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Source rock evaluation and hydrocarbon potential in the Tano basin, South Western Ghana, West Africa

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Abstract: Three exploratory oil wells (ST-9H, WCTP-2X and WT-1X) from the Tano Basin, south-western Ghana, have been evaluated for their hydrocarbon generation potential by the use of geochemical analysis (TOC, Rock-Eval pyrolysis). The analytical results of samples revealed that the wells have fair to good total organic carbon (TOC) contents, suggesting that there exist conditions in the Basin that favoured organic matter production and preservation. There is a variation in kerogen types and this may be attributed to the relative stratigraphic positions of the outcrops within the basin. Thermal maturity indicated that samples from the well WCTP-2X and WT-1X, are immature and that from ST-9H show late immature to mature stage of the hydrocarbon generation process. Most of the samples from the wells with the exception of two samples from ST-9H are non-indigenous (migrated). Hydrocarbon generation potential from all three wells particularly ST-9H display sufficient organic matter contents to produce oil and gas. The hydrocarbon potential is good and capable to make expulsions of oil and gas from the wells. Kerogen Type IV, III and II are present in well ST-9Hand Types II and III kerogen in wells WCTP-2X and WT-1X.

Keywords: Total Organic Carbon (TOC), Tano Basin, Vitrinite Reflectance, Hydrocarbon Potential, Genetic Potential, Kerogen

1. Introduction

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. Since then the basin has 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 hydrocarbon potential of the Tano Basin has since been known based on onshore oil seeps, but the first major discovery was made in 2007 (Jubilee Field).

This work aims at evaluating the quantity of organic matter, characterizing the type of kerogen as well as determining its maturity status in order to deduce the Hydrocarbon potential of the basin, from organic geochemical data from wells ST-9H, WCTP-2X and WT-1X.

1.1. Geologic Setting

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 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 Upper Cretaceous, the Tano basin became a depositional focus, and a thick clastic sequence consisting of fluvial and lacustrine facies was deposited. This sequence, in addition to the thin Tertiary section, provided adequate thickness to mature the Cretaceous source rocks in the central and western region of the Tano Basin. Rapid drowning of the West African Transform Margin created ideal conditions for deposition of thick rich source rock in the Cenomanian. Creation of a deep basin with significant river systems onshore, led to the deposition of large turbidite fan/channel complexes (forming stratigraphic traps for oil) in deep water.

The basin (Cretaceous to Eocene) forms part of the broad Apollonian Formation occupying the southwest corner of Ghana and larger portion of southeast Côte d'Ivoire. The rocks onshore consist of alternating sands, clays and limestones with gentle dips overlying the Precambrian metamorphosed Birimian System composed of schist, phyllite and greywackes. At depth, the sands and clays are more compact and pass into sandstones and shales. [4].

The basin comprises a thick Upper Cretaceous drift section which is dominated by basin floor fans, stratigraphic traps and channel systems. The rift section comprises shallow marine to continental deposits. The working play type is the Cretaceous Play, which consists of Cenomanian-Turonian and Albian shales as source rocks with Turonian slope fan turbidite sandstones and Albian sandstones in tilted fault blocks as reservoirs. Trapping is both stratigraphic and structural [3]. 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 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 oil and gas for discovery and development

2. Methodology

2.1. Samples

The study was carried out on 54 samples from well South Tano - 9H (ST-9H) within intervals 1470 ft -7260 ft, 55 samples from well WCTP - 2X within intervals 3980 ft – 9440 ft and 33 samples from intervals 5000 ft – 9840 ft of well WT – 1X (Figure 1). All three wells are in the Tano Basin and their geochemical data are summarized in Appendix 1(a,b,c) respectively.

The samples were processed in the Organic Geochemistry 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, Rock-Eval pyrolysis techniques. To characterize their hydrocarbon generating potential, the samples were geochemically investigated to determine the total organic content, identify organic matter type, and determine the maturity of organic matter.

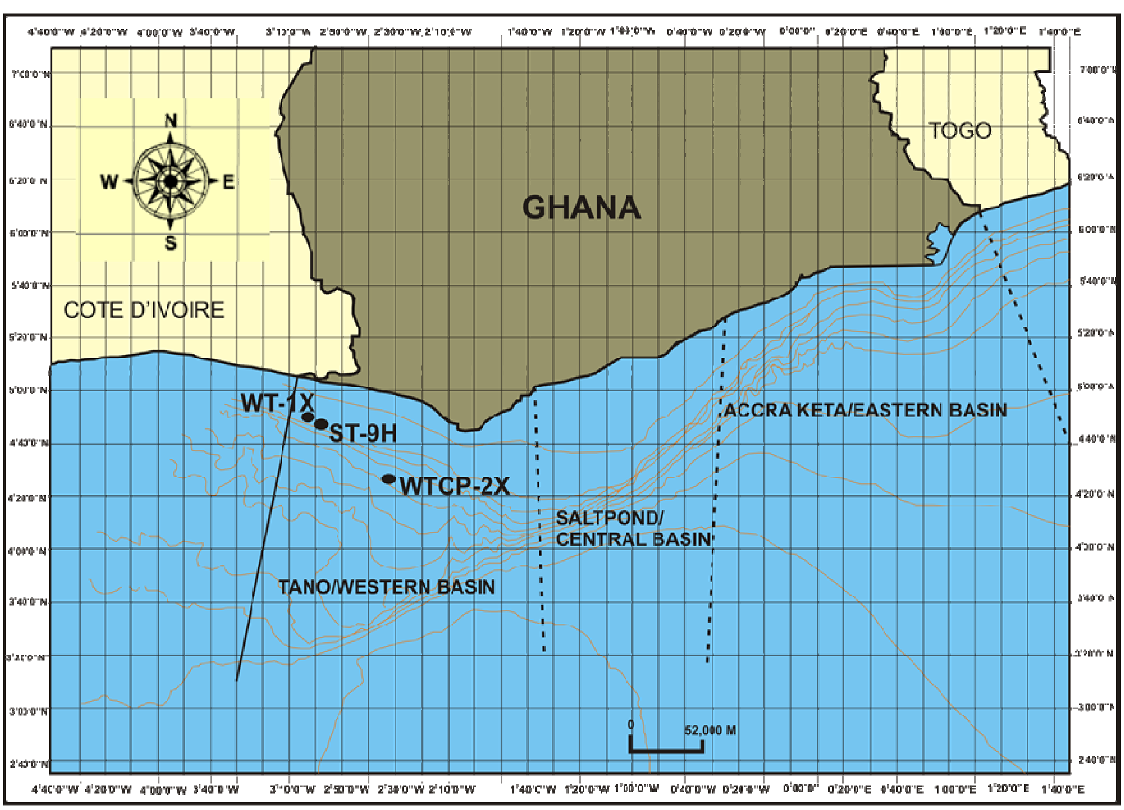

Figure 1. Map of offshore sedimentary basins showing studied well in the Tano basin.

2.2. Total Organic Carbon and Rock Eval Analysis

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 300 º C 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 25 ºC/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 [5]. 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 300-390 ºC, was detected with a thermal conductivity detector (TCD).

The calibration data for the thermal models includes vitrinite reflectance and the temperature. Since vitrinite measurement was not done, modelled vitrinite reflectance was derived from the equation R_O % = (0.018* Tmax) -7.16 [6]

3. Results and Discussion

Table 1. *Guidelines for interpreting source rock quantity, quality and maturation, and commonly used Rock-Eval parameters. SOURCE: {[8], [9], [10], [11], [12], [13]}.*

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)	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 (^{0}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

In Geochemical analysis, the purpose of geochemical logging and cross plots is to measure the following parameters relating to source rock evaluation in sedimentary rocks: quantity of organic matter, quality of the organic matter and the thermal maturation of the organic matter. The knowledge of these three parameters permits accurate evaluation of the source rock geochemistry and hydrocarbon potential in the Tano Basin. Scatter plots are actually cross plots whereby the parameters obtained from pyrolysis are plotted against each other and are used in interpreting the properties and hydrocarbon potential of the study area. Four parameters S_1, free hydrocarbon: S_2, pyrolyzed hydrocarbon resulting from the cracking of kerogen; S_3, quantity of CO_2, and Tmax, the temperature at which the maximum generation of the products of pyrolysis occurs were used to calculate the following:

OI, oxygen index [OI = (S_3/TOC) x 100)]

HI, hydrogen index [HI = (S_2/TOC) x 100]. Plot of HI versus OI can be used to deduce the type of organic matter present in the source rock [7]

PI, production index [PI = S_1 / (S_1 + S_2)]

Hydrogen richness in the kerogen = S_2/S_3

Genetic potential of the source rock = S_1 + S_2

The TOC contents and Rock-Eval data results for the studied samples of the 3 exploratory wells, Well ST – 9H, Well WCTP – 2X and WT – 1X are presented in the Appendix 1 (a,b,c). Table 1 below serves as a guide for interpreting source rock quantity, quality and maturation, and commonly used Rock-Eval parameters.

3.1. Organic Richness and Hydrocarbon Potentiality

The organic richness and 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 of the rock samples [14]. [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 contain from 0.5 to 1.0 wt % TOC and S_2 from 2.5 to 5 mg/g are fair source rocks and 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.

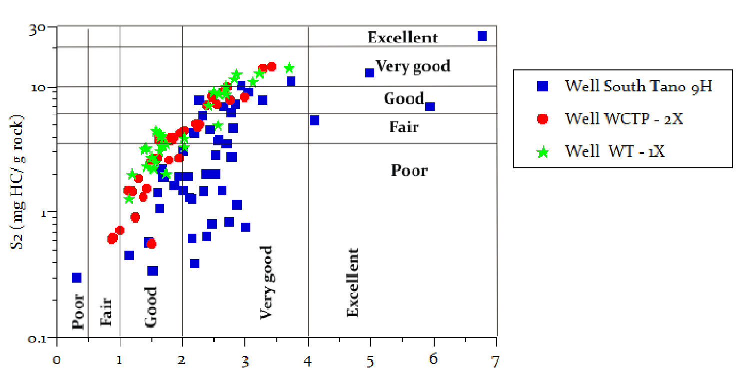

Figure 2. *Plot of S_2 versus TOC indicating hydrocarbon potentiality and source rock efficiency.*

Figure 2 shows a hydrocarbon yield of S_2 versus TOC cross plot. Based on the above criterion, rock samples from well ST-9H are good to excellent source rocks and those from wells WCTP-2X and WT-1X as good to very good source rocks.

The plot of S_2 versus TOC and determining the regression equation is the best method for analyzing the true average HI and measuring the adsorption of hydrocarbons by the rock matrix[15].The analyzed samples from well ST-9H gave an average HI of 134 mg HC/g TOC, thus falling in the range of gas prone kerogen. Well WCTP-2X on the other hand gave an average HI of 208 mg HC/g TOC, thus falling in the range of oil and gas prone kerogen. From Figure 3, it can however be observed that in addition to type II/III kerogen, the type III is also very dominant thereby making the samples in the well more gas prone.

The average HI from well WT-1X is 256 mg HC/g TOC, which is both oil and gas prone. Figure 3, however, shows dominant oil prone type II kerogens in addition to type III kerogens, thereby making the samples present in the well more oil prone.

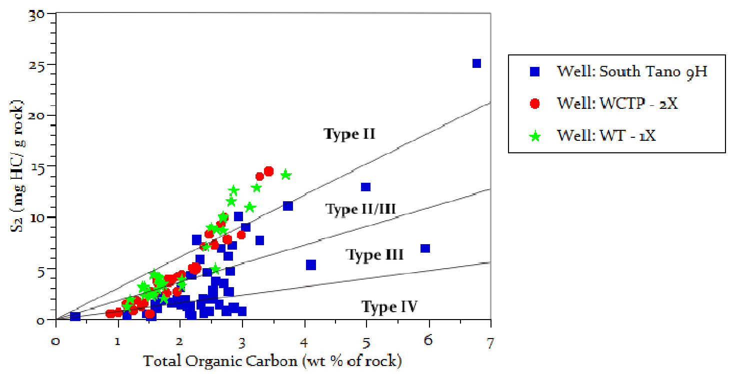

Figure 3. *Plot of S_2 versus TOC indicatingthe kerogen types of the studied samples.*

3.2. Type of Organic Matter

Organic matter type is an important factor in evaluating source rock potential and has important influence on the nature of the hydrocarbon products. 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 [12] and [16] there are four types of kerogen in sedimentary rocks:

- Type-I, composed of oil-prone hydrogen-rich organic matter generally in lacustrine and some marine sediments;
- Type-II, also composed of oil-prone hydrogen-rich 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 kerogen [17]
- Type-III composed of terrestrial organic matter derived mainly from woody plant material that is low in hydrogen content and generates mainly gas, and
- Type-IV composed of dead or inert carbon that has little or no generating capacity.

The organic matter type is an important parameter in evaluating source rock potential and has important influence on the nature of the hydrocarbon products. The kerogen designation is based entirely on HI [17] but the kerogen quality and maturity are determined by plotting HI versus Tmax rather than HI versus OI (Figure 4 and Figure 5). This eliminates the use of OI as a kerogen type indicator (comparable to the O/C in the Van Krevelen diagram).

From Table 1, HI values for kerogen Type III range from 50-200, mixed kerogen type II/III from 200 - 300, whereas the oil-prone kerogen Type II has HI > 300. 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.

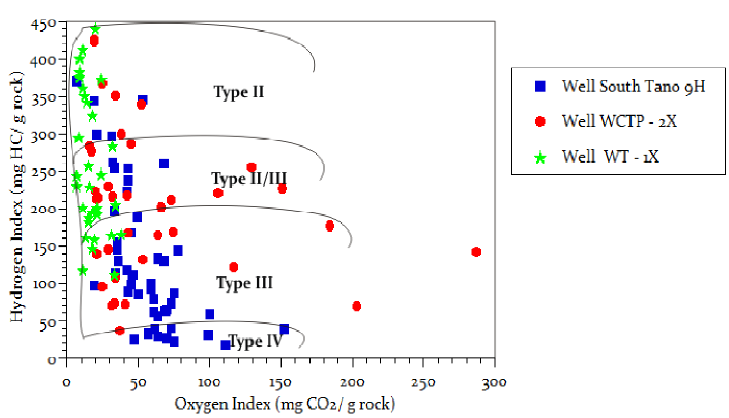

Figure 4. *Modified Van Krevelen diagram indicating the Kerogen types of the studied samples.*

The results from this study showed that for well ST-9H, most samples have HI values between 50 and 200 which indicate gas-prone organic matter and HI of 200-300 which is indicative of mixed kerogen type (Oil and/or Gas). About 5 samples show HI values > 300, which is indicative of very rich oil source. 10 samples from the well, however, indicate kerogen Type IV, which yields neither oil nor gas.

For well WCTP-2X, the sample from depth of about 9440 ft showed HI < 50, 15 samples have HI values of 50-200 which indicate gas-oil prone organic matter, and 15 samples indicate the mixed kerogen Type II/III which has the potential to yield oil and/or gas. About 5 samples from the same well have HI values greater than 300 which indicate oil-prone Type II kerogen.

Most of the samples from well WT-1X have HI values of 50-200 which indicate gas-prone organic matter. 10 samples have HI value 200-300, indicating gas-oil prone organic matter. About 10 samples have HI values > 300, which is indicative of very rich oil sources.

The modified Van Krevelen diagram (HI versus OI) (Figure 4) shows that almost all the samples from the 3 exploratory wells consist predominantly of Types II and III kerogens, which are capable of generating gas-oil and gas respectively at suitable temperature at depth. Few samples from well ST-9H indicate Type IV kerogen which generate neither oil nor gas.

A plot of HI versus Tmax is commonly used to avoid influence of the OI for determining kerogen type [17]. As indicated from the relationships between HI and Tmax (Figure 5), the samples in the wells WCTP – 2X and WT – 1X have HI values of between 50 - 450, which means they are composed mainly of types II and III kerogen which are oil- and gas-prone respectively. These samples have Tmax values <435°C indicating moderately immature samples with the potential to generate oil and gas.

Well ST – 9H on the other hand is made up of types II, III (dominant) and IV kerogen. Rocks from this well are however likely to yield more gas than oil. In terms of temperature, most of the samples are moderately immature with few matured ones in the hydrocarbon generation zone (oil and gas window). However, from Appendix 1a and Figure 5, it can be inferred that the immature sample with Tmax of 397.8 ^{0}C, and 164 mg HC/ g rock HI at depth of 5780 ft depth is contaminated during the screening process or as a result of carving in. This is because of the extremely low Tmax value it recorded.

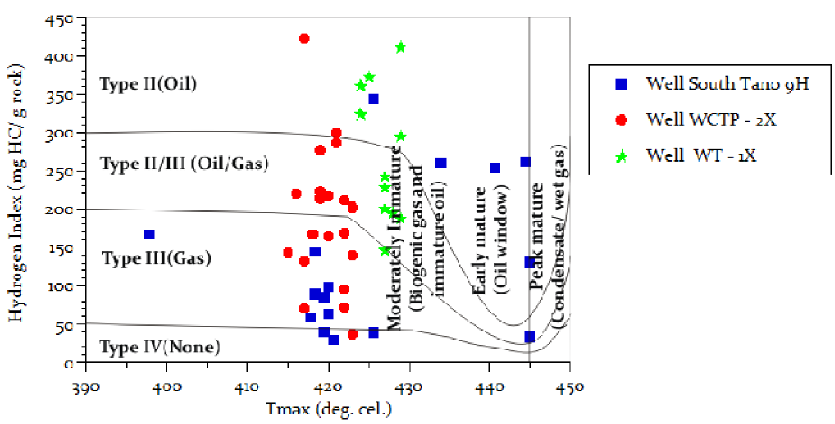

Figure 5. *Plot of Hydrogen Index versus Tmax showing the relationship between kerogen types and maturity levels.*

3.3. 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 [5]. The degree of thermal evolution of the sedimentary organic matter was deduced from Tmax (^{o}C), Production Index and Vitrinite Reflectance.

The increase of maturity level of organic matter corresponds to an increase in Tmax. This phenomenon is related to the nature of chemical reactions that occur through thermal cracking. The weaker bonds breakup in the early stages while the stronger bonds survive until higher temperatures in the late stages [18].

Combining and finding relations between the essential Rock-Eval parameter, Tmax, and calculated Rock-Eval parameter, PI, is a valuable method for indicating the thermal maturity of organic matter. The following relations between Tmax and PI are observed:

1. Immature organic matter has Tmax and PI values less than 430°C and 0.10, respectively;
2. 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;
3. Mature organic matter within the wet gas-zone has PI values greater than 0.4; and
4. Post-mature organic matter usually has a high PI value and may reach 1.0 by the end of the dry-gas zone [10, 12, 19]

In well ST – 9H, most of the samples have Tmax < 435 ^{0}C and PI of 0.1-0.4. This indicates majority of the samples are early mature (oil window) with few samples having PI > 0.4, indicating mature organic matter (gas window). Most of the samples here are non-indigenous except for two samples which fall within the hydrocarbon generation zone.

Most of the samples in wells WCTP – 2X and WT – 1X, have Tmax< 435 ^{0}C and PI <0.1 thereby making them immature and non-indigenous. Samples from the three exploratory wells ST – 9H, WCTP – 2X, WT – 1X except for two samples in ST – 9H are non-indigenous (migrated) hydrocarbons (Figure 6).

The degree of thermal alteration of organic matter due to heating is called maturity [12]. Organic matter has three different maturity phases:

1. Immature (<435^{0}C), which has not been obviously affected by temperature and may be affected by biological diagenesis processes;
2. Mature (435-450^{0}C), which is (or was) within an oil window and has been converted to petroleum via thermal processes; and
3. Post-mature (450-470^{0}C), which is in the gas window because it is hydrogen deficient material due to the influence of high temperatures [12]

According to [20] and [21], 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, Ro values varying from 0.7 to 1.0% reflect a moderate source-rock grade, Ro values between 1.0 and 1.3% refer to a high source-rock grade.

Based on the above criteria, most of the samples from South Tano 9H, are immature with few mature ones in terms of both Tmax and Ro, and can be classified as low and moderate grade source rocks respectively. From Appendix 1c, the main depth of mature source rocks (hydrocarbon generation zone) in the well is from 5200 – 6500 ft.

Wells WCTP – 2X and WT – 1X on the other hand have Tmax values <435 ^{0}C and Ro of 0.2 – 0.6%, making the samples immature (Figure 7). Rocks in these two wells are likely to yield biogenic gas and immature oil making them low grade source rocks.

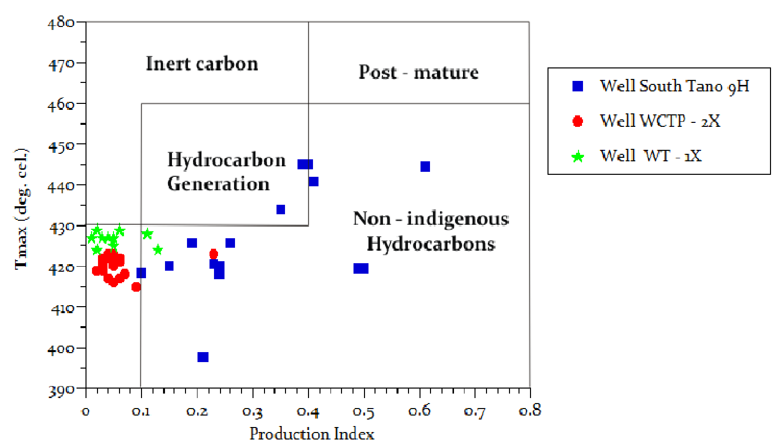

Figure 6. *Plot of Tmax versus Production Index showing the hydrocarbon-generation zone.*

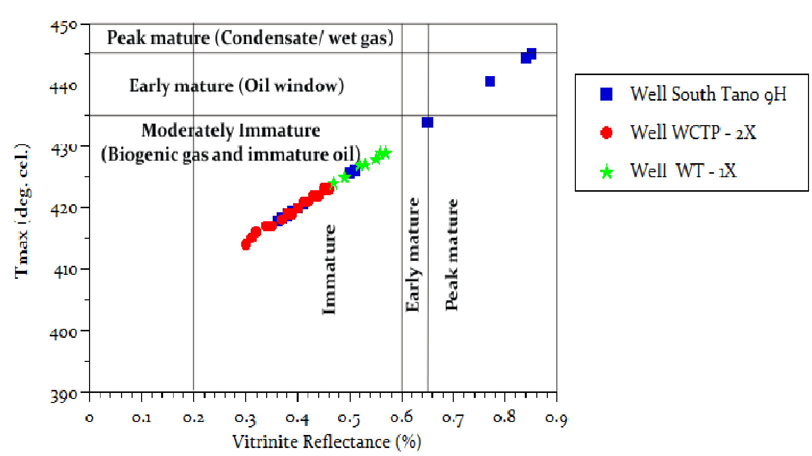

Figure 7. *Plot of Tmax versus Vitrinite Reflectance (Ro) showing the maturity levels.*

3.4. Source Rock Richness, Kerogen Type 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 [10], the TOC values between 0.5 and 1.0% indicate a fair source-rock generative potential, TOC values 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 greater than 4.0% are considered to have excellent generative potential. Plot of HI versus TOC (Figure 8) shows the samples from well ST-9H have a good to very good generative potential, with few samples showing excellent generative potential. This is supported by the presence of type II/III and III kerogens even though few type IV and II kerogens were present.

The good to very good generation potential of samples in well WCTP-2X is supported by the presence of type II, II/III & III kerogens (Figure 8). Well WT-1X has samples with good generation potential (1-2 % TOC) which yield Type III (Gas-prone) and Type II/III (Gas and/or Oil prone) kerogens whilst those with very good generation potential (2-4 % TOC) yields type II (Oil prone) kerogens

According to [12] and [17], the ratio S_2/S_3 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 (Figure 9)

The TOC results of rock samples in this study reveal that for well ST-9H, the samples have good to excellent generation potential source rocks because they have 1.0 % - 7.0% TOC. Samples with good generation potential yields type IV and III kerogen, very good generation yields type IV, III, II/III. Samples with Excellent generation potential contain predominantly type III (Gas-prone) kerogens.

For well WCTP-2X, samples with good generation potential (1-2 wt %) contains mainly type III and II kerogens and that for very good generation potential (2-4 wt %) contains type III,II and some with type I kerogens. Well WT – 1X has samples with good to very good organic carbon content. Organic carbon content between 1-2 wt % (good TOC) is likely to yield type III, II and I kerogens. Samples with very good generation potential, 2-4 % TOC, contain type I kerogen which is oil-prone.

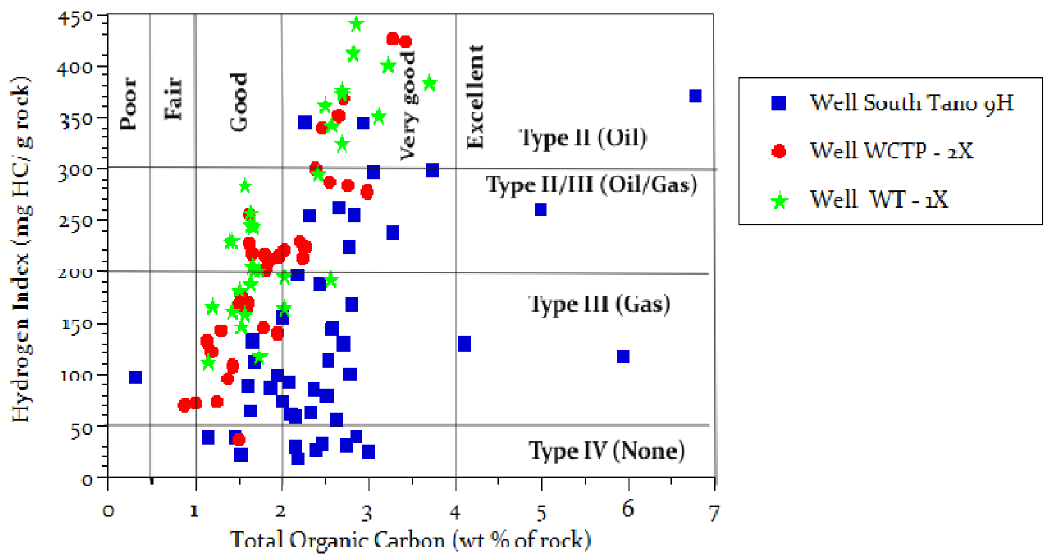

__Figure 8.__ Plot of Hydrogen index versus TOC indicating amount of kerogen types and generation potential.

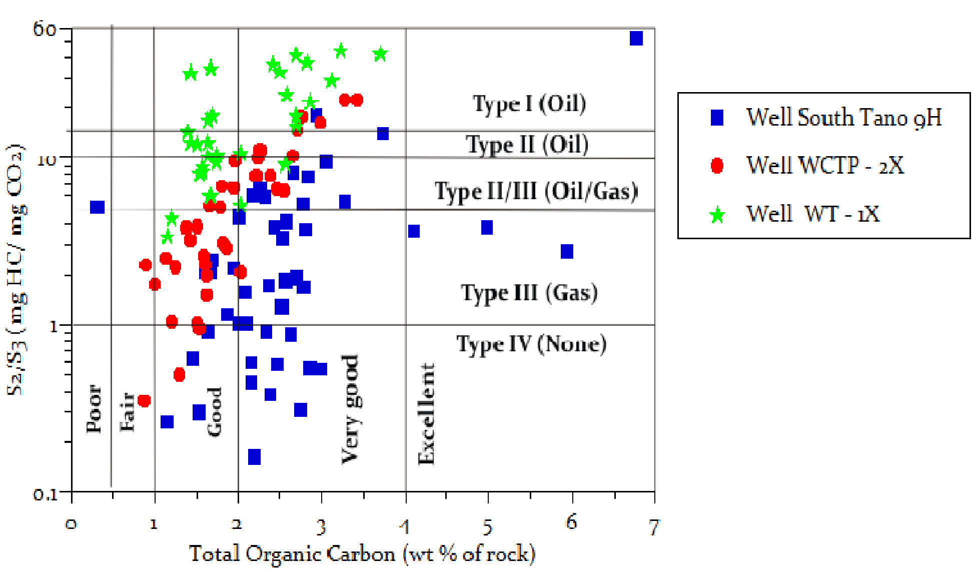

__Figure 9.__ Plot of S2/S3 versus TOC indicating amount of kerogen types and generation potential.

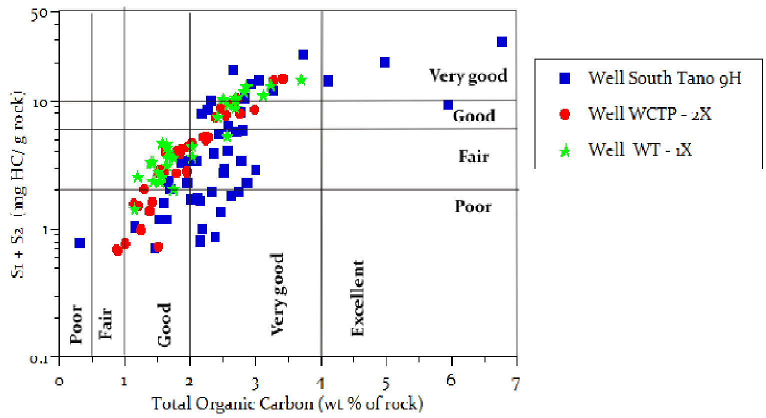

Figure 10. *Plot of S_1+S_2 versus TOC showing the Genetic potential for the studied samples.*

$S_1 + S_2$ 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.

[5] proposed a genetic potential (GP = $S_1 + S_2$) for the 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. They added further that those 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.

Thus, the samples in well ST-9H (Figure 10) with good to excellent organic carbon content have poor to very good genetic potential. Based on the above criterion, the rocks can be described as predominantly moderate to excellent source rock with the ability to generate both oil and gas.

Rocks from wells WCTP-2X and WT-1X (Figure 10) have good to very good total organic content, with fairly good genetic potential; and may constitute moderately good source rocks, with the ability to generate both oil and/or gas at sufficient depths.

4. Conclusion

The results from geochemical data (rock-eval pyrolysis/ TOC and vitrinite reflectance) revealed that the three exploratory wells in the Tano Basin, have fair to excellent total organic carbon (TOC) content, suggesting that there might exist conditions in the basin that favour organic matter production and preservation.

The geochemical data indicate that the samples from well ST-9H are immature to marginally mature source rocks, have good to excellent organic richness, genetic potential of poor to very good giving rise to kerogen type IV, III and type III/II. However, samples from well WCTP-2X are immature source rocks and have good to very good organic richness, moderately good source rocks with fairly good genetic potential which are likely to yield kerogen type III and III/II.

Samples from well WT-1X are also immature source rocks and have good to very good organic richness. They also are moderately good source rocks with fairly good genetic potential with a dominant presence of kerogen type III/II and II, which has the ability to generate both oil and/or gas at sufficient depths.

Acknowledgement

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

Appendix

Appendix 1a. *Rock-Eval Analysis of samples from Well South Tano-9H, Tano Basin, Ghana.*

WELL: SOUTH TANO - 9H											
Company: GNPC											
LOCATION: OFFSHORE GHANA											
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)**	**Petroleum Potential (mg HC/ g rock)**	**Production Index**	**Hydrogen Index (mg HC/ g rock)**	**Oxygen Index (mg CO2/ g rock)**	**Ro (%)**	**Tmax (°C)**
1470	2.57	0.39	3.69	2	1.84	4.08	0.1	144	78	0.37	418.3
1980	2.15	0.4	1.27	2.15	0.59	1.67	0.24	59	100	0.36	417.8
2100	2.26	0.75	7.79	1.2	6.5	8.54	0.09	345	53		
2610	0.93									0.38	418.9

WELL: SOUTH TANO - 9H

Company: GNPC

LOCATION: OFFSHORE GHANA

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)	Petroleum Potential (mg HC/ g rock)	Production Index	Hydrogen Index (mg HC/ g rock)	Oxygen Index (mg CO2/ g rock)	Ro (%)	Tmax (^oC)
3120	1.29										
3240	1.46	0.13	0.57	0.91	0.63	0.7	0.19	39	62	0.5	425.6
3360	2.53	0.09	2.85	0.86	3.31	2.94	0.03	113	34		
3480	1.6	0.16	1.43	0.69	2.08	1.59	0.1	89	43	0.37	418.3
3630	1.69	0.16	1.9	0.78	2.44	2.06	0.08	112	46		
3750	1.14									0.51	426.1
3870	1.64	0.13	1.06	1.15	0.92	1.19	0.11	65	70		
3900	1.66	0.17	2.21	1.06	2.08	2.38	0.07	133	64		
4110	1.4									0.39	419.4
4230	2.01	0.23	1.49	1.47	1.02	1.72	0.13	74	73		
4350	2.01	0.32	3.11	0.7	4.42	3.43	0.09	155	35		
4500	1.95	0.33	1.93	0.88	2.2	2.26	0.15	99	45	0.4	420
4650	1.53	0.85	0.34	1.15	0.3	1.19	0.71	22	75		
4820	2.18	3.68	4.29	0.72	5.96	7.97	0.46	197	33		
4880	2.37	1.93	2.01	1.19	1.7	3.94	0.49	85	50	0.39	419.4
4940	2.58	2.54	3.76	0.9	4.16	6.3	0.4	146	35		
5080	3	2.12	0.76	1.41	0.54	2.88	0.74	25	47		
5240	4.1	8.89	5.35	1.48	3.62	14.24	0.62	130	36		
5360	2.86	1.15	1.14	2.09	0.55	2.29	0.5	40	73	0.39	419.4
5540	2.78	0.65	2.77	1.64	1.69	3.42	0.19	100	59		
5572	2.16	0.18	0.62	1.38	0.45	0.8	0.23	29	64	0.41	420.6
5600	2.63	0.35	1.48	1.68	0.88	1.83	0.19	56	64		
5660	2.38	0.24	0.64	1.67	0.38	0.88	0.27	27	70		
5780	2.81	1.23	4.68	1.26	3.7	5.91	0.21	167	45		397.8
5900	2.33	0.46	1.47	1.61	0.91	1.93	0.24	63	69	0.4	420
5960	3.73	12.02	11.12	0.78	14.2	23.14	0.52	298	21		
6080	2.77	2.03	6.19	1.16	5.32	8.22	0.25	223	42		
6140	2.1	0.44	1.31	1.28	1.02	1.75	0.25	62	61		
6200	2.43	0.97	4.57	1.19	3.84	5.54	0.18	188	49		
6260	2.84	3.17	7.23	0.94	7.71	10.4	0.3	255	33		
6280	2.46	0.53	0.81	1.4	0.58	1.34	0.4	33	57	0.85	445
6300	2.52	0.8	1.99	1.54	1.29	2.79	0.29	79	61		
6330	2.74	1.1	0.84	2.71	0.31	1.94	0.57	31	99		
6350	1.15	0.59	0.45	1.75	0.26	1.04	0.57	39	152		
6370	2.19	0.62	0.39	2.43	0.16	1.01	0.61	18	111		
6380	5.94	2.48	6.95	2.49	2.79	9.43	0.26	117	42		
6390	4.98	7.08	12.95	3.39	3.82	20.03	0.35	260	68	0.65	433.9
6400	3.27	4.2	7.77	1.41	5.53	11.97	0.35	238	43		
6409	6.77	4.11	25.07	0.47	52.9	29.18	0.14	370	7		
6418	2.94	3.49	10.12	0.56	18.12	13.61	0.26	344	19	0.5	425.6
6420	0.31	0.48	0.3	0.06	5.09	0.78	0.62	97	19		
6424	1.39			1.65	0				119		
6433	3.05	5.28	9.05	0.95	9.57	14.33	0.37	297	31		
6622	1.13			0.77					68		
6639	1.08			0.81					75		
6800	2.7	2.22	3.52	1.84	1.92	5.74	0.39	130	68	0.85	445
6860	1.87	1.75	1.63	1.4	1.16	3.38	0.52	87	75		
7050	2.66	10.69	6.93	0.85	8.14	17.62	0.61	261	32	0.84	444.4
7120	2.08	1.49	1.94	1.23	1.58	3.43	0.43	93	59		
7260	2.32	4.03	5.89	1	5.9	9.92	0.41	254	43	0.77	440.6
Minimum	0.31	0.09	0.30	0.06	0.00	0.70	0.03	17.81	7.00	0.36	397.78
Average	2.40	2.07	3.95	1.32	4.25	6.02	0.32	133.76	57.54	0.52	425.06
Maximum	6.77	12.02	25.07	3.39	52.90	29.18	0.74	370.31	152.00	0.85	445.00

Appendix 1b. *Rock-Eval Analysis of samples from Well WCTP – 2X, Tano-Cape Three Point Basin, Ghana.*

WELL: WCTP - 2X											
Company: GNPC											
LOCATION: OFFSHORE GHANA											
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)**	**Petroleum Potential (mg HC/ g rock)**	**Production Index**	**Hydrogen Index (mg HC/ g rock)**	**Oxygen Index (mg CO2/ g rock)**	**Ro (%)**	**Tmax (^{o}C)**
3980	1.1										
4220	0.87	0.08	0.61	1.77	0.35	0.69	0.12	70	203		
4400	0.98										
4490	1.3										
4670	1.3	0.18	1.86	3.73	0.5	2.04	0.09	143	287	0.31	415
5120	2.02	0.23	4.44	2.14	2.07	4.67	0.05	220	106	0.32	416
5300	1.54									0.34	417
5390	1.53	0.16	2.71	2.82	0.96	2.87	0.06	177	184		
5480	1.28									0.3	414
5570	1.19	0.06	1.45	1.39	1.04	1.51	0.04	122	117		
5660	1.13	0.07	1.49	0.6	2.49	1.56	0.04	132	53	0.35	417
5750	1.24	0.07	0.91	0.41	2.22	0.98	0.07	73	33		
5840	0.89	0.04	0.63	0.28	2.28	0.67	0.06	71	31	0.35	417
5930	0.74										
6020	1	0.05	0.72	0.41	1.76	0.77	0.06	72	41	0.44	422
6110	1.09										
6200	1.43	0.08	1.55	0.49	3.19	1.63	0.05	108	34		
6290	1.38	0.06	1.32	0.35	3.83	1.38	0.04	96	25	0.43	422
6470	1.94	0.1	2.71	0.41	6.65	2.81	0.04	140	21	0.45	423
6560	1.78	0.13	2.6	0.52	5.04	2.73	0.05	146	29		
6740	2.24	0.16	4.77	0.47	10.14	4.93	0.03	213	21	0.39	419
6830	2.33										
6920	2.76	0.2	7.8	0.44	17.66	8	0.03	283	16		
7010	2.98	0.21	8.24	0.51	16.27	8.45	0.02	277	17	0.39	419
7280	2.21	0.13	5.06	0.64	7.9	5.19	0.03	229	29		
7370	2.26	0.16	5.04	0.45	11.15	5.2	0.03	223	20	0.38	419
7550	1.59	0.08	2.63	1.02	2.58	2.71	0.03	165	64	0.4	420
7640	1.65										
7730	1.96	0.14	4.2	0.43	9.74	4.34	0.03	214	22	0.39	419
7820	1.84										
7910	1.6	0.09	2.7	1.18	2.28	2.79	0.03	169	74	0.43	422
8090	1.65	0.17	3.58	0.69	5.17	3.75	0.05	217	42	0.4	420
8150	1.8	0.19	3.88	0.58	6.74	4.07	0.05	216	32		
8240	1.51	0.18	2.54	0.65	3.91	2.72	0.07	168	43	0.37	418
8300	1.22										
8330	1.67										
8360	3.42	0.54	14.48	0.65	22.28	15.02	0.04	423	19	0.34	417
8390	3.28	0.45	13.98	0.62	22.43	14.43	0.03	426	19		
8450	2.65	0.3	9.29	0.9	10.31	9.59	0.03	351	34		
8540	1.72										
8570	1.82	0.19	3.68	1.2	3.06	3.87	0.05	202	66	0.46	423
8660	1.62	0.2	4.15	2.09	1.99	4.35	0.05	256	129		
8780	2.38	0.24	7.15	0.9	7.91	7.39	0.03	300	38	0.41	421
8840	2.45										
8870	2.44										
8900	2.71	0.46	9.96	0.68	14.7	10.42	0.04	368	25		
8930	2.04										
9020	2.46	0.44	8.34	1.28	6.52	8.78	0.05	339	52		
9080	2.39										
9140	2.54	0.46	7.29	1.14	6.38	7.75	0.06	287	45	0.42	421
9200	1.83										
9260	1.86	0.21	3.92	1.36	2.89	4.13	0.05	211	73	0.44	422
9320	1.62	0.25	3.68	2.45	1.5	3.93	0.06	227	151		
9350	2.12										
9440	1.5	0.17	0.56	0.56	1.01	0.73	0.23	37	37	0.46	423
Minimum	0.74	0.04	0.56	0.28	0.35	0.67	0.02	37	16	0.3	414
Average	1.82	0.19	4.44	1.01	6.3	4.63	0.05	205	62	0.39	419
Maximum	3.42	0.54	14.48	3.73	22.43	15.02	0.23	426	287	0.46	423

Appendix 1c. *Rock-Eval Analysis of samples from Well WT – 1X, Tano Basin, Ghana.*

WELL: WT - 1X											
Company: GNPC											
LOCATION: OFFSHORE GHANA											
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)**	**Petroleum Potential (mg HC/ g rock)**	**Production Index**	**Hydrogen Index (mg HC/ g rock)**	**Oxygen Index (mg CO2/ g rock)**	**Ro (%)**	**Tmax (^oC)**
5000	2.69	0.57	10.03	0.65	15.54	10.6	0.05	373	24	0.49	425
5200	2.57	0.59	8.8	0.36	24.46	9.39	0.06	342	14		
5400	2.5	1.32	9.05	0.28	32.91	10.37	0.13	362	11	0.47	424
5490	3.12	0.18	10.96	0.37	29.27	11.14	0.02	351	12		
5580	3.7	0.43	14.19	0.33	42.61	14.62	0.03	384	9		
5760	3.22	0.44	12.92	0.29	44.58	13.36	0.03	401	9		
5850	2.86	0.5	12.61	0.57	22.05	13.11	0.04	441	20		
5940	2.82	0.27	11.61	0.31	37.43	11.88	0.02	412	11	0.57	429
6040	2.69	0.15	10.12	0.24	41.8	10.27	0.01	376	9		
6340	2.69	0.21	8.71	0.48	17.99	8.92	0.02	324	18	0.47	424
6740	1.73	0.17	3.48	0.36	9.58	3.65	0.05	201	21	0.53	427
6940	1.66	0.19	3.41	0.56	6.04	3.6	0.05	205	34		
7040	1.74	0.03	2.03	0.19	10.61	2.06	0.01	117	11		
7140	1.53	0.06	2.25	0.28	8.17	2.31	0.03	147	18	0.52	427
7240	1.57	0.06	2.49	0.3	8.35	2.55	0.02	159	19		
7340	1.42	0.09	3.26	0.1	32.8	3.35	0.03	230	7		
7440	1.64	0.07	3.08	0.25	12.52	3.15	0.02	188	15	0.57	429
7540	1.43	0.04	2.32	0.19	12.48	2.36	0.02	162	13		
7640	1.5	0.05	2.73	0.23	12.13	2.78	0.02	182	15		
7840	1.39	0.13	3.19	0.22	14.34	3.32	0.04	229	16	0.53	427
7940	1.57	0.25	4.46	0.5	8.88	4.71	0.05	284	32		
8040	1.64	0.38	4.22	0.25	17.15	4.6	0.08	257	15		
8240	1.67	0.05	4.08	0.12	34.9	4.13	0.01	244	7	0.53	427
8440	1.64	0.3	4.03	0.39	10.24	4.33	0.07	246	24		
8540	2.02	0.49	3.93	0.36	10.81	4.42	0.11	195	18	0.55	428
8740	1.15	0.15	1.29	0.38	3.4	1.44	0.1	112	33		
8840	1.68	0.35	3.37	0.18	18.24	3.72	0.09	201	11		
8940	2.41	0.47	7.12	0.19	36.93	7.59	0.06	295	8	0.56	429
9040	2.56	0.43	4.95	0.54	9.21	5.38	0.08	193	21		
9140	2.03	0.34	3.33	0.63	5.29	3.67	0.09	164	31		
9540	0.86										
9640	0.91										
9840	1.2	0.6	1.99	0.46	4.36	2.59	0.23	166	38		
Minimum	0.86	0.03	1.29	0.1	3.4	1.44	0.01	112	7	0.47	424
Average	1.99	0.3	5.81	0.34	19.2	6.11	0.05	256	18	0.53	427
Maximum	2.69	0.6	10.03	0.65	15.54	10.6	0.23	373	38	0.49	429

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