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RESEARCH ARTICLE

Hydrocarbon Source Rock Potential and Thermal Maturity of Baong, Peutu, and Bampo Formations in the North Sumatra Basin, Indonesia

Fahri Adrian[1,*], Hidayat Syah Putra[1], Dewi Sartika[1], Rifqan[1,2], Haffiza Fajrin[1]
[1] *Department of Geological Engineering, Faculty of Engineering, Universitas Syiah Kuala, 23111, Indonesia.*
[2] *Tsunami Disaster Mitigation Research Center, Universitas Syiah Kuala, 23111, Indonesia.*

* Corresponding author : fahri.adrian@usk.ac.id
Tel.:+6281262879923
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Abstract

This study investigates the hydrocarbon source rock potential and thermal maturity of shale and mudstone outcrop samples from the Baong, Peutu, and Bampo Formations in the North Sumatra Basin, Indonesia. These fine-grained, calcareous, organic-rich, and low-permeability rocks are widely recognized as potential hydrocarbon source rocks. Source rocks generate hydrocarbons through thermal maturation processes, and their effectiveness is primarily controlled by organic richness, kerogen type, and thermal maturity. A total of six (6) outcrop samples were collected and analyzed using Rock-Eval Pyrolysis and Vitrinite Reflectance methods to evaluate their geochemical characteristics. The Baong Formation samples show very good organic richness, with Total Organic Carbon (TOC) values ranging from 2.2 to 2.5%, and are dominated by Type II/III kerogen, indicating potential for mixed oil and gas generation. Tmax values of 428–429°C suggest that these samples are thermally immature. The Peutu Formation samples exhibit very good source rock potential, with TOC values of 3.3–3.8% and predominantly Type II/III kerogen, suitable for mixed oil and gas generation. Tmax values indicate thermal immaturity to early maturity. In contrast, the Bampo Formation samples are thermally mature but display poor organic richness (TOC < 0.5%) and low Hydrogen Index values, suggesting limited hydrocarbon generation potential dominated by Type III kerogen. Although interpretations are based on outcrop samples, the results provide important implications for evaluating the petroleum system of the North Sumatra Basin, particularly in understanding source rock distribution, quality, and maturity trends.

Keywords: source rock, geochemistry, thermal maturity, kerogen type, North Sumatra Basin

1. Introduction

The North Sumatra Basin is one of the sedimentary basins with significant hydrocarbon potential in Indonesia. Located in the northwestern part of Sumatra Island, the basin has a complex geological history that makes it an attractive area for hydrocarbon exploration. Several studies have emphasized the importance of source rock characterization in understanding petroleum systems in Indonesian basins, particularly through geochemical approaches such as Rock-Eval Pyrolysis and thermal maturity analysis (Manurung et al., 2021)

In this basin, source rock plays an important role in the hydrocarbon formation process. Source rock is a layer of rock that contains organic matter that can produce oil and gas through heating and composting processes. Recent studies published also highlight the importance of integrating geochemical data to evaluate hydrocarbon potential and maturity trends in Indonesian sedimentary basins (Pires et al., 2025).

The North Sumatra Basin has a complex geological history, with rock formations that vary from shales, sandstones and volcanic rocks. Some of these rock formations have been identified as potential source rocks, such as the Bampo Formation, Peutu Formation, and Baong Formation. The North Sumatra Basin has two well-known petroleum systems, the Bampo-Peutu system in the north and the Baong-Belumai/Peutu-Keutapang system in the southeast (Barber et al., 2005). The reservoir rocks of the North Sumatra Basin consist of carbonate (Arun Formation) and clastic sedimentary rocks (Keutapang, Baong and Belumai Formations) of Oligocene to Pliocene age (Barber et al., 2005). Based on the Regional Geological Map scale 1:250,000 Sheet Lhokseumawe (Keats, et al., 1983) and Langsa (Bennett, et al., 1981), those Formations are spread in the area of North Aceh, Lhokseumawe, to East Aceh which is the location of this study.

The Eocene-Early Miocene Bampo Formation consists of organic matter-rich shales and sandstones, making it one of the main source rocks in the basin (Fig. 1). The Early Miocene Peutu Formation mainly consists of carbonate mudstones, turbidite mudstones, and some limestones that function as source and reservoir rocks. The Late Miocene-Pliocene Baong Formation consists of shale, mudstone, and sandstone, this formation has layers that function as source, reservoir, and seal rocks.

Source rock plays a very important role in petroleum systems. It serves as the main source of hydrocarbons formed through geological processes such as thermal maturation and diagenesis. Source rock characteristics, including organic matter content, thermal maturity, and hydrocarbon generation potential, are key factors that determine the success of oil and gas exploration and production in a basin.

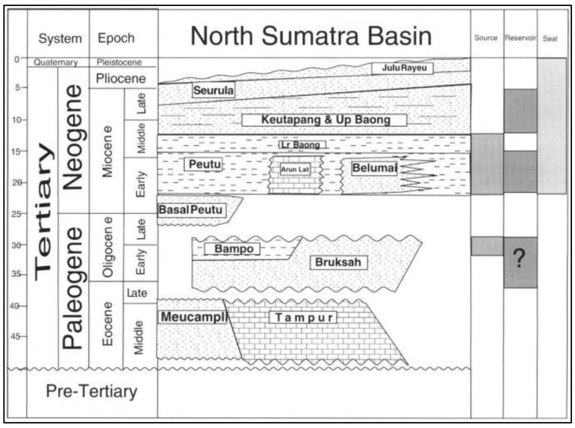

Fig 1. The North Sumatra Basin stratigraphy, which displays the locations of source beds, reservoirs, and seals (Barber et al., 2005).

The source rock must contain high enough organic matter (more than 0.5%) in order to produce hydrocarbons (Peters and Cassa, 1994). This organic matter content is usually measured as Total Organic Carbon (TOC). The quality of the source rock is strongly influenced by the amount and type of organic matter contained in it. A good source rock should have a high TOC, which indicates a great potential to produce hydrocarbons. The TOC is used to categorize source rock richness. For example, rocks with TOC value of more than 2% are often regarded as having "good" to "excellent" hydrocarbon generation potential, whilst rocks with a value of less than 0.5% are usually categorized as "poor" (Peters and Cassa, 1994). Table-1 below illustrates how prospective source rock is classified according to its TOC value. These classifications help in evaluating the potential of the source rocks to generate hydrocarbons, with higher TOC values indicating better potential for hydrocarbon generation.

Table 1. Geochemical TOC and Rock Eval Pyrolisis parameters of the source rock (Peters and Cassa, 1994).

Source Rock Category	Total Organic Carbon (wt %)	Rock Eval Pyrolisis		
		S1 (mg HC/g)	S2 (mg HC/g)	S3 (mg HC/g)
Poor	< 0,5	0 – 0,5	< 2,5	< 2
Fair	0,5 – 1	0,5 – 1	2,5 – 5	2 – 5
Good	1 – 2	1 – 2	5 – 10	5 – 10
Very Good	2 – 4	2 – 4	10 – 20	10 – 20
Excellent	> 4	> 4	> 20	> 20

The depositional environment also has a major impact on TOC levels. Higher TOC is typically found in source rocks that originate in anoxic environments, where organic matter is maintained (Chin, 1991). Increased formation of TOC is also supported by elements like strong organic productivity and quick sedimentation. Numerous techniques, such as organic geochemistry and organic petrology, can be used to quantify TOC. These techniques evaluate the kind and state of organic materials in the rock.

The type, quantity, and thermal maturity of kerogen are key factors that influence the hydrocarbon potential of these rocks (Peters and Cassa, 1994). Kerogen, the insoluble organic matter in sedimentary rocks, plays a crucial role in determining the hydrocarbon generation potential of source rocks. The type of kerogen present in a rock determines the type of hydrocarbons (oil or gas) it can generate upon thermal maturation. Kerogen is classified into four main types based on its origin, composition, and hydrocarbon generation potential. The classification of kerogen types described in Table 2.

A process of thermal maturation must also be applied to the source rock. For the process known as catagenesis to transform organic materials into hydrocarbons, the source rock must have enough temperature and pressure conditions. When determining this degree of thermal maturity, vitrinite reflectance or other factors like Tmax (highest temperature) are frequently used.

Table 2. Parameters characterizing the hydrocarbon prospect's features and kerogen type (quality) kerogen (Peters and Cassa, 1994).

Kerogen Type	Hydrogen Index (mg HC/g TOC)	S2/S3	Main Product at Peak Maturity
I	> 600	> 15	Oil
II	300 – 600	10 – 15	Oil
II/III	200 – 300	5 – 10	Oil / Gas
III	50 – 200	1 – 5	Gas
IV	< 50	< 1	None

The fraction of light reflected from the surface of vitrinite particles in sedimentary rocks is measured geochemically as vitrinite reflectance (Peter and Cassa, 1994). It is a crucial measure of the thermal maturity of organic materials in these rocks and is represented by the symbol %Ro. The %Ro readings climb with increasing maturity, suggesting considerable thermal change of the organic matter. The oil window is typically occupied by source rocks with %Ro values between 0.5% and 1.0%, whereas values above 1.0% suggest the possibility of gas generation (Peters and Cassa, 1994).

Tmax is a quantity that is measured during the Rock-Eval pyrolysis process, which is a petroleum geochemistry method used to assess the source rocks' hydrocarbon potential. It stands for the temperature at which the thermal breakdown of kerogen produces hydrocarbons at its fastest pace possible. Tmax figures come from pyrolysis tests, in which the organic content of a rock sample is measured by heating it. Greater Tmax values show that the organic matter has been exposed to greater temperatures throughout geological time and are typically correlated with increased thermal maturity. This is important because it provides information on whether the source rock is inside the window for the creation of gas or oil. The stages of hydrocarbon production are (Peters and Cassa, 1994):

- Immature: Tmax < 435°C
- Mature (Oil Window): Tmax between 435°C and 465°C
- Overmature (Gas Window): Tmax > 465°C

Summarized thermal maturity level based on Total Organic Carbon (TOC), Vitrinite Reflectance, and Thermal Alteration Index (TAI) shown in Table-3.

2. Methods

A total of 6 samples of potential source rocks were collected in the field. Two samples (BG-1 and BG-2) are Early Miocene calcareous shale of the Baong Formation exposed in Bireuen District. The next two samples are carcareous shale of the Peutu Formation exposed in the

Lhokseumawe (PT-1) and East Aceh (PT-2) districts. Two more samples are Bampo Formation mudstones (BP-1 and BP-2) exposed in East Aceh District.

Table 3. Thermal maturity level of potential source rock (Peter and Cassa, 1994)

Thermal Maturity Stage	Maturation			Generation		
	Ro (%)	Tmax (^0C)	TAI Scale 1 - 5	Bitumen TOC	Bitumen (mg/g rock)	Production Index (S1/S1+S2)
Immature	0,2 – 0,6	< 435	1,5 – 2,6	< 0,05	< 50	< 0,10
Early Mature	0,6 – 0,65	435 – 445	2,6 – 2,7	0,05 – 0,10	50 – 100	0,10 – 0,15
Peak Mature	0,65 – 0,9	445 – 450	2,7 – 2,9	0,15 – 0,25	150 – 250	0,25 – 0,40
Late Mature	0,9 – 1,35	450 – 470	2,9 – 3,3	-	-	> 0,40
Post Mature	> 1,35	> 470	> 3,3	-	-	-

The Baong Formation calcareous shale samples are characterized as light gray with silt grain size, closed fabric, matrix supported, and calcareous minerals (Fig.2). There are fissility and parallel bedding sedimentary structures in this outcrop. There are also thin calcareous sandstone inserts between calcareous shale layers.

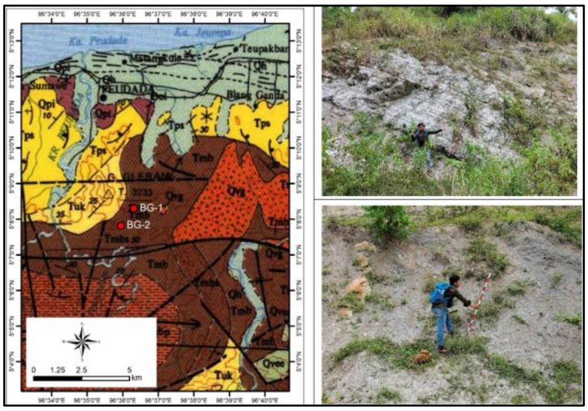

Fig 2. Outcrop location of calcareous shale Baong Formation. Top right photo is location BP-1, and bottom right is location BP-2.

The Peutu Formation calcareous mudstone sample exposed in the Lhokseumawe area (PT-1) has a description of light gray, clay grain size, closed fabric, matrix supported and interbedded with medium sandstone. This rock has clay and calcareous mineral composition. The calcareous mudstone outcrop in East Aceh (PT-2) is characterized by dark to light gray, clay grain size, strong hardness, closed fabric, matrix supported, highly fractured, and interbedded with very thin sandstone. Outcrop of this formation shown in Fig.3.

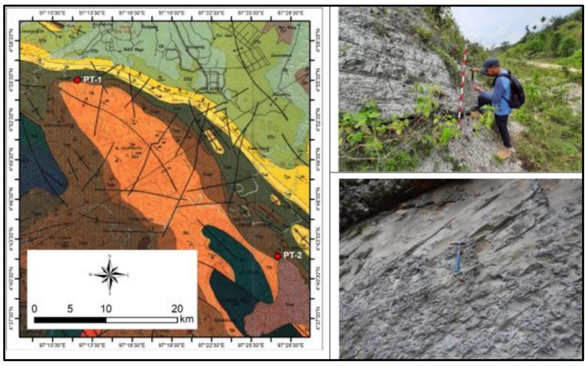

Fig 3. Outcrop location of calcareous mudstone Peutu Formation. Top right photo is location PT-1, and bottom right is location PT-2.

Bampo Formation shale samples taken in Lokop, East Aceh (BP-1 and BP-2) are characterized by black color, clay to silt grain size, well sorted, closed fabric, matrix supported, and composition of clay and siliciclastic minerals (Fig.4). There is a parallel lamination sedimentary structure on this outcrop.

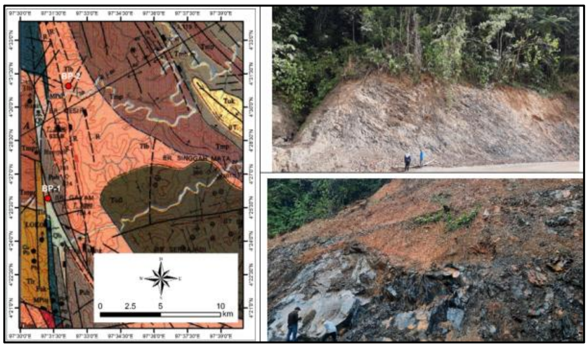

Fig 4. Outcrop location of calcareous mudstone Bampo Formation. Top right photo is location BP-1, and bottom right is location BP-2.

Rock Eval Pyrolysis and Vitrinite Reflectance were the geochemical techniques used in the laboratory testing of the six collected rock samples. A laboratory method called "Rock-Eval pyrolysis" is used to examine the amount of organic matter in rocks and soils. In order to assess the carbon dioxide and hydrocarbons that are produced as a result of the organic matter being broken down, a small sample of rock is heated in the absence of oxygen. In order to examine the TOC, Tmax, and S1 and S2 values, rock eval pyrolysis was done. A high TOC value suggests that the source rock has a strong chance of producing hydrocarbons. Tmax is the temperature during a Rock-Eval analysis where the maximum pyrolysis peak occurs. The source rock's thermal maturity is evaluated using Tmax. S2 is the total quantity of hydrocarbons that can be produced from kerogen during pyrolysis, whereas S1 is the amount of free hydrocarbons that are already present in the rock. The source rock's potential for producing hydrocarbons can be inferred from the S1/S2 ratio. The value of S2 is also used to determine kerogen type with combination of Hydrogen Index (HI) value.

The second method involves determining vitrinite reflectance by microscopic assessments employing imaging systems and reflected light microspectrophotometers. Vitrinite Reflectance is measured using reflected light microscopy on a composite sample submerged in oil. Concentrated kerogen is the sample, which is polished after being mounted in an epoxy disk. In-situ, caving, solid bitumen, semi-fusinite, and reworked/oxidized vitrinite are the several types of vitrinite macerals. The sample maturity is expressed in percentage Ro (reflectance in oil) using in situ vitrinite.

Geochemical evaluation using Rock-Eval Pyrolysis and thermal maturity indicators such as Tmax and vitrinite reflectance has been widely applied in source rock studies. These methods provide reliable parameters for determining organic richness, kerogen type, and hydrocarbon generation potential. Similar approaches have been successfully applied in various Indonesian basins to predict source rock quality and maturity distribution (Setyawan et al., 2020). Previous studies have also evaluated the potential of fine-grained shales as hydrocarbon source rocks using geochemical methods. For example, Middle Miocene black shale of the Airbenakat Formation in the Jambi Sub-basin showed variations in TOC and pyrolysis parameters that relate to hydrocarbon potential, with indications of immature source rock characteristics (Afifah and Setiawan, 2019).

Details defining the classification of petroleum potential and stage of thermal maturity potential source rocks, maturity level parameters, and kerogen type are available in Table 1 - 3.

It should be noted that all samples analyzed in this study were collected from surface outcrops, and therefore the geochemical characteristics and maturity levels may differ from those of equivalent formations in subsurface conditions.

3. Results

Six (6) outcrop samples, comprising two samples of calcareous shale, two samples of calcareous mudstone, and two samples of shale, were obtained from the study region and subjected to geochemical analysis. These samples contain of Bampo Formation, Peuteu Formation, and Baong Formation outcrop samples.

3.1 Potential Source Rock

To assess the source rock potential of the outcrop samples, a combination of Total Organic Carbon (TOC), Pyrolysis Rock Eval, and Kerogen Typing data has been utilized. The findings for the Pyrolisis Rock Eval and TOC data are shown in Table 4.

Table 4. TOC and Pyrolysis Rock Eval Data Outcrop Samples - Study area North Sumatera Basin, Aceh

No.	Age	Formation	Sample No.	Ana-lised Lithology	TOC	S1	S2	S3	PY (S1 + S2)	S2/S3	PI (S1/S1+S2)	PC	T-max	HI (S2/TOC x 100)	OI (S2/TOC x 100)
					(% wt)	mg/g rock							(°C)	mg HC/g TOC	mg CO2/g TOC
1	Late Miocene	Baong	BG-1	Calc. Shale	2.16	1.47	4.63	2.86	6.10	1.62	0.24	0.51	428	214	132
2			BG-2	Calc. Shale	2.53	0.55	5.49	1.44	6.04	3.81	0.09	0.50	429	217	57
3	Mid Miocene	Peutu	PT-1	Calc. Mudstone	3.75	0.87	9.06	0.59	9.93	15.36	0.09	0.82	430	242	16
4			PT-2	Calc. Mudstone	3.25	1.01	8.97	0.26	9.98	34.50	0.10	0.83	435	276	8
5	Late Oligocene	Bampo	BP-1	Shale	0.22	0.19	0.16	0.17	0.35	0.94	0.54	0.03	***	73	77
6			BP-2	Shale	0.25	0.20	0.13	0.21	0.33	0.62	0.61	0.03	***	52	84

Notes:

TOC: Total Organic Carbon
S1: Amount of Free Hydrocarbon
S2: Amount of Hydrocarbon released from kerogen
S3: Organic Carbon Dioxide
PY: Potential Yields, amount of Total Hydrocarbons = (S1 + S2)
PI: Production Index = (S1/ S1 + S2)
PC: Pyrolysable Carbon
Tmax: Maximum Temperature (0C) at the top of S2 peak
HI: Hydrogen Index = (S2/TOC) x 100
OI: Oxygen Index = (S3/TOC) x 100
NDP: No Determination Possible
***: Erroreneous Tmax Readings due to lack of S2

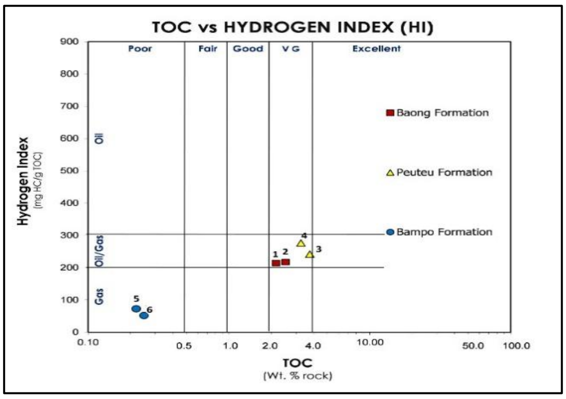

Fig.5. Hydrogen Index (HI) versus TOC diagram illustrating kerogen type and hydrocarbon generation potential of shale samples.

The geochemical analysis of two calcareous shale samples from the Baong Formation (Sample BG-1 and BG-2) provides valuable insights into their potential as hydrocarbon source rocks. According to Table-4, both samples exhibit TOC values that classify them as 'very good source rocks' based on their TOC values = 2.2% and 2.5%. Their S2 values = 4.7 and 5.5 mg/g rock indicates the amount of hydrocarbons that can be generated from the kerogen present in the rock. With Potential Yield (PY) = 6.1 and 6.0 mg/g rock, reflects the total hydrocarbon generative potential of the samples, which includes both free hydrocarbons and those generated from kerogen. As presented in Table-4 and Fig. 5, HI values = 214 and 217 mg HC/g TOC respectively indicating a ‘good’ potential for mixed oil and gas generation. The presence of Type II/III kerogen further categorizes these samples as 'good source rocks.'

The analysis of two calcareous mudstone samples from the Peutu Formation (Sample PT-1 and PT-2) reveals significant understanding into the quality as source rocks for the NSB. As shown in Table-4, the TOC values range from 3.3 – 3.8% classify both samples as having 'very good' organic richness. These high TOC values are indicative of substantial organic matter content, which is essential for hydrocarbon generation. The S2 values for PT-1 and PT-2 are 8.9 mg/g rock and 9.0 mg/g rock, respectively. The values obtained suggest that both samples have 'good source rock' potential (Fig. 5). The HI values indicate the efficiency of the organic matter in generating hydrocarbons. Based on Table-4, HI values ranges from 242 and 276 mg HC/g TOC are typical for Type II/III kerogen, which is capable of generating both oil and gas. These values for both samples place them in the category of 'good source rock' for mixed oil and gas generation.

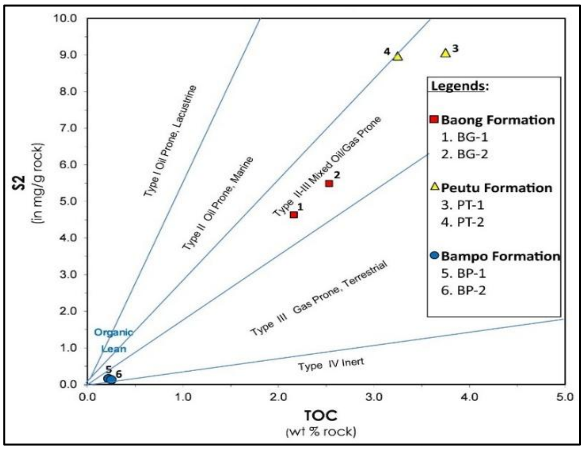

Fig.6. S2 versus TOC diagram showing kerogen type potential of the shale samples.

The analysis of two shale samples from the Bampo Formation (Sample No. BP-1 and BP-2) indicates their category for hydrocarbon source rocks. According to Table-4, both samples as having 'poor' organic richness due to their TOC values which are <0.5%. Low TOC values suggest a limited amount of organic matter present, which is a critical factor for hydrocarbon generation. The S2 content are 0.1 and 0.2 mg/g rock suggest that both samples have 'poor source rock' potential. The PY values that indicate the total amount of hydrocarbons that can be generated only ranged between 0.3 – 0.4 mg/g rock, which further confirming the 'poor' potential of these samples as source rocks. The HI values are 52 – 73 mg HC/g TOC which are categorized low, indicating that the efficiency of the organic matter in generating hydrocarbons is limited. HI values below 150 mg HC/g TOC are typical for Type III kerogen, which is more gas-prone and less efficient in hydrocarbon generation (Fig. 6). The absence of Type II kerogen (0%) suggests that there is no significant potential for oil generation in these samples.

3.2 Thermal Maturity of Potential Source Rock

The thermal maturity of the rock samples has been determined using a combination of vitrinite reflectance (Ro%) and pyrolysis Rock-Eval (Tmax). The values for the Tmax shown in Table-4, and vitrinite reflectance kindly is presented in Table-5.

As shown in Table-5, the analysed calcareous shale samples from the Baong Formation (BG-1 and BG-2) are thermally immature. The VR values for the samples range from 0.31% to 0.32% Ro, which are below the thermal maturity boundary of 0.60% Ro. The Tmax values of 428°C and 429°C in the Table-4 are below the maturity threshold of 435°C. This further supports the analysis that these samples are thermally immature. These combined indicators confirm that the calcareous shale samples BG-1 and BG-2 from the Baong Formation are thermally immature and have not yet reached the thermal maturity levels required for significant hydrocarbon generation (Fig.7).

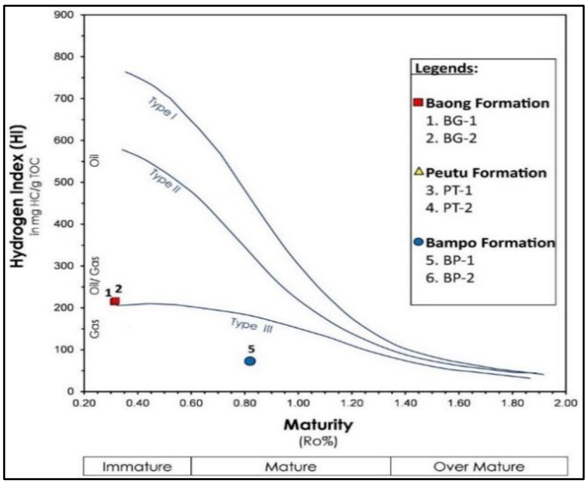

Fig. 7. Thermal maturity determined by comparing the HI vs. Ro% comparative diagrams.

Table 5. Vitrinite Reflectance Data Outcrop Samples - Study area North Sumatera Basin, Aceh

No.	Age	Formation	Sample No.	Analised Lithology	Org. Mat. Recovery	Vitrinite Clasts Content	Distribution of Ro% Values											
							Cavings/Sup-pressed			Indigeneous/Insitu						Reworked/Oxidized		
							#R	Range Min - Max	Mean	#R	Range Min - Max	Mean	Std. Dev.	Med.	Mode	#R	Range Min - Max	Mean
1	Lt.	Baong	BG-1	Calc. Shale	G	M				9	0.28 - 0.34	0.31	0.02	0.31	0.31			
2			BG-2	Calc. Shale	G	M				14	0.28 - 0.35	0.32	0.03	0.32	0.28			
3	Mid.	Peutu	PT-1	Calc. Mudstone	G	B						B						
4			PT-2	Calc. Mudstone	G	B						B						
5	Lt.	Bampo	BP-1	Shale	P	VP				3	0.78 - 0.86	0.82	0.06	0.82	-			
6			BP-2	Shale	P	VP						NDP				3	1.61 - 1.78	1.69

Notes :
Preparation Type : Polished Kerogen Concentrate
B: Barren
NDP: No Determination Possible
VP: Very Poor
P: Poor
M: Moderate
G: Good
VG: Very Good

Based on Table-5, visual microscopic analysis revealed a very poor content of vitrinite phytoclasts in the calcareous shale samples from the Peutu Formation (Samples PT-1 and PT-2), which were mostly degraded. Consequently, Vitrinite Reflectance (Ro%) could not be determined for these samples. However, Table-4 showed the Tmax values for both samples range from 430°C to 435°C, indicating that the samples are in the thermally immature to early mature stage. These characteristics collectively confirm that the organic matter in the calcareous shale samples PT-1 and PT-2 from the Peutu Formation has not yet reached the thermal maturity levels necessary for significant hydrocarbon generation but is progressing through the early stages of thermal alteration.

The Tmax readings from Pyrolysis Rock-Eval were found to be erroneous due to the lack of sufficient kerogen (S2) content in the both Shale Bampo Formation samples (BP-1 and BP-2). Very low S2 values in the samples indicated insufficient kerogen for accurate pyrolysis analysis. Nevertheless, the maturity level can be interpreted by VR analyses that resulted 0.82 %Ro for Sample BP-1 only (Table-5). This value indicates that this sample has reached the thermally mature stage, commonly referred to as 'peak mature,' which is suitable for hydrocarbon generation. This level of maturity is indicative of significant thermal alteration of the organic matter, enabling hydrocarbon expulsion. This process likely resulted in the reduction of S2 and Hydrogen Index (HI) values as hydrocarbons were generated and expelled. The HI values also low, ranged between 72 – 73 mg HC/TOC which is can be considered
as Type III Kerogen which is gas-prone and less effective in generating oil.

Summarized geochemical data and the interpretations of such as : potential source rock, thermal maturity, kerogen type, and hydrocarbon product at peak mature can be seen in Table-6.

Table 6. Summary of Potential Source Rock and Thermal Maturity - Study area North Sumatera Basin, Aceh

No	Age	Formation	Sample No.	Lithology	Petroleum Potential		Thermal Maturation	Kerogen Type and Expelled Product		Remarks
					Quality	Quality	Stage of Thermal Maturity	Kerogen Type	Main Product at Peak Maturity	
1	Late Miocene	Baong	BG-1	Calc.Shale	Very Good	Poor to Good	Immature	II/III	Mix Oil & Gas	Immature Poor to Fair Source Rock, Type II/III and III Kerogen, Mixed Oil/Gas and Gas Product at Peak Maturity
2			BG-2	Calc.Shale						
3	Mid Miocene	Peutu	PT-1	Calc. Mudstone	Very Good	Good	Immature	II/III	Mix Oil & Gas	Immature to Early Mature Fair to Good Source Rock, Type II/III Kerogen, Mixed Oil/Gas Product at Peak Maturity
4			PT-2	Calc. Mudstone			Early Mature			
5	Late Oligocene	Bampo	BP-1	Shale	Poor	Poor	Mature	III	Gas	Mature Poor Source Rock, Type III Kerogen, Gas Product Only at Peak Maturity
6			BP-2	Shale						

4. Discussions

The North Sumatra Basin (NSB) in Indonesia has several potential source rocks that contribute to the hydrocarbon resources in the region. The Bampo, Peutu, and Baong Formations are considered to be the source rocks in the basin, with depths ranging from 2000 to 4000 meters (Barber et al., 2005). These formations are recognized as effective source rocks for hydrocarbons. They contain organic-rich sediments that have undergone thermal maturation, generating hydrocarbons over time.

Calcareous shale samples from Baong Formation (sample BG-1 and BG-2) are categorized as 'very good source rock'. Several geological processes have influenced the hydrocarbon accumulation in the Baong Formation of the North Sumatra Basin. These Baong's shale has a high total organic content (TOC), which is the key features for 'very good' source rock. This TOC amount suggests significant potential for hydrocarbon generation. The presence of Type II/III kerogen, underscores the potential for mixed oil and gas generation. Type II kerogen is derived from marine algae and plankton and is known for its high oil-generating capacity, while Type III kerogen, originating from terrestrial plant material, is more gas-prone. The mixed presence of these kerogen types in the Baong Formation samples highlights their versatility in hydrocarbon production. The thermal maturity of the samples, as indicated by Tmax values ranging from 428° to 429°C, suggests that it is in the immature stage. This thermal maturity level is conducive to hydrocarbon generation and accumulation. However, the thermal maturity indicators suggest that the Baong Formation samples analyzed at the outcrop level remain thermally immature. This observation aligns with previous studies that reported variations in maturity between surface and subsurface source rocks due to differences in burial depth and thermal history (Wibowo et al., 2024). The Baong Formation was deposited in a open marine outer sublitoral on top, upper bathyal on base in part inner sublittoral (Barber et al., 2005). The tectonic configuration of these depositional system has influenced the formation's hydrocarbon potential. Subsurface data also indicates the Baong Formation consists predominantly of bathyal shale, with local concentrations of planktonic foraminifera forming thin, muddy limestone beds which is high organic content (Wardhana et al., 2021). The sedimentation of the Baong shale reflects a change in tectonic regime as well as a rise in relative sea level. This change in sedimentation environment has contributed to the formation's hydrocarbon potential. These geological processes have collectively contributed to the hydrocarbon accumulation in the Baong Formation, making it a significant source rock and reservoir in the North Sumatra Basin.

The samples of Peutu Formation (PT-1 and PT-2) is primarily composed of calcareous shale, which is rich in organic material. This composition is conducive to hydrocarbon generation, as the organic matter can convert into oil and gas under appropriate thermal conditions. Based on geochemical data, calcareous shale of Peutu Formation defined as 'very good source rock'. The samples is characterized by high total organic carbon

(TOC) content of the this research, which is essential for hydrocarbon generation. This organic richness allows for the effective production of oil and gas, making it a vital source rock within the basin. These samples also primarily composed of type II or III kerogen, which is highly efficient in generating hydrocarbons, particularly mix oil and gas. The microscopic analysis of the Peutu Formation samples provides insights into their thermal maturity and organic matter composition. The vitrinite phytoclast content is observed to be very poor across all analyzed samples, with most vitrinite being too degraded to measure Vitrinite Reflectance (Ro%). Despite this limitation, alternative methods such as Tmax values, offer valuable information on the thermal maturity of the organic matter. In the analyzed samples, The Tmax values of the samples range between 430°C and 435°C, which are consistent with the thermally immature to early mature stages. The TOC and pyrolysis characteristics of the Baong and Peutu Formation shales in this study are comparable with results from the Airbenakat Formation black shale, where similar geochemical parameters were used to evaluate source rock potential, revealing immature to low-potential source characteristics (Afifah and Setiawan, 2019).

Bampo Formation shale samples (BP-1 and BP-2) are categorized as 'poor source rock'. This result based on the TOC content are below 5%. The low TOC levels hinder the formation's potential as a robust source rock for oil and gas generation. This limited amount of organic matter can be caused by very high carbonaceous contain in the rock which are shown by the black colour of the samples. This composition is less favorable for organic matter accumulation compared to other formations in the basin. The depositional environment also can be the factor. Based on Barber (2005), Bampo formation was deposited in a fluvial, paralic, and restricted marine environment, which may not have been as conducive to the accumulation of organic-rich sediments. However, the Bampo's shale can be considered as potential source based on kerogen type and thermal maturity. Although the Bampo Formation samples is characterized by relatively lean organic matter (TOC < 1 %), it contains type III kerogen, which is conducive to gas generation. This kerogen type result also followed by the low HI values and paralic depositional environment, which is dominance of terrestrial material. These type of depositional environment can be categorized for Type III kerogen (Peter & Cassa, 1994). The thermal maturity of the Bampo Formation samples can be analyze only for one sample (BP-1) due to no possible determination Vitrinite Reflectance value on sample BP-2. Despite the low HI values indicating that this potential is not fully realized, the VR analysis of Sample BP-1, which resulted in a value of 0.82% Ro, indicates that this sample has reached the thermally mature stage ('peak mature'). According to Bennett (1981) and Barber (2005), the Bampo Formation was deposited during the Oligocene epoch, a period characterized by significant tectonic activity and subsidence. The prolonged burial and thermal exposure over millions of years have contributed to its mature thermal maturity. Burial depth also can be one of the factor that can be caused the mature thermal maturity level. Based on regional stratigraphy (Barber et al., 2005), Bampo Formation were overlying by Peutu, Baong, Keutapang, Seureula, and Julu Rayeu Formation. This means Bampo Formation has been buried to significant depths. This deep burial has subjected the organic matter to high temperatures, leading to its thermal maturation. This limited maturity means that while some hydrocarbons may be generated.

5. Conclusions

The conclusions of this research can be summarize as follows:

- With a total organic content (TOC) ranging from 2.2 to 2.5%, the Baong Formation (Sample BG-1 and BG-2) is categorized as very good in terms of organic richness. The presence of Type II/III kerogen indicates a potential for mixed oil and gas generation. The Tmax values (428-429°C) suggest that the Baong Formation is thermally immature, which is favorable for hydrocarbon generation and accumulation.
- Composed of high TOC content (3.3 - 3.8%), calcareous shale of Peutu Formation (Sample PT-1 and PT-2) is identified as a very good source rock. With kerogen type predominantly type II/III kerogen, which is efficient in generating mixed oil and gas. The formation is thermally immature to early mature, indicating sufficient thermal alteration for hydrocarbon production.
- Thermally mature of of the analysed samples of Bampo Formation (Sample BP-1 and BP-2) have 'poor'organic organic richness and classified as 'poor source rock'. These may not be sufficient to be hydrocarbon generated as its HI is relatively low (Type III Kerogen).

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