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Relationship between the petrophysical properties and microfacies variations of carbonate rocks

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Abstract: One of the key success of improving the recovery in carbonate reservoir rock is to have a better understanding of the "cause – effects" between petrophysical properties and microfacies variations. Due to pore systems complexities in carbonate reservoir, the relationship between fluid flow characteristics and the geological attributes remains unclear. This study seeks to determine the relationship between fluid flow and geological properties. From petrographic analysis, eleven microfacies deposited from restricted platform interior to deep water environments have been identified. Taking into account these microfacies on the log – log Reservoir Quality Index versus Normalized Porosity plot, there is no correlation between the microfacies and Fluid Zone Indicator (FZI), reflecting similar pore attributes. However, regardless the microfacies and the depositional environment, the log – log Reservoir Quality Index versus Normalized Porosity plot indicates seven groups of similar pore attributes. These imply that one microfacies can have more than one group of similar pore attributes and also one similar pore attributes can be derived from one or more microfacies.

Key words: Carbonate rock; Fluid zone indicator; Reservoir quality index; Porosity; Permeability; Microfacies

1. Introduction

In carbonate reservoirs, one of the main challenges is to predict the fluid flow parameter closely linked to petrophysical data (porosity and permeability). This is because the pore attribute variations and complexities, such as the presence of abundant vugs (Ehrenberg & Nadeau, 2005), are controlled by the carbonate rock fabric which is very heterogeneous. Therefore, several researches and discussions have been focused on correlating fluid flow/ rock fabric (Orodu et al., 2009; Nooruddin and Hossain, 2011) and porosity – permeability / rock fabric (Lucia, 1995).

One of the first correlation between fluid flow and rock fabric has been proposed by Archie (1952). His classification is very useful for visual estimation (x10 microscope) of porosity and for permeability approximation. However, because of technology limitation, the classes of pore size less than 10µm are not considered in pore study influencing the fluid flow within carbonate rocks (Coalson et al., 1980 and Hartmann, 1998).

Later, Hearn et al. (1984) proposed the idea of flow unit, which describes and groups similar petrophysical properties of rock controlling fluid flow. Therefore, fluid flow is influenced by mineralogical compositions, texture, cement types and diagenesis. Amaefule et al. (1993) and Tiab (1993) developed a new method to identify and to characterize Hydraulic (Flow) Units related to an unique parameter Flow Zone Indicator (FZI), based on core analysis . This parameter is derived from Reservoir Quality Index (RQI) (ratio between permeability and porosity) and normalized Porosity (ratio between pore volume and grain volume). FZI is related to texture, and in turn, to pore geometry attributes (pore volume, pore throat size, length, connectivity, and tortuosity). This technique is mathematically derived from Kozeny – Carman equation to estimate the permeability an uncored well. Amaefule et al. (1993)'s technique is widely used, very simple and practical (Davies and Vessel, 1996; Shenawi et al., 2007).

Lucia, (1999) and Martin et al., (1999) discussed about petrophysical flow units in carbonate reservoirs. In their discussions, Lucia pointed out that despite the fact the Winland R35 method cannot be applied in vuggy carbonate rocks; there is no relationship between depositional facies and uniform pore size. Furthermore, pore size considerably varies within a rock - fabric. On the other hand, Martin et al., (1999) replied that the R35 method has been used to subdivide pore throat size. Therefore, similar permeability/ porosity ratios give similar pore throat size controlled by rock fabric and in turn, by the depositional environment.

Moreover, the issue faced by Lucia (1995 , 1999) and Lønøy, (2006) to characterize accurately porosity – K relationship is caused by the diversity of the pore types (origin, morphology) within

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carbonate reservoir rock (Johnson, Barnett, & Wright, 2010).

The discussions and the previous works reported early highlight that there is still a debate on correlating fluid flow parameters and carbonate rock fabrics. This is due to variation of pore types in carbonate rock. Therefore, the link between microfacies variations fluid flow properties still remains unclear. The aim of this study is to determine the relationship between fluid flow characteristics and the geological properties controlling the flows such as pore filling (cement) and fundamental properties (microtexture, grain types) within carbonate rocks.

2. Materials and methods

2.1. Microfacies evaluation

Eleven carbonate rocks microfacies from seven different exploration wells located in offshore Sarawak Basin, Malaysia have been identified and studied. The microfacies study is mainly based on petrographic studies by using thin section and SEM (Scattered Electron Microscope). These microfacies are classified based on texture, grain types, matrix, and pore types. Dunham's classification is used to classify the texture (Dunham, 1962) . The pore types are defined by using Choquette and Pray, (1970) and Lucia, (1995) classification. Once the microfacies has been analyzed, the concept of Standard Microfacies Types (SMF) introduced by Flugel, (2004) in combination with microfossil identification are used to summarize the microfacies and to determine the related depositional environment based on Standard Facies Zone of Wilson, (1975) .

2.2. Petrophysical study

The porosity and permeability used to define FZI are derived from Helium – porosimetry. In order the determine FZI, the concept of Reservoir Quality Index (RQI) developed by Amaefule et al., (1993) is used. This method tends to group carbonate rocks with internal consistency of geological and petrophysical properties affecting the fluid flow (Ebanks, 1987).

Once the detailed microfacies of the different core plugs are identified, the RQI (μm) of each core plug are calculated using the equation below (Amaefule et al., 1993):

$$RQI = 0.0314\sqrt{\frac{K}{\Phi}} \qquad (1)$$

Where:
RQI: Reservoir Quality Index (μm)
K: Permeability (mD)
Φ: fraction porosity

In order to define FZI, the RQI is log –log plotted against normalized porosity (Φz) which is defined as pore volume to grain volume ratio. The FZI corresponds to RQI where Φz=1. Therefore, carbonate rocks with similar FZI and in turn geological and petrophysical rock properties lie on unique straight line.

$$\Phi z = \frac{Vp}{Vg} = \frac{\Phi}{1-\Phi} \qquad (2)$$

Where
Vp: Volume of pore
Vg: Volume of matrix
Φ: porosity

3. Results and discussion

3.1. Microfacies analysis

Inhomogeneous dolomitic wackestone: This microfacies is mud – supported. The matrix is composed by 2 different cement types, microcrystalline and granular microsparite (Fig. 1). The granular cement fills the pores like mosaics. The grains are mainly bioclasts such red algae, mollusks, foraminiferas and gastropods. This microfacies would be related to SMF 8 of Flugel, (2004) and deposited in open marine platform interior environment.

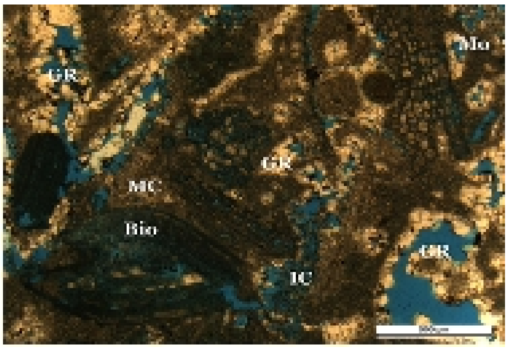

Fig. 1 Representative photomicrographs different cement type: micrite (MC) and granular microsparite (GR)

This facies is also characterized by several pore types such as intrafossil pores (Fig. 2), moldic, microfractures and intercrystalline pores. The porosity varies from 9.8% to 18.7% with permeability ranging from 15.3mD to 409.6mD. The presence of microstylolite (non – parallel reticulate, nodule -bounding) implies chemical compaction during burial diagenesis.

Fig. 2 SEM image showing different pore types (IF: Intrafossils; MO: Moldic pores; IC: Intercrystalline pores)

Dolomitic mudstone: This microfacies is mud – supported with less than 10% of allochems. The matrix is dominated by microcrystalline cement (Fig.

3). However, there are some minor calcitic and dolomitic cement granular cements. Within this microfacies, grains are quasi – absent, only sparse individual echinoid flower – like, foraminifera and lithoclasts are observed. This microfacies would correspond to SMF3 of Flugel, (2004) and probably deposited in deep sea or in toe – of - slope.

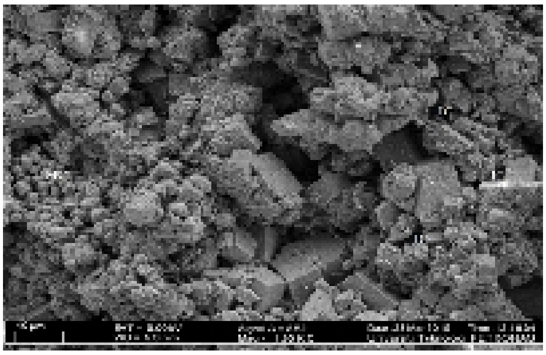

Fig. 3 SEM microcrystalline cement (MC) and intercrystalline pore (IC)

The observed pores are mainly microfractures pores along stylolites (Fig. 4), moldic and intercrystalline pores. The porosity and permeability vary from 2.3 to 35.7% and 0.07mD to 11.45mD respectively.

This microfacies is also composed by swarm's parallel sutures seams stylolites, filled by very fine dark materials which can be organic – rich calcimudstone or ferri – magnesium materials (Fig. 4).

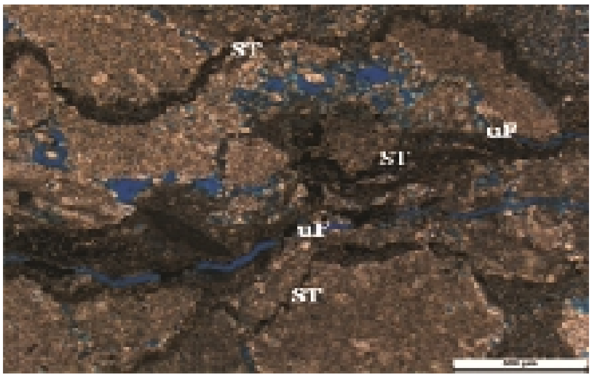

Fig. 4: Mudstone microfabric showing stylolites (ST) filled by fine dark materials and microfracture pores (µF)

Homogeneous wackestone with large bioclasts: This microfacies is mud –supported, with large fossils. The cement is homogeneous microcrystalline (64.6%) (Fig. 5) with well to very well sorted crystals. It consists of very large bioclasts (larger than 2mm size), fractured red algae fragments. This microfacies is associated to SMF 8 of Flugel, (2004) and the carbonate can be deposited in open marine or in deep shelf.

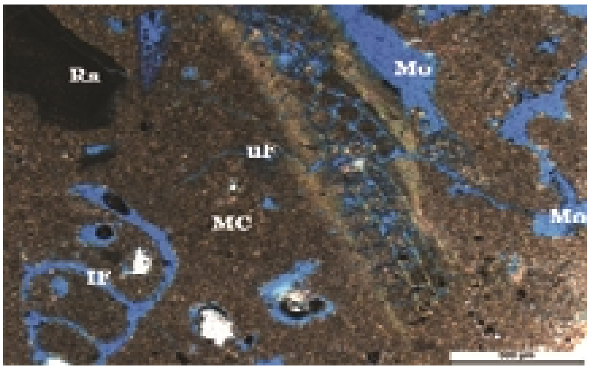

Fig. 5: Photomicrographs showing micrite cement (MC) moldic (MO) pores, microfracture pores (µF) and red algae fragment (RA)

The pores are mainly intrafossils, microcrystalline, moldic, and microfractures pores (Fig. 6). The porosity and ranges from 16% to 33.3% and the permeability from 1.9mD to 49.1mD.

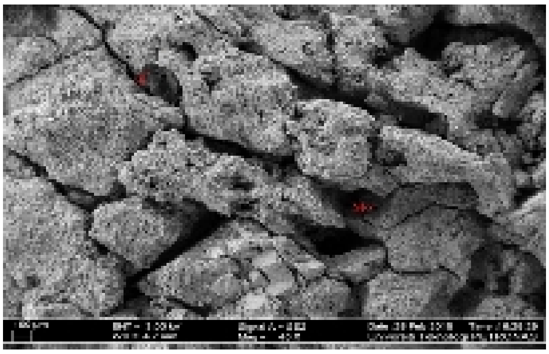

Fig. 6: Microfacture (µF) and moldic (MO) pore

Moldic mudstone - wackestone: This facies is dominated by microcrystalline cements (56%). It also consists of 4.4% of microsparite cement and 15.8% of dogtooth cement growing perpendicularly to the substrate. The skeletal grains which are mainly red algae are very sparse. This microfacies is related to SMF 3 of (Flugel, 2004) and correspond to deep sea or toe – of – slope environments.

The pores of this facies are mainly large moldic (Fig. 7) and intrafossils pores. However, some few microfractured pores are observed. Many of these pores are plugged by calcite cement that is the effect of recrystallization (Fig. 8). In this facies, porosity varies from 8% to 24.4% and the permeability from 1.39mD to 26mD.

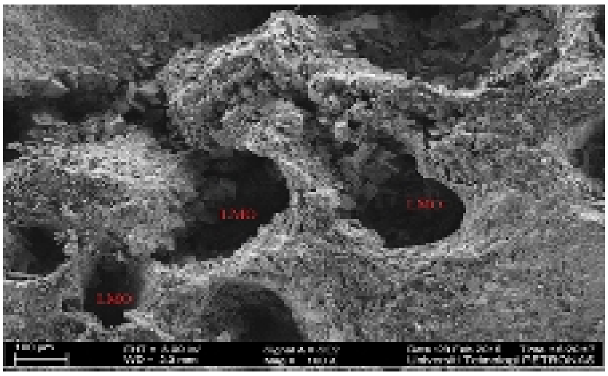

Fig. 7: large moldic pores (LMO)

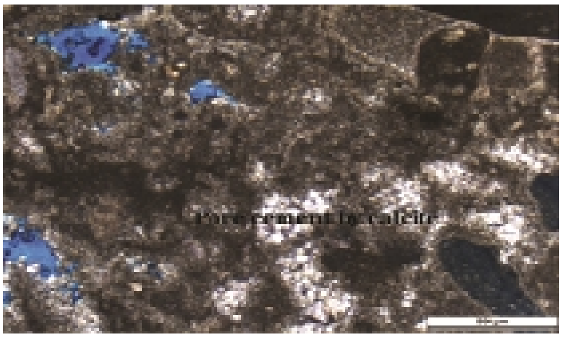

Fig. 8: Pore cemented by calcite

Boundstone: This facies has lack of mud. Some drusy sparse sparite cements are filling the pores (Fig. 9). In this microfacies, the pores are very well connected. It is associated to SMF 7 of Flugel, (2004) and most likely deposited in platform margin reefs corresponding to FZ 5 of Wilson model.

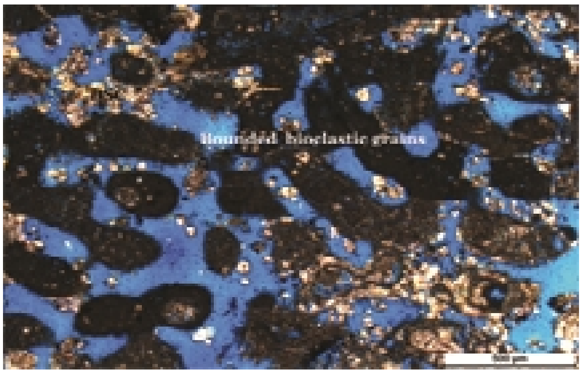

Fig. 9: Skeletal grains bounded together with drusy sparite cement (DSC)

The pores are dominated by intergranular and intercrystalline pores with some minor intrafossil and microfracture pores. This facies shows excellent porosity and permeability varying from 29.2% to 36% from 738.36 mD to 2347.73mD respectively.

Grainstone: This facies is grain – supported with lack of mud (micrite). It is characterized by granular cements (45.8% to 59.4%) (Fig. 10) and some minor dogtooth cement (Fig. 11). The major grains are skeletal grains such as microbioclast fragments. Some partially dissolved red algae are also observed. This microfacies is associated to SMF5 of Flugel (2004) and deposited in the slope of platform.

The pores within this facies are dominated by intergranular and intercrystalline pores. Some few micro intrafossil pores are also noted. The facies shows porosity varying 17% to 21%. However, the permeability is relatively low (2.76mD to 4.58mD) due to the presence of high amount granular cement filling the pores.

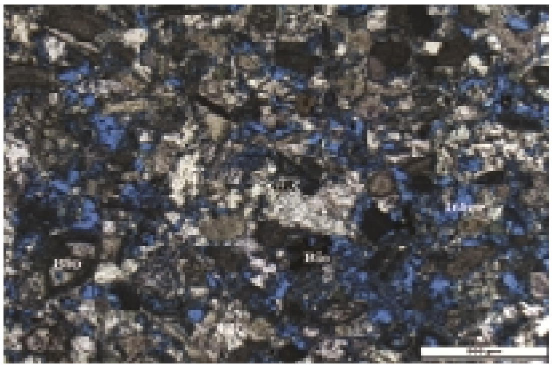

Fig. 10: Grainstone texture supported by bioclasts (Bio) with granular cement (GR) filling Intergranular (inter) pores

Fig. 11: Dogtooth cement from SEM, perpendicular to the substrate

Moldic Wackestone: This facies shows 2 different types of cements which are microcryalline cement (Fig. 12), drusy cement with larger calcite crystal. The fossils occuring within this facies are foraminifera and red algae representing 20% of the bulk volume of the facies. These bioclasts are partially or completely dissolved. In some cases, the dissolution creates rims around the grains. This microfacies would correspond to SMF 8, or SMF 9 or SMF 10 of Flugel, (2004). The sediment of this microfacies can be deposited in open marine, or in deep shelf.

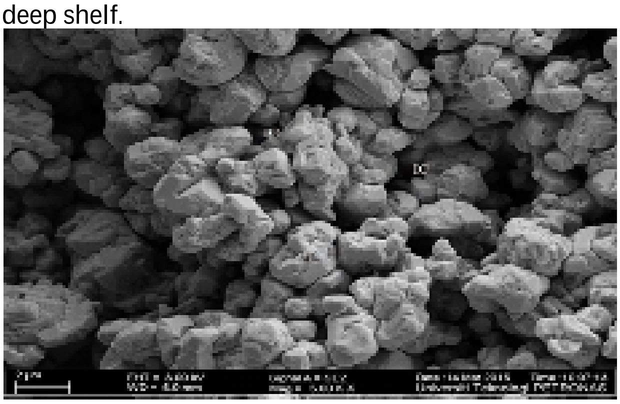

Fig. 12: Microcrystalline cement (µC) with intercrystalline pores (IC)

The pores are dominated moldic pores (Fig. 13) resulting from the leaching of some bioclastic grains. The fossils which are partially leached create intrafossils pores. Some few microfracture and intercrystalline pores are also observed. The porosity of this facies varies from 9.5% to 24.8% and the permeability ranges from 0.68mD to 20.96mD.

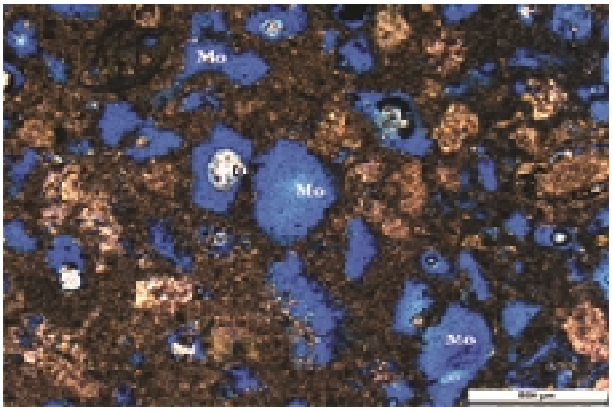

Fig. 13: Moldic pores (MO)

Leached Mudstone: This facies is mainly composed by microcrystalline cement (85%) (Fig. 14) and fragment of micro – bioclasts. The sparse observed fossils are completely or partially dissolved. These grains are foraminifera and echinoderms. This microfacies is characteristic of SMF 3 of Flugel, (2004). The sediment of this microfacies may have been deposited in toe – of – slope or in deep water.

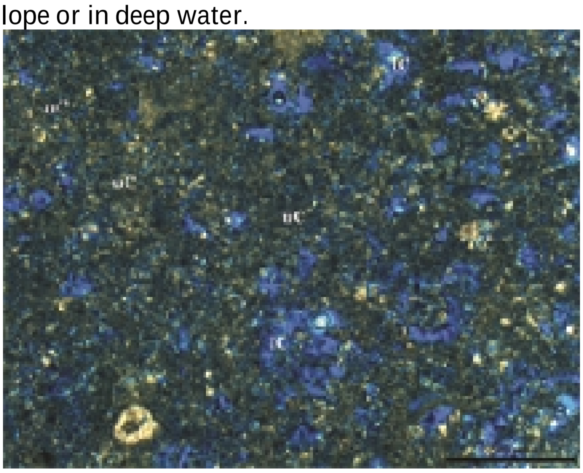

Fig. 14: Mudstone texture, mainly micrite (µC) with intercrystalline pore in blue

The pore types are mainly intercrystalline. Some moldic and intrafossil pores are also present within the facies. The porosity varies from 8.5% to 29.1% and the permeability from 0.09 mD to 19.17mD.

Crystalline: In this facies the depositional texture cannot be recognized. The sparry blocky crystalline cement is the main constituent of the bulk rock. However, some individual crystallized broken fossils can be identified. Based on these studies, the paleo depositional environment of this facies cannot be determined because the microfabric is greatly affected by diagenetic process (recrystallization).

From thin section study, no pore can be identified, excepted pore along some few stylolites (Fig. 15). However, from SEM analysis, intercrystalline pores are observed (Fig. 16). Porosity of this facies varies from 1.4% to 33.8%, and permeability from 0.12mD to 3.47mD. The large amount of porosity can be attributed to the micro – intercrystalline pore.

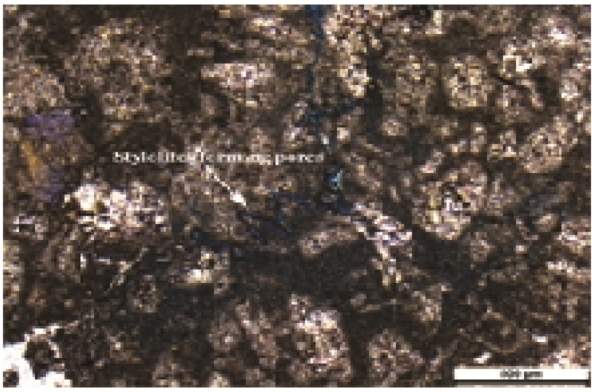

Fig. 15: Blocky cement (BL) with stylolites forming pores

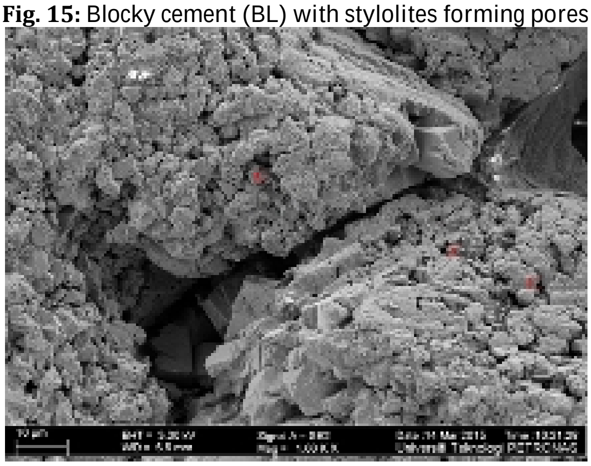

Fig. 16: Intercrystalline pores (IC)

Packestone: This facies shows packestone texture. There are 2 types of cements. The dominant cement is the sparry blocky cement and the minor cement is the microcrystalline cement. The grains are mainly skeletal grains such as red algae, gastropods, bivalve, foraminifera, and some unrecognizable fossils fragments (Fig. 17). This microfacies is related to SMF18 of Flugel, (2004). The depositional model of this microfacies corresponds to restrict to open marine platform interior.

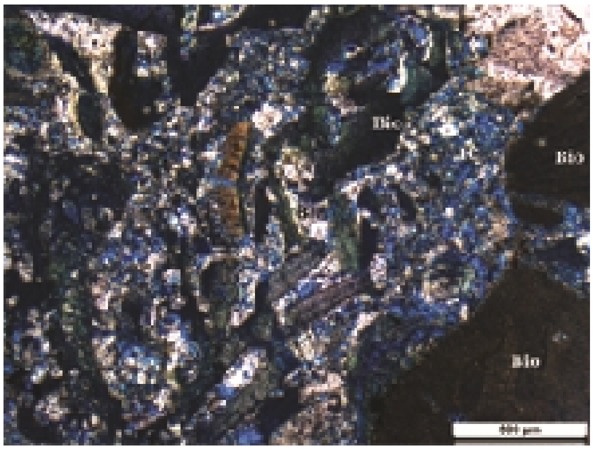

Fig. 17: Photomicrograph showing bioclasts, blocky sparite cement (BL) and intercrystalline pores

The pore types occurring in this facies are mainly intrafossil pores (Fig. 18), intercrystalline pores. The porosity varies from 12.2% to 13.9% and the permeability ranges from 0.2mD to 0.4mD.

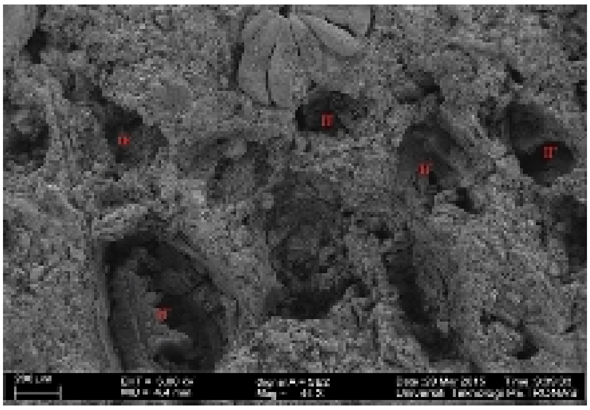

Fig. 18: Intrafossil (IF) pores

Fractured wackestone: This facies is mud – supported, and characterized by 2 types of cements. The main cement is microcrystalline cement with a presence of little dolomite crystal (Fig. 19) and the minor cement is blocky cement with large crystal size and non – equant. The facies is composed by large individual corals, lithoclasts, microfossils and some sparse red algae. This microfacies would correspond to SMF 24 of (Flugel, 2004). The depositional environment of this facies corresponds to restricted platform interior.

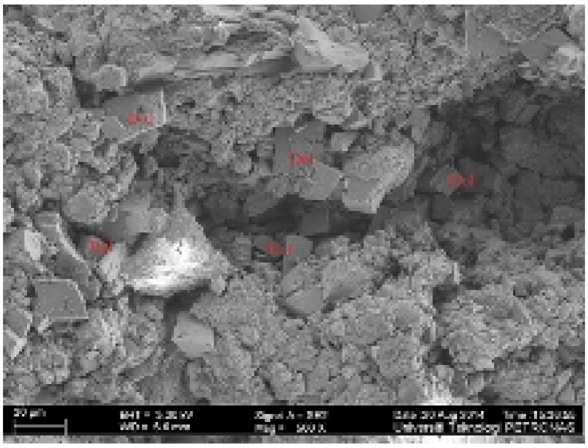

Fig. 19: SEM showing dolomite (Dol) crystals

The pores observed in this facies are mainly microfracture pores (Fig. 20). However, these pores are in some part plugged with very fine dark materials. The porosity is 5.8% to 35.8% and the permeability ranges from 0.08mD to 0.18mD.

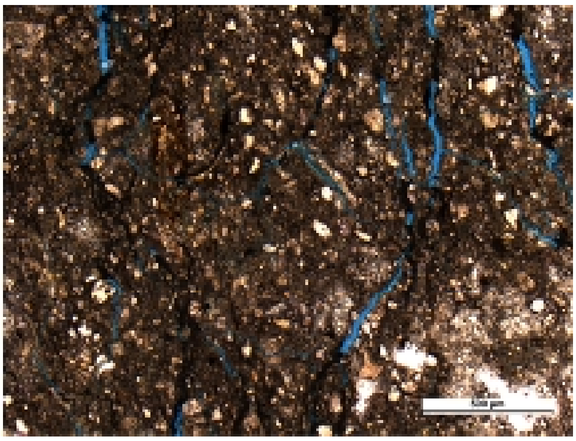

Fig. 20: Microfracture pores (μF) partially filled by dark very fine materials

3.2. Reservoir quality index, flow zone indicator (FZI) analysis

The log – log RQI vs Φ_z plot (Fig. 21) based on microfacies classification does not show any FZI. This is because one particular microfacies may have more than one RQI and thus may fall within one or more FZI. As samples showing similar pore throat attributes (pore throat diameter, length, and connection) lie on the same FZI straight line, this implies that one defined microfacies have several pore attributes. Therefore, it is not worth to determine the FZI and link directly the pore attributes based on / with microfabric such as microtexture, grain types, cement types, and pore types even though they have a great impact on pore systems.

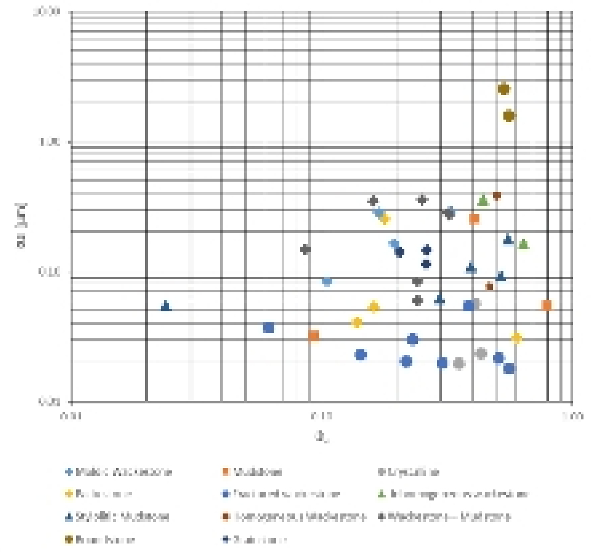

Fig. 21: Log – log RQI vs Φ_z plot by grouping on microfacies basis

However, re –plotting log –log RQI vs Φ_z, and regrouping samples showing the same FZI regardless of the microfacies, Log RQI vs log Φ_z (Fig. 22) indicates the presence of 7 different FZI varying from 0.05 to 1.3. These are related to 7 Hydraulic Flow Units (HFU). Hence, within the 11 studied microfacies, there are 7 groups of pore systems showing similar pore throat attributes. This analysis clearly demonstrates that one microfacies based on texture, cement types, grains types, pore types analysis may show one or more similar pore throat systems and on the other hands, one similar pore throat can be derived from one or more microfacies and, in turn different depositional and diagenetic processes.

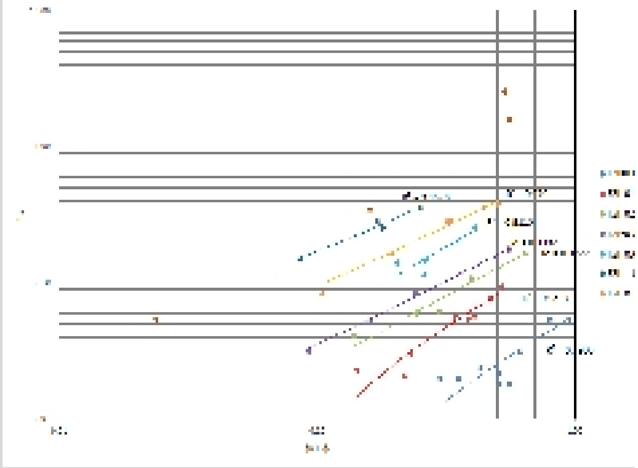

Fig. 22: Log – log RQI vs Φ_z plot regardless of microfacies grouping

4. Conclusion

Eleven microfacies have been recognized and analyzed based on texture variations, grain types, cement types, and pore types within the seven offshore exploration wells from Offshore Sarawak Basin, Malaysia. Taking into account these microfacies characteristics, the log – log RQI vs Φ_z plot does not exhibit any similar pore attributes. On the other hand, by regrouping the samples based on FZI, and regardless of microfacies, in turn of depositional environment and diagenetic processes, 7 Hydraulic Flow Units corresponding to 7 similar pore throat attribute have been identified. Therefore, one particular microfacies can lead to one and more similar pore attributes and one FZI can be derived from one or several depositional environments and diagenesis.

Acknowledgment

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