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Prognostication of hydrocarbon generative potential in the onshore and offshore Niger Delta, Nigeria using TOC content and rock-eval pyrolysis techniques

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Abstract This article prognosticates the hydrocarbon generation potential of core samples from fields A, B, C and D in Niger delta, Nigeria. The objectives of this study are to characterize the quality of these core samples by organic geochemical analyses. A total of ten core samples collected from fields A, B, C and D in Niger delta were analyzed using total organic carbon (TOC) content analysis, rock-eval pyrolysis technique. The analytical results of the studied core samples reveal that they have generally high total organic carbon contents (TOC), suggesting that conditions in the Niger delta favour organic matter production and preservation. There is a variation in the kerogen types and this may be attributed to the relative stratigraphic positions of the core samples within the Niger delta. The rock-eval results indicate that the samples from fields C and D contain predominantly Type II kerogen with a capacity to generate oil and gas and hence have good generative potential. The samples from fields A and B contain mainly Type III kerogen and are gas-prone with moderate generative potential.

Key words hydrocarbon generation potential; Niger Delta; total organic carbon; rock-eval; kerogen

1 Introduction

Source rock evaluation studies entail assessing the hydrocarbon generating potential of sediments by looking at the sediment's capacity for hydrocarbon generation, type of organic matter (kerogen) present and what hydrocarbons might be expected after generation, and the sediment's thermal maturity and how it has influenced generation (Dembicki, 2008). The commonly used analytical methods for these studies during hydrocarbon exploration are the total organic carbon content (TOC) analysis, rock-eval pyrolysis, and vitrinite reflectance analysis. Some of the possible drawbacks in using these analytical techniques can be overcome by integrating the results of various analyses, and keeping in mind the possible errors that might arise from each method.

The Niger Delta is considered among the world's best studied delta provinces. There are three lithostratigraphic units recognized in the Niger Delta namely the Akata, Agbada and Benin Formations (Short and Stauble, 1967). Source rock of the Niger Delta hydrocarbon has been a subject of controversy. Short and Stauble (1967) and Frankl and Cordry (1967) proposed the shale of the paralic Agbada Formation as the source rocks, while Weber and Daukoru

(1975) argued that in most parts of the delta, the Agbada Formation is immature and suggested the source rock to be the marine shale of the Akata Formation which are more matured. There has been much discussion about the source rock for petroleum in the Niger Delta (e.g. Evamy and others, 1978; Ekweozor and others, 1979; Ekweozor and Okoye, 1980; Lambert-Aikhionbare and Ibe, 1984; Bustin, 1988). Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation and the marine Akata shale, and a Cretaceous shale (Weber and Daukoru, 1975; Evamy and others, 1978; Ekweozor and Okoye, 1980; Lambert-Aikhionbare and Ibe, 1984; Stacher, 1995; Frost, 1977; Haack and others, 1997).

The Agbada Formation has intervals that contain organic-carbon contents sufficient to be considered good source rocks (see data in 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 and others, 1978; Stacher, 1995).

Based on organic-matter content and type, Evamy and others (1978) proposed that both the marine shale (the Akata Formation) and the shale interbedded with paralic sandstone (the lower Agbada Formation) were the source rocks for the Niger Delta oils.

Bustin (1988) in a detailed source-rock study on side-wall core and cuttings from the Agbada-Akata transition or uppermost Akata Formation, concluded that there are no rich source rocks in the delta. With respect to oil potential, Bustin claimed that the poor source-rock quality has been more than compensated by their great volume, excellent migration pathways, and excellent drainage. The oil potential is further enhanced by permeable interbedded sandstone and rapid hydrocarbon generation resulting from high sedimentation rates. The total organic-carbon content (TOC) of sandstone, siltstone, and shale in his study is essentially the same (average of 1.4% to 1.6% TOC). The content, however, seems to differ with age of the strata—a trend of decreasing content with decreasing age (average of 2.2% in the Late Eocene compared with 0.9% in the Pliocene strata). Ekeweozor and Okoye (1980) reported TOC values from 0.4% to 14.4% in the both onshore and offshore paralic sediments. Nwachukwu and Chukwura (1986) reported values as high as 5.2% in paralic shales from the western part of the delta. The organic matter consists of mixed maceral components (85%–98% vitrinite with some liptinites and amorphous organic matter) (Bustin, 1988). There is no evidence of algal matter and the shales being low in sulfur (0.02 % to 0.1 %). Hydrogen indices (HI) are quite low and generally range from 160 to lower than 50 mg HC/g TOC. HI values over 400 have been measured (U.S. Geological Survey, unpublished proprietary data). Pristane/phytane in extracts ranges between 2 and 4 (Bustin, 1988). Bustin found that both HI values and pristane/phytane change with stratigraphic position similarly to TOC contents (lower values in younger strata). He attributed these stratigraphic trends in organic-matter to increased dilution as sedimentation rates increased and possibly an increase in oxidizing conditions of the depositional environment.

This study investigated and characterized the hydrocarbon generation potential of ten (10) samples from four (4) producing fields in the Niger delta, Nigeria using the TOC content analysis and rock-eval pyrolysis technique. The research objectives were to determine the total organic carbon content and identify organic matter kerogen type. Figure 1 shows the stratigraphy, depobelts and sample locations of the studied area in Niger delta.

1.1 Geology of the Niger Delta and hydrocarbon habitat

The Niger Delta, situated at the apex of the Gulf of Guinea on the west coast of Africa, covers an area of about 75000 km^2 and consists of 9–12 km total thickness of regressive clastic sequence. The geology of the tertiary Niger Delta province has been described by several workers (Short and Stauble, 1967; Weber and Daukoru, 1975; Weber et al., 1978; Evamy et al., 1978; Haack et al., 2000). Basement tectonics related to crucial divergence and translation during the Late Jurassic and Cretaceous continental rifting probably determined the original site of the main rivers that controlled the early development of the Delta. The Cenozoic development of the delta is also believed to have taken place under approximate isostatic equilibrium. The main depocenter is thought to have been at the triple junction between the continental and oceanic crust where the delta reached a main zone of crustal instability.

The stratigraphy (Fig. 1) of the thick sedimentary sequence is divided into three lithostratigraphic units namely; the Akata, Agbada and Benin Formations (Short and Stauble, 1967). The Akata Formation, which is the oldest (the Paleocene to Recent), consists mainly of overpressured shale deposited under fully marine conditions. This Formation has not been drilled in most parts of the delta, except at the continental margin. The Agbada Formation overlies the Akata Formation, ranging in age from the Eocene to Recent, composed of a paralic sequence consisting of interbedded sands and shales. It is about 4000 m thick in the central part, thinning seaward and towards the delta region. The Benin Formation, which is the youngest (the Eocene to Recent), is composed of mainly fluviatile gravels and sands. It is up to about 2000 m thick in the central onshore part and thins towards the delta margin.

The basin is partitioned into six to seven east-west bound blocks corresponding to depositional belts or depobelts (Fig. 1). Each depobelt is believed to constitute a more or less independent unit with respect to sedimentation, structural deformation and hydrocarbon generation and accumulation (Evamy et al., 1978).

Studies have shown that available source rocks in the basin exist mainly in the lower parts of the paralic sequence (the Agbada Formation) and uppermost strata of the continuous marine shale (the Akata Formation). The hydrocarbon habitat of the Niger delta is mostly within the sandstone reservoir of the Agbada Formation where oil and gas are usually trapped in rollover anticlines associated with growth faults. The thickness and age of the reservoir range from 10 to 20 m and the Eocene to the Pliocene respectively (Ejadawe, 1986). The reservoirs are widely spaced in depth in most of the fields.

2 Methodology

2.1 Samples

Ten core samples were collected at stratigraphic depths ranging from 4646 to 9877 feet in four producing fields of the onshore and offshore Niger delta. The sample locations are shown in Fig. 1. The samples descriptions, fields and depth details are summarized in Table 1. The core samples were taken to the Organic Geochemistry Laboratory, Yangtze University, Wuhan-China where they were oven-dried overnight at 110℃, and pulverized with the aid of pestle and mortar. The crushed rock samples were analyzed geochemically by TOC contents, rock-eval pyrolysis techniques. The samples were geochemically investigated in order to determine the total organic carbon, identify organic matter type, and hence characterize their petroleum generation potential.

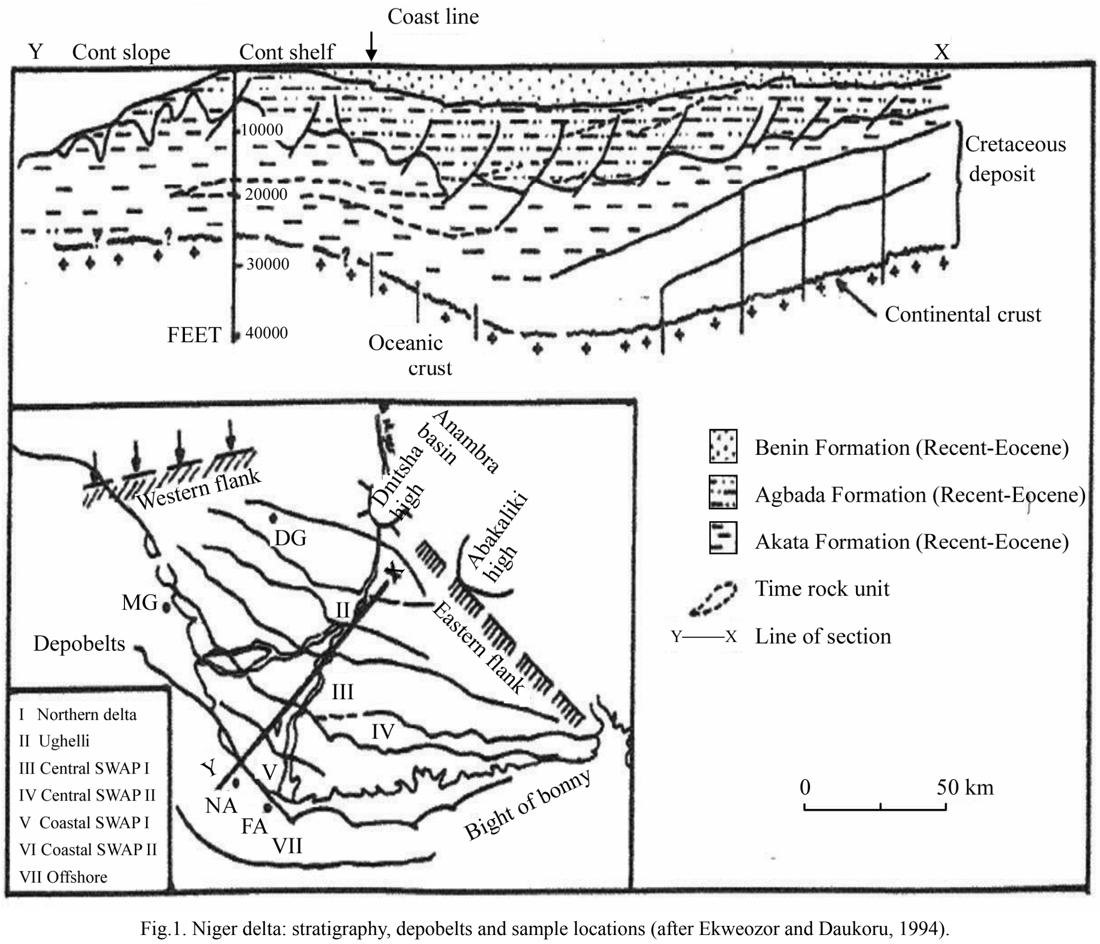

Fig.1. Niger delta: stratigraphy, depobelts and sample locations (after Ekweozor and Daukoru, 1994).

Table 1 Table showing the sample details from the four fields, Niger delta, Nigeria

Sample description	Field	Depth (feet)
NA-1	A	4646-5000
NA-21	A	6488-6500
NA-29	A	9594-9604
FA-6	B	5812-5820
FA-27	B	6812-6822
FA-14	B	7288-7298
OG-3S	C	6085-6091
OG-10	C	9418-9430
ME-10	D	5379-5388
ME-12	D	9871-9877

2.2 Total organic carbon contents (TOC) and rock-eval analyses

The pulverised rock samples submitted to Organic Geochemical Laboratory, Yangtze University, Wuhan-China were analysed for TOC contents, hydrogen index (HI), the oxygen index (OI) and T_{max} (temperature of maximum kerogen pyrolysate yield), using Rock-Eval II instrument. The oven was initially kept isothermally at 300℃ for 3 minutes during which time the free hydrocarbons were volatilized and the S_1 peak was measured with a flame ionization detector (FID). Pyrolysis of organic matter was later performed at 300–600℃ with a temperature rise of 25℃/min. This is the phase of volatilization of the higher carbon number hydrocarbons compounds (>C_{40}) as well as the cracking of non-volatile organic matter. The hydrocarbons released from this thermal cracking were measured as the S_2 peak (by FID). The temperature at which S_2 reached its maximum depended on the nature and thermal maturity of the kerogen and this was measured as T_{max}. The CO_2 produced from kerogen cracking was trapped in the 300–390℃ range. The trap was heated, and CO_2 was released and detected with a thermal conductivity detector (TCD) during the cooling of the pyrolysis oven (S_3 peak). The HI was determined as the yield of reduced products of pyrolysis (S_2) relative to the TOC (mg HC/g TOC) and OI was the yield of the oxygen and bound organic carbon (S_3).

3 Results and Discussion

The results of the TOC contents and rock-eval data for the studied outcrop samples are presented in Table 2. In a bid to display the distributions of the TOC values of the samples, TOC versus sample description (as used in Table 1) plot is generated and presented in Fig. 2.

In order to characterize the organic matter type (kerogen type) of the samples, the modified Van Krevelen diagram (HI versus OI) is displayed in Fig. 3. For the evaluation of the generation potential, graphs of PG against TOC (Ghoria, 1998) and the Rock-Eval HI versus TOC (Walters, 2006) are plotted and shown in Figures 4 and 5 respectively.

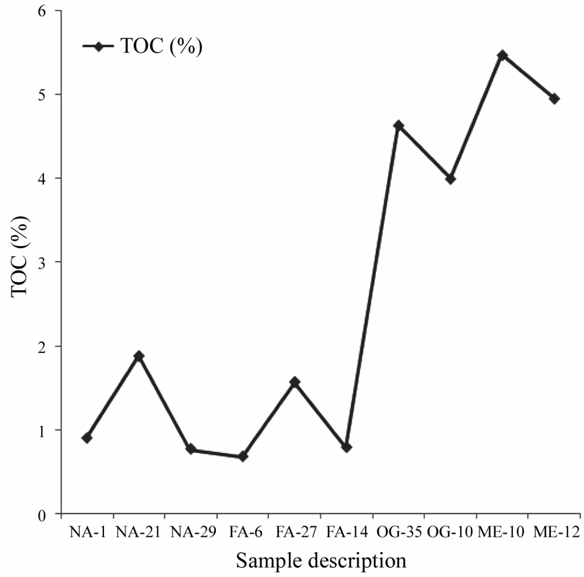

Fig. 2. Trend of TOC values in the studied core samples.

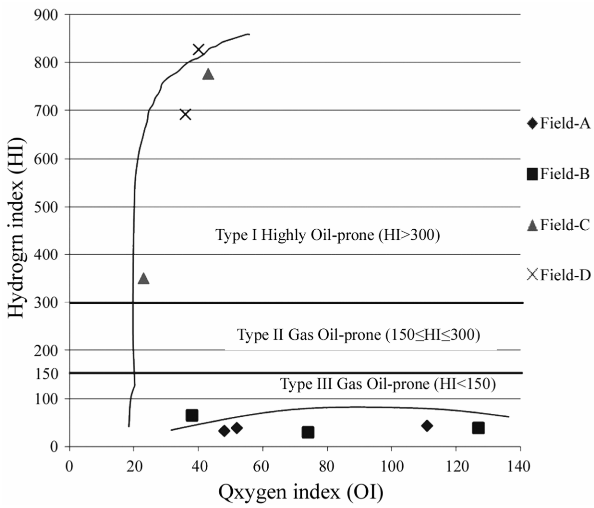

Fig. 3. Modified Van Krevelen diagram showing the organic matter types of the studied samples.

3.1 Organic matter (kerogen) type

The organic matter type is an important parameter in evaluating source rock potential and has important influence on the nature of the hydrocarbon products (Hunt, 1979; Tissot and Welte, 1984; Barker, 1996). Peters (1986) proposed that, for mature source rock, HI for gas-prone organic matter is lower than 150, gas-oil-prone organic matter is ranged between 150 and 300, whereas the oil-prone organic matter is higher than 300 HI. Thus, it is very important to determine the kerogen types of the source rocks as they have a first-order control on the hydrocarbon products after maturation. The results from this study show that the HI values are higher than 300 (Table 2) for samples from fields C and D. Thus, they are oil-prone. However, there are few exceptions. The samples from fields A and B have HI values lower than 66 mg/g, meaning that they are ideal potential gas generators. Tissot and Welte (1984) proposed a genetic potential ($PG=S_1+S_2$) for the classification of source rocks. According to their classification scheme, rocks having PG of lower than 2 mg HC/g correspond to gas-prone rocks or non-generative ones, rocks with PG between 2 and 6 mg HC/g are moderate source rocks, and those with PG higher than 6 mg HC/g are good source rocks. Based on the above criteria, all the samples from fields A and B have PG values lower than 2, meaning that they are gas-prone rocks or non-generative rocks. Again all the samples from fields C and D have PG values higher than 6, meaning that they constitute good source rocks at sufficient depths. They added further that those rocks with exceptionally high PG values in order of 100 or 200 mg HC/g may provide either an excellent source rock, if the burial depth is sufficient, or an oil shale, if the burial depth is shallow.

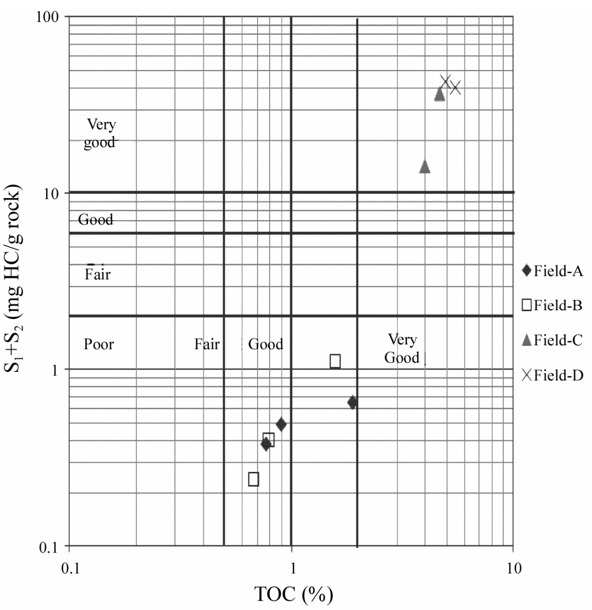

Fig. 4. Generative potential for the studied samples (Ghoria, 1998).

The modified Van Krevelen diagram (HI versus OI) (Fig. 3) shows that samples ME-10 and ME-12 from field D and samples OG-3S and OG-10 from field C consist of Type II kerogen. This is because their HI values are higher than 300, meaning that they are capable of generating both oil and gas at suitable temperature in depth. Again all the samples from fields A and B consist of Type III kerogen because their HI values are lower than 150 and therefore they are gas-prone. These results confirmed the findings of the earlier workers on the potential source rocks of Niger Delta (Bustin, 1988), that there is a variation in kerogen types which may be related to the relative stratigraphic positions of the outcrops within the Niger delta.

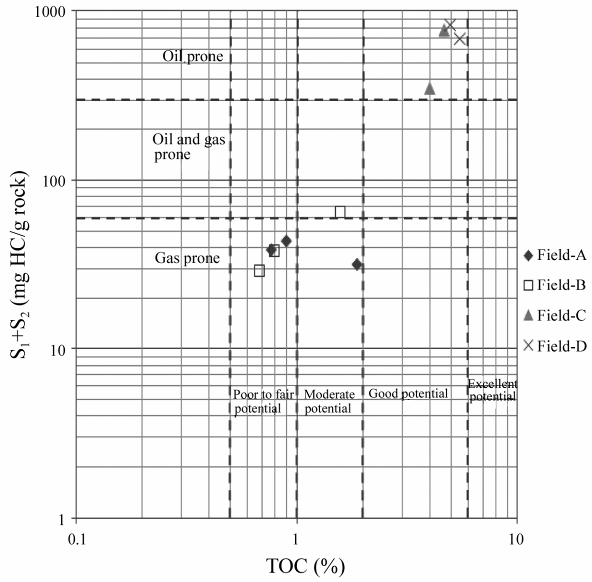

Fig. 5. Generative potential of potential source rocks of Niger delta.

3.2 Source rock richness and generation potential

The organic matter richness of source rocks is determined usually using the total organic carbon content, which is the total amount of organic material (kerogen) present in the rock, expressed as a percentage by weight (TOC wt.%). By and large, the higher the TOC, the better the chance and potential for hydrocarbon generation. According to Peters (1986), the TOC values between 0.5% and 1.0% indicate a fair source-rock generative potential, TOC values varying from 1.0% to 2.0% reflect a good generative potential, TOC values between 2.0% and 4.0% refer to a very good generative potential, and rocks with TOC higher than 4.0% are considered to have excellent generative potential.

Based on that criterion, the TOC results of rock samples in this study reveal that the samples NA-1 and NA-29 from field A and samples FA-6 and FA-14

Table 2 Rock-Eval analysis of samples from 4 producing fields, Niger delta, Nigeria

Sample	Field	Depth (feet)	TOC (%)	S_1	S_2	S_3	T_{max} (℃)	PG (S_1+S_2)	OI	HI
NA-1	A	4646–5000	0.90	0.09	0.4	1.00	437	0.49	111	44
NA-21	A	6488–6500	1.88	0.05	0.6	0.90	435	0.65	48	32
NA-29	A	9594–9604	0.77	0.08	0.3	0.40	438	0.38	52	39
FA-6	B	5812–5820	0.68	0.04	0.2	0.50	436	0.24	74	29
FA-27	B	6812–6822	1.57	0.10	1.0	0.60	438	1.10	38	64
FA-14	B	7288–7298	0.79	0.10	0.3	1.00	436	0.40	127	38
OG-3S	C	6085–6091	4.64	1.00	36	2.00	430	37.00	43	776
OG-10	C	9418–9430	4.00	0.30	14	0.90	436	14.30	23	350
ME-10	D	5379–5388	5.48	2.00	38	2.00	432	40.0	36	693
ME-12	D	9871–9877	4.96	2.00	41	2.00	425	43.0	40	827

Note: S_1 and S_2 are in mg hydrocarbon/g rock, S_3 is in mg CO_2; HI. Hydrogen Index (HI=S_2/TOC*100); OI. Oxygen Index (OI=S_3/TOC*100); TOC. Total Organic Carbon (wt.%), PG. Genetic Potential (PG=S_1+S_2).

from field B (Table 2) have fair generative potential source rocks because their TOC values fall between 0.5% and 1.0%. Again samples NA-21 from field A and sample FA-27 from field B have good generative potential source rocks because their TOC values fall between 1.0% and 2.0%. Furthermore, all the samples from fields C and D have excellent generative potential source rocks because their TOC values are higher than 4.0%. These results confirmed the findings of Ekeweozor and Okoye (1980) which reported TOC values from 0.4% to 14.4% in both onshore and offshore paralic sediments. That is demonstrated in the plot of the Rock-Eval HI versus TOC (Fig. 5). The fair to excellent generation potential of all the samples in particular is supported by the presence of type II & III kerogens (Fig. 3). Figure 4 shows the generative potential for the studied samples. It is also worth pointing out that the samples from fields C and D fall within the field of typical oil-prone source rocks (Walters, 2006) as shown in Fig. 5.

4 Conclusions

Results of TOC and rock-eval analyses of potential hydrocarbon source rocks of the ten (10) samples in the four producing fields, offshore Niger delta show that the prevailing conditions favour organic matter production and/or preservation. That led to high organic matter contents in various stratigraphic intervals of samples from all the fields in the Niger delta, Nigeria. The samples from fields C and D contain predominantly Type II kerogen and are both oil- and gas-prone, and the organic matter content excellent generative potential. Finally, the samples from fields A and B contains mainly Type III kerogen and are gas prone, but the organic carbon content is generally from fair to good so generative potential is good. The Niger Delta can be regarded as having good petroleum source rocks and could be part of a petroleum system if sufficient burial and maturation have occurred.

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