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Source Rock Evaluation in the "Idea" Field, Bintuni Basin, West Papua: A Geochemical Approach

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Abstract

The Bintuni Basin is one of the largest hydrocarbon-bearing basins in Eastern Indonesia, although only a limited number of oil and gas fields are currently. Consequently, further investigation into its petroleum system, particularly the potential of its source rocks. In hydrocarbon exploration, characterizing source rock is critical to evaluating the presence of organic-rich strata capable of generating hydrocarbons. Geochemical analysis is a widely used method for assessing source rock potential, utilizing total organic carbon (TOC), rock-eval pyrolysis, and vitrinite reflectance data. In this study, geochemical data were obtained from one well and two outcrop samples to evaluate the quantity, quality, and thermal maturity of organic matter. The geochemical assessment of rock samples from four stratigraphic formations indicates that the Permian Ainim Formation exhibits the highest source rock potential. TOC values range from 1% to 80% with hydrogen index (HI) values range between 13 and 431 mg HC/g TOC classifying the formation as a good to excellent potential. The dominant organic matter consists of kerogen type II/III suggesting the potential for both oil and gas generation. Thermal maturity analysis indicates that the Ainim formation has reached the oil and gas generation window at depths of 8,075–8,420 feet. These findings demonstrate that the Ainim Formation represents a significant source rock within the Bintuni Basin, contributing valuable insights into the region's petroleum system and hydrocarbon prospectivity.

Keywords: Bintuni Basin; Maturity; Quality; Quantity; Source rock.

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Introduction

The Bintuni Basin located in West Papua Province, Indonesia is one of the most significant sedimentary basins in the region and has been proven to contribute substantially to the country's oil and gas production (Utomo et al., 2022). This basin has attracted considerable interest due to its complex geological history and its potential for hydrocarbon generation. Among the various stratigraphic units present, Permian-aged sediments particularly the Ainim Formation are believed to be the primary source rocks responsible for hydrocarbon generation in the basin.

Understanding the source rock characteristics is fundamental in petroleum system analysis as it provides critical insights into the quantity, quality, and thermal maturity of organic material—key factors determining the potential of hydrocarbon generation (Haris et al., 2017, Jamaluddin et al., 2018; 2023; 2024a,b). Despite its proven petroleum potential, the Bintuni Basin has been the subject of limited comprehensive geochemical studies. This gap is particularly notable in source rock characterization. Therefore, this study aims to evaluate the source rock potential in the "Idea" Field by employing geochemical analysis, which includes total organic carbon (TOC) measurement, rock-eval pyrolysis, and vitrinite reflectance. These techniques provide a detailed assessment of the organic richness, kerogen type, and thermal maturity of the studied formations, particularly the Ainim Formation which has been identified as a promising source rock potential. While its petroleum potential has long been recognized, detailed studies focusing on geochemical characterization of source rocks are still relatively scarce.

Previous research on source rock characterization in the Bintuni Basin began with early works such as Alam & Setiadi (2019), highlighting the significance of Permian sedimentary sequences in hydrocarbon generation. Subsequent investigations have confirmed the basin's petroleum potential, particularly within pre-Tertiary and Tertiary formations. Recent technological advances have significantly improved the evaluation of source rock potential in complex basins like Bintuni.

Recent advancements in organic geochemistry and basin modeling have provided more sophisticated methods for evaluating source rock potential (Jamaluddin & Sea, 2018). Studies utilizing Rock-Eval Pyrolysis, TOC analysis, and Vitrinite Reflectance have proven effective in assessing the hydrocarbon-generating capability of sedimentary formations (Jamaluddin et al., 2018; 2025). Furthermore, advancements in petroleum geochemistry and thermal maturation studies have enhanced the ability to predict hydrocarbon expulsion and migration pathways (Hamzah et al., 2018; Indriyani et al., 2020; Syarifah et., 2021).

This research aims to bridge the gap in knowledge by applying geochemical analysis techniques to assess the Ainim Formation's source rock potential. By integrating geochemical data with regional geological insights, this study contributes to a better understanding of the petroleum system in the Bintuni Basin and provides valuable information for future exploration and resource assessment. The findings of this study are expected to support more efficient exploration strategies and enhance the basin modeling framework for the region.

Regional Geology

The Bintuni Basin, located in West Papua, Indonesia, is a prominent foreland basin renowned for its complex geology and significant hydrocarbon resources. Geologically, the basin sits at the northern margin of the Australian continental plate, adjacent to the Bird's Head (Vogelkop) region, and has been shaped by the dynamic interactions between the Australian, Pacific, and Eurasian tectonic plates (Harahap, 2012; Handyarso & Padmawidjaja, 2017; Alam & Setiadi, 2019). The basin's structural framework is characterized by major strike-slip and thrust faults, which have influenced its evolution through two main tectonic phases: an extensional phase from the Permian to the Late Oligocene, marked by rifting and subsidence, and a compressional phase from the Late Oligocene to the present, associated with uplift and the formation of structural traps, especially during the Miocene–Pliocene due to the activity of the Lengguru Fold and Thrust Belt (Sapiie et al., 2012; Haris et al., 2017).

The stratigraphy of the Bintuni Basin reflects a prolonged depositional history, beginning with the Kemum Formation (Silurian–Devonian), which forms the metamorphic basement complex (Harahap, 2012) (Figure 1). This unit comprises dark slate, phyllite, metamorphic greywacke, quartzite, and conglomerate, interpreted as marine turbiditic deposits associated with a pre-Tethys rift system. Intruded by Devonian granites and affected by Hercynian orogeny during the Carboniferous–Permian, the Kemum Formation represents the basin's pre-rift tectonic phase (Nuarihidayah et al., 2022; Lelono et al., 2023).

Overlying the Kemum Formation is the Tipuma Formation (Triassic–Early Jurassic), a siliciclastic succession deposited in fluvial-deltaic environments. Composed of quartz-rich sandstones and carbonate-rich shales, this formation marks a transition to non-marine sedimentation following Permian–Triassic tectonic uplift and erosion. While the Tipuma Formation itself is primarily non-marine, its deposition preceded the Middle Jurassic shift to marine conditions in the region, which became pronounced in the overlying Lower Kembelangan Formation (Middle–Late Jurassic) (Nopiyanti et al., 2020; Nuarihidayah et al., 2022).

The transition to marine sedimentation accelerated during the Late Jurassic–Cretaceous, with deep-marine shales (e.g., Jass Formation) developing as regional caprocks (Nuarihidayah et al., 2022; Utomo et al., 2022). This stratigraphic progression-from metamorphic basement (Kemum Fm.) to fluvial clastics (Tipuma Fm.) and later marine deposits-highlights the basin's evolution through extensional rifting, subsidence, and subsequent compressional phases linked to the Lengguru Fold Belt (Sapiie et al., 2012).

During the Permian to Jurassic extensive carbonate platform development occurred, represented by the Ainim, Kembelangan, and Kopai Formations, which contain significant source and reservoir rocks (Sapiie et al., 2012). The basin was later influenced by Cretaceous to Paleogene tectonism, leading to subsidence and the deposition of deep marine sediments (Haris et al., 2017; Ustiawan et al., 2019). Subsequent Neogene compressional tectonics resulted in structural deformation, including folding and faulting, which played a crucial role in hydrocarbon trap formation (Winardi et al., 2014; Edmundo et al., 2021; Li et al., 2022).

The depositional environments in the basin range from fluvio-deltaic to carbonate platform settings, resulting in diverse reservoir and source rock facies. Structural traps, primarily related to folding and faulting from the Lengguru Belt, play a crucial role in hydrocarbon accumulation, while overlying shales and carbonates provide effective seals (Winardi et al., 2014; Edmundo et al., 2021). The combination of rich source rocks, excellent carbonate reservoirs, and well-developed traps and seals has made the Bintuni Basin one of Indonesia’s most important oil and gas provinces, with ongoing exploration and production activities targeting its prolific petroleum systems.

Materials and Methods

This study conducts a comprehensive geochemical evaluation of source rocks in the 'Idea' Field, Bintuni Basin, West Papua, using secondary data from PT Petroenergy Wiriagar KSO Pertamina EP Wiriagar (Figure 2). A total of 10 cutting samples and 36 outcrop samples were systematically collected and analyzed to evaluate their hydrocarbon generation potential. The sampling strategy was designed to ensure a representative distribution across different stratigraphic intervals and lithological units, including claystone, shale, and coal, thereby capturing the variability in organic richness, kerogen type, and thermal maturity (Hazra et al., 2019).

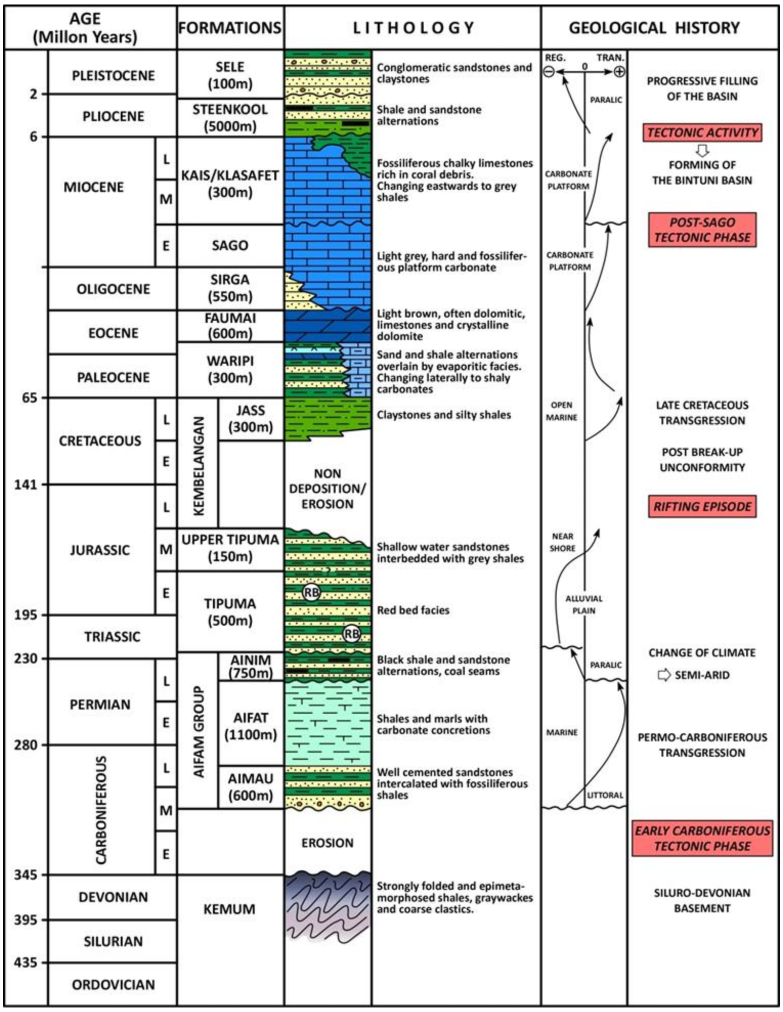

Figure 1. Stratigraphy of Bintuni Basin (Harahap, 2012).

The geochemical analysis commenced with Total Organic Carbon (TOC) determination to quantify the organic matter content within the samples. TOC is a fundamental parameter for evaluating source rock quality as it indicates the concentration of organic material that may generate hydrocarbons under suitable thermal conditions (Table 1). Following TOC analysis, rock-eval pyrolysis was conducted to obtain Hydrogen Index (HI) and T_{max} values. The HI provides insight into the type of organic matter present distinguishing between oil-prone, gas-prone, or inert kerogen, while T_{max}, the temperature at which the maximum release of hydrocarbons occurs during pyrolysis, serves as an indicator of the thermal maturity of the source rock.

Table 1. Geochemical Parameters Describing the Petroleum Potential (Quantity) of an Immature Source Rock (Jamaluddin et al., 2018).

Potential (Quality)	**Organic Matter**		
	TOC (wt.%)	**Rock-Eval Pyrolysis**	
		S_1	S_2
Poor	0 – 0.5	0 – 0.5	0 – 2.5
Fair	0.5 – 1	0.5 – 1	2.5 – 5
Good	1 – 4	1 – 2	5 – 10
Very Good	2 - 4	2 - 4	10 - 20
Excellent	> 4	> 4	> 20

Table 2. Geochemical Parameters Describing Level of Thermal Maturation (Jamaluddin & Sea, 2018)

Stage of thermal maturity	**Maturation**	
	Ro (%)	$T_{max.}$ **(°C)**
Immature	0.2 – 0.6	< 435
Mature		
Early	0.6 – 0.65	435 – 445
Peak	0.65 – 0.9	445 – 450
Late	0.9 – 1.35	450 – 470
Postmature	> 1.35	> 470

To enhance the accuracy of thermal maturity assessments, petrographic analysis including vitrinite reflectance (VR) measurements was performed on selected samples (Table 2). Vitrinite reflectance is a widely accepted method for determining the level of organic matter maturation as it measures the percentage of light reflected from vitrinite particles in polished rock samples. This analysis provided additional confirmation of the thermal evolution of the source rocks complementing the T_{max} data from rock-eval pyrolysis.

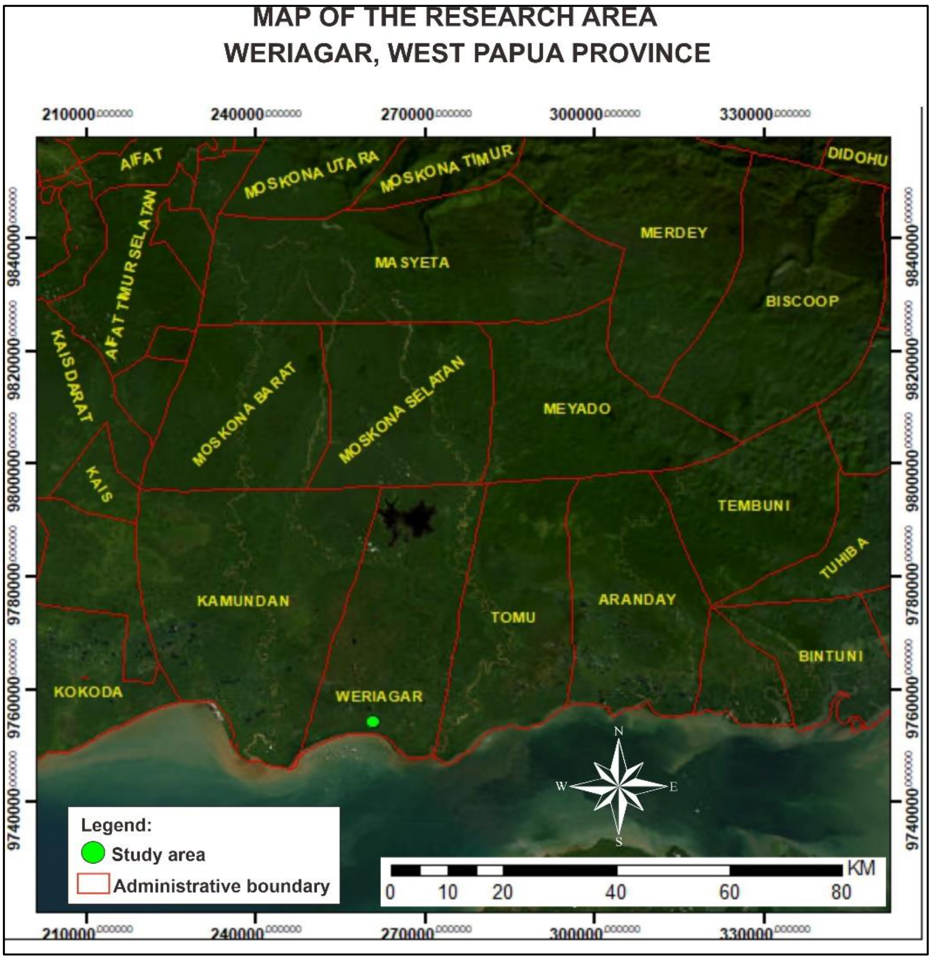

Figure 2. Location map of the research area in the Idea Field, Bintuni Basin, West Papua.

Results and Discussion

Organic matter richness and Petroleum generative potential

The geochemical evaluation of source rocks in the "Idea" Field, Bintuni Basin, West Papua, provides critical insights into the petroleum generation potential of the Ainim and Aifat Formations. The graph presents a relationship between TOC and Potential Yield (mg HC/g Rock), which are key parameters in assessing the quality of source rocks.

The TOC values indicate the richness of organic matter within the source rocks. In this study, coal samples exhibit the highest TOC values, ranging from 1.31 wt.% to 76.84 wt.% signifying excellent organic matter content. Shale samples have lower TOC values varying between 0.14 wt.% and 6.43 wt.%, while claystone shows the lowest TOC values, typically below 1.1 wt.% (Table 3). The presence of high TOC values in coal suggests a significant potential for hydrocarbon generation.

Table 3. Total Organic Carbon (TOC), Rock-Eval Pyrolysis, and Vitrinite Reflectance data for the analyzed samples

Samples	**Lithology**	**TOC (wt.%)**	**Potential Yield (S_1+S_2)**	**$T_{max.}$ (°C)**	**Hydrogen Index (HI)**	**Vitrinite Reflectance (%Ro)**	**Formation**
Cutting Samples	Coal	1.31	1.24	456	85	0.83	Ainim
	Coal	36.88	78.6	450	205	0.86	Ainim
	Coal	76.84	168.99	452	217	0.86	Ainim
	Claystone	1.22	0.41	455	25	0.86	Ainim
	Coal	53.66	161.23	453	294	0.86	Ainim
	Coal	60.19	156.89	452	256	0.86	Ainim
	Coal	65.84	161.03	450	239	0.89	Ainim
	Coal	65.53	145.6	456	218	0.87	Ainim
	Claystone	1.06	0.91	459	75	0.87	Ainim
	Claystone	1.03	0.48	461	38	0.87	Ainim
Outcrop Samples	Shale	0.05	0.07	0	-	-	Ainim
	Shale	0.4	0.15	37	-	-	Ainim
	Shale	1.18	0.58	48	446	-	Ainim
	Shale	1.21	0.39	31	441	0.59	Ainim
	Coal	34.04	132.28	382	440	0.56	Ainim
	Shale	0.83	0.36	42	443		Ainim
	Coal	23.33	101.71	431	437	0.57	Ainim
	Shale	3.76	1.89	48	443	-	Ainim
	Shale	1.5	1.06	66	447	-	Ainim
	Shale	0.14	0.15	78	459	-	Ainim
	Shale	2.82	4.12	123	455	0.6	Aifat
	Shale	0.55	0.23	38	487	1.5	Aifat
	Shale	0.56	0.17	25	476	-	Aifat
	Claystone	0.5	0.08	14	-	-	Ainim
	Coal	55.21	208.08	369	438	0.65	Ainim
	Shale	0.65	0.37	52	449	-	Ainim
	Shale	3.19	3.67	110	448	-	Ainim
	Shale	0.82	0.16	13	-	-	Ainim
	Coal	49.34	155.46	306	441	0.6	Ainim
	Coal	43.02	187.21	422	440	0.71	Ainim
	Shale	0.68	0.22	29	470	0.73	Ainim
	Claystone	0.1	0.03	16	-	-	Ainim
	Coal	54.73	167.87	298	442	-	Ainim
	Coal	7.15	15.54	212	447	-	Ainim
	Claystone	0.07	0.01	-	-	-	Ainim
	Shale	1.66	2.84	159	448	-	Ainim
	Shale	6.43	19.78	288	447	-	Ainim
	Coal	48.73	178.03	352	450	0.73	Ainim
	Coal	22.39	57.5	234	448	0.71	Ainim
	Shale	1.45	2.11	137	449	-	Ainim
	Coal	35.46	107.07	282	449	-	Ainim

Samples	Lithology	TOC (wt.%)	Potential Yield (S_1+S_2)	$T_{max.}$ (°C)	Hydrogen Index (HI)	Vitrinite Reflectance (%Ro)	Formation
	Coal	25.98	69.74	259	449	-	Ainim
	Shale	0.8	0.69	70	447	0.78	Aifat
	Shale	0.47	0.06	12	-	-	Aifat
	Shale	0.53	0.22	33	475	-	Aifat
	Shale	0.69	0.25	30	462	0.93	Aifat

Potential yield (S_1+S_2) provides an estimate of the hydrocarbon generation capacity. The coal samples demonstrate high potential yields with values reaching up to 208.08 mg HC/g rock indicates a strong capability for hydrocarbon generation. Shale and claystone samples exhibit significantly lower potential yields suggesting their role as secondary or poor hydrocarbon sources.

The Ainim Formation generally exhibits better source rock characteristics compared to the Aifat Formation. Many Ainim samples, particularly the cutting samples, fall within the good to excellent categories indicating high TOC values and significant hydrocarbon-generating potential. In contrast, the Aifat Formation samples are mostly classified as poor to moderate source rocks (Figure 3). Their lower TOC values and potential yield suggest that these rocks contain less organic matter and have a reduced capacity for hydrocarbon generation. This may be due to differences in depositional environments, organic matter type or post-depositional alteration processes such as oxidation or thermal degradation.

The positive correlation between TOC and potential yield observed in the graph is consistent with general geochemical principles. Sediment with higher TOC typically generate more hydrocarbons if they contain thermally mature kerogen. The Ainim Formation, especially its cutting samples, exhibits this trend clearly suggesting that these samples may have been buried deeper and preserved under better conditions compared to the outcrop samples, which are more exposed to weathering and oxidation.

The excellent category which represents the highest-quality source rocks is dominated by Ainim Formation samples. These samples exhibit TOC values exceeding 10% and potential yields well above 10 mg HC/g rock suggesting that they are highly enriched in organic matter. Such high values are typically associated with anoxic depositional environments where organic material is well-preserved due to limited oxygen exposure.

On the other hand, the non-source rocks category includes samples with very low TOC (< 0.5%) and minimal potential yield indicating that these rocks lack sufficient organic content for petroleum generation. Many of the Aifat Formation samples along with some Ainim outcrop samples fall into this category. This suggests that either these rocks were deposited in oxygen-rich environments that prevented organic matter preservation or that they have undergone extensive degradation over time.

The variation in source rock quality between the Ainim and Aifat Formations can be attributed to several geological factors including differences in depositional settings, sedimentation rates, and organic matter input. The Ainim Formation likely represents a more favorable environment for organic matter accumulation and preservation, whereas the Aifat Formation may have experienced higher energy conditions that limited organic matter retention.

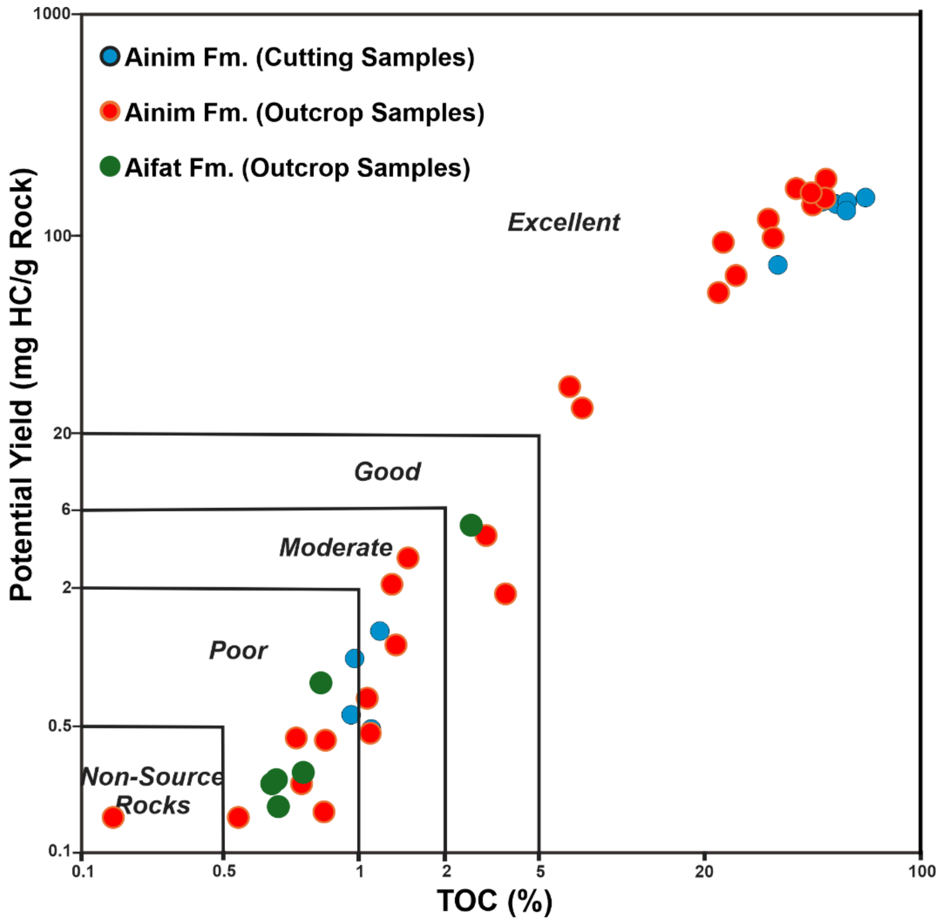

Figure 3. The positive correlation between TOC and potential yield suggests that organic richness significantly influences source rock potential.

Organic matter quality (kerogen type)

Hydrogen Index (HI) values further distinguish the type of organic matter present. Coal samples generally have higher HI values ranging from 85 to 438 mg HC/g TOC, which is indicative of type II and type III kerogens, favoring gas-prone and some oil-prone characteristics. Shale samples exhibit HI values that vary significantly, with lower values suggesting the presence of type III kerogen, which is primarily gas-prone. Hydrogen Index (HI) versus T_{max} plot commonly used in petroleum geochemistry to classify kerogen types and assess the thermal maturity of source rocks (Figure 4). Most of the samples from both the Ainim and Aifat Formations fall within the type III and type II kerogen with HI values ranging predominantly between 50 and 400 mg HC/g TOC. This suggests that most of the organic matter in these formations is gas-prone or mixed oil-and-gas prone. The scarcity of type I kerogen indicates that highly oil-prone source rocks are not dominant in the study area. Additionally, the T_{max} values of most samples range between 435°C and 470°C placing them within the mature oil window with some extending into the postmature zone.

The presence of type III kerogen in the Aifat Formation suggests that the organic matter is primarily of terrestrial origin likely derived from plant material and deposited in deltaic or fluvial environments. This interpretation is supported by the observed lower HI values observed in the Aifat Formation samples which are generally below 200 mg HC/g TOC. These findings indicate that the Aifat Formation is more gas-prone, with limited oil generation potential.

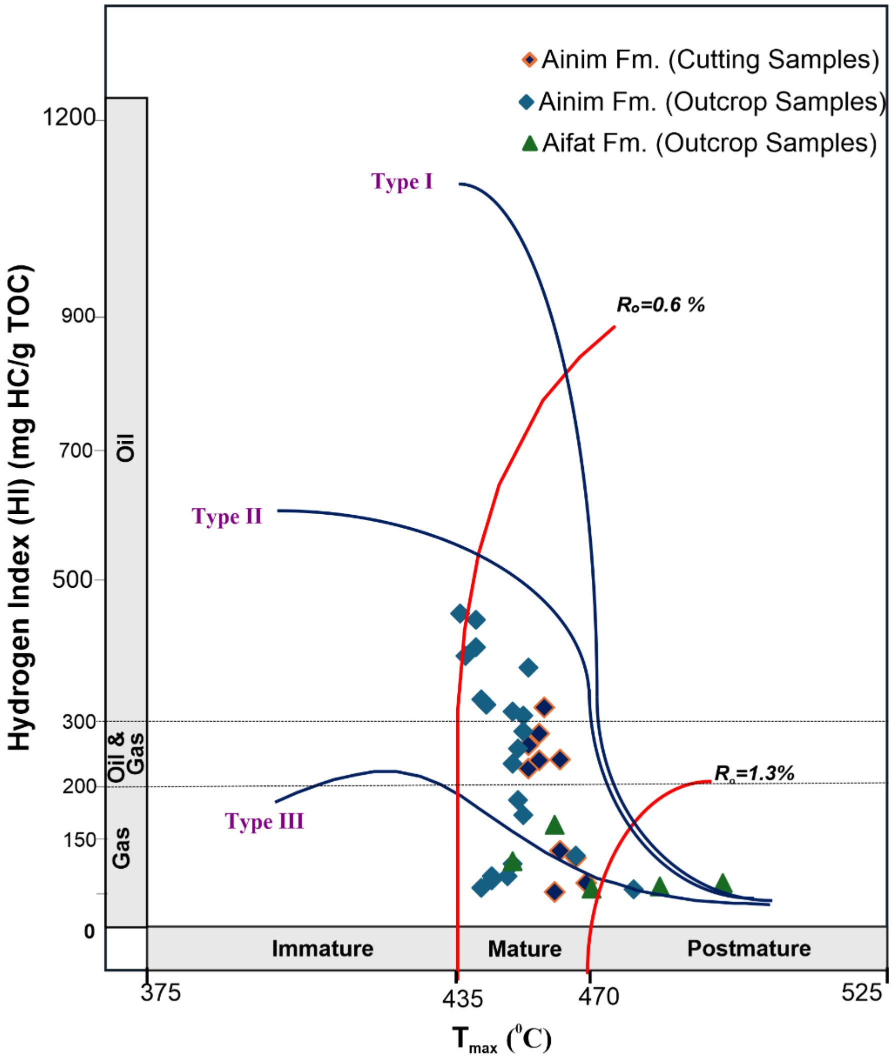

Figure 4. Hydrogen Index (HI) vs. Tmax plot for source rock evaluation of the Ainim and Aifat Formations in the "Idea" Field, Bintuni Basin, West Papua. The diagram classifies kerogen types into type I (oil-prone), type II (oil and gas-prone), and type III (gas-prone).

The Ainim Formation samples, especially the cutting samples exhibit a wider range of HI values with some falling into the type II kerogen category. This suggests that the Ainim Formation contains more hydrogen-rich organic matter potentially sourced from marine or lacustrine environments. The higher HI values in some Ainim samples indicate better oil-generation potential compared to the Aifat Formation. However, the fact that many Ainim samples still fall within the type III range suggests that a significant portion of the organic matter is gas-prone.

The Ainim Formation appears to be the more promising source rock, particularly where type II kerogen is present and thermal maturity is within the oil window. The Aifat Formation, with its dominance of type III kerogen is more likely to be a gas-prone source rock thus rendering it less favorable for liquid hydrocarbon exploration, while indicating potential for gas development. The Ainim Formation exhibits stronger oil potential due to the presence of type II kerogen and suitable thermal maturity, while the dominance of type III kerogen in the Aifat Formation underscores its primary prospect as a gas-prone source.

Thermal maturation of organic matter

The vitrinite reflectance (%Ro) versus T_{max} plot is an essential geochemical tool for assessing the thermal maturity of source rocks (Figure 5). T_{max} is the temperature at which the maximum hydrocarbon generation occurs during pyrolysis. Typically, T_{max} values below 435°C indicate immature source rocks, while values between 435°C and 450°C correspond to the early oil window. T_{max} values in the range of 450°C to 470°C indicate peak maturity, and values above 470°C suggest postmaturity.

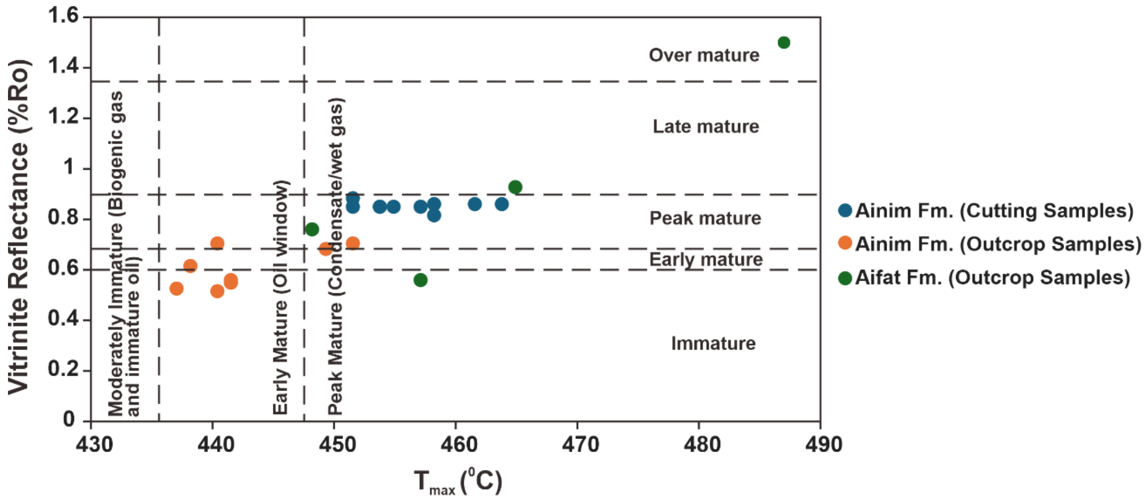

Figure 5. Vitrinite Reflectance (%Ro) vs. T_{max} plot for the Ainim and Aifat Formations in the Idea Field, Bintuni Basin, West Papua.

The coal samples present Ro% values between 0.56% and 0.87%, suggesting a maturity range from early to peak oil generation. Some shale samples show higher Ro% values reaching up to 1.5%, indicating potential dry gas generation. The claystone samples do not provide consistent Ro% data, which suggests they may not be significant contributors to hydrocarbon generation.

The Ainim Formation outcrop samples generally fall within the moderately immature to early mature stages with %Ro values ranging from approximately 0.5% to 0.7% indicates that these samples are at or near the onset of the oil window suggesting limited hydrocarbon generation potential in their current state. However, with continued burial and thermal exposure they could evolve into more effective source rocks.

The Ainim Formation cutting samples exhibit higher thermal maturity predominantly within the peak mature stage with %Ro values clustering between 0.7% and 1.0%. These samples suggest that deeper sections of the Ainim Formation have reached optimal conditions for oil and condensate generation. Their T_{max} values ranging between 450°C and 465°C further confirm that they are within the main oil window and approaching the wet gas generation zone.

The Aifat Formation outcrop samples show a wider range of thermal maturity with some samples falling within the peak mature stage while others extend into the late mature and over mature stages. One sample in particular exhibit a Ro value exceeding 1.3% indicating it has reached a highly mature state where oil generation has ceased, and secondary gas generation may be occurring. This suggests that certain sections of the Aifat Formation have undergone extensive thermal evolution, potentially making them more gas-prone.

The distribution of thermal maturity across the formations suggests that burial history and geothermal gradients have played a significant role in hydrocarbon generation potential (Hazra et al., 2019). The Ainim Formation, especially in deeper subsurface areas as represented by cutting samples, has reached an optimal level of thermal maturity. the organic matter within the formation has been exposed to just the right combination of temperature and time to efficiently generate oil and gas, but not so much that the hydrocarbons are destroyed or converted entirely to gas (Syarifah et al., 2021; Li et el., 2022). In contrast, the Aifat Formation appears to have undergone a more complex burial and heating history. This complexity may be due to variations in sedimentation rates, episodes of uplift or erosion, or differences in geothermal gradients across the formation. As a result, some samples from the Aifat Formation show signs of overmaturity (Utomo et al., 2022; Syarifah et al., 2021).

Conclusion

The evaluation of source rocks in the Bintuni Basin shows that the Ainim Formation has stronger hydrocarbon potential compared to the Aifat Formation. The Ainim Formation contains claystone, shale, and coal with high TOC and a mix of type II and type III kerogen making it suitable for generating both oil and gas. Thermal maturity data from cutting samples show that it is mostly in the peak oil window, which is favorable for oil and condensate generation. However, outcrop samples are only in the early maturity stage and may need further burial to become productive. The Aifat Formation mainly consists of shale with lower TOC and is dominated by type III kerogen, indicating it is more suitable for gas generation. Its thermal maturity varies with some samples being overmature, which limits its potential for oil but supports gas generation. The Ainim Formation, especially in the subsurface areas like the "Idea" Field is the more promising target for oil and gas exploration due to its high organic content and mature thermal state.

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Author Contribution

Conceptualization, D.A and J.; methodology, D.A, W.U.; validation, J., W.U, A.M, and J.W; formal analysis, D.A and B.M.U; investigation, D.A. and J; data curation, D.A, W.U, A.M, and J.W; writing—original draft preparation, D.A and J.; writing—review and editing, W.U, A.M, B.M.U, N.M, A.S and J.W; visualization, D.A and J.; Supervision, W.U, A.M, and J.W. All authors have read and agreed to the published version of the manuscript

Conflict of Interest

The authors declare no conflict of interest.

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