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THE USE OF LORENZ COEFFICIENT IN THE RESERVOIR HETEROGENEITY STUDY OF A FIELD IN THE COASTAL SWAMP, NIGER DELTA, NIGERIA

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Abstract

This study presents a quantitative method for the characterization of static measure of the heterogeneity of reservoirs of a field in the Coastal Swamp Depobelt, Niger Delta, using Lorenz coefficient (LC). The understanding of reservoir heterogeneity and fluid flow channels enables proper prediction of hydrocarbon recovery from the field. Lorenz curve was obtained using the petrophysical model to generate the permeability-porosity and normalization of the flow capacity (kh) and storage capacity (φh). Then, the Lorenz coefficient was calculated as the area between the curve and the diagonal, and it was used quantitatively to identify levels of heterogeneity in the reservoirs. The results show good porosity of 0.21-0.32v/v and permeability of 4,381.66-94,084.98mD. There is significant spatial heterogeneity in the reservoirs with a Lorenz coefficient (LC) of between 0.6464 and 0.9400 for Res 1-A, 2-A, 3-A and 3- of all the 3 wells and fairly heterogeneous reservoir areas with Lorenz coefficient of between 0.3770 and 0.2430 in Res 1-B, C, D for well-1, Res 2-B, C, D, for well-2 and Res 3-B, C for well-3. The Lorenz coefficients show that most of the reservoirs are fairly heterogeneous, hence, enhances the overall hydrocarbon recovery potential of the reservoirs. The findings from this study have important implications for the variability of fluid flow and possible management decision on the hydrocarbon recovery of the field.

Keywords: *Reservoir heterogeneity; flow and storage capacity; Lorenz coefficient.*

1. Introduction

Reservoir heterogeneity has long been recognized as an important factor governing reservoir performance [1]. In many cases, the predicted performance of a reservoir is so completely dominated by irregularities in the physical properties of the formation that the assumption of a particular form for the variation can reduce the solution of the problem to mere exercise [2]. The property normally considered when referring to heterogeneity is that which controls flow (i.e., porosity, permeability). Several kinds of literature existed both theoretical and field studies on the impact of this heterogeneity on reservoir quality [3-7]. Most of the described techniques are required to assess and mitigate its effect on reservoirs. The theoretical studies, however, enable awareness of the adverse effect of heterogeneity and also provide some techniques for applying the result obtained to situations of immediate interest notwithstanding the fact that each reservoir is uniquely heterogeneous. The uniqueness of each reservoir, however, does not necessarily prevent the heterogeneity studies either but the essence of such (e.g., this study) will be to identify the features which impact the performance and quantitatively define their levels. This study, however, focuses on the static measure of heterogeneity for the reservoirs of a field in the Coastal Swamp, Niger Delta (Fig. 1), using the Lorenz coefficient. Obtaining the Lorenz coefficient involves the use of a mathematical model of reservoir properties (porosity-permeability), determined from well logs to evaluate the degree of heterogeneity in a pay-zone section and to identify its possible effect on hydrocarbon recovery. The research will serve as a guide in reservoir management decision when the degree of heterogeneity is known for a particular reservoir in the field.

2. Geological setting and stratigraphy

The Niger Delta clastic wedge spans a 75,000 km^2 in southern Nigeria and is located at the apex of Gulf of Guinea, offshore Nigeria (Fig. 1).

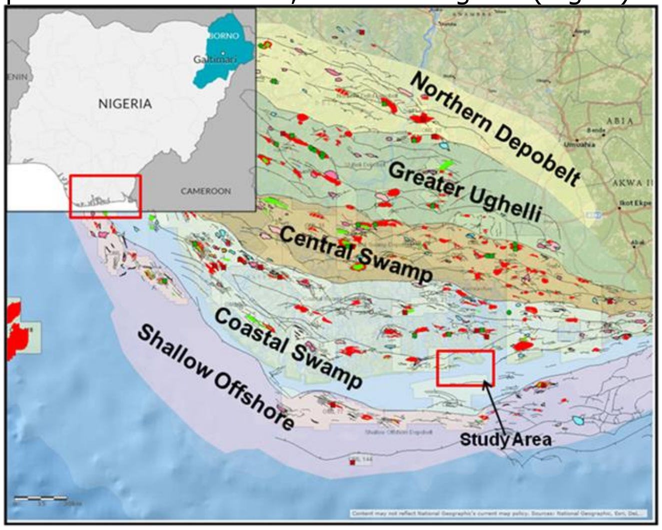

Fig.1. Map of Nigeria showing the location of the sty area in the Niger Delta *(Modified from Ejedawe [18])*

It lies between latitudes 3° and 6°N and longitudes 5° E and 8°E. It is made up of an overall regressive clastic sequence that reaches a maximum thickness of 30,000 to 40,000ft (9000 to 12,000m) [8]. Stacher [9] developed a hydrocarbon habitat model for the Niger Delta based on sequence stratigraphic method. The Tertiary deltaic complex was divided into three major facies units based on the dominant environmental influences [10]. These sedimentary environments are the continental environment, the transitional environment, and marine environment. In an advancing delta, such as the Niger Delta, sediments of the three environments mentioned above become stratigraphically superimposed and its stratigraphic sequence is represented by marine shales. The middle part of the sequence is represented by interbedded shallow marine and fluvial sands, silts, and clays which are typical of a parallic setting. The sequence is capped by a section of massive continental sands.

The three main lithostratigraphic units in the subsurface of the Niger Delta are known as the Akata, Agbada and Benin formations (Fig. 2) decrease in age basin ward, thereby reflecting the overall regression of depositional environments within the Niger Delta.

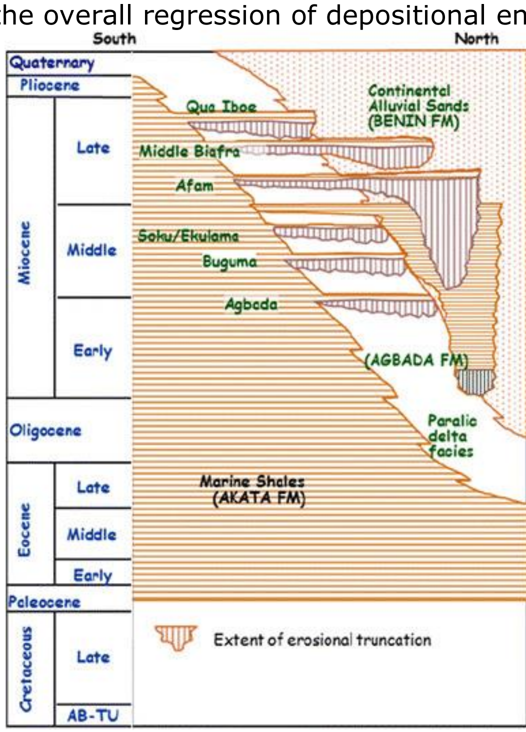

Fig. 2: Regional stratigraphy of the Niger Delta showing different formations *(after Ozumba [19])*

The Akata Formation is interpreted to be deep water low stand deposits by Stacher [9]. It is estimated to be 21,000 ft thick in the central part of the clastic wedge [11]. Marine planktonic foraminifera make up to 50% of the microfauna assemblage and suggest shallow marine shelf deposition that ranges from Paleocene to Recent [11]. The onshore equivalent of this formation is exposed as the Imo shale. The formation also crops offshore in diapirs along the continental slope where deeply buried marine shales are typically over pressured. Agbada Formation overlies the Akata and it occurs throughout the Niger Delta clastic wedge with a maximum thickness of about 13,000 ft. The lithologies consist of alternating sands, silts and shales arranged within ten to hundred feet successions defined by progressive upward change in grain size and bed thickness. The strata are generally interpreted to have formed in fluvial-deltaic environments and ranges in age from Eocene to Pleistocene. The Benin Formation is the top part of the Niger Delta clastic wedge, from the Benin-Onitsha area in the north to beyond the coast line [10]. The top of the Formation is recent, sub aerially exposed delta top surface and its base extends to a depth of 4,600 ft. The base is defined by the youngest marine shale. Shallow parts of the formation are composed entirely of non-marine sand deposited in alluvial or upper coastal plain environments during progradation of the delta [11]. Although lack of preserved fauna inhibits accurate age dating, the age of the formation is estimated to range from Oligocene to Recent [10].

3. Materials and methods

In this study, a suite of well logs from three wells (Fig. 3), of a field in the Coastal Swamp, Niger Delta was analyzed using PETREL and Mat lab software.

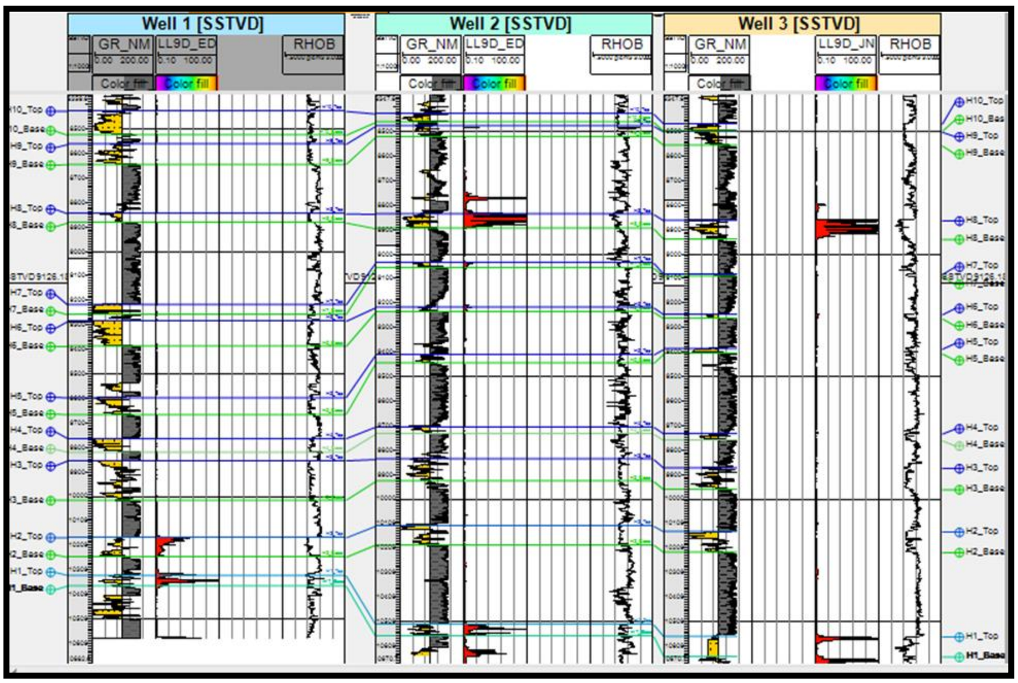

Fig. 3. Correlation panel for Wells 1, 2 and 3 in a dip section

The petrophysical characteristic of the reservoir was evaluated using the suite of well logs (i.e., neutron, density, gamma ray, resistivity, etc.) to calculate the porosity and permeability [12], which are the major parameters required to assess the quality of the reservoir and its heterogeneity. The stile plot is one of the most commonly used techniques for measuring the static heterogeneity. To achieve this, the product of the representative thickness (h) and the permeability (k) was arranged in descending order alongside the corresponding product of representative porosity (ϕ) and thickness (h) for a reservoir. The cumulative of the product (kh) was normalized (between 0 & 1) known as a fraction of the total flow capacity (F). A similar normalization was performed on the cumulative values of ϕh and the result is known as a fraction of total storage capacity(C). A plot of F against C gives the Lorenz curve.

$$F = \sum_{i=1}^{n} kh \Big/ \sum_{i=1}^{N} kh \qquad (1)$$

$$C = \sum_{i=1}^{n} \emptyset h \Big/ \sum_{i=1}^{N} \emptyset h \qquad (2), \text{ where } 1 \leq n \leq N$$

The curve was made to pass through (0, 0) and (1, 1). The Lorenz coefficient was then calculated using 2 multiplied by the area between the curve and the diagonal. This area was computed by integrating the curve.

4. Results and discussion

4.1. Well-1(5,500 -10,500ft)

The results show that four reservoirs (1-A to 1-D) were delineated from well-1. Reservoir 1-A has a gross thickness of 1459ft between 5385.5ft to 6844.5ft, with a net thickness of 1082ft (Table 1).

Table 1. Average petrophysical properties and Lorenz coefficient evaluated for Well-1 Reservoir

Res. No.	Depth interval (ft)		Net Thick-ness, (ft)	IGR (API)	Vsh (v/v)	Φ_e	Sw (v/v)	Sh (v/v)	K (mD)	Lorenz coefficient (LC)
	Top	Base								
1-A	5385.50	6844.5	990.00	0.23	0.13	0.25	0.10	0.89	18880.53	0.6286
1-B	7272.50	7776.0	404.50	0.30	0.14	0.23	0.26	0.74	7627.83	0.3532
1-C	7942.00	8566.0	376.50	0.36	0.20	0.21	0.29	0.71	6443.27	0.3498
1-D	9328.50	9431.0	102.50	0.18	0.06	0.26	0.30	0.70	7823.27	0.2491

The average volume of shale (Vsh) of the reservoir is 0.13v/v decimal indicating dirty sand zone [13]. Its average effective porosity (ϕ_e) is 0.244v/v which indicates a good reservoir for hydrocarbon accumulation [14]. The reservoir is predominantly (~90%) hydrocarbon saturated and 10% water saturated. An average permeability value of 18880.53mD suggests excellent connectivity for fluid to flow in the reservoir. The Lorenz coefficient value was estimated to be 0.6286 (Table 1), which shows high heterogeneous reservoir. Also, an observed modified Lorenz plot (MLP) shows substantial separation between the storage and flow capacities (Fig.4a & b), which indicates that all pores are not contributing to flow within the reservoir interval.

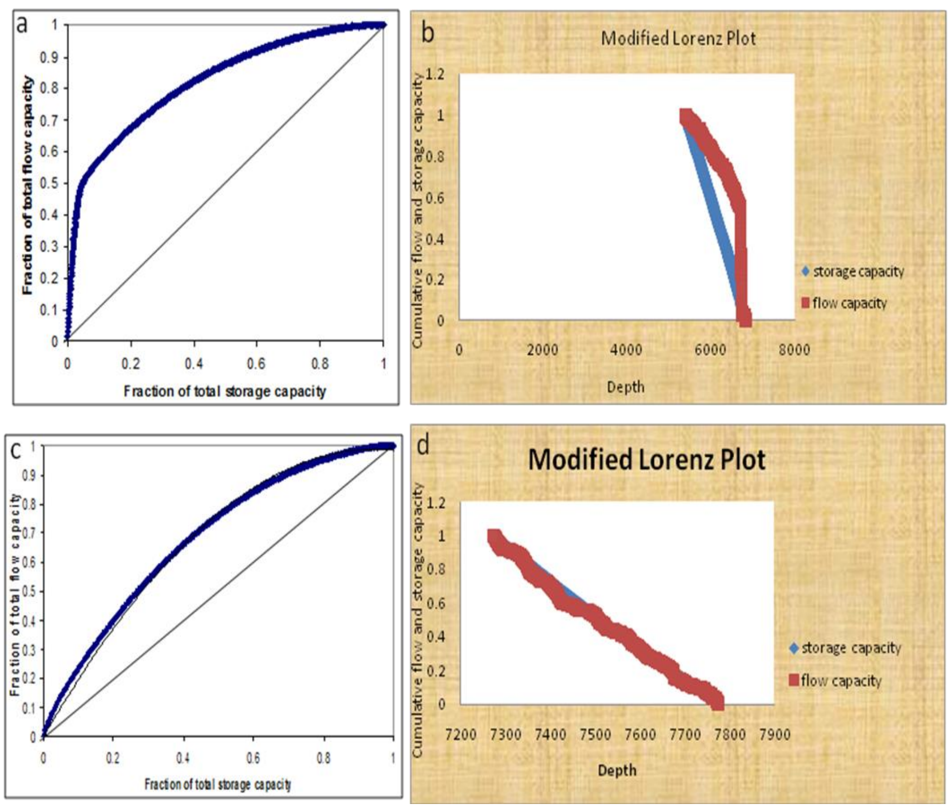

Fig. 4. Lorenz plot and modified Lorenz plots for Well 1: Reservoir 1-A interval (5385.5-6844.5ft) – (a) Lorenz plot (b) modified Lorenz plot; Reservoir 1-B interval (7272.5-7776.0ft) – (a) Lorenz plot (b) modified Lorenz plot

The high heterogeneity of this reservoir has great potential to affect hydrocarbon recovery, possibly causing production of water before the predicted time. Reservoir 1-B has a net thickness of 404.5ft (7272.5-7776.0ft) with an average shale volume (Vsh) of 0.142v/v (Table 1). Although the sand is shaly, it is also within the acceptable limit of clay in the reservoir [13]. Its average effective porosity of 0.23v/v decimal and average permeability of 7627.83mD suggests good pore volume with excellent fluid flow system. The reservoir is dominantly hydrocarbon saturated with little water (~26%) saturation. Estimated Lorenz coefficient of 0.3532 shows that the reservoir is slightly heterogeneous and can easily be ignored. Additionally, a quick look at the MLP indicates an overlap between the flow and storage capacity (Fig.4c & d), which shows that all the pores are contributing equally to flow within the reservoir interval [15]. Reservoir 1-C has net thickness of 376.5ft (7942-8566ft) with an average shale volume (Vsh) of 0.2v/v decimal (Table 1), which is above the limit of 15% that can affect the water saturation value. The average effective porosity and permeability are 0.21v/v and 6443.27mD indicate good reservoir. Average hydrocarbon and water saturations are 71% and 29% respectively indicates shows that the reservoir is predominantly hydrocarbon. Its Lorenz coefficient value of 0.3498 suggests that the reservoir is slightly heterogeneous.

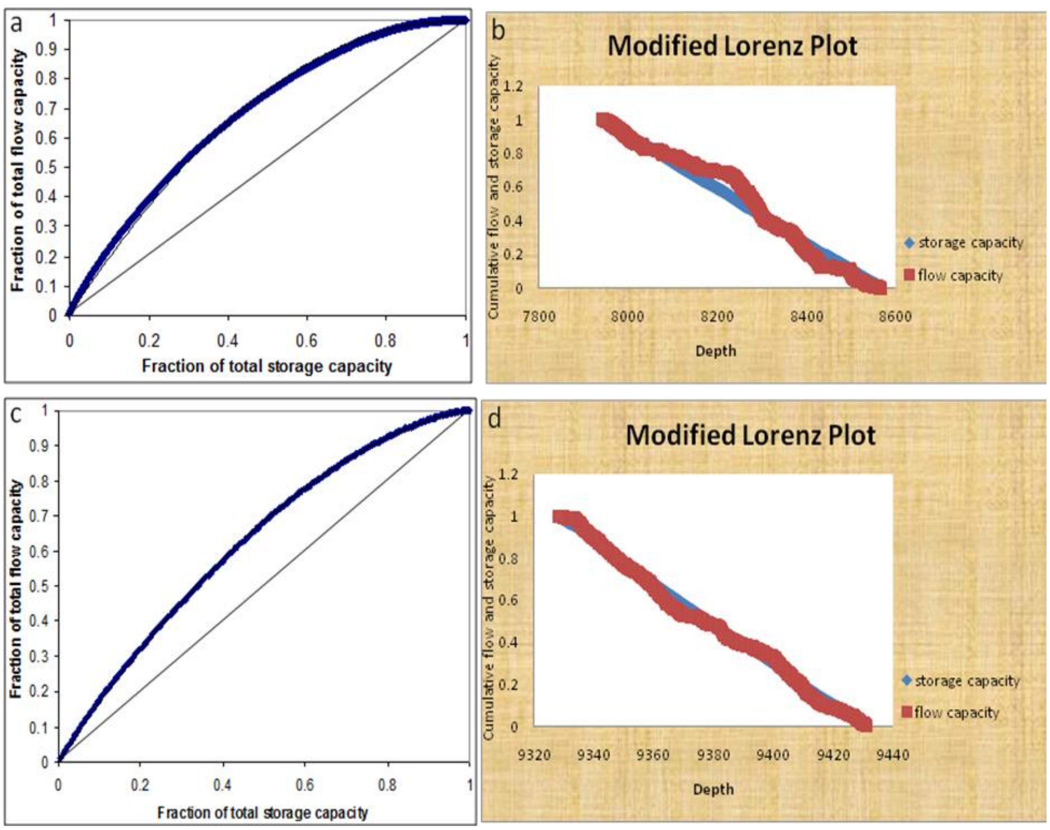

Fig. 5. Lorenz plot and modified Lorenz plots for Well 1: Reservoir 1-C interval (7942.0-8566.0ft) – (a) Lorenz plot (b) modified Lorenz plot; Reservoir 1-D interval (9328.5-9431.0ft) – (a) Lorenz plot (b) modified Lorenz plot

4.2. WELL-2 (5,500 -11,000ft)

In this well, four reservoirs (2A-2D) were delineated (Table 2). Reservoir 2-A is 506ft net thick (5895-6472ft) with an average shale volume (Vsh) of 0.2v/v indicating shaly-sandstone. The average effective porosity and permeability of 0.32v/v and 9408.9mD respectively are quite high and excellent despite the high volume of shale.

Table 2. Average petrophysical properties and Lorenz coefficient evaluated for Well-2 Reservoir

Res. No.	Depth interval (ft)		Net Thick-ness, (ft)	IGR (API)	Vsh (v/v)	Φ_e	Sw (v/v)	Sh (v/v)	K (mD)	Lorenz coefficient (LC)
	Top	Base								
2-A	5895.0	6472.0	577	0.22	0.11	0.32	0.15	0.85	94084.98	0.7245
2-B	6729.0	7009.0	280	0.33	0.16	0.21	0.31	0.69	4508.89	0.3472
2-C	7134.5	7482.0	348	0.35	0.18	0.21	0.34	0.66	5347.38	0.3499
2-D	7944.0	8055.5	112.5	0.29	0.14	0.22	0.36	0.65	4381.66	0.2984

This suggests that the clay type/form is not those that can reduce pore volume but might create baffles that can reduce both vertical and horizontal flows [17]. The Lorenz coefficient value of 0.7245 for the reservoir indicates highly heterogeneous sand (Fig. 6a & b).

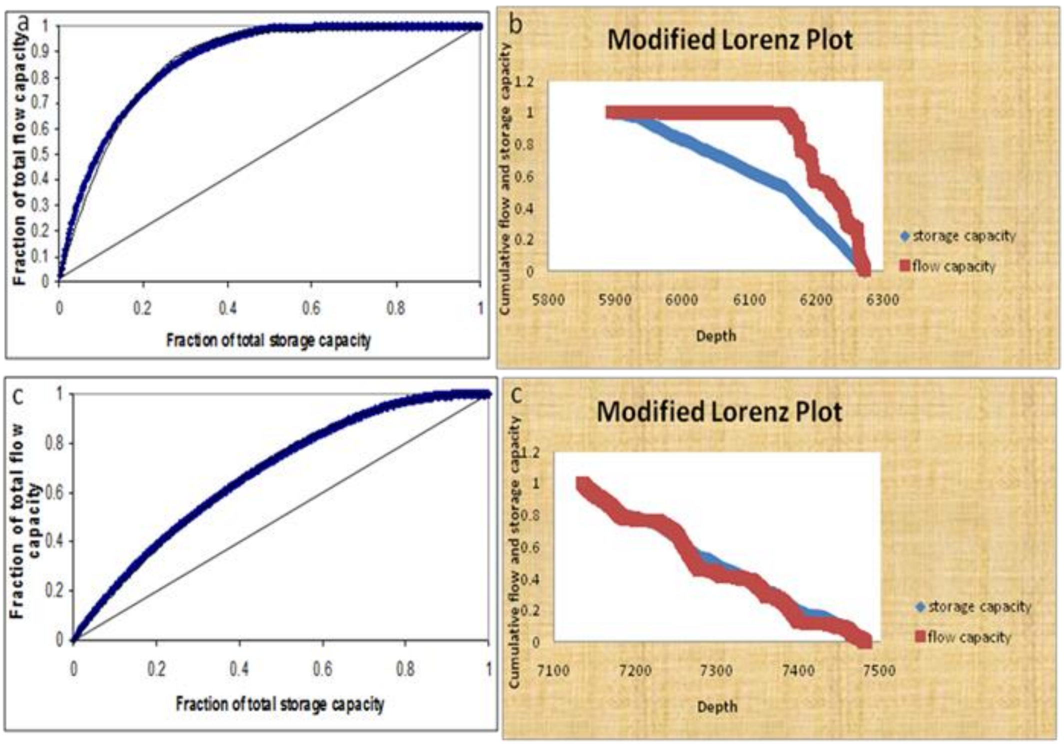

Fig. 6. Lorenz plot and modified Lorenz plots for Well 2: Reservoir 2-A interval (5895.0-6472.0ft) – (a) Lorenz plot (b) modified Lorenz plot; Reservoir 2-C interval (7134.5-7482.0ft) – (a) Lorenz plot (b) modified Lorenz plot

Similarly, the modified Lorenz plot (MLP) shows strong separation between the storage and flow capacity. These results apparently show that the pores are not uniformly contributing to the flow system [15], hence has a high effect on hydrocarbon recovery over time. Average hydro-carbons and water saturations are 85% and 15% respectively which shows that the reservoir is dominantly hydrocarbon saturated. The net thickness of reservoir 2-B is 205ft which occurs at a depth interval of 6729-7000ft (Table 2). The volume of shale (Vsh) is 0.16v/v which is a little above the limit of 15% that can affect the water saturation value [13]. The reservoir also has an effective porosity of 0.21v/v and permeability of 508.89mD, which indicates good reservoir quality for hydrocarbon accumulation and production. Hydrocarbon and water saturation of 69% and 31% respectively were computed for the reservoir. Lorenz coefficient value was also calculated to be 0.3472, an indication that the reservoir is slightly heterogeneous with the minute rate of spreading.

Reservoir 2-C was delineated between 7134.5ft and 7482ft with a net thickness of 227ft (Table 1). The average volume of shale (Vsh) is 0.179v/v indicating a sand shaly zone. The average effective porosity of 0.21v/v shows good reservoir quality (Table 2). Also, the permeability obtained for the interval is 5347.38mD, which shows an excellent reservoir for hydrocarbon production. The reservoir is relatively hydrocarbon filled with a saturation of 0.66v/v. Its Lorenz coefficient value of 0.3499 indicates a low level of heterogeneity (Fig. 6c &d). The deepest reservoir (2-D) has a net thickness of 88.5ft (7944-8055ft) with shale volume (Vsh) of 0.14v/v. The average effective porosity and permeability are 0.22v/v and 4382.66mD respectively (Table 2); with hydrocarbon saturation of 0.65v/v (65%). The reservoir is slightly heterogeneous with Lorenz coefficient value of 0.298. The MLP shows overlapping between the flow and storage (Fig. 7a & b); capacity indicating that all the pores are contributing equally to flow with an encouraging prospect that will enhance smooth hydrocarbon recovery.

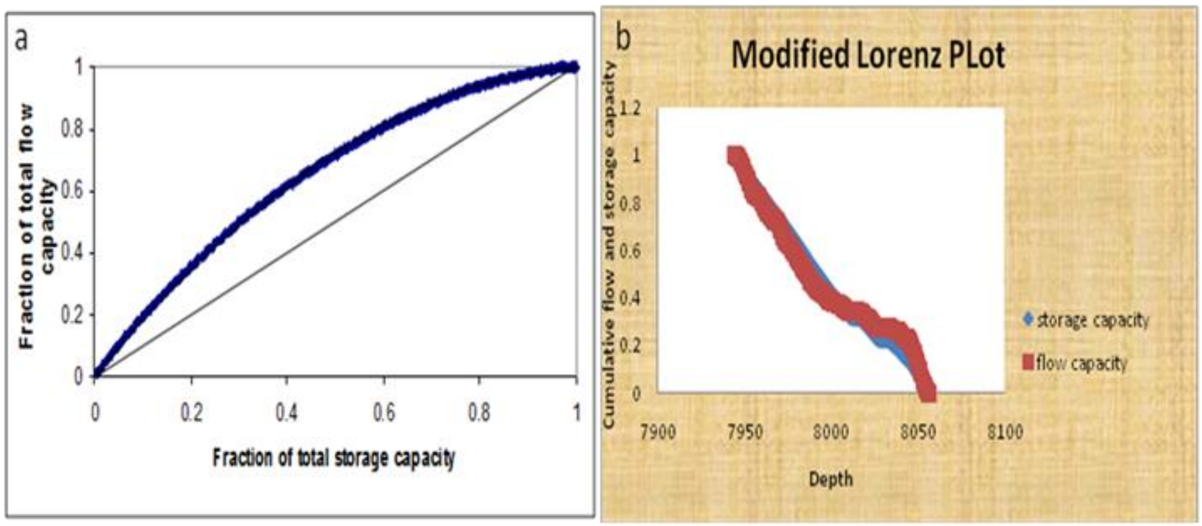

Fig. 7. Lorenz plot and modified Lorenz plots for Well 2: Reservoir 2-D interval (7944.0-8055.5ft) – (a) Lorenz plot (b) modified Lorenz plot

4.3. WELL-3 (5500 -11,000ft)

In this well, four reservoir units were also delineated from Reservoir 3-A down to 3-D (Table 3). Reservoir 3-A occurs at depth 7061-7620ft with a gross and net thickness of 559.5ft and 483.5ft respectively. The average shale volume (Vsh) content is 0.16v/v, having an effective porosity of 0.26v/v. Also, the estimated permeability for this unit is 21799.17mD. The porosity-permeability values are good despite the marginally high value of the shale volume. Also, the Lorenz coefficient value of 0.6464 shows a high degree of reservoir heterogeneity; indicating high variability of flow performance. Also, the modified Lorenz plot (MLP) shows separation between storage and flow capacity (Fig. 8a & b), which is a confirmation that the reservoir is highly heterogeneous, hence, all the pores are not contributing to flow.

Table 3. Average petrophysical properties and Lorenz coefficient evaluated for Well-3 Reservoir

Res. No.	Depth interval (ft)		Net Thick-ness, (ft)	IGR (API)	Vsh (v/v)	Φ_e	Sw (v/v)	Sh (v/v)	K (mD)	Lorenz coefficient (LC)
	Top	Base								
3-A	7061.0	7620.0	559.5	0.419	0.16	0.26	0.31	0.69	21799.17	0.6464
3-B	7698.5	7995.0	296.5	0.221	0.10	0.24	0.35	0.65	6077.31	0.3039
3-C	8519.0	8607.0	88.0	0.410	0.21	0.22	0.34	0.66	7456.62	0.3369
3-D	8913.0	8988.5	75.5	0.415	0.20	0.24	0.05	0.95	27263.86	0.5103

Nevertheless, the reservoir has substantial hydrocarbon saturation of 69% with minimal water. The second reservoir unit (3-B) has net thickness of 256.5ft with an average shale volume (Vsh) of 0.1v/v which is within the negligible value that could affect water saturation. The reservoir has an average porosity is 0.24v/v and permeability of about 6077.31mD, which indicates good quality reservoir that can contain and transmit fluids homogenously. The reservoir's good quality is also confirmed by the Lorenz coefficient of 0.3039 (Fig. 8c & d), which indicates low level of reservoir heterogeneity.

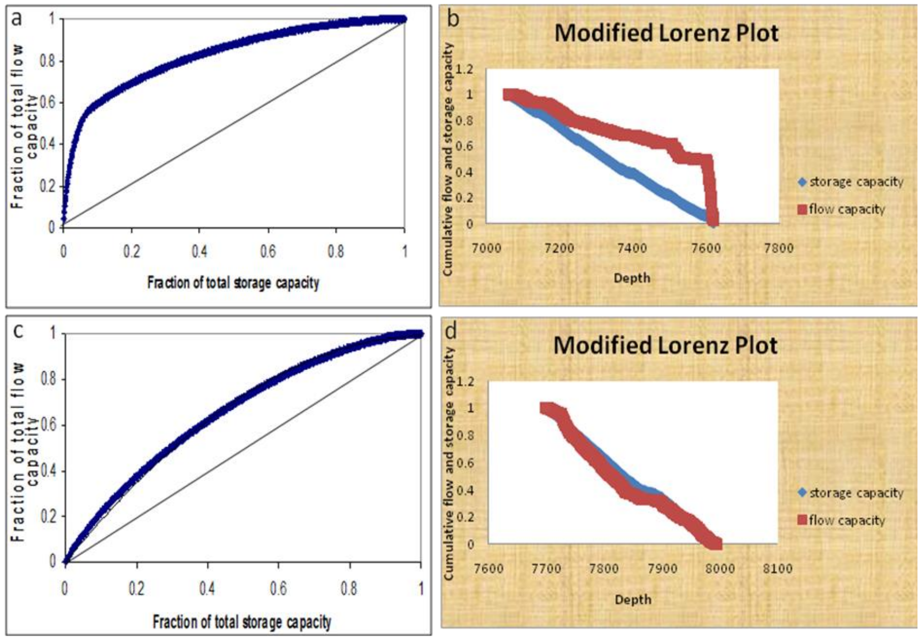

Fig. 8. Lorenz plot and modified Lorenz plots for Well 3: Reservoir 3-A interval (7061-7620ft) – (a) Lorenz plot (b) modified Lorenz plot; Reservoir 3-B interval (7698.5-7995.0ft) – (a) Lorenz plot (b) modified Lorenz plot

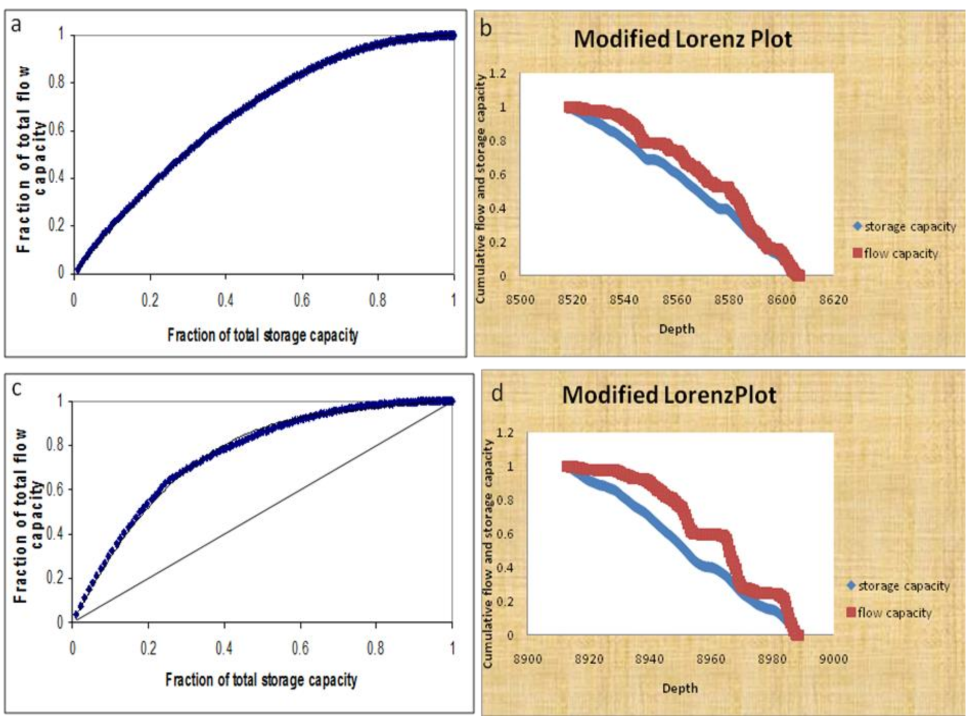

Fig. 9. Lorenz plot and modified Lorenz plots for Well 3: Reservoir 3-C interval (8519.0-8607.0ft) – (a) Lorenz plot (b) modified Lorenz plot; Reservoir 3-D interval (8913.0-8988.5ft) – (a) Lorenz plot (b) modified Lorenz plot

Reservoir 3-B is mainly hydrocarbon filled with an estimated hydrocarbon saturation of 65% against 30% water saturation. Also, the Reservoir 3-C has a net thickness of 61ft and an average shale volume (Vsh) of 0.21v/v indicating a shaly sand zone. Reservoir quality of the unit is relatively good with its porosity-permeability values as 0.22v/v and 7456.62mD (Table 3). Lorenz coefficient value 0.3369 shows the reservoir to be slightly heterogeneous and can be ignored because its effect on reservoir performance is minimal. The modified Lorenz plot (MLP) also shows slight separation between the storage and flow capacities (Fig. 9a & b), which confirms that the pores are relatively contributing to the flow. An average hydrocarbon saturation of 66% shows that the reservoir is dominantly hydrocarbon saturated (Table 3). The deepest reservoir in well-3 (3-D) has net thickness of 47.5ftwith an average shale volume (Vsh) of 0.21v/v and average effective porosity of 0.24v/v. It also has an excellent permeability of 27263.86mD and is dominantly hydrocarbon filled with 95% hydrocarbon saturation. The Lorenz coefficient value calculated is 0.5103 (Table 3), which indicates a relatively high level of reservoir heterogeneity. On the other hand, the modified Lorenz plot (MLP) shows separation of the storage and flow capacities (Fig. 9c & d), which indicates relatively high variability of the flow performance, thereby, increasing the risk of water production before the predicted time.

5. Conclusions

The degree of static reservoir heterogeneity of three oil wells has been effectively studied using the Lorenz coefficient derived from Lorenz and Modified Lorenz Plots. The results indicate that the reservoirs' heterogeneity ranges from significant to fair. Significant heterogeneity occurs in the reservoir (1-A, 2-A, 3-A, and 3-D) of all the three wells. The rest of the reservoirs studied are fairly heterogeneous; which including Res1-B, C, D for well-1, Res 2-B, C, D, for well-2 and Res 3-B, C for well-3. It implies that the reservoirs with a high degree of heterogeneity have a greater number of baffle zones with non-homogeneous pore contributions, giving rise to a steady shallow decline in production. On the other hand, those with a fair level of heterogeneity have a greater number of speed zones (flow units) that constitute greater contribution from the numerous pores which are associated with ling time dominance with production. Thus, hydrocarbons production over a long time can be steadily sustained from these baffles, which usually have shallow production decline as compared to the speed zones with a sharp decline. This study guides in the accurate design of reservoir simulation, apart from capturing the reservoir heterogeneity, which is a major factor that affects oil recovery.

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