Petrophysical Analysis to Determine Reservoir and Source Rocks in Berau Basin, West Papua Waters

Analis Petrofisika untuk Menentukan Batuan Reservoar dan Batuan Induk pada Cekungan Berau, Perairan Papua Barat

Popy Dwi Indriyani¹, Asep Harja¹ and Tumpal Bernhard Nainggolan²

¹Geophysics Department, Padjadjaran University, Jl. Raya Bandung Sumedang KM. 21, Jatinangor, 45363
²Marine Geological Institute, Jl. Dr. Djundjunan No. 236, Bandung, 40174

Corresponding author: popy.dwi23@gmail.com

(Received 14 March 2020; in revised form 17 March 2020 accepted 7 May 2020)

ABSTRACT: Berau Basin is assessed to have same potential in clastic sediments with Mesozoic and Paleozoic ages, where reservoirs and source rocks are similar to productive areas of hydrocarbons in Northwest Shield Australia. This study aims to identify the hydrocarbon prospect zones and potential rocks zones using petrophysical parameters, such as shale volume, porosity, water saturation and permeability. Petrophysical analysis of reservoir and source rock are carried out on three wells located in the Berau Basin, namely DI-1, DI-2 and DI-3 in Kembelangan and Tipuma Formation. Qualitative analysis shows that there are 4 reservoir rock zones and 4 source rock zones from thorough analysis of these three wells. Based on quantitative analysis of DI-1 well, it has an average shale volume (V_sh) 9.253%, effective porosity (PHIE) 20.68%, water saturation (S_w) 93.3% and permeability (k) 55.69 mD. DI-2 well's average shale volume, effective porosity, water saturation and permeability values are 29.16%, 2.97%, 67.9% and 0.05 mD, respectively. In DI-3 well, average shale volume, effective porosity, water saturation and permeability values are 6.205%, 19.36%, 80.2%, and 242.05 mD, respectively. From the reservoir zone of these three wells in Kembelangan Formation, there are no show any hydrocarbon prospect.

Keywords: reservoir, source rock, shale volume, porosity, water saturation, permeability, Kembelangan Formation, Tipuma Formation, Berau Basin

INTRODUCTION

Hydrocarbon exploration in West Papua region has been found on a field located on the Bintuni Bay of the carbonate rocks. These carbonate rocks deposited in shallow sea that have bigger energy environment as sandy limestone and in deeper sea that have low energy environment as shaly limestone (Ustiawan et al., 2019). Clastic sediments with Mesozoic and Paleozoic ages are the target of exploration in West Papua region including Bintuni, Salawati and Berau Basins (Pigram et al., 1982). These sediments indicate initial prospect areas with reservoir and source rocks similar to
productive areas in Australia's Northwest Shelf. In Berau Basin, there are clastic sediments with ages in the Mesozoic and Paleozoic eras.

Tectonic studies on the West Papua region indicate that the Indo-Australia continental plate is moving to the north, while the Pacific oceanic plate is moving to the southwest (Adyagharini, 2009). Several important geological features that influenced tectonic history of Bird's Head, such as formed the boundaries of Cenderawasih Bay, the east-west trending Sorong-Yapen Fault Zone, Waipoga Basin, Tarera-Aiduna Fault, Kemum High and Lengguru Fold-Thrust Belt (Figure 1).

Berau Basin is situated in between Salawati-Bintuni Basin in the NE-SW direction and produced by collision between West Papua micro-continent and the northwestern margin of the Australian continent (Pigram et al., 1982) (Figure 2). Deposition of platform and pelagic carbonates were interrupted by several tectonic events during Late Jurassic to Early Tertiary. The deposition formed Kembelangan Formation as reservoir rock objective and Tipuma Formation as underlying source rock.

As described in Berau Basin stratigraphy, West Papua waters are arranged into several formations, namely Klasaman/ Klasafet Formation, Kais LST Formation, Faumai Formation, Waripi Formation, Kembelangan Formation, Tipuma Formation and Aifam Formation (Figure 3).

According to Yang (2017), basically petrophysics study consists of three parts, namely the physical properties of reservoir fluids (including the physical properties of oil, gas and water at high pressure-temperature and phase changes), physical properties of reservoir rocks (porosity, permeability, water saturation and sensitivity to formation) and physical properties in porous media. In this study, reservoir quality analysis is carried out to identify ideal reservoir based on shale volume, effective porosity, water saturation and permeability.

DATA AND METHODS

Well log data of these three wells are analyzed to obtain information on petrophysical properties of rock formation and its fluid content. The main logs used for this study are gamma ray (GR), resistivity (ILD), density (RHOB) and sonic (DT) logs.

The study area is situated on Berau Basin which is part of the West Papua Province. It is geographically located in between 130° - 132°E and 2° - 3°S (Figure 4). This research focuses on reservoir quality and quantity analysis in 3 (three) wells, namely DI-1, DI-2 and DI-3 wells using petrophysical parameters.
Petrophysical Calculations

Shale volume

The volume of shale is used to calculate the amount of shale in porous rocks. Usually, the shale content is calculated according to the linear equation (Ulum et al., 2014):

\[ IGR = \frac{GR_{log} - GR_{clean}}{GR_{shale} - GR_{clean}} \]  

where:

- \( IGR = V_{sh} \) = Gamma Ray Index (%)
- \( GR_{log} \) = Gamma ray log reading (API)
- \( GR_{clean} \) = Log response the clean sand (GR_min)
- \( GR_{shale} \) = Log response in the shale zone (GR_max)

Besides the simple linear equation, there are non-linear equations for more optimistic calculating of \( V_{sh} \):

- Larionov equation on Tertiary rocks:
  \[ V_{sh} = 0.083 \times (2.37 \times IGR - 1) \]  

- Steiber equation:
  \[ V_{sh} = \frac{IGR}{3 - 2 \times IGR} \]  

- Clavier equation:
  \[ V_{sh} = 1.7 - \sqrt{3.38 - (IGR + 0.7)^2} \]  

- Larionov equation for older rocks:
  \[ V_{sh} = 0.33 \times (2.3 \times IGR - 1) \]
Porosity

Porosity is the void fraction of being porous in the rocks formations for accumulating fluids (water, oil and gas). Porosity is further classified as total porosity and effective porosity. Total porosity is defined as the ratio of the entire pore space in a rock to its bulk volume. Effective porosity is the total porosity less the fraction of the pore space occupied by shale or clay. In clean sand formation, total porosity is equal to effective porosity. According to Irawan et al. (2009), the value of porosity can be calculated using neutron porosity and porosity density. The porosity can be calculated based on the equations such as:

\[
\phi_D = \frac{\rho_{ma} - \rho_f}{\rho_{ma} - \rho_e} \quad (6)
\]

\[
\phi_{total} = \frac{\phi_D + \phi_N}{2} \quad (7)
\]

\[
\phi_{effective} = \sqrt{\phi_{Ncorr}^2 + \phi_{Dcorr}^2} \quad (8)
\]

\[
\phi_{Dcorr} = \phi_D - (V_{sh} \times \phi_{Dmn}) \quad (9)
\]

\[
\phi_{Ncorr} = \phi_N - (V_{sh} \times \phi_{Nmn}) \quad (10)
\]

where:
- \(\phi_D\) = Porosity density from density log data (%)
- \(\rho_{ma}\) = Density of rock matrix (gr/cc)
- \(\rho_f\) = Density of rock matrix (gr/cc) obtained from density log data
- \(\rho_e\) = Fluid density (value 1.1 for mud, 1 for fresh water)
- \(\phi_{total}\) = Total porosity (%)
- \(\phi_N\) = Neutron porosity from Neutron log porosity data (fraction)
- \(\phi_{effective}\) = Effective porosity (%)
- \(\phi_{Ncorr}\) = Correction of neutron porosity
- \(\phi_{Dcorr}\) = Correction porosity density
- \(\phi_{Dsh}\) = Porosity density of the nearest shale zone
- \(\phi_{Nsh}\) = Porosity neutron of the nearest shale zone

Water Saturation

In a formation containing oil and/or gas, both of which are non-conductors of electricity, with a certain amount of water, the resistivity is a function of water saturation \(S_w\) (Tiab and Donaldson, 2004). The water saturation value \(S_w\) clean sand formation can be calculated using Archie’s equation (Harsono, 1997). Simandoux equation:

\[
S_w = C \cdot \frac{R_w}{\Phi^2} \left[ \frac{\phi_n^2}{R_w \cdot R_t} + \left( \frac{V_{sh}}{R_{sh}} \right)^2 \right] \quad (11)
\]

Indonesia equation:

\[
S_{w, Indonesia} = \left( \frac{1}{\frac{1}{R_t} - \frac{C}{R_{sh}}} + \frac{\phi_n^m}{a \cdot R_w} \right)^{\frac{2}{m}} \quad (12)
\]

where:
- \(S_w\) = Water saturation (fraction)
- \(C\) = Conductivity values (on sandstones 0.4 and on limestone 0.45)
- \(R_w\) = Formation water resistivity (ohm.m)
- \(R_t\) = Formation resistivity value (read from log data) (ohm.m)
- \(\Phi\) = Porosity (%)
- \(V_{sh}\) = Volume shale (%)
- \(R_{sh}\) = Resitivity of shale
- \(m\) = Cementation exponent
- \(n\) = Saturation exponent

Permeability

Permeability is the ability of rock to drain fluid, in unit of Darcy (D) or milliDarcy (mD). Permeability of the rock formation also depends on the porosity and saturation of water and it can be calculated using the equation,

\[
k = a \cdot \frac{\phi_n^b}{S_w^c} \quad (13)
\]

where:
- \(k\) = Permeability (mD)
- \(S_w\) = Water saturation (%)
- \(\Phi_n\) = Effective porosity (%)
a, b, c = Schlumberger constants (a = 10000, b = 4.5, c = 2)
RESULTS

Well log correlation can be considered as the identification and/or connection of equivalent strata units in time, age, or position along log curves of adjacent wells. In this research, well log correlation of three wells on Berau Basin are interpreted with assistance of physical characters of lithology, resistivity and porosity logs (Figure 5). Well correlation panel across well log data on three wells creates trajectory horizons into top and bottom layer formations. Gamma ray and spontaneous potential logs are used to determine lithology and boundary of formation. Resistivity logs can determine the type of hydrocarbons by looking at the low and high resistivity formation response to induced electrical current (Erryansyah et al., 2020).

Qualitative analysis

Qualitative interpretation in this study uses gamma ray, neutron and density. Shale typically has high concentrations of natural radioactive elements such as potassium, thorium and uranium thus increases the gamma ray log response. Sand and limestone have low concentration of radioactive elements thus decreased gamma ray response. Cross-over neutron porosity NPHI curve log against bulk density RHOB curve log which is overlaid each other to detect hydrocarbon bearing zone (Nopiyanti et al., 2020). Based on those characteristics, the qualitative analysis shows there are

Figure 5. Well logs correlation of three wells on Berau Basin
four reservoir zones that are estimated to have hydrocarbon potential in three wells of Kembelangan Formation. DI-1 well is divided into two zones, zone 1 (5,884-5,940 ft) and zone 2 (6,326-6,364 ft). DI-2 and DI-3 wells have reservoir zones with range of 8,000-8,039.5 ft and 11,350-11,405 ft, respectively (Table 1). Reservoir zones in DI-1 well are marked on several factors including gamma ray log values ranging from 22.71 to 75.44 API which represent low radioactive content. Resistivity values in these zones show range of 2.83-1,841.48 ohm.m, which is likely the reservoir’s fluid is water and/or oil. Density values show range of 1.58-2.65 g/cc determines uncompact to slightly compact rock hardness. Neutron values indicate that both zones have low hydrogen content. In conjunction, DI-2 and DI-3 wells indicate similar characteristics in different depths range of 8,000-8039.5 ft and 11,350-11,405 ft. Figure 6 shows the zones in yellow range of reservoir rock in log display.

There are four zones of source rock on various depths in Tipuma Formation based on lithology, resistivity and density-neutron logs. DI-1 and DI-2 wells have zones of source rock with range of 6,436-6,539 ft and 8,041-8,092 ft, respectively. DI-3 well is divided into two zones, zone 1 (11,877.5-11,920 ft) and zone 2 (11,978.5-12,078 ft) (Table 2). These zones in three wells are marked on several factors including high gamma ray values until 155.79 API, it tends to absorb radioactive elements as impermeable rock properties. Resistivity values in each zone tends to be low and sonic log values tend to be high and analyze as source rock but not yet mature. Figure 7 shows the zones in yellow range of source rock in log display.

**Quantitative analysis**

**Shale Volume**

Figure 8 shows the comparison graph of shale volume values calculated using the linear, Larionov, Steiber and Clavier equations on DI-1 well in

| Well  | Zone | Depth (ft) | Gamma ray (API) | Resistivity (ohm.m) | Density (g/cc) | Porosity (v/v) |
|-------|------|------------|-----------------|--------------------|----------------|----------------|
| DI-1  | 1    | 5,884-5,940| 22.71-70.12     | 2.83-66.91         | 1.71-2.65      | 0.039-0.381     |
|       | 2    | 6,326– 6,364| 32.66-75.44     | 2.11-1,841.48      | 1.58-2.62      | 0.015-0.43      |
| DI-2  | 1    | 8,000-8039.5| 36.66-97.67     | 4.74-52.02         | 2.48-2.73      | 1-17           |
|       | 1    | 11,350-11,405| 30.09-79.171   | 7.35-1,990.88      | 1.79-2.69      | 0.04-0.53       |

Table 1. Zones of reservoir rock
Larionov equation has a high degree of optimism because it produces lower shale volume values. It shows on gamma ray value rising slowly but shale volume values are not increasing rapidly compared to the other linear and non-linear methods. Therefore, this study adopts the Larionov equation for tertiary rocks. Shale volume values using Larionov equation on Tertiary rocks (Equation 2) in DI-1, DI-2 and DI-3 wells are 9.253%, 29.16% and 6.205%, respectively.

Porosity

In this study, porosity is calculated using neutron and density logs. The total porosity (PHIT) and effective porosity (PHIE) values in the calculation are porosity values in one selected point of each reservoir zones (Table 3).

Table 2. Zones of source rock

| Well | Zone | Depth (ft) | Gamma ray (API) | Resistivity (ohm.m) | Sonic (μs/ft) |
|------|------|------------|-----------------|---------------------|--------------|
| DI-1 | 1    | 6,436-6,539| 63.87-113.55    | 1.81-9.35           | 66.47-111.96 |
| DI-2 | 1    | 8,041-8,092| 25.94-130.03    | 6.64-1,397.47       | 4.70-74.63  |
| DI-3 | 1    | 11,877.5-11,920| 62.62-155.79 | 1.97-24.79          | 67.67-83.35 |
|      | 2    | 11,978.5-12,078| 32.30-132.78   | 4.25-18             | 61.92-98.23 |

Table 3. Total porosity and effective porosity in reservoir zones

| Well | Zone | Depth (ft) | PHIT (%) | PHIE (%) |
|------|------|------------|----------|----------|
| DI-1 | 1    | 5,884-5,940| 17.65    | 17.36    |
|      | 2    | 6,326-6,364| 23.86    | 23.79    |
| DI-2 | 1    | 8,000-8,039.5| 5.1     | 2.97     |
|      | 2    | 11,350-11,405| 19.99   | 19.46    |

Figure 7. Log display on zones of source rock

Figure 8. Comparison graph of linear and non-linear shale volume calculations

Kembelangan Formation. Based on comparison graph, Larionov equation has a high degree of optimism because it produces lower shale volume values. It shows on gamma ray value rising slowly but shale volume values are not increasing rapidly compared to the other linear and non-linear methods. Therefore, this study adopts the Larionov equation for tertiary rocks. Shale volume values using Larionov equation on Tertiary rocks (Equation 2) in DI-1, DI-2 and DI-3 wells are 9.253%, 29.16% and 6.205%, respectively.
Water Saturation

The important parameter to calculate saturated fluid in place from well log is the formation water resistivity ($R_w$). Determination of $R_w$ is done using the pickett plot method by plotting a crossplot between PHIE and $R_t$. The outermost points of the crossplot are on a line called the $R_p$-line. All points on this line have $S_w = 100\%$ or $S_w = 1$ (Manurung et al., 2017). At the point of intersection between the line $S_w = 1$ with porosity $100\%$, if $a = 1$, the $R_w$ value can be determined. Based on the results of the crossplot between PHIE and $R_t$, $R_w$ values range of 0.04-0.804 ohm.m of the three wells (Figure 9). DI-1 well has $R_w$ values of 0.28 ohm.m in zone 1 and 0.738 ohm.m in zone 2. DI-2 and DI-3 wells have $R_w$ values range of 0.04 ohm.m and 0.804 ohm.m, respectively.

DISCUSSION

Based on shale volume calculation, highest shale content are found in the Kembelangan Formation of DI-2 well that inhibits rock in flowing fluid. DI-3 well has a lower shale content compared to other wells so it can be stated as the most consolidated carbonate reservoir rock. DI-1 and DI-3 wells are categorized as good to very good reservoir rock with effective porosity values range of 17.56-23.79%. While, DI-2 well has poor effective porosity value range of 2.97%. DI-1 and DI-3 wells tend to have high water saturation percentage so that they are estimated to contain water fluid. Whereas DI-2 well has water saturation value that tends to be fair

![Kembelangan Formation PHIE to Rt plot](image)

Figure 9. PHIE to Rt plot of 2 zones in Kembelangan Formation

Based on the three wells consisting shaly sand formation, calculation of water saturation is decided by using Indonesian equation. It shows that the formation does not only contain sand, but there are shale fraction in sand content. If water is the only fluid contained in rock pores, then the value of $S_w = 1$, but if the rock pores contain hydrocarbon fluid, the value of $S_w < 1$ (Tiab and Donaldson, 2004). $S_w$ values in DI-1 well are range of 92.2-94.4%. DI-2 and DI-3 wells have $S_w$ values 67.9% and 80.2%.

Permeability

The permeability values in the calculation are permeability values in one selected point of each reservoir zones. DI-1 well has permeability values range of 18.35-93.04 mD, while DI-2 and DI-3 wells have permeability values of 0.05 and 242.05 mD, respectively.

From stratigraphic and well log correlation, Kembelangan Formation lies in Early Cretaceous to Late Jurassic age. Shale intermittent sedimentary rocks with sandstone and limestone are found, with coarse grained sandstone, coarse grained, not compact until well consolidated. Shale is not compact and generally contains carbonate material. Source rock Tipuma Formation contains shale and sandstone with shale dominantly.
CONCLUSION

The petrophysical analysis of this study appraise the reservoir rocks and source rocks of three wells in Berau Basin and suggest no show hydrocarbon prospect. The neighboring area to the north east of Berau Basin is economically viable for hydrocarbon exploration including Bintuni and Salawati Basin. The southern side of the study area is avoided due to the high concentration of water and excessive impermeable reservoir rocks. Based on the result of petrophysical analysis in this study, the Kembelangan reservoir rocks in Berau Basin are considered not similar to productive areas of hydrocarbons in Northwest Shield Australia.

ACKNOWLEDGEMENT

Sincere appreciation and many thanks to honorable Head of Marine Geological Institute for the trusting and supervising to the authors.

REFERENCES

Adyagharini, A.C. 2009. Tatanan Geologi Teluk Cenderawasih Dalam Kaitannya dengan Evolusi Tektonik Kepala Burung, Papua. Thesis. Institut Teknologi Bandung.

Erryansyah, M., Nainggolan, T.B. and Manik, H.M. 2020. Acoustic impedance model-based inversion to identify target reservoir: a case study Nias Waters. IOP Conf. Series: Earth and Environmental Science, 429 (1). DOI: 10.1088/1755-1315/429/012033.

Harsono, A. 1997. Evaluasi Formasi dan Aplikasi Log. 8th Edition. Schlumberger Oilfield Services, Jakarta.

Irawan, D., Utama, W. and Parafianto, T. 2009. Analisis Data Well Log (Porositas, Saturasi Air, dan Permeabilitas) untuk menentukan Zona Hidrokarbon, Studi Kasus: Lapangan “ITS” Daerah Cekungan Jawa Barat Utara. Jurnal Fisika Dan Aplikasinya, 5 (1): 1-7. DOI: 10.12962/j24604082.v5i1.935.

Manurung, L.S., Dewanto, O. and Haerudin, N. 2017. Analisis Sw Berdasarkan Nilai Rw Spontaneous Potensial Dan Rw Pickett Plot Pada Formasi Berai Cekungan Barito Dengan Menggunakan Metode Well Logging. Jurnal Geofisika Eksplorasi, 3 (3): 73-87. DOI: 10.23960/jge.v3i3.1049.

Nopiyanti, T., Nainggolan, T.B., Dewanto, O. and Haq, D.A. 2020. Well log analysis and geochemical data to identify source rock and hydrocarbon reservoir: Northeast Java Basin study case. AIP Conference Proceedings, 2245 (1). DOI: 10.1063/5.0006978.

Pigram, C.J., Robinson, G.P. and Tobring, S.L. 1982. Late Cainozoic Origin for the Bintuni Basin and Adjacent Lengguru Fold Belt, Irian Jaya. Indonesian Petroleum Association Proceedings, 11th Annual Convention. DOI: 10.29118/ipa.291.109.126.

Sapiie, B., Adyagharini, A., Naryanto, W. and Panumpuni, A. 2012. Geology and Tectonic Evolution of Bird Head Region Papua, Indonesia: Implication for Hydrocarbon Exploration in Eastern Indonesia. Search & Discovery Article, 30260.

Tiab, D. and Donaldson, E.C. 2004. Petrophysics: Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties, 2nd Edition, Elsevier Inc., 880. DOI: 10.1016/C2014-0-03707-0.

Ulum, Y., Hastuti, E. and Herlin, W. 2014. Studi Evaluasi Data Logging Dan Sifat Petrofisika Untuk Menentukan Zona Hidrokarbon Pada Lapisan Batu Pasir Formasi Duri Lapangan Balam South, Cekungan Sumatera Tengah. Jurnal Ilmu Teknik Sriwijaya, 2 (3).

Ustiawan, A.B., Nainggolan, T.B. and Setywana, R. 2019. Interpretasi Struktur Geologi di Perairan Aru Selatan, Maluku Berdasarkan Data Seismik 2D Multi Channel. Jurnal Geosains dan Teknologi, 2 (2): 53-60. DOI: 10.14710/jgt.2.2.2019.53-60.

Yang, S. 2017. Fundamentals of Petrophysics, 2nd Edition. Springer-Verlag Berlin Heidelberg, 502. DOI: 10.1007/978-3-662-55029-8.

| Well  | Depth (ft) | Reservoir lithology | Shale Volume (%) | Effective Porosity (%) | Water Saturation (%) | Permeability (mD) | Remarks (high, moderate, low) |
|-------|-----------|---------------------|------------------|------------------------|---------------------|------------------|-----------------------------|
| DI-1  | 5,884-6,364 | Sandstone           | 9.253            | 23.79                  | 92.2-94.4           | 18.35-93.04      | Moderate                   |
| DI-2  | 8,000-8,039.5 | Shaly sandstone    | 29.16            | 2.97                   | 67.9               | 0.05             | Low                         |
| DI-3  | 11,350-11,405 | Shaly sandstone    | 6.250            | 19.46                  | 80.2               | 242.5            | Moderate                   |

Table 4. Quantitative petrophysics calculation of three wells in Berau Basin.
