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Research Article

SOURCE ROCK EVALUATION AND HYDROCARBON POTENTIAL OF WELL 2/1-2, 2/4-17 AND 1/3-8 IN THE NORTH SEA BASIN, NORWAY.

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ABSTRACT

The North Sea Basin is situated between Norway and Great Britain, to the north of the Netherlands, and spans an area of 625,000 km^2. This study's main objective is to assess the source rock utilizing the Vitrinite Reflectance (Ro), Total Organic Carbon (TOC), and Rock-Eval pyrolysis technique. The hydrocarbon generation potential of three exploratory oil wells (2/1-2, 1/3-8, and 2/4-17) located in the North Sea Basin of Norway has been assessed by the application of geochemical analysis (TOC, Rock-Eval pyrolysis). The wells' total organic carbon (TOC) levels, as determined by sample analysis, range from poor to good, indicating that the Basin may offer favorable circumstances for the generation and preservation of organic matter. Thermal maturity indicated that samples from well 1/3-8 and well 2/1-2 are immature to early mature, and that from well 2/4-17 show immature to late mature stage of the hydrocarbon generation process. The outcrop's relative stratigraphy in the basin may be the cause of the variance in kerogen kinds. Only a small number of samples from wells 2/1-2 and 2/4-17 are indigenous hydrocarbon; the majority of the samples from the wells are non-indigenous hydrocarbon (migrated). Potential for producing hydrocarbons from all three wells, in particular 1/3–8 show enough organic matter content to generate hydrocarbon. Wells 1/3-8 has Kerogen Types I, II, and III, whereas wells 2/1-2 and 2/4-17 have Kerogen Types II, III, and IV. Good hydrocarbon potential allows for the production of gas and oil to be ejected from wells.

INTRODUCTION

Hydrocarbons, including natural gas and liquid petroleum, are combined to form North Sea oil, which is extracted from oil reservoirs located beneath the North Sea. The petroleum industry, according to Stauble and Milius (1990), commonly uses the term "North Sea" to refer to areas that are not officially part of the North Sea, such as the Norwegian Sea and the area referred to as "West of Shetland," "the Atlantic Frontier," or "the Atlantic Margin." The North Sea's commercial oil extraction history began in 1851 when James Young extracted oil from torbanite, often known as oil shale or boghead coal, which was produced in Scotland's Midland Valley (Glennie, 1998).

Oil was discovered in the Wietze field near Hanover, Germany, across the sea in 1859. This led to the discovery of seventy other fields, most of which were in Lower Cretaceous and Jurassic reservoirs, producing a total of about 1340 m^3 (8,400 barrels) per day (Glennie, 1998).

Petroleum geochemistry applications, when combined with petroleum geology, have seen a significant transformation in the last few years, moving from a post-mortem science to a generally recognized exploration prediction tool (Hagen and Kvalheim, 1992). Petroleum geochemistry has evolved over the past ten years into a practical and widely used tool for petroleum exploration.

When geochemical techniques are used in hydrocarbon exploration, the processes of hydrocarbon formation, movement, and accumulation within a basin are better understood before any drilling is done. Geochemical techniques can delineate intricate basin filling histories, elucidate anomalous hydrocarbon distributions, and pinpoint the origins of oil and gas as additional samples become accessible.

Problem Statement:

The pursuit of prospects in increasingly complex plays is giving exploration and production companies a renewed appreciation for one of the fundamental principles of exploration. The viability of any prospective reservoir depends on an effective source rock. The essence of Petroleum geochemistry is in helping operators evaluate source rocks and quantify the elements and processes that control the generation of oil and gas. Rock-Eval pyrolysis is the geochemical technique that will be used in evaluating the source rock potentiality of generating hydrocarbon in this project. Geochemistry is also an important tool for reducing uncertainty inherent in exploration and production (Hunt, 1996).

Scope and Objectives:

This study involves the hydrocarbon generating potential and source rock evaluation of three (3) wells drilled within the North Sea Basin. This work involves the use of geochemical data and rock-eval pyrolysis parameters to evaluate and confirm the hydrocarbon generating potential of the source rock in the basin where well (2/1-2, 1/3-8 and 2/4-17) were drilled. Different type plots will be made with pyrolysis parameters in this work to aid in achieving the aims and objectives of this project.

The aim of my study is to evaluate source rock hydrocarbon generating potentials using Rock-Eval pyrolysis data, Vitrinite Reflectance and Total Organic Carbon (TOC).

The objectives would include:

- Quantifying and characterizing the organic matters contained in the samples of various wells (2/1-2, 1/3-8 and 2/4-17) within the North Sea Basin.
- Identification of kerogen type and quality.
- Determining maturation of kerogen in order to deduce the hydrocarbon generated.

The goal of the project is to use geochemical data obtained from well 2/1-2, 1/3-8 and 2/4-17 to provide result about the source rock ability to generate hydrocarbon.

Study Area:

The three wells of study are located in the North Sea. Well 2/1-2 is located on the Sørvestlandet High, 6 km northwest of the Gyda Field in the North Sea (Fig. 1.1). Well 2/1-2 has North- South degrees of 56° 57' 30.76'' N and East-West degrees of 3° 12' 32.07'' E (NPD, 2015). Well 1/3-8 is located on the Hidra High in the North Sea (Fig. 1.2). Well 1/3-8 has North- South degrees of 56° 52' 7.14'' N and East-West degrees of 2° 53' 20.75'' E (NPD, 2015). well 2/4-17 is located on Sørvestlandet High, 8 km northwest of the Gyda Field in the North Sea (Fig. 1.3). Well 2/4-17 has North- South degrees of 56° 41' 2.6'' N and East-West degrees of 3° 13' 45.2'' E (NPD, 2015).

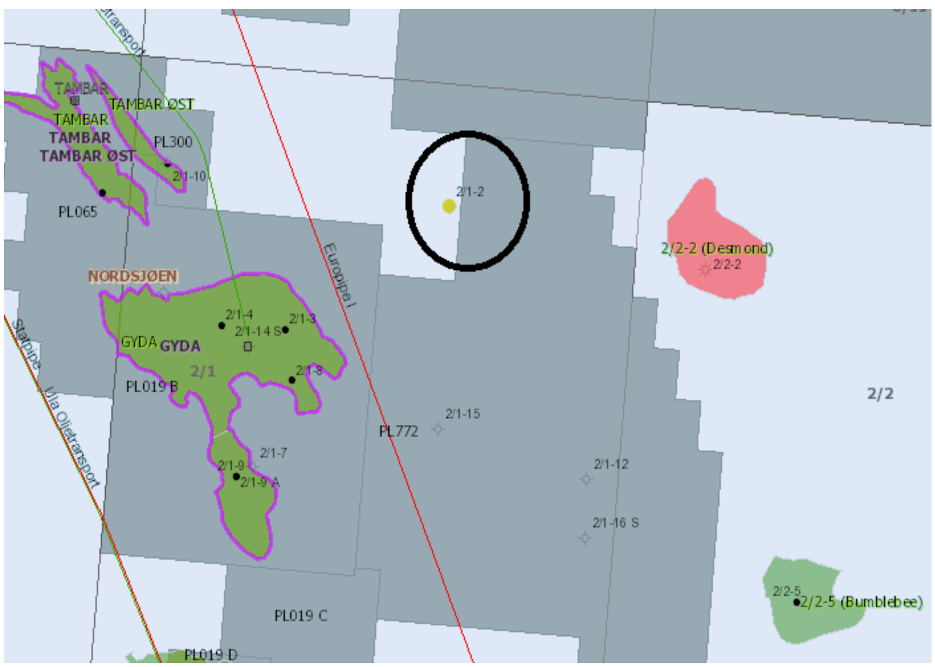

Figure 1.1: Base map showing well 1/1-2 (Source; NPD, 1980)

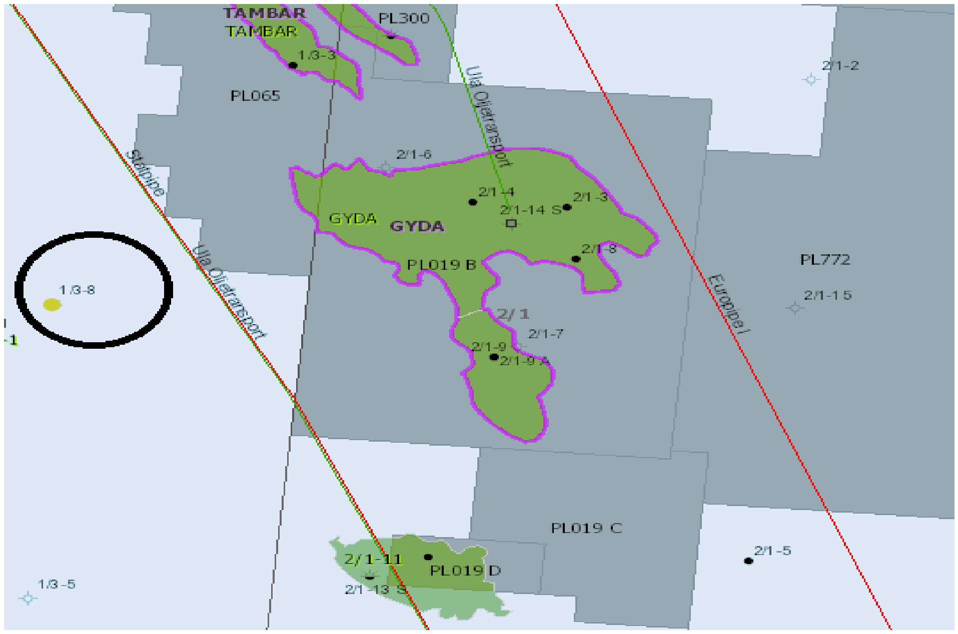

Figure 1.2: Base map showing well 1/3-8 (Source; NPD, 2010)

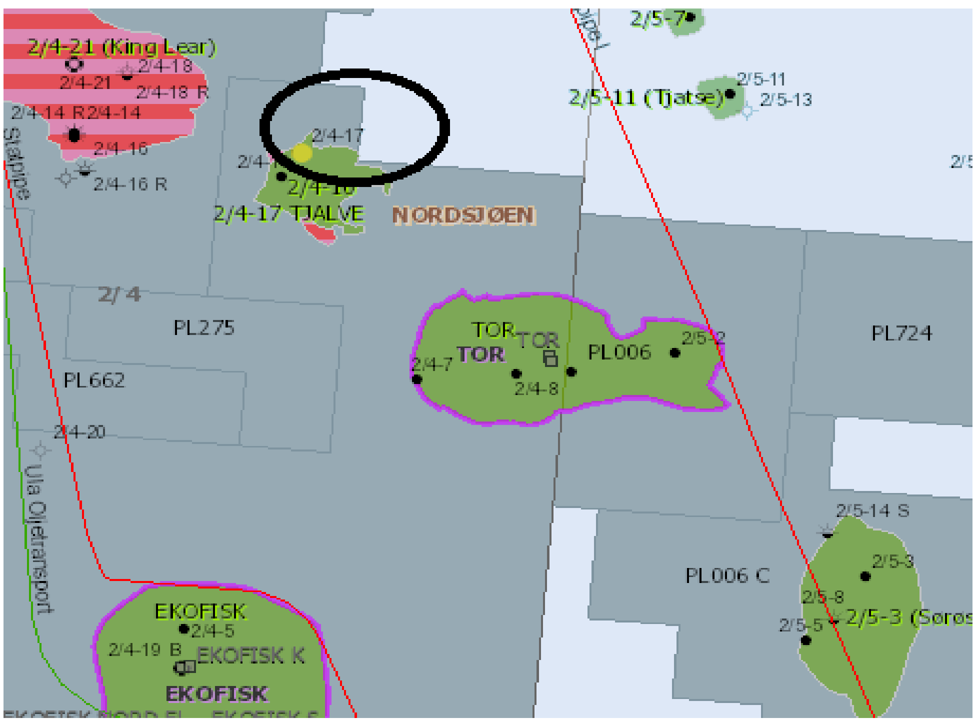

Figure 1.3: Base map showing well 2/4-17 (Source; NPD, 2006)

The North Sea Basin covers an area of 625,000 km^2, having 56.0000° N, 3.0000° E coordinates and lies north of the Netherlands and in between Norway and Great Britain (Fig. 1.4) (Leeder, 1999).

Figure 1.4: Location map of North Sea (Source; Jacobson, 1991).

Justification:

It is envisaged that at the end of this research the following outcome will be realized.
1. Plots of the pyrolysis parameters with depth will help in the identification of area of interest such as the depth (and geological age) within oil generation and thermal maturity occurs.
2. Plots of pyrolysis parameters will aid in deducing kerogen types, hydrocarbon potentiality and source rock efficiency.

Geological Settings:

The northern end of the North Sea is a rift basin, which stretches from the East Shetland Platform to the Øygarden Fault Zone, covering an area of nearly 40,000 km2. It includes three main regions: the East Shetland Basin and Tampen Spur in the west, the North Viking Graben and the Horda Platform in the east (Glennie and Underhill, 1998). The North Sea rift basin is part of the north- west European continental shelf. It is distinguished by an extensive and intricate geological history (Glennie and Underhill, 1998) spanning from pre- Devonian times. The basin is characterized by a prolonged history of extension that began in the Devonian with the extension of the thickened crust formed during the Caledonian Orogeny

Subsequently, the basin was subjected to Permo-Triassic and mid-late Jurassic intracontinenetal lithospheric extensional phases, which were accompanied by a thermal subsidence and cooling to produce the North Sea Sedimentary Basin (Faeseth et al., 1997). These two extensional events have mainly resulted in the present-day structural configuration of the North Sea

Structural Evolution:

The main tectonic processes which controlled the structural development of the central and northern North Sea comprise those related to the original (pre-Mesozoic) tectonic reorganization (Glennie and

Underhill, 1998) and those that reworked the framework into the present day (Mesozoic-Cenozoic) configuration (Zanella and Coward, 2003).

The Mesozoic-Cenozoic deformational phases, which shaped the present-day structural configuration, can be divided into six main phases namely (Zanella and Coward, 2003):

- ❖ Permian to Triassic rifting
- ❖ Post rift subsidence in mid-late Triassic to early Jurassic
- ❖ Thermal uplift and volcanism during the mid-Jurassic
- ❖ Mid-late Jurassic to Early Cretaceous rifting
- ❖ Cretaceous to Cenozoic post rift thermal subsidence and,
- ❖ Cenozoic uplift of basin the margins

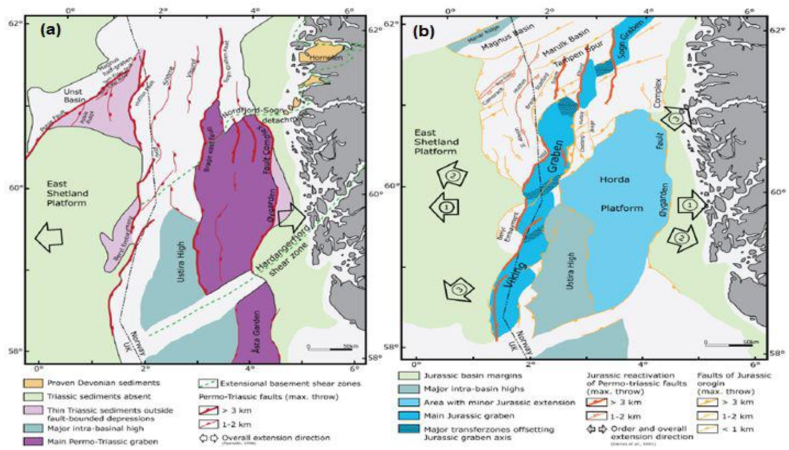

Figure 2.1: Map of the northern North Sea showing key structural elements in the (a) Permo Triassic and (b) Jurassic rifting events (Source; Faerseth, 1996).

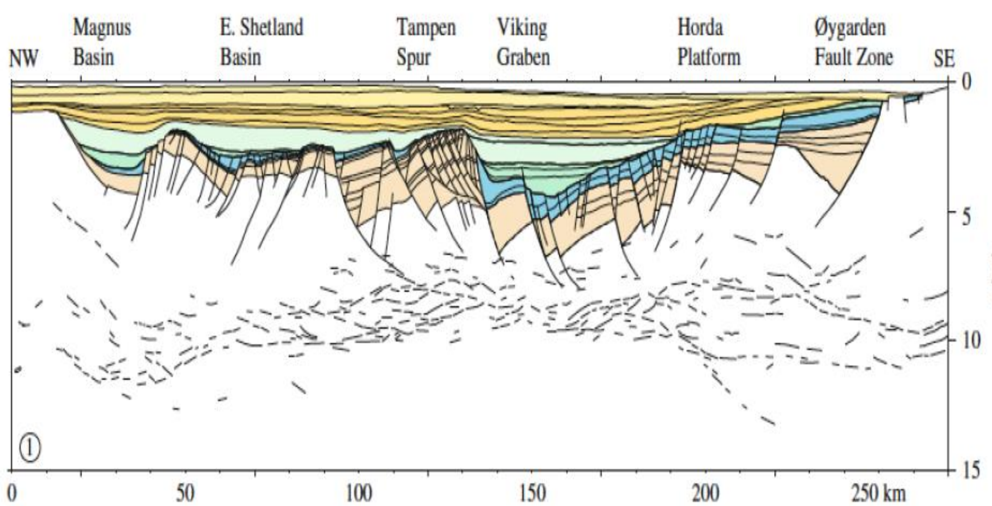

Figure 2.2: Interpreted regional seismic lines through the North Sea (Source; Christiansson et al., 2000).

Stratigraphy:

The stratigraphy of the North Sea spans from Devonian to the Cenozoic. A generalized stratigraphy of the North Sea is shown in Figure 2.4.

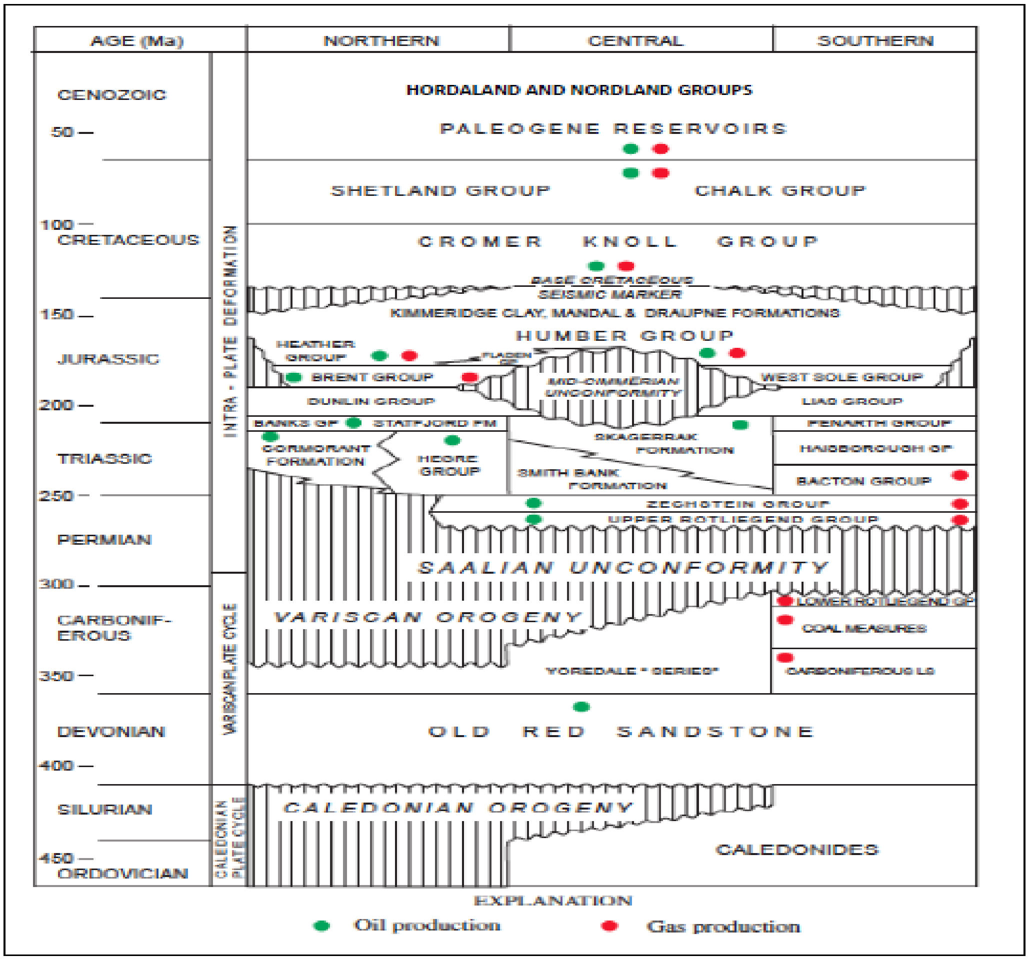

Figure 2.4: Generalized stratigraphy of the North Sea (Source; Brennand et al., 1998).

METHODOLOGY

In this project work (geochemical analysis) scattered diagram is the main analytical chart that will be used in evaluating the source rock. This project will be done with geochemical data (i.e., Rock-Eval pyrolysis and Vitrinite Reflectance %Ro) obtained from Amoco Norway Oil Company, Norway. Several plots will be done with the geochemical data.

Scatter plots are actually cross plots whereby the parameters obtained from pyrolysis are plotted against each other and will be used in interpreting the properties and hydrocarbon potential of the study area. Four parameters S1, free hydrocarbon: S2. The following was calculated using the pyrolyzed hydrocarbon that was produced when kerogen cracked, S3, the amount of carbon dioxide (C02), and Tmax, the temperature at which the maximal formation of pyrolysis products occurs:

Oxygen index [OI = (S3/TOC) x 100)]

Hydrogen index [HI = (S2/TOC) x 100]

Production index [PI =S1/ (S1+ S2)]

Hydrogen richness in the kerogen =S2/S3

Genetic potential of the source rock=S1+S2

Rock-Eval Pyrolysis Data:

Rock-Eval pyrolysis data will give information on the quantity, type and thermal maturity of the organic matter. Pyrolysis is a widely used degradation technique that allows breaking a complex subsidence into fragments by heating it under an inert atmosphere (Peters and Cassa, 1994).

RESULTS AND DISCUSSION:

The rules for evaluating the quantity, quality, and maturation of source rock, as well as the frequently used Rock-Eval characteristics, are displayed in Table 4.1 will be used in evaluating the quantity of organic matter, characterizing the type and quality of kerogen as well as determining its maturity status (Epstein et al., 1977; Espitalie et al., 1985; Peters, 1986; Traverse, 1988; Peters and Cassa, 1994; and Fowler et al., 2005) in order to deduce the hydrocarbon potential of the basin.

Quantity	**TOC**	**S_1(mg HC/g rock)**	**S_2(mg HC/g rock)**
Poor	<0.5	<0.5	<2..5
Fair	<0.5-1	<0.5-1	2.5-5.0
Good	1-2	1-2	5-10
Very Good	2-4	2-4	10-20
Excellent	>4	>4	>20
Quality	**HI (mg HC/g TOC)**	**S_2/S_3**	**Kerogen Type**
None	<50	<1	IV
Gas	50-200	1-5	III
Gas and Oil	200-300	5-10	II/III
Oil	300-600	10-15	II
Oil	>600	>15	I
Maturation	**R_o (%)**	**Tmax (^oC)**	**TAI**
Immature	0.2-0.6	<435	1.5-2.6
Early Mature	0.6-0.65	435-445	2.6-2.6
Peak Mature	0.65-0.9	445-450	2.7-2.9

Late Mature	0.9-1.35	450-470	2.9-3.3
Post Mature	>1.35	>470	>3.3

Table 4.1: Guidelines for interpreting source rock quantity, quality and maturation, and commonly used Rock-Eval parameters. (Source: Epstein et al., 1977; Espitalie et al., 1985; Peters, 1986; Traverse, 1988; Peters and Cassa, 1994; and Fowler et al., 2005).

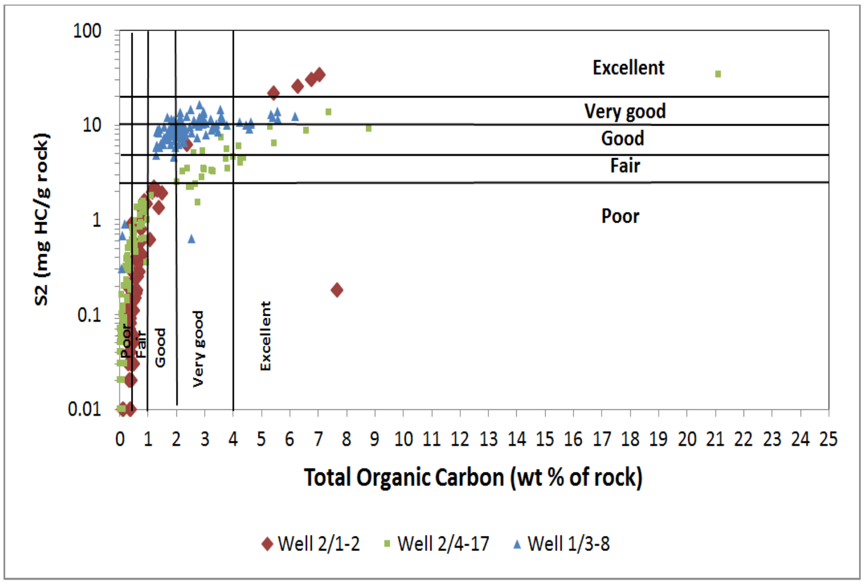

Figure 4.1: Plot of S_2 versus TOC indicating hydrocarbon potentiality and source rock efficiency.

The result of S_2 versus TOC plot (Fig. 4.1) shows that majority of rock samples from Well 2/1-2 and Well 2/4-17 has TOC values of 0 to 1 %. This implies that these rock samples have poor to fair organic matter. Rock samples from Well 2/4-17 and Well 2/1-2 also have few samples with TOC values of 2 % to 10 %, which gives good, very good and excellent organic matter content. Most samples from the two wells are poor in terms of S_2, with S_2 values less than 2.5 mg HC/g rock. Samples from both wells are seen at depth of 3100 m to 5000 m (Fig. 4.1b).

Majority of rock samples from Well 1/3-8 has TOC values of 1 % to 7 % (Fig. 4.1). This implies that these rock samples are rich in organic matter. Samples from this well have S_2 values of 5 to 20 mg HC/g rock making them good and very good. At depth of 4200 m to 5200 m samples from this well are seen (Fig.4.1b).

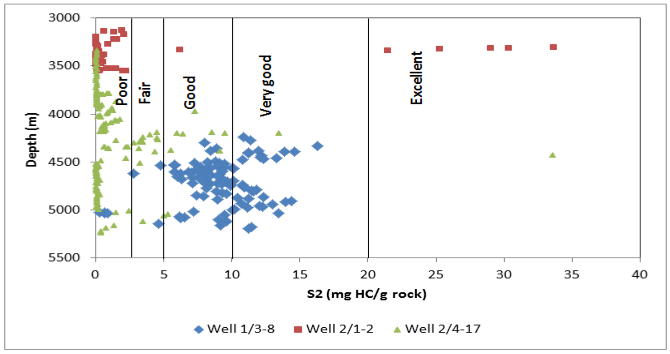

Figure 4.1b: Plot of Depth versus S_2

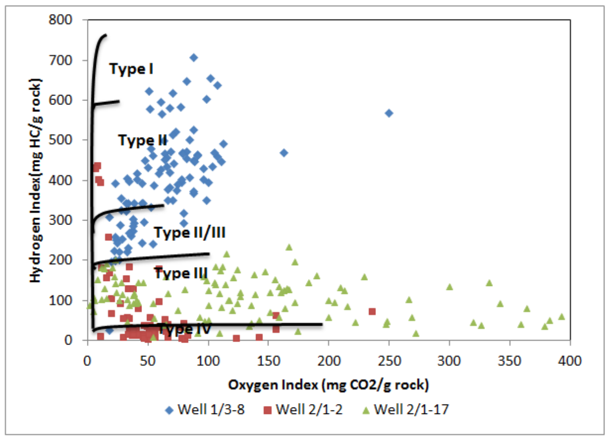

Figure 4.2: Modified Van Krevelen diagram indicating the Kerogen types of the studied samples.

The result of Hydrogen Index versus Oxygen Index plot (Fig. 4.2) shows that samples from Well 1/3-8 are composed of organic matter that will produce Type I, II, and II/III kerogen (Type II predominantly).Well 2/1-17 has organic matter that will generate kerogen Type II/III, III and IV (Type III predominantly) (Fig. 4.2). Well 2/1-2 has organic matter that will generate kerogen Type II II/III, III and IV (Type III predominantly) (Fig. 4.2).

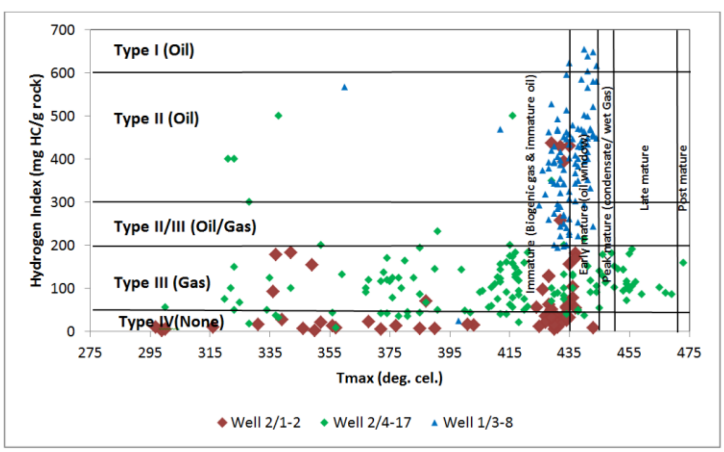

Figure 4.3: Plot of Hydrogen Index versus Tmax showing the relationship between kerogen types and maturity levels.

Hydrogen Index versus Tmax (Fig. 4.3) shows a relationship between type of kerogen and maturity levels. Most samples from Well 1/3-8 and early mature while others are immature, having kerogen Type I, II and II/III. Majority of samples from Well 2/4-17 are immature, while others are early mature, peak mature, late mature and one sample post mature with kerogen Type II, II/III, III and IV (Fig. 4.3). Majority of samples from Well 2/1-2 are immature, while others are early mature with kerogen Type II, II/III, III and IV (Fig. 4.3).

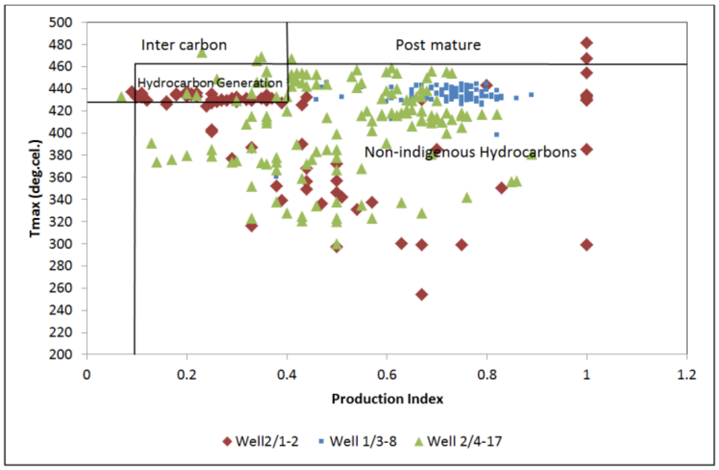

Figure 4.4: Plot of Tmax versus Production Index showing the hydrocarbon-generation zone

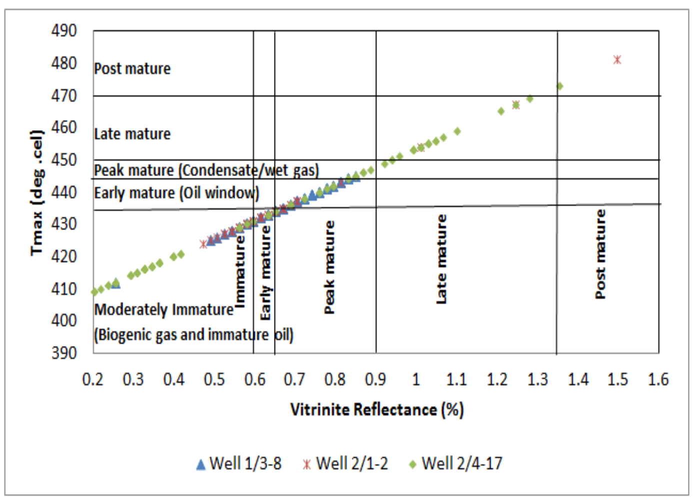

Figure 4.5: Plot of Tmax versus Vitrinite Reflectance (R_o) showing the maturity levels.

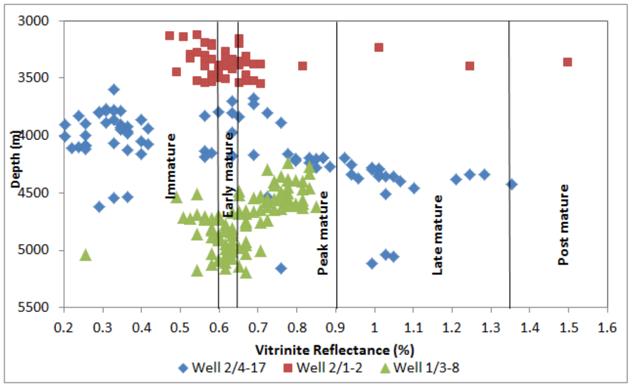

Figure 4.5b: Plot of Depth versus Vitrinite Reflectance.

Maturity levels indication (Fig. 4.5) shows that samples from Well 1/3-8, relating to vitrinite reflectance are immature, early mature and peak mature at a depth of 3600 m to 5200 m (Fig. 4.5b). Well 2/1-2 samples, relating to vitrinite reflectance (Fig. 4.5) are immature, early mature and peak mature at a depth of 3100 m to 3600 m (Fig. 4.5b). Well 2/4-17 samples, relating to vitrinite reflectance are immature, early mature, peak mature, late mature and post mature.

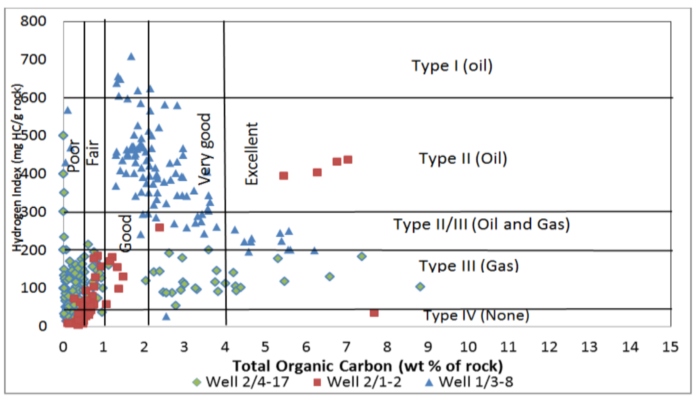

Figure 4.6: Plot of Hydrogen index versus TOC indicating amount of kerogen types and generation potential.

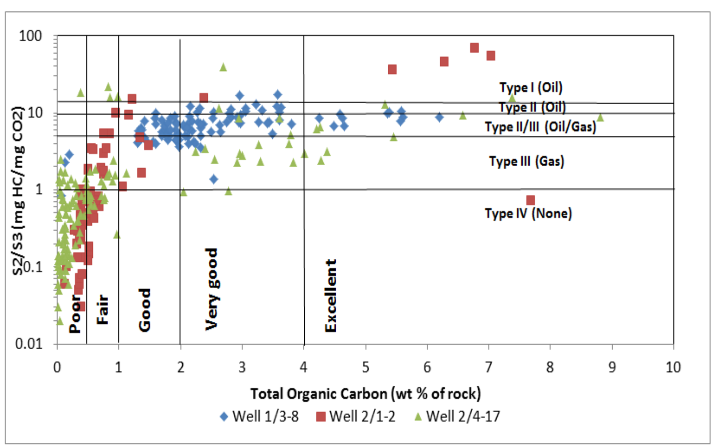

Figure 4.7: Plot of S_2/S_3 versus TOC indicating amount of kerogen types and generation potential

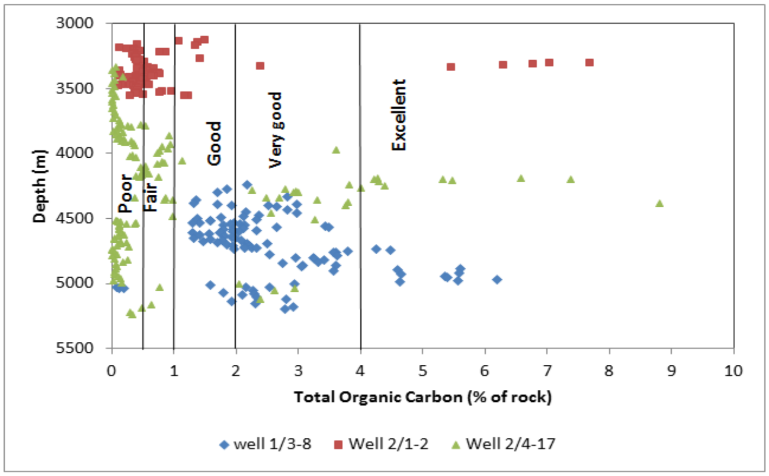

Figure 4.7b: Plot of Depth versus TOC

Plot of Hydrogen Index versus TOC (Fig. 4.6) and plot of S_2/S_3 versus TOC (Fig. 4.7), indicating amount of kerogen types and generation potential shows that Well 1/3-8 rock samples has TOC values of 1 to 6 % (good, very good and excellent), with the potentials of generating Oil and Gas (Fig. 4.6, 4.7 and 4.8). Well 2/1-2 rock samples (most) has TOC values of 0 to 1 %, and few samples has 1 to 8 % having the ability to generate Oil and Gas (Fig. 4.6, 4.7 and 4.8). Majority of samples from Well 2/4-17 has TOC values of 0 to 1 % (poor and fair), other samples has TOC values of 2 to 9 % (very good and excellent) with the potential of generating Oil and Gas (Fig. 4.6, 4.7 and 4.8).

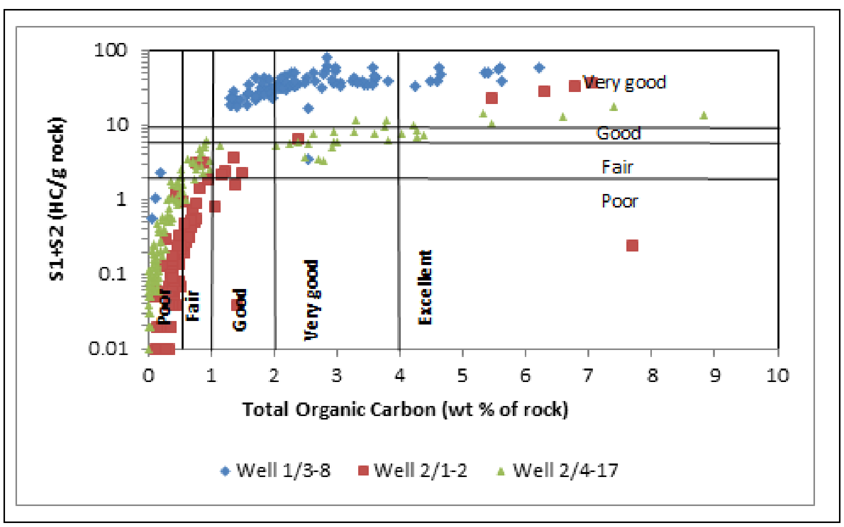

Figure 4.8: Plot of S_1+S_2 versus TOC showing the Genetic potential for the studied samples

DISCUSSION

Hydrocarbon potentiality and organic richness:

By calculating the total organic carbon (TOC) in the rock and using the S2 obtained from pyrolysis, one may assess the organic richness and potential of a rock sample (Waples et al., 1992). According to Peters (1986), poor source rocks include those with less than 0.5 weight percent TOC and less than 2.5 mg/g S2. Good source rocks are those with S2 from 5 to 10 mg/g and TOC from 1 to 2 wt%, while samples with S2 from 2.5 to 5 mg/g and TOC from 0.5 to 1.0 wt% are considered fair source rocks. Samples with TOC greater than 4 weight percent and S2 greater than 20 mg/g are outstanding source rock, whereas samples with S2 between 10 and 20 mg/g and 2 to 4 weight percent are regarded as very good source rock.

Figure 4.1 shows a hydrocarbon yield of S_2 versus TOC cross plot. Based on the above criterion, samples from well 2/1-2 are poor to good source rock with TOC values of 0 % to 8.0 %, few samples plotting on excellent and a sample on very good. Majority of the samples have S_2 values less than 2.5 mg HC/g which implies majority of the samples are poor with few samples exceeding 2.5 to 30 HC/g implying fair to excellent (Fig. 4.1). These rocks can be described as moderate to good source rock.

Samples from well 2/4-17 shown in Figure 4.1 are poor to very good source rock with TOC values of 0 % to 9.0 %, some samples plotting on very good and excellent. Most of the samples have S_2 values less than 2.5 mg HC/g implying those samples are poor and other samples exceed 2.0 to 20 HC/g implying fair to excellent (Fig. 4.1). These rocks can be described as moderate to good source rock.

Samples from well 1/3-8 shown in Figure 4.1 are good to very good source rock with TOC values of 1.0 % to 7.0 %, majority of the samples are good to very good with few excellent samples. This means, these rocks are very good source rock. Most of the samples have S_2 values of 5 mg HC/g to 20 mg HC/g implying these samples are good to very good (Fig. 4.1). These rocks can be described as good to very good source rock.

Figure 4.1b shows that samples from well 2/1-2 are seen at the depth of 3100 m to 3550 m. Most of the samples have S_2 values less than 2.5 mg HC/g which implies these samples are poor. Few of these samples have S_2 values greater than 20.0 mg HC/g (excellent). Figure 4.1b shows that samples from well 1/3-8 are seen at depth range of 4200 m to 5200 m. Most of the samples have S_2 values above 5.0 mg HC/g rock which implies these samples are good to very good. These rocks can be described as good source rock. Figure 4.1b shows that samples from well 2/4-17 is seen at depth range of 3300 m to 5000 m. Most of the samples have S_2 values less than 2.5 mg HC/g which implies these samples are poor. Some samples have S_2 values ranging from 2.5 to 20.0 mg HC/g with one sample exceeding 20.0 mg HC/g rock. This means samples are fair, good and very good with one sample excellent. These rocks can be described as moderate to good source rock.

Type of Organic Matter:

The type of organic content has a significant impact on the composition of the hydrocarbon products and is a crucial aspect in assessing the potential of source rocks. Owing to the variations in the chemical structures of organic materials and hydrocarbon products, kerogen types must be identified. According to (Peters and Cassa, 1994) and (Jacobson, 1991) there are four type of kerogen in sedimentary rocks.

From Table 4.1, Hydrogen Index values for kerogen Type IV (None) range from 0 to 50 (less than 50), kerogen Type III (Gas) ranges from 50 – 200, mixed kerogen Type II/III (Gas and Oil) range from 200-300, kerogen Type II (Oil) ranges from 300-600, kerogen Type I (Oil) ranges from 600 above (greater than 600). Hence, from the kerogen types, it is essential to determine the source rocks as they have a first-order control on the hydrocarbon product after maturation (Hunt, 1996).

The result of the plot of Hydrogen Index versus Oxygen Index from Figure 4.2 showed that for well 2/1-2, most samples have Hydrogen Index values between 50 and 200 which indicate kerogen Type III (gas-prone organic matter). Some samples have Hydrogen Index values less than 50 which indicate kerogen Type IV, which yield neither oil nor gas. A sample has Hydrogen Index value between 200 and 300 which indicate a mixed kerogen Type II/III (gas and oil). Four samples have Hydrogen Index between values 300 and 600 which indicate kerogen Type II (oil prone organic matter).

Figure 4.2 shows that majority of samples from well 2/1-17 have Hydrogen Index values between 50 and 200 which indicate kerogen Type III (gas-prone organic matter). Other samples have Hydrogen Index values less than 50 indicating Type IV kerogen, which yield neither oil nor gas. Two samples have Hydrogen Index values between 200 and 300 which indicate a mixed kerogen Type II/III (gas and oil). Most samples from well 1/3-8, as shown in Figure 4.2 have Hydrogen Index values between 300 and 600 which are indicative of Type II kerogen (rich oil source). Six samples have Hydrogen Index values greater than 600 which indicate Type I kerogen (oil-prone organic matter). Some samples have Hydrogen Index values between 200 and 300 which indicate a mixed kerogen Type II/III (gas and oil).

A plot of Hydrogen Index versus Tmax is commonly used to avoid influence of the Oxygen Index for determining kerogen type (Hunt, 1996). As indicated from the relationships between Hydrogen Index and Tmax (Fig. 4.3). The samples in well 2/1-2 have Hydrogen Index values from 0 to 500 which implies that they are composed of kerogen Type I,II,II/III and IV (Type IV predominantly) which are oil and gas prone but Type IV generate neither oil nor gas (Fig. 4.3). Majority of these samples have Tmax values less than 435 ^{o}C indicating moderately immature samples with the potential to generate biogenic gas and immature oil. Few samples have Tmax values from 435 ^{o}C to 445 ^{o}C indicating early mature (oil window).

The samples in well 2/1-17 (Fig. 4.3) has Hydrogen Index values ranging from 0 to 600 which implies that they are composed of kerogen Type I,II,II/III and IV (Type III predominantly) which are oil and gas prone but Type IV generate neither oil nor gas. Majority of these samples have Tmax values less than 435 ^{o}C (Fig. 4.3) indicating moderately immature samples with the potential to generate biogenic gas and immature oil. Some samples have Tmax values from 435 ^{o}C to 445 ^{o}C indicating early mature (gas window). Some samples have Tmax values ranging from 445 ^{o}C to 450 ^{o}C indicating peak mature (condensate/wet gas). Some samples also have Tmax values ranging from 450^{o}C to 470^{o}C indicating late mature. A sample has Tmax value greater than 470 ^{o}C indicating post mature.

The samples in well 1/3-8 (Fig. 4.3) have Hydrogen Index values ranging from 200 to 700 which means these samples consist of kerogen Type I, II and III (Type II predominantly) which are oil and gas prone. Some of the samples have Tmax values less than 435 ^{o}C indicating moderately immature samples with the potential to generate biogenic gas and immature oil (Fig. 4.3). Majority of the samples have Tmax values ranging from 435 ^{o}C to 445 ^{o}C indicating early mature (oil window).

Organic Matter Maturity:

The degree of thermal alteration of organic matter due to heating provides an indication of source rock maturity. In addition to other elements like mineral matter, content, burial depth, and age, the kind of organic matter in the source rock and the existence of excess free hydrocarbon also affect thermal maturity (Tissot and Welte, 1984). The thermal evolution of the sedimentary organic matter was inferred from the following factors: Vitrinite Reflectance, Production Index, and Tmax (oC).

The increase of maturity level corresponds to increase in Tmax. This is related to the nature of chemical reactions that occur through thermal cracking. The weaker bonds break up in the early stages while the stronger bonds survive until higher temperature in late stage (Whelan and Thompson, 1993). The relationship between Tmax and Production Index (PI) is a valuable method for indicating the thermal maturity of the organic matter. The following relationship between Tmax and Production Index (PI) are observed (Peters, 1986; Peters and Cassa, 1994; Bacon et.al, 2000).

- ❖ Immature organic matter has Tmax and PI values less than 430 ^{o}C and 0.10, respectively;
- ❖ Mature organic matter has a range of 0.1to 0.4 PI. At the top of oil window, Tmax and PI reach 460 ^{o}C and 0.4, respectively;
- ❖ Mature organic matter within the wet gas zone has PI values greater than 0.4; and
- ❖ Post-mature organic matter usually has a high PI value and may reach 1.0 by the end of the dry gas zone (Peters, 1986; Peters and Cassa, 1994; Bacon et.al, 2000).

From Figure 4.4, in well 2/1-2 most of the samples have Tmax less than 440 ^{o}C and PI of 0.1 to 0.4. This indicate majority of the samples are early mature (oil window). Some samples have PI greater than 0.4, indicating mature organic matter (gas window). Majority of the samples falls within the hydrocarbon generation zone (indigenous). Some of the samples are non-indigenous (migrated) hydrocarbon. Two samples plot within the post mature zone and a sample plot within the inter-carbon zone (Fig. 4.4).

In well 1/3-8 (Fig. 4.4), most of the samples have Tmax less than 450 ^{o}C and PI greater than 0.4.This indicate majority of the samples are mature organic matter (gas window). None of the samples from this well falls within the hydrocarbon generating zone. This implies that the samples are non-indigenous hydrocarbon (migrated) (Fig. 4.4).

The degree of thermal alteration of organic matter due to heating is called maturity (Peters and Cassa, 1994). Organic matter has different maturity phases:

- ❖ Immature less than 435 ^{o}C which has not been affected by temperature and may be affected by biological diagenesis processes (biogenic gas and immature oil);
- ❖ Early mature ranging from 435 ^{o}C to 445 ^{o}C (oil window).
- ❖ Peak mature ranging from 445 ^{o}C to 450 ^{o}C (condensate/wet gas).

- Late mature ranging from 450 °C to 470 °C, which is the gas window because it is hydrogen deficient material due to influence of high temperature (Peters and Cassa, 1994).
- Post mature greater than 470 °C

According to Dow (1977) and Waples (1985), an overview of maturity distribution is provided by R_o data, which is considered to be the most reliable and most commonly used maturity indicator. Vitrinite Reflectance (R_o) values between 0.2 to 0.6 indicates Immature source rock, R_o values between 0.6 to 0.65 indicates Early Mature source rock, R_o values between 0.65 to 0.9 indicates Peak Mature, R_o values between 0.9 to 1.35 indicates Late Mature, R_o value greater than 1.35 indicates Post Mature.

As shown in Figure 4.5, in well 2/1-2, relating to Vitrinite Reflectance, most samples are immature with few mature ones for both Tmax and R_o, and can be classified as moderated grade source rock. From Figure 4.5b, samples plot from Immature to Peak Mature ranging from the depth of 3100 m to 3550 m. The main depth of mature source rock (hydrocarbon generation zone) in the well is from 3200 m to 3500 m. Well 2/1-2 has source rock having the potential of producing biogenic gas and immature oil, and oil.

As shown in Figure 4.5, well 1/3-8, relating to Vitrinite Reflectance, some of the samples are late Mature, some samples is peak mature, some samples are early mature while others are immature. For that of Tmax samples ranges from Immature to peak mature. From Figure 4.5b, samples range from the depth of 3600 m to 5000 m. The main depth of mature source rock in the well is from 3700 m to 4200 m. Well 1/3-8, has source rocks having the potentials of producing biogenic gas and immature oil, oil, condensate/wet gas.

CONCLUSION

The total organic carbon (TOC) content of wells 2/1-2, 2/4-17, and 1/3-8 is found to be poor to excellent, according to the results of geochemical data (Rock-Eval pyrolysis, TOC, and Vitrinite Reflectance). These suggest that organic matter production and preservation conditions exist in the North Sea Basin. Geochemical data indicates that the samples from well 1/3-8 are immature to early mature source rocks, having good to excellent organic richness, genetic potential of very good and giving rise to type I, II, II/III and II kerogen. Samples from this well indicate good source rocks.

Samples from well 2/1-2 are immature to early mature source rocks and have poor to excellent organic richness, moderately good source having genetic potential of poor to very good and giving rise to type I, III, II/III and IV kerogen.

Samples from well 2/4-17 are immature to late mature source rocks and have poor to excellent organic richness, moderately good source having genetic potential of poor to very good and giving rise to type II, III, II/III and IV kerogen.

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