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CONTROLS ON POROSITY IN SANDSTONE RESERVOIRS IN SOUTHERN PATTANI BASIN, GULF OF THAILAND

Pongtachchai Panachaiboonpipop*

Petroleum Geoscience Program, Department of Geology, Faculty of Science, Chulalongkorn University, Bangkok 10330, Thailand

*Corresponding author email: pongtachchai@gmail.com

Abstract

The reservoir rock in southern Pattani Basin, Gulf of Thailand is sandstone, which was deposited in various environments from fluvial to marginal marine. This study integrated conventional core, side-wall core, wireline data, and petrographic data to recognize and better understand the factors that control porosity in this area. The porosity can be divided into 3 zones (west, central and east). The west and east zones has one porosity trend, but the central zone has two porosity trends, which has the increased porosity shift in the lower reservoir section. The central zone has better reservoir quality in the lower section than the others. The nearby fields also have two porosity trends. Compaction, clay content, and cementation are the major influences on porosity in this area, while lithology, composition, sorting, and dissolution have less impact. Dissolution enhances porosity while the others destroy porosity. Dissolution pores are normally filled or partially filled with authigenic clay. The two porosity trends in this area are probably caused by different cement agents in the upper and lower sections

Keywords: Porosity trend, Sandstone reservoir, Southern Pattani Basin, Cementation

1. Introduction

The study area is located near the boundary of the N-S trending southern Pattani Basin and the North Malay Basin in the Gulf of Thailand (Figure 1), where the regional depositional environments vary from fluvial to marginal marine. Previous observation indicates some wells in the study area and nearby fields have two porosity trends in the main sandstone reservoirs. However, there is no study of the higher porosity trend in the nearby field. Thus, it is necessary to improve the understanding of the controls on porosity by integrating all core and wireline data.

The aim of the study is to recognize and better understand the factors that control porosity in this area by integrating conventional core, side-wall core, wireline data, and petrographic data. Porosity distribution was used to define a potential reservoir in the southern Pattani Basin. In addition, the study area is an exploration area with 19 exploration wells without production and covers approximately 1,300 square kilometers (Figure 2).

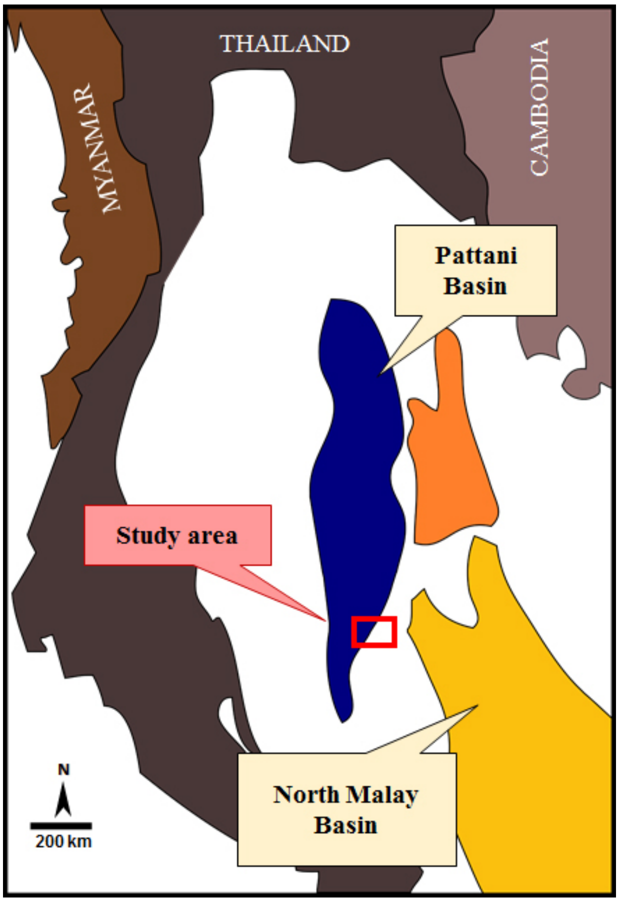


Figure 1. Location map of the study area, Pattani Basin, Gulf of Thailand

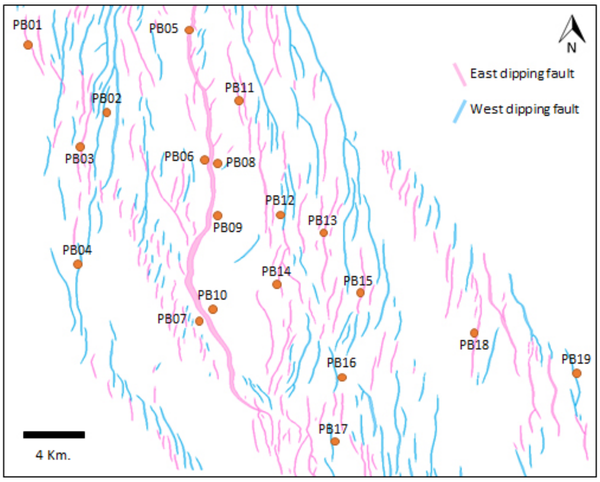


Figure 2. Location of wells in the study area

2. Geological setting

The Pattani Basin is a Tertiary basin which is located near the center of the Gulf of Thailand. The Pattani Basin was formed by failed Oligocene rifting along a north-south axis which created multiple en-echelon graben systems (Crossley, 1990). The Pattani Basin contains as much as 8,500 meters of almost entirely nonmarine fluvial to delta plain sediments from Oligocene to present which are divided into five stratigraphic units (Figure 2) above pre-Tertiary basement as following. Unit 1 : (Oligocene) Lacustrine and alluvial syn-rift sediments , which are associated with failed Oligocene rifting movements within the basin. Unit 2 : (early Miocene) Fluvial flood plain and delta plain sediments. Unit 3 : (early middle Miocene) Marginal marine delta plain and fluvial sediments. Unit 4 : (late middle Miocene) Fluvial floodplain sediments. The top of Unit 4 is marked by a regional unconformity (MMU), which represents uplift and erosion in the late middle Miocene. Unit 5 : (late Miocene to present) Delta plain sediments.

3. Porosity analysis

3.1 Core and Wireline porosity

The core porosity data consists of two wells (PB12 and PB14), which are located in the central of the study area (Figure 2). The core porosity was derived from two methods: Helium gas test in core plugs and point count analysis in thin sections. The core porosity from Helium gas testing is higher than the core porosity from point count analysis (Figure 3) because Helium gas can inject into the microporosity in kaolinite. However, microporosity cannot be counted on thin section. So, the core porosity from Helium gas test is more accurate.

The wireline porosity data came from 19 wells in the southern Pattani Basin. The porosity was calculated from neutron and density logs. Wireline porosity is similar to helium gas test porosity (Figure 3) indicating that wireline porosity is reliable for porosity analysis.

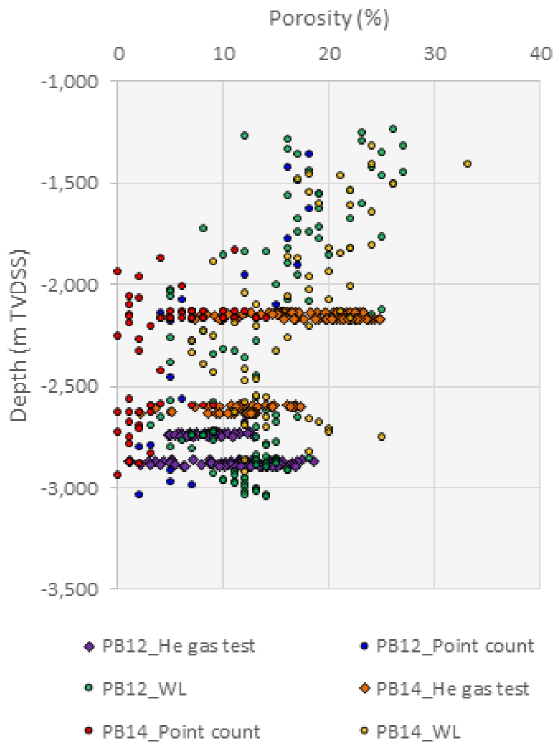
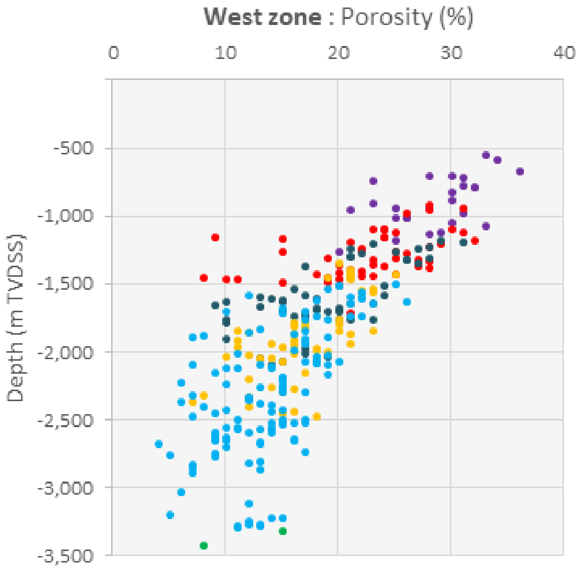
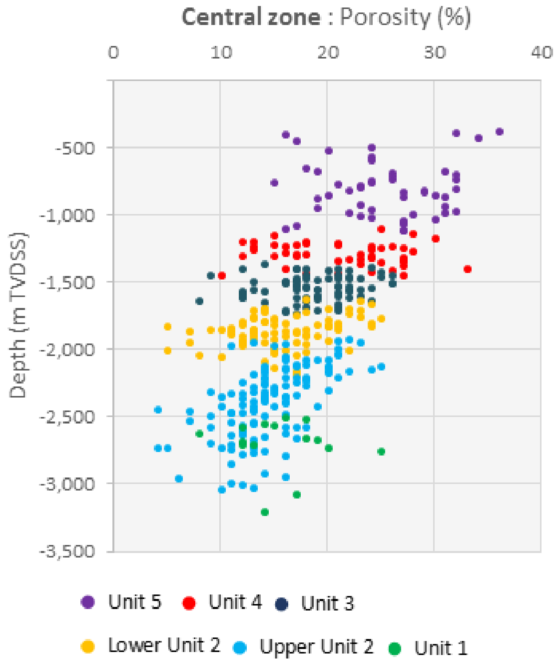


Figure 3. Core and wireline porosity vs depth in PB12 and PB14.

3.2 Porosity distribution

In a normally compacted formation, porosity decreases exponentially as depth increases (Athy, 1930) because of diagenesis. In the study area, porosity can be divided into 3 zones (west, central and east) by using structure and porosity trend. The west zone includes wells PB01, PB02, PB03, PB04, PB05, PB06, and PB07, which are located on the foot wall of the large east dipping fault. The west zone porosity trend is a single decreasing exponential trend from Unit 5 to Unit 1. The central zone includes wells PB08, PB09, PB10, PB11, PB12, PB13, and PB14, which are located on the hanging wall of the large east dipping fault. The central zone porosity trend is a decreasing exponential trend, but lower Unit 2 is shifted to a higher porosity trend compared to the overlying rock. The east zone includes wells PB15, PB16, PB17, PB18, and PB19, which are located far from the large east dipping fault. The east zone porosity trend is a single decreasing exponential trend from Unit 5 to Unit 1 (Figure 4).





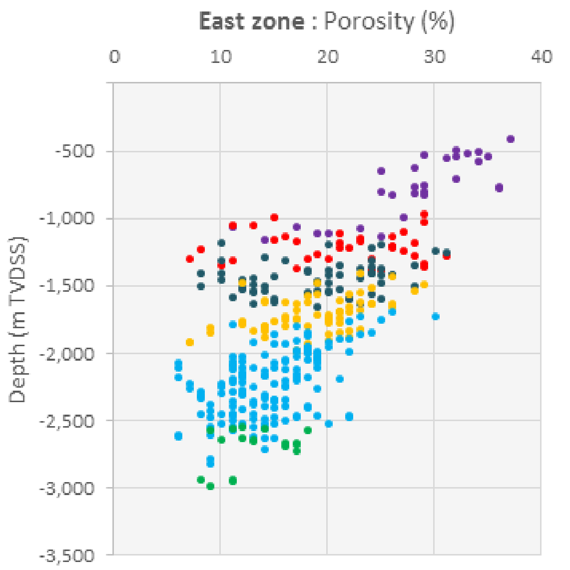


Figure 4. Wireline porosity vs depth in the west, central and east zones colored by stratigraphic unit (filtered Vshale 0-30%)

(Juntra, 2003) concludes that mechanical compaction, carbonate and quartz overgrowth, authigenic clay, and dissolution impact porosity more than depositional environment. In addition, the major factors influencing porosity in the Moragot area, which is near the study area, are compaction, grain size, clay content, sorting, and dissolution, while cementation has a minor influence on porosity (Praiwan, 2015).

3.3.1 Mechanical compaction

Mechanical compaction was observed in every thin section from Unit 4 to Unit 1 in PB12 and PB14. The intergranular porosity of the samples has been lost due to grain rotation (slippage) in response to burial loading of quartz and feldspar and deformation of ductile grains, including micas and phyllite rock fragments. The degree of compaction is related to the maximum depth of burial (M.Scherer, 1987), which is equal to present day depth because there has been no uplift in Pattani Basin. The shallow section has a fairly close packing arrangement and grain deformation

(Figure 5a). Conversely, the deep section has a very close packing arrangement and grain deformation (Figure 5b). Thus, compaction is the main controlling factor on porosity reduction.

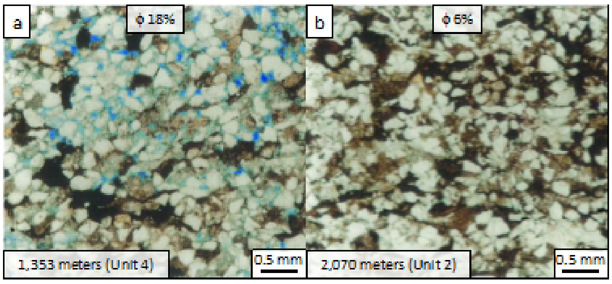


Figure 5. a) Fairly close packing and deformation of ductile grains, b) Very close packing arrangement and deformation of ductile grain

3.3.2 Clay content

Clays are both detrital and authigenic, although most of the clay is authigenic, which can affect permeability and porosity and may acutely reduce reservoir potential (Wilson and Pittman, 1977). Authigenic clay was observed as clay cement (grain-rimming clay or grain coating clay) and clay from alteration. The common clay minerals indicated by X-ray diffraction analysis (XRD) and scanning electron microscope (SEM) in PB12 and PB14 are kaolinite, chlorite, illite, and smectite.

Clay content or shale volume can also be estimated from gamma ray log. The porosity profile from wireline indicates the increasing shale volume with decreasing porosity (Figure 6). Thus, the percentage of clay, or volume of shale, effects and controls sandstone porosity.

3.3.3 Cementation

Cementation reduces porosity after mechanical compaction. Authigenic minerals including quartz overgrowth, authigenic clay mineral, dolomite, siderite, and calcite are the main cementing agents in PB14 (Juntra, 2003) and PB12. The distribution of cementing agents varies through the section in PB12 (Figure 7). Quartz overgrowths, authigenic clay minerals, dolomite, and siderite are the main cementing agents in the upper section (Unit 4 to upper Unit 2). Authigenic clay-mineral, calcite, and quartz

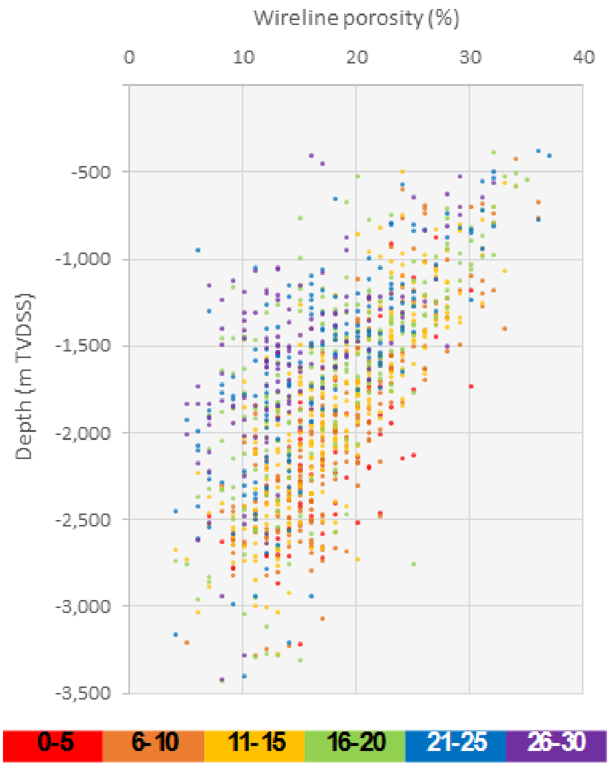


Figure 6. Wireline porosity vs depth in 19 wells colored by percentage of clay (Vshale)

overgrowth also are the main cementing agents in the lower section (lower Unit 2 to Unit 1).

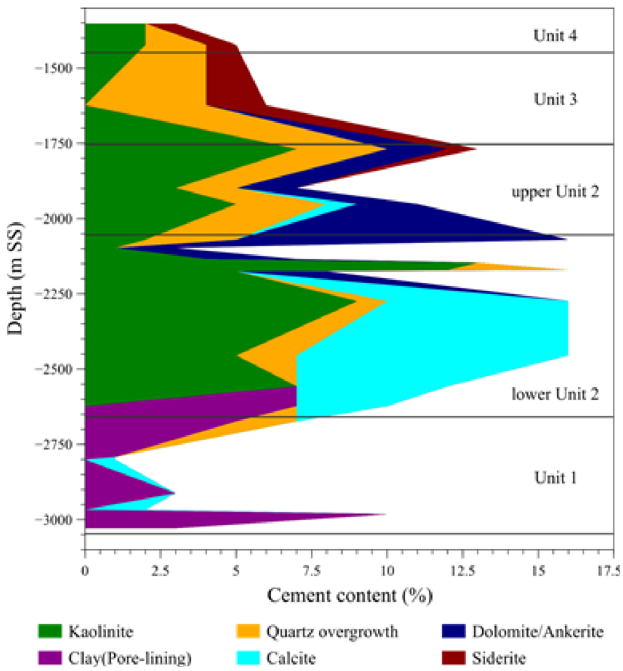


Figure 7. Distribution of cement type vs depth from thin section in PB12

In addition, the clay coatings limit extensive quartz cementation in sandstone, which can preserve intergranular porosity (Taylor et al, 2010). Clay rimming or coating and quartz overgrowths in this study can be seen in thin section (Figure 8) and with scanning electron microscope (SEM). The upper section (Unit 4 to upper Unit 2) has less clay cement than lower section (lower Unit 2 to Unit 1), so quartz cement is more abundant in the upper section in PB12.

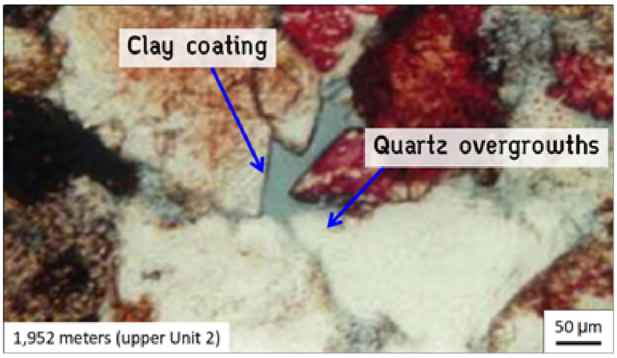


Figure 8. Clay cements coat framework grains to limit quartz cementation in thin section

3.3.4 Composition

Sandstone from Unit 4 to Unit 2 in PB12 and PB14 contains quartz more than feldspar and lithics. Furthermore, the composition in this section does not vary too much; quartz~50-80%; feldspar ~5-15%; lithics~20-40%. The majority of sandstone in this section is litharenite (Folk, 1974) with more than 50% quartz. However, the composition of sandstone from Unit 1 is variable; quartz~30-80%; feldspar ~10-70%; lithics~0-40%. Sandstone from Unit 1 is more variable than sandstone from Unit 4 to Unit 2, which includes many types (arkose, subarkose, lithic arkose, feldspathic litharenite, and sublitharenite) because the depositional environment of Unit 1 is lascustrine while Unit 2 to 4 is fluvial to maginal marine, so the source of sediment may be different. The overall composition trend from sandstone above Unit 1 to Unit 1 is increasing feldspar, and decreasing quartz and lithics (Figure 9).

3.3.5 Sorting

Well sorted sandstone generally has high

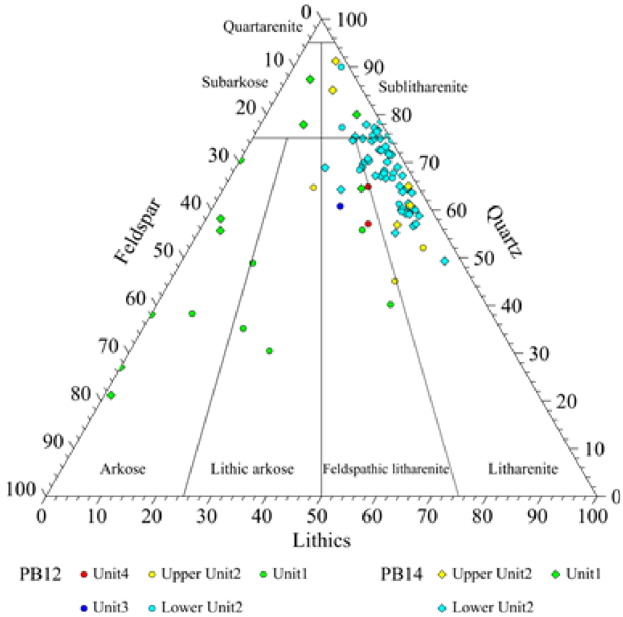


Figure 9. Sandstone classification in PB12 and PB14 (Folk, 1974) colored by stratigraphic unit

3.3.5 Sorting

Well sorted sandstone generally has high porosity, while poorly sorted sandstone has low porosity. Sorting can be measured by using the Trask sorting coefficient, which is the square root of the ratio of larger quartile, Q1, of the particle to smaller quartile, Q3 (Pettijohn, 1975). A high value of Trask sorting coefficient means poorly sorted sandstone and low porosity.

The overall distribution of sorting coefficient in PB12 and PB14 is increasing with depth, which means that sorting is better in the upper section than in the lower section. The sorting of sandstone in PB12 varies from 1.3-1.5 in Unit 4 to upper Unit 2, 1.3-1.8 (excluding a very poorly sorted sandstone; sorting 4.4 at 2,134 m) in lower Unit 2, and 1.6-2.1 in Unit 1 (Figure 10). In addition, the sorting of sandstone in PB14 varies from 1.2-1.4 in upper Unit 2, 1.2-2.0 in lower Unit 2, and 1.4-1.6 in Unit 1. From sorting data, the primary porosity of the upper section should be higher than the lower section. However, the shifted higher porosity trend in the central zone occurs in the lower section, so sorting and grain size are not significant controlling factors on porosity.

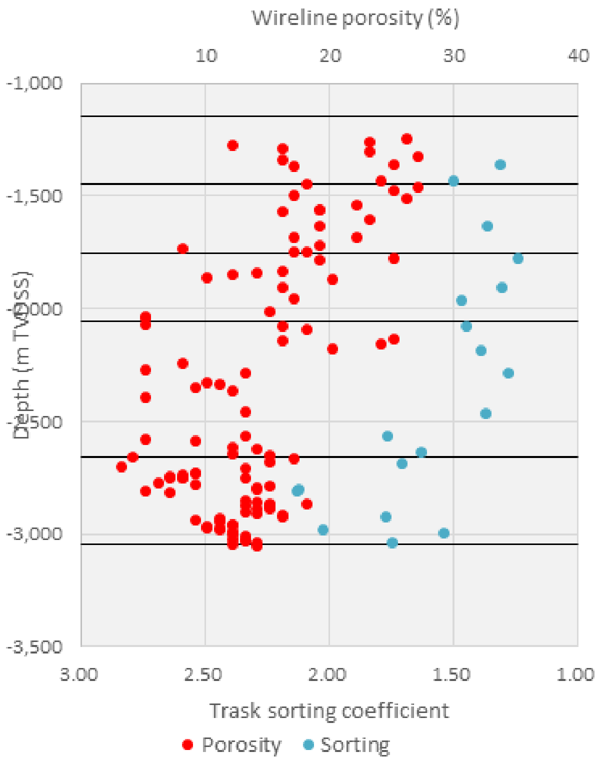


Figure 10. Wireline porosity and sorting vs depth in PB12

3.3.6 Dissolution

Dissolution pores in Unit 4 to Unit 1 in PB12 and PB14 are the result of leaching of unstable grains which created secondary porosity. However, the dissolution pores are typically isolated pores. The dissolution pores normally filled or partially filled with authigenic clay from feldspar alteration (Figure 11). Feldspar diagenesis is related to late stage clay cementation. Dissolution pores form important porosity in deeper sections.

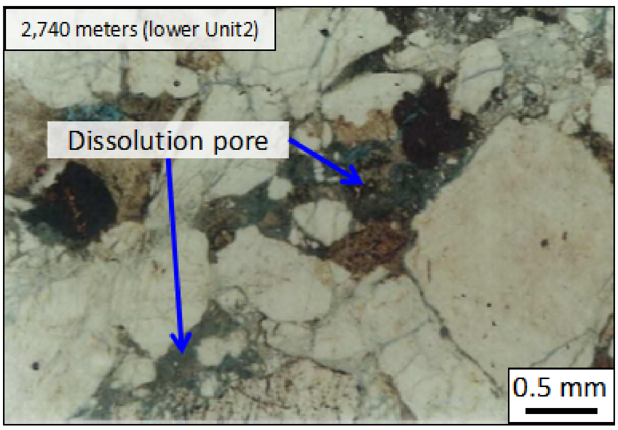


Figure 11. Partial dissolution pores (blue, L-6, G-11), which are occluded by clay cement (largely illite and illite-smectite)

4. Discussion

Porosity is controlled by the combination of several factors. The overall porosity trend is decreasing exponentially with increasing depth. Nevertheless, there are highly variable porosity values in the trend. Diagenesis affects porosity more than primary porosity, for lithology, composition, and sorting of the main sandstone reservoir is similar in Unit 4 to Unit 2. Compaction, clay content, and cementation are significant controls on porosity.

The sandstone in this area is easily compacted because there is no overpressure, thick overburden sediments, and low net to gross of sand in the fluvial delta plain environment. Increasing clay content corresponds to decreasing porosity in every section, since clay has plugged the pore throats via cementation and grain deformation. Clay cementation is probably the cause of the porosity shift to better porosity in the middle of Unit 2 (Figure 4) in the central zone, based on core data from PB12. The clay coating cement on framework grains occurred before quartz and calcite cementation. In addition, the clay cement content in the lower section (lower Unit 2 to Unit 1) is higher than in the upper section (Unit 4 to upper Unit 2). Thus, the clay coating cement helped to prevent quartz from filling intergranular porosity more in the lower section than in the upper section. Core data also indicates more quartz overgrowths in the upper section than in the lower section. However, carbonate cementation may also contribute and it is different in the upper section (siderite,dolomite, and ankerite) from in the lower section (calcite). Cementation in the west and east zones are expected to be same through the section.

This study suggests clay cementation occurred in early to late diagenesis and before quartz cementation. Conversely, Juntra (2003) and Praiwan (2015) suggested clay cementation occurred after quartz cementation in late diagenesis only. If quartz overgrowths occurred before clay cement, clay cement should coat over quartz overgrowths. However, the thin sections in this study reviewed that authigenic clay cement has coated grains, but not quartz overgrowths, which means authigenic clay cement definitely occurred in early diagenesis before quartz cementation. However, authigenic clay cement also filled dissolution pores in late diagenesis.

Finally, the porosity distribution indicates that the porosity trend in the upper section is similar all across the study area but porosity in the lower section in the central zone is higher than in the west and east zones, the central zone has better reservoir potential than the others. The exploration should focus on the central zone.

5. Conclusions

Core data, petrographic data, and wireline log were integrated to analyze controls on porosity and porosity distribution. The results are:

1) Core porosity from Helium gas tests is more reliable than core porosity from point count analysis because core porosity from point count analysis does not include microporosity. Wireline porosity is similar to the core porosity from Helium gas tests.

2) Porosity typically decreases exponentially with increasing depth. Porosity can be divided into 3 zones (west, central and east). The west and east zones have one decreasing porosity trend, but the central zone has two decreasing porosity trends. The increasing porosity trend in the central zone occurs in the middle of Unit 2, the central zone has better reservoir potential than the others.

3) Porosity resulted from a combination of several factors. Diagenesis affected porosity more than primary porosity. The major influencing factors were compaction, clay content, and cementation. Lithology, composition, sorting, and dissolution have the minor influence.Dissolution caused porosity enhancement while the others cause porosity reduction, but dissolution pores normally are filled or partially filled with authigenic clay.

4) The shifted porosity trend in the central zone probably was caused by different cement agents in the upper and lower sections. Clay cementation occurred in early to late diagenesis and before quartz cementation.

6. Acknowledgment

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