Bulletin of the Geological Society of Malaysia, Volume 78, November 2024, pp. 91 - 102
DOI: https://doi.org/10.7186/bgsm78202408

Oil characteristics and the onset of biodegradation on the eastern flank of the Malay Basin, offshore Peninsular Malaysia

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Abstract: There is a great variety of oil types in the eastern Malay Basin flank area. We observe heavier, hence lower quality, oil at shallow reservoir levels, but mostly light oil in deeper petroleum reservoirs. The oils are characterized by varying amounts of wax, a fairly low sulphur content and, occasionally, significant levels of CO_2. Many of the shallow reservoir oils appear to have been derived from originally light oils that suffered from biodegradation, and are slightly enriched in sulphur, compared to the native oils. Oils in reservoirs with a temperature of less than 75 °C appear to have been biodegraded, whereas hotter reservoirs with temperatures above 90 °C appear to have been unaffected.

Keywords: API gravity, thermal gradient, biodegradation, Malay Basin, oil, petroleum, sulphur, viscosity, CO_2

INTRODUCTION

Biodegradation of crude oil in subsurface petroleum reservoirs is an important alteration process with major economic consequences (Connan, 1984), and have adversely affected the majority of the world's oil reserves, making recovery and refining of the oil more costly (Roadifer, 1987). At temperatures up to about 80 www°C, petroleum in subsurface reservoirs is often biologically degraded over a relatively short time span, by micro-organisms that alter the hydrocarbons and other components into denser 'heavy oils' (Head *et al*., 2003; Jones *et al*., 2008). This temperature threshold for biodegradation may represent the maximum temperature above which micro-organisms could not survive especially in the nutrient-depleted deep Earth.

Oil and gas occurrences and resources in offshore Peninsular Malaysia are located almost entirely in the Malay Basin (Madon *et al*., 1999; Tan, 2009; Figure 1), with only small discoveries made in the Penyu Basin, as summarised by Madon *et al*. (2019). A basinal cross-section in the North Malay basin in Figure 2 shows a relatively simple and large syncline, *ca.* 200 km wide, with gentle compressional anticlines induced by strike-slip tectonism. The biggest fields lie along the axis of the basin centre,

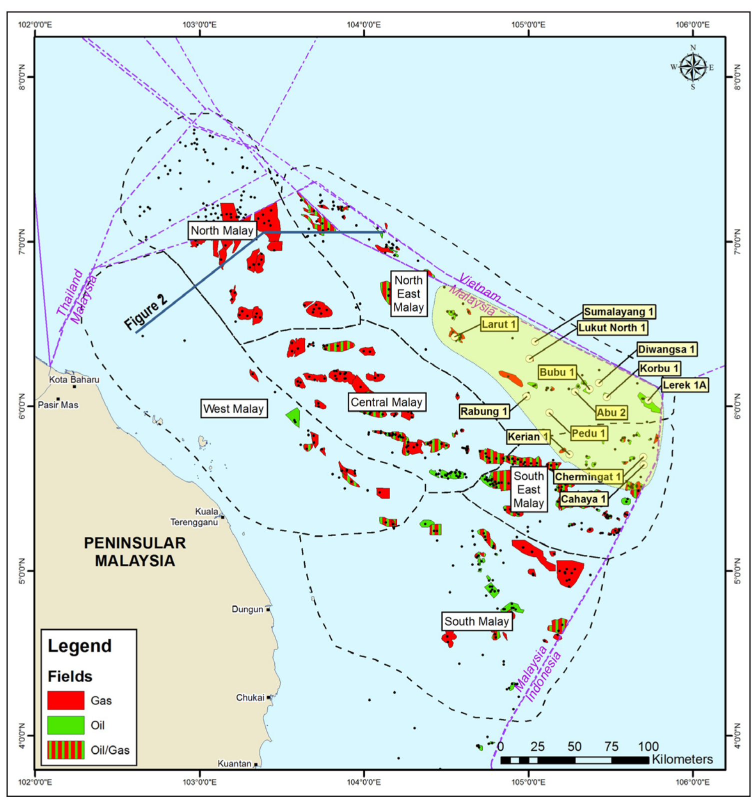

Figure 1: Oil and gas fields/discoveries in the Malay Basin and basin sub-division according to Tan (2009). The highlighted pale yellow zone is the study area with investigated well locations covering NE Malay and SE Malay resource regions, which we termed the "eastern Malay Basin flank" area.

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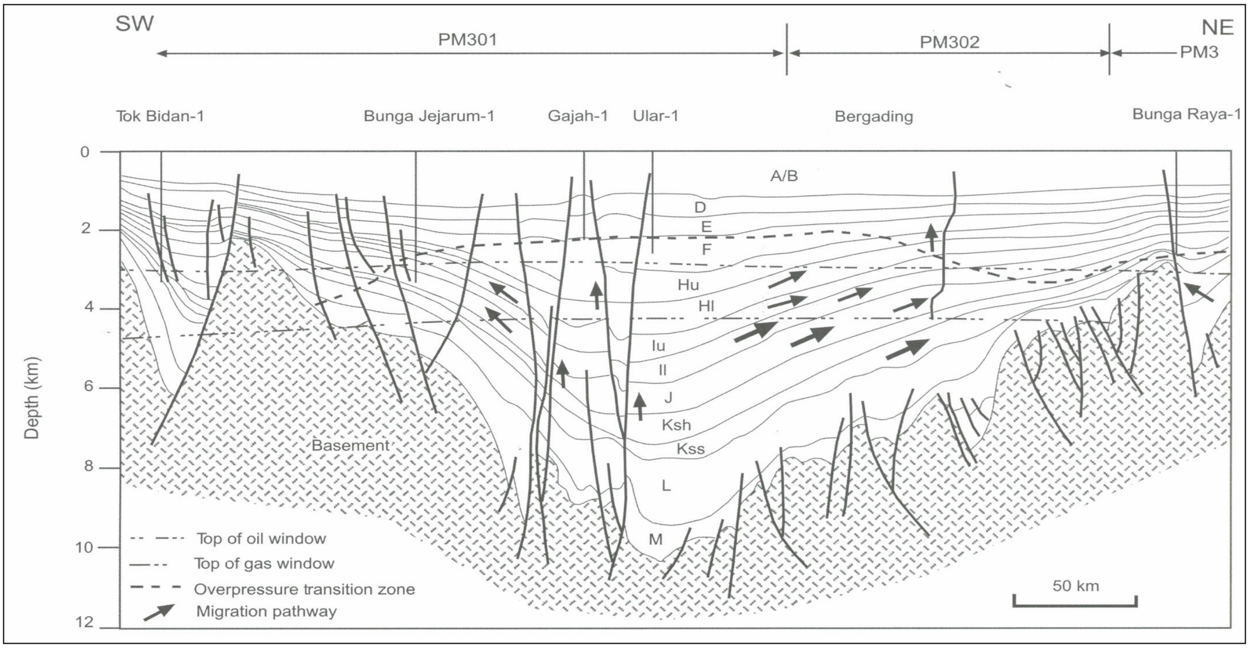


Figure 2: Schematic cross-section of the northern Malay Basin showing the main hydrocarbon migration routes. Hu = upper Group H, Hl = lower Group H, Iu = upper Group I, Il = lower Group I, Ksh = Group K shales, Kss = Group K sandstones (from Tan, 2009 and modified after Madon *et al*., 2006). See Figure 1 for line location. It is noted that a similar petroleum system is observed in the southern Malay Basin with the eastern edge located in the study area.

where the effects of strike-slip movements and structural development were most pronounced. The present study area is on the eastern basin flank (Figure 1). This flank area hosts a number of small to medium size discoveries, of which some remain undeveloped, and are characterized by small strike-slip induced pop-up structures in which stacked fluvial channel reservoirs were discovered (e.g., Korbu Field in Figure 1).

In general, most workers have identified two main petroleum systems in the Malay Basin, namely an Oligocene-Lower Miocene system with a lacustrine signature, and a Miocene system with a coaly signature (Creaney & Hussein, 1992; Bishop, 2002; Madon *et al*., 2006; Madon, 2019) (Figure 3). In addition, there may be smaller, locally restricted kitchen areas in half-grabens on the eastern basin flank, as well as on the western flank of the basin.

The hydrocarbon source, expulsion history and migration pathways in the Malay Basin are complex. In this paper, we investigate the oil characteristics and the effects of biodegradation may have on oil reservoirs and, consequently, the petroleum quality in some oil fields in the eastern Malay Basin. It is noted that it is rare to find relevant data in the public domain and a detailed discussion on hydrocarbon biodegradation in the Malay Basin is lacking. We hope the findings presented in this paper will help to reduce the knowledge gap for future research on the topic of oil biodegradation that characterised some shallow heavier oils in the study area.

PETROLEUM SYSTEMS

According to the study by Madon *et al.* (2006) in the northern and central Malay Basin (Figure 1), oil geochemistry reveals three main types of source rocks for the oils: lower coastal plain, fluvial deltaic and lacustrine (Figure 3). Vitrinite reflectance data and basin modelling studies indicate that hydrocarbons were generated in the basin from source rocks within two main stratigraphic intervals (Figure 3): Group H and Group I, (Lower to Middle Miocene), which are presently in the peak oil and gas generation stages, respectively. The mentioned source intervals are, however, immature in most areas of the south-eastern basin margin. Most of the basin centre oils and condensates are lower coastal plain oils, and have migrated upwards from the mature source levels beneath. Vertical migration of hydrocarbons, assisted by deep-seated faults, is the dominant process in the basin centre. The enormous volume of thermogenic gas generated at the basin centre appears to have largely flushed out much of the younger Group H oil that may have filled the Groups D and E reservoirs initially (Madon *et al*., 1999; 2006). Some accumulations on the eastern flank of the basin (e.g., Bunga Raya, Bunga Pakma, etc.) were sourced directly from lacustrine source rocks in the adjacent half-graben kitchens, whereas marine influence has been found in oils originating from a central position in the basin.

It is noted that heavy to intermediate, and variably waxy oils are found in some K-10 reservoirs (North Lukut:

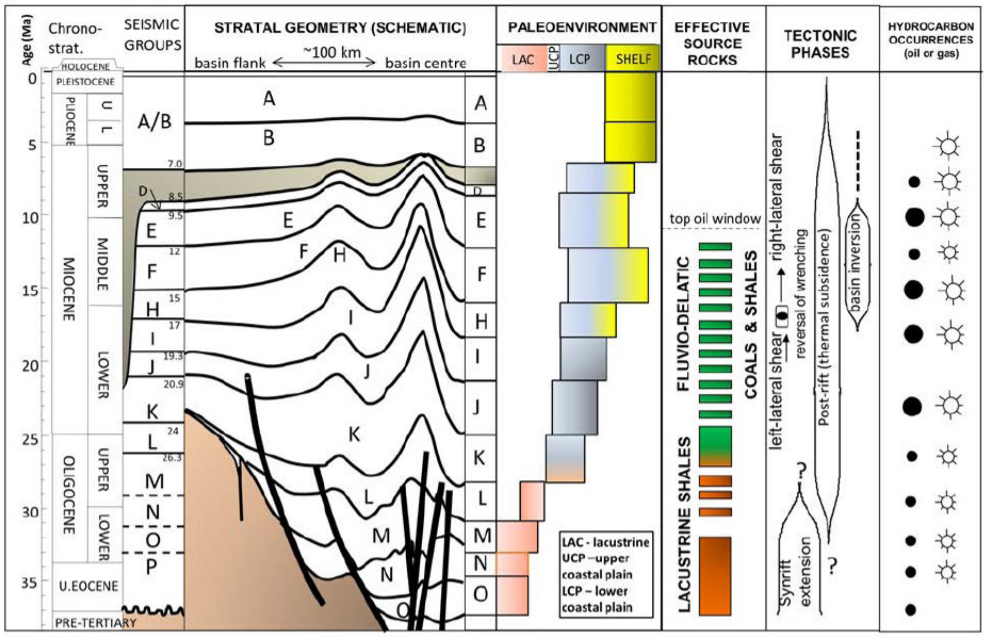


Figure 3: Petroleum systems of the Malay Basin, illustrated as petroleum system event charts with paleo-environment, effective source rocks, structuration and HC occurrences at various stratigraphic intervals (after Madon *et al*., 2006 and Madon, 2021).

API 21.9°, 8.21 % wax; Cahaya: API 24.0°, 0.22 % wax). Group K shales contain sequences of lacustrine source rocks, which may have charged the adjacent reservoirs. Keeping this exception in mind, there is good evidence that light oils are mostly preserved in deeper reservoirs, whilst heavy, low API oils dominate the shallow reservoirs.

Accordingly, oil is more likely to have been re-migrated and trapped along the faulted basin margins in the eastern and western flanks, away from the basin-centre gas kitchen (Figure 2). Furthermore, the study by Madon *et al*. (2006) suggests that oil reservoirs in the study area (Figures 1-3), are likely to have been charged from the basin centre kitchen area in at least two generative pulses, resulting in a mixture of more recent and older hydrocarbons.

WELL DATABASE AND OIL CHARACTERISTICS (SUMMARY IN TABLE 3)

The present study is based on oil data from the following thirteen eastern Malay Basin flank accumulations, in alphabetical order: Abu Kecil, Bubu, Cahaya, Chermingat, Diwangsa, Kerian, Korbu, Larut, Lerek, North Lukut, Pedu, Rabung and Sumalayang (Figure 1). The relevant oil data and parameters were extracted from the original operator's final well reports and studies, without applying any corrections. The observed oil parameters and characteristics are summarised below.

Viscosity

Viscosity is a measure of a fluid's resistance to flow, and describes the internal friction of a moving fluid, which would affect oil recovery from subsurface reservoirs. Unfortunately, there are only a few viscosity measurements available in the study area. The very limited data, however, indicate that a reasonable correlation exists between oil viscosity and oil gravity (Figure 4). The observed high viscosity in the interpreted biodegraded oils may result in production challenges and poor oil recovery (see chapter "GC-MS and Biodegradation") below.

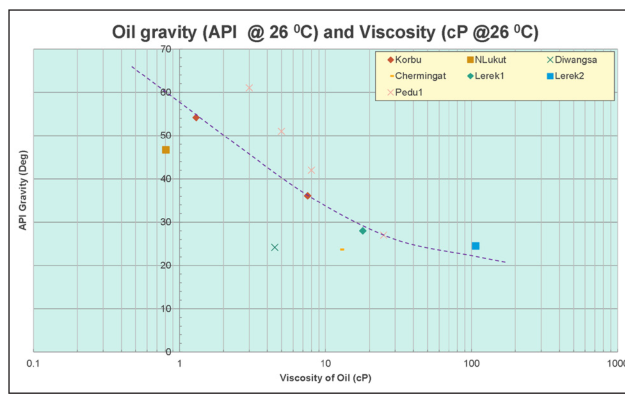


Figure 4: Oil gravity and viscosity relationship. A moderate correlation between oil viscosity and oil gravity can be observed. Low gravity oil with high viscosity would pose a production challenge.

Sulphur

Although the studied crude oils are generally low in sulphur, we observe a marked enrichment of sulphur in the biodegraded oil samples, compared to the light non-

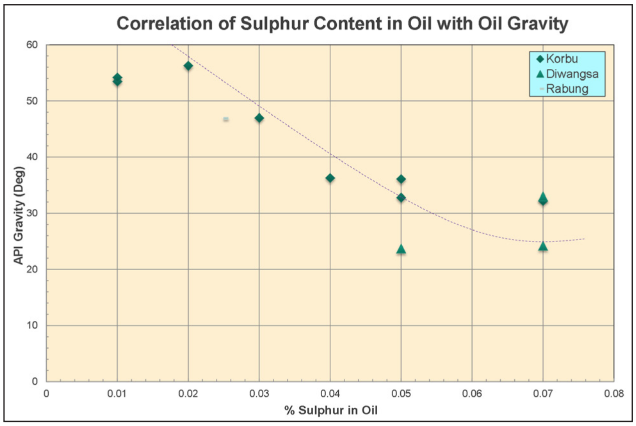


Figure 5: Oil gravity and sulphur correlation. A moderate correlation between sulphur content and oil gravity can be observed with low gravity oil samples exhibiting a marked enrichment in sulphur content.

biodegraded oils (Figure 5 and Table 3: Korbu oils show a 0.07 % sulphur content in biodegraded 32.2°Api crude, but only 0.01 % sulphur in non-biodegraded 53.5°Api oil; Diwangsa moderately biodegraded 24.2°Api crude contains 0.07 % sulphur, but only 0.05 % in 31° Api crude; the non-biodegraded Rabung 46.89°Api crude contains only 0.025 % sulphur). The higher sulphur content in the biodegraded crude would also imply future production challenges such as pipe selection and appropriate corrosive coating. The sulphur in biodegraded oils may have been enriched by oxidation of organic matter in the samples due to bacterial activity. For further study, it is recommended that sulphur isotopic investigation to be conducted to identify such bacterial action.

Pour point and wax content

Wax deposition is one of the chronic problems in the petroleum industry, as the removal of wax from the system could add to the incremental cost of production. Various crude oils of the world contain up to 51 % wax (Hunt, 1979). Paraffin waxes consist of straight-chain saturated hydrocarbons with carbon atoms ranging from C_{18} to C_{36}. Waxes may precipitate as the temperature decreases and a solid phase may arise due to their low solubility. For instance, paraffinic waxes can precipitate out of the oils when temperature decreases during oil production, transportation through pipelines, and oil storage (Rehan *et al*., 2016).

In this study, the wax content of oils is reported to be between 1 % and 9 %, but most data points show relatively low wax contents of between 2 % and 3 %. The sources of higher molecular weight waxes in the studied oil samples have not yet been proven and are under investigation. Possibly, the wax content could be related to liptinitic input, particularly from mangrove remnants in the source rock. It is noted that there is no obvious correlation between the wax content of the oils and the depth of the reservoirs and biodegradation. (Figure 6: N´Lukut oils, wax % 8.2-8.9, slightly? to moderately biodegrades crude; Korbu oils, wax % 1-3.5, both biodegraded and non-biodegraded crudes; Rabong oils, wax % 1.8, non-biodegraded; Diwangsa oils, wax % 2.5-4.7, pristine to mildly biodegraded crudes).

Further values on wax contents and other oil parameters are also shown in Table 3. There is also no significant correlation between pour point and oil gravity (Figure 7). Arguably, the pour point may be influenced by other chemical components such as asphaltenes, which appear to be more resistant to the biodegradation process, and hence are likely to be preserved in both virgin light oils and biodegraded heavy oils.

CO_2

The CO_2 content in the oils studied varies between 1 and 10 mol%, but the high values appear to be confined to the North Lukut Field area (Figure 8). In the Malay Basin, the source of the CO_2 is relatively unknown, albeit gases dominated by CO_2 are predominantly sourced from the basement (Waples & Ramly, 1996). The study by Madon *et al.* (2006) suggest high CO_2 concentrations (>50 mol%) are typical of reservoirs in Groups I and older and are mainly derived from inorganic sources. Low CO_2 concentrations

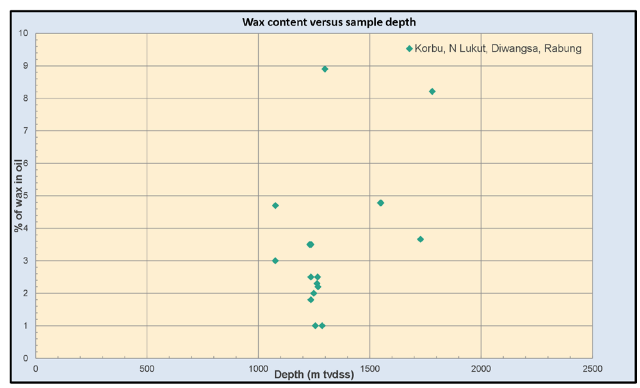


Figure 6: Wax content and depth relationship in Malay Basin eastern flank wells. There is no obvious correlation between the wax content of the oils and reservoirs. The highest amount of wax (> 8 %) is both found in Groups I and J reservoirs in North Lukut.

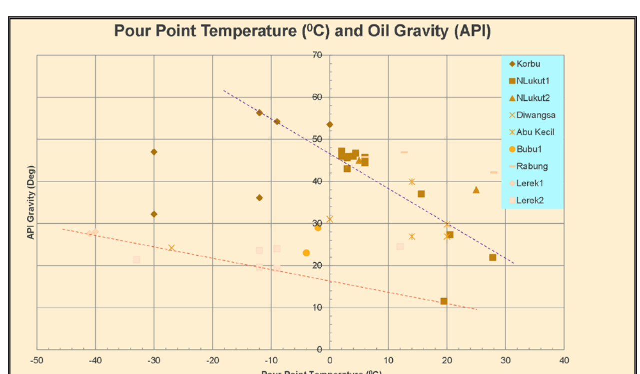


Figure 7: Oil gravity and pour point relationship. No correlation could be established.

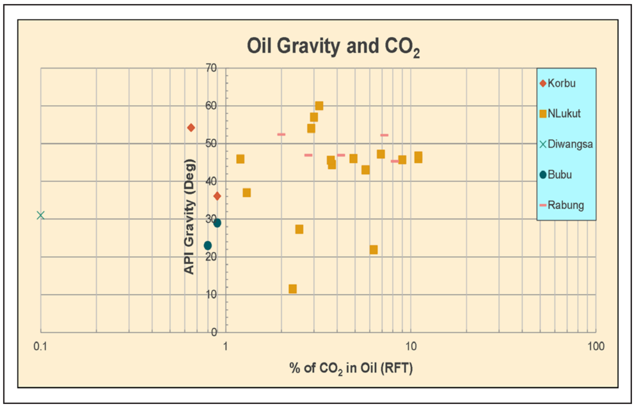


Figure 8: Oil gravity and CO_2 relationship, data from Repeat Formation Test (RFT). We observe a relatively high CO_2 constituent in oils from North Lukut and Rabung. The source of the CO_2 is however remains unknown.

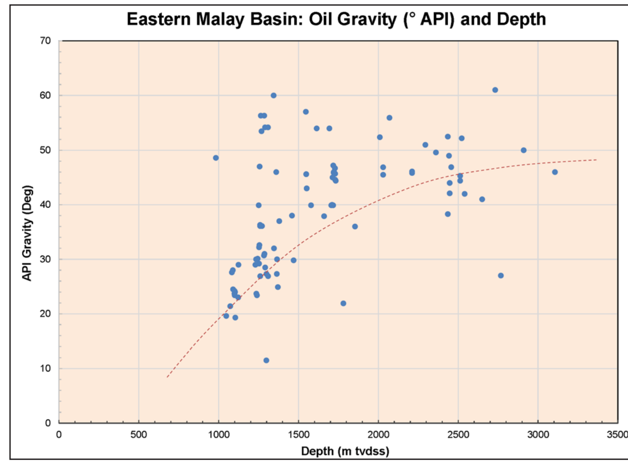


Figure 9: Oil gravity and depth relationship in East Malay Basin oils, with a poor correlation. At depth shallower than 1500 m, the low to intermediate API grade oils (120 to 300) dominate the shallow reservoir sections as a likely consequence of microbial biodegradation. At a depth greater than 2000 m, most oils have a gravity above 40° API.

(<6 mol%) are more typical of the reservoirs in Groups D and E, and are derived from organic sources by thermal degradation of kerogen. The inorganic CO_2 distribution appears to be governed by proximity to deep-seated faults that act as conduits for fluid migration.

A study by Anuar & Hoesni (2007) indicated that the opinion that CO_2 percentages increase with increasing depth may be an over simplification and is not supported by the available data. Plots of CO_2 percentages against depth for the Malay Basin wells illustrate that CO_2 occurrences may increase or decrease with depth. Furthermore, as carbonate rocks have been reported to occur in the basement; one might speculate that these carbonates contributed to the high CO_2, having reached the required thermal breakdown temperature of 320 °C (Anuar *et al*., 2006), at depth of greater than 7 km.

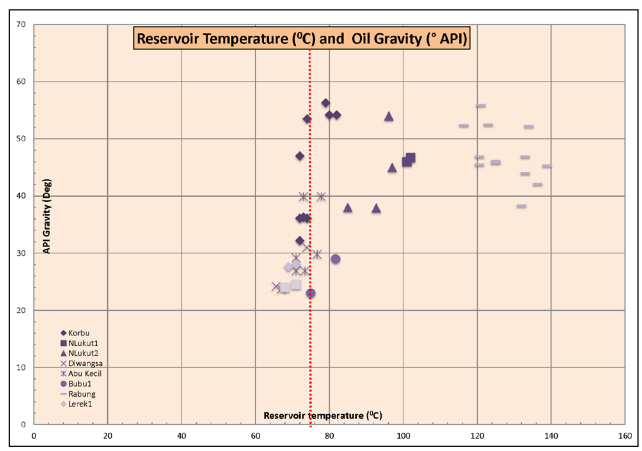


Figure 10: Reservoir temperature and oil gravity relationship (relatively poor) in East Malay Basin wells. The low to intermediate API grade oils (220 to 300) are found mainly in the shallower section with reservoir temperature below 75 °C.

Asphaltenes and NSO´s

Asphaltenes form together with waxes and resins in the residuum that remains after distillation. Asphaltenes are dark brown to black amorphous solids, and are molecular substances that are found in crude oil, along with resins and other organic materials consisting of aromatic and naphthenic ring compounds (Hunt, 1979). The asphaltene fraction of crude is defined as the organic part of the oil that is not soluble in straight-chain solvents such as pentane or heptane (Schlumberger, 2020). Asphaltene percentages in the studied samples are in the order of 0.5 % to 3.2 %. Distillation of Korbu I-110 reservoir oil produced significant amounts of residue, whilst the deeper I-135 reservoir oil achieved a very high liquid recovery after distillation, with hardly any residue. The origin of the high content of asphaltenes, however, is not well understood and needs further investigation.

We see poor correlations between API gravity and reservoir depth (Figure 9), and between API gravity and temperature (Figure 10). The correlations between several important oil parameters are shown Table 1 and also Table 3.

BIODEGRADATION AND GC, GC-MS

Biodegradation is a process in which organic molecules are broken down by microorganisms. Sediments, soils and water contain a wide variety of microorganisms that utilize hydrocarbons as the sole source of energy for their metabolism. Paraffins, naphthenes, and aromatics, including gases, liquids and solids, are all susceptible to microbial decomposition. There are more than 30 genera and 100 species of various bacteria, fungi and yeast that attack one or more kinds of hydrocarbons (Hunt, 1979). The degradation of petroleum fractions in reservoirs is primarily controlled by reservoir temperature, the type of chemical compounds being biodegraded, and the relationships between the oil-water contact area and oil volume (Larter *et al*., 2006).

Table 1: Correlation between crude oil parameters in the area of studies.

Correlation	Strength	Figure	Comments
Bottomhole temperature and depth	strong	11	Linear relation
Oil gravity and depth	poor	9	
Oil gravity and reservoir temperature	poor	10	2-3 clusters
Oil gravity and viscosity	moderate	4	Limited data base
Oil gravity and sulphur content	moderate	5	Limited data base
Oil gravity and pour-point temperature	none	7	
Wax content and depth	none	6	
Oil gravity and CO_2	none	8	Rabung and North Lukut fields contain CO_2

Biodegradation in south-eastern Malay Basin oils is shown by the examples of Lerek-1 and Lerek-2 in (see later Figure 14). The Gas-Chromatography (GC) and Gas Chromatography-Mass Spectrometry (GC-MS) traces indicate a moderately to strongly biodegraded oil in Lerek-1 and a very substantially biodegraded oil in Lerek-2. GC-MS is a tool that provides an exact and quick analysis that helps in the determination of the rate of biodegradation (Singh *et al*., 2015). GC-MS is used to identify all the composition of petroleum hydrocarbons.

These methods are highly selective, and compounds can be authenticated by analysing their unique mass spectra and retention times. Hence, GC-MS traces can prove the presence of target components and can be utilized for the separation of complex and simple hydrocarbons into groups.

Bacteria tend to preferentially digest the shorter alkane molecules of the gasoline fraction first. In the process, hydrocarbon chains are fragmented and the individual segments are oxidized into decomposed products such as H_2O, CO_2, biogenic CH_4, SO_2 and others (e.g., Head *et al*., 2003). On Earth, the temperature window for biodegradation lies between -30° and 100 °C. Below -30°C, the rates of biochemical processes are so slow that their effects may be negligible. Above 100 °C, bacteria and fungi do not survive. Biodegradation works fast such that hydrocarbons can be partly decomposed and oxidized over a span of a couple of years (e.g., Medina-Bellver *et al*., 2005; Das & Chandran, 2010).

As the biodegradation progresses in reservoirs, the size of the remaining molecules and, oil gravity increases over time resulting in the concentration of heavier components. On the eastern flank of the Malay Basin, biodegradation is limited to fairly shallow reservoirs where the temperature gradient is perfectly linear and fairly steep, at 4.26 °C/100 m (Figure 11).

To determine the precise onset of biodegradation in stacked oil pay-zones in the study area, the temperature readings and oil composition in the respective reservoir levels in three fields were examined:

- *Korbu-1*: In well Korbu-1, the onset of significant biodegradation is observed at about 75-85 °C, which corresponds to a well depth of *ca.* 1286 m. This means that reservoirs cooler than 75 °C may have been strongly affected by biodegradation (Figure 12). Oil samples from the deeper Group I reservoirs are mostly non-biodegraded, with API ranging from 47° to 56° at reservoir temperatures greater than 79 °C.
- *North Lukut-1*. North Lukut oils in the I-35 and shallower reservoirs are biodegraded, I-10 and deeper reservoirs including J-70/80 are not biodegraded (Figure 13). The boundary between biodegraded and non-bio degraded oils lies between 80 °C and 91 °C. The oil in the deep K-10 reservoirs is of low API gravity, and was not subjected to biodegradation, given the high measured reservoir temperature of 105 °C.
- *Lerek (Table 2)*: This field is located on the southeastern flank of the basin, where the J-70/80 oil-bearing reservoir sands overlie weathered basement rock in a fault-bounded monocline at a depth of +/- 1100 m. The oil gravity is intermediate to heavy while the oil pressure gradient in is 0.448 psi/ft. Sulphur content is surprisingly low. It is pertinent to note that 'heavy oil' is often applied inconsistently to crude oil that has

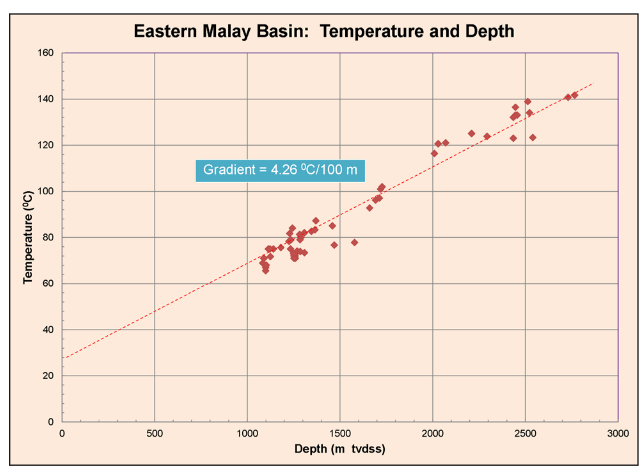
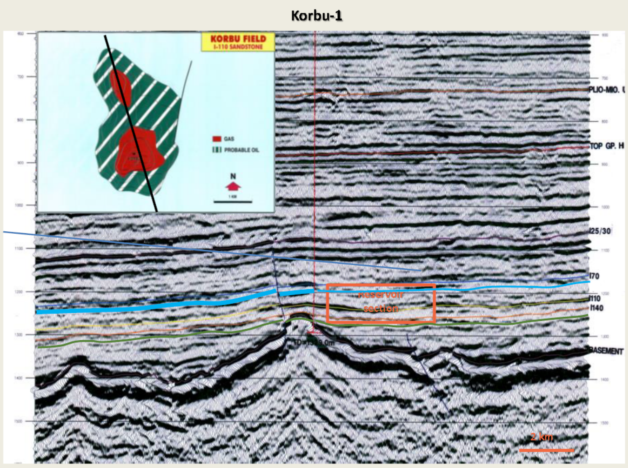


Figure 11: Temperature and depth relationship in East Malay Basin wells. The BHT´s are mainly from logs and uncorrected. The resulting temperature gradient is linear and steep with a calculated 4.26 °C/100 m. The minor deviation of data points from the straight line could point to different geothermal settings possibly due to lithology changes. There is also a possibility that different densities of the strata cause local variations of the heat flow.



Depth (m, bdf)	Temp. (deg C)	Stratum	Gravity (deg API)	Comments
1252.5	72		32.2	Some bio-degradation
1259	72	I-110	36.1	
1271.2	74		36.1	
1285.3	79		56.3	No bio-degradation
1290	80	I-135	54.2	
1308.4	82	J-10	54.2	

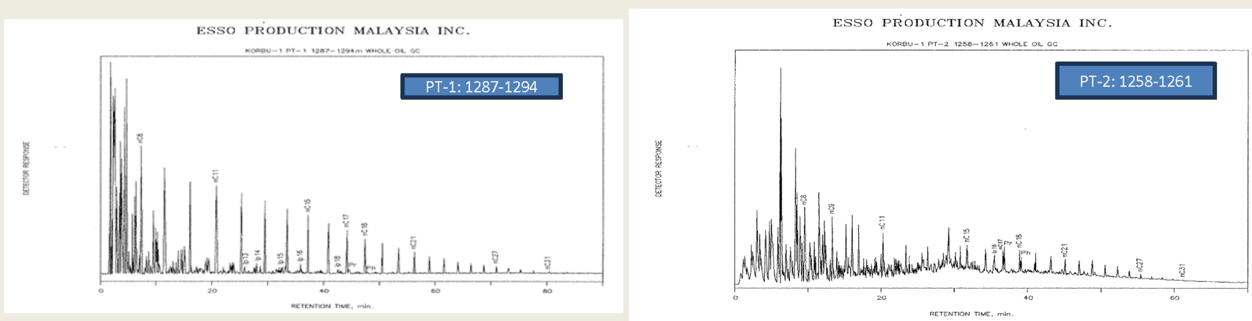
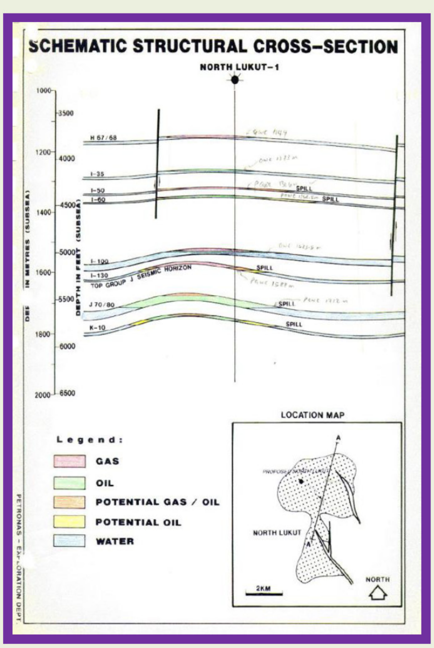
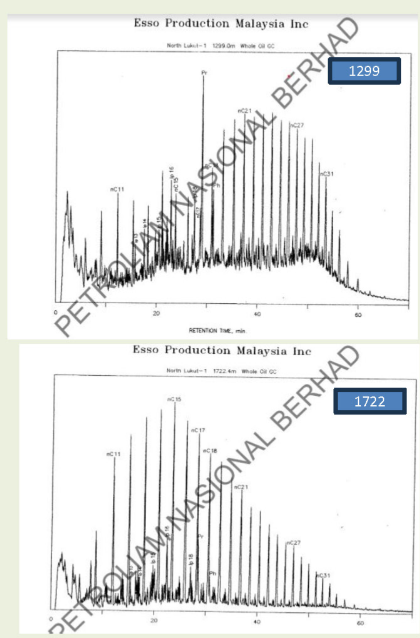


Figure 12: A NNW – SSE seismic section over the Korbu Field, a drape feature over a basement high with the main reservoir residing (between blue and orange lines) in Group I-110 sand. Reservoirs shallower than 1272 m contain moderately biodegraded oil.





Depth (m bdf)	Temp (deg C) M= measured E= estimated	Stratum	Gravity (deg API)	Comment
1299	80 (E)	I-35	28.8	Bio-degraded, high NSO
1548	91 (E)	I-100	45.6	Non Bio-degraded
1720	101 (M)	J 70/80	46	
1722	101 (E)	J 70/80	46	
1728	102 (M)	J 70/80	47	
1780.9	105 (E)	K 10	21.9	Different oil source

Figure 13: Summary of the North Lukut Field, located on a gentle drape structure. Crudes are located in Groups I, J, and K reservoirs. Biodegraded oils are seen in the I-35 reservoir only, whilst deeper pay units have escaped biodegradation.

Table 2: Parameter comparison of Lerek oil.

Parameter	Lerek-1	Lerek-2	Lerek-3	Lerek-4
Temperature °C	68.9-71	68-71	No data	59-69
Gravity °API	28	19.6 -24.5	No data	No data
Pourpoint °C	<- 40	-9 to -33	No data	No data
Kinematic viscosity @ 20 °C	23.15	189.86	No data	No data
Sulphur content (%)	<0.05	< 0.05	No data	No data
Wax (%)	2.31	1.8 - 5.21	No data	No data
Asphalthenes (%)	<0.5	<0.5	No data	No data
Crude colour	Dark brown-black	No data	No data	Dark brown

an API gravity of less than 20° in oil basins. Other definitions classify heavy oil as having an API gravity of less than 25° API and usually, but not always, a sulphur content higher than 2% by weight (Speight, 2015). The geological setting suggests that oil had migrated from the basin centre up the flank into the Lerek structure (Figure 14). As shown in Lerek-4 (see Table 2), temperatures in the reservoir section are below the critical 75 °C temperature boundary. It has long been observed that fresh, oxygenated waters in contact with reservoir oil can cause extensive aerobic biodegradation. More recently, it has been recognized that anaerobic sulfate-reducing and fermenting bacteria also can degrade petroleum (Wenger *et al*., 2002).

DISCUSSION

The Korbu-1 well, as well as other wells in the study area, reveal a boundary between reservoirs containing strongly biodegraded oils and with reservoirs of slightly biodegraded oils beneath. The deeper oil/aquifer cells are significantly hotter and may represent a more static, and perhaps more isolated fluid fill environment that could retain its original temperature regime. It would be useful, from both economic as well as scientific standpoints, to have a better understanding of these aquifers. The challenge is to be able to map the reservoir and seal packages and the respective aquifers with confidence. This may be achievable with improvement with the latest seismic acquisition technologies and/or processing algorithms.

With regards to the inter-relationships between the various oil parameters, in general, there appears to be a correlation between API gravity, viscosity, reservoir depth and reservoir temperature (except in shallow sections). There is, however, one type of low-gravity oil occurring in the older Groups J, K, and M 'hot' reservoirs, which cannot be explained by biodegradation and may represent early expulsion of oil in some instances. A reasonable correlation between sulphur content, and oil gravity can be observed in low gravity oil samples which exhibit a marked enrichment in sulphur, from sulphur-containing molecules that survived the biological breakdown. On the other hand, there is a weak correlation between API gravity and pour point, which is controlled by biodegradation-resistant components such as wax.

It may be useful to compare our data with oil samples from other oil-producing areas, such as offshore Brunei where, according to Sandal (1996), two main oil crude types occurred as a function of depth (Figure 15):

1. Normal, waxy low sulphur crude, decreasing in API gravity from 40° at 3000 m to 35° at 1500 m.
2. Heavy, non-waxy, bacterially transformed crude with slightly higher sulphur content (as observed in this study). The API gravity decreases from 25° at 1500 m to 17° at 150 m.

It is noted that the depth dependence of oil gravity is related to bacterial transformation, and the lower boundary of the transformation zone lies between 900 m and 1400 m (Figure 15). This depth interval is obviously related to the variable temperature gradients in offshore Brunei, which range from 2.0 to greater than 4.0 °C/100m. Nevertheless, the observation from Brunei data concurs well with the eastern Malay Basin data presented in this study.

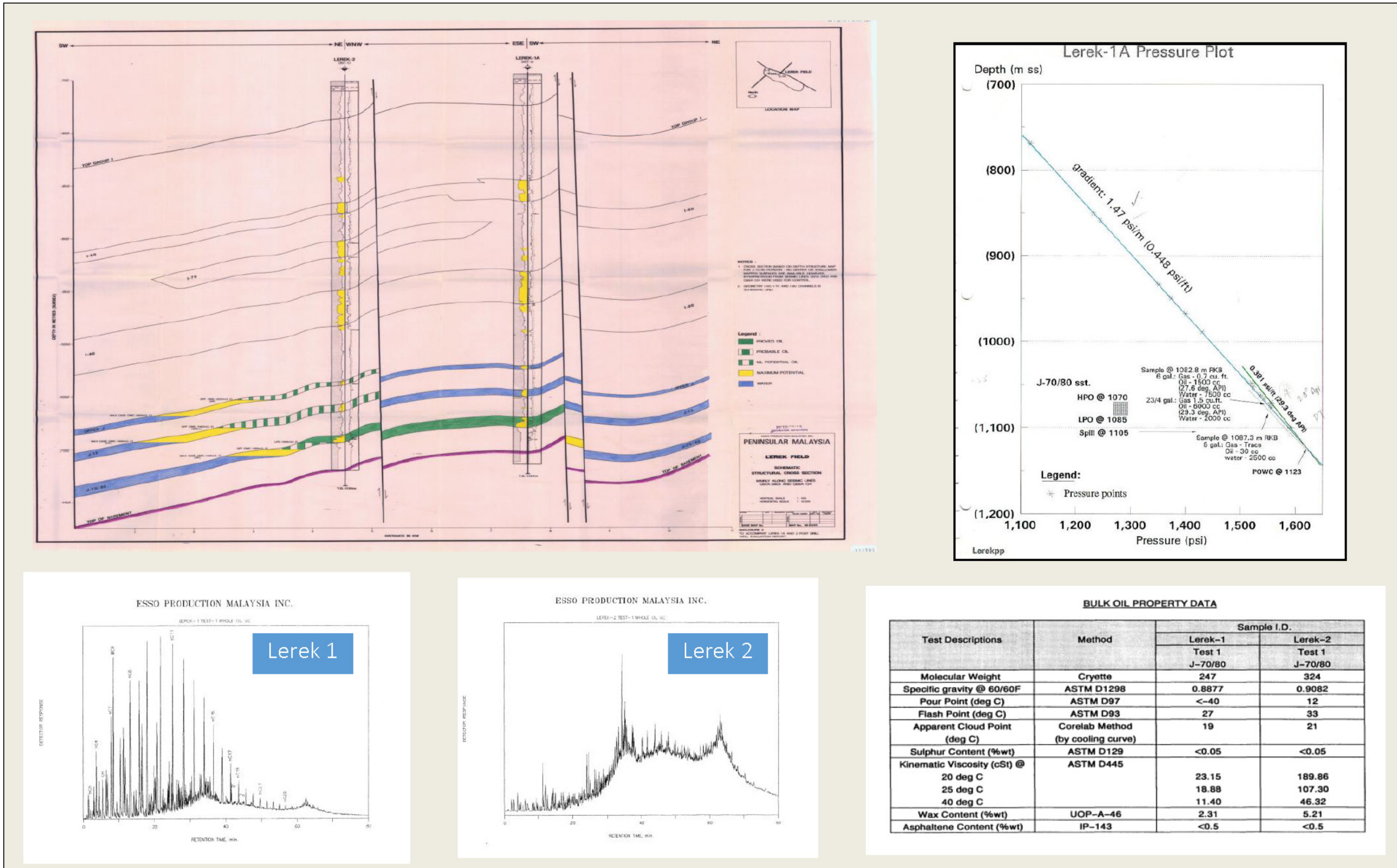
CONCLUDING REMARKS

There is a great variety of oils in the eastern Malay Basin (and in the Malay Basin overall; Creaney & Hussein, 1992), where heavier oil, hence lower quality is observed at shallow levels, and light oil that occurs mostly in deeper reservoirs. The studied oils contain various amounts of wax, low sulphur and occasionally CO_2. Major amounts of asphaltenes appear to occur only in a few reservoirs in the Korbu Field. Many of the shallow reservoir oils in the area were derived from originally light oils that had been subjected to biodegradation. The lighter gasoline fraction of the oils has been consumed by microorganisms (Figures 12, 14), resulting in a decrease in alkanes and API gravity, a measure that correlates with their economic value.

Sulphur content, high oil viscosity and waxiness, for example, may have a negative impact on oil production (by reducing well flow rates, and crude value) and refining margins. Oils in reservoirs with temperatures of less than 75 °C appear to be biodegraded, whereas hotter reservoirs with

Table 3: Oil data summary sheet.

WELL	Depth	Test	Level	Temp	Aspect	% wax	Viscosity	Pourp deg C	Flashp deg C	Sulpfur %	CO_2 %	Asphaltenes	Api
							26 deg C cp						
Korbu	1252.5	RFT 5/1		72		3.5		-30		0.07		2.7	32.2
Korbu	1259	PT-2	I-110	72		2	7.54	-12	9	0.05	0.9	1	36.1
Korbu	1271.2	RFT 5/2		74		2				0.05		2.6	36.1
Korbu	1290	PT-1	I-135	80		1	1.3	-9	9	0.01	0.65	2.9	54.2
Korbu	1308.4	RFT 3/2	J 10	82		1		-9		0.01		3.2	54.2
Korbu	1259	RFT 4/1		73		2.5				0.04			36.3
Korbu	1285.3	RFT 3/1		79		2.3		-12		0.02			56.3
Korbu													
Korbu	1256			72		1		-30		0.03			47
Korbu	1263.4					2.3		-12		0.02			56.3
Korbu	1268			74		2.2		0		0.01			53.5
N Lukut	1299	RFT1-1	I-35		drk brown	8.9		20.5			2.5		27.3
N Lukut	1298	RFT1-1	I-35					19.5			2.3		11.5
N Lukut	1551	RFT-17	I-100			4.78		3			5.7		43
N Lukut	1728	RFT-11	J-70/80			3.66	0.807						46.7
N Lukut	1854												36
N Lukut	1780.9	RFT 16.1	K-10		waxy	8.21		27.8			6.3		21.9
Diwangsa	1098.8	MDT 1/22	I-60	65.6		2.5	4.5	-27		0.07		3.1	24.2
Diwangsa	1098.9	MDT 1/23	I-60	67		3				0.07			23.7
Diwangsa	1286.2	MDT 2/26B	I-130	73.9	green brown	4.7		0		0.05	0.1	2.6	31
AbuKecil1	1291	RFT-4A	I-60	79h		3.07		-1	-1	0.06		6.1	28.5
AbuKecil1	1716.5	RFT-2	J-70/80			3.81		30	-32	0.05		1	39.9
AbuKecil1	1363.7	RFT-4B	I-66			3.01		-6	-13	0.07			27.3
AbuKecil1	1570.2	RFT-5A	I-125	76									
Rabung-1	2029.5	RFT-6	I-80L	120.6		1.8		12.7	13	0.025	2.8		46.89
Rabung-1	2211	RFT-7	J-10	125		1.84		6		0.024			45.82
Lerek1	1088	Test 1	J-70/80	71	yellow clear	2.31	18	-40	27	0.045		0.45	28
Lerek1	1082.8	RFT 1/58	J-70/80	68.9	black (unfiltr)			-41					27.6
Lerek-2	1090	Test	J-70/80	71		2.31	107	12	33	0.045		0.45	24.5
Lerek-2	1046.8	RFT-2	J			5.01		-12		0.1			19.6
Lerek-2	1072	RFT-2	J-15			1.83		-33		0.06			21.4
Lerek-2	1104	RFT-2				2.94		-9		0.05			19.3
Lerek-2	1100	Test 1	J-70/80			3.94		-12		0.045	0.05	0.25	23.4
Lerek-2	1102	Test 1		68		4.14		-9		0.06			24



Test Descriptions	Method	Sample I.D. Lerek-1 Test 1 J-70/80	Sample I.D. Lerek-2 Test 1 J-70/80
Molecular Weight	Cryette	247	324
Specific gravity @ 60/60F	ASTM D1298	0.8877	0.9082
Pour Point (deg C)	ASTM D97	<-40	12
Flash Point (deg C)	ASTM D93	27	33
Apparent Cloud Point (deg C)	Corelab Method (by cooling curve)	19	21
Sulphur Content (%wt)	ASTM D129	<0.05	<0.05
Kinematic Viscosity (cSt) @	ASTM D445		
20 deg C		23.15	189.86
25 deg C		18.88	107.30
40 deg C		11.40	46.32
Wax Content (%wt)	UOP-A-46	2.31	5.21
Asphaltene Content (%wt)	IP-143	<0.5	<0.5

Figure 14: Summary of the Lerek Field, located on a faulted basement high. Crudes are located in Group J reservoirs. Biodegraded and viscous, they display different GC properties which points to a complex migration history.

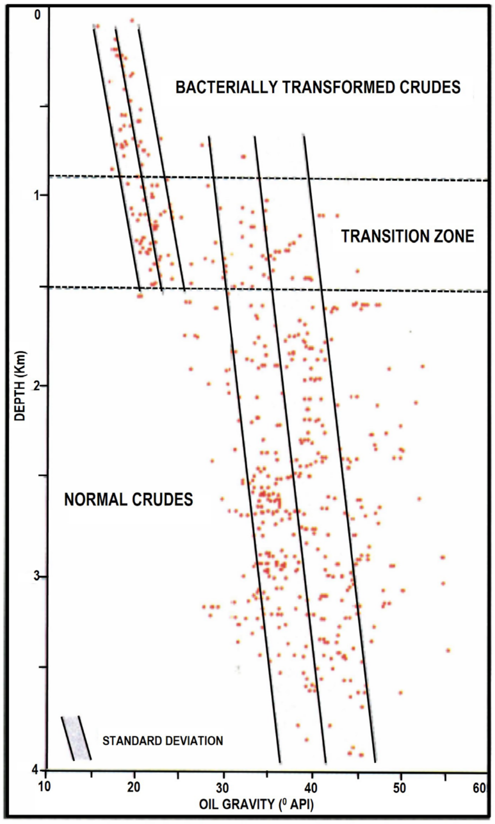


Figure 15: Oil gravity is shown as a function of depth, data from various fields in offshore Brunei. Note the rapid drop of API gravity in the transition zone from 900 m to 1400 m (From Sandal, 1996).

temperatures above 90 °C appear to be unaffected. The high viscosity of several shallow reservoir oils is a potential issue for oil production and recovery and must be considered for all shallow targets (depth < 1280 m below mudline). Moreover, attempts to predict the occurrence of particularly problematic oils in the study area can guide further exploration effort. The available data from this study also suggest the presence of distinct regional aquifer systems, of which some might be recharged in the coastal areas, whilst deeper and hotter aquifers are isolated in static cells. At this point in time, however, we do not have geochemical data from reservoir fluids to support this hypothesis. Beyond the scope of this study, detailed mapping of these aquifer systems using the latest 3D seismic technologies is recommended to properly identify and characterize isolated aquifer cells.

ACKNOWLEDGEMENTS

The authors would like to acknowledge the work of previous oil companies in the study area, and in this regard, we gratefully acknowledge PETRONAS for making the well reports available for research purposes via myPROdata, a subscription-based national E&P data repository.

Fruitful discussions with our ex-colleagues in Lundin and PCSB are highly appreciated, and our gratitude is also extended to our reviewers for offering constructive comments, which helped to improve the quality of this paper.

AUTHORS CONTRIBUTION

FLK is the main author who prepared the manuscript and figures. JJ and MM provided support on the regional setting and stratigraphy and oil characteristics investigation. All authors reviewed the results, interpretation and final write-up of the manuscript.

DECLARATION OF COMPETING INTEREST

The authors have no conflicts of interest to declare that are relevant to the content of this paper.

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Manuscript received 30 May 2023;
Received in revised form 11 October 2023;
Accepted 22 January 2024
Available online 30 November 2024