Application of Real-Time Mud Gas Logging to Identify Additional Pay Zone in the Randegan Field, Northwest Java Basin

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Abstract. The C1-C8 mud gas service was deployed in a recent development well to identify additional pay zones of commercial interest in the Randegan field located in the Java Basin. Twenty-five previous wells drilled to exploit the primary reservoir in Cibulakan Atas (CBA) Formation, were characterized as light oil. There is one secondary target in the lower part of CBA Formation, and two secondary targets in the Batu Raja Formation (BRF). With oil production from the primary reservoir declining with time, any additional pay zone is a productivity enhancement.

Real-time mud gas measurement and analysis were performed as a mitigation plan to delineate zones of interest, with a qualitative assessment of fluid variations in the reservoirs penetrated. A gas system with high-speed chromatography was deployed on this well for superior quality and accurate detection of compounds from Methane through Octane, Benzene, Toluene, Carbon dioxide and Nitrogen. Gas ratios calculated from the measured compounds provided indicators in real-time in a continuous manner. Further analysis was made using cross plots combining gas ratios and drilling parameters, and the result was validated by comparing with offset Jatiasri's well production using the same mud gas system.

Comparison of all zones of interest in the primary target reservoir and potential zones of interest made by real-time gas ratios and interpretative cross plots are proposed for advanced geochemical insights. The result of the mud gas analysis facilitated the wireline log evaluation process by highlighting the main zones of interest and reducing uncertainties in the selection of intervals for testing. A new zone of interest that was bypassed and not tested in previous wells was found to be potential hydrocarbon-bearing based on mud gas data. This zone was later confirmed with DST samples. The method combined with multiple gas ratios has proven to be reliable in this petroleum setting would also be considered as standard in the upcoming development wells in the area.

Real-time mud gas analysis reduces uncertainty by facilitating downhole log evaluation process, selection of intervals for DSTs, and increases net pay for production.

Keyword: New hydrocarbon zone, Mud Gas Analysis, Real-time.

1 Introduction

Randegan Field is located at 25km West of Cirebon City, West Java. Oil and gas produced from Mid Cibulakan member. The structure is in the Jatibarang Sub Basin, North West Java Basin. Randegan field is a structure in the form of a 3-way dips fault dependence. The anticline stretches NE-SW which is bounded by the main fault in the NE-SW area. Many oil reservoirs are found in the reservoir layer of the Upper Cibulakan Formation and Baturaja Formation Equivalents.

Randegan Stratigraphy can be explained based on two well logs drilled in 1972 that reached the Jatibarang Formation volcanic rock. Names such as Lower, Middle, and Upper Cibulakan Members are adapted to lithological characteristics in each formation such as the Talangakar Formation (TAF), Baturaja Formation (BRF), and Cibulakan Formation (CBA). The Jatibarang Formation is composed of Tufa (dominant) and andesitic lava. The lithology of the Talangakar Formation (TAF) consists of shales, limestones, and sandstones. BRF limestone develops quite well with varying thickness, up to 200m thick, up to 437m thick. The lithology of the Cibulakan Formation consists of the intersection of shales, sandstones, and limestones. Limestone of the Parigi Formation (PRG). On top of the PRG, about 100m thick gluconate sandstone found, which is the lowest part of the Cisubuh Formation.

To reduce uncertainties and distinguish the thin permeable layers, an advanced mud gas acquisition system capable of providing accurate C1-C8 hydrocarbon gases and aromatics was used during the drilling operation in the one recent well in Randegan field name is R-1.

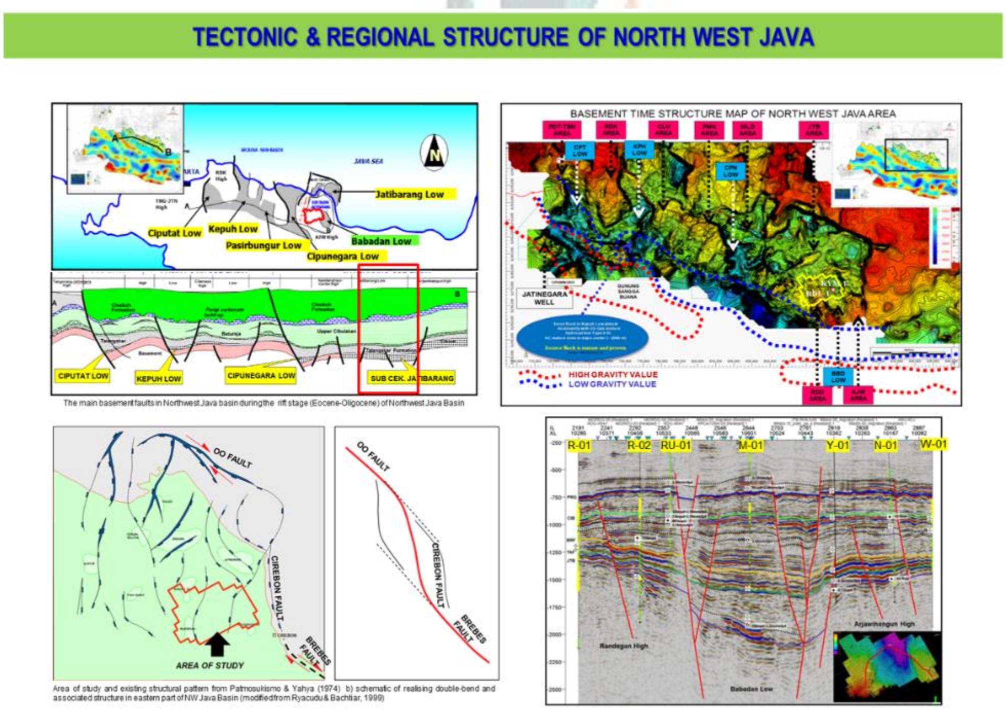


Figure 1. Sub-basin Jatibarang Configuration of North West Java Basin

This paper describes how the integration of drilling parameters, advanced gas detection system and LWD/Wireline provided robust fluid characterization in potential hydrocarbon-bearing zones in the clastic reservoirs of the Upper Cibulakan Formation from R-1 well (figure 2 and 3).

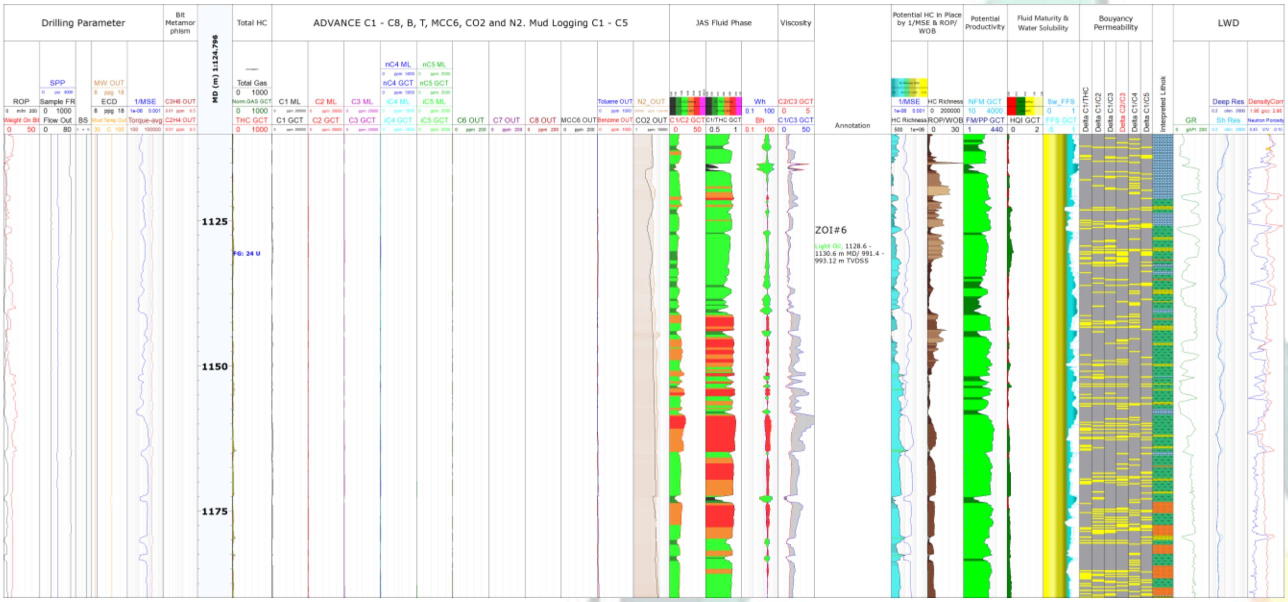


Figure 2. Composite Log of Mud Logging, Advanced Mud Gas Logging data, and LWD in the main target ZOI#6 in the Cibulakan Atas Formation

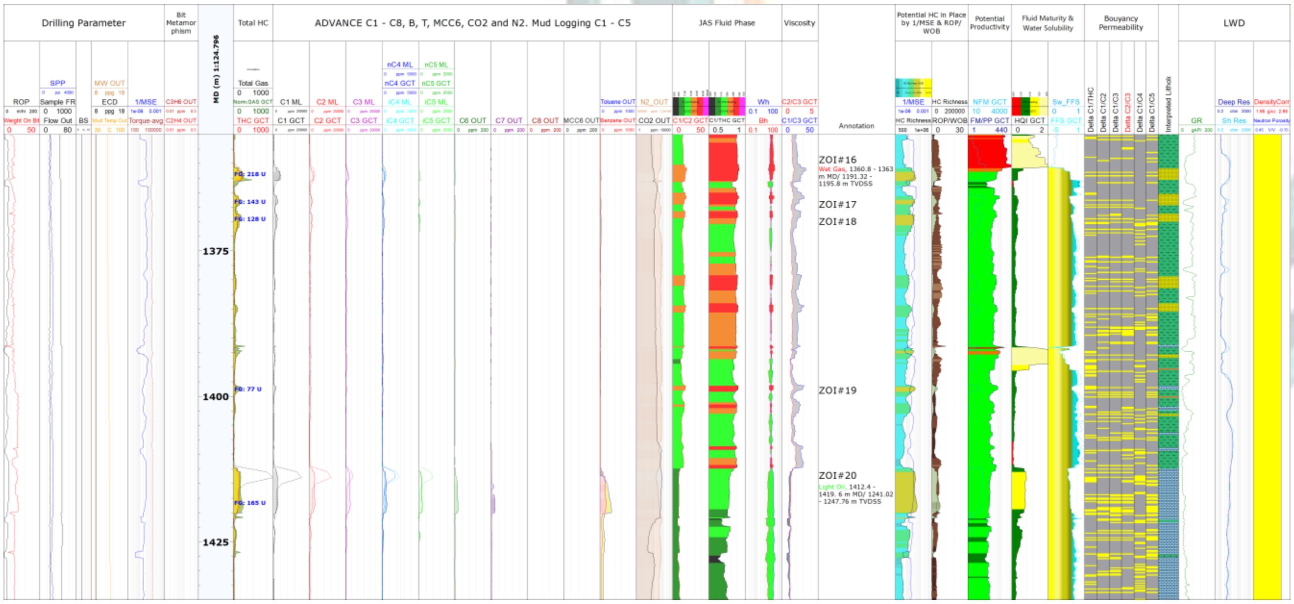


Figure 3. Composite Log of Mud Logging, Advance Mud Gas Logging data, and LWD in a potential additional pay zone ZOI#16 and ZOI#20 in the Cibulakan Atas Formation

2 Data and Mud Gas Model Methodology

The advanced mud gas logging uses a gas extractor fully immersed in the mud close to the bell nipple to ensure the optimal flow regime with minimal loss of gas at the surface. The extracted gas sample was transported to a high-speed chromatograph equipped with a thermal conductivity type detector placed 3 meters from the point of extraction. The gas chromatograph was configured to measure methane through octane, benzene, toluene, nitrogen, and carbon dioxide gas compounds during drilling.

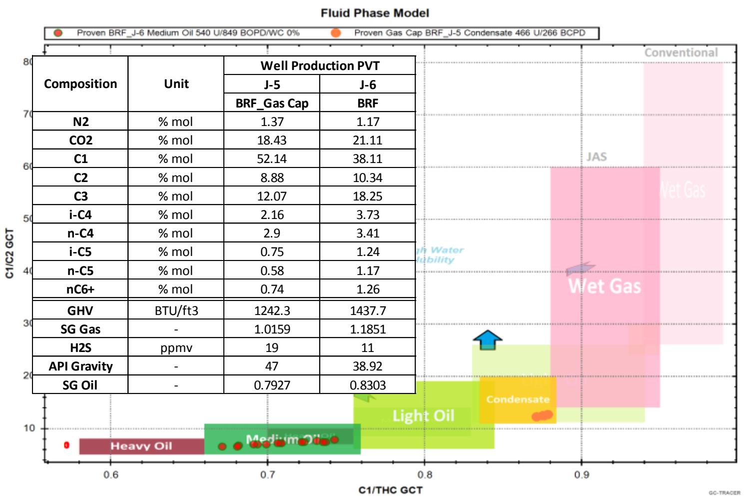
The drilling parameters from mudlogging sensors, gas data from advanced mud gas logging chromatography, and third party LWD data were acquired and aggregated in the mudlogging system database in a real-time manner. The processed data generated a series of geochemical gas ratios Vs. depth using pre-defined agreed templates, and used to create formation evaluation and composite logs, aggregating all wellbore information and applied to in a geochemical software to obtain cross-plots panels applicable to the context of this well.

As the first step of the analysis, the gas ratio THC (Total Hydrocarbon Content) was used to delineate potential ZOI (Zone of Interest). THC is defined as the sum of hydrocarbon compounds recorded by chromatography. THC gas peaks that were three times above the background THC concentrations were selected as potential ZOIs. The data quality was re-validated, and each ZOI was individually analyzed using geochemical software. The result of this analysis is presented as the cross-plot model in figures 4-9.

The interval recording high THC values might not always be commercially productive. High THC recorded from intervals rich in organic matter like coal is not of commercial interest in this project. Alternatively, low THC is not always a non-productive reservoir, because a higher density of the HC tends to reduce fluid mobility and results in lower THC recorded. The THC should always be interpreted based on the conditions like drilled cutting volume, drilling mud type and properties, mud circulation parameters, HC fluid properties that fill in the pore space, and drilling parameters. Consistent reading of mud gas logging is the key to generate a proven mud gas model with an individual cut off after the drilling parameters. More reference wells, drilled with the same mud gas equipment, using the same drilling mud environment, improves the correlation and data interpretation process.

The THC cut off was determined based on the study of twelve offset proven productive Jatiasri's (JAS's) wells located close to the Randegan field. ZOI linked parameters were determined based on the mud gas data, and the derived model was validated using proven fluid types from J-5 and J-6 production wells drilled in the BRF reservoir. The well J-5 is producing a condensate gas cap (47° API) while the well J-6 is producing medium oil (39° API). BRF is the closest reservoir after the CBA reservoir.

The ZOI geochemical parameters include hydrocarbon fluid phase & genetic fluid phase (figures 4a and 4b), Hydrocarbon Richness (HCR) & Potential Hydrocarbon in Place (PHCP) based on qualitative cutting volume ROP/WOB(figure 5), Potential Productivity (PP) (figure 6) Hydrocarbon Quality Index (HQI), Fractionation Fluid Saturation (FFS) (figure 7), Buoyancy Permeability (BP) (figure 8(a) and 8(b)) and permeability by C1/C3 – C2/C3 – C1/N2 (figure 9). The cut off has been identified as a single dedicated value to support the interpretation.



Composition	Unit	Well Production PVT	
		J-5	J-6
		BRF_Gas Cap	BRF
N2	% mol	1.37	1.17
CO2	% mol	18.43	21.11
C1	% mol	52.14	38.11
C2	% mol	8.88	10.34
C3	% mol	12.07	18.25
i-C4	% mol	2.16	3.73
n-C4	% mol	2.9	3.41
i-C5	% mol	0.75	1.24
n-C5	% mol	0.58	1.17
nC6+	% mol	0.74	1.26
GHV	BTU/ft3	1242.3	1437.7
SG Gas	-	1.0159	1.1851
H2S	ppmv	19	11
API Gravity	-	47	38.92
SG Oil	-	0.7927	0.8303

Figure 4a. Fluid Phase Model. Generated from twelve JAS wells using data from advanced mud gas calibrated with DST and PVT results. The model was corrected with a genetic fluid path as intercalated organic matter or lithology may interfere with the analysis. The final fluid phase interpretation here includes fluids that can be produced, and mud gas analysis is calibrated using those PVT analyses.

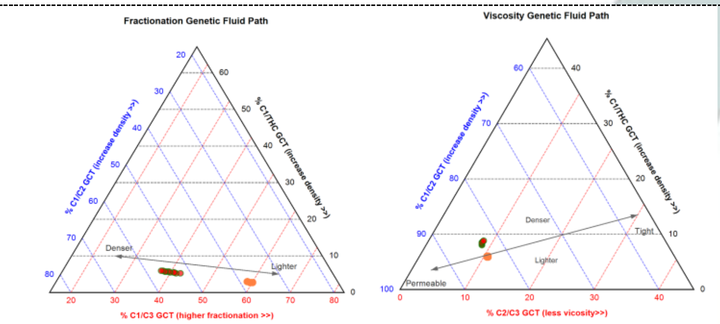
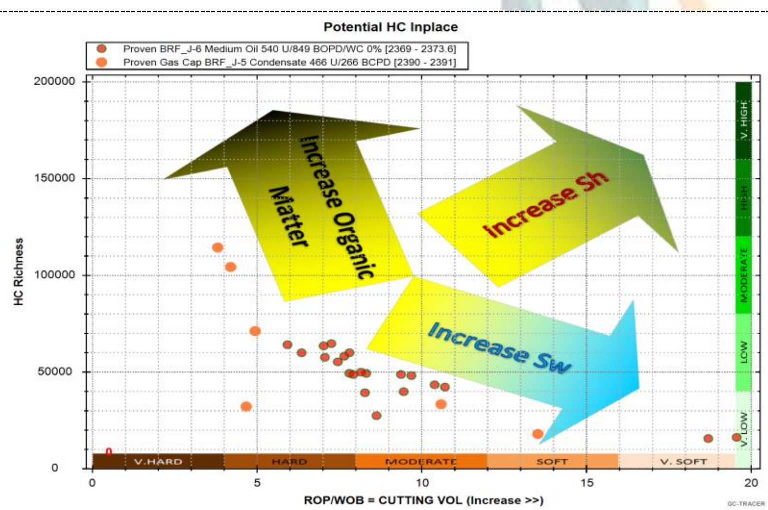


Figure 4b. Genetic Fluid Path Model from Viscosity and Fractionation. Regularly plotted together with the fluid phase model (figure 4a) for fluid phase correction, when required. The genetic fluid paths from and fluid phase for J-5 and J-6 wells showed consistent results, indicating condensate and medium oil type, respectively.



HCR = NTHC*WOB (Unit.klbs)	PHCP = HCR / (ROP/WOB), Unit.klbs^2.hr/ft	
0 – 30K = Very Low (Score: 1)	>10K – 15K = V. Good (Score 5)	>8K – 10K = Good (Score 4)
>30K – 60K = Low (Score:2)	>15K – 25K = Good (Score 4)	>6K – 8K = Moderate (Score 3)
>60K – 90K = Moderate (Score:3)	>25K – 35K = Moderate (Score 3)	>4K – 6K = Low (Score 2)
>90K – 120K = High (Score: 4)	>35K – 45 K = Low (Score 2)	>2K – 4K = V. Low (Score 1)
>120K – 150K = Very High (Score: 3)	>45K – 55K = V. Low (Score 1)	<2K = Water (Score 0)
>150K = Organic Matter (Score: 2)	>55K = Organic Matter (Score 0)	

Figure 5. Potential Hydrocarbon in Place (PHCP) by volume cuttings. The cross-plot shows zones of interest where an increase of potential hydrocarbon richness correlates with an increase in the volume of cuttings as indicated by increase ROP/WOB. THC is defined as the total hydrocarbon content, and NTHC as total hydrocarbons normalized for ROP (ft/hr), flow rate (gpm), and hole size (in). The parameter HCR (hydrocarbon richness) is calculated using NTHC and WOB. Based on the context of this reservoir, the best reservoir would fall in the diagonal line bottom left to the top right of the model. Data from the wells J-5 and J-6 indicated moderate PHCP.

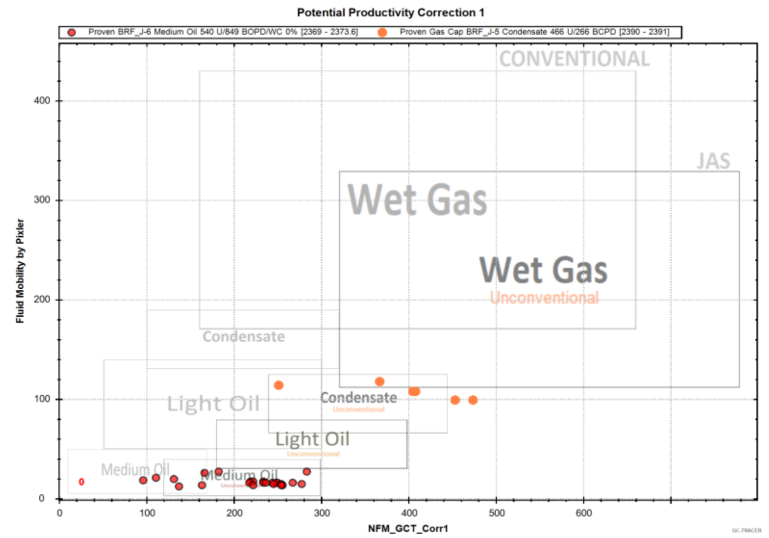


Figure 6. Potential Productivity (PP). This model is the cross plot between normalized fluid mobility versus fluid mobility from Pixler [8]. Normalized Fluid Mobility (NFM) includes a calculated fluid mobility ratio, fluid-phase ratio, mud weight, and drilling parameters. Each fluid phase has a different PP cut off. Usually, the fluid mobility in an individual fluid phase would not be higher than the cut-off. If it below the cut-off, it is suggested to be due to water alteration. NFM values higher than the cut off suggests tight formation and the opposite case would be low to a non-productive zone. In this case, J-5 and J-6 well fall within productive PP, indicating condensate and medium oil fluid phase respectively.

PP (Potential Productivity) = Normalize Fluid Mobility/Fluid Mobility by Pixler

JAS Medium Oil	**JAS Condensate**
0 – 5 = V. Low PP (Score: 1)	2 – 3 = V. Low PP (Score: 1)
>5 – 10 = Low PP (Score:2)	>3 – 4 = Low PP (Score:2)
>10 – 15 = Productive (Score:3)	>4 – 5 = Productive (Score:3)
>15 – 20 = Poor Porosity (Score: 2)	>5 – 6 = Poor Porosity (Score: 2)
> 20 = Tight (Score: 1)	> 6 = Tight (Score: 1)
JAS Light Oil	**JAS Wet Gas**
2 – 4 = V. Low PP (Score: 1)	1.0 – 1.5 = V. Low PP (Score: 1)
>4 – 6 = Low PP (Score:2)	>1.5 – 2.0 = Low PP (Score:2)
>6 – 8 = Productive (Score:3)	>2.0 – 3.0 = Productive (Score:3)
>8 – 10 = Poor Porosity (Score: 2)	>3.0 – 3.5 = Poor Porosity(Score: 2)
> 10 = Tight (Score: 1)	> 3.5 = Tight (Score: 1)

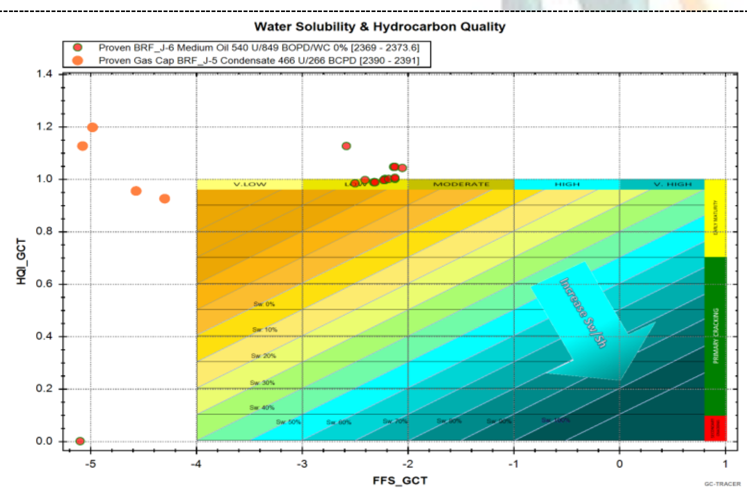


Figure 7. Fractionation Fluid Saturation (FFS) vs Hydrocarbon Quality Index (HQI). Data tending towards the lower right in the cross plot are interpreted to indicate higher water content. FFS is a normalized fluid saturation based on Pixler [8] ratio that includes fluid phase and gas viscosity ratio. HQI is a new maturity ratio C3/iC4, normalized with fluid-phase ratio C1/C2 to indicate degree of thermal maturity. FFS and HQI are closely related, and the relationship can indicate water saturation from mud gas data (SWsol). SWsol can be estimated as shown from the model in figure 7. Data from the wells J-5 and J-6 well fall within the early thermal maturity range with no water solubility in the HC or SWsol = 0.

SWsol:	**HQI (Hydrocarbon Quality Index)**
>80 – 100% = V. High SW (Score: -1)	0 – 0.1 = Water Alteration (Score 0)
>60 – 80% = High SW (Score:0)	>0.1 – 0.2 = Transition 2 (Score 1)
>40 – 60% = Moderate Sw (Score:1)	>0.2 – 0.3 = Transition 1 (Score 2)
>20 – 40% = Low Sw (Score: 2)	>0.3 – 0.6 = Primary Cracking (Score 3)
0 – 20% = V. Low SW (Score: 3)	>0.6 – 0.7 = Transition (Score 2)
	>0.7 – 1.0 = Early Mature (Score 1)
	>1.0 = Very Early Mature (Score 1)

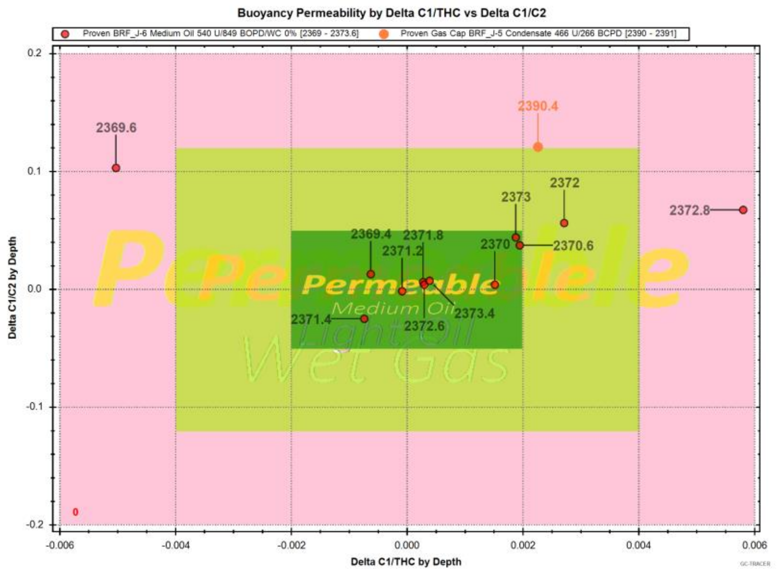


Figure 8a. The Buoyancy Permeability (BP) model is based on C1/THC Vs. C1/C2 delta values. BP is considered as a vertical permeability., Due to smaller size, gas molecules with lower molecular weight can pass through oil zones, while larger liquid component molecules cannot go through gas zones.

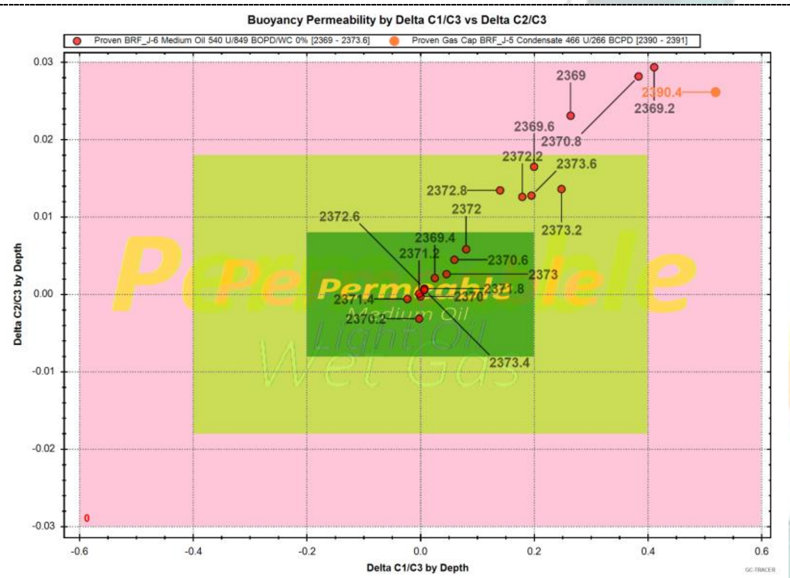
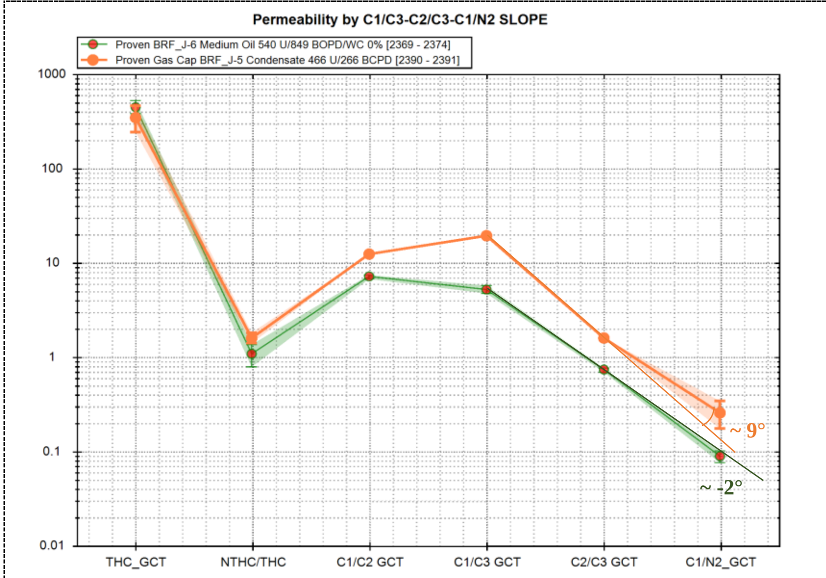


Figure 8b. The Buoyancy permeability (BP) model using the delta values of C1/C3 Vs. C2/C3. This relative BP estimation shows the consistency of a permeability effect by fractionation and viscosity. Considering permeable HC based on these two ratios, the shallow intervals would exhibit relatively higher fractionation and lower viscosity than the deeper intervals. The relative BP is expressed in percentage; higher percentage indicating a zone with higher relative permeability. In this case, the J-5 reservoir indicates higher buoyancy than J-6 reservoir

Relative BP (Buoyancy Permeability):
>0 – 20% = Low (Score 1)
>20% - 40% = Moderate (Score 2)
>40% = High (Score 3)
0 = Impermeable



Permeability by C1/C3-C2/C3-C1/N2 slope
< -3° = Poor (Score 0)
≥ -3° - ≤ 3 = Moderate (Score 1)
> 3° - ≤ 20° = Fair (Score 2)
> 20° = Good (Score 3)

Figure 9. Permeability proxy estimation from geochemical ratios C1/C3 – C2/C3 – C1/N2. The NTHC/THC and C1/C2 ratios are integrated into this model as indicators of lithological hardness and fluid phase, respectively. The C1/C3, C2/C3, and C1/N2 ratios are used as a proxy to permeability. C1/C3 ratio indicates hydrocarbon fractionation, C2/C3 relates to lithological hardness, and C1/N2 suggests porosity changes (especially with J-5 datapoints). The linear relationship of these ratios suggests a relationship between hydrocarbon type, lithology, and pore space. The slope serves as a proxy to relative permeability or minimum permeability (HC flow).

The geochemical data processing software calculates a statistical average for every ZOI ratio selected and generates a final score for each ZOI. Table -1 summarizes the scores obtained for the wells J-5 and J-6.

Table 1. Results for J-5 and J-6 Well Potential ZOI

Well	Top, MDm/ TVDm	Bottom, MDm/ TVDm	Thick Ness, MDm TVDm	Max THC, Unit	C1/C2 AVG	C1/THC	Fluid Phase	J-5 & J-6 Well POTENTIAL ZONE OF INTEREST (Score 1 - 24): ROP/WOB, Cutting Vol. (0 - 20)	HCR (0 - 200K) Score: 1 - 4	PHCP Score: 0 - 5	NFM Corr1. (0 - 1000)	FM (0 - 400)	PP Score: 0 - 3	HQI (0 - 1) Score (0 - 3)	SWsol Score: (-1) - 3	Relative Buoyancy Permeability Score: 0 - 3	C1/C3-C2/C3-C1/N2 Slope Permeability Score: 0 - 3	Total Score Permeability	Score 1 - 24	Highlighted
12.25" Hole, Batu Raja Formation																				
J5	2390 2302.6	2391 2303.4	1 0.8	466	12.40	0.88	Condensate	6.00	60000 2	10000 4	400.0	100.0	4.00 3	1.000 1	0% 3	1 20.00%	9º	3	16	Recommended
J6	2369 2317.1	2373.6 2321	4.6 3.9	540	7.02	0.71	Medium Oil	8.00	50000 2	6250 3	240	10	24.00 3	1.000 1	0% 3.0	9 39.13%	- 2º	3	15	Recommended

The J-5 and J-6 are proven wells with a production rate of 266 BCPD and 849 BOPD respectively. The dataset was selected as a reference for R-1 well in the Randegan field.

3 Result and Discussion

The R-1 well was drilled through the Parigi – Cibulakan Atas – Batu Raja formations. Parigi and Cibulakan Atas formations were penetrated in the 12.25” hole section, and Batu Raja formation in the 8.5” hole section. The main target was determined to be in the Cibulakan Atas formation, and a potential secondary target was expected in the deeper Baru Raja formation.

The advanced mud gas logging setup in the current R-1 well was similar to the JAS wells, for a consistent comparison with the referenced wells discussed.

Real-time mud logging data and advanced mud gas logging gas data were acquired in a real-time manner. LWD data was available for integration and further data processing. All the acquired data were processed Vs. time and Vs. depth to generate formation evaluation logs and composite logs. The processed data was fed into geochemical data processing software to generate various cross-plots discussed earlier.

A total of 23 ZOI were initially delineated in the current R-1 well based on the THC cut-off. ZOI #6 was recorded within the main objective as expected. Two additional zones of potential interest (ZOI #16 and #20) were observed with THC content higher than the main objective. Three secondary objectives were penetrated, recording lower hydrocarbon content in ZOI #21-23. The secondary objectives are, however, not discussed in this paper.

The overall hydrocarbon content remained low throughout the well. ZOI #6 within the main target recorded a very low gas of 24 Units, Relatively higher THC was recorded in ZOI #16 and #20, with 216 and 165 gas Units respectively. In the 12.25” section, intervals with coal / organic matter recorded high THC but were excluded for any interpretation.

The three ZOI (#6, #16, #20) from the current R-1 well were plotted together with the two reference wells J-5 and J-6 in the derived geochemical models as detailed below.

On the models (figure 10), ZOI # 6 in the main target falls within a light composition. ZOI #16 within a wet gas range, and ZOI #20 within a denser light oil range. ZOI #6 lies in the main objective of this well. The fluid composition is intermediate between J-5 (condensate) and J-6 (medium oil), indicating a very light oil composition. A higher ratio C1/C2 relative to ratio C1/THC in the model possibly indicates a higher water content as compared to the J-5 well.

ZOI #16 fluid composition shows the same fractionation as the well J-5, however, the fluid density is relatively lower and viscosity higher. The fluid composition is wet gas to condensate with possible high water content. ZOI # 20 fluid phase is consistent with the fractionation and viscosity trends, indicating a denser light oil composition following appropriate correction. The data points plot close to ZOI # 6 and # 16 indicating the same level of water content.

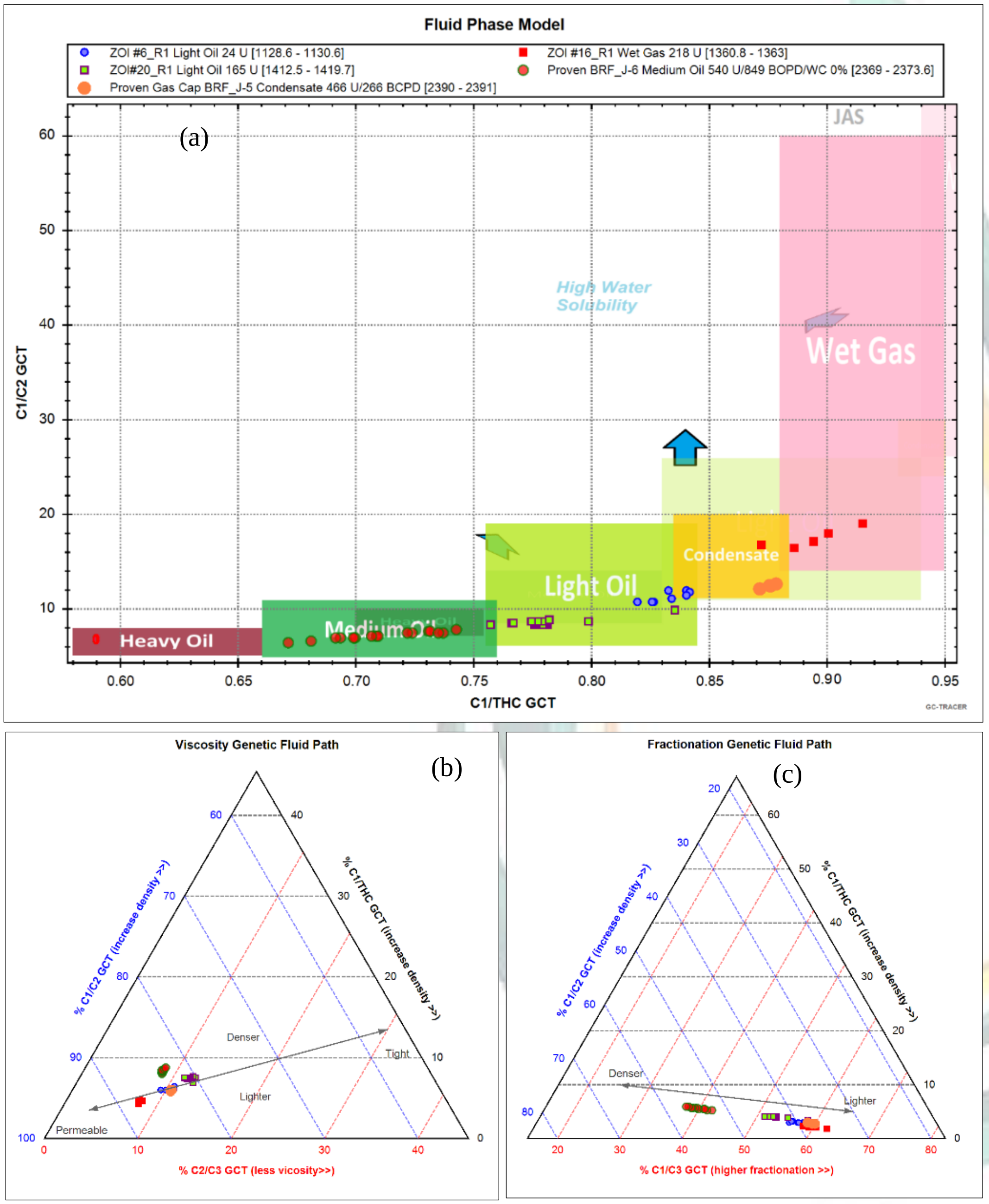


Figure 10. Fluid Phase with Fractionation and Viscosity Fluid Path for ZOI #6, #16 and #20 compared to J-5 and J-6 reference data

The PHCP model (figure 11) indicates that ZOI # 6 is of no commercial interest. The HCR is very low, despite the higher cutting volume generated while drilling. PHCP and HCR in ZOI # 16 are lower than in ZOI # 20, and even the THC shows the opposite trend. J-6 and ZOI # 16 are in a diagonal PHCP, but the HCR is lower in ZOI # 16.

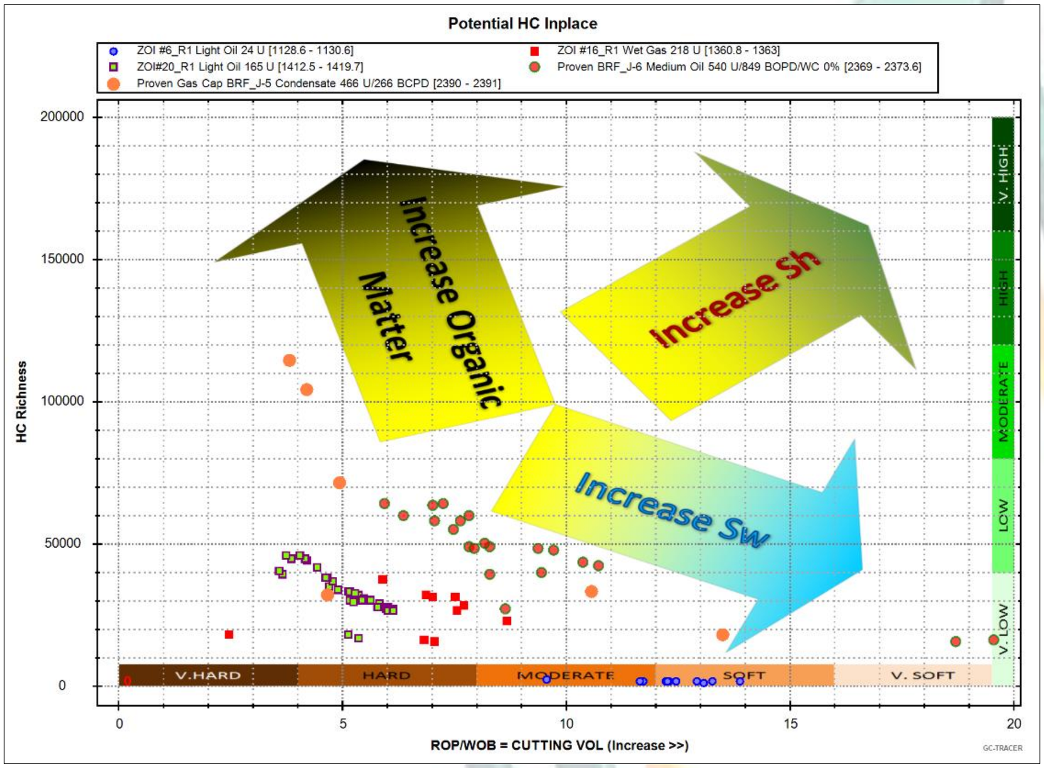


Figure 11. PHCP and HCR for ZOI # 6, #16 and # 20 with J-5 and J-6 well Reference

The potential productivity (PP figure 12) of the main target ZOI #6 is of little interest as the datapoints fall below the values usually encountered in conventional reservoirs. Wet gas bearing ZOI#16 NFM plots as conventional light oil with low fluid mobility. ZOI#20 shows poor mobility. According to the PP (Potential Productivity) referenced model no ZOI can be recommended.

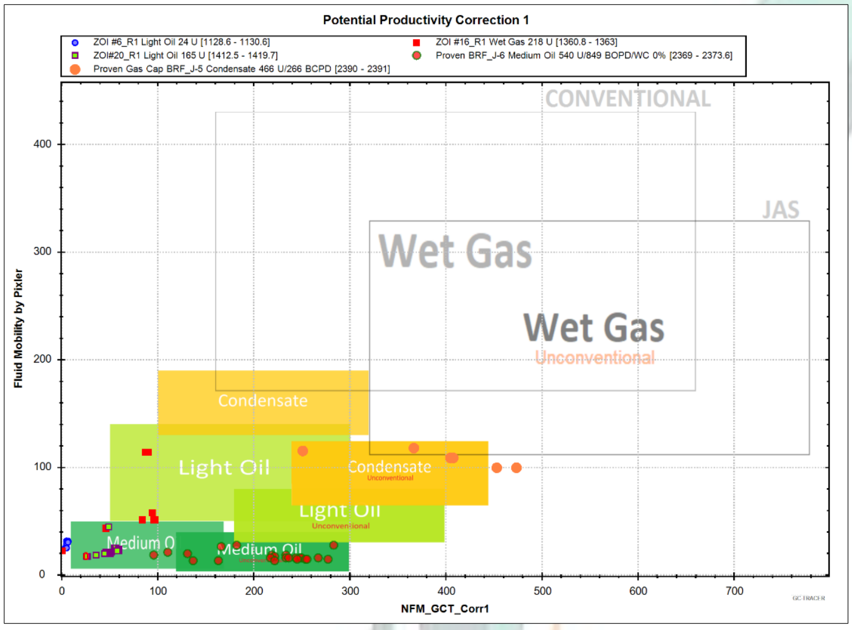


Figure 12. PP for ZOI #6, #16 and #20 with J-5 and J-6 well Reference

Hydrocarbon in the BRF and TAF that underlies the CBA formation, exhibit early HC thermal maturity. In a normal migration scheme, CBA HC would be expected to be less mature than hydrocarbons in the BRF and TAF sediments due to its structural position. If some hydrocarbons of CBA formation appear more mature, it maybe an artefact or caused by more water interactions (water washing or biodegradation) which may impact the gaseous hydrocarbons compositions.

The HQI ratio (Hydrocarbon Quality Index, measured as fluid HC maturity from two gas ratios C3/iC4 and C1/C2) in the selected ZOI # 6, # 16, and # 20 in the R-1 well plot below a value of one, hinting at a high water content in the selected ZOI. The water content in these HC bearing zones may have caused alteration affecting the ratios due to different solubilities of HC components in water. As shown in figure 13, the very high SWsol of 80% is inferred in ZOI # 6, intermediate in ZOI # 16 with SWsol of 60%, and lowest in ZOI # 20 with SWsol of 20%. SWsol % represents the percentage of water in solution with HC indicating that there could be an additional presence of free, mobile, water in these zones.

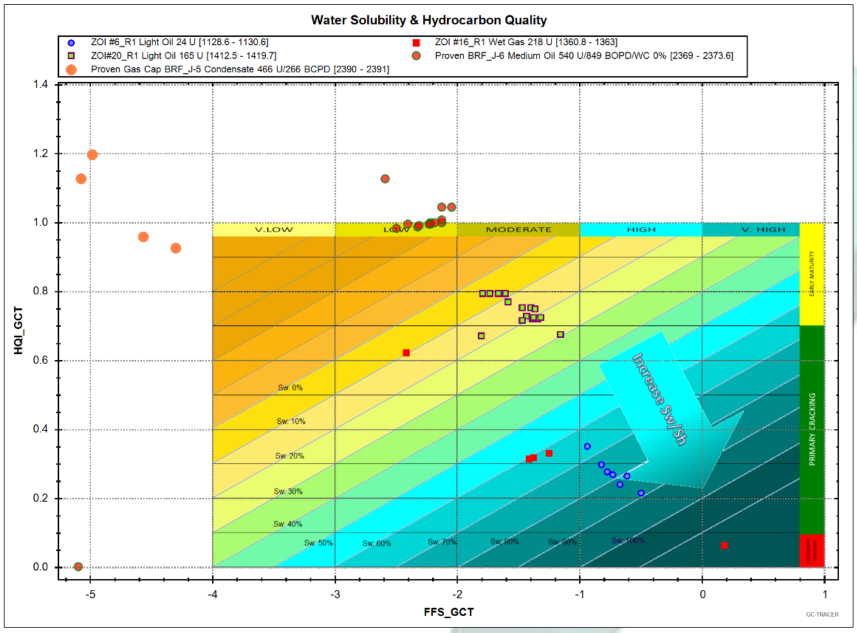


Figure 13. FFS vs HQI parameters from gas evaluation of ZOI # 6, # 16 and # 20 with J-5 and J-6 as well references

Figure 14 is a model for estimating the relative buoyancy permeability (BP). This methodology does not work in the thin-bed pay zones, as the gas compressibility factor is more dominant and interferes with mud gas data resolution due to expansion while being transported to surface via drilling mud. Liquid HC with more than 3 meters pay zone is ideal for this method. From the three ZOIs proposed, only ZOI # 20 exhibits a value of ~17% buoyancy permeability, while the rest two are seemingly impermeable sediments.

Buoyancy permeability was assessed with calculated ratios C1/C3 – C2/C3 – C1/N2 in the suggested geochemical permeability method (Figure 15). This method works very well, even in the thin-bed pay zones. ZOI #6 shows poor permeability (value ~-18°) while ZOI #16 falls within moderate permeability (value ~1°) area. Although ZOI #20 shows a lower permeability value estimated ~ -9°. It is the best ZOI in the well R-1, suggesting a need for reservoir stimulation to increase permeability.

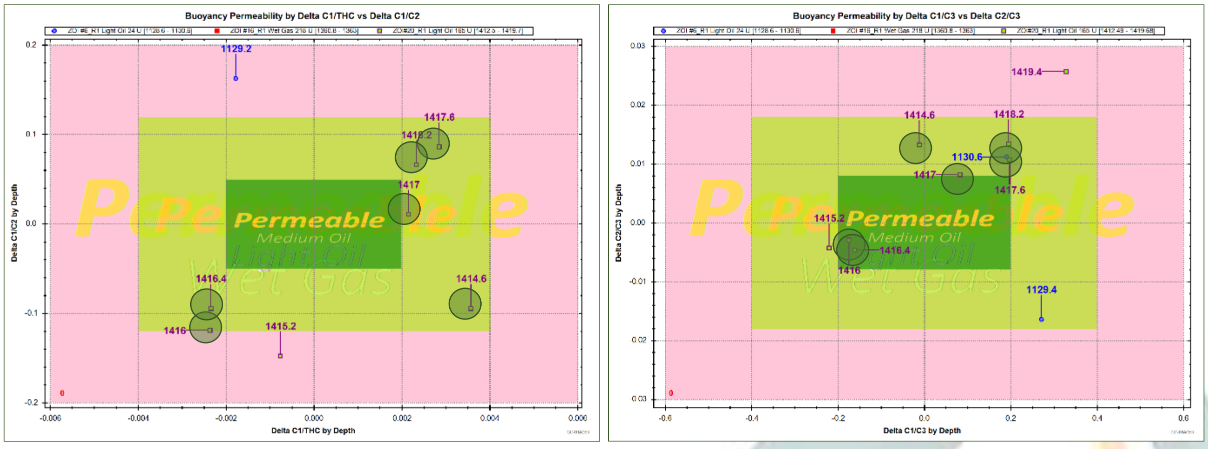


Figure 14. Relative Buoyancy Permeability for ZOI # 6, # 16 and # 20

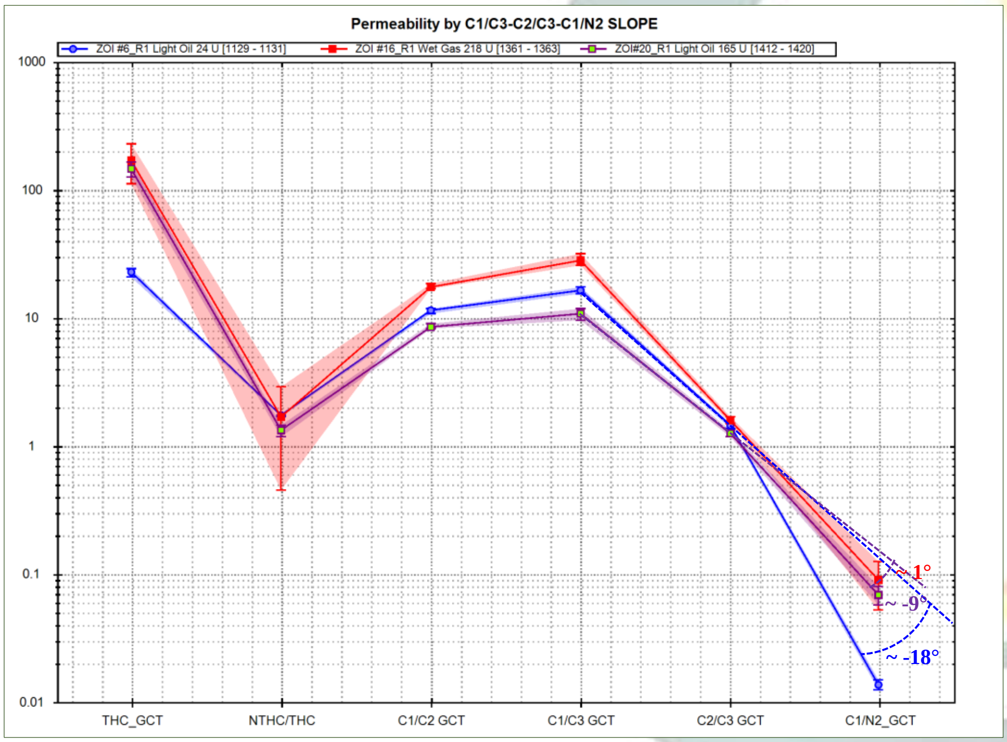


Figure 15. C1/C3 – C2/C3 – C1/N2 permeability for ZOI # 6, # 16 and # 20

The results of the analyses have been summarized in table 2. The main objective ZOI # 6 scores very low (2), and is not recommended for production due to low THC and high water content in solution. ZOI # 16 recorded low HCR and PHCP compared to ZOI #20, despite higher THC. The significant presence of water and condensate type fluid does not make ZOI # 16 a potential interval, even if it exhibits moderate permeability.

ZOI # 20 indicated denser light oil with the highest HCR and PHCP. PP and SWsol are the lowest compared to other ZOIs. Poor permeability in this ZOI indicates the need for well stimulation. Water content remained significant in this zone.

Table 2. Results for R-1 Well Potential ZOI

ZOI	Top, MDm/ TVDm	Bottom, MDm/ TVDm	Thick Ness, MDm TVDm	Max THC, Unit	C1/C2 AVG	C1/THC	Fluid Phase	R-1 Well POTENTIAL ZONE OF INTEREST (Score 1 - 24)												Highlighted
								ROP/WOB, Cutting Vol. (0 - 20)	HCR (0 - 200K)	PHCP	NFM Corr1. (0 - 1000)	FM (0 - 400)	PP	HQI (0 - 1)	SWsol	Relative Buoyancy Permeability	C1/C3-C2/C3-C1/N2 Slope Permeability	Total Score Permeability	Score 1 - 24	
									Score: 1 - 4	Score: 0 - 5			Score: 0 - 3	Score (0 - 3)	Score: (-1) - 3	Score: 0 - 3	Score: 0 - 3			
12.25" Hole, Batu Raja Formation																				
6	**1128.6** 1031.46	**1130.6** 1033.18	**2** 1.72	24	12.40	0.88	Light Oil	12.30	1435 1	117 0	6.3	29.1	0.22 0	1.000 1	70% 0	Impermeable	- 18°	0	**2**	Low HC, High Water
16	**1360.8** 1231.38	**1363** 1235.14	**2.2** 3.76	218	7.02	0.71	Condensate	6.87	24925 1	3628 1	82	65	1.26 0	1.000 1	50% 1.0	Impermeable	1°	1	**5**	Low PHCP, High Water
20	**1412.4** 1281.08	**1419.6** 1287.82	**7.2** 6.74	165	7.02	0.71	Light Oil	5.14	32142 2	6253 3	49	22	2.26 1	1.000 1	20% 2.0	6 16.67%	- 9°	1	**10**	High Water

4 Conclusion

The advanced mud gas logging data and data analysis following the drilling indicated that the main and secondary objectives did not show any production potential. An additional ZOI # 20 was penetrated, suggesting a light oil fluid phase with high water content. Well stimulation was recommended in this zone.

Based on advanced mud gas analysis, LWD, and wireline logging data, Pertamina EP tested ZOI # 20, stimulating with acid. Production testing in this well-recorded 263 BLPD / 108 BOPD / 59 % WC/ 0,14 MMSCFD

The advanced mud gas logging results matched closely with production data. In the current R-1 well, a score of 10 in the oil zone from mud gas logging corresponded to 108 barrel oil per day produced. This was proportional to a score of 16 in the well J-6 corresponding to 849 barrel of oil production per day.

Until recently, Pertamina EP Asset#3 has continued using Advanced Mud Gas Logging for the Northwest Java Basin area, drilling 18 wells until August 2020. This gas data was utilized to reduced any uncertainty in characterizing hydrocarbon-bearing zones and recommendations of the well test, including the additional pay zones, bypassed in the previous wells.

Abbreviations Used

Geology

BRF	Batu Raja formation	Formation Target
CBA	Cibulakan Atas formation	Formation Target
PRG	Parigi Formation	Non-target formation
TAF	Talangakar Formation	Formation Target
JAS	Jatiasri	A field in North-West Java.

Advanced Mud Gas Methods

BP	Buoyancy Permeability, %	BP is the percentage delta value based on light component gas ratios C1/C2, C1/THC, C1/C3 and C2/C3. Delta is calculated for each ratio for each depth step recorded.
FFS	Fractionation Fluid Saturation, Unitless	It is calculated as the normalization of the Fluid Saturation (FS) from Pixler [8] C1/C2 and C2/C3
FM	Fluid Mobility by Pixler, Unitless	FM = (C1 + C2)/ (iC4+nC4+iC5+nC5)
HC	Hydrocarbon	Hydrocarbon in the formation.
HCR	Hydrocarbon Richness, Units.klbs	HCR is calculated using NTHC (Units) and WOB (klbs) as a normalization during controlled drilling rates.
HQI	Hydrocarbon Quality Index, Unitless	Evaluated by taking the C3/iC4 ratio with fluid-phase ratio (C1/C2)
NTHC	Normalized Total Hydrocarbon Content, Units.	THC normalized with ROP (ft/hr), FR (gpm) and BS (inch)
NFM	Normalized Fluid Mobility, Units.ppg	Pixler [8] fluid mobility normalized with MW (ppg), THC and fluid phase gas ratio (C1/C2).
PHCP	Potential Hydrocarbon in Place, Unit.klbs^2.hr/ft	ROP/WOB versus HCR
PP	Potential Productivity, Units.ppg	Evaluated by plotting NFM versus FM
SWsol	Water Saturation in Solution, %	Assessment of water saturation in solution in HC by mud gas logging. SWsol model and value were determined based on twelve offset proven productive JAS's wells.
TAF	Talangakar Formation	Formation target
ZOI	Zone of Interest	Zones where THC values are three times above the THC background.

BS	Bit Size, inch	Drilling parameter
ROP	Rate of Penetration, ft/hr	Drilling parameter
WOB	Weight on Bit, klbs	Drilling Parameter.
FR	Flow Pump Rate, gpm	Drilling Parameter

Downhole Logs

LWD	Logging While Drilling	Downhole Electric Logging While Drilling
WL	Wireline	Post drilling Downhole Electric Logging.

Well Testing and Production

BOPD	Barrel Oil per Day	Production Oil Rate from Production Testing (DST)
BLPD	Barrel Liquid per Day	Production Liquid (Oil+Water) Rate from Production Testing (DST)
DST	Drill Stem Test	Well Testing Method
MMSCFD	Milliion Million Standrad Cubic Feet per Day	Production Gas Rate from Production Testing (DST)
WC	Water Cut, %	Water production percentage from production testing (DST)

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