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Petrophysical Study and Rock Type Determination of Siliciclastic Reservoir: Case Study Sand of Bekasap Formation, AF Field, Central Sumatra Basin, Indonesia

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ABSTRACT. An integrated subsurface study has been performed for a large and mature field at the Bekasap Formation in Central Sumatra Basin. The Bekasap Formation sand represents an undeveloped reservoir because of its heterogeneity. Five sand reservoirs (BK1, BK2, BK3, BK4, and BK5) from Bekasap Formation, each zone or layer bounded by a flooding surface. Each sand reservoir has a particular characterization based on petrophysical properties representing sedimentological processes. The petrophysical properties consist of shale volume, porosity, and water saturation obtained by wireline log calculation. This study uses conventional core data to validate the log calculation to achieve an accurate interpretation. Bekasap Reservoir is a sandstone reservoir deposited in the Tide-dominated estuarine. Formation evaluation was done to determine the interest zone by petrophysical properties. The result well-log calculation and reservoir cut-offs showed the thickest reservoir in the BK 3 with the best average values of petrophysical properties with an average shale volume of 0.32 and; porosity of 0.245. Otherwise, four lithofacies are divided in the reservoir in rock type determination based on flow units. The sample RT 1 and RT2 provided the best reservoir zones with HFU1 and HFU2. RT 3 and RT 4 dominated HFU3, and HFU4 had the lowest potential zones of the reservoir. The final findings showed a good correlation between sedimentological analysis and petrophysical properties in the rock type determination. As a result, the best reservoir quality development is controlled by the depositional environment (texture and structure) rather than the diagenetic process in this reservoir. Petrophysical properties in BK1 prove it, and BK2 is coastal barrier sand (tidal sand bar) has more clean sand than in BK3 and BK4 deposited in the offshore bar.

Keywords: Bekasap Formation · Petrophysical study · Rock type determination · Siliciclastic reservoir.

1 INTRODUCTION

AF field has been a productive oil field in the Central Sumatera Basin since 1957, located on the onshore of Sumatera Island (Figure 1). The field was discovered in June 1955 and put into production in September 1957 and currently consists of more than 100 producing wells. The peak production occurred in 1970 with 120 MBOPD and gradually declined (Agan *et al.*, 2009). During the long period of its production, most of the main reservoirs have shown depletion in production and pressure. The water injection scheme has been implemented to maintain reservoir production in a good quality sand reservoir. The good quality reservoir in Menggala and Bangko Formation is already in

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production and swept by existing vertical wells. At the same time, low-quality sand is referred to as shaly sands with poor permeability but still quite potent in producing some oil. Shally sand reservoirs are often found in transition deposits such as Bekasap Formation. Following the success story from another field in the Central Sumatra Basin, Bekasap Formation became a main target for analysis to find the potential reservoir.

Permeability is critical in developing an effective reservoir description, especially in improving recovery factors in the mature field (Pramudyo *et al.*, 2007). Normally, using well-log data to derive permeability estimates is the lowest-cost method. Combining some petrophysical properties such as volume shale, porosity, and water saturation or combining logging data establishes the correlation. The correlation gives the equation to find continuous permeability value in well-log data (Lev, 2000). This study aims to determine petrophysical properties in each reservoir layer and rock type distribution by flow unit characterization in Bekasap Formation. Integrating all data is expected to help interpretation and improve further field development.

2 GEOLOGICAL SETTING/SITE CHARACTERIZATION

The Central Sumatra Basin (CSB) is a series of back-arc basins actively subsiding during the Tertiary. The tertiary stratigraphic section is a transgressive – regressive cycle as a syn-rift phase at Eosen-Oligocene. Developed longitudinal growth faults striking subparallel and various left-stepping graben made extensional deformation during Pematang, Menggala, Bangko, Bekasap, and early Telisa time (Heidrick and Aulia, 1993).

The main reservoir in the AF field is Menggala, Bangko, and Bekasap formation (Sihapas group), which was deposited in Early Miocene. The formation was deposited in nonmarine (Menggala, Bangko) to transition (Bekasap) environment. Bekasap Formation deposited in transgressive conditions at the tide-dominated estuarine environment. The lithology is sandstone has a gradual grain size (coarse to very fine sand) with good sortation and shale in the upper part. The main mineral composition is quartz, feldspar, clay mineral, and siderite, with slight calcite and glauconite. There are five sand reservoirs with different characters, each bounded by flooding surface in the area (Figure 2). By reservoir geometry, there are two types of reservoir zone, such as "channel" sand body (estuarine channel) and "tidal sand flat/sand bar" sand body, in which an estuarine channel has a better reservoir quality than a tidal sand bar (Waren and Noeradi, 2010).

Structural configuration in AF Field is anticline with northwest to southeast trending that plays as several faults cross trapping. In the west part, it is bounded by a main reverse fault trending NW–SE and dipping to NE-ward, while in the east part is bounded by a wrench fault system having north-south (N–S) trending (Pramudyo *et al.*, 2007). There are nine fault configurations identified from seismic, representing nine reservoir compartments and making the trap in this field (LKFT UGM, 2021) (Figure 2).

3 DATA AND METHODOLOGY

3.1 Sedimentology analysis

The petrographic description and mineralogical composition from three wells (AF32, AF333, AF34) are used to identify lithology, diagenesis, and depositional environment. Interpretation of dynamic sedimentation using electrofacies because there is no conventional core description. Electrofacies interpretation was guided by literature study from other fields in the same formation. Next, the flooding surface (fs) was determined to identify each event's reservoir zone and connectivity. The Folk (1974) classification described sandstone in Bekasap Formation. The point count method was used to calculate mineral composition in thin sections to understand the depositional environment and diagenesis.

3.2 Petrophysical analysis

A petrographic description and wireline log data identified reservoir quality. The petrographic description identified some rock types based on textural and diagenetic properties. The wireline log data was used to determine petrophysical properties such as shale volume (Vsh), porosity (phi), permeability (k), and water saturation (Sw) continuously from 15 wells.

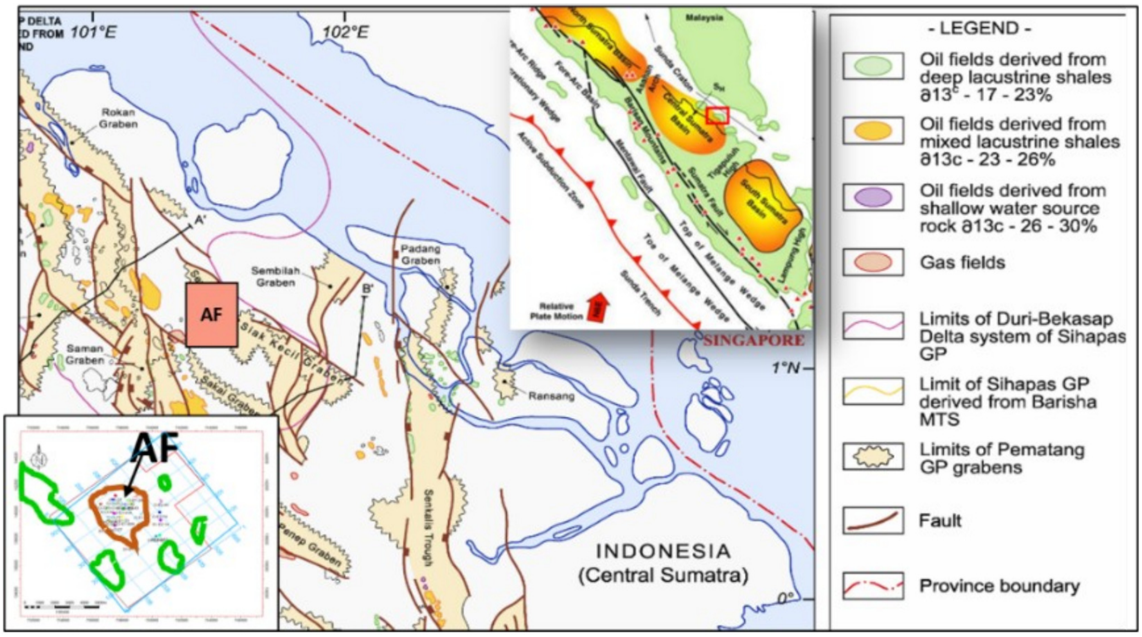

FIGURE 1. The Sitemap of Central Sumatra Basin shows the AF Field Association's location with another field in Riau Province, Indonesia. The geological map recognized features and hydrocarbon potential in the Central Sumatra Basin from Heidrick and Aulia (1993) and Pertamina BPPKA (1996).

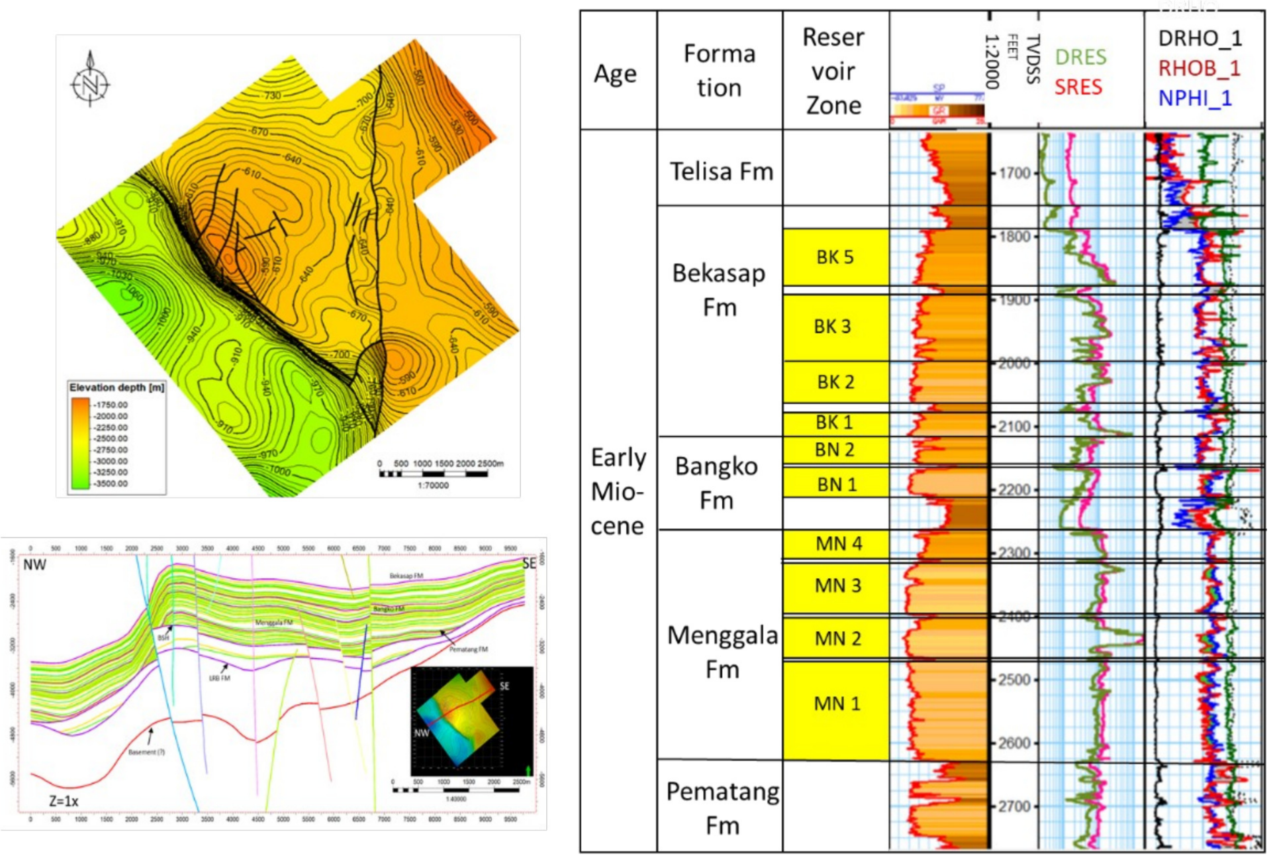

FIGURE 2. The structural map at Top Bekasap Formation and a cross-section through AF Field showed some fault configuring the Area. Stratigraphic succession and reservoir identification at Bekasap (BK), Bangko (BN), and Menggala (MN) Formation (LKFT UGM, 2021).

Result validation used routine core analysis (RCAL) data such as porosity (phi), permeability (k), and water saturation (Sw) from seven wells and got a correlation min 75 %. The following sub-section describes the details of various methods applied during reservoir assessment.

3.2.1 *Shale volume (Vsh)*

Shale volume (Vsh) was required to differentiate between the reservoir and non-reservoir rock and correct porosity and water saturation. The most common models used to calculate shale volume are based on the Gamma-ray (GR) log, Spontaneous (SP) log, or cross-plot of the Neutron (NPHI) – Density (RHOB) log. The calculation used gamma-ray (GR) log because the composition of the formation was a siliciclastic rock (sandstone or shale or a mix of them), and shale composition was radioactive minerals (Thorium, Potassium, and Uranium) that were detected by gamma-ray. The following formula (Asquith and Gibson, 1982) as recommended by many authors, e.g. (Amaefule *et al.*, 1993; Sawy *et al.*, 2020)

$$Vsh = \frac{GR\log - GRmin}{GRmax - GRmin} \times 100\% \quad (1)$$

Where $GRmax$ is the shale baseline (maximum record of Gamma-ray in formation), and $GRmin$ is the sand baseline (minimum record of Gamma-ray in formation).

3.2.2 *Porosity (phi) and permeability (k)*

Porosity reflected the capacity of fluid stored in the reservoir. There are three standard tools to evaluate: using sonic (DT), density (RHOB), and neutron (NPHI) logs. Each tool, such as cross-plot neutron-density logs, can be used independently and simultaneously. The total porosity (PHIT) calculation mostly uses a neutron-density log (Equation 2), and the effective porosity (PHIE) is directly calculated by total porosity, which is corrected by shale volume (Equation 1) followed by Equation 3.

$$PHIT = \frac{\phi Ndsh \times \phi D - Ddsh \times \phi N}{(Ndsh - Ddsh)} \quad (2)$$

$$PHIE = PHIT - (Vsh \times BVWSH) \quad (3)$$

Where $BVWSH$ is bound to water volume, and Vsh is shale volume. The permeability calculation uses two models, Wyllie Rose and Rock Type (porosity and permeability transform). Wyllie Rose permeability models (Equation 4) used log data to calculate permeability (Coates and Dumanoir, 1973). Therefore, the calculation based on the rock type method was calculated zone by zone based on the rock type formulation.

$$Wyllie - Rose, k = 65000\, Cor \frac{\phi e^x}{Swirr^y} \quad (4)$$

Cor is the correlating parameter equal to 1 for oil and 0.1 for gas. Swirr's irreducible water saturation was determined by bucket plots between porosity and water saturation from capillary pressure data at AF 32 and AF 33 wells (Buckles, 1965).

3.2.3 *Water saturation (Sw)*

Water saturation is measured by two methods, Archie and Simandoux methods. The Archie was applied in only a clean sandstone reservoir. Therefore, the Simandoux water saturation method was used in the shaly sand reservoir (Kumar, 2010; Camyra *et al.*,2022). Bekasap reservoir is a transitional environment product in which the common lithology is shaly sand, and the suitable method is Simandoux. Water saturation (Sw) is described in Equation 5.

$$Sw = \frac{c.Rw}{\phi e^2}\left[\sqrt{\frac{5\phi e^2}{Rw \times Rt} + \left(\frac{Vsh}{Rsh}\right)^2} - \frac{Vsh}{Rsh}\right] \quad (5)$$

Where c is the variable (0.4 for sands and 0.45 for carbonate), "a" is the tortuosity factor, "m" is the cementation exponent, and "n" is an exponent of saturation. The coefficient "a, m, and n" came from Special core analysis (SCAL) data from AF 32 and AF 33 wells. Based on SCAL data, a value is 1; m is 1.65, and n is 1.88. Rw is formation water resistivity that is determined by Pickett's plot method. Pickett's plot is a cross-plot between resistivity and porosity. The part believed to contain 100 % water is selected, and the resistivity water values near 0.343 ohm were identified in reservoir temperature.

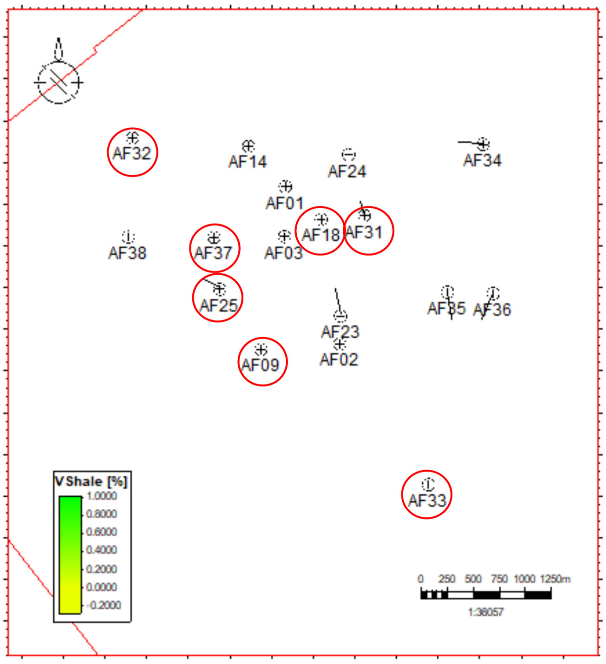

FIGURE 3. Wells distribution map at AF field (RCAL data).

3.3 Rock type analysis

Based on routine core analysis (RCAL) data, the reservoir, and non-reservoir facies are distinguished by petrophysical properties (porosity and permeability). Seven wells with RCAL data (AF09, AF18, AF25, AF31, AF32, AF33, AF37) were chosen to determine the relationship of petrophysical properties, as shown in Figure 3. A cross-plot of porosity versus permeability was constructed, and their histogram showed some trend of data distribution. An interpreter chose a trend that characterized each reservoir rock quality and may lead to an unexpected error. Therefore, capillary pressure in special core analysis (SCAL) data are important parameters to control in trend selection.

Several important parameters have been calculated to define rock type based on the flow zone indicator (FZI) method introduced by Amaefule *et al.* (1993). The pore volume to matrix volume is known as the normalized porosity index (∅z / NPI), reservoir quality index (RQI), and flow zone indicator (FZI) to discriminate the hydraulic flow units (HFU) of the reservoir rock, described in Equations 6 and 7.

$$\phi_z = \frac{\phi}{1-\phi} \tag{6}$$

$$RQI = 0.0314 \times \sqrt{\frac{k}{\phi}} \tag{7}$$

Where porosity (ϕ) is measured in percent (fraction) and permeability (k) is measured in mD. The Flow Zone Indicator (FZI) is a unique parameter that incorporates the geological attributes of texture and mineralogy in the discrimination of distinct pore geometrical facies (flow units) Amaefule *et al.* (1993). So, the flow zone indicator is calculated as written in Equation 8.

$$FZI = \frac{RQI}{\phi_z} \tag{8}$$

The next step is determining the Hydraulic Flow Unit (HFU) to represent rock quality categories. Each separate reservoir rock unit has its flow zone indicator (FZI) values. In this research, a cluster analysis technique (hierarchical) was used to identify results of FZI that have similar hydraulic flow features (Kassab *et al.*, 2017). On a log-log plot of RQI versus ϕ_z, all data with analog flow zone indicator (FZI) will locate on a straight line with one slope. Data with meaningfully dissimilar FZI values will place on other parallel lines with unit slope lines. Every line represents an HFU, and the average FZI values for every HFU can be determined from the intercept of the unit slope straight line with ϕ_z = 1 (Amaefule *et al.*, 1993). FZI indicates the relation between the pore throat, tortuosity, and the effective surface area based on the textural characteristics of the depositional model, such as the type of clay filling, geometry of the interstices system, and the diagenetic effects, as depicted in Equation 9 (Porras *et al.*, 1999).

$$\log FZI = \log RQI - \log \phi_z \tag{9}$$

After validation, propagate the result rock type in core to the non-cored interval at all wells. Establishing a quantitative relationship between GR, shale volume, and porosity (*phi*) data and the calculated FZI values from core data, using Multi Regression Graph-Based Clustering (MRGC) algorithm, to make model FZIs and HFUs. The MRGC approach will likely be implemented for estimating permeability using well logs data (Moosavi *et al.*, 2022). We compared the predicted FZI with the FZI calculated from core porosity-permeability to ensure the model worked properly.

The Multi Regression Graph-Based Clustering (MRGC) method is used to find out the best correlation of permeability from the core with multiple well-log data as a variable input. The relationship between core permeability and well-log data was then used to extend the permeability prediction to uncored wells.

4 RESULTS AND DISCUSSION

4.1 Facies and electrofacies analysis

The sedimentological analysis of petrographic analysis indicates that the Bekasap sands reservoir has two types of sand; Subarkose sandstone and Glauconite sub arkose sandstone (Figure 4). Siderite, pyrite, and glauconite minerals appeared as accessories and interpreted the environmental condition. Siderite mineral indicated a high salinity and evaporated environment like a flat tidal environment. Glauconite and pyrite minerals interpreted marine environments with reductive conditions (Flugel, 2010). The minerals commons appeared in the transitional area such as delta or estuarine.

Lithotype was identified based on crossplot density log and neutron log. Three types of lithology were identified, clean sandstone, shaly sandstone, and shale. Next, a Gamma-ray cut-off was used to understand reservoir and non-reservoir rock. The nearest cut-off is 98 gAPI for the reservoir and non-reservoir zone, and RCAL data validated all interpretations.

Electrofacies were identified by gamma-ray pattern (bell shape, funnel shape, or blocky shape). Based on the petrographic analysis and regional overview of the Bekasap Formation. The facies association consisted of marine shale, lagoonal shale, offshore, transversal, and longitudinal bars deposited at estuarine with tidal influences. The pattern of well-logs showed the marine shale and lagoonal shale has high GR with the serrated pattern. Tidal bars include transversal and longitudinal bars with gradual GR values with funnel shape (coarsening upward). It showed a high gap between density and neutron combination at the base and close to the top. Offshore bars have GR patterns such as bell (fining upward) till serrated -blocky with abrupt contact at the base and have low to moderate GR values. Integrating thin section and electrofacies analysis, five lithofacies were classified in AF Fields.

As mentioned in the petrography analysis (Figure 4) and lithofacies determination (Table 1), reservoir quality can be determined by rock texture (grain size, sorting, and detrital clay content). Based on thin section analysis, the grain size decreased (fine to very fine-grained), and the sorting was moderate to poorly sorted. The visible porosity was good range (0.24; 0.225; and 0.2), but the values were decreased with decreasing grained size and sorting. Therefore, good reservoir quality was associated with good porosity, fine-grained, moderately sorted, and minimum clay content.

4.2 Petrophysical analysis

Reservoir zonation in each event was primarily identified through the composite plots of GR and resistivity log responses in the AF Field (Figure 7). Among these zones, five major sand group zones have been recognized as reservoir zone. Before making a petrophysical analysis, there are some steps: pre-calculation, bad-hole identification, environmental correction, and log normalization. Pre-calculation gave pressure, mud resistivity, and temperature data at reservoir conditions. The average pressure at the Bekasap reservoir is 500–800 psi with 180–190°F temperature. Bad-hole identification and environmental correction were important steps to get better data and minimize misleading tool reading. Log normalization was used in GR log because the data distribution was spread unevenly (0–250 gAPI). After the normalization, the range log between 0 to 170 gAPI.

The measuring petrophysical specified in shale volume, porosity, permeability, and water saturation is calculated by availability log data. The parameter of petrophysical input (cons and baseline) is analyzed in one formation, not in each reservoir, because the environmental condition was equal.

4.2.1 Shale volume (Vsh)

Shale volume is determined by the gamma-ray log (Equation 1). From the log data analysis,

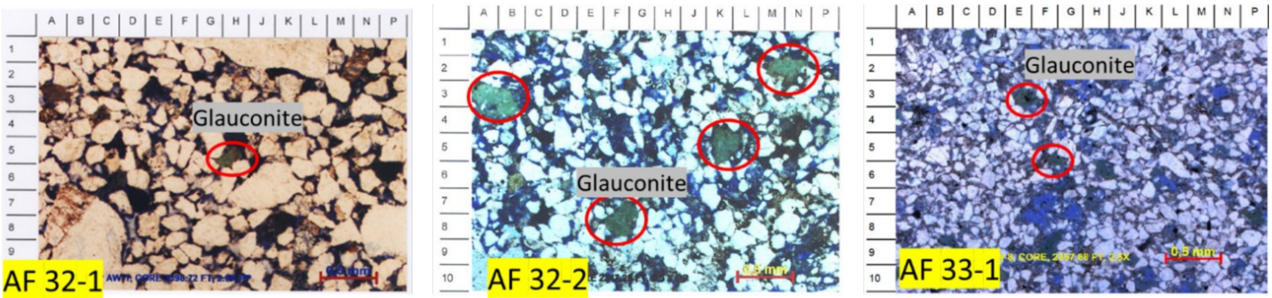

FIGURE 4. In thin section analysis at AF Field in Bekasap Sand Reservoir, the grain from left to right was decreased (fine-grained - very fine-grained) with moderately to poorly sorted. The detrital grains are dominated by quartz and rock fragments. The presence of glauconite, pyrite, and clay minerals is observed as accessory minerals (Lemigas, 2013).

TABLE 1. Lithofacies determination at Bekasap Formation.

Electro-facies	Lithology	Porosity (%)	Log Type	Genetic Facies	Reservoir Rock Type (RRT)
F-1	Very coarse to coarse sandstone	20 – 24	Blocky (cylindrical) & fining upward	Tidal sand bars (axis) or coastal barriers	RT1
F-2	Coarse to Medium sandstone	23	Blocky (cylindrical) & fining upward	Tidal sand bars (axis) or coastal barriers	RT1, RT2
F-3	Medium to Fine sandstone	20 – 22	Coarsening upward (the funnel), sharp top	Tidal sand bars or offshore bars	RT2, RT3
F-4	Fine to very fine sandstone	13 – 18	Coarsening upward (the funnel) and serrated	Offshore bars	RT3, RT4
F-5	Shale	-	Serrated	Mudflat or Floodplain	RT5

the shale volumes of 15 wells at AF Fields in Bekasap formation intervals are 5 %, 36 %, and 90 %, respectively. The correlation between core data (thin section) is up to 88 %. The increment of clay content at the reservoir will be followed by the increment of bulk density, especially in clay sandstone with high porosity, and the clay fills up in the pore space. The shale-adjusted cut-off is 15 %. The zone with Vsh $\leq$15 % represents the clean sand formation, and between 15–55 % indicates shaly sand formation.

4.2.2 *Porosity (phi) and permeability (k)*

Neutron and density logs have been used simultaneously to determine the porosity. The average bulk densities of the dry shale and wet shale formation measured from the density log are 2.67 and 2.35 g/cc. The porosity calculation using Equations 2 and 3. The average total porosity ($PHIT$) in the Bekasap reservoir is 25 %. The coastal barrier deposit (estuarine bar deposit) where BK1, BK2, and BK3 sand reservoir has an average porosity of 26 %. At the same time, the offshore bar has 23 % of the total porosity (Figure 9a). The effective porosities that are the resulting porosity after applying a shale correction are calculated as 18 % for BK5 and BK4, 22 % for BK3, 20 % for BK2, and 24 % for BK1 zones based on the porosity distribution in hydrocarbon-bearing zones, representing a good quality formation. The effective reservoir has minimum effective porosity of 13.2 % based on minimum hydrocarbon permeability flow (1 mD). The lumping of the effective reservoir zone is available in Table 2. Permeability calculation following equation Wyl-

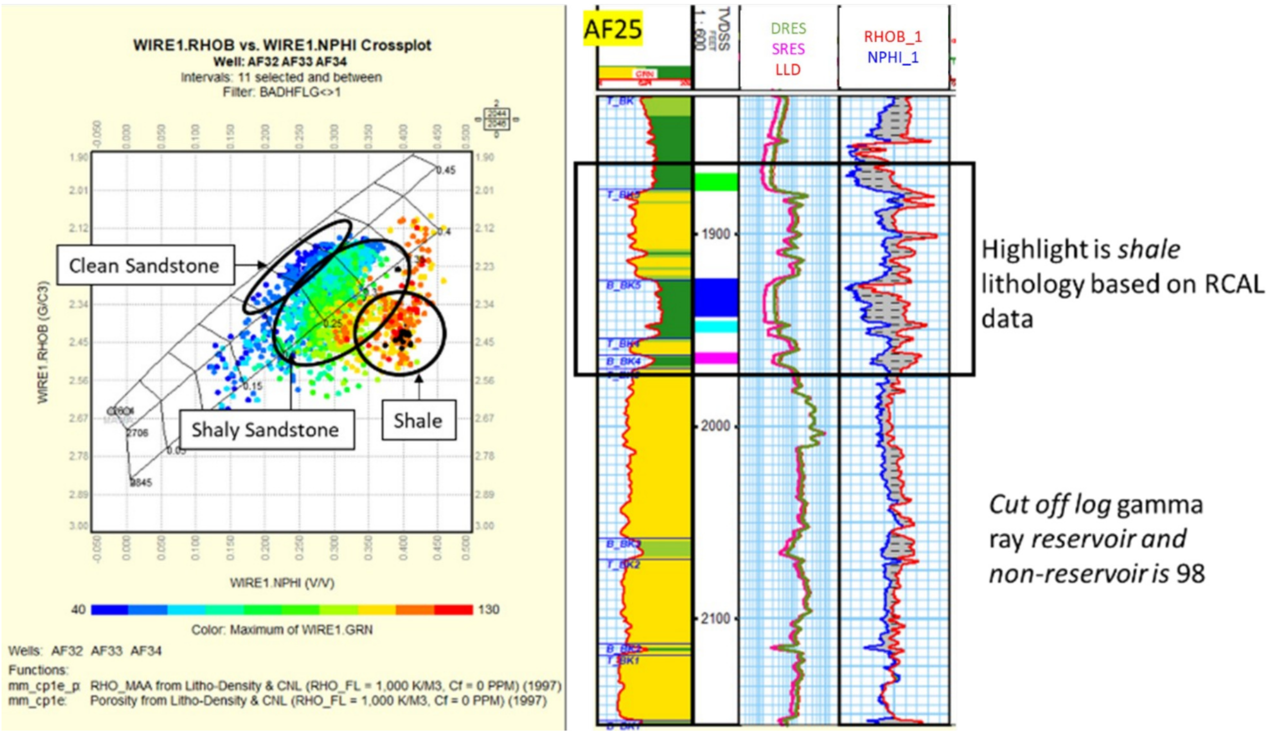

FIGURE 5. Three lithotypes (clean sandstone, shaly sandstone, and shale) types were identified in Bekasap Formation. Density and neutron cross-plot was used to cut off the GR log and got 30–98 gAPI as the reservoir zone (sand), and the upper 98 gAPI was non-reservoir (shale).

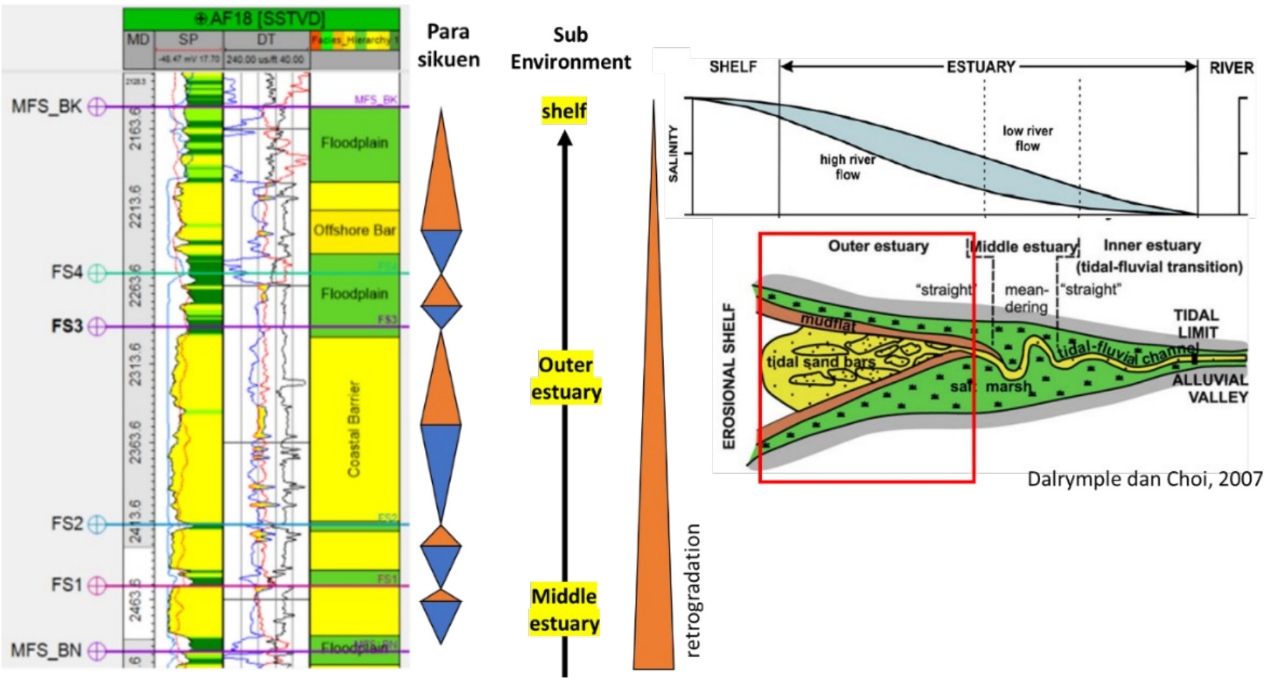

FIGURE 6. Four stratigraphic markers (flooding surface) were identified by shale break barrier and interpreted estuarine environment with tide influences at Bekasap Formation (Dairymple and Choi, 2007). The dynamic sedimentation from the lower to the top gave a retrogradation pattern and illustrated the area getting to the shelf environment. All lithology shale (green color) interpretations can be considered floodplain, mudflat, or marine shale (non-reservoir zone), and the zone below MFS_BK is interpreted as marine shale.

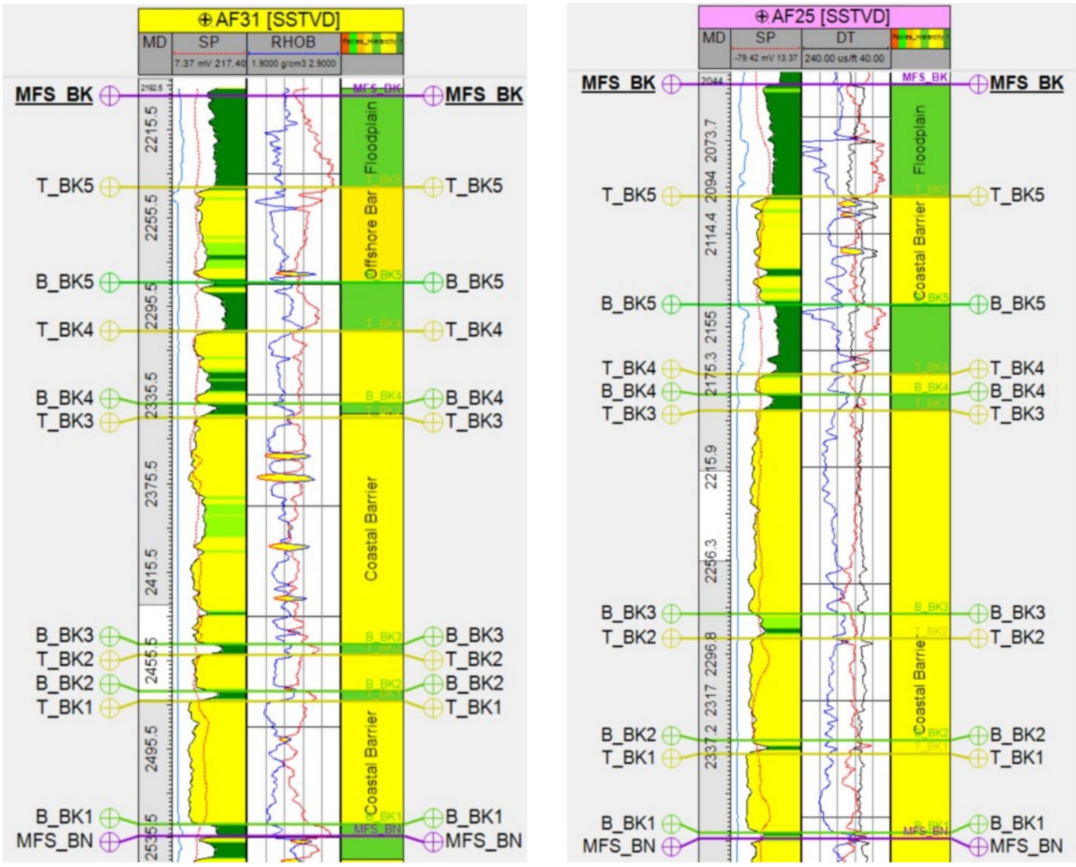

FIGURE 7. Five reservoir zonations (BK1, BK2, BK3, BK4, and BK5) were identified by composite log responses where regional markers bounded upper and lower formations.

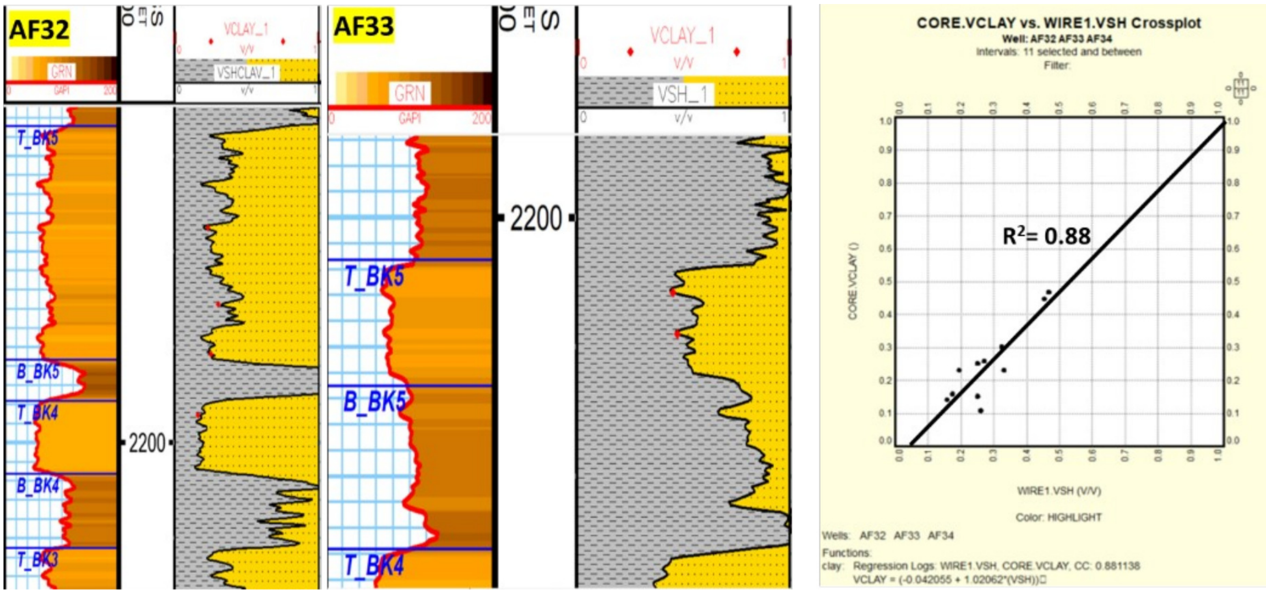

FIGURE 8. Shale volume calculation at AF32 and AF33 with validated data from core data (XRD analysis) gave a good correlation of 0.88.

lie formula (Equation 4) with "cor" values is 1 (for oil). Irreducible water saturation got from cross-plot porosity (phie) and water saturation (Sw) at core data (SCAL analysis). The permeability distribution is presented in Figure 9b. The calculation was validated with core data and got a 0.7 correlation factor. Based on the porosity and permeability classification at Koesomadinata (1978), the quality of porosity is good to excellent porosity (10–>26 %), and permeability is fair to very good permeability (5–1000 mD).

The porosity and permeability reduction for the Bekasap sandstone reservoir is significantly controlled by decreasing grain size and sorting. It is also correlated with increasing the clay matrix at the reservoir. That was verified by petrography (thin section) analysis (Figure 4) that the porosity decreased while the grain size decreased and was poorly sorted.

4.2.3 *Water saturation (Sw)*

The water saturation of the Bekasap sand reservoir is calculated by the Simandoux formula (Equation 5). Water resistivity (Rw) has used 0.343 Wm at reservoir temperature (188°F). The values obtained from the Pickett plot between true resistivity (DRES) and effective porosity ($PHIE$) were validated with water sample analysis. The shale resistivity (Rsh) is 5 Wm by observation of the resistivity log at shale lithology. The petrophysical parameters such as Archie constant, a = 1; cementation factor, m = 1.65; water saturation exponent, n = 1.88, have been used for evaluation (constant parameter). Core analysis (RCAL) water saturation was available to calibrate the logged measurement. The average water saturation (Sw) results at BK5, BK4, BK3, BK2, and BK1 intervals are 46.2–82 %; 57–93 %; 41–76 %; 48–80.6 %; 43.8–88 %. The validation was done with RCAL data and gave 0.86 correlation values (Figure 10).

4.2.4 *Cut-off reservoir*

Some parameter cut-offs are needed to obtain an effective reservoir zone (net reservoir). This study used core data and flow tests to determine the net reservoir. There are four properties such as maximum shale volume (Vsh), minimum porosity (phi), and minimum permeability (k). Firstly, using the Vsh cut-off chosen, the net sands should not contain porosities much below a level corresponding to 1 mD permeability in oil zones and 0.1 mD in gas zones. The value of 55 was chosen as its ties in with the core description. So, the good reservoir's maximum shale volume (Vsh) is 55 %. The flow test determined porosity and permeability cut-offs based on the minimum hydrocarbon (gas) flow theory within 1 mD permeability (Crain, 2001). Cross-plot between porosity and permeability showed the 1 mD permeability has minimum 13.2 % effective porosity (Figure 11). The cut-off was validated b flow test data and got similar values. Table 2 summarizes the petrophysical sums and averages for the net reservoir; either 13.2 % porosity or 50 % Vsh of gamma-ray was considered a reservoir cut-off.

4.2.5 *Rock type analysis*

The porosity and permeability core data measurements were examined to discover their relationship and how their interaction can affect the reservoir quality (Amaefule *et al.*, 1993; Sawy *et al.*, 2020; Shalaby, 2021). Porosity and permeability can reflect the effect of variable petrophysical parameters on reservoir quality in the Bekasap reservoir. All data have been corrected with overburden pressure and Klinkenberg correction. Calculated petrophysical parameters such as Normalized porosity index (ϕ_z/NPI), Reservoir Quality Index (RQI), and Flow Zone Indicator (FZI) to test and modeled the hydraulic flow at AF Field (Amaefule *et al.*, 1993; Sawy *et al.*, 2020, Shalaby, 2021). Plotting permeability between RQI and FZI (Figure 12a and Figure 12b) indicates good relations (R^2 = 0.844 and 0.99). Based on the RQI and FZI parameter calculation, which evaluates the permeability value, reservoir quality is directly controlled by permeability rather than porosity.

The output data were sorted based on FZI values and performed probability analysis. The Cross-plot between FZI and cumulative probability showed five trends indicating five rock types composing the Bekasap Formation (Figure 12c). The four reservoir rock types are distributed and distinguished into four petrophysical flow units with varying reservoir outputs by FZI ranges. The high-quality sandstone categories are in rock type 1 (RT1), and the worst

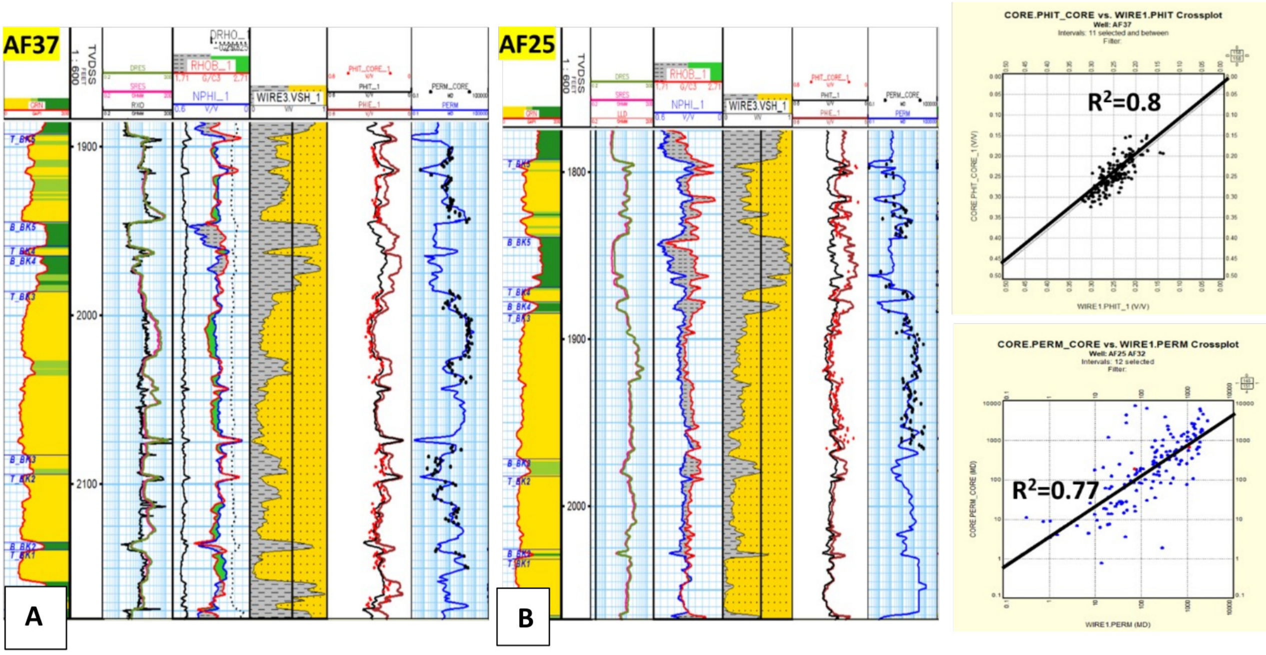

FIGURE 9. (a) Porosity calculation at AF 37 wells and got the close correlation as 0.8 and (b) Permeability calculation using Wyllie formula and got correlation factor as 0.77 with core data (RCAL).

TABLE 2. The resume of interpreted reservoir zones (BK1, BK2, BK3, BK4, and BK5) and petrophysical properties of Bekasap Formation, AF Fields.

Reser-voir	Gross Thickness (ft)	Net Thickness (ft)	Net to Gross Ratio/NGR (fraction)	Avg *phi* (fraction)	Avg *Vsh* (fraction)	Avg *Sw* (fraction)
BK5	24.33 – 85.99	8 – 76.5	0.785	0.247	0.386	0.824
BK4	5.39 – 46.36	0.55 – 44	0.605	0.239	0.304	0.798
BK3	82.81 – 115.83	71.75 – 104.83	0.858	0.265	0.233	0.732
BK2	0.48 – 52.92	0.48 – 44.07	0.787	0.254	0.244	0.771
BK1	10.44 – 75.52	1.25 – 60.02	0.851	0.263	0.14	0.791

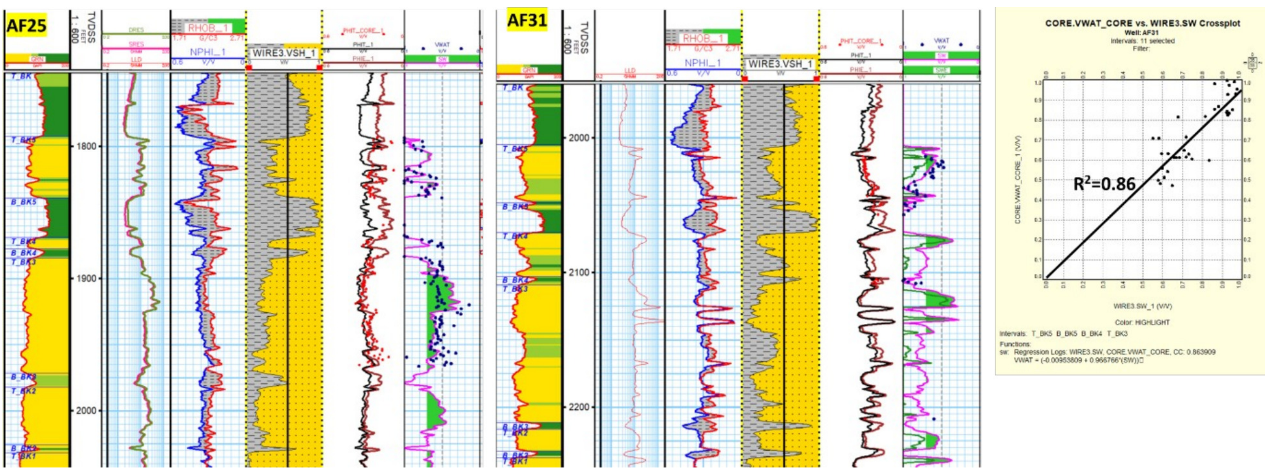

FIGURE 10. Water saturation calculation using the Simandoux formula is suitable for shaly sand reservoirs such as BK 5 and BK4. The correlation between log analysis and core measurement is 0.86.

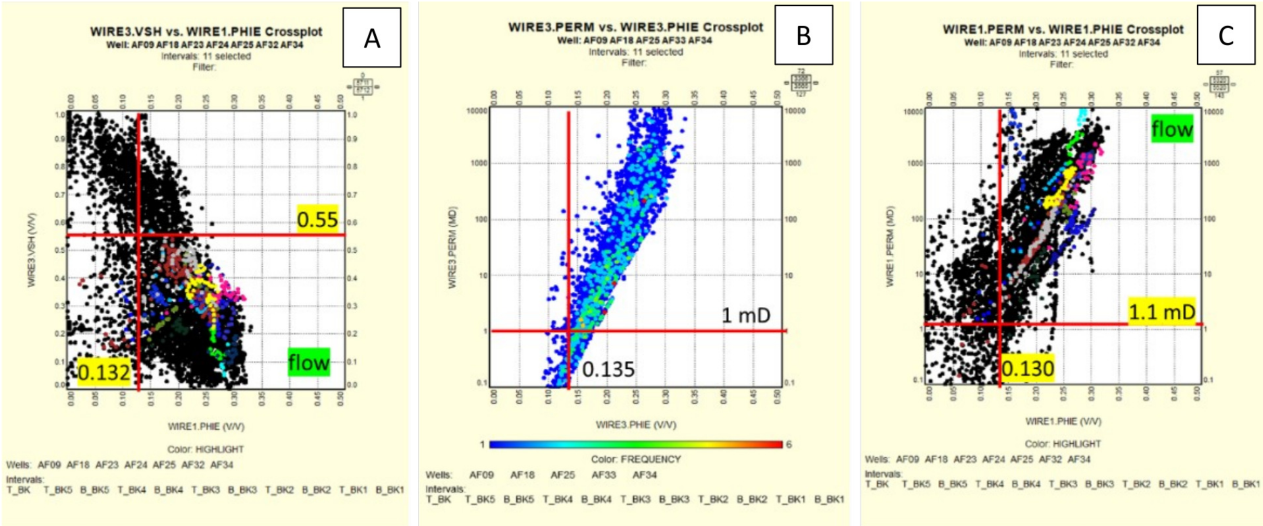

FIGURE 11. A. Cut-offs porosity (PHIE) and Shale volume (Vsh) are determined by flow test; B. Cut-off porosity ($PHIE$) based on minimum permeability hydrocarbon flows within 1 mD; C. Cut-offs reservoir determined by flow test and core data, and it is obtained the maximum shale volume (Vsh) of 55 %, the minimum porosity of 13.2 % and minimum permeability of 1 mD.

quality in rock type 5 (RT 5). The strong correlation or relationship (R^2) in each rock type has ranged from 0.9061 to 0.9956. The summary of the average values of each rock type is in Table 3.

Hydraulic flow units (HFUs) are characterized by petrophysical properties and reservoir quality (RQI). Plotting between RQI as a function of PHIZ and taking the FZI values got the HFU areas (Figure 13). The best quality reservoir (RT1) into HFU1 with FZI more than 10 µm and the worst rock type (RT5) into HFU 5.

Clustering and rock type propagation using the MRGC method at uncored data using shale volume (Vsh) and porosity (phi) log to get the cluster of reservoir rock (Figure 14). This input data shows four reservoir rock types composed in the reservoir interval. This analysis has a good correlation with geological facies.

Next, the permeability calculation in each rock type with permeability equation based on rock type, as written in Equation 10.

$$K = 1014 \times (FZI)^2 \times \frac{\phi e^3}{(1-\phi e)^2} \tag{10}$$

From this equation, getting four equations to calculate permeability:

$RRT1 \rightarrow 1014 * (9.552^2) * ((PHIE^3)/((1 - PHIE)^2)$

$RRT2 \rightarrow 1014 * (2.352^2) * ((PHIE^3)/((1 - PHIE)^2)$

$RRT3 \rightarrow 1014 * (1.2327^2) * ((PHIE^3)/((1 - PHIE)^2)$

$RRT4 \rightarrow 1014 * (0.5505^2) * ((PHIE^3)/((1 - PHIE)^2)$

Compared with the Wyllie Rose equation, the rock-type equation has a better correlation with core data (correlation >96 %) and has a good trend (Figure 15).

5 CONCLUSION

This study has been carried out to evaluate and determine the petrophysical properties and rock type determination of the Bekasap sand reservoir at AF Field. Five reservoir zones have been identified (BK1, BK2, BK3, BK4, and BK5) stratigraphically.

- The BK1, BK2, and BK3 reservoirs are dominated by coastal barrier bar (tidal sandbar) facies with 14.6–34 % shale content values and porosity values between 20–22.6 %, water saturation 15–79 % and permeability between 218–980 mD. The BK4 and BK5 reservoirs are dominated by offshore bars facies with shale content values between 20–48.7 %, porosity values of 16.82–19.4 %, and permeability of 200–409 mD.
- Petrographically, there are four reservoir rock types recognized by sedimentary textures: Very coarse to coarse sandstone (RT1), Coarse to medium sandstone (RT2),

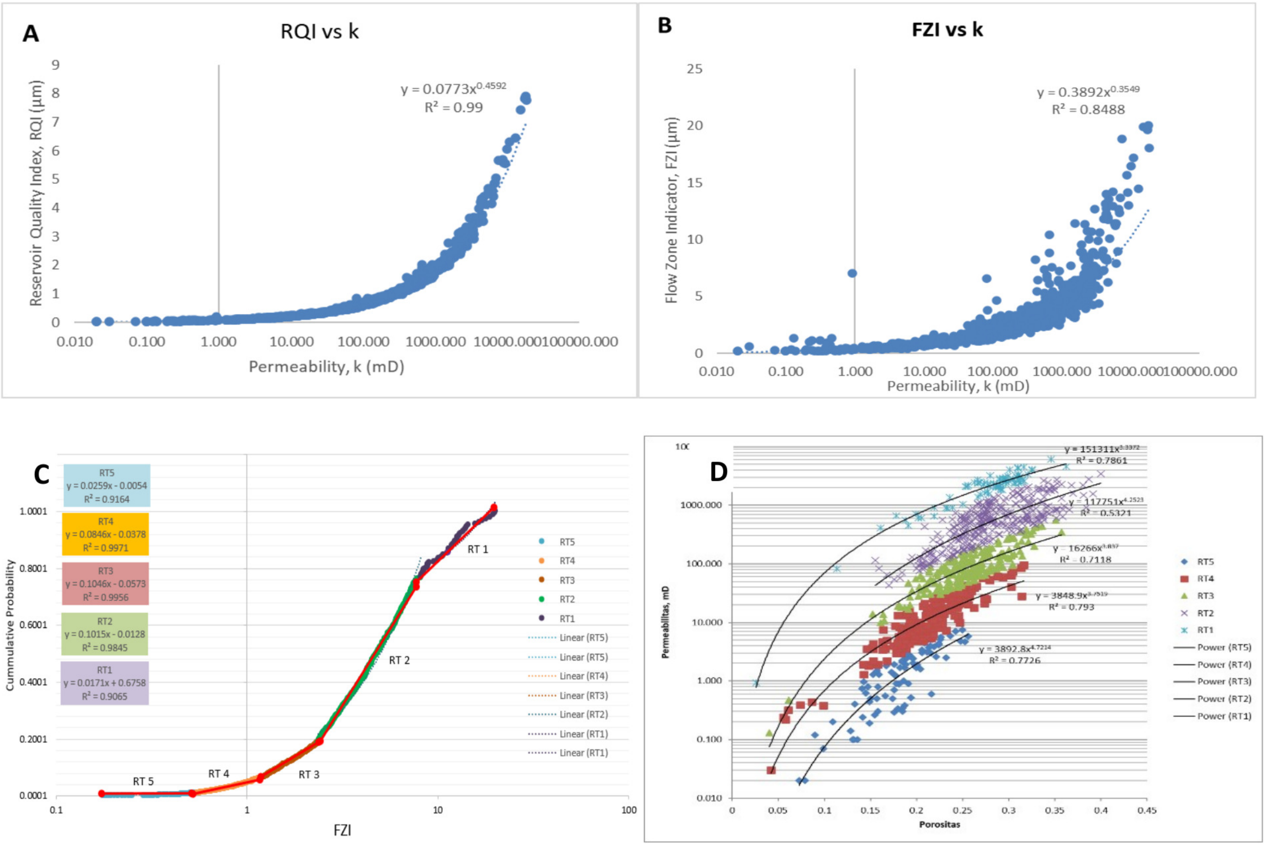

FIGURE 12. A. Cross plot between RQI versus permeability (k); B. Cross plot between FZI versus permeability (k); C. Rock type division based on FZI; D. Cross plot between porosity ($PHIE$) versus permeability (k). All figures explain the reservoir quality index (RQI) and Flow Zone Indicator (FZI) between porosity and permeability.

TABLE 3. Reservoir rock type determination based on flow zone indicator (FZI) and Hydraulic Flow Unit (HFU).

Reservoir Rock Type (RT)	FZI **(µm)**	RQI **(µm)**	**Porosity (*phi*)**	**Permeability (*k*) mD**
RT1	>9.552	3.29 – 6.451	>0.235	>665
RT2	9.552 – 2.352	0.096 – 5.559	0.176 – 0.342	43 – 661
RT3	2.352 – 1.2327	0.056 – 1.542	0.154 – 0.273	10 – 173
RT4	1.2327 – 0.5505	0.018 – 0.517	0.05 – 0.237	1.2 – 42
RT5 (non-reservoir)	0.5505 – 0.171	0.002 – 0.171	0.0726 – 0.225	0.02 – 5.08

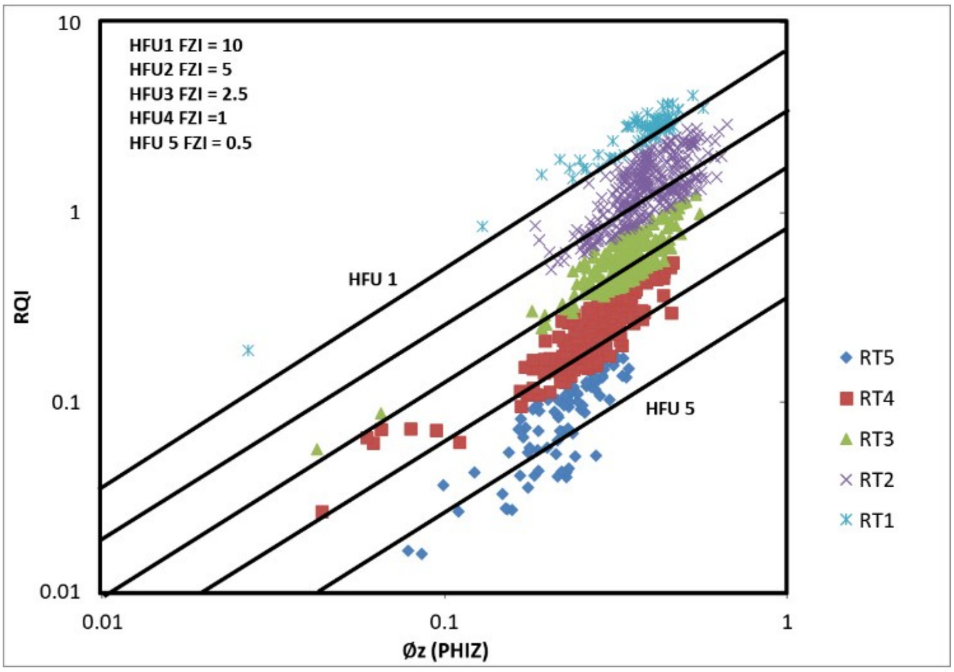

FIGURE 13. Hydraulic Flow Units by plotting porosity normalized (PHIZ) and reservoir rock quality (*RQI*).

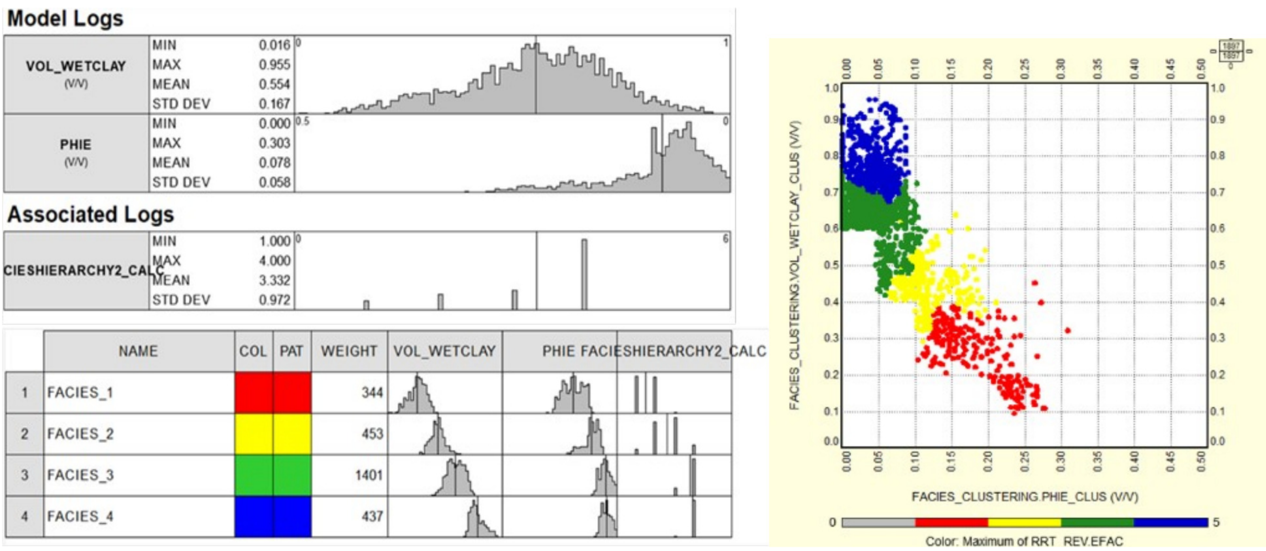

FIGURE 14. Clustering analysis at AF Fields using MRGC method and resulting four facies (rock type).

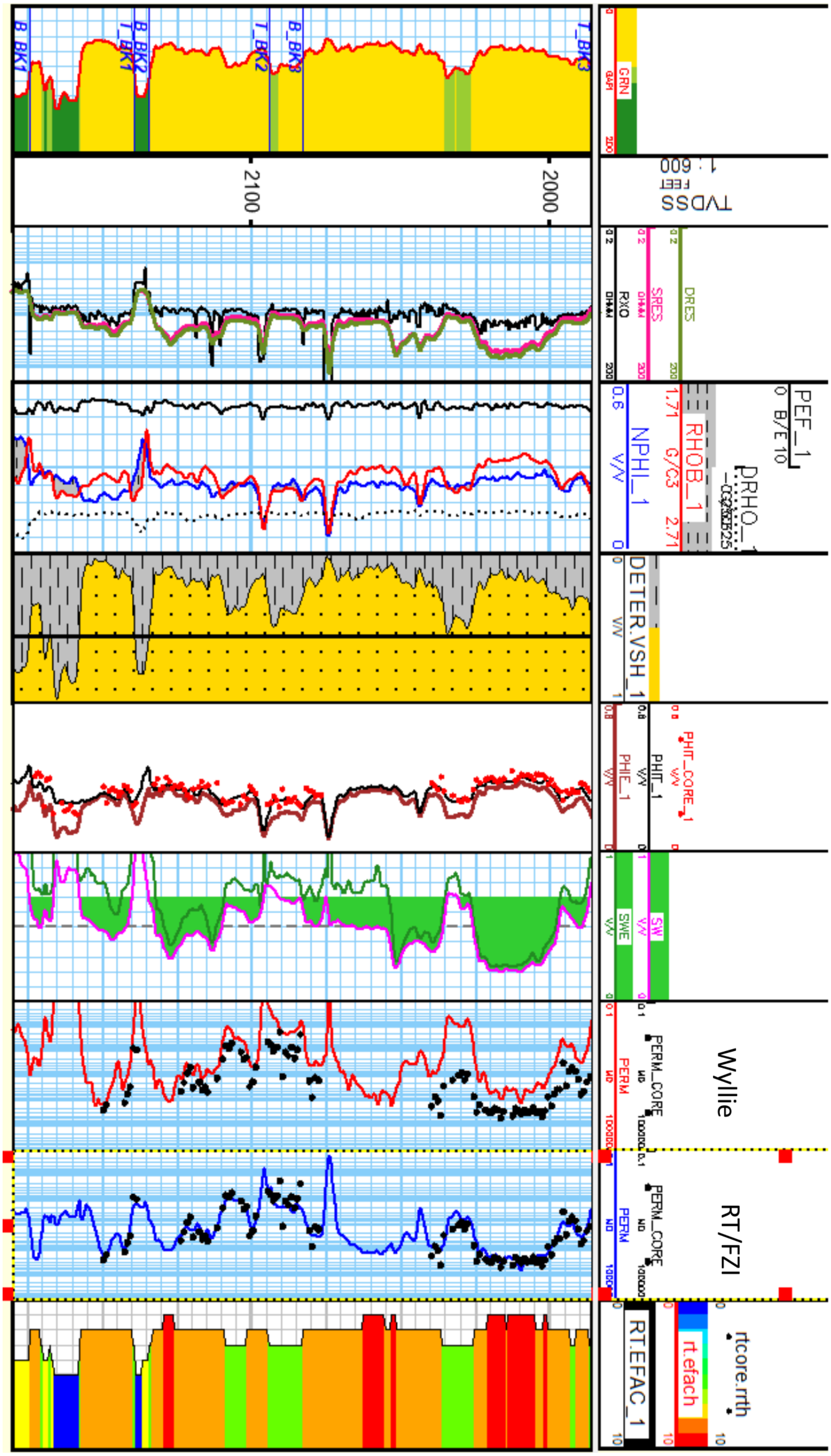

FIGURE 15. Permeability comparison between Wyllie rose and FZI equation to get best permeability values.

medium to fine sandstone (RT3), fine to very fine sandstone (RT4). All sandstone deposited in the estuarine with tide dominated at outer estuarine. Specifically, RT-1 dominates the coastal barrier bar (tidal sandbar) facies. RT-2 is generally a coastal barrier bar (tidal sandbar) facies deposit. RT-3 is located at the coastal barrier bar (tidal sandbar) and offshore bars facies. RT-4 dominates the coastal barrier bar (tidal sandbar) and offshore bars facies. RT-5 is located at mudflat or floodplain facies and slightly offshore bars.

- For petrophysical properties, divided into four rock type such as RT1 and RT2 has the best quality sand reservoir with HFU1 and are associated with a tidal sand bar in the geological facies, RT3 and RT4 has a good quality reservoir and are associated with tidal and offshore sand bar and separated in the BK4 and BK5 reservoir zones.
- The appropriate permeability determination method in the Bekasap Formation's net reservoir applies Petrophysical log properties and the rock type division.

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