Petroleum and Coal

Article **Open Access**

SOURCE - ROCK POTENTIAL OF THE LOWER CRETACEOUS SEDIMENTS IN SD – 1X WELL, OFFSHORE TANO BASIN, SOUTH WESTERN GHANA

P. Garry[1], D. Atta-Peters[2*], C. Achaegakwo[2]

[1]*Job House Services Ltd, Accra, Ghana*
[2]*Department of Earth Science, University of Ghana, P.O. Box LG. 58, Legon, Accra, Ghana*

Received June 20, 2016; Accepted September 5, 2016

Abstract

66 cutting samples from the South Dixcove – 1X (SD - 1X) well in the Tano Basin, South-Western Ghana been subjected to TOC, Rock – Eval pyrolysis and Tmax analysis to evaluate their hydrocarbon potential. TOC values of between 0.69 - 8.58 (ave. 2.4 wt% TOC) show good to excellent total organic content (TOC), S_2 values of 0.2 – 44.39 (ave. 6.28 mg HC/g rock) implies a good to very good source rock of kerogen types II, II/III and III which are oil prone, oil-gas prone and gas prone respectively. The thermal maturation parameter, Tmax values of 342 – 450 (ave 427.0°C) indicates that majority of the source rocks in the well are immature to early mature. Production Index (PI) values of between 0.02 – 0.53 (ave 0.11) indicates that the samples are indigenous hydrocarbons and with low levels of contamination.

Keywords: Total Organic Carbon (TOC), South Dixcove (SD), Tano Basin, Kerogen, Thermal Maturity, Production Index, Vitrinite Reflectance, Genetic Potential.

1. Introduction

The Tano Basin is situated close to Ghana's western border with Ivory Coast and is the eastern extension of much larger Ivory Coast Basin. It is developed between the Coastal Fault System, St Paul's and Romanche Fracture Zones. The Tano Basin occupies an area of at least 3000 km^2, with the onshore component estimated at about 1165 km^2 [1]

The Tano structure is located approximately 39 km from the Ghana coast and approximately 24 km east of the Ghana - Cote d'Ivoire border, with a water depth in the area ranging from 91 m to 125 m. The Tano Basin began its tectonic sedimentary evolution as an extensional rift basin modified by wrench tectonism. This rifting was initiated by complex movements due to the separation of the continents of South America and Africa [2].

The Tano Basin located in southwestern Ghana, has been a major target for oil and gas exploration since 1896. The basin has since been subjected to serious exploration activities until 1978 when the first truly deepwater well (greater than 1000 ft) was drilled some 40 miles offshore. With further advances in seismic imaging technologies, more complex and subtle geological features were identified and mapped. The first major hydrocarbon potential of the Tano Basin was made in 2007 (Jubilee Field).

The objectives of this work are to study the probabilities and organic geochemical characteristics of the source rock units to identify: 1) the organic richness and hydrocarbon potential; 2) type of kerogen; and 3) thermal maturation of the source rocks from SD 1X well in the offshore Tano Basin. In other to achieve this tasks, the following will be approached: determining the total organic carbon (TOC) to evaluate the organic richness of the rock units; evaluate the kerogen types from Rock Eval pyrolysis data; using available geochemical data to establish thermal maturation of the source rock.

2. Geology and Geologic Setting

The Cretaceous–Tertiary rocks of the Tano Basin are grouped together as the Apollonian Formation and overlie the Birimian Precambrian basement rocks. It is about 3048 m thick onshore with an offshore component of 1768 m. Onshore, the rocks are alternating sandstone, shale and limestone with a general dip to the SSW. The upper limestone unit (i.e., Nauli limestone) (Campanian-Maastrichtian) is a stratigraphic marker, because of its abundant fauna/flora constituents. The Tano-Cape Three Points Basin is a Cretaceous wrench modified pull-apart basin. It is bounded by the African main land to the north, Saltpond Basin in the East and the St. Paul Fracture Zone in the West. The three main tectonic phases of the Tano Basin is as follows:

- Pre-Rift represented by Precambrian to late Jurassic rocks
- Syn-Rift phase with sediments of early Cretaceous age. The end of the syn-rift stage is delineated by a major unconformity which separates it from the marine post-transform rocks of the uppermost Albian and Cenomanian.
- Post-Rift phase of marine Cenomanian to present day.

The Tano basin resides on a transform margin, between the Romanche and St Paul transform faults and is the eastern extension of the Cote d'Ivoire-Ghana Basin and formed because of trans-tensional movement during the separation of Africa and South America, and opening of the Atlantic in the Albian. Active rifting and subsidence during this period resulted in the formation of a deep basin [3] The Tano basin was part of an extensional rift basin system which received substantial clastic sediment input from the African continent. In the late Cretaceous, the Tano basin became a depositional focus, with thick clastic sequences, consisting of fluvial and lacustrine facies. This was most likely initiated in the Barremian and Aptian times. It is thought that movement along a series of transform faults including faults in the Romanche Fault Zone during this continental separation led to the development of the large rift basin in the Tano area [4]. As a result of these movements, by Aptian - early Albian time, a large rift basin had developed in the Tano Basin area. This was followed in middle - late Albian times by widespread deposition of shallow marine sandstones and shales with minor limestone in the area. General evidence suggests that final separation on the continents took place in latest Albian [4]. It is believed that, a thermal anomaly with subsequent uplift occurred at the margin of the newly created African and Brazilian continental plates in the Tano area. This uplift occurred in late Albian time and may be the plate tectonic model for the development of the Tano structural trend.

As reservoir rocks are predicted to be in close proximity to the source rocks, a minimal hydrocarbon migration pathway is assumed. The prolific Tano Basin is thus the results of:

- an exceptionally favourable coincidence of regional and geological factors
- rich source rocks deposited and matured for oil
- tectonics and structural geology establishing framework for focusing charge
- world class turbidite reservoirs deposited in giant stratigraphic traps
- highly effective seals preserving discovery and development

3. Materials and methodology

3.1. Samples

The present study focuses on geochemical analysis of sixty-six (66) samples from the depth interval (5940 – 6000 ft) – (15,570 – 601 ft) (Table 1; Appendix 1) penetrating the South Dixcove (SD)-1X well offshore Tano Basin. The samples were processed in the Organic Laboratory, Ghana National Petroleum Corporation (GNPC) where they were oven-dried overnight at 110°C, and pulverized with the aid of pestle and mortar. The crushed rock samples were analyzed geochemically by TOC contents and Rock-Eval pyrolysis techniques.

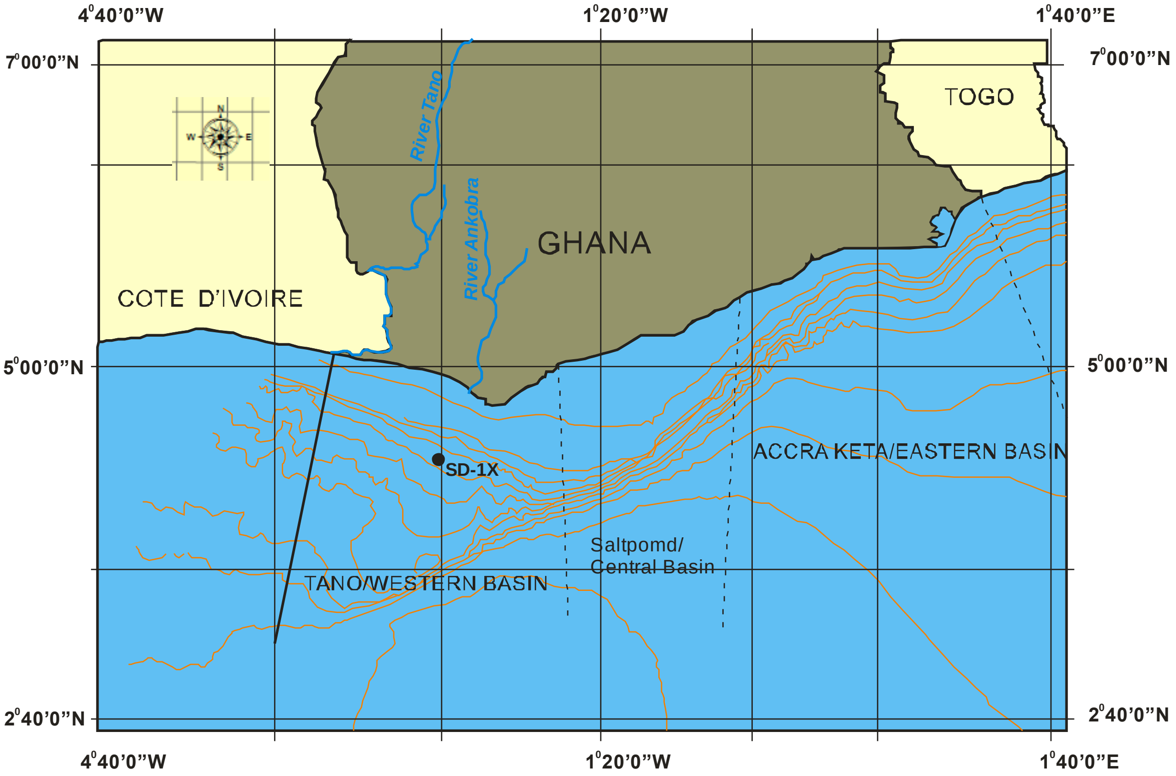


Figure 1. Map showing location of South Dixcove (SD) – 1X well in the offshore Tano Basin

3.2. Total Organic Carbon and Rock – Eval Pyrolysis

Rock – Eval pyrolysis data obtained from Ghana National Petroleum Corporation (GNPC) (Appendix 1), was used to determine the maturity and type of organic matter in the sediments and their hydrocarbon potential. About 100 mg of each sample was analyzed by using Rock Eval II instrument. The output from this sensor provides the peak data for the S_1 and S_2 indices. At low temperatures kept isothermally at 300ºC for 4 minutes the free hydrocarbons in the sample were volatilized and S_1 measured with a Flame Ionization Detector (FID).

At increasing temperatures by programmed pyrolysis in an inert helium atmosphere at 25ºC/min to 600ºC, hydrocarbons are expelled from the kerogen itself by cracking. This peak was measured as the S_2. The temperature at which the maximum generation of cracked hydrocarbons occurred at S_2 peak is termed Tmax. Tmax is a maturation parameter that is kerogen-dependent. The S_3 peak which is a result of CO_2 produced from the kerogen cracking and trapped between 300 - 390ºC, was detected with a thermal conductivity detector (TCD).

The calibration data for the thermal models includes vitrinite reflectance and the temperature. Since measurement for vitrinite reflectance (Ro) was not done, modelled vitrinite reflectance was derived from the equation $Ro\ \% = (0.018 * Tmax) - 7.16$

4. Results and discussion

Evaluation of source rocks for their hydrocarbon potential is essential in exploration processes. To evaluate the hydrocarbon source potential of the South Dixcove 1X well, samples were subjected to Rock Eval pyrolysis. Four parameters were acquired, these are:

- S_1 signal represents free hydrocarbons that can be volatilized out of a rock without cracking the kerogen (mg HC/g rock) at 300°C;
- S_2 measures the amount of pyrolyzed hydrocarbons (mg HC/g rock) from the cracking of kerogen at temperature-programed pyrolysis (300-600°C). This peak represents the existing potential of a rock to generate petroleum if burial and maturation would go to completion.

- S_3 is the peak corresponding to the quantity of CO_2 released due to pyrolysis break off between 300 and 390°C expressed in milligram of CO_2 per gram of rock(mg HC/g rock) and
- Tmax, the Rock-Eval pyrolysis oven temperature at which most of the hydrocarbons liberated (S_2) is observed and measures the thermal maturation [5].

These parameters were used to calculate the following: $S_1 + S_2$ which is the measure of genetic potential or the total amount of petroleum that would be generated from a rock. S_2/S_3 is the hydrocarbon type index which indicates the potential of the rock to generate hydrocarbon and is generally less than 2 for gas and greater than 5 for oil-prone rocks [6-7]. Production Index [PI S_1 / [$S_1 + S_2$] indicates the level of thermal maturation and also the presence of migrated hydrocarbons or contamination by drilling fluids.

Oxygen Index [OI = (S_3/TOC) x 100 mg CO_2/g TOC], is related to the amount of oxygen in the kerogen Hydrogen Index [HI = (S_2/TOC) x 100 mg HC/g TOC] is the normalized S_2 value (S_2/TOC) that indicates the potential of kerogen in a rock to generate petroleum [7].
Table 1 below shows the standard guidelines for interpreting source rock quantity, quality and maturation, and commonly used Rock-Eval parameters.

Table 1. Guidelines for interpreting source rock quantity, quality and maturation, and commonly used Rock-Eval parameters. SOURCE: [7-12].

Quantity	TOC	S1(mg HC/g rock)	S2(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)	S2/S3	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	Ro (%)	Tmax (^{o}C)	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

4.1. Organic carbon richness and hydrocarbon generation potential

The organic richness and source rock potential of a rock sample is evaluated by measuring the amount of total organic carbon (TOC) in the whole rock and pyrolysis derived S_2 samples [13].

Peters [10] reported that samples which contain TOC less than 0.5 wt % and S_2 less than 2.5 mg/g are considered poor source rocks. Samples which contain 0.5 to 1.0 wt % TOC and S_2 from 2.5 to 5 mg/g are fair source rocks. Those containing TOC from 1 - 2 wt % and S_2 from 5 – 10 mg/g are good source rocks and samples that contain more than 2 wt% TOC and $S_2 >$ 10 mg/g are considered very good source rocks. The analyzed samples of the SD-1X source rock have TOC ranging from 0.68 – 8.58 wt % (ave. 2.40 wt %) (Table 1, Fig. 2), reflecting that the organic richness is variegated mainly from fair to excellent source rock. The hydrocarbon potentiality are characterized by S_2 values between 0.2 – 44.4 mg/g (ave. 6.28 mg/g) (Table 1, Fig. 2), indicating poor to excellent source potential.

Hydrogen content of the organic matter source rock is the most important factor controlling hydrocarbon generation potential. But because this parameter is difficult to determine, HI values from Rock-Eval pyrolysis are commonly used as proxy. High HI values indicate an aquatic origin of organic matter, whereas low values indicate more terrigenous contribution or strong degradation or maturation of organic matter. The HI values vary between 29 - 517 mg HC/g

TOC (ave. 214) and are typical of type II, II/III, and III. This is further supported by the plot of HI versus OI as well as S_2/S_3 values (Appendix1).

Plot of HI versus TOC (Fig. 4) shows that samples from well SD – 1X have good to very to excellent generative potential. This is supported by the presence of Type II and III kerogens.

According to [5] and [7] the ratio S2/S3 is proportional to the amount of hydrogen in a source rock and is an indicator of the potential to generate oil and gas. The quality of the organic matter present has a direct relationship with the kerogen type present. The plot of S_2/S_3 versus TOC (Fig. 5) shows that the samples have good to excellent generation potential source rocks. Samples with good generation potential yielded type III and II kerogens whilst those with very good and excellent generation potential yielded type II and I kerogens.

$S_1 + S_2$ is a measure of the genetic potential of the source rock. The genetic potential of the source rock is defined as the total amount of oil and gas that unit quantity of the source rock could produce if the rock were buried deep enough and long enough. [13] proposed a genetic potential (GP = $S_1 + S_2$) classification of source rocks. According to their classification scheme, rocks with GP of less than 2 mg HC/ g rock correspond to gas prone rocks or non-generative ones, rocks with GP between 2 and 6 mg HC/ g rock are moderate source rocks with fair gas/oil potential, and those with GP greater than 6 mg HC/ g rock are good source rocks. Rocks with exceptionally high GP values in order of 100 or 200 mg HC/ g rock may provide either an excellent source rock, if the burial depth is sufficient, or an oil shale, if the burial depth is shallow.

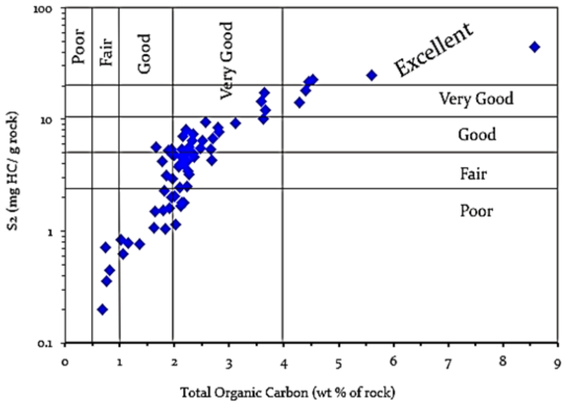


Fig. 2. Plot of S_2 versus TOC indicating hydrocarbon potentiality and source efficiency

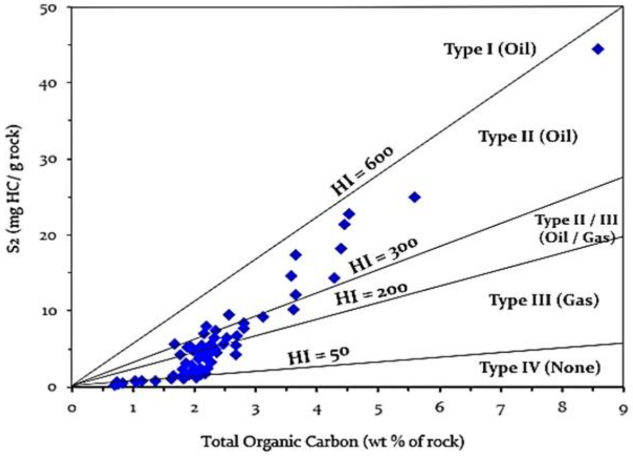


Fig. 3. Plot of S_2 versus TOC indicating the kerogen types of the studied samples

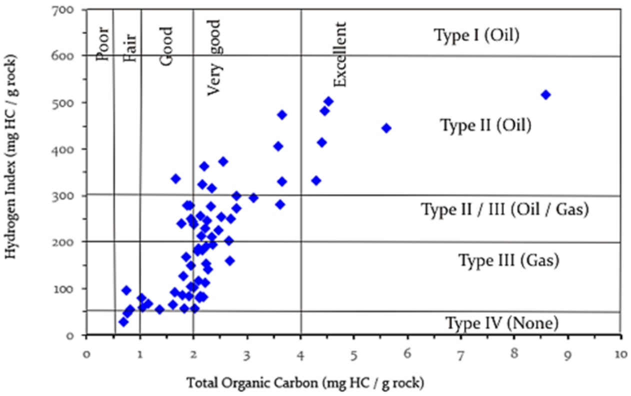


Fig. 4. Plot of Hydrogen Index versus TOC indicating kerogen types and generation potential.

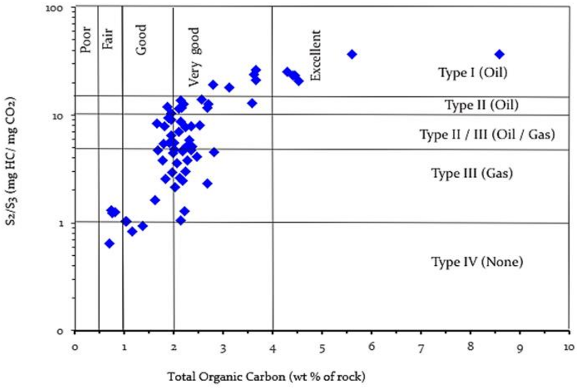


Fig. 5. Plot of S_2/S_3 versus TOC indicating kerogen types and generation potential

Some samples from the well (Fig. 6), have poor to good organic carbon content, poor to moderate genetic potential with fair oil and gas potential. The majority of the samples however have very good to excellent organic carbon content, moderate to excellent genetic potential and can be classified as good to excellent source rock. These samples have the potential to generate large amounts of hydrocarbons at sufficient depth and temperature.

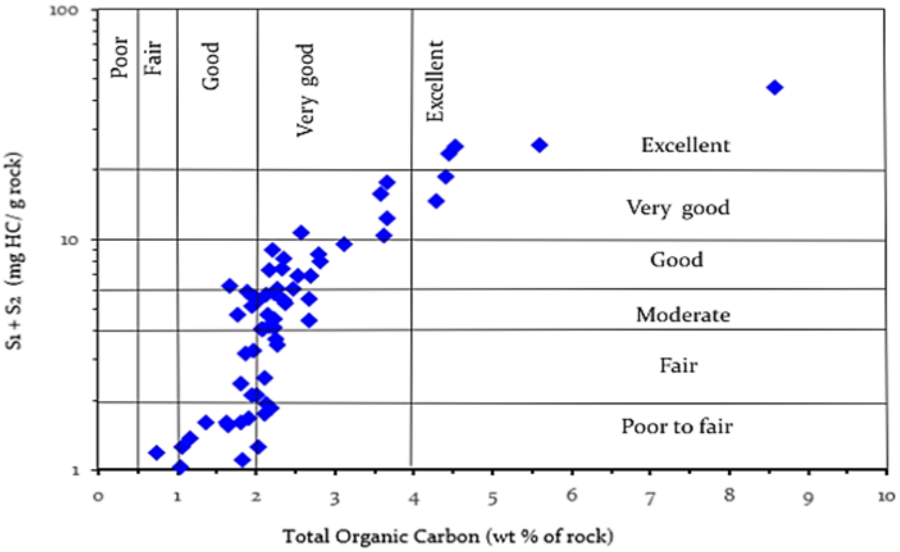


Fig. 6. Plot of S_1+S_2 versus TOC showing the genetic potential for the studied samples

4.2. Kerogen types

The organic matter type is an important parameter in evaluating source rock potential and has a first order control on the nature of the hydrocarbon products. Kerogen types can be identified by optical methods and organic geochemical methods where values of elemental analysis of C, O, and H are used in plotting HI versus OI from Rock-Eval pyrolysis on a modified Van Krevelen diagram [14]. It is very important to determine the kerogen types due to the variation of the chemical structure of organic matters and the hydrocarbon products.

According to [7] and [15], there are four types of kerogen in sedimentary rocks:

1. Type - I, composed of oil-prone hydrogen matter generally in lacustrine and some marine sediments;
2. Type - II, also composed of oil-prone hydrogen organic matter mainly in marine sediments, Even though oil is the main product of Type II kerogen, it actually produces more gas than Type III kerogens.
3. Type - III composed of terrestrial organic matter derived mainly from woody plant material.
4. Type-IV composed of dead or inert carbon that has little or no generating capacity.

Waples [16] and Obaje [17] used the HI values to differentiate between types of organic matter. Type IV kerogen normally exhibits very low, less than 50 mg/g and is formed under very oxic conditions. HI values for type III kerogen, is moderately low, between 75 – 300 HC/g TOC and has more type III than type II and are prone to generating mixed gas and oil, but mainly gas. However, humic coals (with type III kerogen) may have HI up to 300 HC/g TOC and possess the capacity to generate oil. Kerogen with HI between 350 - 600 HC/g TOC contain type II macerals and has a good source potential for generating oil and gas at the appropriate level of maturity. Kerogen with HI above 600 HC/g TOC is indicative of type I kerogen and has excellent potential to generate oil.

The plot of S_2 versus TOC and determining the regression equation (as seen in Fig. 3) is the best method for analyzing the true average HI and measuring the adsorption of hydrocarbons by the rock matrix [18]. The analyzed samples from SD – 1X well (Appendix 1) gave an average HI of 214 mg HC/g TOC, indicating type II, II/III and III kerogen, but with the tendency to yield more gas (Fig. 7). The kerogen designation according to [5] is based entirely on HI, but the quality and maturity are determined by plotting HI versus Tmax rather than HI versus OI (Fig. 7 and 8). This eliminates the use of OI as a kerogen type indicator (comparable to the O/C in the Van Krevelen diagram).

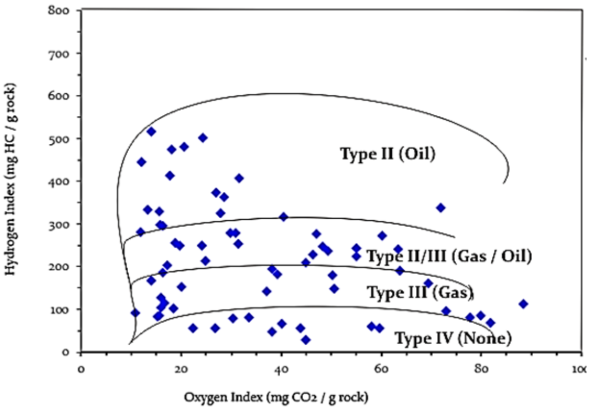


Fig. 7. Modified Van Krevelen diagram indicating kerogen types of the studied samples

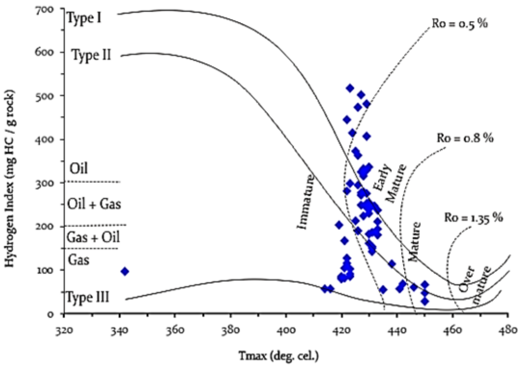


Fig. 8. Plot of Hydrogen Index versus Tmax showing the relationship between kerogen types and maturity levels

4.3. Maturity of organic matter

The degree of thermal alteration of organic matter due to heating provides an indication of source rock maturity. Thermal maturity is influenced by source rock organic matter type and the presence of excess free hydrocarbon together with the other factors like mineral matter, content, depth of burial and age [11]. Data indicators for maturity are Tmax, Production Index (PI) and Vitrinite Reflectance. The increase of maturity level of organic matter corresponds to an increase in Tmax particularly for immature samples. PI = {S_1 / [S_1 + S_2]} is a valuable method for indicating the thermal maturity of organic matter. The following relations between Tmax and PI are observed:

- Immature organic matter has Tmax and PI values less than 430°C and 0.10, respectively;
- Mature organic matter has a range of 0.1– 0.4 PI. At the top of oil window, Tmax and PI reach 460°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 [8, 10, 15].

In well SD – 1X, majority of the samples are indigenous except for a few dispersed within the hydrocarbon generation and non-indigenous windows (Fig. 9, Fig. 10). The Tmax values of < 435 and PI < 0.4, indicates that majority of the samples are immature to early mature and few samples having PI > 0.4, indicating mature organic matter (wet gas zone).

According to [16] and [18], an overview of maturity distribution is provided by Ro data, which is considered to be the most reliable and most commonly used maturity indicator. The Ro values between 0.5 and 0.7% indicate low source rock grade, 0.7 to 1.0% reflect a moderate source-rock grade, and 1.0 to 1.3% refer to a high source-rock grade. Based on the above criteria, most of the samples from SD – 1X have inferred vitrinite reflectance (Ro) of between -1.00 – 0.94; (ave 0.53) and are thus immature to the early mature in terms of both Tmax and Ro (Fig.11). They can be classified as predominantly low to moderate grade source rocks.

Plot of Production Index versus Tmax (Fig. 12) indicate that rock samples from well SD – 1X have poor to fair source rock quality which are mainly immature or early mature with low level of conversion and no contaminated or migrated hydrocarbons.

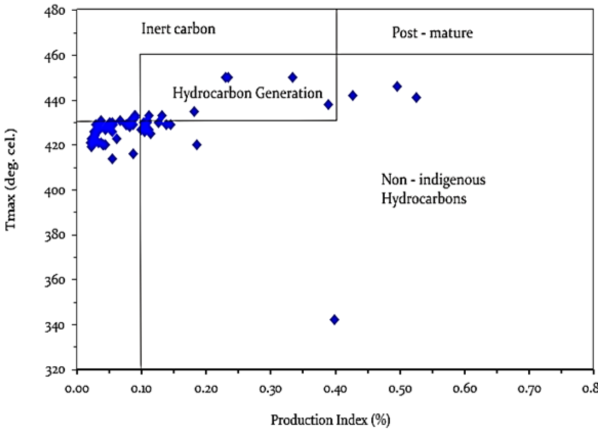


Fig. 9. Plot of Tmax versus Production Index showing the hydrocarbon generation zone

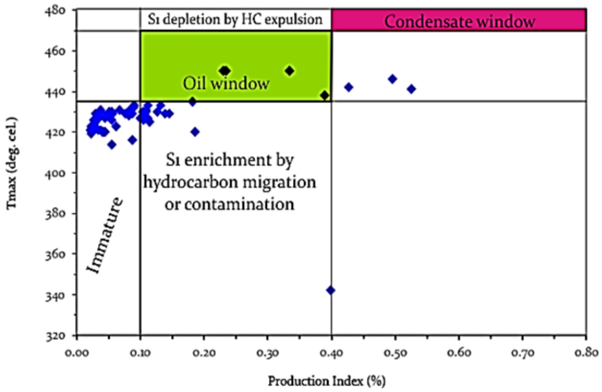


Fig. 10. Plot of Tmax versus Production Index showing hydrocarbon generation zone.

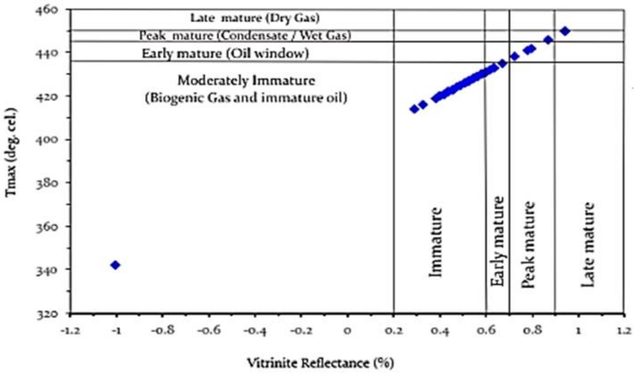


Fig. 11. Plot of Tmax versus Vitrinite Reflectance (Ro) showing maturity levels

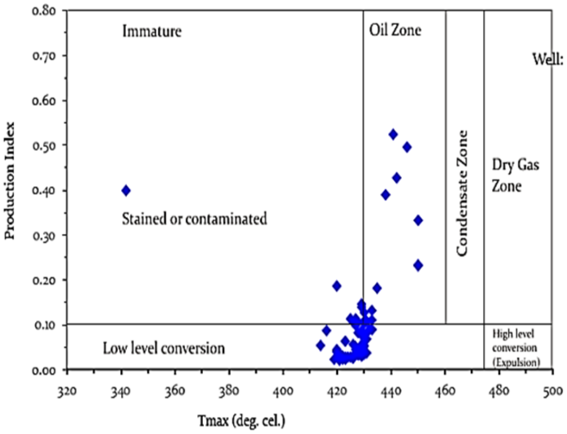
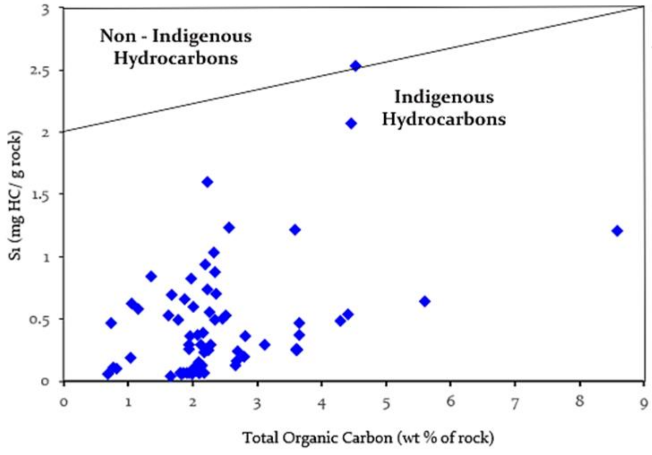


Fig. 12. Plot of Production Index versus Tmax showing levels of kerogen conversion and maturity



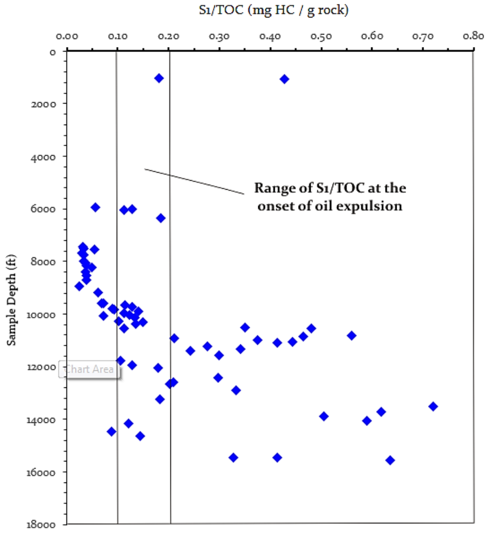


Fig. 13. S_1 versus TOC as an indicator of indigenous and non-indigenous hydrocarbons

Fig. 14. Depth versus S_1/TOC ratio as an indicator of oil expulsion

4.4. Expulsion ability

S_1 represents the free hydrocarbons already present in the sample, and S_2 represents the hydrocarbons generated during pyrolysis. Free hydrocarbons are those already produced from organic material and will be proportional to the Total Organic Carbon (TOC) of any given source rock. The Ocean Drilling Program uses S_1/TOC of 1.5, to determine the presence of indigenous versus migrated or non-indigenous hydrocarbon levels [5]. The plot of S_1 versus TOC (Fig. 13) shows that all source rocks contain an expected level of S_1 hydrocarbons for their given TOC, and are hence predominantly indigenous.

S_1/TOC had to reach 0.1- 0.2 for oil expulsion to start. The fact is that hydrocarbons may be generated but S_1 steadily increases before being expelled. In most ideal situations, S_1/TOC increases as thermal maturity increases, and after expulsion remains constant and then gradually decreases with increasing depth and maturity [19]. Source rocks with S_1/TOC values exceeding 1.5 indicate a contribution of non-indigenous oil. A range of S_1/TOC= 0 - 0.80 (Fig. 14) therefore suggests mainly indigenous hydrocarbons with free (reservoir) hydrocarbons.

5. Conclusion

The organic geochemical studies consisting of TOC and Rock-Eval pyrolysis analysis of 66 samples for South Dixcove (SD – 1X) in the Tano Basin reflect that:

1. The source rocks show a good to excellent organic matter with TOC values between 0.69 – 8.58 wt. % (ave 2.39 wt. %) which suggests that there might exist conditions in the basin that favour organic matter production and preservation.
2. In terms of thermal maturity, the samples have Tmax values of 342 – 450 °C (Ave. 427 °C), with majority of them indicating moderately immature to early mature source rocks, with good to excellent organic richness.
3. The organic matter contained in the samples have fair to excellent potential kerogen types II, II/III and III for generating oil, oil/gas and gas respectively.
4. The production index (PI) of between 0.02 – 0.53 (ave 0.11) indicate that majority of the samples are indigenous hydrocarbons and with low levels of contamination.

Acknowledgement

The authors would like to acknowledge the management of Ghana National Petroleum Corporation (GNPC), Ghana, for providing data to undertake this study.

References

[1] Kesse GO. Mineral and Rock Resources of Ghana. A. A. Balkema Publishers. Rotterdam, Netherlands, 1985.

[2] Atta-Peters D, Kyorku NA. Palynofacies analysis and sedimentary environment of Early Cretaceous sediments from Dixcove 4-2X well, Cape Three Points, Offshore Tano Basin, Western Ghana, International Research Journal of Geology and Mining, 2013; 3:7, 270-281.

[3] Adda WG. The Petroleum Geology and Prospectivity of the Neo-Proterozoic, Paleozoic and Cretaceous Sedimentary Basins in Ghana, Search and Discovery; 2013; 10544.

[4] Davies G. Geological and tectonic framework of the Republic of Ghana and petroleum geology of the Tano Basin, Southwestern Ghana. Unpublished consultancy report prepared for Petro-Canada International Corporation on behalf of GNPC, 1989; 24 pp.

[5] Hun JM. Petroleum geology and geochemistry, Second edition: W.H. Freeman and Company, New York, 1996.

[6] Tissot BP, Welte DH. Petroleum Formation and Occurrence. New York, Springler-Verlag, 1984.

[7] Peters KE. Cassa MR. Applied source rock geochemistry, in: Magoon, LB, Dow, WG, (eds), The petroleum system – from source to trap: American Association of Petroleum Geologists, 1994; 60: 93-120.

[8] Epstein AG, Epstein JB, Harris LD. Conodont colour alteration-an index to organic metamorphism: U. S. Geological Survey Professional Paper, 1977; 995:27 pp.

[9] Espitalié J, Marquis F, Barony I. Geochemical logging, in: Voorhees K.J (Ed.), Analytical pyrolysis: techniques and applications. Butterworth, London, 1984; 276–304.

[10] Peters KE. Guidelines for evaluating petroleum source rock using programmed pyrolysis: American Association of Petroleum Geologists Bulletin, 1986; 70: 318-329.

[11] Traverse A. Paleopalynology, Unwin Hyman, Boston, 1988.

[12] Fowler M, Snowdon L, Stasiuk V. Applying petroleum geochemistry to hydrocarbon exploration and exploitation. American Association of Petroleum Geologists Short Course Notes, June 18-19, 2005, Calgary, Alberta, 2005; 224 pp.

[13] Waples DW, Kamata H, Suizu M. The art of maturity modeling: Part 1. Finding a satisfactory geological model: American Association of Petroleum Geologists Bulletin, 1992; 76: 31–46.

[14] Batten DJ. Palynofacies and paleoenvironmental interpretation, in: Jansonius, J, McGregor, DC, (Eds.), Palynology: Principles and applications; American Association of Stratigraphic Palynologists, Foundation, 1996, 3: 1011-1064.

[15] Jacobson SR. Petroleum source rocks and organic facies, in Merrill, RK, (ed.), Source and migration processes and evaluation techniques: American Association of Petroleum Geologists Handbook of Petroleum Geology, 1991; 1–11.

[16] Waples DW. Geochemistry in petroleum exploration. Reidel Publ. Co., Dordrecht and IHRDC, Boston, 1985.

[17] Obaje NG, Wehner H, Scheeder G, Abubakar MB, Jauro A. Hydrocarbon prospectively of Nigeria’s inland basins: organic geochemistry and organic petrology, American Association of Petroleum Geologists Bulletin, 2004; 88:3, 325-353.

[18] Dow WG. Kerogen studies and geological interpretations, Journal of Geochemical Exploration, 1977; 7: 77– 99.

[19] Smith JT. Petroleum system logic as an exploration tool in a frontier setting, in: Magoon, LB, Dow, WG, (eds.), The petroleum system - from source to trap. AAPG Memoir, 1994; 60: 25-49.

---

*(Corresponding author Email): dattapeters@gmail.com

Appendix 1

Table 1. Rock-Eval Analysis of samples from Well South Dixcove 1X, in the Tano Basin, South-Western Ghana.

WELL: SOUTH DIXCOVE 1X (SD – 1X) LOCATION: OFFSHORE GHANA

Company: GNPC

Sample Depth (ft)	TOC (wt % of rock)	S1 (mg HC/ g rock)	S2 (mg HC/ g rock)	S3 (mg CO2/ g rock)	S2/S3 (mg HC/ mg CO2)	Genetic Potential (mg HC/ g rock)	Production Index	Oxygen Index (mg CO2/ g rock)	Hydrogen Index (mg HC/ g rock)	Ro (%)	Tmax (°C)	S1/ TOC (mg HC/ g rock)
5940-6000	2.13	0.12	1.8	1.7	1.06	1.92	0.06	80	85	0.45	423	0.06
	2.68	0.16	4.3	1.86	2.31	4.46	0.04	69	160	0.58	430	0.06
6000-061	2.81	0.36	7.64	1.69	4.52	8	0.05	60	272	0.53	427	0.13
6060-121	2.23	0.25	4.24	1.42	2.99	4.49	0.06	64	190	0.51	426	0.11
6360-420	1.03	0.19	0.83	0.8	1.04	1.02	0.19	78	81	0.40	420	0.18
7440-500	2.18	0.07	1.78	0.73	2.44	1.85	0.04	33	82	0.42	421	0.03
7500-560	2.11	0.07	1.68	0.64	2.63	1.75	0.04	30	80	0.40	420	0.03
7560-620	2.02	0.11	1.15	0.54	2.13	1.26	0.09	27	57	0.33	416	0.05
7680-741	2	0.06	2.04	0.37	5.51	2.1	0.03	19	102	0.45	423	0.03
7740-801	2.1	0.07	2.43	0.35	6.94	2.5	0.03	17	116	0.44	422	0.03
7980-8040	1.83	0.06	1.04	0.41	2.54	1.1	0.05	22	57	0.29	414	0.03
8040-101	1.95	0.07	2.02	0.31	6.52	2.09	0.03	16	104	0.42	421	0.04
8160-221	1.8	0.07	1.53	0.28	5.46	1.6	0.04	16	85	0.40	420	0.04
8220-280	2.67	0.13	5.42	0.46	11.78	5.55	0.02	17	203	0.38	419	0.05

Sample Depth (ft)	TOC (wt % of rock)	S1 (mg HC/ g rock)	S2 (mg HC/ g rock)	S3 (mg CO2/ g rock)	S2/S3 (mg HC/ mg CO2)	Genetic Potential (mg HC/ g rock)	Production Index	Oxygen Index (mg CO2/ g rock)	Hydrogen Index (mg HC/ g rock)	Ro (%)	Tmax (ºC)	S1/ TOC (mg HC/ g rock)
8400-460	1.91	0.07	1.59	0.29	5.48	1.66	0.04	15	83	0.40	420	0.04
8520-580	1.86	0.07	3.12	0.26	12.00	3.19	0.02	14	168	0.42	421	0.04
8700-760	1.81	0.07	2.3	0.29	7.93	2.37	0.03	16	127	0.44	422	0.04
8940-9000	1.65	0.04	1.51	0.18	8.39	1.55	0.03	11	92	0.45	423	0.02
9180-240	2.14	0.13	4.57	0.53	8.62	4.7	0.03	25	214	0.49	425	0.06
9600-660	3.62	0.25	10.15	0.43	23.60	10.4	0.02	12	280	0.44	422	0.07
9600-660	2.8	0.2	8.36	0.44	19.00	8.56	0.02	16	299	0.45	423	0.07
9660-720	5.6	0.64	24.9	0.68	36.62	25.54	0.03	12	445	0.44	422	0.11
9720-780	3.65	0.47	17.31	0.66	26.23	17.78	0.03	18	474	0.51	426	0.13
9780-840	2.69	0.24	6.7	0.53	12.64	6.94	0.03	20	249	0.53	427	0.09
9840-900	3.12	0.29	9.2	0.51	18.04	9.49	0.03	16	295	0.51	426	0.09
9900-960	8.58	1.21	44.39	1.21	36.69	45.6	0.03	14	517	0.45	423	0.14
9960-10020	4.29	0.48	14.28	0.57	25.05	14.76	0.03	13	333	0.54	428	0.11
10020-080	4.4	0.54	18.24	0.78	23.38	18.78	0.03	18	415	0.47	424	0.12
10080-140	2.09	0.15	3.9	0.34	11.47	4.05	0.04	16	187	0.60	431	0.07
10140-200	1.94	0.26	5.41	0.6	9.02	5.67	0.05	31	279	0.54	428	0.13
10200-260	2.16	0.39	7.01	0.6	11.68	7.4	0.05	28	325	0.53	427	0.18
10260-320	3.66	0.37	12.06	0.57	21.16	12.43	0.03	16	330	0.56	429	0.10
10320-380	1.95	0.29	4.87	0.47	10.36	5.16	0.06	24	250	0.56	429	0.15
10380-440	2.13	0.29	5.44	0.4	13.60	5.73	0.05	19	255	0.58	430	0.14

Sample Depth (ft)	TOC (wt % of rock)	S1 (mg HC/ g rock)	S2 (mg HC/ g rock)	S3 (mg CO2/ g rock)	S2/S3 (mg HC/ mg CO2)	Genetic Potential (mg HC/ g rock)	Production Index	Oxygen Index (mg CO2/ g rock)	Hydrogen Index (mg HC/ g rock)	Ro (%)	Tmax (ºC)	S1/ TOC (mg HC/ g rock)
10500-560	1.88	0.66	5.23	0.56	9.34	5.89	0.11	278	30	0.53	427	0.35
10560-620	2.56	1.23	9.54	0.69	13.83	10.77	0.11	373	27	0.49	425	0.48
10560-620	2.24	0.25	3.44	0.45	7.64	3.69	0.07	154	20	0.60	431	0.11
10740-800	2.2	0.94	8	0.63	12.70	8.94	0.11	364	29	0.51	426	0.43
10800-860	4.52	2.53	22.73	1.1	20.66	25.26	0.10	503	24	0.53	427	0.56
10860-921	4.45	2.07	21.42	0.92	23.28	23.49	0.09	481	21	0.56	429	0.47
10920-981	2.52	0.53	6.39	0.79	8.09	6.92	0.08	254	31	0.56	429	0.21
10980-11040	2.35	0.88	7.42	0.95	7.81	8.3	0.11	316	40	0.54	428	0.37
11040-100	2.32	1.03	6.4	1.09	5.87	7.43	0.14	276	47	0.56	429	0.44
11100-160	1.98	0.82	4.81	1.09	4.41	5.63	0.15	243	55	0.56	429	0.41
11220-280	1.77	0.49	4.25	1.12	3.79	4.74	0.10	240	63	0.58	430	0.28
11340-401	3.58	1.22	14.56	1.13	12.88	15.78	0.08	407	32	0.56	429	0.34
11400-461	2.26	0.55	5.57	1.09	5.11	6.12	0.09	246	48	0.62	432	0.24
11580-641	2.01	0.6	4.78	0.99	4.83	5.38	0.11	238	49	0.63	433	0.30
11760-821	2.17	0.23	3.95	0.85	4.65	4.18	0.06	182	39	0.58	430	0.11
11940-12001	2.27	0.29	3.21	0.84	3.82	3.5	0.08	141	37	0.60	431	0.13
12060-111	2.07	0.37	3.72	1.04	3.58	4.09	0.09	180	50	0.63	433	0.18
12420-481	2.36	0.7	4.58	0.9	5.09	5.28	0.13	194	38	0.63	433	0.30
12600-661	2.34	0.49	4.92	1.05	4.69	5.41	0.09	210	45	0.63	433	0.21
12660-721	2.47	0.5	5.56	1.36	4.09	6.06	0.08	225	55	0.54	428	0.20

Sample Depth (ft)	TOC (wt % of rock)	S1 (mg HC/ g rock)	S2 (mg HC/ g rock)	S3 (mg CO2/ g rock)	S2/S3 (mg HC/ mg CO2)	Genetic Potential (mg HC/ g rock)	Production Index	Oxygen Index (mg CO2/ g rock)	Hydrogen Index (mg HC/ g rock)	Ro (%)	Tmax (ºC)	S1/ TOC (mg HC/ g rock)
12900-961	2.22	0.74	5.09	1.03	4.94	5.83	0.13	229	46	0.58	430	0.33
13250-321	1.96	0.36	2.93	0.99	2.96	3.29	0.11	149	51	0.60	431	0.18
13500-561	2.22	1.6	2.51	1.96	1.28	4.11	0.39	113	88	0.72	438	0.72
13710-761	1.36	0.84	0.76	0.81	0.94	1.6	0.53	56	60	0.78	441	0.62
13880-971	1.15	0.58	0.78	0.94	0.83	1.36	0.43	68	82	0.80	442	0.50
14060-121	1.05	0.62	0.63	0.61	1.03	1.25	0.50	60	58	0.87	446	0.59
14170-241	0.82	0.1	0.45	0.36	1.25	0.55	0.18	55	44	0.67	435	0.12
14480-521	0.69	0.06	0.2	0.31	0.65	0.26	0.23	29	45	0.94	450	0.09
14640-701	0.76	0.11	0.36	0.29	1.24	0.47	0.23	47	38	0.94	450	0.14
15460-512	1.67	0.69	5.63	1.2	4.69	6.32	0.11	337	72	0.58	430	0.41
15460-513	1.62	0.53	1.06	0.65	1.63	1.59	0.33	65	40	0.94	450	0.33
15570-601	0.74	0.47	0.71	0.54	1.31	1.18	0.40	96	73	-1.00	342	0.64
Minimum	0.69	0.04	0.2	0.18	0.65	0.26	0.02	29	11	-1.00	342	0.02
Average	2.40	0.47	6.28	0.76	8.91	6.76	0.11	213.57	36.05	0.53	427.05	0.21
Maximum	8.58	2.53	44.39	1.96	36.69	45.6	0.53	517	88	0.94	450	0.72