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RESEARCH ARTICLE

INFLUENCE OF PRESSURE ON POROSITY–PERMEABILITY RELATIONSHIP IN SOUTHERN NIGER DELTA, NIGERIA

Chukwu C. Ben, Ngeri A. Paddy, Udota S. Benjamin

Department of Physics, Faculty of Science, Rivers State University, Nkpolu-Oroworukwo Port Harcourt, Nigeria.
****Corresponding Author Email: benedict.chidi@yahoo.com***

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ABSTRACT

Well logs data comprising of comprising of gamma ray, spontaneous potential, density and neutron logs from four oil wells were analysed for determining the influence of pressure on porosity–permeability relationship in the study area. Porosity values were deduced from well log whereas permeability and pressure values were computed using empirical equations. The average porosity, permeability and pressure values for the four wells range from 0.1% to 30.9%, 34.9mD to 306.4mD, 61926.9psi to 109928.1psi respectively. The lithostratigraphic correlation section of the wells revealed a sand – shale sequence which is a characteristic of a typical Niger Delta formation. The results of this work show that three reservoirs (sand A, sand B and sand C) were identified and correlated across the four wells, each reservoir sand unit spread across the wells and differs in thickness ranging from 8ft to 155ft, with some unit occurring at greater depth than their corresponding unit. The analysis of the wells show that wells OTIG9 and OTIG11 have better reservoirs indicating high potentiality and productivity due to their more porous and permeable nature, reflecting well sorted coarse grained sandstone and linearity in the relationship between porosity, permeability and pressure. The reservoir of well OTIG7 is the least porous but most permeable, thus is highly productive but less potential. The reservoir of OTIG2 has moderate potentiality and good productivity, hence is said to have average production capacity. The results of this work can be used as an evaluation tool for reservoir engineering activities, structural engineering, well stability analysis, blowout and lost circulation prevention.

KEYWORDS

Pressure, Porosity, Permeability, Well log, Reservoir.

1. INTRODUCTION

The measure of the void space in a rock is defined as its porosity, while the measure of the ability of the rock to transmit fluid is its permeability. The knowledge of these two parameters is essential before questions concerning types of fluid, amount of fluid, rate of fluid flow and fluid recovery estimates can be answered (Djebbar and Erle, 2016). The flow of fluid through rock materials is governed by properties such as the porous nature, interconnectivity of the pores, as well as the properties of the following fluid (Saar, 1998). Porosity indicates the potentiality or fluid storage capacity of a reservoir or rock. It is the first of the two essential attributes of a reservoir and is universally symbolized by the Greek lower case letter phi (Φ) (Salley, 1998). Permeability is the measure of the ease with which a fluid of a given viscosity can pass or flow through the pore spaces of a rock. To evaluate the productivity of a reservoir, it is necessary to know how easily fluid can flow or pass through its pore system (Schlumberger, 1989).

Well logging is a geoscientific surveying process used to derive information about the sequence of rocks penetrated by a wellbore. It defines the depth to geological interfaces, provides a means of correlating geological information between wellbores and help to obtain information about the in-situ properties of the wallrock, identifies geologic formations and formation fluid as well as evaluate the productivity of the reservoir or well (Kearey et al., 2002). The use of well logs in the identification of geological formations and fluids present in them thus evaluating the productivity of such of reservoirs make the method widely acceptable in the oil and gas industry (Kunsuik-Mengrai, 1989; Telford et al., 2001). Well logging is carried out from a logging truck sometimes referred to as a mobile laboratory or laboratory truck. A well log is a record which shows the measurement of the physical properties of rocks (like density, resistivity, hydrogen index etc) as a function of depth in a wellbore (Telford et al., 2001).

Geophysical well logs provide continuous information about depth, resistivity, conductivity, temperature, pressure etc of the well. There is real time measurement and analysis of data as well as in-situ and direct geological information of the well with the use of well-log (Doll, 1948). Only well logs can reveal the entire sequence drilled. Most well logs (except radioactivity logs) are dependent on direct contact with the rocks through the walls of the well and have to be run after successive intervals of the drilling, before each stage of the steel casing can be installed in the well (Knut, 2010; El-Werr, et al., 2017).

2. STUDY AREA AND GEOLOGY OF NIGER DELTA

2.1 Study Area

The Niger Delta as shown in figure 1 is interpreted as being a river dominated Delta, the post Oligocene delta is a typical wave dominated

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delta with well-developed shore face sands, beach ridges, tidal channels, mangrove and freshwater swamps. It is one of the world's largest Deltas and shows overall upward transition from marine shales (Akata Formation) through a sand/shale paralic interval (Agbada Formation) to continental sands of the Benin Formation (Asadu et al., 2015).

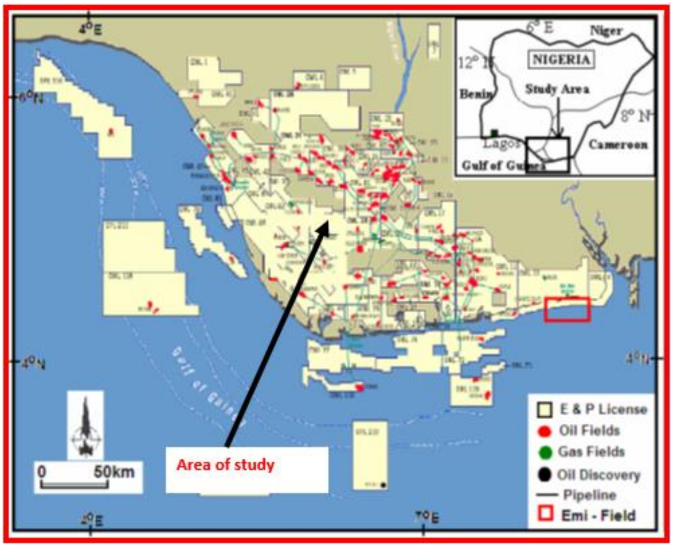


Figure 1: Map Showing the Study Area (Doust and Omatsola, 1990)

2.2 Geology of Niger Delta

Lithostratigraphically, the Niger Delta is divided into three units, and they are:

1) Benin Formation

2) Agbada Formation

3) Akata Formation

The three lithostratigraphic units are aged from early Tertiary to Recent and spread across the entire delta. They are seen in the present outcrops and depositional environments. The Hydrocarbons in the Niger Delta are found in the Agbada Formation (Doust and Omatsola, 1990). Figure 2 shows the three lithostratigraphic unit of the Niger Delta.

1. The Benin Formation is the topmost sequence of the Niger Delta clastic wedge, and has been described as the Coastal Plain Sands which outcrop in Benin, Onitsha and Owerri provinces and elsewhere in the delta area. It consists of massive continental (non-marine) sands and gravels considered to have been deposited in the alluvial or upper coastal plain environment. Very little oil has been found in the Benin Formation (mainly minor oil shows). The formation is generally water bearing, thus the main source of portable ground water in the Niger Delta (Asadu et al., 2015).

2. The Agbada Formation overlies the Akata Formation and forms the second of the three strongly diachronous Niger Delta Complex formations. This forms the hydrocarbon-prospective sequence in the Niger Delta. As the principal reservoir of Niger Delta oil, the formation has been studied in some detail. The Agbada Formation is represented by an alternation of sands (fluviatile, coastal, fluviomarine), silts, clays, and marine shales (shale percentage increasing with depth) in various proportion and thicknesses, representing cyclic sequences of offlap units. These paralic clastics are the truly deltaic portion of the sequence and were deposited in a number of delta-front, delta-topset, and fluvio-deltaic environments and range in age from Eocene to Pleistocene.

3. The Akata Formation is the basal unit of the Tertiary delta complex. This lithofacies is composed of shales, clays, and silts at the base of the known delta sequence. They contain a few streaks of sand, possibly of turbiditic origin, and were deposited in holomarine (delta front to deeper marine) environments (Asadu et al., 2015, Doust and Omatsola, 1990). The thickness of this sequence is not known for certain but may reach 7000m in the central part of the delta. Marine shales form the base of the sequence in each depobelt and range from Paleocene to Holocene in age (Asadu et al., 2015).

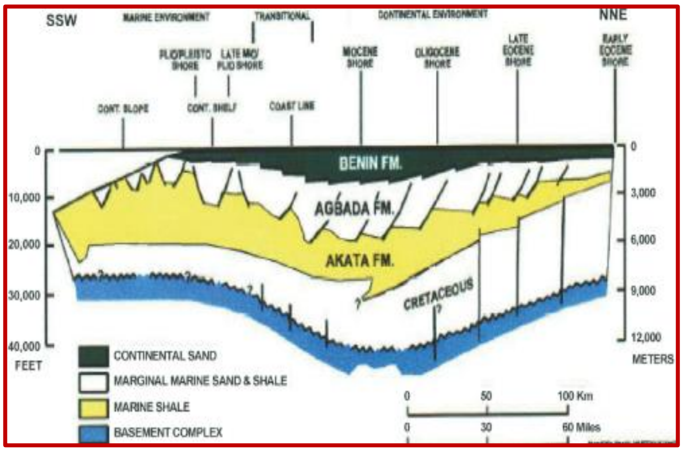


Figure 2: Akata, Agbada and Benin Formations (Doust and Omatsola, 1990)

3. Materials and Methods

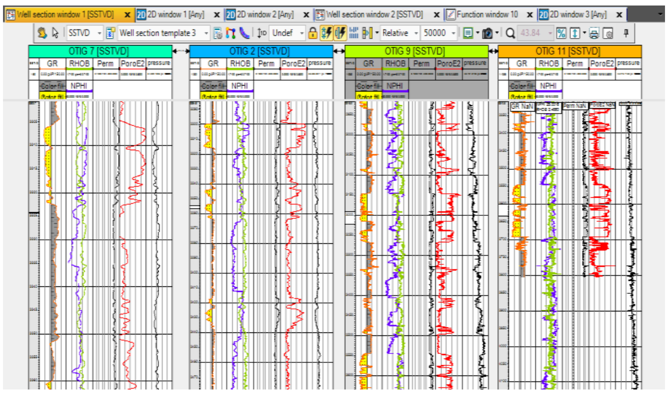
3.1 Materials

Gamma ray (GR), Spontaneous potential (SP), neutron and density logs obtained from four exploratory wells were used for this study. Petrophysical parameters (porosity and permeability) and pressure which aid in reservoir characterization were computed and reservoir units delineated.

3.1.1 Data Set

Data set comprising of gamma ray, spontaneous potential, neutron and density logs values obtained from Shell Petroleum Development Company (SPDC) were used for this study. Table 1 shows the well logs available for each drilled well (OTIG 2, OTIG 7, OTIG 9 and OTIG 11) prior to interpretation. The logs were provided from the depth of 3000ft to 5000ft. Well OTIG 11 is the deepest well with a depth ranging from 3000ft to 4450ft, while well OTIG 9 is the shallowest well in the study area with a depth range of 3000ft to 3650ft.

Gamma ray, spontaneous potential, density, neutron and sonic logs were available for all the wells except well OTIG 11 which does not have a sonic log. Figure 3 shows the various logs for the wells after loading and quality assessment, with gamma ray log placed in track 1, both neutron and density log are placed in track 2, spontaneous potential log placed in track 3 and sonic log placed in track 4. Various colours were assigned to the log for easy identification of the relevant reservoir properties.



A: OTIG 2 B: OTIG 7 C: OTIG 9 D: OTIG 11

Figure 3: Display of Sections of Well Logs used in the Well

3.1.2 Software

Schlumberger Petrel Software 2014 version was used in this study to analyze and interpret the data sets as well as for reservoir or well parameters correlation (Schlumberger, 2018). Petrel is a software used in the exploration and production sector of the petroleum industry. Petrel software was developed by a company called Technoguide in Norway and taken over by Schlumberger (Technoguide, 2014). This software allows the user to interpret seismic data, perform well correlation, visualize reservoir simulation results, build reservoir models and design development strategies to maximize reservoir exploitation.

Table 1: Log Types Present in each Well				
Well	**Gamma ray log**	**SP log**	**Density log**	**Neutron log**
OTIG 2	Yes	Yes	Yes	Yes
OTIG 7	Yes	Yes	Yes	Yes
OTIG 9	Yes	Yes	Yes	Yes
OTIG 11	Yes	Yes	Yes	Yes

3.2 Method

Well log data analysis method comprising of six stages as shown in Figure 4 was used for this study.

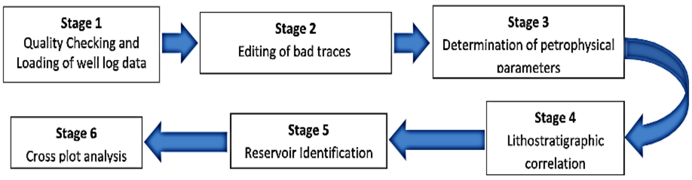


Figure 4: Workflow chat for the stages of the method used

3.2.1 Loading of Well Log Data

The data set from the four well logs were quality checked, loaded into the petrel software, analyzed and interpreted.

3.2.2 Editing of Bad Traces

The log data were normalized (corrected), de-spiked and filtered in order to remove anomalous data points, which may have resulted from gas or shale effect and from instrument reading or computational error.

3.2.3 Determination of Petrophysical Parameters

3.2.3.1 Determination of Lithology

Gamma ray (GR) log as shown in Figure 3 was used to delineate the lithology of the formation into shale and sandstone beds. The gamma ray (GR) log values ranges from 0.00 to 150.0API. As the log reading tends towards the higher values, the formation becomes more shaly while as it tends towards the lower values, the formation becomes more sandy.

According to a study, to determine the percentage volume of shale and sand in the well or reservoir, the equations below were used (Schlumberger, 2000):

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

$$V_{sh} = 0.33(2^{2I_{GR}} - 1.0) \quad (2)$$

$$\%Shale = V_{sh} \times 100\% \quad (3)$$

$$\%Sand = 100 - \%Shale \quad (4)$$

Where $I_{GR} = Gamma\ ray\ index$

$\%Shale$ = Percentage volume of shale

$\%Sand$ = Percentage volume of sand

GR_{log} = Gamma ray log reading of the formation

GR_{min} = Gamma ray log reading in sand zone.

GR_{max} = Gamma ray log reading in shale zone.

3.2.3.2 Determination of Porosity, Φ

Density log was used to determine the porosity values of the wells by applying the equation below according to (Asquith and Gibson, 1983):

$$\Phi_D = \frac{P_{mat} - P_b}{P_{mat} - P_f} \quad (5)$$

Where Φ_D = Porosity derived from density log.

P_{mat} = Density of matrix (270g/cc for sandstone used).

P_b = Formation bulk density read directly for the log.

P_f = Formation fluid density (Oil = 0.95g/cm³)

3.2.3.3 Determination of Permeability, K

In this study, permeability values of the reservoirs were determined using Kozeny's correlation equation which relates the porosity, permeability and radius of the reservoir by the equation (Kozeny's, 1927):

$$K = \frac{\Phi r^3}{8} \quad (6)$$

Where K = Permeability of reservoir

Φ = Porosity of reservoir

r = Radius of reservoir

3.2.3.4 Determination of Pressure

Under ideal hydrostatic conditions, according to a group researchers, pressure increases with depth and its values for the wells were determined using empirical relation below (Knut, 2010):

$$P = \rho_f g d \quad (7)$$

Where P = Geostatic pressure

ρ_f = Formation bulk density read from log

g = Gravitational acceleration

d = depth

3.2.4 Lithostratigraphical correlation

Lithostratigraphic units were identified on the logs and correlated across the four wells for proper lithology delineation as shown in figure 5.

3.2.5 Reservoir Identification

Three reservoirs were identified and considered in this study, and they are Sand A, Sand B, and Sand C. Figure 6 shows the three reservoirs in OTIG 2 and OTIG 7. Figure 6 shows the three reservoirs in OTIG 9, while Figure 8 shows the three reservoirs in OTIG 11.

3.2.6 Cross plot Analysis

Cross plot analysis was used to determine well parameters that better differentiate the reservoirs and show their relationships. They include porosity–permeability, porosity–pressure, permeability–pressure, as shown in figures 9 to 20.

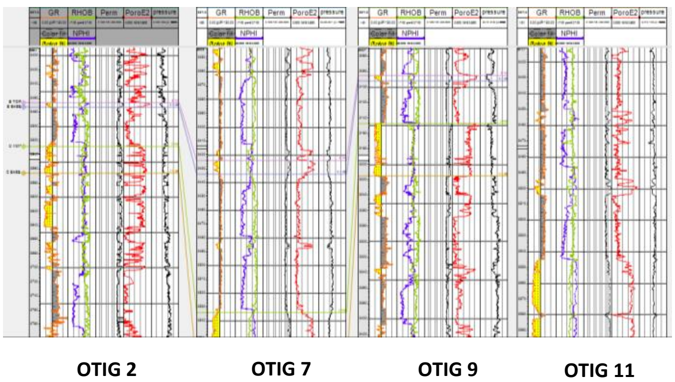


Figure 5: Lithostratigraphic Correlation of the Various Wells

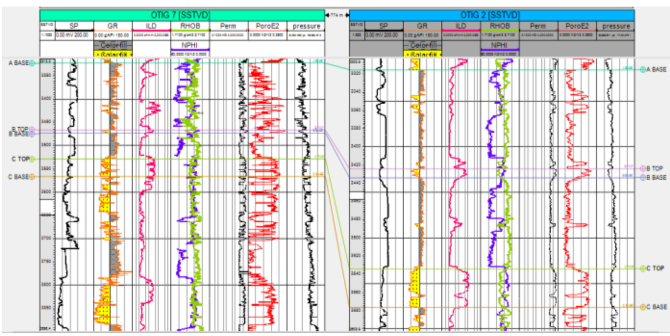


Figure 6: Display of the Three Reservoirs in Wells OTIG 7 and OTIG 2

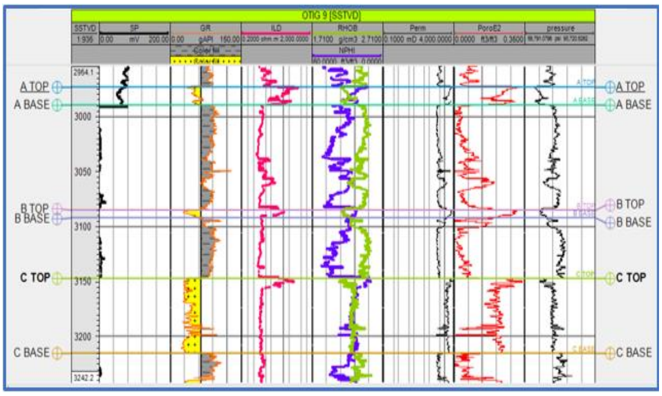


Figure 7: Display of the Three Reservoirs in Well OTIG 9

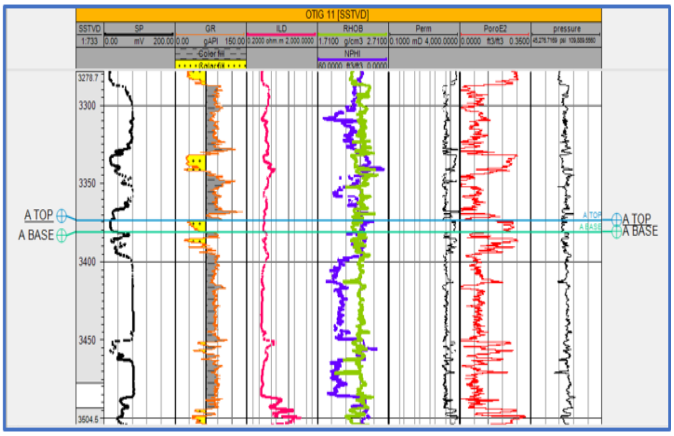


Figure 8: Display of the Three Reservoirs in Well OTIG 11

4. Results and Discussion

4.1 Petrophysical Parameters Evaluation

The results of the petrophysical parameter evaluation of the wells are presented in Tables 2 to 5 which show the values of porosity, permeability and pressure for the wells.

4.2 Cross Plot Analysis

Figure 9 to 20 shows the cross plots of porosity-permeability, porosity-pressure, permeability-pressure for the wells.

Table 2: Petrophysical Parameters Generated for Well OTIG 2

Porosity (%)	Permeability (mD)	Pressure (psi)
12.6	149.6	66829.1
14.2	138.1	68502.6
8.4	88.2	72547.9
20.4	228.1	66813.3
11.5	108.9	73518.4
28.0	213.0	69537.2
9.5	82.7	77638.2
13.8	141.8	75047.4
14.0	118.3	77523.3
15.1	135.6	77626.1
16.3	121.2	79620.6
20.4	136.3	79838.5
20.4	162.3	79501.3
26.1	197.3	78831.3
17.6	191.1	80213.9
6.5	110.9	86012.1
8.0	71.3	90490.4
20.1	136.5	86568.4
17.8	139.4	87516.1
7.3	65.7	94678.1
3.4	55.6	97114.3
4.1	53.7	98638.5
5.8	57.9	99228.1
5.0	61.5	99980.3
13.6	76.7	99425.2
14.3	104.9	97964.8
15.5	89.9	100461.8
1.1	34.9	109928.0

Table 3: Petrophysical Parameters Generated for Well OTIG 7

Porosity (%)	Permeability (mD)	Pressure (psi)
10.4	132.9	67633.6
9.9	65.8	73123.9
10.1	73.2	73664.8
17.7	150.3	70141.3
2.9	85.5	75083.0
23.6	178.4	71024.6
0.1	187.4	71718.3
10.2	105.2	77208.4
7.4	92.7	79230.1
7.0	135.9	77606.2
21.3	306.4	71211.5
26.8	203.3	76396.8
24.1	185.0	78344.6
22.9	150.2	81272.9
12.3	124.0	83982.2
1.6	84.4	88081.5
12.2	83.9	89295.7
23.5	159.5	85184.8
17.1	144.2	87206.5
18.4	144.9	90298.4

Table 4: Estimated Petrophysical Parameters for Well OTIG 9

Porosity	Permeability (mD)	Pressure (psi)
30.1	208.1	61926.9
10.9	102.1	70479.1
30.9	255.9	64750.7
5.6	78.3	74447.7
22.5	159.1	70821.9
9.2	74.7	77128.6
4.6	69.5	78740.1
28.1	216.7	71524.3
6.8	94.6	79098.4
7.1	71.4	82147.8
12.7	107.2	80540.4
4.0	68.7	84743.9
21.5	148.5	80258.9
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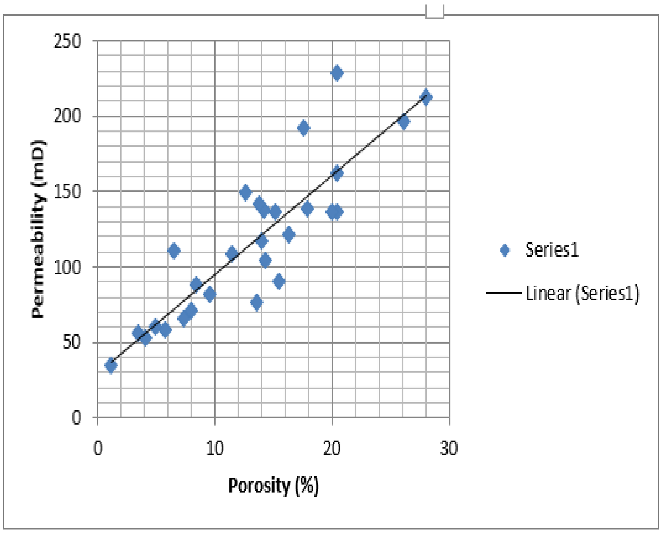

Figure 9: Porosity–Permeability Relationship for OTIG 2.

Table 5: Estimated Petrophysical Parameters for Well OTIG 11

Porosity	Permeability (mD)	Pressure (psi)
12.6	109.9	68870.8
9.7	122.5	69312.7
7.0	81.3	73041.5
4.8	109.8	68728.9
27.5	206.6	73986.4
10.2	120.6	71012.7
25.4	203.4	74325.3
23.1	155.5	73233.2
27.1	201.8	74800.4
9.8	122.5	80254.6
6.1	111.3	82088.3
8.7	101.3	77258.9
27.8	207.9	84661.0
13.2	98.0	81046.2
25.1	174.8	89285.1
2.1	71.4	82831.4
11.1	182.4	82924.9
-	202.0	86907.5
-	151.4	90707.1
-	109.5	87871.3
-	170.3	87728.1
-	192.5	95548.1
-	92.6	97697.2
-	82.1	100410.8
-	67.8	102445.8
-	61.0	102445.8
-	-	-
-	-	-
-	-	-
-	-	-

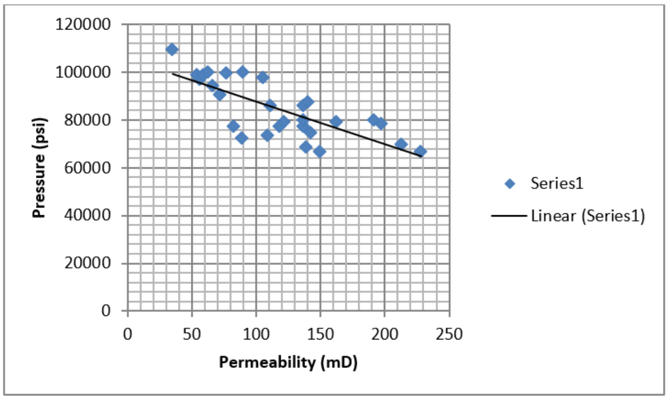

Figure 10: Pressure–Permeability Relationship for OTIG 2.

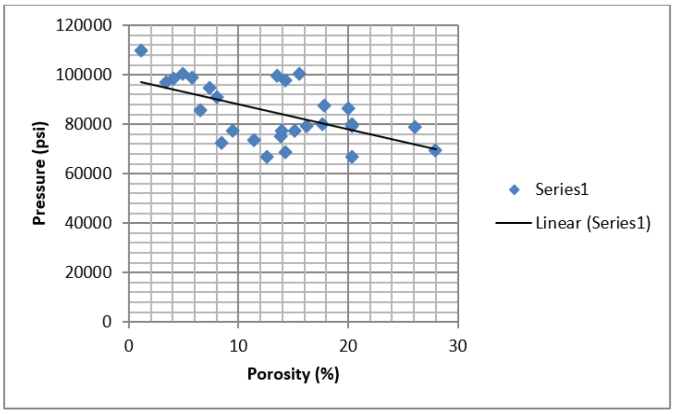

Figure 11: Pressure–Porosity Relationship for OTIG 2.

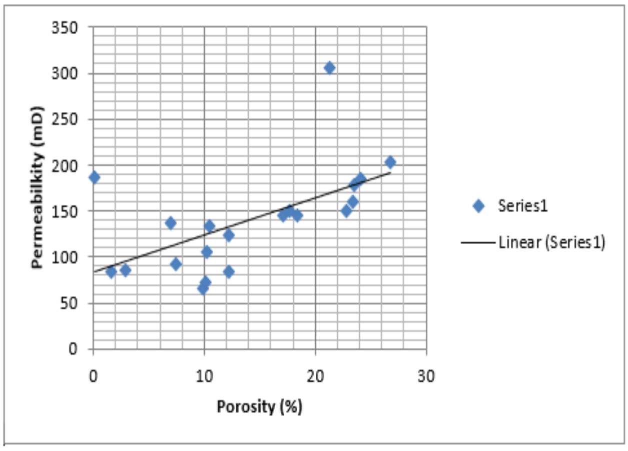

Figure 12: Porosity–Permeability Relationship for OTIG 7.

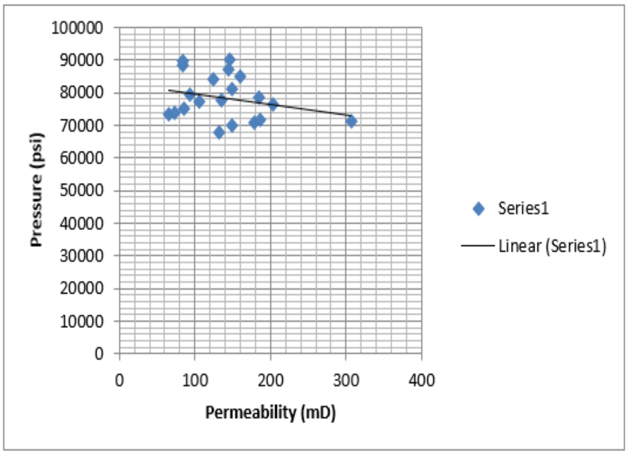

Figure 13: Pressure–Permeability Relationship for OTIG 7.

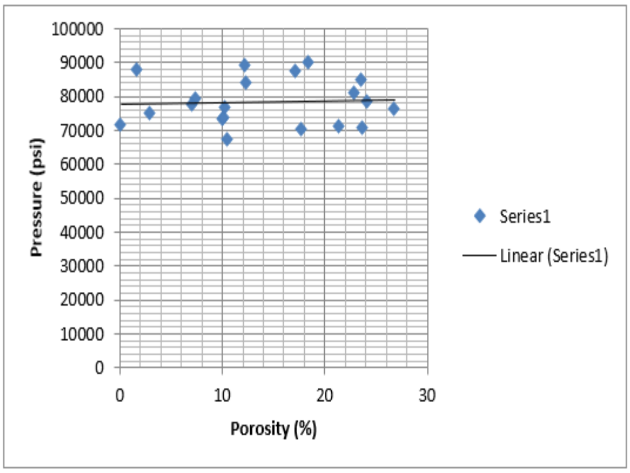

Figure 14: Pressure–Porosity Relationship for OTIG 7.

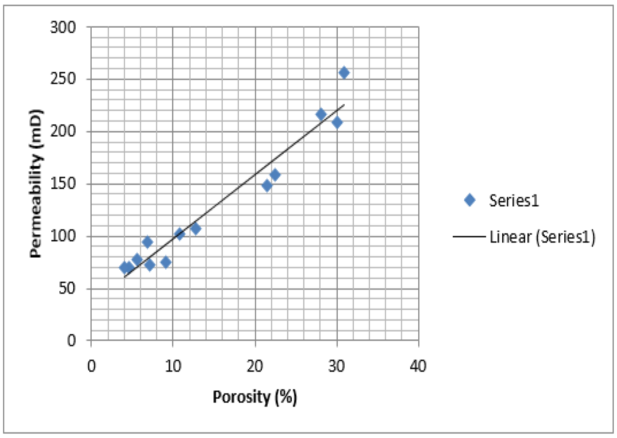

Figure 15: Porosity–Permeability Relationship for OTIG 9.

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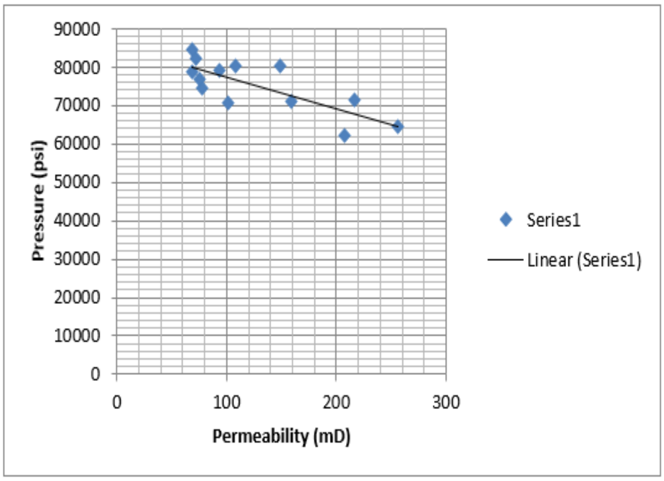

Figure 16: Pressure–Permeability Relationship for OTIG 9

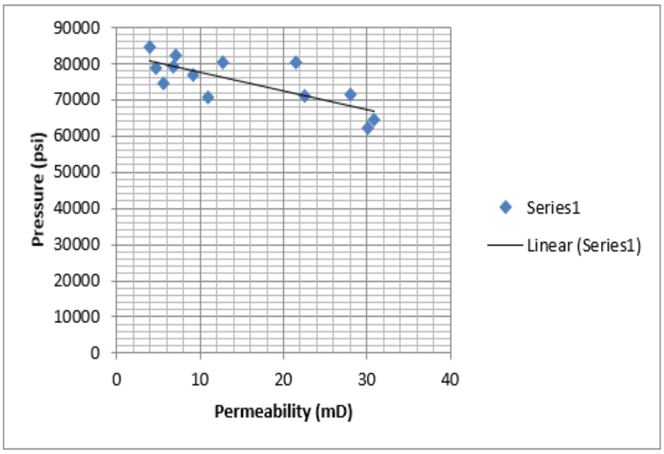

Figure 17: Pressure–Porosity Relationship for OTIG 9

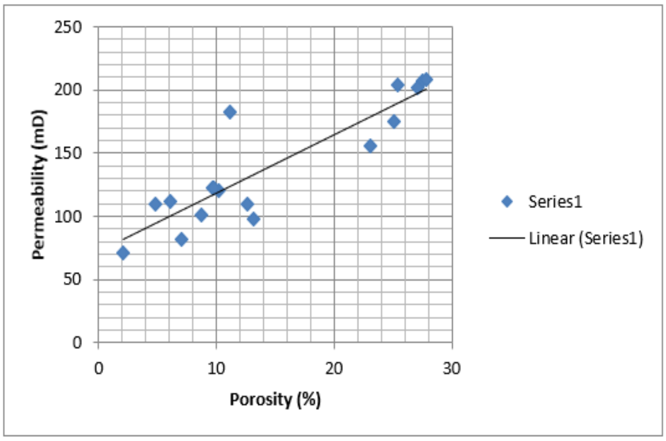

Figure 18: Porosity–Permeability Relationship for OTIG 11.

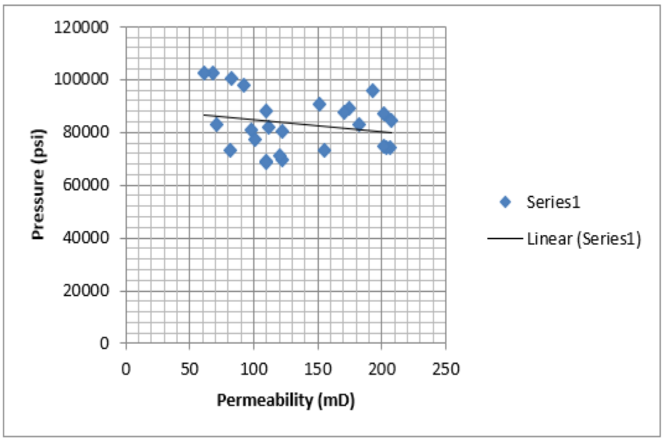

Figure 19: Pressure–Permeability Relationship for OTIG 11.

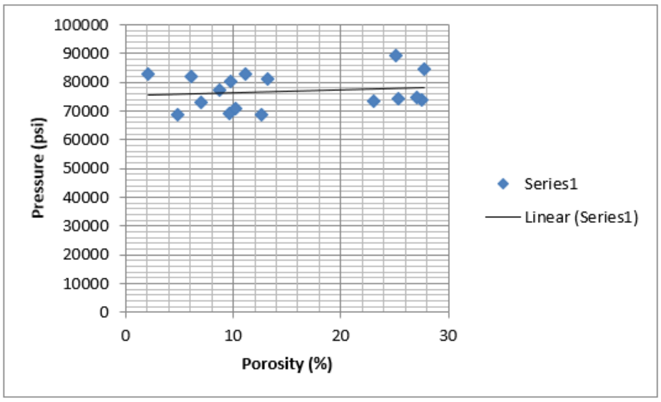

Figure 20: Pressure–Porosity Relationship for OTIG 11.

4.3 Porosity – Permeability Relationship

Figures 9, 12, 15 and 18 Show the relationship between porosity and permeability for the four wells. It is observed that there is an linear increase in the values of porosity and permeability in the four wells.

4.4 Permeability – Pressure Relationship

Figures 10, 13, 16, and 19 show pressure and permeability relationship for the four wells. There is a general decrease in permeability as pressure increases, this implies that the higher the pressure, the lower the permeability because higher pressure causes compaction and reduction in porosity and thus reduction in permeability.

4.5 Porosity – Pressure Relationship

It is observed from Figures 11, 14, 17 and 20 which show the Porosity and pressure relationship that porosity decreases with increase in pressure. The deeper the formation, the more pressure from overburden which causes compaction of the formation and reduction in porosity.

4.6 Delineation of Reservoir

The top and base of the identified reservoirs of interest for wells OTIG 2, OTIG 7, OTIG 9 and OTIG 11 are shown in Table 6. The lithostratigraphic correlation revealed that each reservoir sand unit spread across the wells and differs in thickness with some unit occurring at greater depth than their corresponding unit. This could possibly be as a result of subsidence and/or faulting.

4.7 Porosity

The range of porosity value for the well are as follows: OTIG 2: 0.011(1.1%) to 0.280 (28.0%), OTIG 7: 0.001(0.1%) to 0.268 (26.8%), OTIG 9: 0.040 (4.0%) to 0.309(30.9%) and OTIG 11 is from 0.021 (2.1%) to 0.278 (27.8%). According to Levorsen (1964), rocks have negligible porosity when ≤ 5%, poor porosity when >5 ≥ 10%, good porosity when > 10 ≤ 20%, very good when > 20 ≤ 30% and excellent when >30%. Based on this classification, the porosity values recorded for OTIG 9 is classified as excellent and very good for OTIG 2, OTIG 7 and OTIG 11.

4.8 Permeability

Permeability measures quantitatively the ability of a porous medium to transmit fluid. It depends largely on the interconnectivity of the pore spaces, the grain size of rocks and cementation between the rock grains. A rock could be extremely porous, but if the pores are not interconnected, the rock would be impermeable. The results of well permeability ranges from 34.999mD to 228.127mD for OTIG 2, 65.761mD to 306.360mD for OTIG 7, 68.680mD to 278.089mD for OTIG 9, and from 61.039mD to 207.913mD for OTIG 11. Both Levorsen (1967) and Rider (1996) classified reservoir quality based on permeability values as follow; ≤10mD (poor to fair), > 10 ≤ 50mD (moderate), > 50 ≤ 250mD (good), > 250 ≤ 100mD (very good), and >1000mD (excellent). Based on this classification, wells OTIG 2 and OTIG 11 are classified as good whereas well OTIG 7 and OTIG 9 are very good.

4.9 Overburden Pressure

As deposition and accumulation of sediments increases to a greater thickness, overburden stress is induced by the weight of the overlying formations or rocks. Overburden pressure is the pressure on rock from the weight of rock and earth above the formation, thus porosity and permeability are reduced (Knut, 2010). When overburden pressure is low, it implies the formation is loosely packed, and there is a lot of space for sand grains to realign under pressure. The results of the pressure values of the wells range from 66813.328psi to 109928.054psi for OTIG 2, 67633.593psi to 90298.351psi for OTIG 7, 61926.863psi to 84783.570psi for OTIG 9 and from 68870.750psi to102445.796psi for OTIG 11.

Table 6: Reservoir Sand Units in the Wells

Well	Reservoir	Top	Base	Thickness (ft)
OTIG 2	Sand A	2100ft	2120ft	20
	Sand B	2475ft	2495ft	20
	Sand C	3532ft	3572ft	40
OTIG 7	Sand A	3280ft	3320ft	40
	Sand B	2426ft	2436ft	10
	Sand C	3530ft	3565ft	35
OTIG 9	Sand A	2949ft	2990ft	41
	Sand B	2086ft	2094ft	08
	Sand C	3145ft	3215ft	70
OTIG 11	Sand A	3275ft	3319ft	44
	Sand B	3520ft	3675ft	155
	Sand C	3730ft	3820ft	90

5. Conclusion

From the results of this study, it is concluded that there is a linear increase in the values of porosity and permeability in the four wells. Porosity decreases with increase in overburden pressure, there is a general decrease in permeability as overburden pressure increases. The reservoirs of wells OTIG9 and OTIG11 are more porous and permeable compared to the reservoirs of OTIG2 and OTIG7.

Recommendation

It is recommended that 3-D seismic data and vertical seismic profiling (VSP) data should be incorporated into related work to allow for detailed and complimentary study of oil wells. As this will give room or make provision for the generation and analysis of seismic images or sections that will reveal more details of the geologic features of the well.

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