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Unconventional Hydrocarbon Potential of the Nigerian Inland Basins: a Clue from the Duvernay Shale Gas Resource Estimation in Western Canadian Sedimentary Basin

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Abstract

Duvernay Formation which is a home for the unconventional shale gas reservoir exploitation also serves as the source rock of the Ludec-age reef of east central Alberta in the Western Canadian Sedimentary Basin. The main objective of this study is to look at the shale rocks that have good possible source rock potentials that can be exploited within the Nigerian Inland Basins from rock Eval pyrolysis analyses and adsorption isotherm analysis and then to calculate the OGIP of the Duvernay shale gas formation of Alberta in the WCSB which will serve as an example for exploring the Nigerian potentials. From the findings the OGIP was calculated to be 17.172bcf per section within an area of 532 acre of the formation. Nigeria consist of seven sedimentary basins including four inland basins and the best possible source rocks include the Awgu Formation in the Benue Trough, Patti Shales in Bida Basin, the Dukamaje Formation in Sokoto Basin, Fikka Shales of Borno-Chad Basin are having an average TOC greater than 1%. These source rocks have TOC, organic maturation and T_{max} similar to those of the Duvernay Formation and if exploited like the Duvernay for unconventional hydrocarbons, will yield large volumes of oil and gas for the Nigerian government and peoples on a long-term basis. It is also recommended that a thorough research on the areas within the Nigerian Inland Basins be properly looked at and fully understood with regards to unconventional properties and parameters necessary for optimization of its hydrocarbons and other resources altogether.

Keywords:
Unconventional,
Basin,
Shale Gas,
Maturation and
Formation

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Background to the Study

The fall in the global prices of petroleum around the world may have many explanations however, one of the major reasons can be attributed to the increase in the exploitation of the unconventional hydrocarbon potentials like shale gas, shale oil, tight gas, coalbed methane, and geopressured gas, gas hydrates and ultra-deep gas (Rogner, 1997) in places that have once been written-off with regards to their hydrocarbon potentials.

According to Faraj et al (2004) and Agrawal et al (2010), shale gas reservoirs are those with low porosity and extremely low permeability that can only be exploited economically at a profit when multilateral horizontal wells and hydraulic fracturing are employed. Countries in the forefront of this technological innovation include the USA, Canada, China and Argentina. These countries have greatly improved their reserves by the exploitation of the shales within their basins thereby reducing their demands for exported hydrocarbons since the lower the demand, the lower the price.

This shale gas production has created more reserves and added greatly to the world energy-mix but Ayodele in 2011 suggested that there is a great 'disconnect' between Nigeria and the rest of the world with respect to these unconventional hydrocarbon advancement and this has to be tackled. Nigeria has a great potential for this source of energy as there are abundant shale rock presence in all the inland basins of the country but little progress has been made in terms of its development. Shale gas technology and innovation is at best in its infant stage in the country.

Ayodele (2011) further pinpointed out in his work on the development of the Nigerian unconventional hydrocarbon resources that: "Unconventional hydrocarbon resources have the potentials to generate more royalty and tax revenues for the Nigerian government on a long-term basis and that rules guiding their developments should be incorporated now in the Petroleum Industry Bill (PIB) our lawmakers are looking into, just as several jurisdictions around the world are dusting their hydrocarbons laws and working to include rules for the development of unconventional hydrocarbon resources" The prospects of shale gas resources in Canada are very bright as will be seen in this research particularly in the Alberta area of the Western Canada Sedimentary Basin (WCSB).

Objectives of the Study

The aim of this study is to look at the shale rocks that have good possible source rock potentials that can be exploited within the Nigerian Inland Basins and then to calculate the original gas-in-place of the Duvernay shale gas formation of Alberta in the Western Canadian Sedimentary Basin which will serve as an example for exploring the Nigerian potentials. Data were extracted from the field and laboratory analyses done and documented in the works of the Energy Resources Conservation Board (ERCB) and the Alberta Geological Society (AGS) gotten from Beaton *et al*, (2010) and (Anderson et al, 2010).

Gas-initially-in-place will only be estimated accurately when the percentage of adsorbed gas is rightly accounted for therefore, this is crucial in achieving this aim. Some sets of objectives where formulated and followed including:

1. Critically review the existing work on the petroleum potentials of the four Inlands basins of Nigeria; the Benue Trough (Upper, Middle and Lower), the Bida Basin, the Sokoto (or SE lullemmeden) Basin and the Southern Chad (or Borno) Basin.
2. Pinpointing the possible shale source rocks in the Nigerian Inland Basins that can be exploitable for shale gas evaluation in the four basins with regards to their organic maturation, TOC and HI.
3. Determining the percentage of adsorbed gas in the Duvernay formation using the Langmuir volume and Langmuir pressure from isotherm plot also known as the Langmuir Isotherm.
4. Calculating the original gas-in-place of an area in the Duvernay formation using as a summation of the free gas-in-place and the adsorbed gas-in-place and determining their ratios.

Materials and Methods

This research has integrated quantitative mathematical calculations combined with extensive published literature. Literature review was aimed at evaluating the present state of theoretical, practical and experimental knowledge the four inland basins source rock potentials, Duvernay formation in Canada and of existing evaluation techniques for calculating the original gas in place of shale gas reservoirs systems.

Mathematical procedures to calculate the Original Gas in Place where done on data generated from laboratory studies on shale sample slides from Alberta's Duvernay formation cores and outcrops and they included rock Eval pyrolysis analyses for TOC, organic maturation and hydrogen index etc. and also adsorption isotherm analysis of some core samples to determine the gas holding capacity of organic matter within the formation respectively.

Literature Review

Duvernay Formation which is a home for the unconventional shale gas reservoir exploitation also serves as the source rock of the Ludec-age reef of east central Alberta in the Western Canadian Sedimentary Basin (Stoakes and Creaney, 2012).

The formation is organic-rich basinal carbonaceous shales with extremely low porosity and permeability when compared to the conventional sandstone and limestone reservoirs. This implies that a normal conventional organic rich and mature-enough source rock in the Nigerian Inland Basin can be a very good reservoir of oil and/gas when unconventional investigation is made and the right approach is applied. Although shales have extremely low porosity and permeability as the case in Nigeria, the use of multi-lateral horizontal drilling and hydraulic fracturing can be applied to exploit the potentials of these shales within the inland basins. Nigeria consist of seven sedimentary basins including four inland basins namely; the Benue Trough, the Bida Basin, the Sokoto (or SE lullemmeden) Basin and the Southern Chad (or Borno) Basin. Sediments were successfully deposited in these inland basins from middle Mesozoic to Recent age.

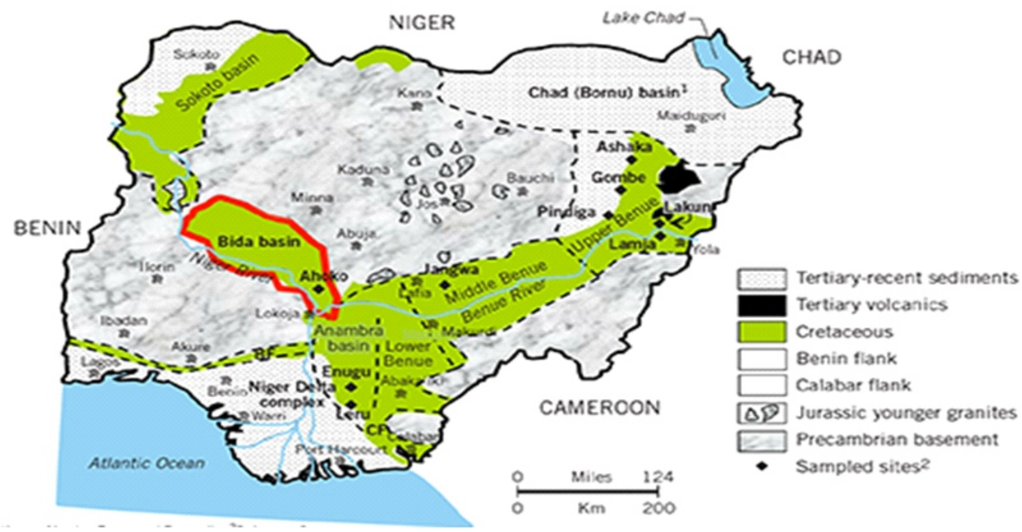

Figure 1: Sedimentary basins of Nigeria and their Ages
Source: Rocks of the Nigerian Inland Basins

The Benue Trough is further subdivided into Lower, Middle and Upper sections. The Middle Benue Trough has according to Yohanna (2015) six formations namely: Asu River Group, Awe formation, Keana formation, Ezeaku formation, Awgu formation and Lafia formation. The best possible source rock from Yohanna's (2015) research in the Middle Benue Trough is the Awgu Formation of Coniacian age.

The stratigraphic succession of the Bida or Mid-Niger Basin which can be divided into Northern and Southern (or Lokoja) Sub-Basins are: a. Lokoja Formation, Bida Formation, Patti Formation, Sapke, Enagi Formations, Abgaja and Patati Formations. Patti Shales are the best possible source rocks here.

The Lullemmeden Basin in Northern Nigeria is locally called the "Sokoto Basin". The stratigraphy shows that the Gundumi-Illo Formation is at the base then followed successively by the Taloka, Dukamaje and Wurno formations, then Dange, Kalambaina, Gamba and Gwandu formations with decreasing ages. The Dukamaje Formation provides the best possible source potential from available researches.

Borno or Southern Chad Basin is poorly exposed in Nigeria and is separated with the Upper Benue Trough by the Zambuk Ridge. The formations here are; Bima Sandstone, Yolde Formation, Gongila Formation, Fikka Shales, Gombe Sandstone and the Kerri-Kerri Formation. Fikka Shales are the best possible source rocks in this basin.

Studies of data sets containing gas shales show the need to account for the adsorbed gas in the calculation of the original gas in place. The second aspect of the methodology is quantitative in nature (in which the field and laboratory analyses compiled by the Energy Resources Conservation Board (ERCB) and the Alberta Geological Society (AGS) where done in Canada).

Characterizations of Best Possible Source Rock in Each Inland Basin of Nigeria

According to Dyman et al (1996), source rock potentials are mainly characterized with respect to their TOC and other genetic potential, when they assessed the Cretaceous rocks of South West Montona, USA. Here the TOC, Organic Maturation and Maximum temperature T_{max} of the Inland Basin source rocks are characterized.

TOC is a fundamental attribute of gas shale and is a measure of present-day organic richness. The minimum value usually required for a potential petroleum source rock is 0.5 wt. %, TOC for Barnett range from 1—4.5%. Organic maturity is often expressed in terms of vitrinite reflectance (% Ro), where a value above approximately 1.0%–1.1% Ro indicates the organic matter is sufficiently matures to generate gas and could be an effective source rock (Yohanna, 2015). Tmax correspond to the maximum pyrolysis oven temperature during maximum generation of hydrocarbons as shown in Fig2 bellow.

Stage	T_{max}
Onset of oil	
Type I kerogen	~445°C
Type II kerogen	~435°C
Type III kerogen	~440°C
Onset of gas	~460°C

Figure 2: These Figure shows the T_{max} Range and the Related Kerogen Type in a Tabular Format

The results of the best possible source rocks as investigated are as follows:

AWGU FORMATION-BENUE TROUGH: It is composed of bluish grey bedded shale with occasional intercalations of limestone, fine grained calcareous sandstone and coal seams. TOC range from 1.5% to 3.5 in lower sections, and up to 6.54% in the middle parts and the organic maturation value here is between 0.83—1.13%Ro (Yohanna, 2015) and T_{max} values range from 444-481˚C with TYPE III and TYPE IV kerogen.

Patti Shales-Bida Basin: These are carbonaceous shales intercalated with sands and clays. Average TOC for Patti Formation is 2.1%, Ro from 0.4-0.6% and the Tmax of between 407-426˚C. TYPE III kerogen is most likely.

Dukamaje Formation-Sokoto Basin: The Dukamaje Formation has a TOC range of about 0.01-10.93% and Tmax of 423-499 obtain from a shallow well drilled in Sokoto (Obaje et al, 2013).

Fikka Shales Borno-Chad Basin: These shales are having an average TOC greater than 1%. The T_{max} values range between 427°C and 436°C. Type II (oil and gas-prone) kerogen.

Duvernay Shales

There are many similarities between the Duvernay Formation in Canada and the above listed source rocks of the Nigerian Inland basins. For instance the Devonian Duvernay Formation of WCSB has an average of 4.5% TOC but may range from 0.2-8.0% in some places which is quite similar to those seen in the Nigerian source rocks. The exploitation of the Duvernay Formation for shale gas in in its advance stage and many data for TOC, maturation, HI, OI, PI etc are available as compiled by Rokosh et al, (2010).

Original Gas-in-Place Estimation Method

To rightly calculate the OGIP, the adsorbed gas has to be properly accounted for. Novas Consulting Ltd (2011) and Rogner (1997) did some work on calculating the OGIP using the TOC and hydrogen index (Clarke, 2011) but the approach adopted for this study uses the adsorption isotherm formula in a similar pattern with the Energy Information Administration (EIA), (2011).

Data Set for Calculating Adsorption Isotherm in Raw Basis

The raw data that was employed for the determination of the Langmuir pressure and Langmuir volume were gotten from different samples within the area selected for this study. Pressure and gas content for different points in each sample were measured and recorded at constant temperature. The samples are numbers 8995, 9261, 9262 and 9263. Tables1, 2, 3, and 4 are the tables that show these raw pressure and volume of gas for the above mentioned tables respectively in SI units and practical units.

Table1: Point Data for Sample 8995 with its Pressure and Gas Volume modified from Beaton *et al*, (2010)

Points	GasContent (scc/g)	Pressure (Mpa)	Gas Content (scf/ton)	Pressure (Mpa)
1	0.02	0.43	0.80	63
2	0.07	0.80	0.20	116
3	0.12	1.54	3.70	224
4	0.18	2.92	5.70	424
5	0.27	5.72	8.70	829
6	0.34	8.48	11.0	1230
7	0.40	12.35	12.7	1791
8	0.43	16.37	13.7	2374
9	0.45	20.46	14.4	2968

Table2: Point Data for Sample 9261 with its Pressure and Gas Volume modified from Beaton *et al*, (2010)

Points	GasContent (scc/g)	Pressure (Mpa)	Gas Content (scf/ton)	Pressure (psia)
1	0.07	0.88	2.10	128
2	0.13	1.63	4.10	236
3	0.21	3.17	6.70	460
4	0.32	6.21	10.10	900
5	0.41	9.20	13.10	1,335
6	0.46	13.08	14.70	1,897
7	0.50	17.46	16.10	2,533
8	0.57	22.86	18.40	3,316
9	0.60	27.86	1920	4,041

Table3: Point Data for Sample 9262 with its Pressure and Gas Volume modified from Beaton *et al*, (2010)

Points	GasContent (scc/g)	Pressure (MPa)	Gas Content (scf/ton)	Pressure (psia)
1	0.06	0.86	1.8	125
2	0.11	1.62	3.4	235
3	0.17	3.19	5.4	462
4	0.27	6.34	8.6	919
5	0.31	9.20	9.9	1,335
6	0.37	13.12	11.8	1,903
7	0.42	17.29	13.3	2,508
8	0.43	22.54	13.8	3,269
9	0.45	27.66	14.3	4,012

Table4: Point Data for Sample 9263 with its Pressure and Gas Volume modified from Beaton *et al*, (2010)

Points	GasContent (scc/g)	Pressure (MPa)	Gas Content (scf/ton	Pressure (psia)
1	0.02	0.79	0.5	114
2	0.04	1.50	1.3	217
3	0.06	2.94	2.0	426
4	0.09	5.78	2.8	838
5	0.11	8.71	3.5	1,263
6	0.13	12.66	4.1	1,836
7	0.15	16.85	4.7	2,444
8	0.16	21.23	5.0	3,079
9	0.16	27.13	5.0	3,935

Table.5 is a result of the calculated Langmuir Pressures and volumes from the values given for points in samples 8995, 9261, 9262 and 9263 respectively with their calculated average (for field units only).

Table5: Estimated Langmuir Volume and Pressure as derived from the previous tables modified from Beaton *et al*, (2010)

Point No.	S.I. Units		Field Units	
	Langmuir Volume (scc/g)	Langmuir Pressure (MPa)	Langmuir Volume(scf/ton)	Langmuir Pressure (psia)
1	0.02	0.79	0.5	114
2	0.04	1.50	1.3	217
3	0.60	2.94	2.0	426
4	0.09	5.78	2.8	835
5	0.11	8.71	3.5	1,263
6	0.13	12.66	4.1	1,836
7	0.15	16.85	4.7	2,444
8	0.16	21.23	5.0	3,079
9	0.16	27.13	5.0	3,935
Average V_L and P_L in field Units			17.3	1049.03

Adsorption Isotherm

The Langmuir Isotherm was used here over other isotherms such as Freundlich's and Temkin's because it provides useful insight on the dependence of surface adsorption on pressure and it is one of the simplest of all (Suits and Martin, 1974). The data for the gas content and pressure (raw basis) that led to the plot for the isotherm are;

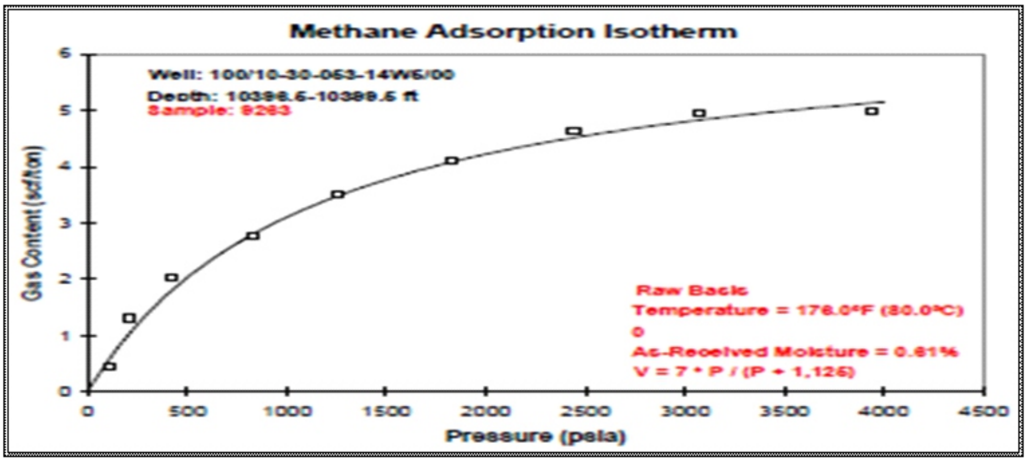

Figure3: Langmuir Adsorption Isotherm Plot of sample 9263 (Anderson et al, 2010)
The gas content was then plotted against the pressure at a temperature of 176.0K (80°C) to determine the Langmuir Pressure (P_L). This represents the pressure at which the gas content equals a half of the maximum gas storage volume as seen in Figure3 above.

Adsorbed Gas-In-Place
The equation for calculating the adsorbed gas content is;

$$G_c = \frac{(VL \text{ x } P)}{(PL + P)} \quad \text{............ eqn 1}$$

Where:
G_c (Adsorbed gas content) =?
P (Reservoir Pressure) = 4941.200psi (32MPa)
V_L (Langmuir volume average) = 17.39scf/ton (0.520scc/g)
P_L (Langmuir pressure average) = 1049.030psia (7.230MPa)
Substituting this into eqn1 we have

$$G_c = \frac{(17.390 \text{ x } 4941.2)}{(1049.03 + 4941.2)} = \frac{85927.47}{5990.23} = 14.34 \text{ scf/ton}$$

For the adsorbed gas-in-place, Crain, (2001) gave an equation (2) as shown below;
$\mathbf{GIP_{adsorb} = 1.3597 \text{ X } 10^{-6} \text{ x } A H \text{ x } G_c \text{ x } \rho_{shale}}$ eqn2
Where GIP_{adsorb} (Adsorbed gas-in-place) =? **A** (Area estimated) = 532 Acre (2.153km^2)
H (Average thickness) = 65.620ft (20m) * ρ_{shale} (Shale density) = 50lb/ft^3 (0.811g/cc)
GIP_{adsorb} = 1.3597 x 10^{-6} * 532 * 65.620 * 14.340 *0.811 = 0.552 bcf/section
∴GIP_{adsorb} = 0.552billion cubic feet (15.620million cubic meters)

Free gas-in-place
The volumetric formula for calculating the free gas-in place (Ahmed, T. 2006) uses the following conventional standard reservoir engineering equation:

$$GIP_{free} = \frac{Ah\text{Ø} * (1 - Sw)}{(Bg)} \qquad ....eqn\ 3$$

Where GIP_{free} (free gas-in-place) =?
T (Initial reservoir temperature) = 716.670°R (398K) **H** (Average thickness) = 65.620ft (20m)
Z (Gas compressibility) = 0.989 **A** (Area of interest) = 532 acre (23,172,929ft or 2.153km^2)
Ø (Average porosity) = 6.333% S_w (Water saturation) = 0.300

B_g(Gas formation volume factor) = $\frac{0.02827\ xZT}{P}$ =0.02827$*$ 716.67$*$ 0.989/4941.2 = 4.0552 x 10^{-3} ft^3/scf

Then, **GIPfree** = $\frac{23{,}172{,}920 * 65.62 * 0.0633 * (1-0.3)}{4.0552 \text{ x } 10\text{-}3}$ = $1.662 \text{ x } 10^{10}$

Therefore GIP_{free}= 16.62bcf (470.21 million cubic meters)

Total Original Gas-in-Place
The total original gas-in-place is a summation of the free gas-in-place and the adsorbed gas-in-place and using eq^n. 5 from chapter three it implies that;

$OGIP_{total}$= GIP_{free} + GIP_{adsorb}= 16.62 + 0.552 = 17.172 bcf (485.83million cubic meters)
The total original gas-in-place in the Duvernay formation in the estimated area of 532acre of shale is 17.172billion cubic feet per section.

Conclusion and Recommendations
The study of the Duvernay Formation which is a home for the unconventional shale gas reservoir exploitation shows that a shale rock can serve as the source rock and reservoir for oil and gas accumulation as seen in the Ludec-age reef of east central Alberta in the Western Canadian Sedimentary Basin.

Nigerian sedimentary basins include four inland basins namely; the Benue Trough, the Bida Basin, the Sokoto Basin and the Southern Chad Basin.The best source rocks in Nigeria include the Awgu Formation in the Benue Trough, Patti Shales in Bida Basin, the Dukamaje Formation in Sokoto Basin and the Fikka Shales of Borno-Chad Basin. These source rocks have TOC, organic maturation and Tmax similar to those of the Duvernay Formation and if exploited for unconventional hydrocarbons, will yield large volumes of oil and gas as these have the potentials to generate more royalty and tax revenues for the Nigerian government on a long-term basis.

It is also recommended that the areas within the Nigerian Inland basins be properly studied and fully understood with regards to unconventional properties and parameters necessary for optimization of its hydrocarbons and other resources altogether.

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