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# SYNTHETIC DENSITY LOG AND EFFECTIVE DENSITY POROSITY ESTIMATION OF KATI FORMATION, SERI ISKANDAR, PERAK

*Sufizikri Sahari[1]*, Khairul Arifin Mohd Noh[2], Ahmed Mohamed Ahmed Salim[3]*

*Department of Petroleum Geosciences, Universiti Teknologi PETRONAS, Malaysia*

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**Abstract**

This paper focuses on rock physics study on the Kati formation in Seri Iskandar, Perak in Malaysia, particularly in modelling the P wave velocity and bulk density log by using petrophysical relationship through well log data, and estimate the total and effective porosity from the synthetic log. The absence of density log data and incomplete depth coverage of slowness log from this well have challenged the computation of the formation porosity. Thus, Faust's formula and Gardner's equations were used to obtain the synthetic P wave velocity log (SYN_VP) and synthetic density log (SYN_DEN) respectively. The SYN_VP estimated by using Faust's equation shows a good result with normalize root mean square (NRMSE) of 6.24%. In the same depth, SYN_DEN estimated by Gardner's equation with NRMSE of 5% and have an exceptional tie with measured bulk density from 111 core samples. A total of 28 core samples have been measured for its effective porosity with helium porosimeter and ranged less than 5% in average. Effective porosity log generated from SYN_DEN resulted in good match with effective porosity from core with NRMSE 1.44%. The study use core data to validate the model, and NRMSE is used to show the error percentage calculated between the modelled log and core data. The lower the NRMSE value indicates less error model and concluded as reliable synthetic log.

***Keywords**:* Kati Formation; Synthetic Log; Well Log; Effective Porosity; Petrophysics.

## 1. Introduction

Many old oil fields have incomplete log parameters compared to modern fields. The old days may record the data manually thus present the limited information. To re – evaluate the oil field, a complete set of log data is needed to justify whether the field have a potential for a revisit and potential recovery. Somehow, to acquire a complete data set means increasing the cost as well as the risk. However, the absent log can be projected from another log by using petrophysical relationship. Therefore, this study demonstrates similar methodology used by the industry in accomplishing the prediction of the density log from available log by using proven petrophysical relationship i.e. Faust and Gardner equations, for Kati Formation in Seri Iskandar, Perak. Then, the total porosity and effective porosity of the formation can be estimated and more data can be generated to analyze Kati formation in Seri Iskandar with less ambiguity.

## 2. Study area

The Kati Formation previously named as Kati Beds, lies in between the granites of the Bintang and Kledang ranges. It was introduced by Foo [1], to define a formation that occurs in Kuala Kangsar area and extends southward along the western bank of Sungai Perak into Kinta Valley. Alkhali & Chow [2] mentioned that Kati Formation has many similarities with Kubang Pasu Formation and according to Muhammad Hanif *et al.* [3], Singa Formation depict the identical characteristic with Kubang Pasu Formation, which make Kati, Kubang Pasu and Singa Formation correlated with each other. However, Singa Formation distribution focused in

Langkawi's islands and extended to Gunung Raya and Pulau Langgun area [4]. Meanwhile in Kubang Pasu and Singa Formation, there are fossil found imprint in red mudstone layers called as Posidonomya in several locations i.e. Langkawi Island, Perlis and Kedah, which suggest the age of the fossil ranged from Middle Devonian to Carboniferous [5].

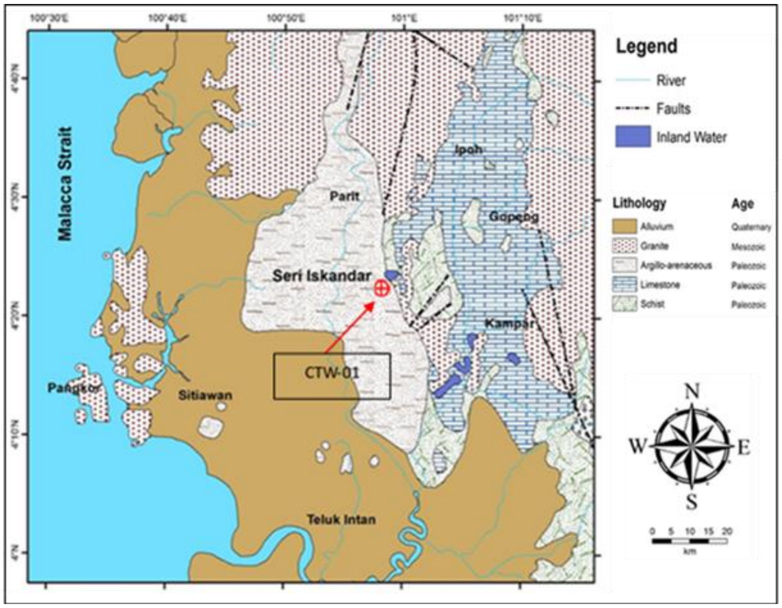


Figure 1 Geological map of Kati Formation and location of CTW-01 well in Seri Iskandar, Perak, Malaysia (*modified after Alkhali & Chow 2014* [3])

In contrast, no fossil has been found within Kati Formation. However, it has been estimated to range from Late Palaeozoic Carboniferous to Permian aged [2]. As in Figure 2, the formation aged as major Upper Paleozoic rocks group in western zone of Peninsular Malaysia by previous researcher [2]. The Kati Formation generally consisted of a mainly monotonous sequence of interbedded metamorphosed reddish brown carbonaceous shale, mud- stones, and sandstones, with minor siltstone "argillaceous and arenaceous rocks" [1,6]. The most recent study of Kati formation has been focused in Seri Iskandar with the idea of Paleozoic hydrocarbon plays [2]. Their qualitative approached research has given a new insight on this Upper Paleozoic rocks. Their studies have contributed to a new assessment on the elements of hydrocarbon systems. The Paleozoic sandstone exposed in Seri Iskandar were evaluated to be potential hydrocarbon reservoir.

As new quantitative approach, this study utilized well log data. In petrophysical analysis, porosity is an important parameter to be determined to analyze the rock. The absence of log data needed to compute the porosity for Kati formation i.e. density log and complete depth coverage of slowness log; has challenged the porosity estimation for the formation. Therefore, the objectives of this paper are to model the synthetic slowness log and density log so the porosity can be estimated. In this study, the synthetic slowness log is needed to cover the depth range from 300 – 415.3m. So that, the synthetic density log can be generated and estimation of the formation bulk density can be made. From that, the effective porosity can be calculated by using synthetic density log as an input. The result then compared with effective porosity measure from core samples to validate the estimation, thus indicates the reliability of the outcome.

## 3. Petrophysical relationship

In rock physics, the geophysical observation and the rock physical properties such as porosity pore fluid content and composition, are closely related [7]. In petrophysics, the technical analysis from laboratory data as well as borehole measurement become the key to get the reservoir properties i.e. shale volume fraction, porosity, permeability and water saturation. Nevertheless, some of the property is not possible to measure it directly due to the philosophy of indirectness. Thus, some other property that is related to the required property is needed. For that fact, interpretive algorithms that relate measurable parameters to reservoir parameters framework are built within the petrophysics [8]. Rock physics parameters that related to the storage capacity, fluid flow capacity are porosity and permeability. The absence of the porosity data makes the analysis more challenging. However, with resistivity data, those unavailable data i.e. density log, can be estimated using the petrophysical relationship i.e. Faust and Gardner empirical relationship [9]

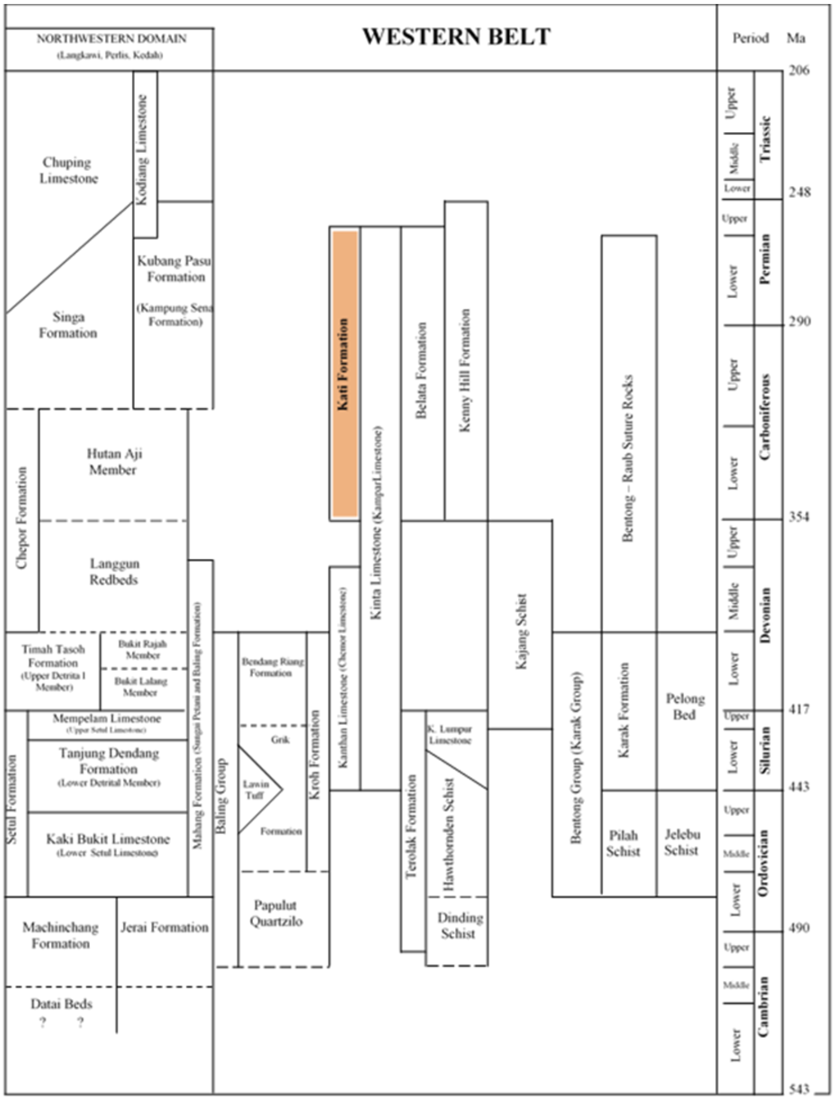


Figure 2 Malaysia's Western Belt stratigraphic chart of Paleozoic sequences *(modified after Alkhali & Chow 2014 [2])*

### 3.1. P wave velocity from resistivity by Faust

Expression for the velocity in a tightly packed spherical particle model which put under pressure has been derived by Gassmann [10]. He observed the elastic constant of such a model vary with pressure. It makes the P wave velocities vary as 1/6$^{th}$ power of the pressure. Then, Faust [11], come out with empirical formula for velocity which, in term of the depth of burial, Z, and the formation resistivity, R. Noted that 'a' constant in Faust's equation is different from Gardner's equation.

Faust's empirical equation:

$$V_p = a(RZ)^{\frac{1}{6}} \tag{1}$$

where: $V_p$ = P wave velocity, m/s; a = constant; R = resistivity, ohm-m; Z = depth.

### 3.2. Density from P wave velocity by Gardner

Bulk density is a vital indicator to delineate shale, in cases of oil sands, accurate density estimation is needed so that the location of the shales can be identified thus interference during the recovery process can be avoided [12]. From a series of controlled field and laboratory measurements of brine-saturated rocks, excluding evaporates, Gardner *et al.* [13] has found an empirical relationship between density and velocity.

Gardner's empirical equation with suggested a and m:

$$\rho = aV^m \tag{2}$$

where: ρ = density; V = P wave velocity; a = 0.31; m = 0.25.

### 3.3. Porosity from density

Density log can be utilized to estimate rock porosities by using the following equation;

$$\emptyset = \frac{\rho_{ma} - \rho_{log}}{\rho_{ma} - \rho_f} \tag{3}$$

where: ∅ = total porosity; ρma = matrix density; ρlog = log density; ρf = fluid density.

Common grain density value which are widely utilize are tabulated in the Table 1. As recommended by Gardner *et al.* [13], the values for density filtrates are 0.9, 1.0, and 1.1 g/cc for oil based mud, freshwater and saturated salt water respectively.

Table 1. Common density value for some minerals and fluid

| Mineral | Density, g/cc | Fluid | Density, g/cc |
|---|---|---|---|
| Quartz | 2.65 | Fresh water | 1.00 |
| Calcite | 2.71 | Saline water | 1.15 |
| Dolomite | 2.87 | Oil | 0.85 |
| Anhydrite | 2.96 | | |

## 4. Materials and methods

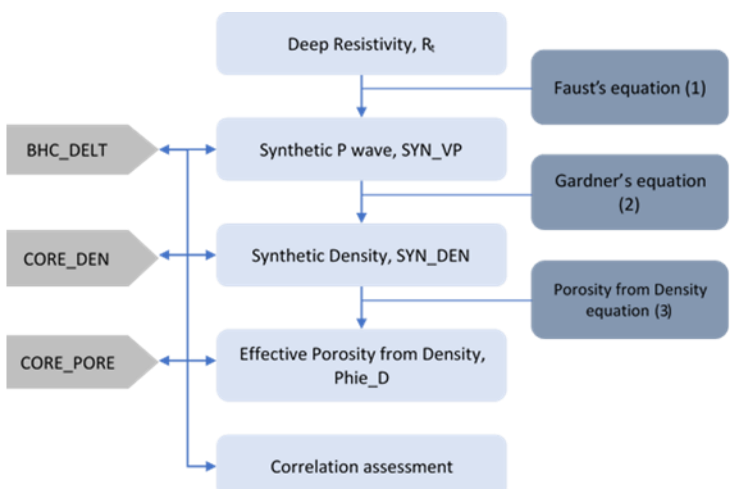


Figure 1. Computation workflow

### 4.1. Synthetic slowness log

The well data from CTW-01 with total logging depth of 415.3m has been used in this study i.e. Gamma ray (GAMMA), Resistivity (RES), and Slowness log (BHC_DELT), as in Figure 2. Apart from that, measured density from core sample are also included in this study as a comparison to the synthetic density (SYN_DEN). The synthetic density log estimation starts by modelling the slowness log first because the available slowness log does not cover the remaining depth after 300m. During data quality check at early stage, the log has been filtered, despiked and smoothed to remove the bad data such as data with negative value.

The Faust's equation has been utilized to determine the synthetic slowness log (SYN_DELT) by applying the equation (1) to the resistivity log and then inverses the obtained P wave velocity (SYN_VP) as in Figure 3. Next, the SYN_DELT log will be compared with reference slowness log measured from the well (BHC_DELT) in the same track to identify the correlation. At this stage, the log has been divided into 3 intervals as; trained data, tested data, and estimated data as in Figure 5. Then, the linear regression model has been built to determine the relationship between estimated slowness log (SYN_DELT) and reference slowness log (BHC_DELT) as in Figure 6. The normalize root mean square error (NRMSE) has been calculated to validate the model as in Table 5. The NRMSE indicates how much error or noise associated with the model. Therefore, the lower the NRMSE the better the model.

NRMSE equation:

$$NRMSE = \frac{\left(\sqrt{\frac{1}{n}\sum_{i=1}^{n}(INPUT - REFERENCE)^2}\right)\;\text{1*}}{\left(\frac{1}{n}\sum_{i=1}^{n}REFERENCE\right)\;\text{2*}} \tag{4}$$

## 4.2. Synthetic density log

To model the synthetic density log, the Gardner's empirical formula has been used. As in the equation (2), one of the parameter for the empirical relationship is P wave velocity, VP. Thus, the SYN_DELT will be inverted to get the P wave velocity as slowness is 1/VP, therefore the P wave velocity used in the equation (2) will be SYN_VP. As in Figure 9, the SYN_DEN log is the outcome calculated using the equation (2). Then, to validate the SYN_DEN log, a total of 111 data samples from core density has been loaded to the log track to train and test the SYN_DEN. Depth interval from 100-250m, has been assigned as a trained data interval and the rest of the depth is the tested data interval as in Figure 10. The linear regression model between core density data (CORE_DEN) and SYN_DEN has been plotted to determine the relationship and the NRMSE will be calculated to show the error of the synthetic density log in comparison with core density data.

## 4.3. Effective porosity from density

After generating the SYN_DEN, porosity can be calculated by using petrophysical empirical relationship equation (3). Porosity data acquired from core sample will be compared to the porosity estimated from the log. Total of 25 core sample has been run through the helium porosimetry apparatus to estimate the core effective porosity (CORE_POR) of the samples. The result from the experiment is tabulated in Table 2.

Table 2 Effective porosity measured from core samples

| Depth, m | PHIE, % | Depth, m | PHIE, % | Depth, m | PHIE, % | Depth, m | PHIE, % | Depth, m | PHIE, % |
|---|---|---|---|---|---|---|---|---|---|
| 108.8 | 5.99 | 135.2 | 3.66 | 187.0 | 3.51 | 259.6 | 1.24 | 342.3 | 1.24 |
| 112.8 | 4.58 | 136.4 | 2.33 | 189.0 | 1.25 | 268.3 | 1.37 | 349.0 | 1.57 |
| 120.1 | 4.28 | 137.5 | 3.51 | 191.7 | 2.49 | 277.1 | 0.19 | 350.5 | 1.05 |
| 122.9 | 3.99 | 139.8 | 4.00 | 193.5 | 2.31 | 280.4 | 1.13 | 396.4 | 1.02 |
| 125.0 | 2.23 | 140.0 | 2.74 | 195.6 | 2.41 | 283.0 | 0.37 | | |
| 130.2 | 4.38 | 141.8 | 3.67 | 214.8 | 1.32 | 295.6 | 0.17 | | |
| 132.6 | 2.81 | 186.5 | 4.52 | 230.0 | 1.49 | 335.4 | 1.31 | | |

To compare the porosity estimated from the core samples, the porosity estimated from the SYN_DEN log must be corrected for the shale effect to get the modelled effective density porosity (PHIE_D), so that the data from both core and log are in the same dimension. Shale volume analysis from GAMMA will be the input for shale correction. The GAMMA log has been divided into 10 intervals to estimate the shale volume. The effective density porosity is derived from total porosity as in equation (4), (5), (6) and computed as in Table 3.

Total porosity from density:

$$\emptyset_{Total} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}, \quad (4)$$

Shale total porosity from density:

$$\emptyset_{T\ shale} = \frac{\rho_{matrix} - \rho_{shale}}{\rho_{matrix} - \rho_{fluid}}, \quad (5)$$

Effective porosity from density:

$$\emptyset_{Effective} = \emptyset_{Total} - (\emptyset_{T\ shale} * VSH), \quad (6)$$

Table 3. Effective porosity computation summary

| Input | | Parameters | | Output | |
|---|---|---|---|---|---|
| Name | Description | Name | Description | Name | Description |
| Bulk density | Density log reading in zone of interest | Bulk density matrix | Density log at 100% matrix. | Total porosity | Total porosity - not corrected for shale effect |
| Shale volume | Calculated shale volume | Bulk density shale | Density log at 100% shale. | Effective porosity | Effective porosity - corrected for shale effect |
| Bulk density matrix | Matrix bulk density | Bulk density fluid | Fluid density i.e. fresh water. | | |
| Bulk density shale | Shale bulk density | | | | |
| Bulk density fluid | Fluid bulk density | | | | |

## 5. Result and discussion

### 5.1. Synthetic log

The RES log shows to be responsive towards the lithology changes as the values deviated accordingly with the lithology boundaries. It is found that within high GAMMA interval, the resistivity values lower compared to the lower GAMMA interval as in Figure 2. High GAMMA value indicates shale and shaly sediment where the presence of clay mineral reduces the resistivity due to its character which is tended to bind with water molecule. This responsive character of resistivity, shows the good data quality. As Crain [14], Faust's empirical formula does not account for gas effect. This well is having no gas bearing interval; therefore, it is suitable to use this petrophysical relationship. RES (64N) and BHC_DELT logs have been set as input for this study with total logging depth of 415.3m and 300m respectively.

Synthetic slowness (SYN_DELT) obtained from Faust's empirical equation with RES (64N) and depth as input, and the constant, 'a' is 635. The data has been trained on the assigned 100-200m depth interval to find the best constant based on the NRMSE value as shown in Figure 5. The next approximately 200-300m depth is used to test the constant. Three intervals with bad data group has been excluded in computation because of the spiked data were too high. As in Figure 5, due to the unavailable BHC_DELT data within 300-400m, the same trained and tested constant from depth 100-300m has been used to project and estimate the slowness on the 300-400m depth interval using the same empirical equation.

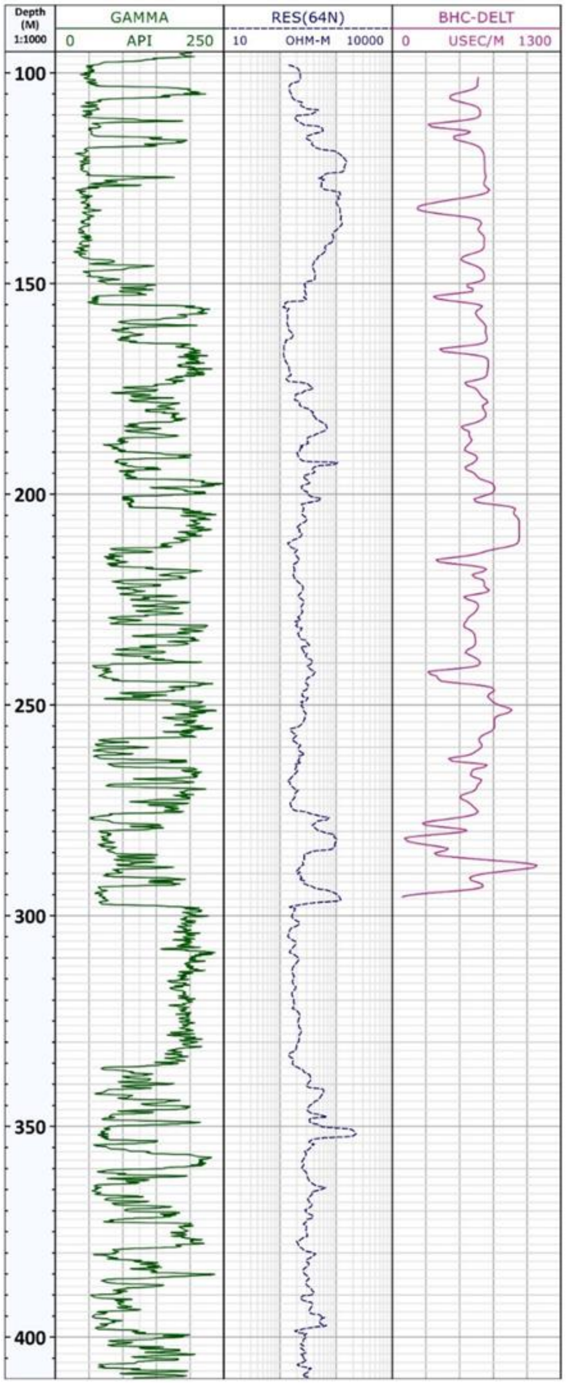


Figure 2. Track from left: depth reference, total gamma ray, formation resistivity log, followed by slowness log. Measured slowness log only up to 300m depth.

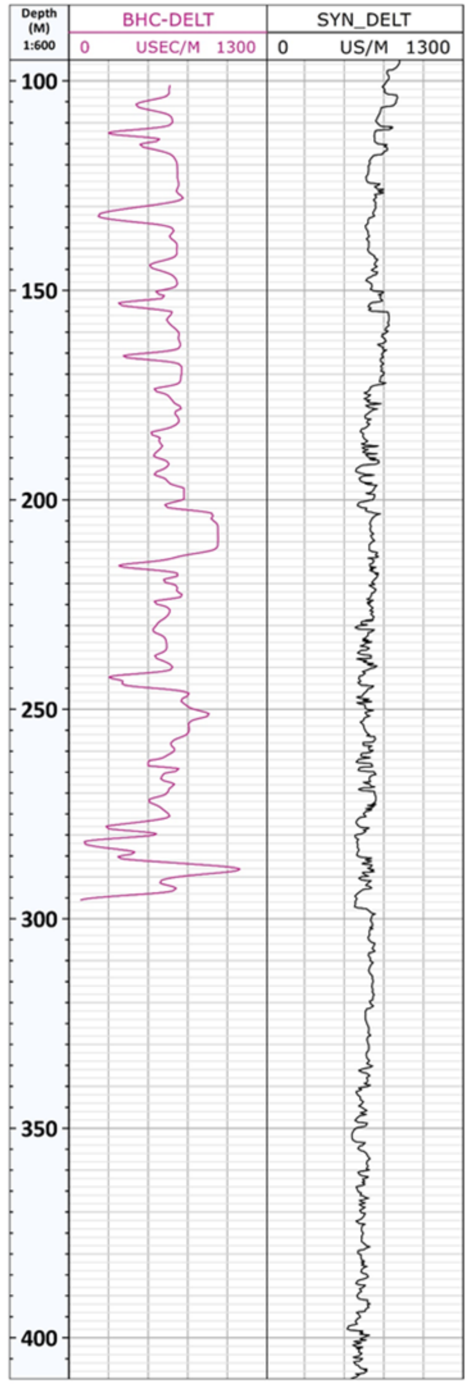


Figure 3. On track 3, SYN_DELT is the slowness log calculated from Faust's equation. The equation product is in P wave velocity. The reason why SYN_DELT is generated; by inverting the product from Faust's equation, the comparison between BHC_DELT and calculated SYN_DELT can be made. From that, the NRMSE can be identify and the error between BHC_DELT and SYN_DELT can be measured.

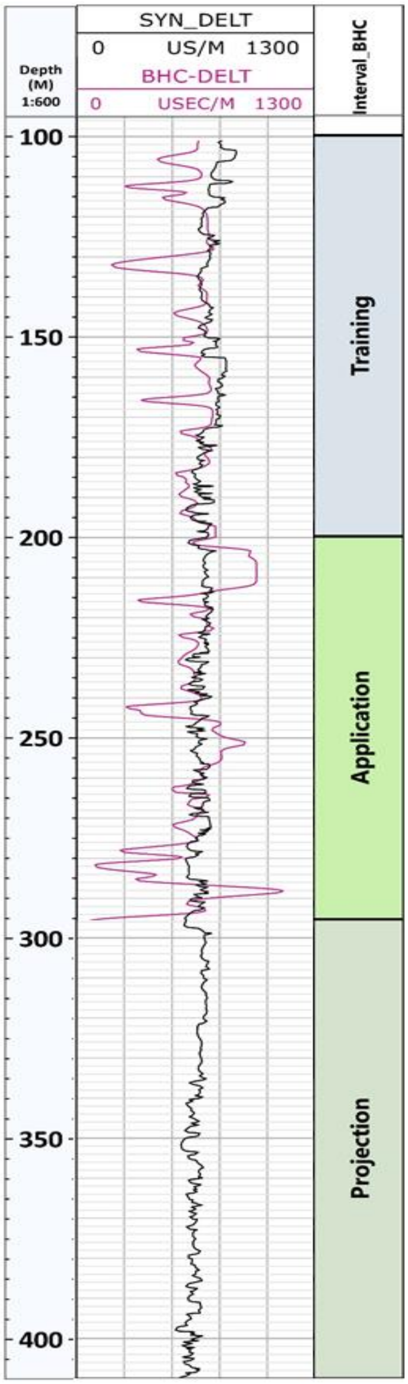


Figure 5. The log track shown the BHC_DELT and SYN_DELT overlain together. Three intervals have been created to train, test and estimate the slowness log. The trained and tested data interval has been highlighted to measure the NRMSE

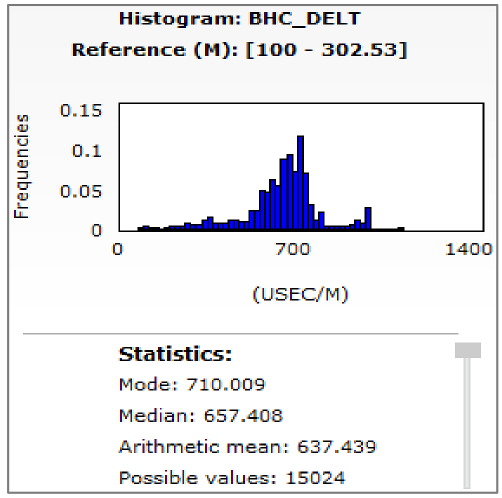


Figure 4. The histogram shows the highlighted reference mean i.e. BHC_DELT. The distinguished spike data intervals however, were excluded

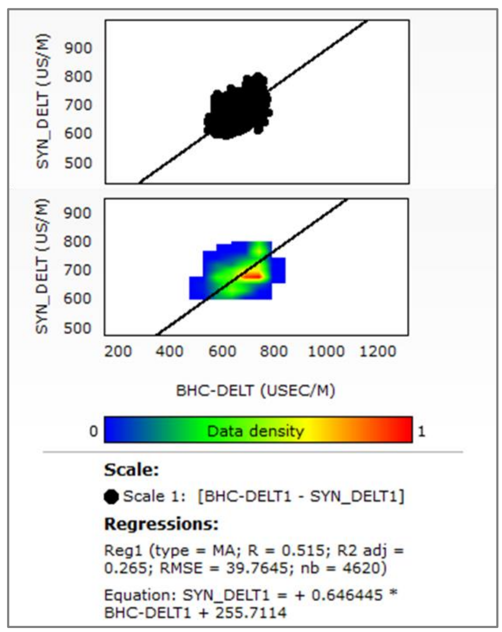


Figure 6. Note the RMSE value obtained from cross plot between BHC_DELT and SYN_DELT in between application interval. Then the NRMSE is calculated and the value is 6.24%. The lower the NRMSE percentage indicates better relationship between modelled and reference log

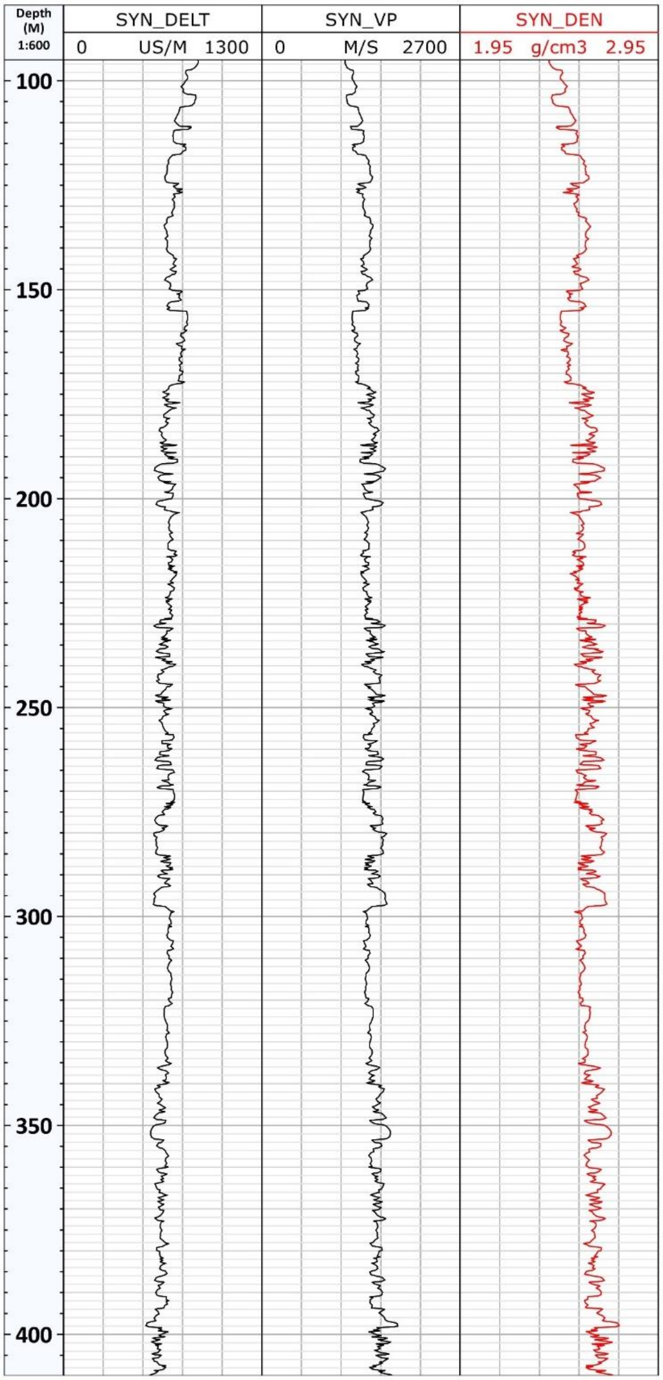


Figure 7. On track 3 the SYN_VP has been acquired from Faust's equation. SYN_DEN has been identified by using Gardner's relationship as on track 4

For this analysis, the relationship between SYN_DELT and BHC_DELT is excellent with NRMSE value of 6.24%. Then, the SYN_VP is used to estimate the formation density using the Gardner's formula. The SYN_DEN has been produced as in Figure 9 by utilizing the Faust and Gardner empirical equation with specifically identified constant for CTW-01. Table 4 summarize the constant used together with associated empirical formula. As shown, the density of the rock increased as it gains in depth due to compaction and diagenesis.

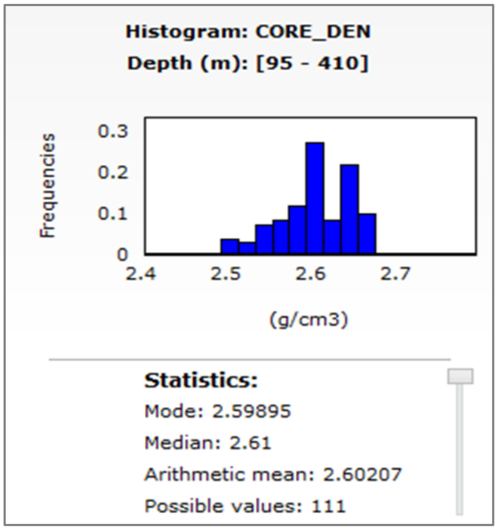


Figure 8. The histogram shows the CORE_DEN statistic values

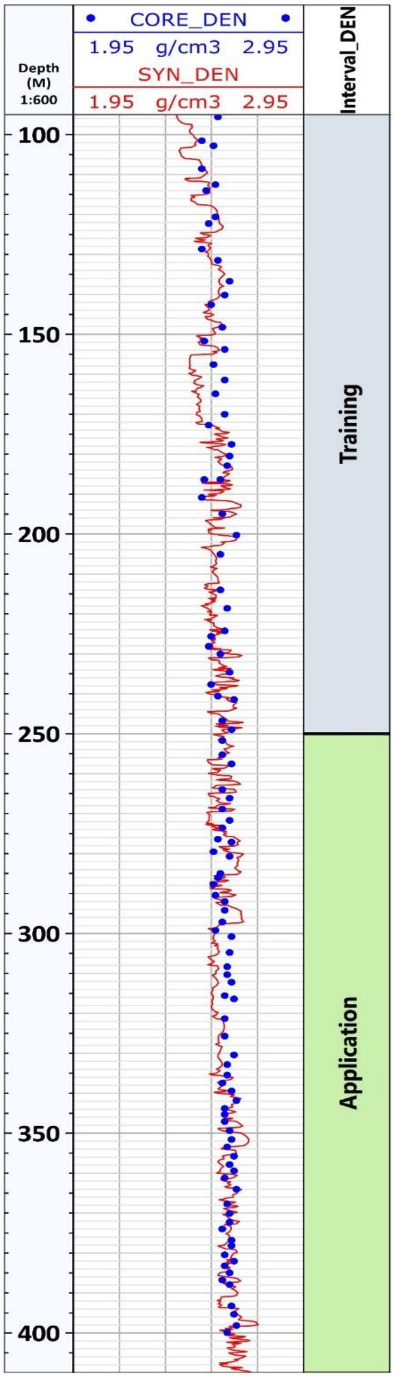


Figure 9. The log track shown the CORE_DEN and SYN_DEN overlain together

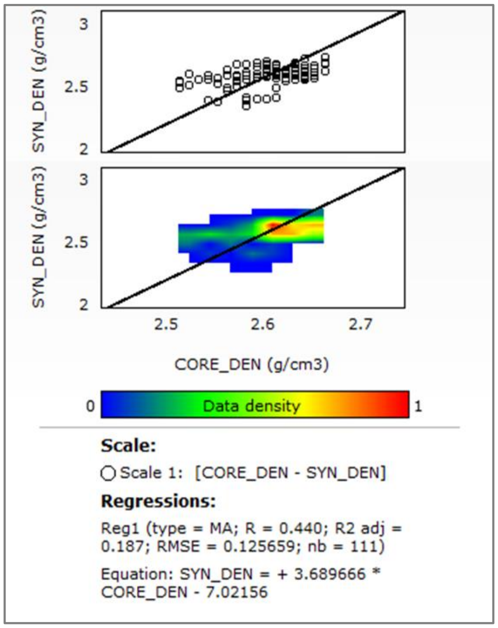


Figure 10. The cross plot indicates the RMSE value between CORE_DEN and SYN_DEN. The calculated NRMSE is 5%

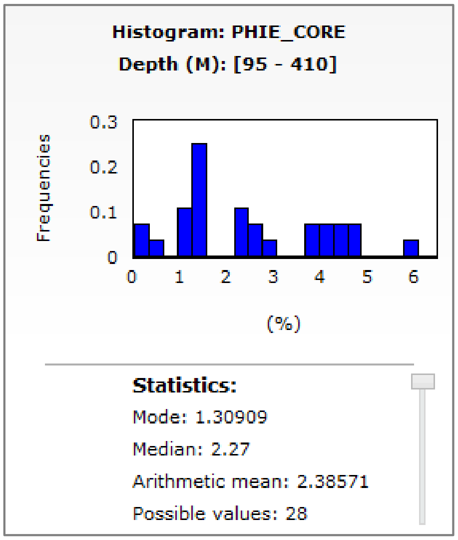


Figure 11. The histogram shown the statistic value for effective porosity from core

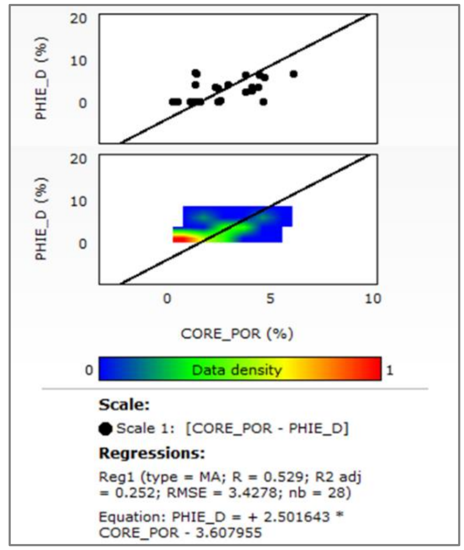


Figure 12. The cross plot indicates the RMSE value for PHIE_D and CORE_ POR. Total of 28 sample have been selected for effective porosity measurement

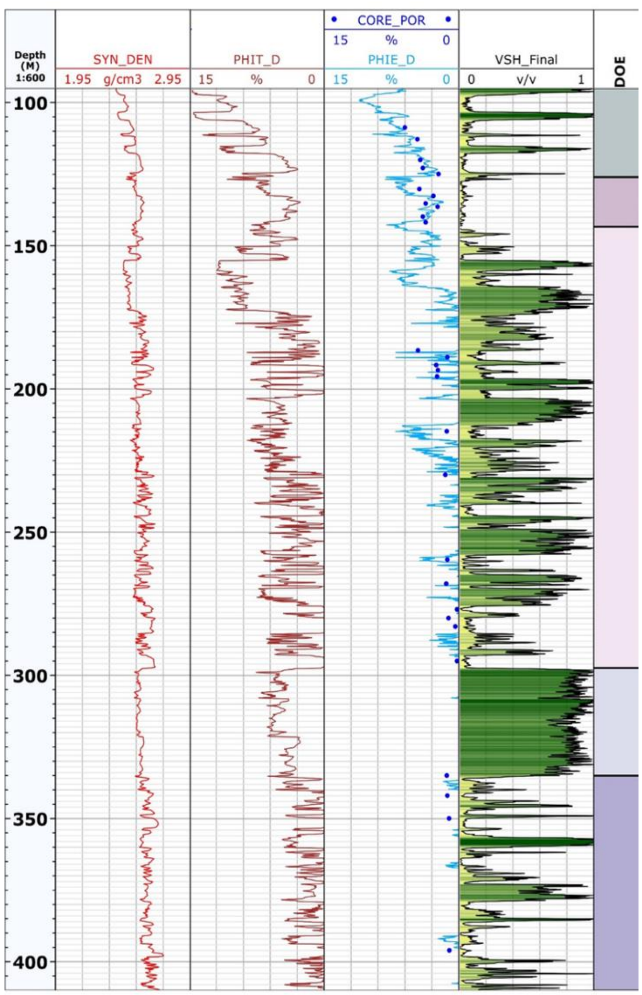



Figure 13. From left, the first track is depth reference track, followed by modelled density (SYN_DEN), modelled density total porosity (PHIT_D), effective porosity from modelled density (PHIE_D) overlain with effective core porosity (CORE_POR), shale volume (VSH_Final), and lastly is the zonation log. Shale volume is needed for effective porosity computation. Shale volume analysis using GAMMA has been done to estimate the shale fraction within certain interval. On track 4, modelled effective porosity from density shown excellent correlation with effective porosity measured from core with NRMSE 1.44%.

To identify the accuracy of the estimated density, total of 111 samples of core density has been loaded into the track as in Figure 10. The SYN_DEN has been divided into two intervals; trained data interval and tested data interval. From that, the 'a' and 'm' can be identified by adjusting its value until the density model fit with the core value. The NRMSE value has been calculated to ensure the relationship between the SYN_DEN and CORE_DEN in a good controlled value ranges. As a result, 'a' and 'm' values are 0.335 and 0.28 respectively with NRMSE value of 4.83%. This study gives an advantage not only in covering the unavailable density log data, yet from the SYN_VP, it estimates the absence of slowness log data within the range of 296.4 – 415.3m depth. By utilizing the Faust and Gardner empirical equation with specifically identified constant for CTW-01. Table 4 summarize the constant used together with associated empirical formula. As shown, the density of the rock increased as it gains in depth due to compaction and diagenesis

## 5.2. Effective porosity from synthetic density log

Based on synthetic density estimated from Gardner's empirical equation, the porosity log can be predicted by transforming the synthetic density log. The result has been combined with helium porosity data obtain from core sample to justify the log. The transformation considers the fluid within the formation is freshwater and the lithology are sand, shaly metasedimentary rock according to the core sample, therefore, $\rho_{fluid}$ = 1.0 g/cc and $\rho_{ma}$ = 2.63 g/cc. Figure 13 shows the synthetic total and effective porosity log obtained by transforming the synthetic density log by using equation (4), (5) and (6).

By transforming the synthetic density log into the synthetic porosity log, helium porosity data from core sample can be compare directly in one track. Result shown in Figure 13, conclude that the synthetic log data estimated from Faust and Gardner empirical equation valid for depth of 100 – 415.3m depth based on the low NRMSE value and visual cross comparison from the core and log data. the NRMSE value for PHIE_D and CORE_POR correlation is 1.44% The effective porosity for this formation is below than 5% in average (Table 2). The porosity of the rock reduced as the depth increase. From 100 – 415.3m depth, the lithology is most likely metasedimentary rock, shale and interbedded shaly metasandstone with fractures and iron stained. Physically, from the core sample, metasedimentary rock is denser compare to the normal weathered sandstone. These factors effected the pore volume of the rock which is why we could see a very low and insignificant total porosity not to mention the effective porosity within 100-415.3m depth interval.

Table 4. Constant value for Faust's and Gardner's formula for the synthetic log

| Petrophysical relationship | Constant | Value |
|---|---|---|
| Faust | a | 635 |
| | m | 0.28 |
| Gardner | a | 0.34 |

*Note that 'a' for Faust and Gardner is a different constant specific only for their equation*

Table 5 NRMSE computation summary

| Input | Reference | RMSE[1*] | Reference mean[2*]. | Reference sample number | NRMSE % |
|---|---|---|---|---|---|
| SYN_DELT | BHC_DELT | 39.76 | 637.44, us/m | 15024 | 6.24 |
| SYN_DEN | CORE_DEN | 0.13 | 2.60, g/cm$^3$ | 111 | 5.00 |
| PHIE_D | CORE_POR | 3.43 | 2.39, % | 28 | 1.44 |

*[1*,2*] Refer equation 4 for NRMSE computation. Note that for porosity the unit is already in percentage thus the final answer does not need a percentage conversion*

## 6. Conclusion

The paper describes the process on predicting the density log data by using few available logs i.e. resistivity. Petrophysical relationship and framework has been fully utilized particularly from Faust's and Gardner's empirical relationship to create the synthetic density log data as well as porosity data for well CTW-01. As in Table 4, the constant value for each equation has been changes until the synthetic log and porosity log fit the reference data i.e. measured log and core data. The tabulated constant in the table is chosen based on the best fitting model with reference data that resulted low normalized root mean square, NRMSE. Table 5 summarize the computed NRMSE value for all the estimated logs. All the modelled logs shown good match and relationship with measured core and well reference data. Effective porosity for Kati formation in Seri Iskandar analyses from CTW-01 is below than 5%. A very low effective porosity range make the rock itself impossible to be a conventional reservoir rock for hydrocarbon. Nevertheless, in unconventional perspective, this formation has a potential to be a fractured reservoir like basement granite reservoir. This is because, from the core sample, lots of fractures found and most of the iron stained present within the open fractured intervals. It indicates the presence of the fresh water.

Therefore, further study is needed to analyze Kati formation with unconventional approach and advance logging tools must be used to acquire the data i.e. neutron log, spectral gamma ray, focus micro imaging log.

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*To whom correspondence should be addressed: Dr. Sufizikri Sahari, Department of Petroleum Geosciences, Universiti Teknologi PETRONAS, Malaysia, sufizikri_g03612@utp.edu.my*