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RESERVOIR CHARACTERIZATION USING WELL LOG DATA AND PETROPHYSICAL ANALYSIS OVER "X- OIL FIELD" NIGER DELTA

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ABSTRACT

Estimating oil and gas reserves for producing oil fields is a process that carries uncertainties. In order to achieve accuracy in such estimates as well as reservoir characterization, petrophysical analysis is usually implemented. Petrophysical analysis of "X-OIL field" involved the analysis of well logs collected from four wells in "X-OIL field" located in the Niger Delta. Hydrocarbon bearing reservoirs were delineated in each well as well as petrophysical parameters such as porosity, permeability, water saturation, reservoir thickness, shale volume etc. The parameters obtained were further analyzed and interpreted qualitatively to estimate the hydrocarbon potentials of each well. As a result of this study, three zones of interest (sand bodies) were delineated, correlated across the field and all three were further identified as potential hydrocarbon reservoirs R1, R2 and R3. Petrophysical properties for the reservoir layers show a porosity range of 21.6% - 36.5%, hydrocarbon saturation 5% - 63%, permeability of 200.3md – 10723.7md. All reservoirs

were estimated to contain hydrocarbon with reservoir sand R1 being the most prolific. Reservoir sands R2 and R3 also contained significant amounts of hydrocarbon but were mostly wet in two of the wells. This project work contributed to evaluation of hydrocarbon potential of the oil field and estimating reservoir properties.

1. INTRODUCTION

The Niger Delta basin, one of the sedimentary basins in Nigeria is located between longitudes 5^0 E to 8^0 E and latitudes 3^0 N to 5^0 N, Figure 1. The presence of large volumes of hydrocarbon in Nigeria has made her one of the oldest and largest producers of oil and gas in Africa. In Niger Delta, petroleum is found in stratigraphic and structural traps. The petroleum is trapped in the reservoir capped by shales. Petrophysical analysis is done to determine the quality of the reservoir. Before petrophysical analysis, well log interpretation must be carried out.

2. PETROPHYSICS

Petrophysics is the study of relationships among the physical properties of rock, for example, porosity, permeability etc relate with measurements made on well logs, for example, volume of shale, V_{sh}, water saturation etc to determine rock properties.

The presence of large volumes of hydrocarbon in Nigeria has made her one of the oldest and largest producers of oil and gas in Africa. The exploration and exploitation of hydrocarbon has been ongoing since the early 90s and remains one of our biggest sources of revenue. Petroleum as a main source of energy in the world has economic importance in major fields such as: transportation, heating and lighting, lubricants & industrial power.

3. GEOLOGY OF NIGER DELTA

a. Stratigraphy of Niger Delta

The Niger Delta has been associated with three main subsurface formations historically. These formations are the continental top facies (Benin formation), the paralic delta front facies (Agbada formation) and pro delta facies (Akata formations) (Amigun *et al*. 2012).

Benin Formation

This is the uppermost and shallowest stratigraphic unit of the Niger Delta. The age of formation varies from Oligocene to Recent. The Benin formation consists of non-marine sands with few shaly intercalations. Its sand intervals are fine to coarse grained with shale content increasing towards the base of formation. It was deposited in the alluvial or upper coastal plain environments following a southward shift of deltaic deposition into a new depobelt (Short and Stauble, 1967). The formation is more than 2000m thick with trapped hydrocarbon of non-commercial quantities present.

Agbada Formation

The Agbada formation forms the hydrocarbon-perspective sequence in the Niger Delta. It is an intermediate formation as it underlies the Benin formation and overlies the Akata formation. The age of the formation is Eocene to Recent and consists mainly of alternating sequences of sandstone, shale and siltstone. The sand is under compacted and contains autogenic cement materials which allow free movement of hydrocarbon within it (Lambert-Aikhiobare et al, 1984). The maximum thickness of the formation is about 4,200m.

Akata Formation

The Akata formation can be found at the base of the Delta and is of marine origin. It consists of thick shale sequences (which can be potential source rocks), turbidite sand (which can be potential reservoirs in deep waters) and small amounts of clay and silts. It is estimated to have a thickness of more than 6,000m and is believed to be the main source rocks within the Niger Delta complex.

4. RESERVOIR ROCK

Petroleum is produced from sandstone and unconsolidated sands predominantly found in the Agbada Formation. Characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial. Reservoir rocks that are known are Eocene to Pliocene in age and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness (Evamy and others, 1978). The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990). Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. Much of this sandstone is nearly unconsolidated, some with a minor component of agrillosilicic cement. Porosity only slowly decreases with depth because of the young age of the sediment and the coolness of the delta complex. Burke (1972) describes three deep-water fans that have likely been active through much of the delta's history. The fans are smaller than those associated with other large deltas because much of the sand of the Niger- Benue system is deposited on top of the delta and buried along with the proximal parts of the fans as the position of the successive depobelts moves seaward (Burke, 1972) .

5. MATERIALS AND METHODS

Materials used for the analysis are listed in Figure 3, the base map. Included in the basemap are the wells, 01, 02, 03 and 04. Each well contains well logs: Gamma Ray (GR), Resistivity Logs, Neutron Porosity (NPHI) log and Bulk Density (FDC) log.

6. METHODOLOGY

Three steps were adopted in the project:

a. Lithology analysis

b. Reservoir analysis

c. Petrophysics analysis

Lithology and Reservoir analysis has been described in Olisa and Okafor (2014) and Olisa and Oke (2014).

Sand and shales were analyzed using lithology logs, gamma ray (GR) and spontaneous (SP) potential logs.

Reservoirs were analyzed by the log motifs.

7. LOG INTERPRETATION

It involves the interpretation of recorded physical responses of the subsurface formation. Log interpretation is carried out in two ways;

- Qualitative Interpretation and
- Quantitative Interpretation

i. QUALITATIVE INTERPRETATION

This is the assessment of reservoir properties, fluid type form, log pattern. It is the determination of prolific regions in the well bore and identification of lithology and discrimination between fluid types.

The type of lithology is determined by the gamma ray and Self Potential logs which is made up of alternating sand and shale units in this case. High API values indicate the presence of shale units while low API values indicate the presence of sand units within the zone of investigation.

Resistivity logs recorded on the second track are used in determining the hydrocarbon bearing region on the log. Neutron logs in combination with density log, is applied in delineating contacts (gas-oil and oil-water contacts). Large separation between the neutron and density cross plot indicates gas while lower separation indicates the presence of oil, this is also dependent on the signatures given by the resistivity log. If the resistivity log signatures is low, whether there is large or little separation the formation is wet.

Well Log Correlation

The geophysical logs used for the project include gamma, resistivity, neutron and density logs. This is to ensure accurate subsurface mapping and also determine the absence or presence of faults and the evaluation of formation in a well relative to other wells.

The correlation process entails aligning the logs with respect to a reference datum to establish the structural positions of the reservoir in the subsurface. The next step is to establish laterally continuous markers, this is done by examining the gamma ray-log to determine the sand reservoir whose signature is a deflection towards the left on the log due to the absence of radioactive elements. The respective reservoirs are then correlated across the other wells in that field.

ii. QUANTITATIVE INTERPRETATION

Information on attributes that are in situ can be derived from well logs. This is done with mathematical models and equations to making geological inferences from the reservoir investigated. For this work, Petrophysical parameters evaluated include Gross Thickness, Net Thickness, Net to Gross Thickness, Volume of Shale, Porosity, Permeability, Water Saturation, and Hydrocarbon Saturation.

- **VOLUME OF SHALE (V_{sh})**

The percentage of clay in sandstone is commonly referred to as the shale volume, (V_{sh}). In the absence of "hot" sandstones, shale volume may be calculated by using Equation

$$V_{sh} = \frac{GR - GR_{\min}}{GR_{\max} - GR_{\min}} \quad \text{................................ (3.1)}$$

Where *GR* is the ay log measurement, $GR_{\min}$ is the gamma ray measurement in clean (no clay) sandstone, and $GR_{\max}$ is the gamma ray measurement in shale.

- **POROSITY**

Porosity (Φ) is the ratio of pore volume per unit volume of a formation; it is the fraction of the total volume of a sample occupied by pores or voids, usually expressed as a percentage, mathematically it is represented as

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad \text{... (3.2)}$$

ρ_{ma} is the grain or matrix density which has a constant value for different formation as indicated on the log, in this case, bulk density for sandstone is 2.65g/cm^3, limestone 2.71g/cm^3 and dolomite 2.85g/cm^3

ρ_f is the density of the fluid residing in the pore spaces or gas, conventionally, a value of 0.2 is assigned for gas, 0.8 for Oil and 1 for water.

- **WATER SATURATION**

Water Saturation S_w is the fraction (%) of the pore volume of a reservoir that is occupied by water. Combining both the first, $R_o = \phi^{-m} R_w$ and the Second, $R_t = R_o S_w^{-n}$ Archie's Equations, Water Saturation can be deduced from

$$S_w = \sqrt{\frac{aR_w}{\phi^m R_t}} \quad \ldots\ldots (3.3)$$

Where R_w is the resistivity of water, R_t is the formation true resistivity and is measured from the log, m is the cementation exponent and a is a constant.

- **HYDROCARBON SATURATION**

$$S_h = 1 - Sw \quad \ldots\ldots (3.4)$$

- **FORMATION FACTOR (F)**

From Archie (1942) formula,

$$F = \frac{a}{\phi^m}$$

For unconsolidated sand, as modified by Humble, we have

$$F = 0.81/\Phi^2 \quad \ldots\ldots (3.6)$$

Where:F=Formation factor

Φ=Porosity

m = Cementation factor

a=Tortuosity factor:a function of the complexity of the path the fluid must travel through in the rock.

For the flushed zone,

$$S_{xo} = (S_w)^{1/5} \ldots\ldots (3.7)$$

- **BULK VOLUME WATER**

Bulk volume water is the product of a formation's water saturation (Sw) and its porosity () given by

$$BVW = Sw\,\Phi \quad \ldots\ldots (3.8)$$

If the BVW calculated at several depth are constant or very close to constant, they indicate that the zone is homogenous and at irreducible water saturation (Swirr) [Asquith, 1982]

This was determined using the equations

$BVO_{mov}= \Phi (S_{xo}-S_w)= \Phi (MOS)$ …………………………………. (3.9)

$BVO_{unmov}= \Phi (1-S_{xo})$ ………………………………………….. (3.10)

- **HYDROCARBON PORE VOLUME (HCPV)**

This is the fraction or percentage of the pore volume occupied by hydrocarbon; it is derived using the formula

$HCPV= \Phi (1-S_w) = \Phi (S_H)$ ………………………………………… (3.11)

- **IRREDUCIBLE WATER SATURATON (S_{wirr})**

This was determined using Schlumberger equation (1989);

$S_{wirr}= (F/2000)^{1/2}$ …………………………………………………… (3.12)

This describes the small amount of water (formation or connate water) in percentage that clings to the grains of the reservoir rock, i.e.the percentage that cannot be displaced by oil as a result of capillary forces. At irreducible water saturation, the flow of water into the formation will cease and the relative permeability (k) to water equals zero; as a consequence, the reservoir will produce water free hydrocarbon (Morris and Biggs,1967).Otherwise, increasing amounts of formation water (S_{wirr}) takes up pore space, thereby inhibiting the presence of other fluids and their ability to move through the rock.

- **PERMEABILITY (K)**

Permeability is a measure of the ease with which a formation permits a fluid to flow through it. To be permeable, a rock must have interconnected porosity. Greater porosity usually corresponds to greater permeability, but this is not always the case.

The ability of a rock to transmit a single fluid when it is completely saturated with that fluid is called absolute permeability while effective permeability refers to the ability of the rock to transmit one fluid in the presence of another fluid when the two fluids are immiscible. The absolute rock permeability in milli-darcy, (md) at irreducible water saturation was determined using the empirical

relationship by Timur (1968),

$K^{1/2} = \underline{250\Phi^3}$ ……………………………………………… (3.13)

s_{wir}

(when reservoir contain oil)

$$K^{1/2} = \frac{250\Phi^3}{s_{wirr}} \quad \ldots\ldots (3.14)$$

[Tixier, 1968 (when the reservoir contain gas)]

Where K = permeability, s_{wirr} = irreducible water saturation.

s_{wirr} is defined as the minimum water saturation at which the relative permeability to water

8. Results

RESERVOIR 1

This reservoir occurs at a depth range of 1800m to 2100m. it has a gross thickness range of 21m to 30m, net thickness range of 15m to 26m and net to gross ratio ranging from 53% to 93%. It has an average porosity value of 29.2% and an average effective porosity value of 25%. The average hydrocarbon saturation of this reservoir is 44.1%, average permeability is 3481.5mD.

The reservoir is also blocky in shape and maintains this shape in three wells indicating that the sand lithology is in abrupt contact with overlying and underlying shales. The petrophysical parameters show that this reservoir has good porosity and permeability and although the reservoir is dirty, it is prolific.

RESERVOIR 2

This reservoir occurs at a depth range of 1900m to 2300m. it has a gross thickness range of 71m to 96m, net thickness range of 71m to 106m and net to gross ratio average value of 93%. It has an average porosity value of 29.9% and an average effective porosity value of 26.8%. The average hydrocarbon saturation of this reservoir is 44.1%, average permeability is 3481.5mD.

The reservoir maintains a serrate blocky shape in just wells 01 and 03. The petrophysical parameters also show that it has good porosity and permeability as well and that it bears hydrocarbon in wells 01, 03 but it mostly wet in wells 02 and 04.

RESERVOIR 3

This reservoir occurs at a depth range of 2000m to 2300m. it has a gross thickness average of 107.6%, net thickness range of 61m to 105m and net to gross ratio average value of 79.7%. It has an average porosity value of 21.1% and an average effective porosity value of 24.5%. The average hydrocarbon saturation of this reservoir is 21.2%, average permeability is 2395.8mD.

The reservoir shape is serrate blocky in just well 01. This reservoir contains hydrocarbons mostly in well 01 and little amounts in Well 02 and 03 whereas it is wet in well 04.

CONCLUSION

The three reservoirs are hydrocarbon bearing but petrophysical results show that only reservoir 1 contains significant hydrocarbon across the four wells. Reservoirs 2 also contains hydrocarbon in significant amounts but only mostly in well 01, 03 and 02 as it is wet in well 04. Reservoir 3 contains significant hydrocarbon in just well 01 and is mostly wet in the other wells. This indicates that reservoir 1 is the most prolific.

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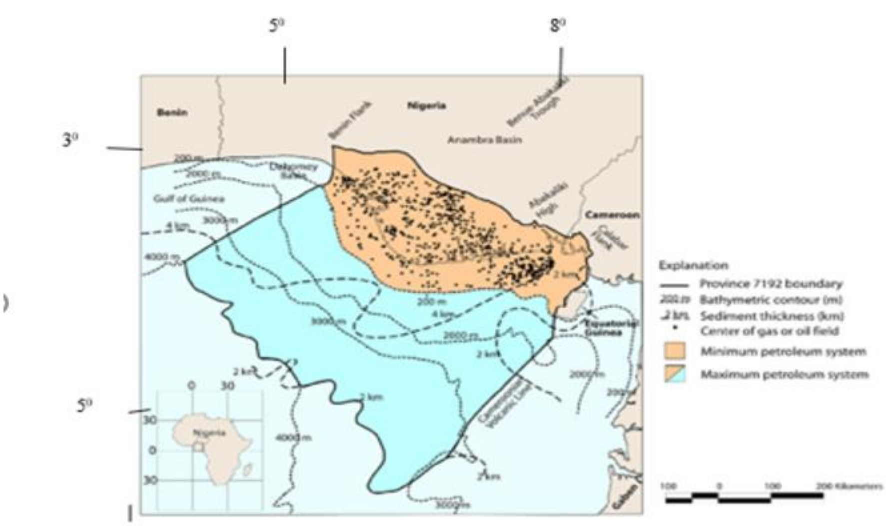

Figure 1: Index map of Niger Delta and Cameroon

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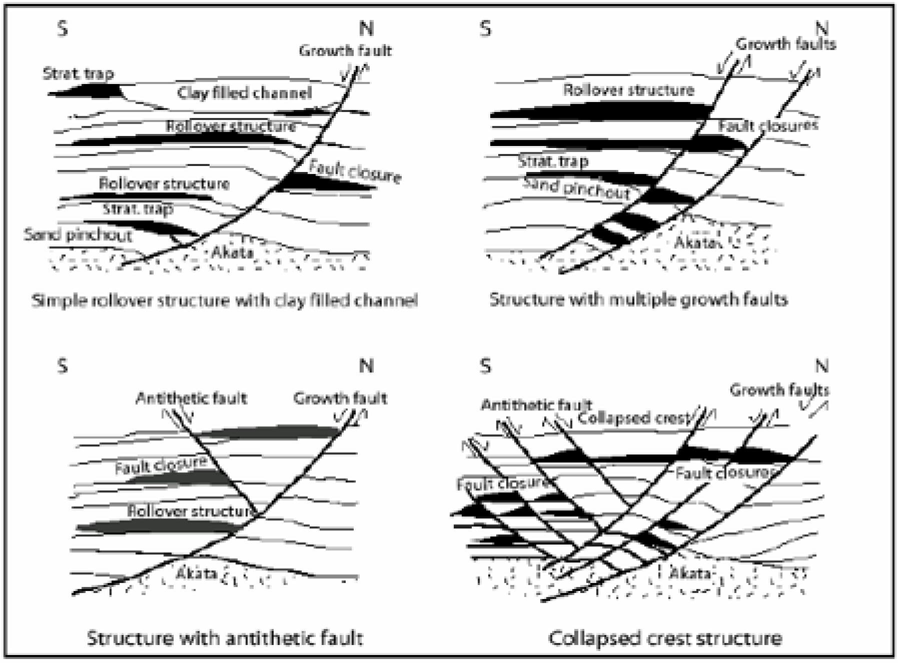

Figure 2. Examples of Niger Delta oil filed structures and associated trap types. Modified from Doust and Omatsola (1990) and Stacher (1995)

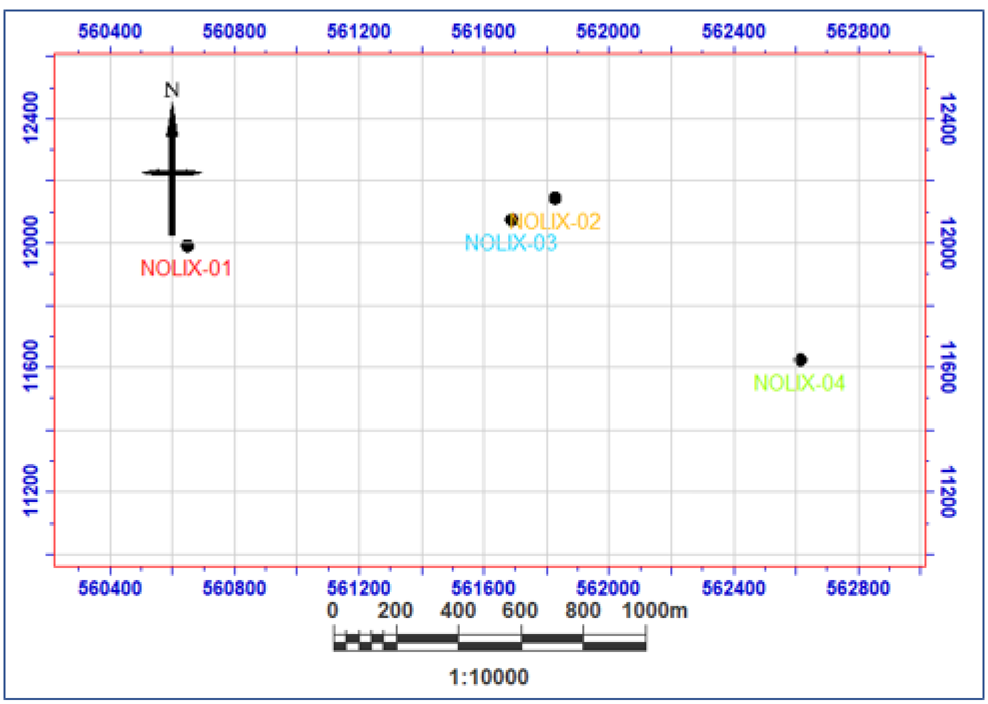

Fig 3: **Generated base map of the field showing well locations (using Petrel 2009 software).**

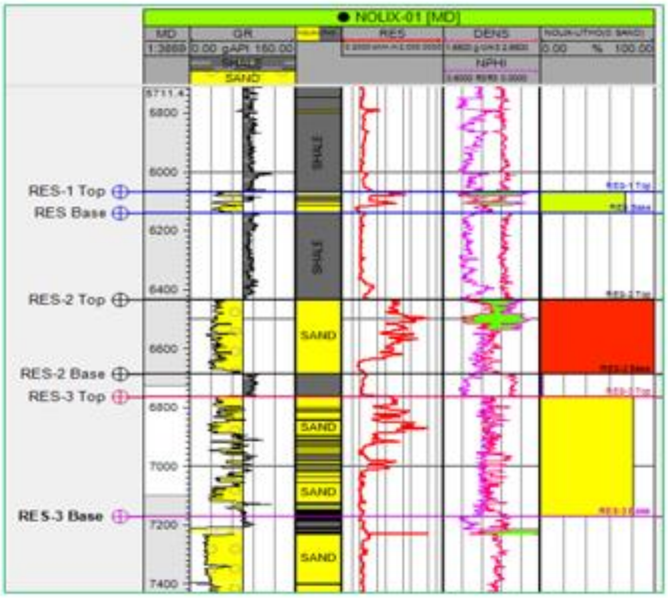

Figure 4: Reservoir Delineation of Nolix 01 Well.

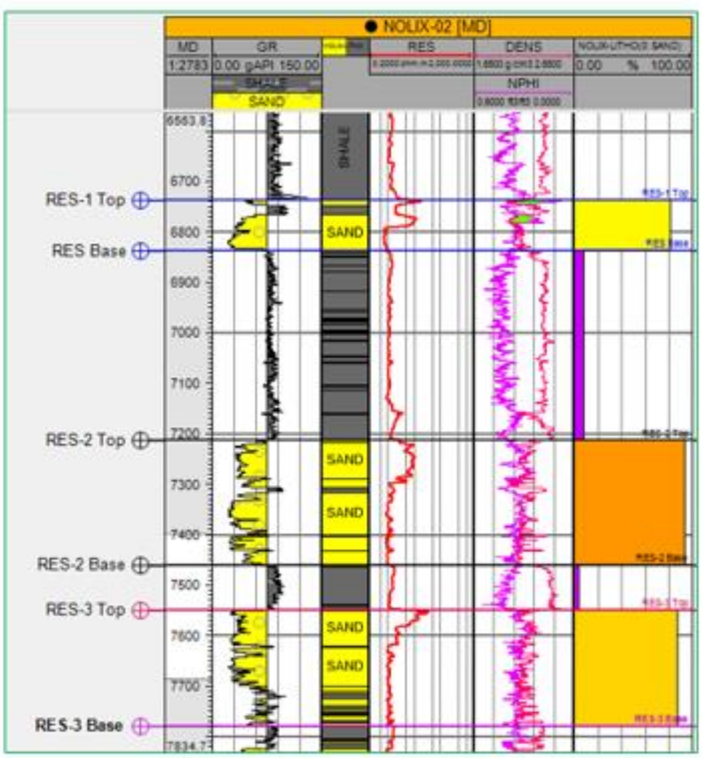

Fig 5: Reservoir Delineation of Nolix 02 Well.

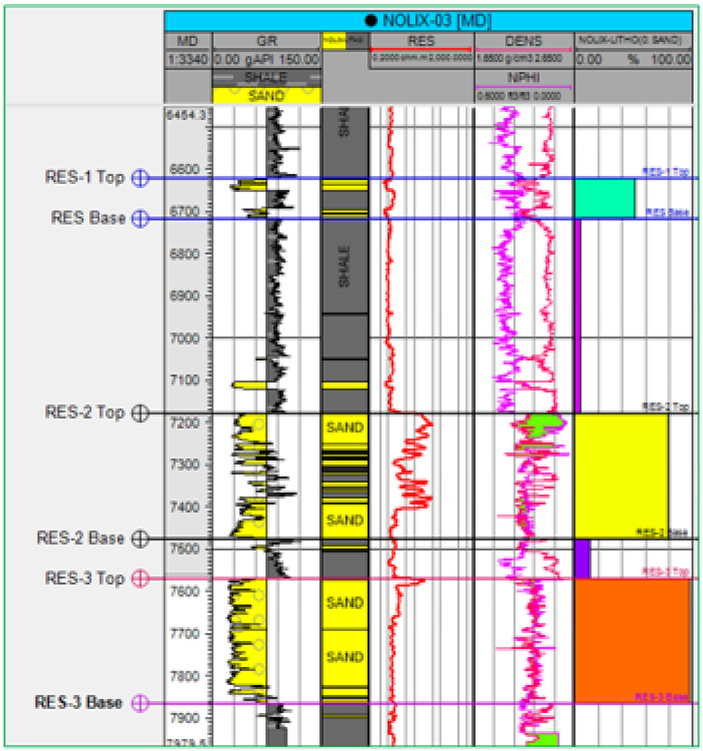

Figure 6: Reservoir Delineation of Nolix 03 Well.

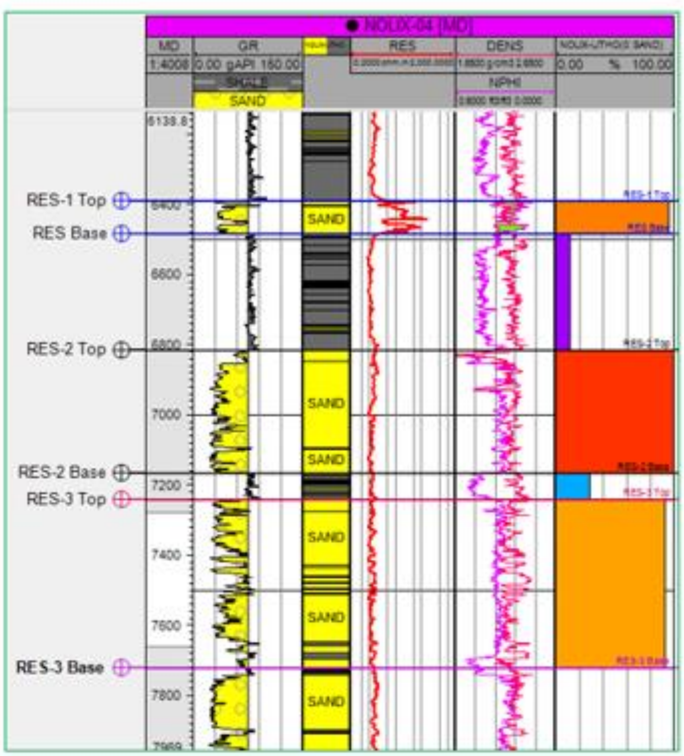

Figure 7: Reservoir Delineation of Nolix 04 Well

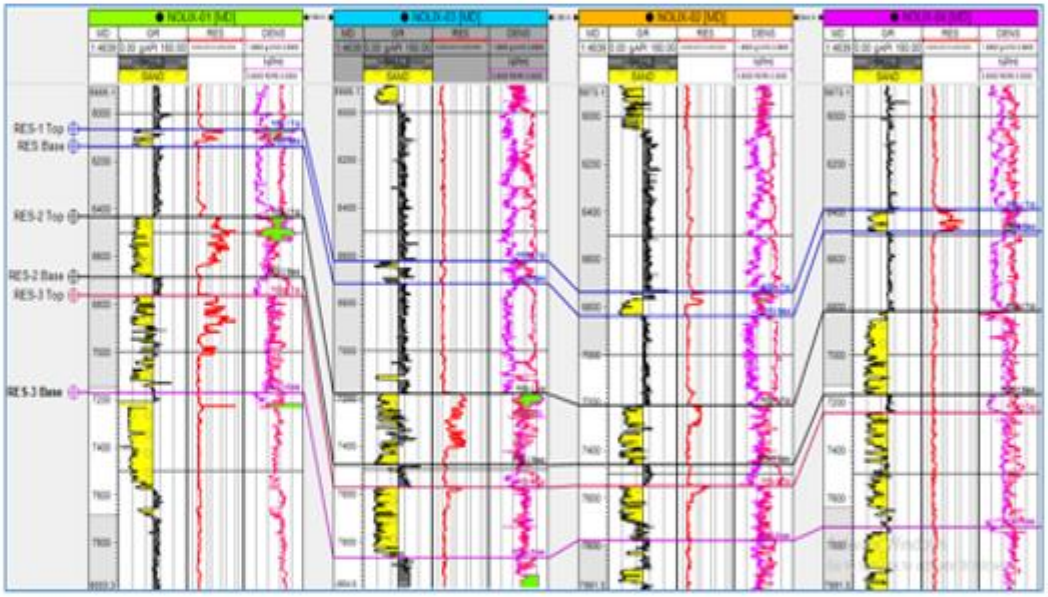

Figure 8: Lithostratigraphic Correlation of the Four Wells.

Table 1: Computed Petrophysical Parameters for Well NOLIX 01

NOLIX 01			
Wells/Petrophysical Paramaters	RES-1	RES-2	RES-3
Top	1848.9	1960.7	2061.3
Base	1870.8	2037.8	2185.4
Gross Thickness(m)	21.9	77.1	124
Net Thickness(m)	16	77.1	105.7
Net/Gross(%)	75	100	85.2
$V_{sh(\%)}$	21.3	12	21
Porosity (ϕ_{AVG})(%)	31	34	30
Effective porosity(ϕ_{eff}) (%)	24.3	29.8	23.6
Permeability(mD)	203.2307	10723.73	1601.082
S_w(%)	47.67	38.43	65
S_h(%)	52.33	61.75	35
S_{wirr} (%)	8.02	6.44	8.28
BVW(%)	11.6	11.4	15.3

Table 2 Computed Petrophysical Parameters for Well NOLIX 02

NOLIX 02			
Wells/Petrophysical Paramaters	RES-1	RES-2	RES-3
Top	2053.1	2197.9	2300.6
Base	2083.6	2273.5	2370.7
Gross Thickness(m)	30.4	75.5	70.1
Net Thickness(m)	24	71.6	61.5
Net/Gross(%)	79	94.7	87.8
$V_{sh(\%)}$	9.77	7.19	8.56
Porosity (ϕ_{AVG})(%)	32	29	29.6
Effective porosity(ϕ_{eff}) $_{(\%)}$	28.8	26.9	27
Permeability(mD)	8083.528	4556.861	4786.318
S_w(%)	54	59	76
S_h(%)	46	41	24
S_{wirr} (%)	6.69	7.21	7.17
BVW(%)	15.5	15.8	20.5

Table 3 Computed Petrophysical Parameters for Well NOLIX 03

NOLIX 03			
Wells/Petrophysical Paramaters	RES-1	RES-2	RES-3
Top	2018.3	2187	2307.3
Base	2047.3	2278.6	2397.2
Gross Thickness(m)	28.9	90.8	89.9
Net Thickness(m)	15.5	71.9	88.0
Net/Gross(%)	53.6	79.1	97.9
$V_{sh(\%)}$	18.7	13.2	7.48
Porosity (ϕ_{AVG})(%)	24	28	25.4
Effective porosity(ϕ_{eff}) $_{(\%)}$	19.5	24.2	23.5
Permeability(mD)	329.8378	1974.174	1528.632
S_w(%)	91	48	79
S_h(%)	9	52	21
S_{wirr} (%)	10.2	8.06	8.33
BVW(%)	17.7	11.6	18.5

Table 4: Computed Petrophysical Parameters for Well NOLIX 04

NOLIX 04			
Wells/Petrophysical Paramaters	RES-1	RES-2	RES-3
Top	1947.6	2077.5	2207.0
Base	1976.3	2184.1	2353.6
Gross Thickness(m)	28.6	106.6	146.6
Net Thickness(m)	26.8	105.7	70.4
Net/Gross(%)	93.6	99.1	48
$V_{sh(\%)}$	10	8	11
Porosity (ϕ_{AVG})(%)	30.4	28.6	26.7
Effective porosity(ϕ_{eff}) $_{(\%)}$	27.4	26.3	23.7
Permeability(mD)	5310.743	3878.459	1667.532
S_w(%)	32	92.6	95
S_h(%)	68	7.4	5
S_{wirr} (%)	7	7.3	8.2
BVW(%)	8.7	24.4	22.6