Bulletin of the Geological Society of Malaysia, Volume 68, December 2019, pp. 69 – 84
DOI : https://doi.org/10.7186/bgsm68201906

The Tembakau gas accumulation, Tenggol Arch, offshore Peninsular Malaysia: Petroleum system, gas composition and gas migration

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Abastract: The Tembakau gas discovery is a mix of biogenic and thermogenic gases, with condensate wetness index increasing with depth in the reservoir. Surprisingly though, even the dry gas in the upper reservoirs appears to have an affinity with oil and Type II kerogenous rock of probably Lower Tertiary age. The temperature regime in the gas-bearing reservoirs is relatively elevated, with a temperature gradient of 4.55 ºC/100m. Given that the potential source rocks in the area surrounding Tembakau were found to be immature for hydrocarbon generation, the discovered hydrocarbons might have reached the accumulation by long distance migration. A deeper source below the Palaeozoic unconformity can be excluded in view of mud-log and gas composition data. Therefore we propose in this study a model that addresses the possibility of aquifer degassing in the Tembakau accumulation, perhaps as a result of a combined recent pressure drop and/or temperature hike in the order of 30 ºC, which could have prompted rapid degassing of the aquifers. The Tembakau gas might therefore be a secondary gas cap, derived from gas saturated aquifers ("water washing") connected to the Sotong and South Angsi fields at the western edge of the Malay Basin, and having reached the Tembakau area after a tortuous migration pathway, whilst being subjected to some degree of biodegradation.

Keywords: Tembakau gas field, gas composition, gas migration, aquifer degassing, Tenggol Arch, Peninsular Malaysia

INTRODUCTION

The Tembakau discovery is a significant gas accumulation, and located in the centre of the Tenggol Arch, offshore east of Peninsular Malaysia in the South China Sea (Figure 1). It is located up-dip from the Sotong Field, a producing oil and gas field characterised by a number of channelised reservoirs, probably facies-contiguous with the Tembakau discovery. The slightly older K Group reservoirs in the Sotong area consist mainly of fluvial channels, with individual thicknesses of 5 to 6 m, stacked into channel complexes 6 to 15 m thick embedded in flood plain, tidal flat and lower shoreface environments (Madon *et al*., 1999; Tan, 2009a).

The Tembakau gas discovery was found in 2013 by Lundin Malaysia B.V, now International Petroleum Corporation Malaysia, after mapping a prominent fault-bounded amplitude anomaly well expressed on a recent 3D and also on some older 2D seismic datasets (Figure 2). The standardised stratigraphy of the Malay Basin and Tenggol Arch area is shown in Figure 3. The discovery well TBK-1 penetrated several gas-bearing sequences of amalgamated and channelised reservoirs, as indicated by log shapes, core data and regional 3D seismic interpretation.

DATA BASE AND STUDY OBJECTIVE

In the current study, we have conducted a literature review of hydrocarbon generation and migration mechanisms, and combined these with seismic, which includes relatively recent vintages of 3D seismic, and older 2D (vintages 1970's to 1990's) of variable quality. The well data from TBK-1 and TBK-2 offer excellent logging data, and rotary side wall cores (TBK-1), and classic cores in the appraisal well (TBK-2). Corelab Malaysia provided various geochemical analyses and finger printing. A fluid inclusion stratigraphy (FIS) was carried out by Fluid Inclusion Technologies, Inc. In this paper, we summarise our analysis of possible charge scenarios for the Tembakau gas accumulation based on the available geochemical data from the wells.

REGIONAL GEOLOGICAL SETTING

The geology and stratigraphy of the study area is relatively well known based on the results of decades of oil and gas exploration, including those published about the neighbouring Indonesian fields.

In respect of the formation of both the Malay and Penyu basins (see Figure 1); there is a wide variety of opinions. The basins are considered to have originated either in a back-arc setting (Kingston *et al*., 1983; Mohd

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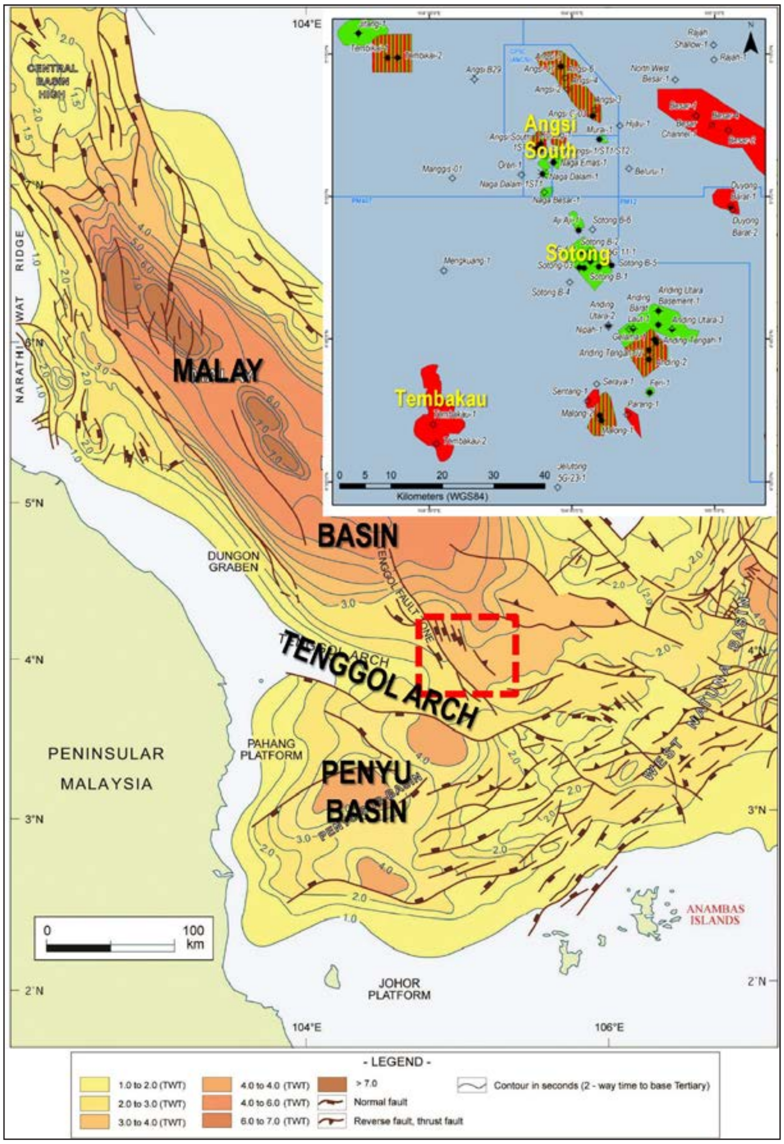


Figure 1: Structural framework map of the Malay Basin, Penyu Basin and the intervening Tenggol Arch, offshore Peninsular Malaysia. The study area located in the Tenggol Arch is outlined in dashed red line. Inset map shows locations of the main fields in the study area (maps from IHS Markit).

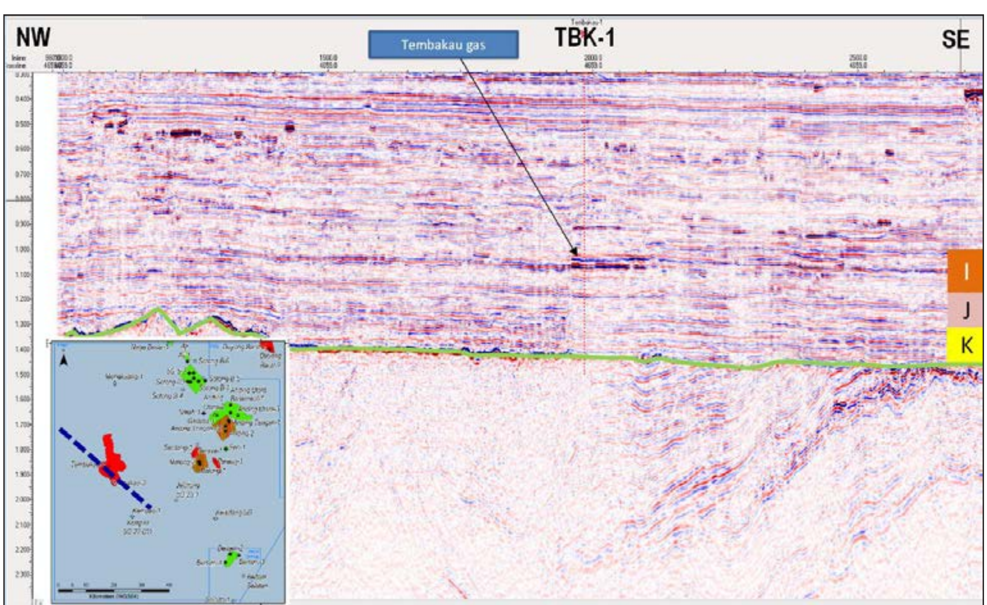


Figure 2: A seismic arbitrary section of ca. 50 km length running NW-SE on the Tenggol Arch with approximate line location shown on the inset map. The geology can be divided into a bottom strongly deformed basement section, with an isopachous Neogene drape above. The basement unconformity is highlighted in light green. A marked amplitude anomaly in the centre of the seismic line is a proven gas anomaly. The stratigraphic group intervals, I, J, K are annotated. The y-axis is in time, the x-axis shows the well location and CDP points (from Jong *et al*., 2019).

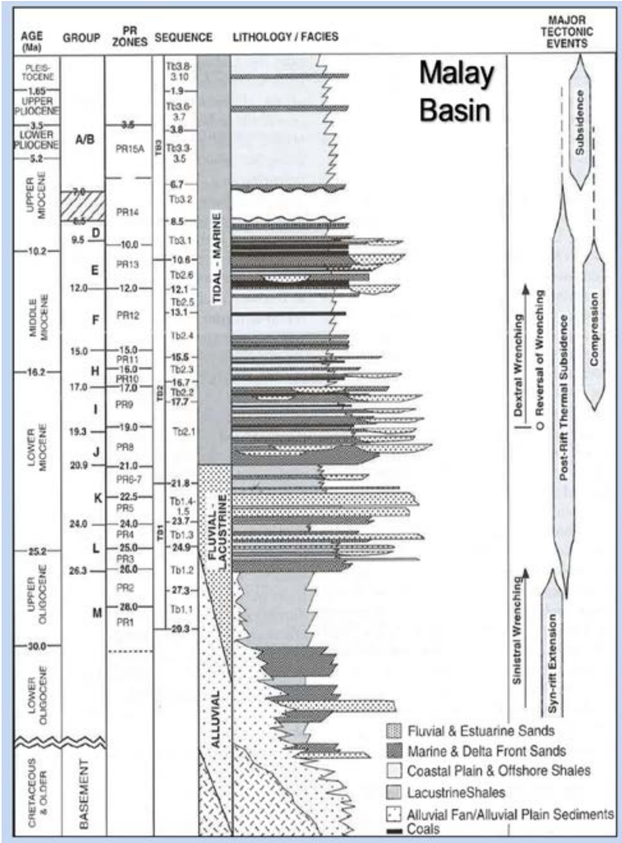


Figure 3: Generalised stratigraphy and major tectonic events of the Malay Basin and Tenggol Arch (from Tan, 2009a, and modified after Madon *et al.*, 1999).

Tahir *et al*., 1994), or as a pull-apart basin developed along a major strike-slip fault (Tapponier *et al*., 1982), or through thinning of continental crust (White & Wing, 1978). Other tectonic models involve crustal extension over a hot spot (which amounts to thinning of the continental crust, Hutchison, 1989; Khalid Ngah *et al*., 1996), extensional subsidence along a major left-lateral shear zone (Madon & Watts, 1998; Md Yazid *et al*., 2014; Maga *et al*., 2015; Kessler & Jong, 2018a; Jong *et al*., 2019), and as a failed rift arm of a triple junction above a mantle hot spot (Tjia, 1999). Morley & Westaway (2006) proposed a geodynamic model of the Malay Basin, involving lower-crustal flow in response to post-rift sedimentation. We are trending more towards a model of "extensional subsidence along a major left-lateral shear zone".

The Tenggol Arch was mainly a peneplain during Early Oligocene times. It is formed by basement rocks such as granitoids, volcanics, phyllites, argillites, slates and limestones (Tan, 2009a). Structuration within the arch is highly complex and may represent a Palaeozoic fold and thrust belt (Figure 4), which was also subjected to Tertiary strike-slip faulting. The Tenggol Arch basement high formed a barrier to sediments advancing basinwards from the Malay Peninsula until the very late Oligocene, and local cuestas shed sediments to the arch and adjacent basin areas. Finally, during the latest Oligocene, clastic sediments from the Johor Platform transgressed the Tenggol Arch and were draped over this peneplained, heavily folded ancient mountain belt (Maga *et al*., 2015; Kessler & Jong, 2018a;

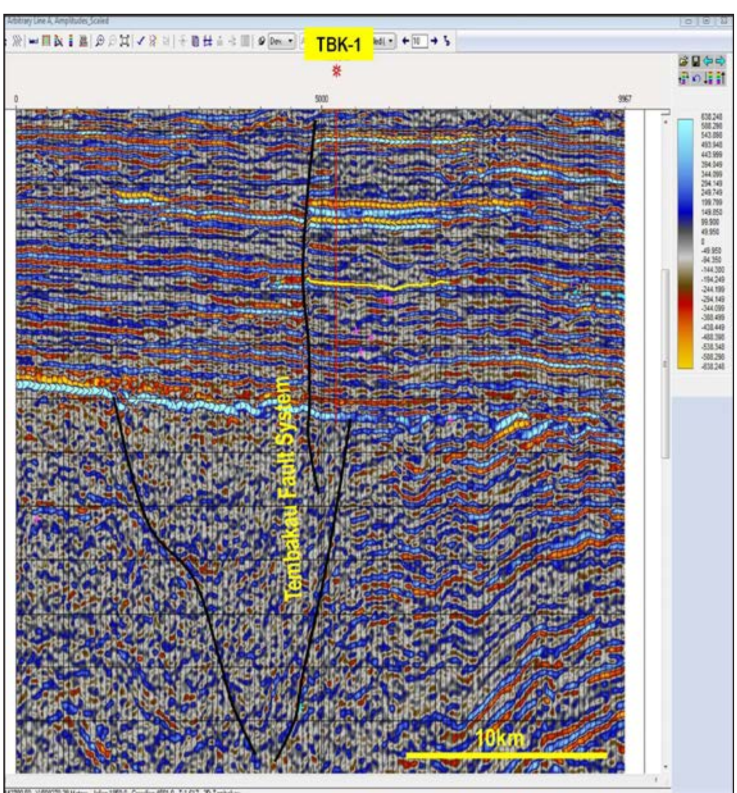


Figure 4: Rock heterogeneity characterises the basement. In particular, the layered pre-Tertiary basement rocks have led to speculations about potential Palaeozoic source rocks providing vertical hydrocarbon migration along the Tembakau Fault into the Tembakau reservoirs.

Jong *et al*., 2019). The sedimentary record of the Tenggol Arch therefore is limited to the Miocene and uppermost Oligocene sequences. In the Early Miocene, subsidence rate in both basins gradually decreased under thermal subsidence, and more sediments derived from uplifted mountain belts on the Malay Peninsula eventually reached the Malay Basin. During the Miocene, the entire region was subjected to compression and strike-slip movements (dextral wrenching) resulting in basin inversion.

STRATIGRAPHY, LITHOFACIES AND PETROLEUM SYSTEM

The stratigraphy of the Tenggol Arch shows an almost isopachous and layered Miocene to recent sequence consisting of channelised sands, claystones and coals (Figure 4). The sediments are of fluvio-lacustrine and intertidal origins, often cyclic and characterised by the occasional periods of marine transgression.

Sediments were deposited, initially, in a low-relief playa environment characterised by stacked meandering channels. As summarised by Ibrahim & Madon (1990), in the nearby Malong Field, these basal sediments pass up into prograding shoreface sequences, consists of upward coarsening units in which heterolithic sandstone-mudstone are overlain by ripple cross-laminated and parallel-laminated sandstone. The inner-shelf sequence is made up of upward-coarsening offshore bar sandstones encased in muds. The shelf sand bodies show evidence for deposition by storm-generated currents, and are characterised by the association of distal, low-energy heterolithic facies overlain by proximal, amalgamated high-energy sandstone units. The fluvial channel sequence consists mainly of trough cross-bedded sandstone, intercalated with minor floodplain mudstone.

Trap and seal

The Tembakau structure is a fault-bounded monoclinal trap, in which fault seal might have been provided by clay smear and lateral seal by clayey host rock at the channel flanks. Figure 4 shows dimmed amplitude anomalies also on the left-hand side of the fault. The fault is quite steep and there is potentially little throw from right to left, and the footwall sand is partly juxtaposed to hangingwall sand and clay. However, it is unknown if clay smear and/or mylonitisation contribute to fault sealing. The top seals of the reservoir zones are formed by thin (few meters) of clay/ mudstone seal (see also Kessler & Jong, 2018b).

Tembakau reservoirs

The Tembakau reservoirs are located within channels that run from SE to NW, and seismic amplitude mapping shows that the channels are between 300 and 1500 m in width. There are three main gas-bearing reservoirs in Tembakau: Group I-10, I-20, and I-80 sands. TBK-1 penetrated all three reservoirs, and sidewall cores were obtained, whilst in TBK-2, the Group I-10 and I-20 reservoir sands were cored. A well correlation between TBK-1 and the appraisal well TBK-2 is shown in Figure 5. The reservoirs consist of siliciclastics deposited mainly in fluvial channels and deltas, with grain sizes vary from coarse (rarely) and medium to fine. From our study, we can discriminate four main reservoir facies types, listed below from best to poor (Table 1):

- Facies A: Medium-coarse sandstone with no gradation and clay content. Porosity is in the order of 30 %, and permeability in the order of 1 Darcy (Table 1and Figure 6).
- Facies B: Medium-coarse sandstone, some cross-bedding and hardly any clay content (Figure 6). Porosity is in the order of 25 %, and permeability in the order of 800 mD.
- Facies C: Cross-bedded sandstone, medium-grained, with flasers formed by clay and coal (Figure 7). Porosity is in the order of 20 %, and permeability in the order of 500 mD.
- Facies D: Clay-dominated facies, with sand flasers or mainly fine sands (Figure 8). Porosity and permeability is good within the sandy flasers, however there is no porosity and permeability in the clay layers. The average porosity for the composite facies is in the order of 10 %, and MNR data suggest that Facies D can still be considered as a producible gas reservoir.

In summary, core data show a variety of reservoir types; with reservoirs formed by fine sand flasers, as well as medium to coarse grained sand beds, interrupted by siltstone baffles and minor coals. Most of the gas resources in the Tembakau accumulation are resided within the Group I-10, I-20, and I-80 reservoirs, with additional gas might be vested in Group I-35 sand.

Gas parameters

Figure 9 shows a temperature curve for TBK-1, and a simplified composition for gasses in the well. The shallower gas-bearing intervals 746-873 m and 946-1196 m appear to be predominantly composed of biogenic methane. The interval 1196-1307 m contains a mixture of both biogenic and thermogenic methane. The deeper reservoir level 1307-1475 m is characterised by temperatures above 80 ^{0}C, there is little or no biogenic methane, and also contains heavier components than methane. The currently available data do not allow for a conclusive answer to whether or not we are dealing with condensate, or perhaps light oil components. The seen composition might also be affected by water washing of downdip reservoirs and/or the chemistry of the aquifer. Regional work in the study area by Lundin has shown that 80 ^{0}C is the threshold for bio-degradation, and gasses in cooler reservoirs are mostly, if not always bio-degraded.

In summary, the Tembakau gas is a mixture of biogenic (biodegraded) and thermogenic gas dominated by C_1 and C_2. As expected, the deeper reservoir unit (at temperatures greater than 80 ^{0}C) contains more thermogenic gas compared to the shallower units (at a temperature of between 65 and 80 ^{0}C, Figure 9). As shown in Table 2 and Table 3,

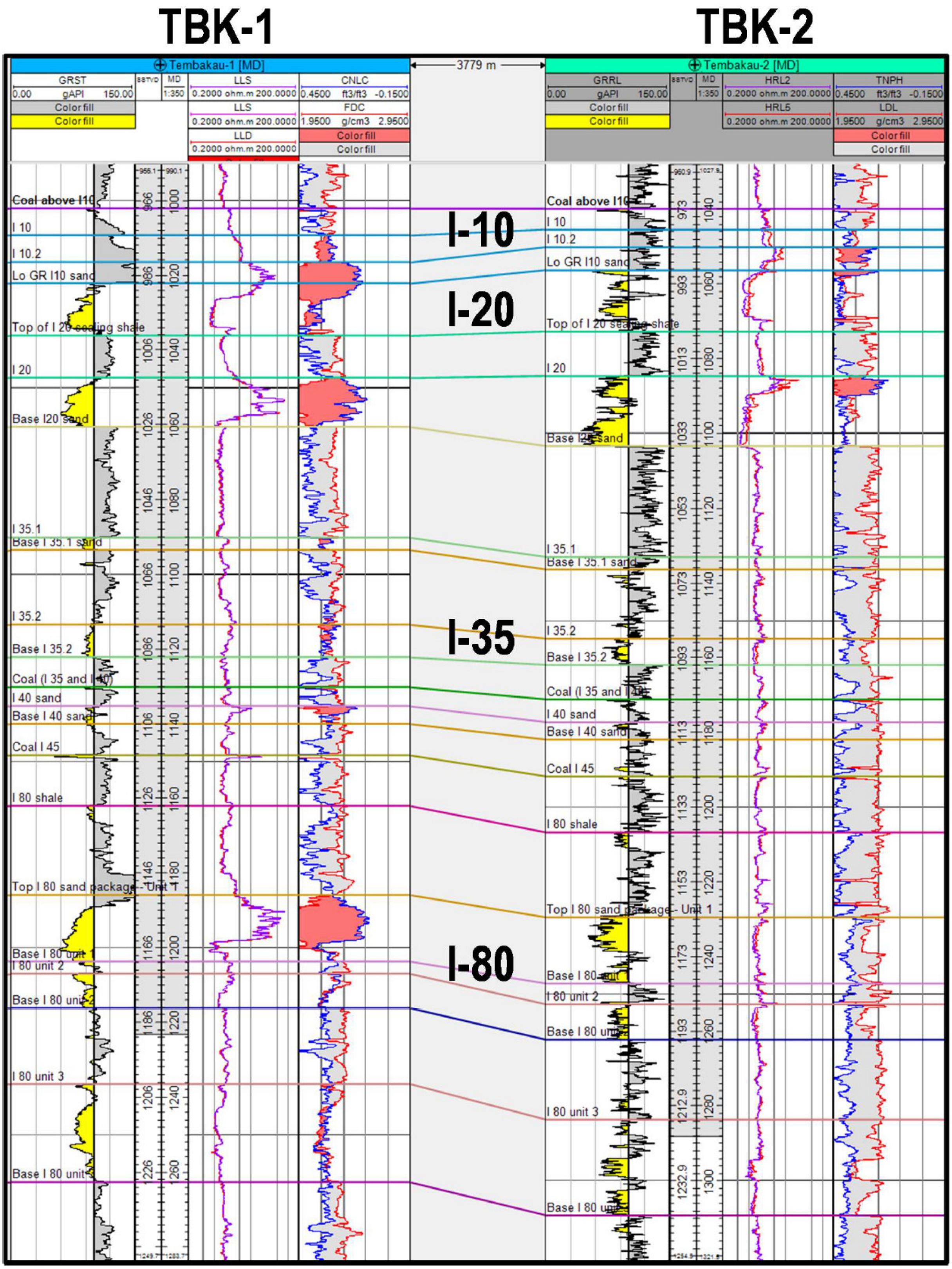


Figure 5: Gas-bearing sands of Group I-10, I-20, I-35 and I-80 in TBK-1 and TBK-2 wells. The reservoirs are well imaged on 3D seismic, and allow for a good correlation between the wells (from Jong *et al.*, 2019).

the upper reservoir unit has dry gas properties, whereas the deeper reservoir is slightly more condensate- or light oil-wet (Table 4).

Source rock evaluation

An immature source rock interval (K Shale) has been identified, however the shallower gas zones offer no fluid inclusions data (Figure 10), and in such way there can be no convincing comparison made between the immature source rock and the gas zones; most likely the poorly compacted reservoir sands did not yield cuttings with hydrocarbon content. The sedimentary overburden on the Tenggol Arch is less than ~2 km, and therefore unlikely that the K Shale penetrated in the bottom section of the well ever yielded significant amount of hydrocarbons due to its low maturity despite the relatively high geothermal gradients (*ca.* 4.55 ^{0}C/100m). Both vitrinite and RockEval maturity data are shown in Table 5. It is noted that the Ro vitrinite-temperature conversion produced temperature values which are different from the measured (and corrected) values. The difference between measured and vitrinite-converted temperatures could be the consequence of a very recent temperature increase, which may not have impacted the vitrinite reflectivity of the Tembakau samples yet. However, it cannot be ruled out that the vitrinite reflectivity may have been

Table 1: Core description of Group I-10 sand in TBK-2 with four reservoir facies Types A, B, C and D discriminated (from Kessler & Jong, 2018b).

Short Reservoir Description	Net Sand (m)	Facies A-D	Est. Porosity % Core/Facies
5 cm hardground, burrows	0		0
74 cm banded clay/silt	0		0
38 cm banded silt	0,03	D	12
46 cm bioturb/and laminated clay	0,15	D	12
16 cm fractured coal	0,02	D	12
21 cm fractured coal	0,03	D	12
78 cm homogenous fine sand	0,78	C	20
56 cm ditto	0,56	C	20
14 cm banded fine sand, clay	0,04	C	20
30 cm laminated clay/slt	0,02	D	12
14 cm ditto	0,02	D	12
85 cm laminated fine sand	0,85	B	25
64 cm fine sand, breccia, fine sand	0,62	C	20
19 cm laminated silt/clay/fine sand	0,1	D	10
17 cm coal, then fine sand	0,11	C	16
40 cm fine sand/laminated with silt, clay	0,39	C	18
60 cm laminated clay/silt/sand	0,2	D	12
100 cm fine sand/laminated/silt/clay/flasers	0,45	C	20
ditto	0,8	C	20
ditto	0,85	C	20
ditto	0,75	C	20
ditto with flasers	0,7	C	20
32 cm ditto	0,3	C	20
68 cm mid-coarse sand	0,63	B	25
100 cm ditto	0,96	B	25
50 cm (partly not recovered)	0,5	B	25
50 cm medium sand, flasers, laminated	0,4	B	25
100 cm ditto	0,96	A	30
32 cm ditto	0,3	A	30
68 cm thin beds/laminated, fine sand, flassers	0,15	C	20
54 cm ditto	0,2	C	20
46 cm sand/silt, laminated clay	0,3	C	20
68 cm thin beds/laminated, fine sand, flassers	0,29	C	18
11 cm laminated clay, little sand	0,05	D	15
21 cm laminated medium sand, clay, coal	0,17	B	25
100 cm ditto	0,98	B	25
	13, 66 Gas		

Figure 6: Raw core picture of Group I-10 sand in TBK-2 showing heterolithic facies Type B (left) and relatively clean massive facies Type A (right) (from Jong *et al.*, 2019).

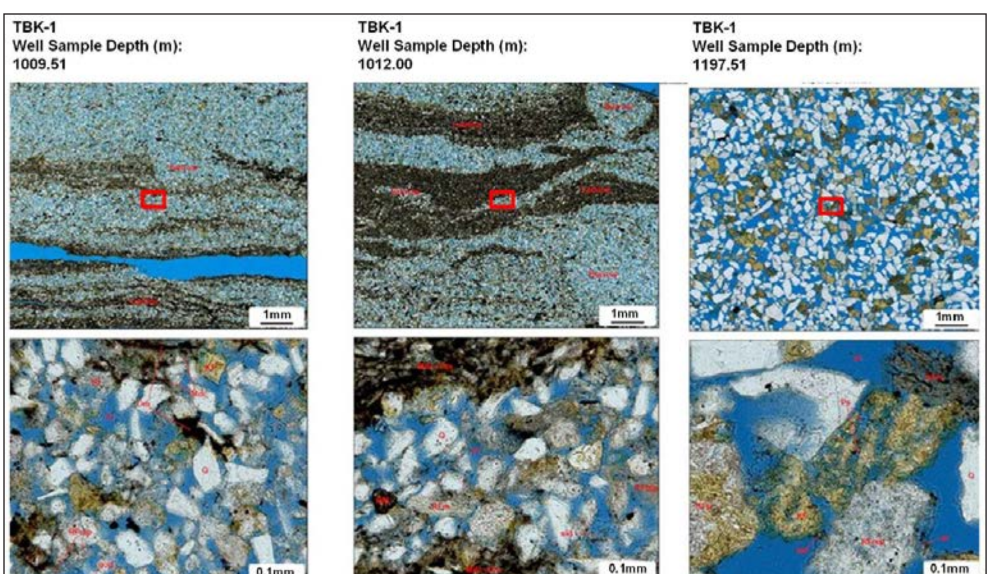


Figure 7: Thin sections of core plugs from TBK-1 showing fine-grained sand in facies Type C. The sample contains chlorite and apatite, the latter being a strong emitter of thorium radiation (from Jong *et al.*, 2019).

Figure 8: Raw core picture from TBK-2 showing facies Type D reservoir in the top section of Group I-10 sand. The thin (1-5 mm, key for scale) grey and gas-bearing sand intervals are flasers, and are intercalated between soft clay beds. The sands however, are very clean and do not contain any significant amount of clay (from Jong *et al*., 2019).

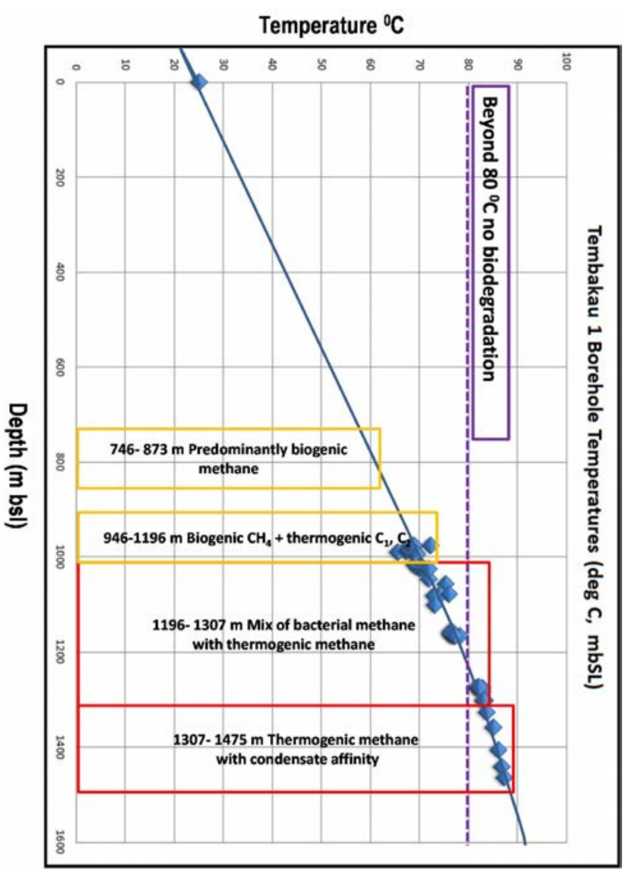


Figure 9: Temperature versus depth relationship reflecting the degree of biodegradation with no biogenic gas signatures observed beyond 80 ^{0}C. The temperature regime in the gas-bearing reservoirs is relatively elevated, with a temperature gradient of 4.55 ^{0}C/100m calculated.

Table 2: Tembakau gas stable isotope composition data. The data indicate a change of gas composition from a dry setting (746-1090 m) to a wet realm (1163 to 1475 m).

Sample Depth (m)	$\delta^{13}C$ methane (C_1) (‰)	$\delta^{13}C$ ethane (C_2) (‰)	$\delta^{13}C$ propane (C_3) (‰)	$\delta^{13}C$ isobutane (iC_4) (‰)	$\delta^{13}C$ butane (nC_4) (‰)	$\delta^{13}C$ carbon dioxide (CO_2) (‰)	Gas Wetness
746.0	-61.80					-19.4	0.16%
873.0	-59.20					-20.8	0.43%
946.0	-55.10					-20.5	0.51%
1011.5	-51.40	-26.90	-11.50	**		-2.0	1.09%
1055.7	-51.10	-25.30	-4.90	**		2.5	1.24%
1090.0	-54.70	-31.10				-19.2	1.71%
1114.0	-53.70	-31.60	-29.00	-30.00	-28.60	-10.6	3.62%
1163.0	-50.90	-31.00	-29.10	-30.10		-19.0	4.23%
1195.9	-52.00	-31.80	-29.30	-29.20	-30.00	-12.3	2.86%
1307.3	-47.00	-29.60	-28.40	-28.90	-29.00	-12.0	5.41%
1475.0	-46.80					-17.9	3.89%

Table 3: Gas composition analysis of TBK-1 gas - C_1 to C_4 alkanes, CO_2, and $\delta^{13}C$ with depth shown. C_1, C_2, C_3 and CO_2 have a break observed between 1000 and 1100 m. C_4 have only data from 1114 and 1307 m of approximately -29.6 for iC_4 and -29.2 for nC_4. iC_4 may have a small depth trend from 1114.0 m ($\delta^{13}C$ -30.0) to 1307.3 m ($\delta^{13}C$ -28.9). The base of the biodegradation zone could be near to a depth of 1000 m. However, there are only few data points. C_1, C_2 and C_4 are becoming slightly heavier with depth from about 1150 m. A chemical divide is seen at 1000 m, which coincides with 80 ^{0}C temperature in the borehole, the threshold of biodegradation.

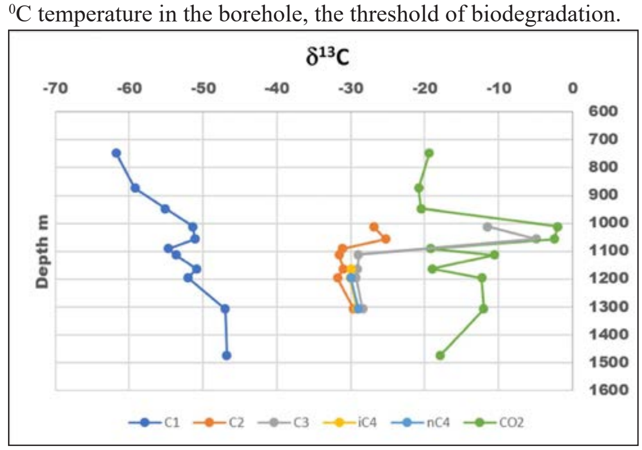
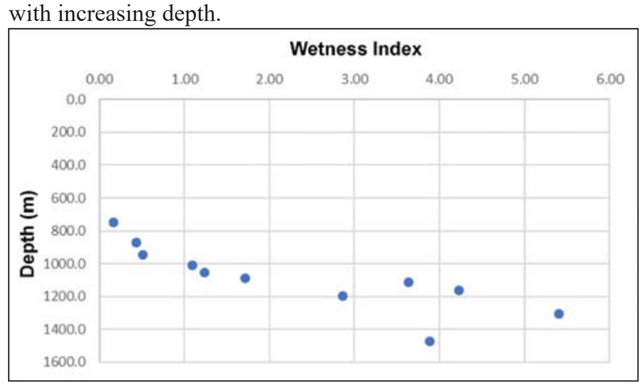


Table 4: An obvious increase of wetness in the gas zones is seen with increasing depth.



suppressed by better preservation and the presence of abundant liptinite and perhydrous vitrinite in the kerogen mix, such that the calculated temperatures may not be the true maximum temperatures attained by the sediments. Vitrinite reflectance suppression in the Malay Basin was documented from well data by Waples *et al*. (1995) and was used to explain its thermal history without the need to invoke a recent heat pulse. Values of the Hydrogen Index in Table 5 seem to suggest that a significant hydrogen-rich component existed in the kerogen mix. Although this has

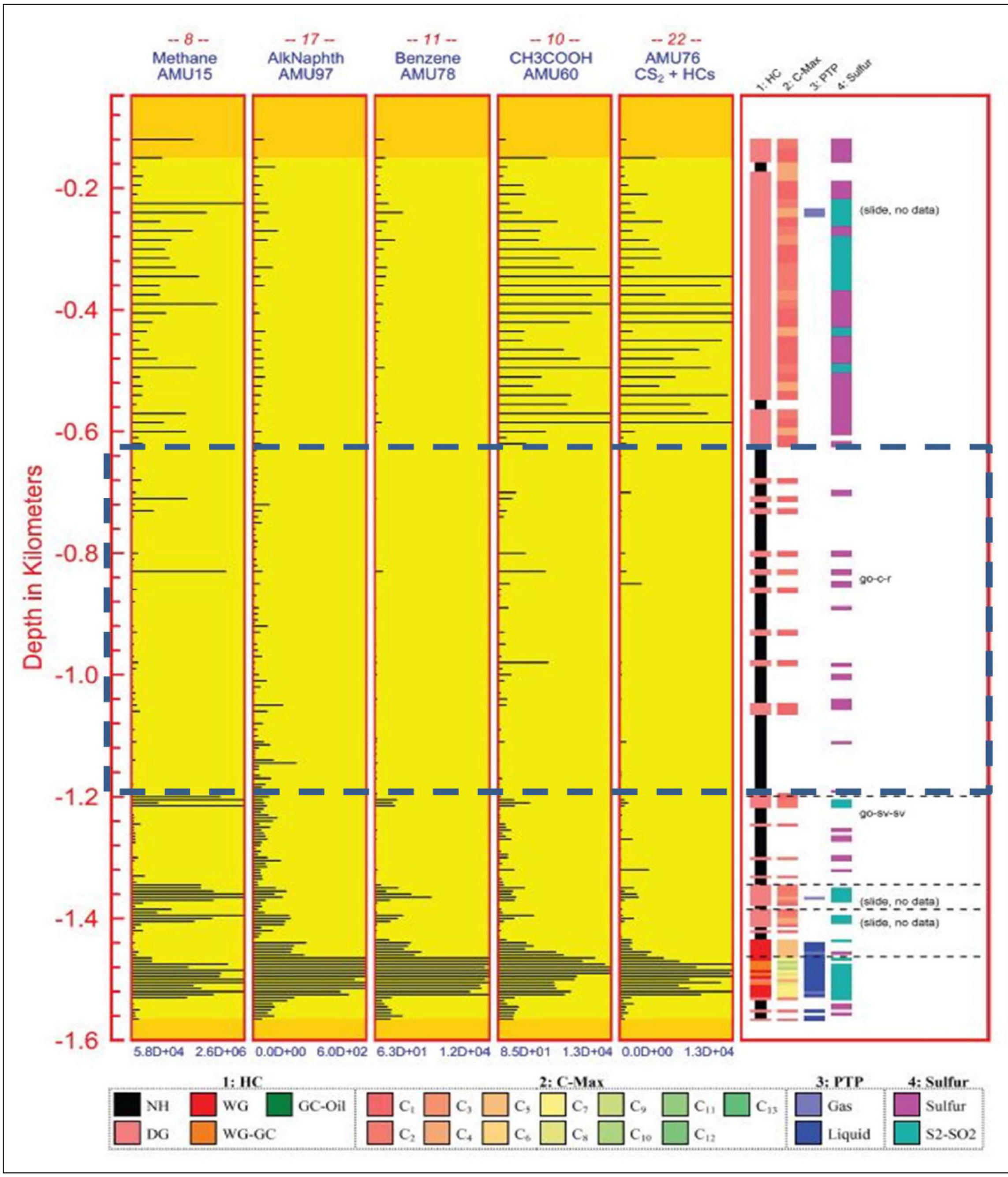


Figure 10: Fluid inclusion stratigraphy of TBK-1. Noted the lack of gas signatures in the dashed blue-outlined zone is puzzling, perhaps suggesting a low sample recovery. The source-rich K Shale layer is positioned between 1.4 km and 1.5 km depth.

been quoted as the main reason for vitrinite suppression, only recently has it been confirmed experimentally that vitrinite suppression occurs in the study area when vitrinite is mixed with liptinite-rich kerogen (Peters *et al*., 2018).

The discussion about and the impact of vitrinite suppression on temperature evaluation remains an interesting research subject, however, it is not the main topic of this paper. The fact is the temperature data obtained from the Tembakau wells suggest that the study area is located in an area of anomalous high temperature readings with a resultantly high geothermal gradient, and hence we believe that the role of vitrinite suppression is limited for temperature interpretation in this study (Table 6).

Hydrocarbon migration

Nonetheless, there have been at least two pulses of oil migration observed (Tan, 2009a). If indeed no oil or gas had been generated on the Tenggol Arch, they must have been derived from either the adjacent Malay or Penyu basins, or from an unknown source. The possibility of a Palaeozoic source rock has been discussed by the operators and within PETRONAS. In such a scenario one would expect a steady

Table 5: Rock-Eval pyrolysis and measured vitrinite reflectivity (VRM). Top - apart from a few intervals, mostly marginal source rock levels were penetrated in TBK-1. Bottom - with a maximum VRM of 0.49, the entire Tertiary section is immature, and the 'pre-Tertiary' appears to be barren of good generative source rocks.

ROCK-EVAL PYROLYSIS AND TOC CONTENT										
Sample Depth (metres)	**Lithology**	**TOC (wt. %)**	**mg/gm rock**			**Tmax (^{0}C)**	**Oil Production Index (OPI)**	**Potential Yield ($S_1 + S_1$)**	**Hydrogen Index**	**Oxygen Index**
			S_1	**S_2**	**S_3**					
860 - 870	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (10%), quartz & pyrite, non calc	0.48	-	-	-	-	-	-	-	-
950 - 960	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (1%), quartz & pyrite, non calc	0.49	-	-	-	-	-	-	-	-
1030 - 1040	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (1%), quartz & pyrite, non calc	0.46	-	-	-	-	-	-	-	-
1145 - 1150	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (1%), quartz & pyrite, non calc	0.51	0.29	1.92	1.06	427	0.13	2.21	379	209
1290 - 1295	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (10%), quartz & pyrite, non calc	0.60	0.27	1.40	0.65	422	0.16	1.67	234	109
1315 - 1320	lt blsh gy Clyst, soft to firm, occ carb & pyrite, trace coal (1%), quartz & pyrite, non calc	0.57	0.28	2.08	1.43	426	0.12	2.36	364	250
1355 - 1360	off wh Sst, loose quartz, transparent	0.08	-	-	-	-	-	-	-	-
1375 - 1380	med lt gy Clyst, soft, occ carb & pyrite, trace coal (1%) & quartz, non calc	0.83	0.35	3.85	0.91	438	0.08	4.3	461	109
1445 - 1450	lt gy Clyst, soft, occ carb & pyrite, trace coal (1%) & quartz, non calc	0.30	-	-	-	-	-	-	-	-
1515 - 1520	lg brnsh gy Sst, fine, soft to friable, trace quartz, non calc	0.10	-	-	-	-	-	-	-	-
1560 - 1565	off wh Sst, loose quartz, transparent, trace coal (1%)	0.03	-	-	-	-	-	-	-	-

VITRINITE REFLECTANCE RESULTS						
Sample Depth (metres)	**Plug Type**	**Mean Ro (%)**	**No. of Readings**	**Minimum Reflectance (%)**	**Maximum Reflectance (%)**	**SD**
860 - 870	WR		Barren			
950 - 960	WR		Barren			
1030 - 1040	WR		Barren			
1145 - 1150	C	0.38	13	0.31	0.49	0.050
1290 - 1295	C	0.42	15	0.32	0.52	0.059
1315 - 1320	C	0.39	8	0.34	0.46	0.045
1355 - 1360	WR		Barren			
1375 - 1380	C	0.40	10	0.33	0.49	0.049
1445 - 1450	WR		Barren			
1515 - 1520	WR		Barren			
1560 - 1565	WR		Barren			

Table 6: Temperatures obtained from vitrinite reflectivity (VRM) conversion are not in equilibrium with borehole temperatures in TBK-1. Accordingly, one possible explanation would be that the Tembakau area is experiencing a recent heat flush and increasing rock temperature by ca. 30 ^{0}C. A similar scenario could also be applied to other parts of the South China Sea, such as in the Bunguran Trough. As discussed in the text, there is some discussion about the validity of vitrinite readings in the Malay and Penyu basins, and the potential role of vitrinite suppression.

Depth in m	Measured VRM	Measured borehole temp. ^{0}C	Temperature calculated using Barker (1988)	Temp. Difference
1145	0.38	76	47	29
1290	0.42	83	58	25
1315	0.39	84	50	34
1380	0.40	86	53	33
Barker's formula (1988): Temp ^{0}C = 104 (Ln Ro) + 148				

downward increase of the mud gas level in the wells from reservoir down towards the source of the gas. This is not the case, however, as there is a steady decline of mud gas from the reservoir downwards (Figure 11). It is thus concluded that neither a local source rock, nor a deep (pre-Tertiary) source was charging the gas accumulations.

RESULTS OF GEOCHEMICAL FINGERPRINTING

A number of screening tests and fingerprinting analyses were performed by Corelab Malaysia and produced the following geochemical parameters:

- *Vitrinite and carbon isotope* (Figure 12): The majority of the TBK-1 gases appear to be originally associated with oil, and stem from relatively early expulsion. The isotope typing appears to be characteristic of a Lower Tertiary/Upper Cretaceous source settings and points to a genetical relationship with re-migrated oil.
- *Isotopic composition of methane and ethane* (Figure 13): The isotope cross-plot for ethane versus methane suggests associated gas of mixed origin.
- *Relationships between the stable carbon isotopes of ethane and propane* (Figures 13 and 14): The plot of Figure 14 indicates a relationship of the TBK-1 gases with Type II kerogen, and some biodegradation (with loss of propane). The diagram of Figure 15 illustrates that the TBK-1 gas has no genetic relationship to a Type III kerogen source, given that the isotopic values do not match those of Type III kerogen at plausible VRM values.

In summary, carbon isotopic signature of TBK-1 gas points to a mixture of thermogenic and biogenic gas derived from an early mature (Type II kerogen) source rock, which is likely to be of Lower Tertiary/Upper Cretaceous age. The isotopic data also indicate that the gas is an associated gas, despite the removal of common indicators normally detected by FIS analysis. It is very intriguing to see that the Group I-10 to I-20 gas reservoirs do not show much indication of any hydrocarbons in FIS; the lack of HC data from the main reservoirs could be explained by inferring the presence of a

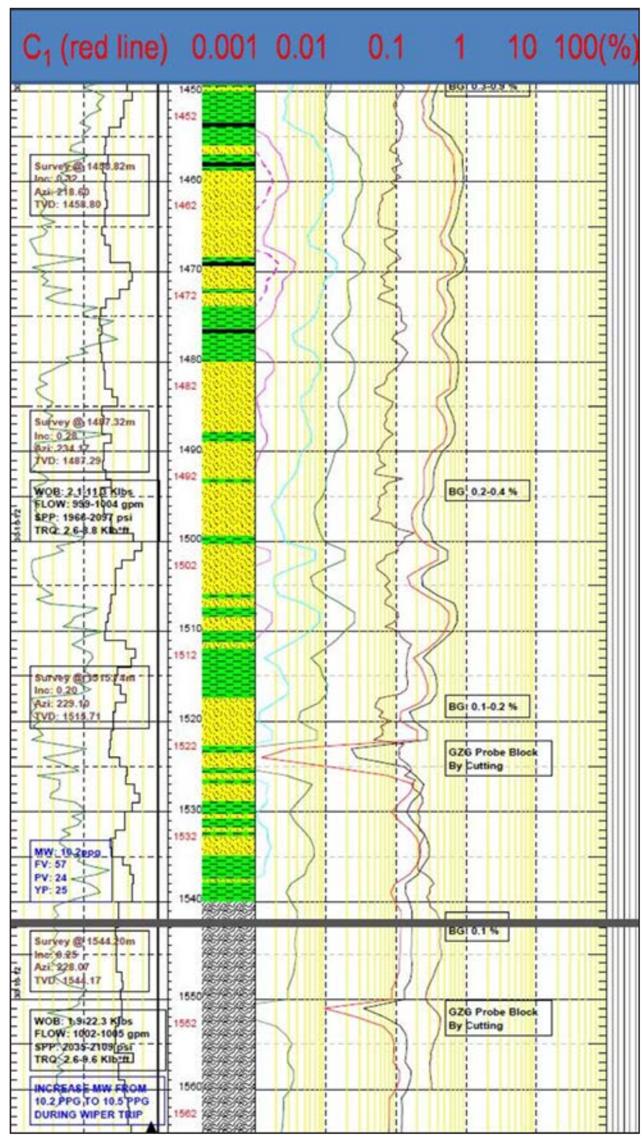


Figure 11: In the bottom-hole section, C_1 level is ca. 0.1 %, hence very low. If charge would come from a 'recent' gas generation emanating from an 'old' source rock, expelling at a high maturity, one would expect at least a sniff of gas, but there isn't any.

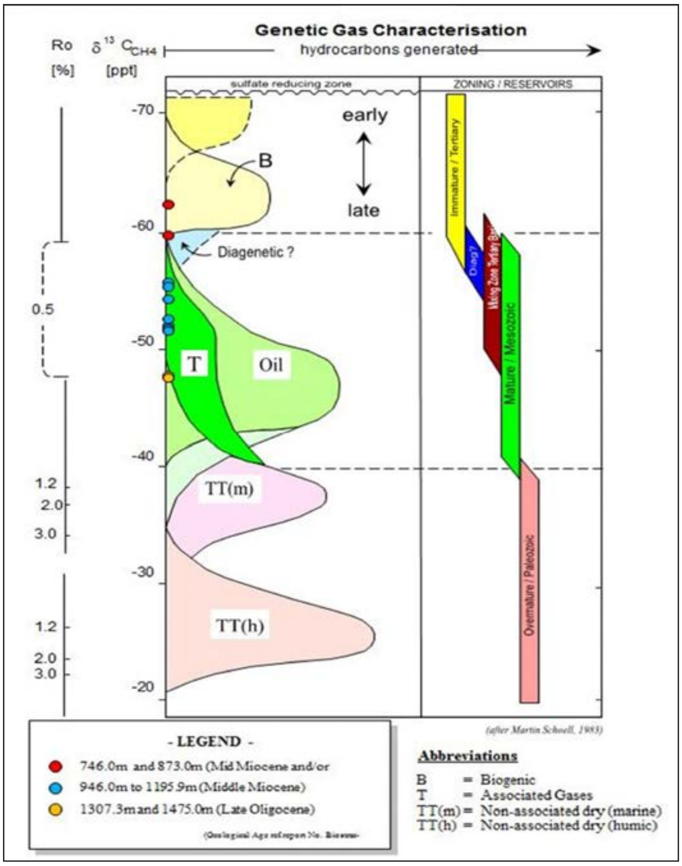


Figure 12: The majority of the TBK-1 gasses appear to be originally associated with oil, and derived from relatively early expulsion. The isotope typing appears to be characteristic for Lower Tertiary/Upper Cretaceous source settings, as seen in both the Malay and Penyu basins (modified after Schoell, 1983).

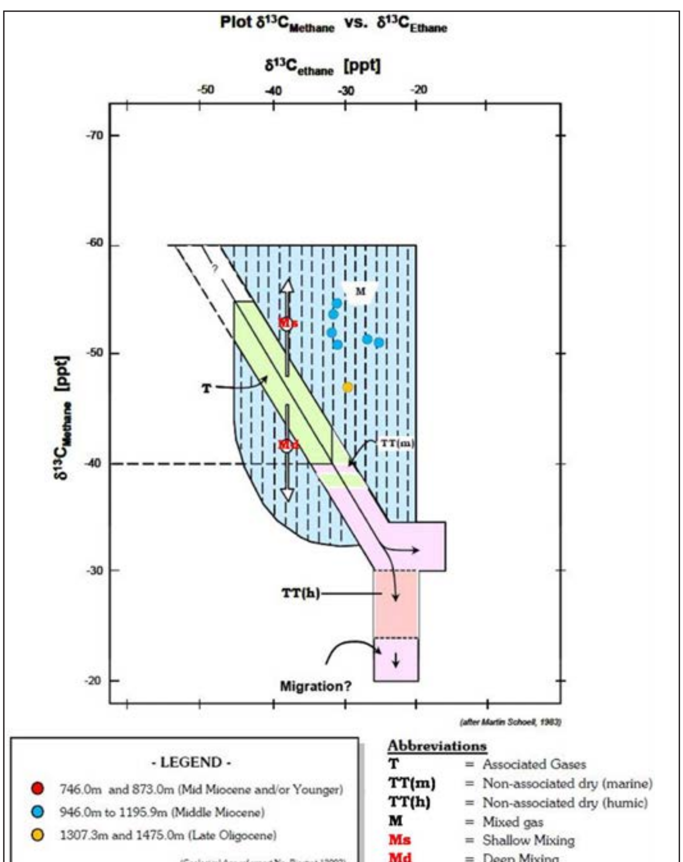


Figure 13: The isotope cross-plot for ethane versus methane suggests an associated gas of a mixed origin (modified after Schoell, 1983).

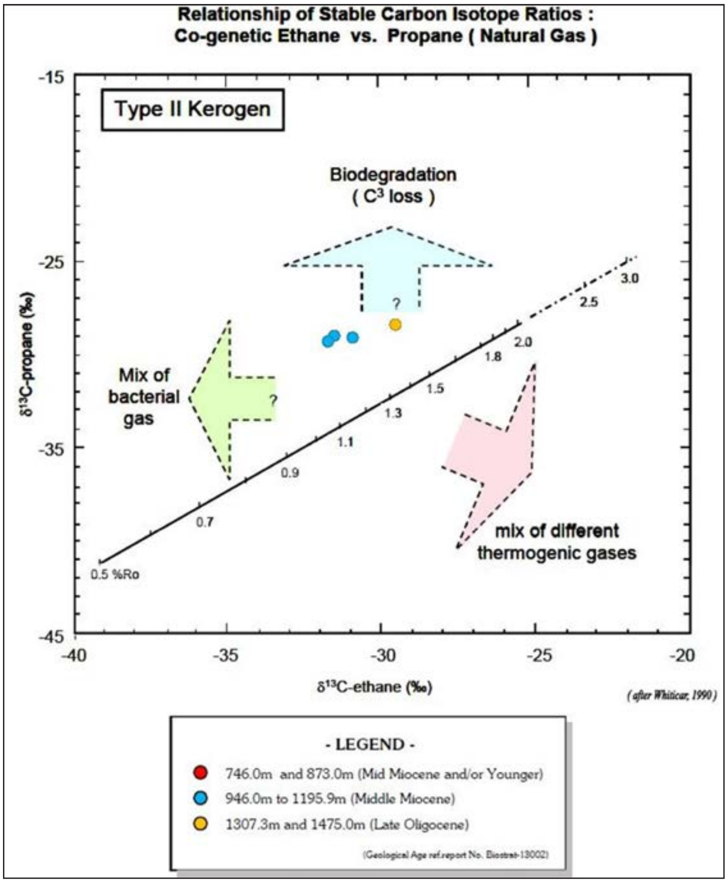


Figure 14: The above cross-plot indicates a relationship of the TBK-1 gasses with a Type II kerogen, and some biodegradation (loss of propane) (modified after Whiticar, 1990).

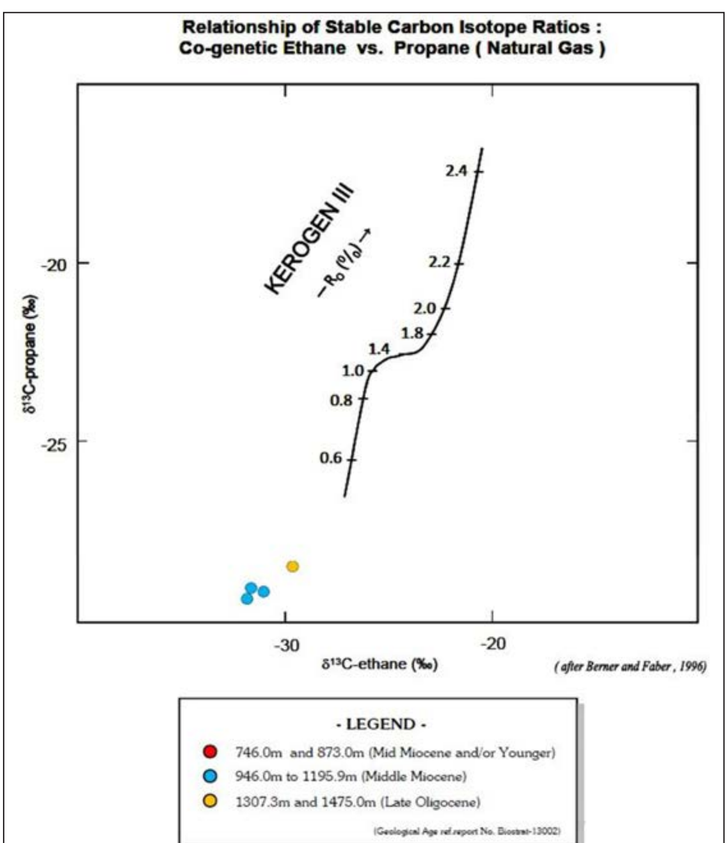


Figure 15: The above diagram illustrates that the TBK-1 gas has no credible relationship to a Type III kerogen source, given that the isotope values do not match Type III Kerogen expulsion at a plausible VRM value. The TBK-1 gas data do not fit the above graph. It is therefore not likely that they have been expelled from a Type III source rock (modified after Berner & Faber, 1996).

weak or unconsolidated sedimentary sequence, and hence preventing a recovery of cuttings.

Most certainly the Group I-10/20 reservoirs have never seen any oil migration; this may be different for the deeper Group I-80, J, and K intervals, since one core plug in J showed oil staining.

DISCUSSION: CAN GAS CHARGE PERCOLATE THROUGH AQUIFERS?

In absence of other alternatives, one might consider a long distance migration along channel axes through the aquifers, given the reservoirs of Tembakau gas discovery are also present down dip in the Sotong and South Angsi fields. The Tembakau gas might have been derived from the mentioned fields, and migrated updip in solution within aquifers. Unfortunately we have no gas data from the mentioned fields, which could help to establish a better correlation. The gas might have accumulated at the highest points on the Tenggol Arch. Migration came to a halt at the Tembakau location, as a result of degassing in the context of pressure, temperature, and possibly also aquifer salinity changes. Accordingly, the strongly biodegraded gas could possibly be originated from gas-saturated water legs of Malay Basin oil and gas accumulations, such as the nearby Sotong and South Angsi fields. If validated, this model could be a play opener for what we termed the "hot basin edge aquifer gas".

According to Duan *et al*. (1992), there are three essential parameters influencing the amount of methane dissolved in water:

- *Pressure.* The solubility of methane in water increases with pressure. A decrease of pressure will cause de-gassing;
- *Temperature.* The effect of temperature is variable, and largely depends on the reservoir pressure. At high temperature, but low pressure there is little or no gas dissolved. At high pressure and high temperature, however, gas solubility is strongly increased. A relative fresh water brine (salt concentration < 1 mol/litre) will hold little CH_4 gas at surface conditions, but could contain 0.07 mol gas at 100 bar (1450 psi) and a temperature of 60 ^{0}C; a temperature increase from 60 to 90 ^{0}C would prompt a release of 0.025 mol gas per litre of aquifer water.
- *Salinity.* Generally speaking, high salinity brines contain less gas compared to fresh water at equal P/T conditions; under certain conditions a mixing of salty brines with freshwater could lead to some degassing.

The Group I-80 aquifer is an unisotropic conduit, where reservoir permeability along the axis of the channel system is believed to be excellent; however lateral permeability within the meandering channelised sand bodies could be variable. The reservoir's relatively low salinity might point to an active freshwater recharge point from freshwater inlets either on the Kuantan coast and/or offshore islands. It might also imply that the aquifer is connected to sand bodies on the western block beyond the Tembakau Fault. Possibly the Tembakau area might form a zone of mixing between recent freshwater from coastal inlets and more salty brines rising from the Malay Basin.

Most aquifers are in a steady percolation, which means dissolved hydrocarbons will be circulated within the confinements of the aquifer. In the case of Group I-80 Tembakau reservoir, the aquifer might be linked to similar age aquifers in the South Angsi area (see Figure 16.25 in Tan, 2009b).

Aquifer and gas parameters are shown in Table 7, and different salinity, pressure and temperature scenarios for degassing and release of CH_4 from aquifers are summarised below:

- Scenario 1: Salinity is constant, with < 1 mol NaCl/litre water; temperature remains constant at 90 ^{0}C. A drop in pressure from 2175 psi to 1450 psi will trigger a release of 0.026 mol CH_4/litre of water.
- Scenario 2: Salinity is constant, with < 1 mol NaCl/litre water; pressure is constant at 1450 psi. A temperature increase from 30 ^{0}C to 90 ^{0}C will trigger a release of 0.025 mol/litre.
- Scenario 3: Salinity is constant, with < 1 mol NaCl/litre water. There is a pressure drop from 2175 psi to 1450 psi combined with a temperature increase from 60 ^{0}C to 90 ^{0}C; under such a scenario, 0.3 mol CH_4/litre of water will be released.
- Scenario 4: Temperature and pressure are constant (60 ^{0}C and 1450 psi, but a mixing of fresh water and brine (1 mol NaCl/litre) occurs; under such scenario, 0.0145 mol CH_4/litre of water will be released.

In any of the shown examples, the aquifer is seen releasing methane, in a location and under P/T conditions as observed in TBK-1. A mass balancing exercise (with parameters shown in Table 8) indicates that a potential aquifer degassing could match the size of the likely gas accumulations in the Tembakau gas discovery.

From these observations, one might invoke the following model (Figure 16):

- Regional aquifers have absorbed light hydrocarbons from the water legs beneath large oil and gas accumulations on the western rim of the Malay Basin.
- Whilst under circulation and in a temperature regime beneath 80 ^{0}C, hydrocarbons heavier than C_1 were decomposed due to biodegradation, and only C_1 and C_2 remained as remnants.
- In the particularly high geothermal gradient area of the Tenggol Arch, the aquifer started to release its dissolved (partly thermogenic, and partly biogenic) gas. Possibly, the Tembakau Fault acted as a pressure relief valve; with lowered pressure in the vicinity of the fault, further degassing might have occurred before the present-day aquifer equilibrium was established.
- In such way, a secondary "gas cap" was formed in Group I-80 reservoir, and possibly in the other reservoirs as well.

Table 7: Tembakau-1 Group I-80 sand key fluid parameters and parameters for fluid calculations.

TBK-1 Group I-80 Upper Sand Key Fluid Parameters

- Proven column (4 points) from 1159 – 1167 m,
- Inferred GWC @ 1167.2 m,
- Gas composition (very dry gas): 95.58 mol % C_1; 0.5 mol % CO_2; 0.7 mol % N_2; spec. gravity 0.58,
- Calculated gas gradient = 0.053 psi/ft,
- Pressure: 1556 psi or 107.28 bar,
- Temperature: 1556 psi @ 77 °C,
- Water salinity: 11000 ppm NaCl = ca. 11 g or ca. 0.188 Mol/litre,
- Water pressure gradient = 0.425 psi/ft,
- Water does not contain any gas (= fully degassed).

TBK-1 Parameters for Fluid Calculations

- Mol value for CH_4: 16 g,
- Mol value for NaCl: 58.44 g,
- Under standard conditions (25 °C, 1 atm), 1 litre of methane weighs 0.656,
- 1 kg of methane corresponds to 53.83 standard cubic ft (surface conditions),
- Under reservoir conditions for Group I-80 sand, 1 litre of water can contain (or may have contained up to) 0.0775 Mol CH_4 /litre of aquifer water (tables computed by Duan *et al.*, 1992) or 1.24 g methane; consequently, there could have been up to 1.24 kg of methane in one cubic meter of a Group I-80 sand aquifer water.

CONCLUSIONS AND FURTHER WORK

Charge in Tembakau gas discovery is of Neogene age, given that it post-dates the inversion and uplift of the Tenggol Arch relative to the Malay and Penyu basins. The Tembakau accumulation is a mix of biogenic and thermogenic gases, with temperature and condensate wetness index increasing downwards in the drilled sequence. Surprisingly, even the very dry gas of the upper reservoirs appears to have affinity with oil of Type II kerogenous rock of probably Lower Tertiary age. Potential source rocks such as those seen in the TBK-1 well bottom section are immature, and did not yield any oil or gas. Accordingly, the logged TBK-1 hydrocarbons could have reached the location only *via* long-distance migration along laterally connected reservoir beds; with Miocene claystone provided effective top, lateral

Table 8: Parameters for Tembakau-1 aquifer mass balance calculations.

- The assumed clay/little sand discounted area of connected aquifer in amalgamated channels, up-dip of Sotong/South Angsi, and ultimately to Tembakau area measures some 181 km^2;
- In average, 25 m of sand;
- In average, 25 % porosity;
- In average, 97 % water saturations;
- Leading to 1,097,312,500 cubic meters of water;
- Originally containing up to 1,360,667,500 kg methane; and
- Corresponding to **733.5 Bcf GIIP** after full degassing.

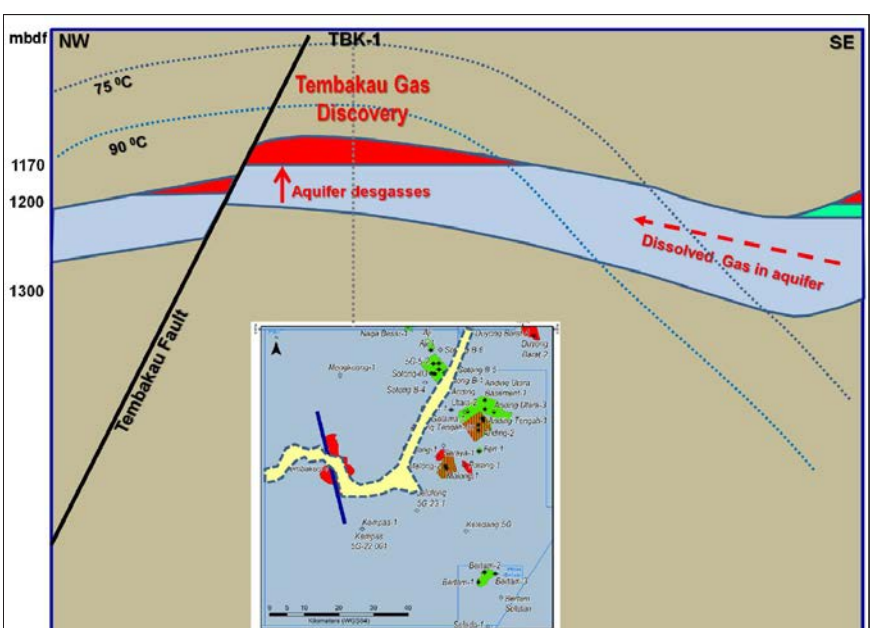


Figure 16: Schematic aquifer degassing model for Tembakau gas accumulation. The inset map shows the approximate line location, and a sketch of Group I-80 channelised feature in yellow extending from Tembakau to Angsi South/Sotong area based on regional RMS amplitude extraction.

and seat sealing. Gas might have reached the well locations from proven down-dip gas accumulations such as the Sotong and South Angsi fields, and migrated within aquifers inside of sand-filled channels such as the Group I-80 reservoir. At the crest of the Tenggol Arch, the aquifer lost its dissolved gas content at an elevated temperature and slightly lower pressure. In particular, the temperature hike of some 30 ^{0}C, plus a mild pressure drop might have sparked the degassing of the aquifer, and the Tembakau Fault seal and clayey top and lateral seals prevented further westward gas migration. Therefore, the Tembakau gas discovery might be considered as a secondary gas cap, derived from gas saturated aquifers connected to fields located at the western edge of the Malay Basin. Moreover, a mass balancing exercise of aquifer degassing points to volumes of similar magnitude compared to the likely gas resources.

Due to limitation of available regional data such as interpretations of regional seismic and horizons, it is noted that the current study is based mostly on analysed geochemical data generated at well locations with trapped gas at the Tembakau area inferred to have been derived from long distance migration. Therefore, an integration of regional structural mapping of the potential mature source rock intervals in the Sotong/Angsi South fields, and correlates to the Tembakau area with the application of basin modeling techniques will enhance or validate the proposed model presented in this paper. Further work should also include a vitrinite data review on Tembakau and adjacent well data, such that the relationship between borehole temperatures and VRM values could be better understood. If validated, this model could be a play opener for what we termed the "hot basin edge aquifer gas".

ACKNOWLEDGEMENTS

The authors would like to thank Malaysia Petroleum Management (PETRONAS) for the permission to publish this paper. We appreciate the analytical work performed by Corelab Malaysia and we extend our gratitude to our colleagues in International Petroleum Corporation Malaysia, and the oil and gas fraternity that have contributed to the ideas presented in this paper. However, any mistakes or shortcomings remain the responsibility of the authors. We thank the constructive comments received from our reviewers Dr. Mike Scherer and Mr. Bob Shoup, which help to improve the quality of the manuscript.

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Manuscript received 20 March 2019
Revised manuscript received 15 May 2019
Manuscript accepted 19 May 2019