INDONESIAN JOURNAL ON GEOSCIENCE
Geological Agency
Ministry of Energy and Mineral Resources

Journal homepage: http://ijog.bgl.esdm.go.id
ISSN 2355-9314 (Print), e-ISSN 2355-9306 (Online)

Hydrocarbon Source Rock Potential of the Sinamar Formation, Muara Bungo, Jambi

Moh. Heri Hermiyanto Zajuli and Hermes Panggabean

Center for Geological Survey, Geological Agency
Jln. Diponegoro 57, Bandung - 40122

Corresponding author: *zajuli_hz@yahoo.com*
Manuscript received: November 14, 2013, revised: April 14, 2014, approved: April 22, 2014

Abstract - The Oligocene Sinamar Formation consists of shale, claystone, mudstone, sandstone, conglomeratic sandstone, and intercalation of coal seams. The objective of study was to identify the hydrocarbon source rock potential of the Sinamar Formation based on geochemichal characteristics. The analyses were focused on fine sediments of the Sinamar Formation comprising shale, claystone, and mudstone. Primary data collected from the Sinamar Formation well and outcrops were analyzed according to TOC, pyrolisis analysis, and gas chromatography - mass spectometry of normal alkanes that include isoprenoids and sterane. The TOC value indicates a very well category. Based on TOC versus Pyrolysis Yields (PY) diagram, the shales of Sinamar Formation are included into oil prone source rock potential with good to excellent categories. Fine sediments of the Sinamar Formation tend to produce oil and gas originated from kerogen types I and III. The shales tend to generate oil than claystone and mudstone and therefore they are included into a potential source rock.

Keywords: *Sinamar Formation, Oligocene, organic petrography, biomarker, shale*

Introduction

The Sinamar Formation has been found in Sumatra, in particular at the area nearby western part of South Sumatra Basin. The stratigraphic sequences and tectonics of the Sinamar Formation are almost similar to the Talangakar, Lemat, and Kasiro Formations of South Sumatra Basin; the Sangkarewang Formation of Ombilin Basin, the Kiliran Formation of Kiliranjao Sub-basin, and the Pematang Formation (Brown Shale) of the Central Sumatra Basin, which all of formations have potential of oil and gas in Sumatra.

The subject of this study is the fine-grained sediments of the Sinamar Formation distributed in Sinamar region, Muara Bungo Regency (Figure 1), which were analyzed to obtain their TOC, rock-eval pyrolysis, and geochemistry data including biomarker (Gas Chromatography and Gas Chromatography-Mass Spectrometry).

The objective of this study is to identify the hydrocarbon source rock potential of fine-grained sedimentary rocks of the Sinamar Formation based on geochemichal characteristics. The Talangakar and Lemat Formations, which have similar characteristics with Sinamar Formation, are famous to be a source rock potential in South Sumatra Basin. Thus, this research is focused to identify fine-grained sedimentary rocks of the Sinamar Formation as the possibility of an alternative potential for hydrocarbon source rock in South Sumatra Basin.

The Sinamar Formation comprises shale, claystone, siltstone, and intercalation of sandstone and coal, deposited in a fluvial - deltaic environment (Rosidi *et al*., 1996) or a lacustrine environment (Zajuli and Panggabean, 2013). Analysis of South Sumatra Basin source rock is a geological study in an upstream sector. This study is expected to be resulted in some detailed data and information

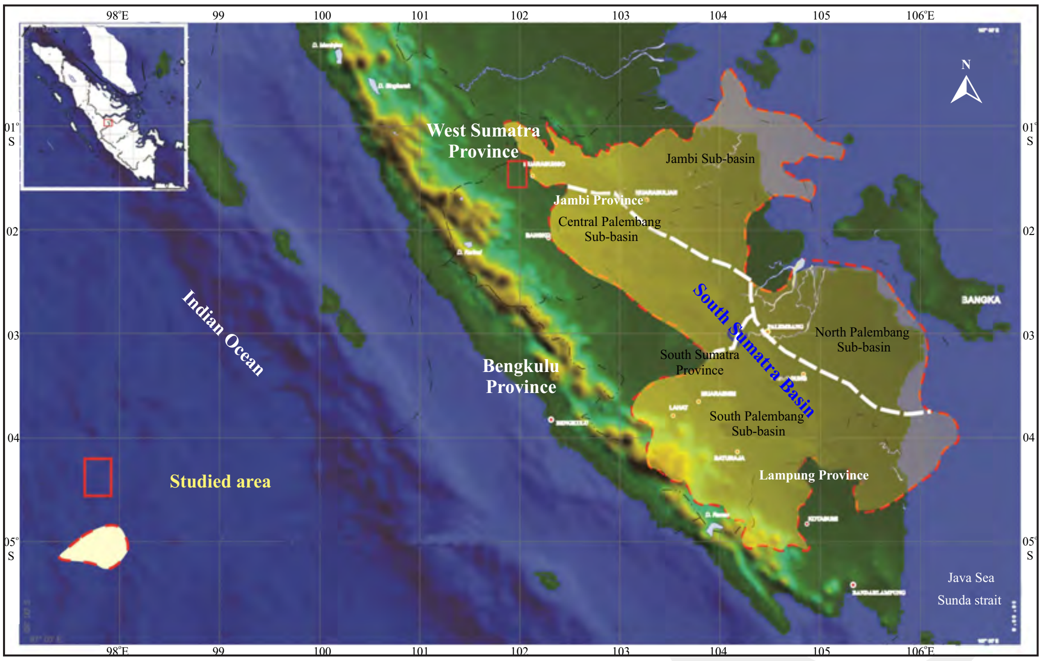

Figure 1. Locality map of the studied area falling under the Muara Bungo Regency.

on source rock existing in the northwestern part of South Sumatran Basin.

Regionally, some workers have studied around this area discussing several matters related to geology, among others is Bemmelen (1949) who carried out a study in Ombilin and Central Sumatra Basins, particularly concerning the basin formation in conjunction with coal characteristics. Furthermore, the Geological Research and Development Centre carried out a series of systematic geological mapping in Painan Quadrangle and northeastern part of Muarasiberut (Rosidi *et al*., 1996), Solok Quadrangle (Silitonga and Kastowo, 1995), and Rengat Quadrangle (Suwarna *et al*., 1994).

Materials and Method

The primary data collected during fieldwork include observation, measurement, and rock sample collection both from outcrop and core samples. Those data gained are focused on geochemical characters related to source rocks.

The core data were supplied by coal mining company of the PT. Kuansing Inti Makmur (KIM), having the coal mining concession, particularly in the western part of Muara Bungo area, Jambi Sub-basin. TOC, rock-eval pyrolysis, and Gas Chromatography-Mass Spectrometry (GC-MS) analyses were carried out in Lemigas, Jakarta, upon rocks from the wells and some outcrops found during the field observation.

There are six wells found in the study area, *i.e*. SNM-4, SNM-9, SNM-10, SNM-11, SNM-13, and SNM-15, from depth between 75 - 200 m. The KIM is the only coal company located in the study area. Rock sampling was only done in certain locations, that are at the outcrop sites and SNM-4 well.

Geological Setting

Physiographically, the study area is an intramountain basin occupying the eastern flank of Barisan Mountain and Bukit Barisan Anticline (De Coster, 1974), bordering the Jambi Sub-basin from South Sumatra Basin. The east slope or wing of the Barisan Mountain spreads out within northwest - southeast direction, around 150 - 1,000 m asl The researched location lies between the South Sumatra back-arc Basin and Ombilin Intramountain Basin (Figure 1). The geological structure developing in the researched area is normal faults generally trending northwest - southeast.

This structure only influences the northwestern part of the formation in the researched area. However, in certain places, northeasterly bed dippings of around 20º can be recognized. In the east, ENE-WSW and NW-SE normal faults are also found, cutting some formations, among others Sinamar and Rantauikil Formations. Pulunggono *et al*. (1992) stated that the normal or horizontal fault directions is E-W up till NE-SW. This fault is estimated to have occured after the anticline-syncline had already been folded, the fault cuts anticline-syncline axis (Pulunggono *et al*., 1992). The researched location is part of the geological map of Painan and the northeastern part of Muarasiberut Quadrangles (Rosidi *et al*., 1996) occupying probably the tip or edge of the northwestern part of Jambi Sub-basin of South Sumatra Basin (Figure 1).

Stratigraphically, the researched area included in the geological map of Painan Quadrangle (Figure 2) consists of Jurrassic up to Quaternary rocks. The basement of this basin is Jurassic granitic rock, unconformably overlain by the sediments of Oligocene Sinamar Formation. In turn, this formation is conformably overlain by the Miocene Rantauikil Formation. Then upwards, the sediments of Plio-Pleistocene Kasai Formation unconformably deposited on those both formations.

The Sinamar Formation is composed of conglomerate and quartzose sandstone occupying the lowest part, then they are overlain by 2 - 5 m layering blackish grey claystone intercalated with 20 cm of coal. Upwards, the Sinamar Formation is characterized by the presence of claystone and sandstone gravels (Hermiyanto, 2010). Further above, there are more shale layers with 30 cm up to 7 m of coal intercalations (Figure 3). The age of Sinamar Formation is Oligocene with Ammonia beccarii and coral contents. The calculated thickness of this formation is 750 m (Rosidi *et al*., 1996).

The Miocene Rantauikil Formation is dominated by claystone, tuffaceous sandstone, clayey sandstone, marl, and thin lenses of claystone. Furthermore, the Kasai Formation of Plio-Plistocene age is composed of pumiceous tuff and tuffaceous sandstone. The youngest unit is alluvial sedimenst consisting of pebbles, gravels, sands, and muds. The sedimentation is still going on up till now as the result of a river erosion activity.

Data Analysis

Organic Material

The organic material of Sinamar fine sedimentary rocks is interpreted based on TOC data carried out upon fifteen rock samples. These data show that the organic material of some Sinamar fine sediments can be divided into three groups based on their existing lithological type. The

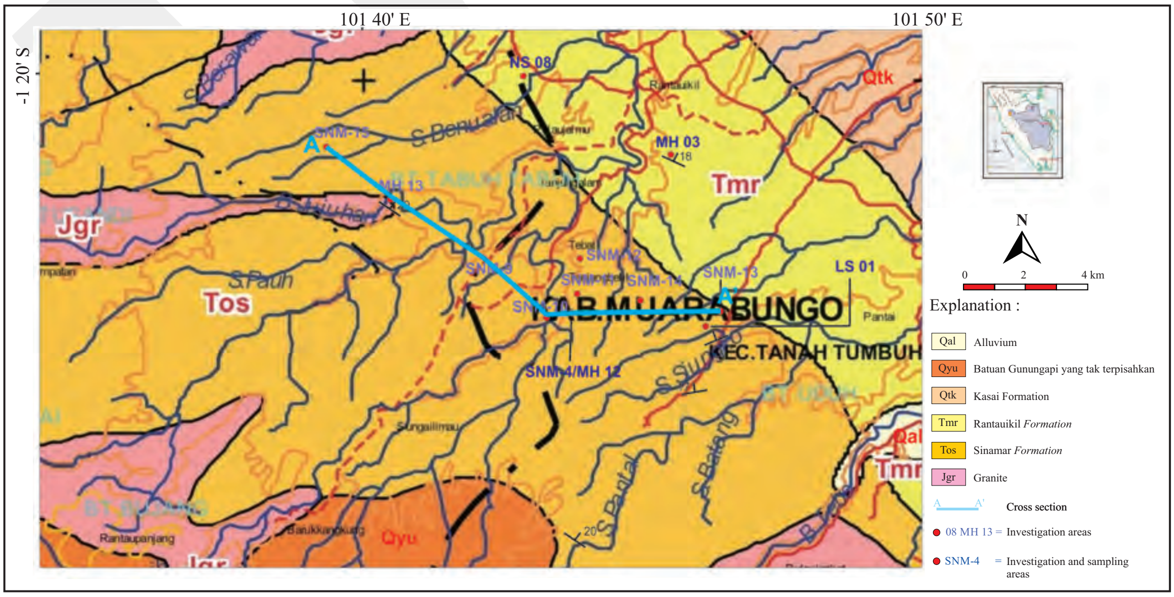

Figure 2. Geological map of the researched area (modified from Rosidi *et al*., 1996).

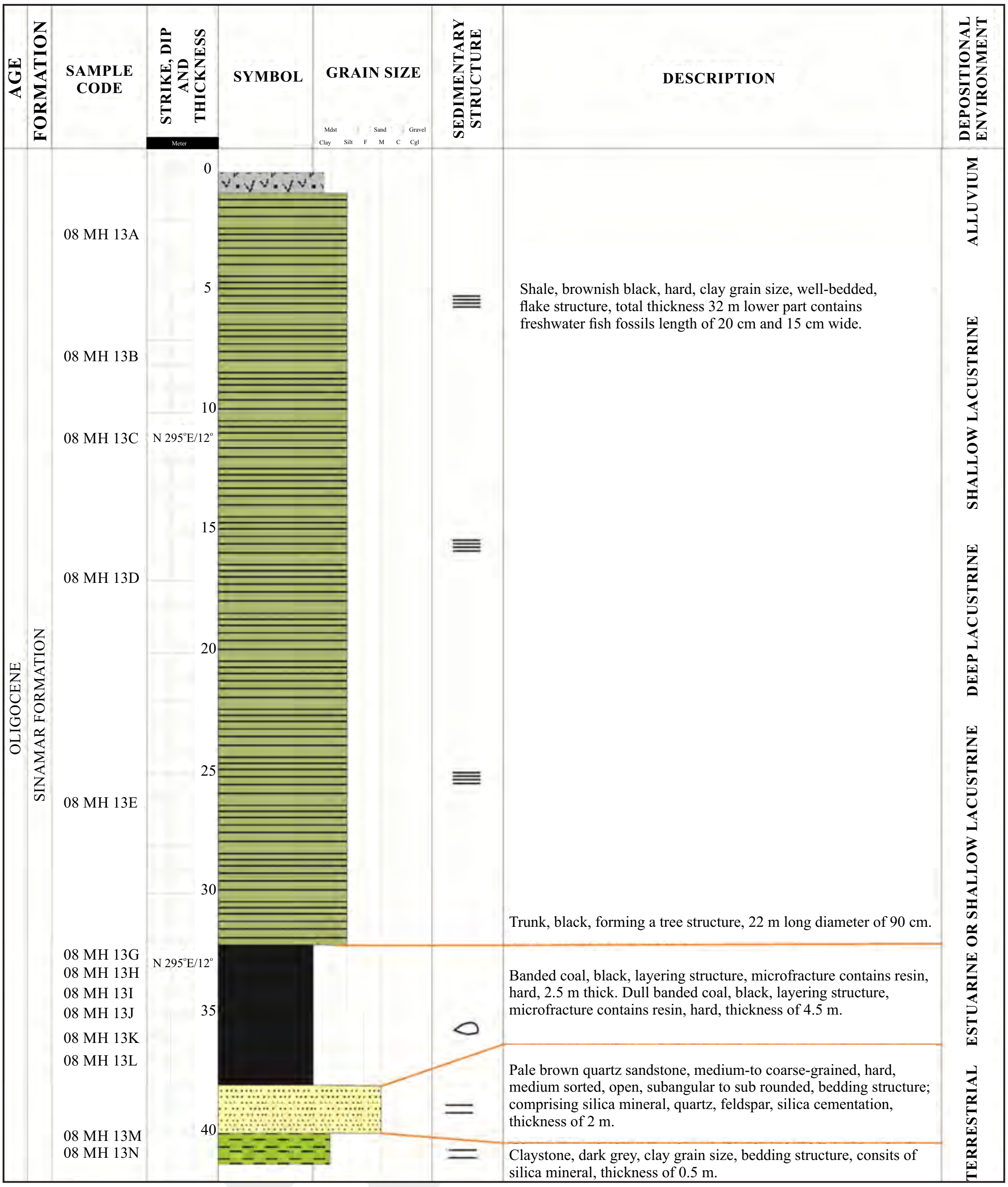

Figure 3. Columnar stratigraphic section of Sinamar Formation cropping out in Sinamar Village (Zajuli and Panggabean, 2013). Coordinate: 01°22'08.1"S and 107°40'16.9" E, Sample 08. MH 13.

shales have 2.8 - 10.84 % TOC value indicating that their ability to be oil-prone is in a good category, claystone has 0.69% - 8.36 % TOC value with a limited up to good category, while mudstone with 0.60% and 0.64% is included into a category with a very limited source rock-prone (Table 1). The existing organic material in the sedimentary rocks shows that shales have the best ability as source rocks.

Organic Material Type

The types of organic material in the researched area are intrepeted on the basis of hydrogen index (HI) and oxygen index (OI) values resulted from Rock-Eval analysis. The type of organic material is a reflection of the sedimentary rock composing macerals. The sediments influence the type of organic material suitable with the presence of some key maceral types. A Hydrogen Index

Table 1. Result of TOC and Rock-Eval Pyrolysis Analyses in the researched Area

No.	Sample No.	Lithology	TOC (%)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	PY (mg/g)	S2/S3	PI	PC	T_{max} (^{0}C)	HI	OI
1.	08 NS 08 A	Mudst, ltgy/gy	0.60	0.08	0.41	0.12	0.49	3.42	0.16	0.04	402	69	20
2.	08 MH 03 B	Mudst, ltgy/gy, calc	0.64	0.09	0.42	0.27	0.51	1.56	0.18	0.04	402	66	42
3.	08 MH 12 M	Clyst, dkgy	0.69	0.02	0.13	0.58	0.15	0.22	0.13	0.01	383	19	85
4.	08 MH 12 P	Clyst, gy/dkgy	2.08	0.21	2.83	0.37	3.04	7.65	0.07	0.25	420	136	18
5.	08 MH 12 R	Sh, brn.dkgy	10.52	2.42	63.48	0.00	65.90	-	0.04	5.47	436	603	0
6.	08 MH 13 A	Sh, brn.gy	9.02	3.00	66.66	0.00	69.66	-	0.04	5.78	436	739	0
7.	08 MH 13 B	Sh, dkbrngy	9.53	2.34	78.02	0.00	80.36	-	0.03	6.67	439	819	0
8.	08 MH 13 C	Sh, brngy	7.45	0.97	51.95	0.22	52.92	236.14	0.02	4.39	439	697	3
9.	08 MH 13 D	Sh, brn dkgy, sl hd, oxid	9.12	2.38	64.76	0.00	67.14	-	0.04	5.57	436	710	0
10.	08 MH 13 E	Sh, dkbrngy, sl hd	10.84	2.11	60.57	1.73	62.68	35.01	0.03	5.20	431	559	16
11.	08 MH 13 E2	Clyst, dkbrngy, sl hd	8.36	0.80	53.30	0.71	54.10	75.07	0.01	4.49	439	638	8
12.	08 LS 01 A	Clyst, dkgy	4.23	0.97	4.83	0.91	5.80	5.31	0.17	0.48	400	114	22
13.	08 LS 01 G	Clyst, Wht lt.gy	0.77	0.16	0.48	0.20	0.64	2.40	0.25	0.05	402	62	26
14.	08 RL 04 B	Sh. gy/dkgy	3.28	0.55	6.22	0.39	6.77	15.95	0.08	0.56	425	189	12
15.	08 RL 25 A	Clyst, dkgy/blk, hd	3.29	0.22	0.59	0.27	0.81	2.19	0.27	0.07	543	18	8

TOC : Total Organic Carbon
S1 : Amount of Free Hydrocarbon
S2 : Amount of Hydrocarbon released from kerogen
S3 : Organic Carbon Dioxide
PY : Amount of Total Hydrocarbons = (S1 + S2)
PI : Production Index = (S1/ S1 + S2)
PC : Pyrolysable Carbon
T_{max} : Maximum Temperature (0C) at the top of S2 peak
HI : Hydrogen Index = (S2/TOC) x 100
OI : Oxygen Index = (S3/TOC) x 100

versus Oxygen Index diagram is used to describe the trend of kerogen and hydrocarbon type that are going to be produced. Based on the diagram, it is known that the Sinamar fine sediments tend to produce oil and gas of kerogen Types I and III (Figure 4).

Kerogen Type I tends to produce oil, while kerogen Type III only produces gas and a little oil. The Hydrogen Index (HI) value determines the amounts of oil or gas. The higher the HI value, the more oil can be produced. The pyrolysis result of Sinamar fine sediments shows that the TOC value is between 0.60 and 10.84%, T_{max} dominantly from 383 - 402 ^{o}C, Potential Yield (PY) is between 0.15 and 80.36 mgHC/g rock, and Hydrogen Index (HI) between 18 and 819 mg. The organic materials of the fine sediments of Sinamar Formation have a trend to be less good up to very good category to be source rocks. The very good category is shown by shale, while poor up to moderate category is shown by claystone and mudstone samples. The Sinamar shales tend to be included into oil prone, while claystone and mudstone are included into gas prone (Figure 5).

Maturity

The maturity of fine sediments as source rocks in the researched area is interpreted based on T_{max} value obtained from Rock-Eval result, vitrinite reflectance value, and biomarker analysis. T_{max} diagram was used in describing the maturity level of the source rocks upon Hydrogen Index (HI) resulted from Rock-Eval pyrolysis.

Based on T_{max} versus Hydrogen Index diagram, the Sinamar fine sediment rocks are included into an immature level up to early mature. Source rocks can be said to be mature if the T_{max} value is > 435 ^{o}C (Waples, 1985). The immature level is shown within claystone and mudstone, while only one shale sample has an early mature level (Figures 6 and 7).

The shales of Sinamar Formation tends to produce oil compared to claystone and mudstone producing gas (Figures 5 and 7). The trend is a reflection of the organic material composition existing in the rock. The organic matter present in the shales are dominantly composed of alginite submaceral (Botryococcus) which produces oil as mentioned in Zajuli and Panggabean (2013).

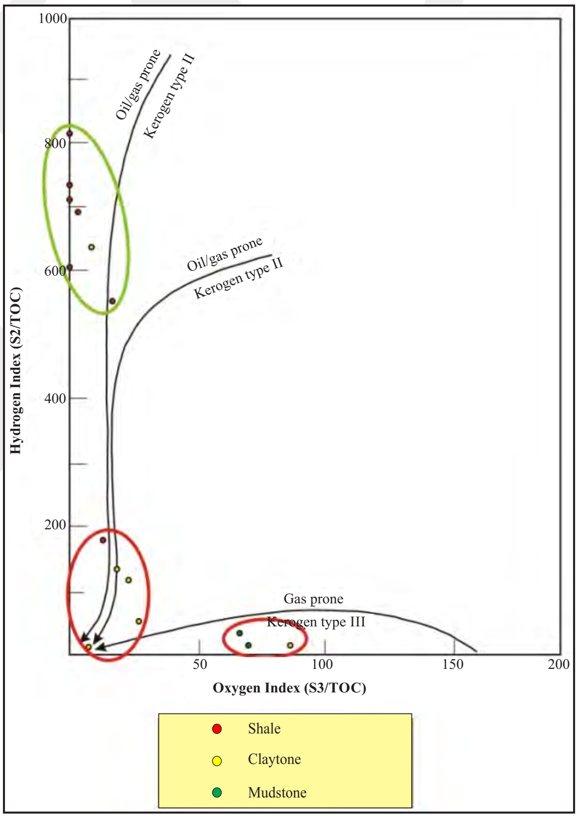

Figure 4. Van Krevelen Plot of the fine sediment of the Sinamar Formation showing kerogen types and oil-gas prone level.

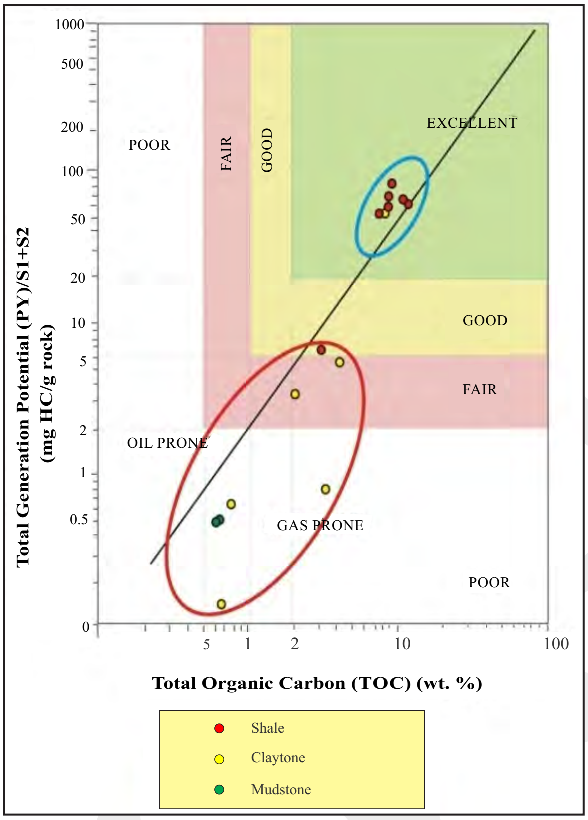

Figure 5. TOC *versus* Total Generation Potential (Py) diagram, showing hydrocarbon potential level of Sinamar fine sediments in the studied area.

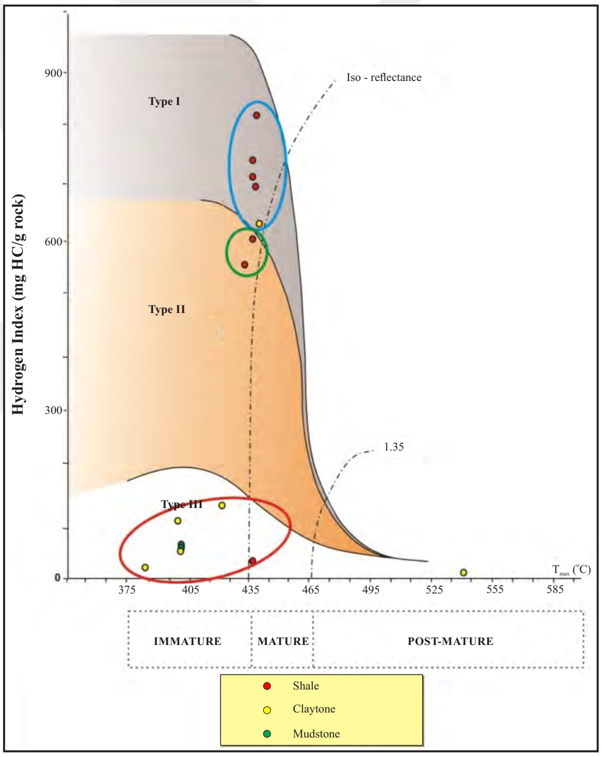

Figure 6. Hydrogen Index (HI) *versus* T_{max} diagram, showing thermal maturity and kerogen types of Sinamar fine sediments in the studied area.

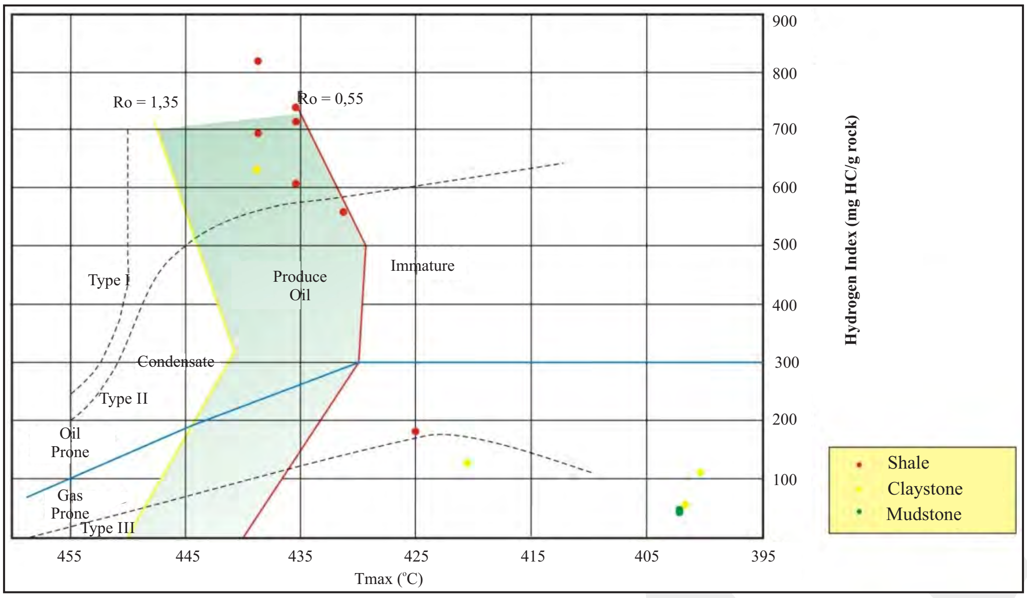

Figure 7. Diagram of T_{max} *versus* Hydrogen Index (HI) showing the maturity level and a trend to produce oil and gas of the fine sediment of Sinamar Formation.

Claystone and mudstone more dominantly consist of vitrinite macerals which are organic materials that produce gas.

Plot between Tm/Ts and C30 morethane/hopane shows that samples 08MH 12R, 08MH 13B, and 08 MH 13E (Table 2) are included into an immature up to early mature levels (Figure 8).

Discussion

On the basis of organic petrography (Table 3), the content of exinite is larger than vitrinite shown by samples 08MH 13C, 08MH 13E, 08MH 13E2 (Zajuli and Panggabean, 2013). Most of exinite content in the fine sediments is composed of alginite whilst the rest comprises resinite, cutinite, and sporinite. The presence of dominant alginite submaceral indicates that the sedimentary rock tends to be included into kerogen Type I which means that if the sedimentary rock acts as the source rock, it produces oil. The index value of maximum vitrinite reflectance of fine sedimentary rock and coal is between 0.34% up till 0.50%.

Based on Rock-Eval pyrolysis, Hydrogen Index value (HI) determines the amount of oil or gas that is produced by rock if it acts as the source rock. The higher the HI value, the more oil can be produced. The Sinamar shales having a trend of HI value of more than 500, tend to show that the shales have a large probability to produce oil if it acts as the source rock. Claystone and mudstone of the Sinamar Formation only have a low HI value, that is below 300 which tends to produce gas and very little oil as shown in Table 1.

Fine sedimentary rocks of the Sinamar Formation, particularly shale, tend to produce oil. Maturity is one of factors influencing a migration process. The Sinamar shales have the early maturity level.

Determination of the shale maturity of Sinamar Formation at SNM-4 and MH 13 locations is also based on biomarker analysis, that is sterane, hopane, and aromatic ratios (Table 2). Maturity of the rock based on m/z 217 shows sterane distribution, which was done upon two forms of normal sterane epimer (20S and 20R). Sample 08MH 13B has the ratio value of 20S with its 20R that 20S/(20R+20S) is 42%, sample 08MH 13E is 15%, while 08MH 12R is 15%. The maturity increases along with the increase in 20S proportion, because 20R molecules change their configuration. At last, an equilibrium was reached by both at the comparison of 55% 20S and 45% 20R (Waples and Machihara, 1991). The maturity border based on the ratio of 20S/(20R+20S) is 55%. Ratio of 20S/(20R+20S) of sample 08MH 13B is 42%, sample 08MH

Tabel 2. Result of Gas Chromatography and Mass Spectrometry on Shale Rocks of the Sinamar Formation

GC and GC-MS Analysis		Sample Code		
		SNM-4/08 MH 12R (shale)	**08 MH 13B (shale)**	**08 MH 13E (shale)**
Ratio of n-alkane	Pristane/phytane	6.43	3.57	1.80
	Pristane/nC17	1.70	1.53	5.13
	Phytane /nC18	0.43	0.22	3.20
	Carbon Preference Index (CPI) 1	1.72	1.13	1.43
	Carbon Preference Index (CPI) 2	1.97	0.73	0.45
Ratio of Triterpane	C30 Moretane/C30 Hopane	1.25	0.25	0.40
	22S/(22S+22R)C31	0.14	0.56	0.24
	Tm	4379548	253963	4924907
	Ts	441344	40160	2119932
	C29/C30 Hopane	0.66	1	2.86
Ratio of sterane	20S/(20S+20R)C29	0.15	0.42	0.15
	C27 sterane	4	35	53
	C28 sterane	22	23	18
	C29 sterane	74	42	29
	C29 αααR	333706	23868	665958
	C29 αααS	1893929	32393	3706247
	C29 αββR	601917	26325	1963239
	C29 αββS	372882	14754	572087
Ratio of Aromatic	DNR-1	5.44	1.06	5.62
	TNR-1	1.11	1.61	0.74
	MPI-1	0.31	0.54	0.43
	MPI-2	0.45	0.64	0.49
	Rc1	0.58	0.72	0.66
	Rc2	2.12	1.98	2.04
	Ro1	0.73	0.85	0,73
	Ro2	0.98	0.89	0.74
	F1	0.40	0.46	0.40
	F2	0.29	0.27	0.23
Total Hopane / Sterane		6.7	13.6	16.67

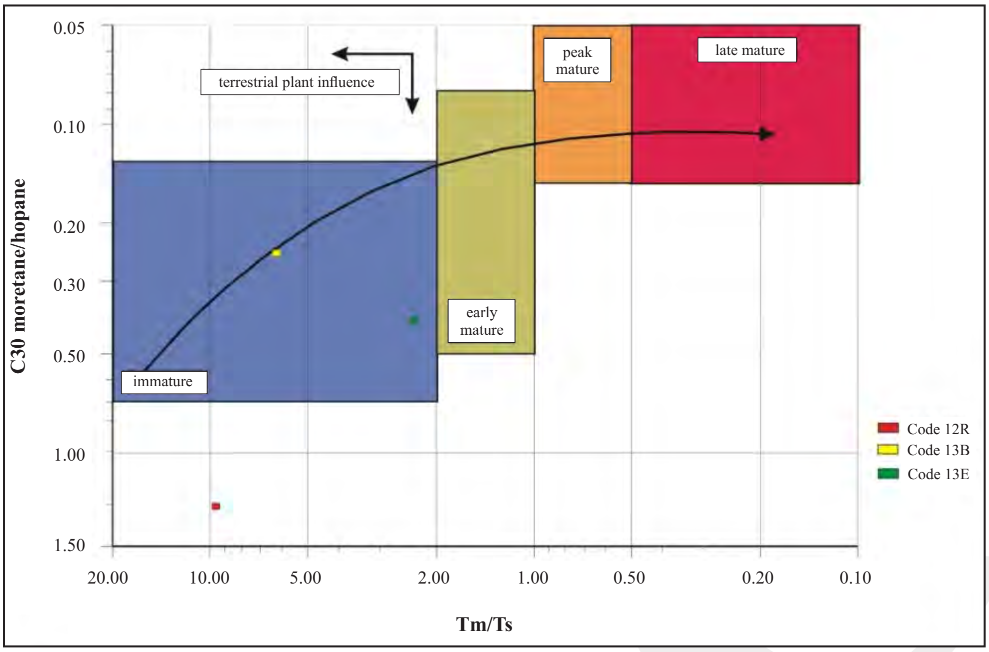

Figure 8. Cross plot of maturity with triterpane parameter shows that the three rock samples are included into immature category till reaching early mature.

Table 3. Total Organic Content of each Location in the Sinamar Formation

Location	Sample Code	Lithology	TOC (%)
Sinamar-4 Well	MH 12 M	claystone	0,69
	MH 12 P	claystone	2,69
	MH 12 R	shale	2,08
MH 13	MH 13 A	shale	9,02
	MH 13 B	shale	9,53
	MH 13 C	shale	7,45
	MH 13 D	shale	9,12
	MH 13 E	shale	10,84
	MH 13 E2	shale	8,36
LS 01	LS 01 A	claystone	4,23
	LS 01 G	claystone	0,77
RL 04	RL 04 B	serpih	3,28
RL 25	RL 25 A	claystone	3,29
MH 03	MH 03 B	mudstone	0,64
NS 08	NS 08 A	mudstone	0,60

13E is 15%, and sample 08MH 12R is 15%. Convertion upon vitrinite reflectance value for sample 08MH 13B is 0.8% which indicates that the maturity has reached the oil window stage. Meanwhile, the other two samples were still at the range of vitrinite reflectance of 0.5% which were included into an immature stage.

Based on mass chromatogram m/z 191 of sample 08MH 13B, 08MH 13E, and 08MH 12R, the maturity can be determined by using ratio C31 22S/22R, C30 morethane/hopane, and Tm/Ts. The proportion change of epimer C-22 from C31 up to C35 increases along with the maturity. On the equilibrium point, the proporsion 225 is 55-60%, while 22R is 40 - 45% (Waples and Machihara, 1991). The proporsion between 22S and 22R of sample 08MH 13B is 56% and 44%, sample 08MH 13E is 24%, and 76%, sample 08MH 12R is 14% and 86%. Therefore, it can be concluded that from the calculation of C31 at the chromatogram, figure mass m/z 191 of sample 08MH 13B has reached equilibrium point or maximum border of maturity that can be measured by triterpane biomarker, while sample 08MH 13E and 08MH 12R have not reached the equilibrium point. If biomarker maturity is converted into vitrinite reflectance (% R^o), the maturity of sample 08MH 13B is 0.6%. It has just reached the diagenesis stage, that has not reached the oil window stage. While the two other rock samples have vitrinite reflectance value of less than 0.5%.

Maturity parameter with ratio C30 morethane/hopane based on morethane is more unstable compared to 17α(H)-hopane, so the concentration decreases by the increase of maturity. Most of morethane disappears in the early mature stage (R0 < 0.6%), so the use of that ratio is very limited. Waples and Machihara (1991) stated that morethane/hopane is said to be mature if the ratio value is less than 0.15%, but less mature if the value is more than 0.15%. The ratio value can only be used as a qualitative indicator of immaturity, if morethane/hopane ratio is above 0.15% and the sample maturity level is less than 0.6% Ro. Sample 08MH 13B and 08MH 13E have morethane/hopane ratio of 0.25 and 0.40, while sample 08MH 12R is 1.25. These three rock samples have the maturity level Ro of < 0.6%.

The increase in maturity causes Tm to disappear, while the concentration of Ts relatively increases. Tm/Ts ratio which begins to decrease at the end of the maturity (Waples and Machihara, 1991) is the contrary to morethane/hopane ratio and ratio 22S/(22R+22R). Tm/Ts ratio becoming inaccurate due to facies is possibly caused by the origin of organic material type (Waples and Machihara, 1991). Therefore, it is used as the nonqualitative indicator for relative maturity must be interseries of rock or oil sample in the same facies. Based on Waples classification (Waples, 1985), the Sinamar shales are categorized as potential source rocks.

Conclusion

Based on the analyses and discussion on the previous parts, it can be concluded that:

1. Fine sedimentary rocks of the Sinamar Formation having the probability to act as source rocks are shale, claystone, and mudstone. The shale has the largest probability to act as a source rock.
2. Shales of the Sinamar Formation have organic material content which is very sufficient to act as the source rock, and are categorized as potential source rocks.
3. Shale kerogen type is categorized as kerogen I type tending to produce oil.
4. Shale maturity is categorized as early mature.

Acknowledgements

The authors express gratitude to the whole parties for the cooperation in writing this paper, especiallly to Prof. Dr. Ir. Eddy A. Subroto and PT. Kuansing Inti Makmur (KIM). Sincere thanks are also addressed to the Head of Centre for Geological Survey, Geological Agency for permitting to publish this paper.

References

Bemmelen, van R.W., 1949. *The Geology of Indonesia*. Vol. I A, The Hague. Netherlands, pp.

De Coster, G.L., 1974. The Geology of the Central and South Sumatera Basins. *Proceedings of Indonesian Petroleum Assosiation 3th Annual Convention*, p.77-110.

Hermiyanto, M.H., 2010. *Karakteristik Batuan Sedimen Halus Formasi Sinamar Untuk Mengetahui Potensinya Sebagai Batuan Induk Di Daerah Muara Bungo, Jambi*.

Thesis, Unpublished, Institut of Teknologi Bandung, 49pp.

Pulunggono, A. Agus Haryo, S., and Kosuma, C.G., 1992. Pre-Tertiary and Tertiary Fault System As a Framework of the South Sumatra Basin: A strudy of SAR MAPS, P*roceedings of Indonesian Petroleum Association, 21st Annual Convention*, Jakarta, p.339-360.

Rosidi, H.M.D., S. Tjokrosapoetro, B. Pendowo, S. Gafoer, and Suharsono, 1996. *Peta Geologi Lembar Painan dan Bagian Timur Laut Lembar Muarasiberut, Sumatra, skala 1:250.000*. Pusat Penelitian dan Pengembangan Geologi, Bandung.

Silitonga, P.H. and Kastowo, 1995. *Peta Geologi Lembar Solok skala 1:250.000*. Pusat Penelitian dan Pengembangan Geologi, Bandung.

Suwarna, N., Budhitrisna, T., Santosa, S., and Mangga S.A., 1994. *Peta Geologi Lembar Rengat skala 1:250.000*. Pusat Penelitian dan Pengembangan Geologi, Bandung.

Waples, D.W., 1985. *Geochemistry in Petroleum Exploration*. International Human Resources Development Corporation, Boston.

Waples, D.W. and Machihara, T., 1991. Biomarkers for geologists - a practical guide to the application of steranes and triterpanes in petroleum geology, American Association of Petroleum Geologists Methods in Exploration Series 9. *The American Association of Petroleum Geologists*, Tulsa, Oklahoma, USA.

Zajuli, M.H.H. and Panggabean, H., 2013. Depositional Environment of Fine-Grained Sedimentary Rocks of the Sinamar Formation, Muara Bungo, Jambi. *Indonesian Journal of Geology*, 8 (1), p.25-38.