vary within reservoirs, their transition across stratigraphic intervals and the quality of the reservoirs. The heterogeneity in the properties of reservoir rocks is either dependent on primary depositional or secondary diagenetic processes.

Reservoir characterization involves a holistic description of a reservoir by integrating all the available data, tools, disciplines, and knowledge. The aim of reservoir characterization is to identify, understand the flow units of the reservoir and predict the inter-well distributions of reservoir properties (including porosity \( \Phi \), permeability \( k \), water saturation \( S_w \), and net-to-gross NTG). By applying reservoir characterization techniques in a field, asset holders will be able to maximally recover hydrocarbon while minimizing costs. Optimal placements of new wells and infill wells are also possible. The key to enhanced reserves determination and improved productivity is not based on the use of empirical correlations but it is based on the establishment of casual relationships among core-derived parameters and log-derived attributes. These theoretically correct relationships can then be used as input variables to calibrate logs for improved reservoir characterization.

The heterogeneities which occur at all scales from pore scale to major reservoir units result to a spatial variation in the reservoir properties. The reservoir heterogeneities should be addressed properly so as to generate an accurate reservoir connectivity while predicting field performance (Maucec et al., 2013), and to prevent under-designed production facilities that will not enhance recovery of hydrocarbon.

The Roan field is a multi-pool oil, gas and gas condensate field located onshore Niger Delta West Belt – Minna (Fig. 1). 2D seismic data acquired for the Roan field in 1986 showed that the reservoirs within the field occur as rollover anticlinal structures, bounded to the north by a major regional boundary fault and dip closure to the east, west and south.

Two wells (Wells 1 and 2) have been drilled into the field. Well 1 was drilled to a total depth of 3680 m in 1978, encountering oil bearing levels that include Reservoir Y. Well-1 commenced production from Reservoir Y, and it was later shut-in in 1993 due to low well head pressure. Well 2 was drilled to a total depth of 3400 and encountered Reservoirs X and Y. The well was drilled to develop Reservoir Y. The well commenced production from this level in 1982 and was shut-in in 1994 due to low well head pressure. The reservoirs are the oil sands in this field with expected STOIIP of 44.9 MMSTB and 72.3 MMSTB respectively based on 2D seismic interpretation1. No integrated 3D static reservoir models had been built to characterize Reservoirs X and Y prior to the recently acquired 3D seismic data.

![Figure 1: Map of the Niger Delta Basin showing the study area (black box) located in the Central Swamp Depobelt. Notice the location of the cross section A-B.](image-url)
In other to enhance oil recovery, a high precision 3D seismic data was acquired with wide Azimuth and 12.5 m by 12.5 m bin size in 2010.

The aim of this paper is to compare STOIIP volumes previously estimated from maps generated from 2D seismic lines and volumes estimated from static reservoir models of Reservoir X and Reservoir Y. The objectives are to: 1) describe and characterize Reservoirs X and Y. 2) build a high resolution static model of the reservoirs. 3) re-evaluate volumetric analysis of the reservoirs and 4) highlight the significance of reservoir characterization by comparing the 3D volumes with the existing 2D volumes.

GEOLOGY OF THE STUDY AREA

The Roan Field is located onshore of the Niger Delta (Fig. 1). The tectonic evolution of the Benue Trough in the Early Cretaceous as a failed arm of a triple rift junction associated with the opening of the South Atlantic. Three major tectonic phases or epirogenic movements were suggested to have influenced the geologic history of the Benue Trough system, which has been subdivided into three paleogeographic areas or sub-basins; the Abakaliki–Benue Trough, the Anambra Basin and the Niger Delta Basin (Murat, 1972). The initial rifting resulted in rapid subsidence and deposition of the Asu River Group during the Albian times. During the Cenomanian, a mild deformational event led to the compressive folding of the Asu River Group and restriction of the Odukpani Formation to the Calabar flank. Continued mantle upwelling and rifting during the Early Turonian resulted to the deposition of the Ezeaku Formation. When mantle upwelling finally ceased and migrated westward by the Santonian, the trough collapsed.

The second tectonic phase started during the Santonian, as a gentle widespread compressive folding, uplifting the Abakiliki-Benue Trough. The Anambra Basin and the Afikpo Syncline subsequently subsided and were filled by two deltaic sedimentary cycles through to Palaeocene. The last tectonic phase resulted from the uplift of the Benin and Calabar flanks during the Eocene – Early Eocene (Murat, 1972). These movements initiated the subsidence and progressive outbuilding of the Eocene – Holocene sediments of the Niger Delta along the Northeast-Southwest fault trend of the Benue Trough. The structural evolution of the Niger Delta has been controlled by basement tectonics as related to crustal divergence and translation during the Late Jurassic to Cretaceous continental rifting. It has also been influenced by isostatic response of the crust to sediment loading. The Niger Delta has been rapidly subsiding because of sediment accumulation, flexural loading, and thermal contraction of the lithosphere (Onuoha, 1982). In the continental margin, from the outer shelf (shallow-water) to the deep slope (deep-water) of the Niger Delta, three distinct structural domains have been observed from previous studies (Fig. 2). These structural zones are: 1) an upper extensional domain dominated by growth faults beneath the continental shelf and upper slope. 2) a translational domain or an intermediate zone characterized by mud diapirism and 3) lower compressional domain characterized by imbricate toe of slope thrusts. This structural configuration is caused by gravitationally driven delta tectonics (Cohen and McClay, 1996).

The Tertiary Niger Delta covers an area of approximately 75,000 km² and consists of a regressive clastic succession, which attains a maximum thickness of 12,000 m. The siliciclastic system of the Niger Delta began to prograde across pre-existing continental slope into the deep-sea during the Late Eocene and is still active today (Orife and Aybobo, 1982). The lithostratigraphy of the Tertiary Niger Delta is divided into three major units: Akata, Agbada and Benin formations, with depositional environments ranging from marine, transitional and continental settings respectively (Figs. 2 and 3). The Akata, Agbada and Benin formations overlie stretched continental and oceanic crusts (Heinio and Davies, 2006). Their ages range from Eocene to Recent, but they transgress time boundaries.

![Figure 2: Schematic section across the Niger Delta showing the three distinct structural zones and lithostratigraphy (Corredor et al., 2005).](image)

Throughout the geological history of the delta, its structure and stratigraphy have been controlled by the interplay between rates of sediment supply and subsidence (Caillet and Batiot, 2003).
DATA AND METHODOLOGY

The dataset available for this study includes 3D interpreted top depth structural maps for Reservoirs X and Y, interpreted fault sticks cutting across these reservoirs and well data from Wells 1 and 2. The well data included: digital wireline logs, formation tops and deviation survey data for both wells.

The study involved a detailed description of two onshore Niger Delta reservoirs by integrating all the available data in the field. Generation of reservoir models and petrophysical evaluation were done interactively. The log types used for quantitative analysis in this study are the gamma ray, resistivity, density and neutron logs. The SP and caliper logs were mainly used for lithology identification and hole washout detection respectively. The two (2) reservoir sands were evaluated by generating various indicator maps such as structural, thickness, fluid distribution, facies, oil saturation and average reservoir property maps. Information derived was pertinent in characterizing the reservoirs and determining in-place volumes.

Shale Volume (Vsh) Determination

Shale volumes were evaluated using both GR and Neutron/ Density curves. Since both results were similar, all the other shale volumes were calculated using GR curves by applying “Larionov Tertiary Rock” method – equation (2). GR curves were used in the evaluation because the two available wells had GR curves.

Larionov method was chosen because it gives good results for Tertiary Niger Delta rocks, hence, it is widely used in the industry. The applied equations are shown below:

\[ GR_{\text{index}} = \frac{GR - GR_{\text{matrix}}}{GR_{\text{shale}} - GR_{\text{matrix}}} \]  \hspace{1cm} (1)

Larionov Tertiary rocks method:

\[ VSH = 0.083 \times \left(2^{(3.7 \times GR_{\text{index}})} - 1\right) \]  \hspace{1cm} (2)

Where,

\( GR \) = GR log reading in the zone of interest;
GR_matrix = GR log reading in 100% matrix rock;

GR_shale is the GR log reading in 100% shale

GR_index is the Gamma Ray index and

VSH is the Volume of Shale

Porosity Determination

Total porosity was estimated majorly from density logs using a rho-matrix value of 2.65 gm/cc and rho-fluid value of 0.808 gm/cc from PVT data. The effective porosity was then deduced by introducing shale volume into the equation.

\[ \phi_T = \frac{\rho_m - \rho_B}{\rho_m - \rho_f} \]  

(3)

\[ \phi_{sh} = \frac{\rho_m - \rho_{sh}}{\rho_m - \rho_f} \]  

(4)

\[ \phi_E = \phi_T - (\phi_{sh} * VSH) \]  

(5)

Where,

*Pma* = Matrix Bulk density,  

*Psh* is the Shale Bulk density,  

*Pf* = fluid density (density log reading in 100% water),  

*PB* = Bulk density (density log reading in the zone of interest),  

*VSH* = Volume of shale,  

*\( \phi_T \)* = Total porosity in the zone of interest,  

*\( \phi_{sh} \)* = Total porosity in shale,  

*\( \phi_E \)* = Effective porosity in the zone of interest.

Water Saturation Determination

Water saturation was estimated from Archie’s and Modified Simandoux equations - equation (6), and equation (7) respectively. In order to estimate water saturation using any of the methods, formation water resistivity (R_w) needs to be estimated. R_w is usually estimated in a clean water-bearing interval (water leg) using deep resistivity reading, Sw=1 and the computed porosity (*\( \phi \)*). However, deep resistivity (R_t) and *\( \phi \)* (porosity) may vary widely within the water-bearing zone making it difficult to get single values of R_t and *\( \phi \). For this reason, a double logarithmic plot of R_t against *\( \phi \) is generally used to estimate R_w. R_w is the intersection on the R_t axis of a best fit line produced from the plot. The plot is commonly referred to as “Picket plot”. In this study, a Picket plot was used in estimating R_w from water-bearing interval. Therefore, Sw (Archie’s equation) was then estimated using the computed R_w and *\( \phi \); local correction factor or tortuosity factor (a) of 1 was assumed; saturation exponent (n) of 2 was also assumed; and cementation exponent (m) of 1.80-1.82. These values commonly apply to reservoirs in this field. R_w ranges from 0.57 to 1.5 ohmm across the reservoirs. Effective porosity saturation was estimated using Simandoux equation by taking cognizance of volume of shale (Vsh). The equations used are highlighted below:

\[ SW = \left( \frac{a * R_w}{R_{tsh}} \right)^\frac{1}{n} = \frac{\phi_E^m}{a * R_w * (1 - V_{sh})} * S_w^2 + \frac{V_{sh}}{R_{sh}} * S_w - \frac{1}{R_t} = 0 \]  

(6)

\[ BVWE = SW_e * \phi_e \]  

(7)

(Modified Simandoux equations)
Where,

\( Sw \) = water saturation, \( Sh \) = hydrocarbon saturation, \( a \) = tortuosity factor, \( Sh = 1 - Sw \)

\( Rw \) = formation water resistivity, \( Rt \) = formation resistivity,

\( R_{sh} \) = resistivity log reading in 100% shale, \( V_{sh} \) = calculated Volume of shale in the zone of interest, \( n \) = saturation exponent, \( m \) = cementation exponent,

\( \theta_e \) = calculated effective porosity, \( \theta_t \) = calculated porosity,

\( BVWE \) = effective bulk volume of water

### 3D Static Reservoir Modelling

Geological modelling or Static modelling generally involves populating the reservoir architecture (structure and stratigraphy) with rock properties. A cell size of 100 by 100m was selected in building the 3D Grid, being small enough to capture all the reservoir details. Total number of 3D grid cells was approximately 1246914 and 153765 for Reservoirs X and Y respectively.

### Structural Modelling

This involves fault modelling, pillar gridding and horizon making. Fault modelling involves definition of the various faults in the model which formed the basis for generating the 3D Grid. Faults and the horizons were modeled to form the basis of the 3D structural framework in Petrel. The faults were built using key pillars and joints of these key pillars formed the fault plane. These faults defined breaks in the 3D grid. Having modeled the faults, the 3D grid was generated. Horizon making involved building of vertical layering in the grid. Layering was then followed to subdivide the reservoir into smaller stratigraphic units with reservoir thickness of 2 ft (0.61 m). After layering, Oil-Water Contact (OWC) was then specified in the model using the make contact process to give an overview of the fluid distribution in the reservoirs.

### Stratigraphic Modelling

This was done using log correlation to delineate the reservoir architecture and continuity. A field and reservoir wide correlation was carried out as a means of validating the reservoir tops and bases to ensure consistency of the reservoir picks.

### Property Modelling

This involved filling the cells of the 3D grid with discrete (facies) and continuous (petrophysical) properties including facies, porosity, water saturation, volume of shale, Net-to-gross and permeability. The interpreted logs were scaled up. Scale up of well logs involves sampling property values from well logs into the 3D grid in such a way that each grid cell will have a single value for each property. Having assigned property values (both facies and petrophysical) to each grid cell at well locations, the distribution of properties in the inter-well grid cells was done in order to realistically preserve the heterogeneity of the reservoirs. This was achieved in Petrel by first performing data analysis and then modeling the properties. Data analysis was done in order to identify trends in the data; remove the identified trends; apply transformations on the residual property data, and eventually define variogram model that describe the data and serve as input into property modeling process. Variogram models parameters that were used in constraining properties in 3D grid using various algorithms during modeling of properties. The two major geostatistical methods (deterministic and stochastic) were applied in modeling the properties. Both Kriging algorithm (deterministic) and Sequential Gaussian Simulation algorithm or Sequential Indicator Simulation (stochastic) were applied to distribute the properties across the entire grid.

### RESULTS AND DISCUSSION

### Structural framework

This field is bounded to the north by an east-west trending synthetic growth fault. Reservoir X is a rollover anticlinal structure with and E – W trending major boundary fault. Reservoir X has a fault model which comprises of 3 faults. The two other fault branches into the major boundary fault (Fig. 4). The eastern culmination shows a non-sealing fault assisted 3-way closure.
Reservoir X modeled horizon showing faults, layers and top horizon of the reservoir. Horizon was modeled using inputs from top and base interpreted horizons and their corresponding well tops it is a simply rollover structure with the trends of the major boundary faults, which has an estimated coverage area of about 31 km² and shows two culminations (East and West) separated by a saddle. The oil-water contacts is at 2295 m TVDSS for Reservoirs X.

Reservoir Y has a single fault model of the E – W trending major fault and has a structure which is somewhat similar to Reservoir X; characterized by a rollover anticlinal structure with two culminations separated by a saddle (Fig. 5). The major (regional) growth fault is an elongate east-west trending fault that assisted the reservoir dip closure in trapping the reservoir oil. Well 1 was drilled close to the crest of the anticlinal structure, while Well 2 was drilled on the flank.

Stratigraphic framework

The paleo-reconstruction indicates that the depositional setting for the reservoirs was predominantly deltaic (Fig. 6). The reservoirs comprise of heterolithic and channelized sandstone deposits. The wells are 1325 m apart and there is an increase in shale from Well 1 towards Well 2 situated south-westwards of Well 1. Reservoir X shows good continuity across both wells.
(Fig. 6). It has an estimated average gross thickness of 50 m. Reservoir Y shows uniform reservoir thickness and good continuity across the wells, however, with a lower estimated gross reservoir thickness of 10 m. These thickness range is justified by the wells but may not capture the full range of reservoir thicknesses in the area.

![Figure 6: Lithostratigraphic correlation of Reservoirs X (a) and Y (b) from well 1 and 2. Notice the good uniform heterolithic reservoir continuity at both well locations.](image)

**Petrophysical model**

Reservoir X shows E - W shale trend with pockets of shaly sands at the western flank (Fig. 7). The facies distribution within this reservoir is marked by a good sand continuity which gets shalier towards the western portion of the field (Fig. 7). This was also observed from the well correlation panel in Figure 4a. The proportionality of facies distribution across the entire 3D has 78.88 % of sand, 17.72 % of shaly sand and 3.41 % of shale (Fig. 7).
Figure 7: Facies model distribution of upscaled facies classes for Reservoir X conditioned to variogram model and distributed using Sequential Gaussian Simulation algorithm. The reservoir shows an E-W shale trend with pockets of shaly sands at the western flank.

The volume of shale across the 3D grid mimics the facies distribution, showing low volume of shale around Well 1 with an increasing shale volume towards the western region of the field (Fig 8). Net-to-Gross model shows a very good NTG distribution around the oil prospect at Well 1. The average Vshale and NTG values are estimated to be 30 % and 70 % respectively (Fig. 8).

Figure 8: Net-to-Gross property model for Reservoir X showing distribution of upscaled NTG properties. The model shows the distribution of high, low and intermediate NTG properties across the reservoir

The porosity distribution was fairly good across the 3D grid, with noticeable good porosity distribution around Well 1 (Fig. 9). The porosity ranges are 14 % - 48 % and 2 % - 34 % for total and effective porosities respectively. The average porosity and effective porosity values are 25 % and 19 % respectively. The hydrocarbon saturation has an estimated average value of 61%.
Figure 9: Effective porosity model for Reservoir X showing porosity distribution of interconnected pore spaces of upscaled effective porosity properties, condition to facies and distributed using the Sequential Gaussian Simulation

Reservoir Y is characterized by just two facies classes (sand, and shaly sand), with an observed trend of shaly sand running NE-SW across the structure (Fig. 10). The proportionality facies distribution across the entire 3D has 77.92 % of sand and 22.08 % of shaly sand (Fig. 10).

Figure 10: Facies model distribution of upscaled facies classes for Reservoir Y conditioned to variogram model and distributed using Sequential Gaussian Simulation algorithm. The two facies classes show a NE-SW shaly sand trend. Porosity distribution was constrained to each facies class

The volume of shale across the grid mirrors the facies distribution (Fig. 11), showing low volume of shale around Well 1 with an increased shale volume around Well 2. Net-to-Gross has a good distribution around the oil prospect at Well 1. The average NTG value was estimated to be 73 %.
The porosity distribution in this reservoir is considerably low when compared to that of Reservoir X (Fig. 12). The porosity ranges are 17% - 32% and 4% - 28% for total and effective porosities respectively. The average porosity values for total porosity effective porosity are 27% and 18% respectively.

The water saturation within the reservoir has an estimated average value of 22% and the hydrocarbon saturation has an estimated average value of 78%.

Figure 11: Net-To-Gross property model for Reservoir Y showing distribution of upscaled NTG properties. The model shows the distribution of high, low and intermediate NTG properties.

Figure 12: Effective porosity model for Reservoir Y showing porosity distribution of interconnected pore spaces of upscaled effective porosity properties and distributed using the Sequential Gaussian Simulation.

Volumetrics

The reservoir properties used to compute STOIPP volumes for both reservoirs included porosity, water saturation and NTG which were taken from the models generated. GRV inputs were derived from the existing horizon interpretations, which has been smoothed slightly and for which the match to well tops was improved. Area depth data was calculated using Petrel software, polygons were used to define the area and to artificially close the structures around the spill point. This method is considered to be more accurate because Petrel calculates the areas accurately within the software. In the absence of pressure plots, fluid type logs revealed that the reservoirs are saturated with oil. The oil-water contacts observed in the wells occur at 2295 m and 2505 m TVDSS for Reservoirs X and Y respectively (Figs. 4, 5 and 6).

Volumes computed for each reservoirs is shown in Tables 1 and 2. The following volumes were computed and presented: net volume, pore volume, hydrocarbon pore volume and original oil in place (OOIP).
Table 1: Computed P50 volumes for Reservoir X

<table>
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<th></th>
<th>Value</th>
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<tr>
<td>Net Volume (m³)</td>
<td>3,635,919</td>
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<tr>
<td>Pore Volume (MSTB)</td>
<td>4,941</td>
</tr>
<tr>
<td>HCPV Oil (MSTB)</td>
<td>2,839</td>
</tr>
<tr>
<td>HCPV Gas (MSTB)</td>
<td>0</td>
</tr>
<tr>
<td>STOIIP (MMSTB)</td>
<td>2.6</td>
</tr>
</tbody>
</table>

Table 2: Computed P50 volumes for Reservoir Y

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Net Volume (m³)</td>
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</tr>
<tr>
<td>Pore Volume (MSTB)</td>
<td>23,265</td>
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<tr>
<td>HCPV Oil (MSTB)</td>
<td>7,642</td>
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<tr>
<td>HCPV Gas (MSTB)</td>
<td>10,032</td>
</tr>
<tr>
<td>STOIIP (MMSTB)</td>
<td>20.45</td>
</tr>
</tbody>
</table>

DISCUSSION

Following the reservoir characterization of Reservoirs X and Y using static geological models built from 3D seismic data, there was a significant discrepancy observed between reported STOIIP volumes for these reservoirs of interest estimated from maps generated from 2D seismic data, and the static models generated from 3D seismic data (this study). An estimated STOIIP of 2.6 MMSTB and 20.45 MMSTB were estimated for Reservoirs X and Y respectively, as against 2.4 MMSTB and 26.87 MMSTB that were estimated using 2D seismic data. The 0.2 MMSTB underestimated volume in Reservoir X, can primarily be attributed to the interpreted top reservoir surface which has been smoothed and had an improved tie to the well tops, this results in slight increase in GRV. For Reservoir Y, the 6.42 MMSTB underestimation STOIIP volume in this study could be attributed to thickness range used, which will impact the GRV calculated. The mid case thickness for Reservoir Y in this study could have been lower than the one used for the previous volumetric assessment based on 2D seismic data. Thus reliance on 2D seismic data for accurate estimation of STOIIP volumes comes with lots of uncertainties and consequently, considerable care needs to be taken when calculating volumes using 2D seismic data.

CONCLUSION

High resolution 3D static geological models provide a better estimation of the gross rock volumes as well as a better description of the distribution of the petrophysical properties of reservoirs. The differences in the STOIIP volumetric calculations in this study can be summarised as: smoothed and well-corrected top reservoir surface for Reservoir X increased GRV and therefore STOIIP while lower range in reservoir thickness for Reservoir Y reduced mid case GRV and STOIIP estimate. Thus these models should be used to estimate volumes of hydrocarbons initially in place when 3D seismic data is available as they provide more accurate estimates than those gotten from maps generated using 2D seismic data.

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