A STUDY OF THE ORGANIC RICHNESS AND PETROPHYSICAL CHARACTERISTICS OF SELECTED SHALES FROM THE ANALYSIS OF WIRELINE LOGS: A CASE OF "NEYA" FIELD, NIGER DELTA

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ABSTRACT

This study evaluated and assessed the organic richness and some petrophysical properties of selected shale intervals from six wells in the "Neya Field", Niger Delta. This was done by quantifying their average total organic carbon (TOC), thickness, volume of shale (VShale) and effective porosity (PHIE) from wireline logs. Six to seven shale intervals were delineated and their properties calculated empirically using established relations. The petrophysical properties of the intervals indicate they have the characteristics typical of shaly to shale zones. The TOC of the shales varies from 7.56 to 12.44 wt% in the wells which exceeds the threshold of 0.5wt% for shale source rocks. These indicate that they have above minimum TOC to generate hydrocarbon and are in fair agreement with TOC values earlier reported in some parts of the paralic sediments of onshore and offshore Niger Delta. Additional results indicate that organic enrichment (TOC) does not have clear dependence on thickness, volume of shale or effective porosity of the shales in the study area.

Keywords: Shale, Petrophysical, TOC, Niger Delta, Nigeria

INTRODUCTION

Source rocks are commonly shales and limestones that contain organic matter (Meyer and Netherlof, 1984; Tissot and Welte, 1984). Among the petroleum geologists and petroleum geochemists, it is universally agreed that rocks sourcing commercial amounts of hydrocarbons normally have a TOC (Total Organic Carbon) value of more than 1 wt% (by weight) although their ultimate commerciality depends on other factors such as organic matter type and expulsion/drainage efficiency (Hunt, 1996).TOC is the measure of concentration (wt%) of organic matter contained within sediments (Adepelumi *et al.,* 2010). According to Jarvie (1991), the quantity of organic matter in a formation, measured as weight percent (TOC), is an indicator of its organic richness and generative potential. It varies from less than 1 wt% in poor source rocks to over 20 wt% in rich so called oil shales (Dresser Atlas, 1979). Peters and Cassa (1994) showed that source rocks with less than 0.5 wt% TOC have poor generative potential; 0.5 to 1 wt% TOC are considered fair; 1% to 2 wt% TOC are considered good; 2 to 4 wt% TOC are considered very good, and source rocks with greater than 4 wt% TOC are considered to have excellent generative potential.

Petrophysical techniques have proven to be valuable in assessing the quality of source rocks for basin studies, especially where the database is restricted to basic log data and little or no geochemical information is available (Adepelumi *et al.,* 2011). Although organic matter content can be determined directly from laboratory analyses of core samples, indirect methods based on wire-line log data can also be used to determine the organic matter contents of a particular basin or prospect (Fertl and Chillingar, 1988). Wireline logs have the added advantage of being readily available and less expensive(Schmoker, 1979, 1981; Aly and Mahmoud, 1994; Aly, 1995; and Ali, 2002). Similarities have also been observed in the organic matter results obtained directly from the laboratory and indirectly from wireline logs with insignificant errors or differences of about 0.2 to 0.4% (Schmoker, 1979; Schmoker and Hester, 1983). Schmoker (1979) and Schmoker and Hester (1983)used both gamma ray and density logs for the calculation of the TOC within the Bakken Formation, Williston Basin, USA. Meissner (1978) had earlier demonstrated the relationship between oil generation and shale resistivity within the basin. The use of ΔlogR for calculating the TOC%has been successfully

applied to many wells worldwide (Passey, et al., 1990) and Meyer and Nederlof (1984), opined that with maturity, the resistivity of a source rock increases by a factor of ten or more. Schmoker and Hester (1989) used resistivity log as an indicator of oil generation in Bakken Shale where they discovered that a formation resistivity of 35 Ωm differentiated thermally immature shales from mature ones. Although, the relative ability of a source rock to generate oil and gas is dictated by the quantity of organic matter (i.e. total organic carbon or TOC), the quality or type of organic matter (i.e. hydrogen content), and the thermal maturity of the organic matter in the rock. The TOC measurement is the first screen for quantifying organic richness (McCarthy *et al.,* 2011). It is after this initial screening test demonstrates sufficient organic content, that the rock is then subjected to additional tests to ascertain organic quality and maturity (McCarthy *et al.,* 2011).

This field does not have any geochemical data, so this study is firstly, an attempt at estimating TOC from wire line logs for some selected shale intervals from established relation proposed by Schmoker (1979) and Schmoker and Hester (1983) and possibly classify them as low or high potential source rocks according to Peters and Cassa (1994).Secondly, it is to compare the TOC obtained from this study to other petrophysical properties of the shales for any relationship and, thirdly compare the TOC results to those obtained by other workers on Agbada Formation. This may confirm that the technique is suitable for quick estimation of TOC where little or no geochemical data are available.

Regional Geology of Study Area

The Tertiary Niger Delta is situated in the Gulf of Guinea in West Africa (Fig. 1). It builds out into the Central Atlantic at the north of the Niger, Benue, and Cross rivers drainage systems (Doust and Omatsola, 1990). The Niger Delta sedimentary basin is located between latitude 4° and 6°N longitude 3° and 9°E (Nwachukwu and Chukwura, 1986). The delta covers a land area in excess of 105,000 km² (Avbovbo, 1978). Three subsurface stratigraphic units have been recognized by Short and Stauble (1967) - the

continental top facies (Benin Formation), the paralic facies (Agbada Formation) and the holomarine (Akata Formation) (Fig. 2). The Benin Formation is the shallowest of the sequence and consists predominantly of fresh water-bearing continental sands and gravels. According to Short and Stauble (1967), the Agbada Formation underlies the Benin Formation and consists primarily of sand and shale and is of fluvio-marine origin. It is the main hydrocarbon-bearing interval. The Akata Formation is composed of shales, clays and silts at the base of the known delta sequence and it is described as the source rock of the basin (Short and Stauble, 1967). The Formation contains a few streaks of sand, possibly of turbiditic origin. The thickness of this sequence is not known for certain, but may reach 7000m in the central part of the delta (Short and Stauble 1967). Avbovbo (1978) suggested that the petroleum in the sandstone of Agbada Formation is trapped mostly in the rollover anticlines formed by growth faults. The Agbada Formation has shale intervals that contain organic carbon contents sufficient to be considered good source rocks (Ekweozor and Okoye, 1980; Nwachukwu and Chukwura, 1986). The intervals, however, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the delta (Evamy *et al.,* 1978; Stacher, 1995).However, the Akata shale is present in large volumes beneath the Agbada Formation and is at least volumetrically sufficient to generate enough oil for a world class oil province such as the Niger Delta. Based on organic-matter content and type, Evamy *et al,* (1978) proposed that both the marine shale (Akata Formation) and the shale interbedded within the paralic sandstone (lower Agbada Formation) were the source rocks for the Niger Delta oils. The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals; clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting and vertical seals (Doust and Omatsola, 1990). In recent years, the deep-water Niger Delta has been opened to exploration. At the deep-water toe of the delta, a series of large fold and thrust belts composed of thrust faults and fault-related folds have been reported (Wu and Bally, 2000; Corredor *et al.,*

2005). Studies from a producing deepwater field have ascribed upper Oligocene age to the lowermost part of the Agbada unit and inferred the Akata interval to be pre-Miocene in the lower delta slope (Chapin et al., 2002).
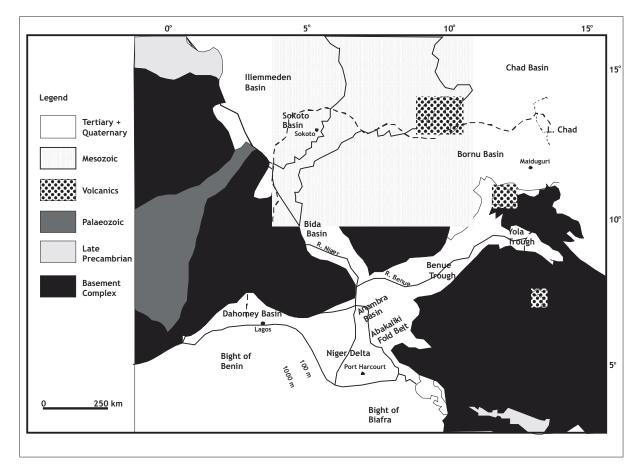

Figure 1: Simplified Geologic Map of Nigeria and Surrounding Areas Showing Location of the Niger Delta and Other Basins (After Whiteman, 1982)
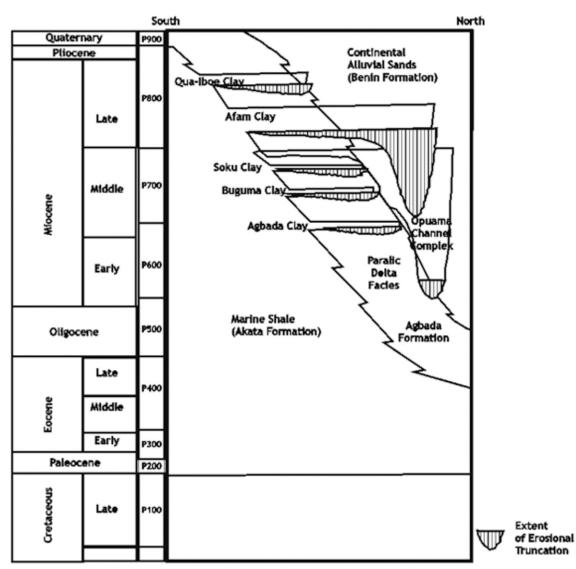
Figure 2: Schematic Representation of the Diachronous Nature of Major Lithofacies Units in the Niger Delta (After Doust and Omatsola, 1990)

Data Analysis

The data used in this study were a suite of well log data from six (6) wells (Figure 3) .Neya-01 has Kelly Bushing (KB) of 14.17 m; Neya-02 has KB of 14.00 m; Neya-03 has KB of 13.72 m; Neya-04 has KB of 12.80 m; Neya-05 has KB of 13.72 m; and Neya-06 has KB of 13.49 m. These wells were drilled to different depths of 3556.74 m, 3685.03 m,3486.91 m, 3566.16 m and 4056.89 m respectively. The logs used were the Gamma Ray (GR), Resistivity (ResD), and Density (RHOB) logs. Geographix™ and Interactive Petrophysics™ software from LMKR and Schlumberger respectively were usedto delineate the shale intervals on the basis of GR signatures.Six to seven shale intervals were selected and delineated in the six wells between depths 2133.60 m and 3962.40 m across six wells.(Figure 4). All the selected shales are within the Agbada Formation with some hydrocarbon bearing reservoirs present at some depths. The petrophysical properties of the shales were estimated directly from logs. In some cases, where log values were not available, these properties were calculated using the empirical relations such as by Dresser Atlas (1979); Asquith and Gibson (1982); Asquith (1990); and Asquith and Krygowski (2004) for volume of shale and determination of porosity.
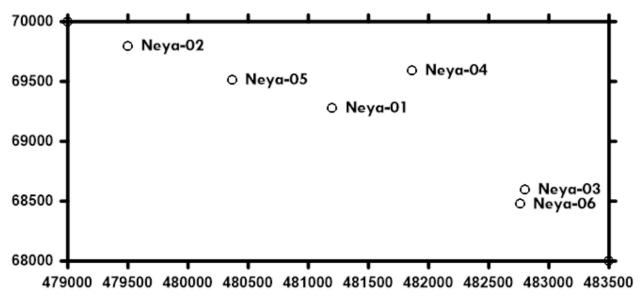
Figure 3: Relative Positions of the Wells in Neya Field

The TOC of the shale intervals was calculated using the Schmoker and Hester (1983) equation which relates bulk density derived from wireline log with TOC:

$$TOC(wt.\%) = \left[\frac{154.497}{\rho_b}\right] - 57.261 \qquad i$$

Where; ρ_b is the bulk formation density as measured by density lohe relationship of TOC and thickness, volume of shale and effective porosity of the shales were also analyzed and interpreted.

Figure 4: Correlation of the Shale Intervals across Four wells.

RESULTS AND DISCUSSION

NEYA-01

Table 1shows the summary of the computations for the well Neya-01. Seven shale units suspected to be potential source rocks were delineated with the aid of Gamma Ray (GR) log. These are tagged Shales 01, 02, 03, 04, 05,06 and 07 with thicknesses of 26.82 m, 65.53 m,22.86 m, 60.96 m, 45.72 m, 83.82m and 76.20 m respectively. They range from depth 2273.81 to3398.52 m. This well has a low average effective porosity of 6.37% which is good for a shale unit. The shale volume (Vsh) ranges between 41 and 64%. Intervals with this type of shaliness have been described by Ghorab *et al,*(2008), to indicate shaly-to-shale zones.

Table 1: Average Petrophysical Parameters and Distribution of TOC in NEYA-01

Source Rock	Depth Interval (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2273.81 - 2300.63	26.82	60.72	6.36	7.57
Shale 02	2404.87 - 2470.40	65.53	56.73	6.07	8.65
Shale 03	2531.36 - 2554.22	22.86	63.91	6.78	8.92
Shale 04	2721.86 - 2782.82	60.96	41.10	8.36	9.24
Shale 05	2855.98 - 2901.70	45.72	48.33	7.41	9.32
Shale 06	3124.20 - 3208.02	83.82	48.29	4.36	8.63
Shale 07	3322.32 - 3398.52	76.20	50.15	5.25	8.11

NEYA-02

Seven shale units suspected to be potential source rocks were picked and studied with the aid of Gamma ray (GR) log (Table 2). These are tagged Shales 01, 02, 03, 04, 05 ,06 and 07 with thicknesses of 24.38 m, 76.20 m, 15.24 m, 56.39 m, 51.82 m, 57.91 m and 45.11 m respectively. They range from depth 2273.81 – 3434.49 m.This well has a low average effective porosity of 4.73% which is good for a shale unit. The volume of shale ranges from35 to 60%.

Table 2: Average Petrophysical Parameters and Distribution of TOC in NEYA-02

Source Rock	Depth Range (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2273.81 - 2298.19	24.38	55.20	7.19	11.44
Shale 02	2395.73 - 2471.93	76.20	53.30	6.55	11.43
Shale 03	2535.94 - 2551.18	15.24	36.33	2.60	9.85
Shale 04	2727.96 - 2784.35	56.39	35.30	6.29	9.85
Shale 05	2855.98 - 2907.79	51.82	58.04	4.07	9.80
Shale 06	3200.40 - 3258.31	57.91	59.69	2.05	8.79
Shale 07	3389.38 - 3434.49	45.11	51.26	4.33	8.79

NEYA-03

In Neya-03, seven shale units tagged Shales 01, 02, 03, 04, 05,06 and 07 were delineated using the GR log signature and listed in Table 3. The thicknesses of the shale units are 44.20 m, 64.01 m, 33.53 m, 73.15 m, 86.87 m, 103.63 m and 89.00 m respectively. They range in depth from 2270.76to 3614.83 m. These shales have an average effective porosity of 4.30% and the shale volume ranges from 38to65%.

Table 3: Average Petrophysical Parameters and Distribution of TOC in NEYA-03

Source Rock	Depth Range (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2270.76 - 2314.96	44.20	63.59	6.67	11.44
Shale 02	2435.35 - 2499.36	64.01	39.70	6.46	11.44
Shale 03	2557.27 - 2590.80	33.53	64.77	3.30	9.84
Shale 04	2796.54 - 2869.69	73.15	38.50	4.00	9.82
Shale 05	2961.13 - 3048.00	86.87	54.76	4.80	9.80
Shale 06	3299.46 - 3403.09	103.63	56.60	2.78	8.88
Shale 07	3525.93 - 3614.93	89.00	59.79	2.00	8.58

NEYA-04

The seven shales in this well occur between the depths of 2255.52 and 3397.91 m (Table 4). These are tagged Shales 01, 02, 03, 04, 05 ,06 and 07 with thicknesses of 44.50 m, 70.10 m, 21.34 m, 58.83 m, 50.90 m, 82.91 m, and 79.86 m respectively. This well has a low average effective porosity of 5.41% which is good for a shale unit. The shale volume ranges from about 37 to 62%.

Table 4: Average Petrophysical Parameters and Distribution of TOC in NEYA-04

Source Rock	Depth Range (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2255.52 - 2300.02	44.50	52.19	5.84	11.24
Shale 02	2412.49 - 2482.60	70.10	40.36	5.12	12.24
Shale 03	2545.08 - 2566.42	21.34	62.31	3.74	9.66
Shale 04	2740.15 - 2798.98	58.83	41.90	7.66	11.59
Shale 05	2880.06 2930.96	50.90	36.71	5.78	12.25
Shale 06	3132.12 - 3215.03	82.91	42.10	4.99	9.75
Shale 07	3318.05 - 3397.91	79.86	44.00	4.73	12.44

NEYA-05

The analysis of Neya-05 shows that the shales occur at depth ranging from 2285. 09 to 3352.80 m(Table 5). Six shale units suspected to be potential source rocks were picked and studied and are tagged Shales 01, 02, 03, 04, 05 and 06 with thicknesses of 25.30 m, 60.05 m, 23.77 m, 60.05 m, 46.94 m, 85.65 m respectively. The seventh shale unit was faulted out. This well has an average effective porosity of 17.65%, though higher than other wells, it is still good for a shale unit. The shale volume ranges between 40 and 65%.

Table 5: Average Petrophysical Parameters and Distribution of TOC in NEYA-05

Source Rock	Depth Range (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2285.09 - 2310.38	25.30	62.47	16.85	9.58
Shale 02	2428.11 - 2488.16	60.05	51.08	18.40	12.05
Shale 03	2552.09 - 2575.86	23.77	57.55	18.23	10.21
Shale 04	2764.84 - 2824.89	60.05	41.00	16.26	11.41
Shale 05	2909.93 - 2956.86	46.94	40.10	20.45	12.08
Shale 06	3267.15 - 3352.80	85.65	65.22	15.68	8.65

NEYA-06

Table 6 shows that the seven delineated shale intervals occur at depths ranging from 2459.74 to 3922.78 mwith thicknesses of 48.16 m, 63.40 m, 72.24 m, 77.11 m, 82.91 m, 102.11 m, and 76.81 m respectively. These shales have average effective porosity of 4.24% and shale volume between 42 and 69%.

Table 6: Average Petrophysical Parameters and Distribution of TOC in NEYA-06

Source Rock	Depth Range (m)	Thickness (m)	Vsh (%)	PHIE (%)	TOC (wt.%)
Shale 01	2459.74 - 2507.89	48.16	53.75	6.98	10.76
Shale 02	2647.80 - 2711.20	63.40	62.10	5.16	11.55
Shale 03	2759.96 - 2832.20	72.24	68.75	5.23	11.14
Shale 04	3055.92 - 3133.04	77.11	57.24	5.43	10.44
Shale 05	3239.11 - 3322.02	82.91	42.10	4.13	10.62
Shale 06	3592.98 - 3695.09	102.11	44.50	1.72	8.64
Shale 07	3845.97 - 3922.78	76.81	41.71	1.04	7.56

The Distribution of TOC in the Shales

The TOC distribution varies across the wells (Tables 1-6). In Shale01, it is between 7.57 and 11.44 wt%; between 8.65 and 12.24 wt% in Shale 02 and between 8.92 and 11.14 wt% in Shale03. It is respectively between 9.24 and 11.59 wt%; 9.32 and 12.25 wt%; 8.63 and 9.75 wt% and 7.56 and 12.44 wt% in Shale04, Shale05, Shale06 and Shale07. These values are greater than the 4 wt% TOC for shales to generate excellent hydrocarbon and so the shales could be regarded as having sufficient organic content to be considered as potential source rocks(Peters and Moldowan, 1993; Peters and Cassa, 1994; Hunt, 1996).

Several authors have reported TOC of the sediments of Niger Delta using standard laboratory process. Bustin (1988), in a detailed source-rock study on side-wall cores and cuttings from the Agbada-Akata transition or uppermost Akata Formation, concluded that the total organic-carbon (TOC) contents of sandstone, siltstone, and shale in his study were essentially the same (average of 1.4 to 1.6 wt% TOC). The contents, however, seemed to vary with age of the strata—a trend of decreasing content with decreasing age (average of 2.2 wt% in the late Eocene compared to 0.9 wt% in Pliocene strata). Bustin (1988) Eocene TOC average was in agreement with the averages of 2.5 wt% and 2.3 wt% obtained for Agbada-Akata shales in two wells (Udo *et al.,*1988). Nwachukwu and Chukwura (1986) reported values as high as 5.2 wt% in paralic shales from the western part of the delta although the higher TOC contents were limited to thin beds and were only easily recognized in conventional cores (Doust and Omatsola, 1990). TheTOC results obtained in this study, which range from 7.56 wt% to 12.44 wt%, are in fair agreement with the range of 0.4 – 14.4 wt% reported by Ekwezor and Okoye (1980) in their study of the paralic sediments in some parts of both onshore and offshore Niger Delta.

Relationship of Petrophysical Properties with TOC

Attempt was made to understand the relationship that might likely exist between the petrophysical properties of the shales and their TOCs (Figure 5). The average TOC is highest in Shale02 (11.23 wt%) and lowest in Shale06 (8.89wt%). It is 10.34 wt% in Shale01; 9.94 wt% in Shale03; 10.39 wt% in Shale04; 10.65 wt% in Shale05; and 9.10 wt% in Shale07. The thickness is highest in Shale06 (86.01 m) and lowest in Shale03 (31.50 m). It is 31.56 m in Shale01; 66.55 m in Shale02; 64.42 m in Shale04; 60.86 m in Shale05 and 73.40 m in Shale07. The VShale is highest in Shale03 (58.94%) and lowest in Shale04 (42.51%). It is 57.99% in Shale01; 50.55% in Shale02; 46.67% in Shale05; 52.73% in Shale06 and 49.38% in Shale07. The effective porosity PHIE is generally lower than 9% for all the Shales. Shale01, Shale02, Shale04 and Shale05 have PHIE of 8.32%, 7.96%, 8.00% and 7.77% respectively. These shales are closely followed by Shale03 with PHIE

of 6.65% and Shale06 (5.37%). Shale07 has the least effective porosity of 3.47%.Taking the individual shale interval, these results indicate that the organic enrichment (TOC) of the shales does not have a clear dependence on their thicknesses, VShale or effective porosity. For example, Shale02 has neither the highest thickness, Vshale nor porosity, but the highest TOC.

CONCLUSIONS

The organic richness (TOC) and petrophysical properties of selectedshale intervals in the "Neya" wells have been estimated from wireline logs of six wells. Seven shale intervals were delineated that have TOC varying from about 7.56 to 12.44wt% across the wells. These results show that (TOC) of the shale intervals exceed the threshold of 0.5wt% set to generate crude oil, indicating that they have above minimum potential to generate hydrocarbon(Peters and Moldowan, 1993; Peters and Cassa, 1994; Hunt, 1996). The estimated TOC values are also in fair agreement with TOC values that had been reported in some parts of the paralic sediments of onshore and offshore Niger Delta (Ekweozor and Okoye, 1980; Tuttle et al., 1999).The petrophysical properties of the intervals indicate they have the characteristics typical of shaly to shale zones (Ghorab et al. 2008) and that their TOCs do not necessarily depend on thickness, volume of shale or effective porosity of the shales in the study area.
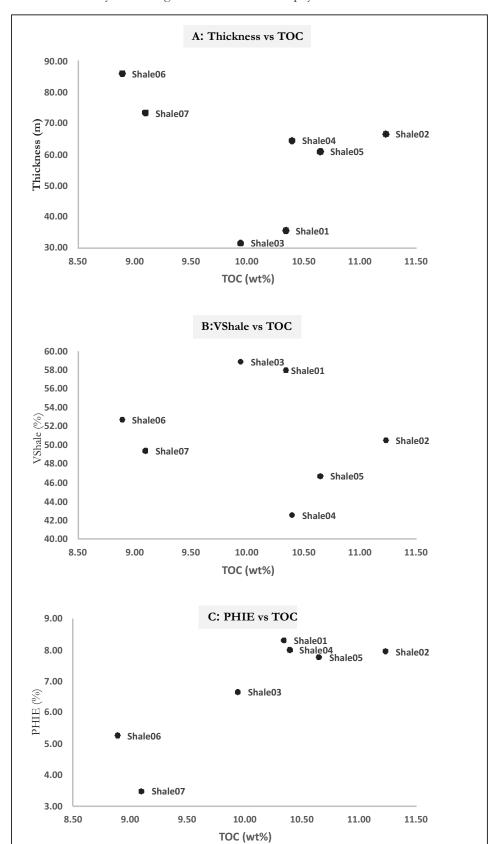
Figure 5: Plot of (A) Thickness, (B) Vshale and (C) Effective Porosity against TOC

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