CHAPTER 5

DISSCUSSION AND CONCLUSION

5.1 Description on petrophysical interpretation

Among the well logs, gamma rays and sonic logs were the most appropriate for stratigraphic correlation in this area. The regional flooding surface with highest reading of gamma ray was typically used to determine the boundaries of reservoir divisions. Based on the characteristics and correlation of gamma ray and sonic logs, 12 reservoir units of 3 divisions were classified. The uppermost boundary of the division, top of reservoir unit KR1-1, gave maximum gamma ray value and its lateral continuity was observed in all wells. Similarly, the tops of reservoir units KR2-1 and KR2-8A were also identified as boundaries for the middle and lower divisions. The reservoir units were split up with their shale breaks established upon the features of gamma ray and sonic crossing over. This feature is also useful to predict the variation of shale/sand vertically and laterally. The unit KR2-1 is the thinnest and dominated by shale. The unit was excluded from the list of reservoir for this area.

Estimating volume of shale (Vsh) based on gamma ray logs is more consistent than using neutron-density logs. Clavier method with gamma ray was selected for the study area because it generates the average of Vcl comparatively with other formulae.

Neutron-density logs with formula by Dewan (1983) and sonic log with formula by Wyllie (1958) were applied to process effective porosity (ϕe). The caliper log shows rugose borehole patterns in many intervals especially in shale zones, and consequently, the porosity tools read unreasonably high porosities in those intervals.

The shale-corrected method with sonic, neutron-density was used for effective porosity.

The critical parameters to determine water saturation (Sw) are resistivity of formation water (Rw), cementation factor (m), porosity factor (a) and water saturation component (n). The laboratory analysis can give the best result for these parameters. Pickett plot method was carried out to estimate the “Rw” and “m” parameters, and “n” was assumed as a generalized value of “2”. As per review on Pickett plot the estimation of “Rw” and “m” lie in the rages between 2.43 to 0.18 and 3.4 to 1.3 respectively. The acceptable values from these ranges were resolved by Arithmetic Mean, and 0.82 for “Rw” and 2.13 for “m” were concluded. These figures agree with the concept of Humble (m=2.15 and a=0.62 for unconsolidated sand, Tertiary). Therefore, the values “m” (2.15) and “a” (0.62) were adopted in water saturation models. The “Rw” values by Pickett plot were primarily fixed in water saturation models.

In water saturation models, “Rw” was recalibrated by adjusting to the nature of resistivity of formation (deep, shallow resistivity), volume of shale and porosity. The “Rw” values ranged between a maximum of 1.63 to a minimum of 0.347 and mean value 0.85 were practically finalized for reservoir units.

Dual water model is the most appropriate to determine hydrocarbon pay-zones in the study area.

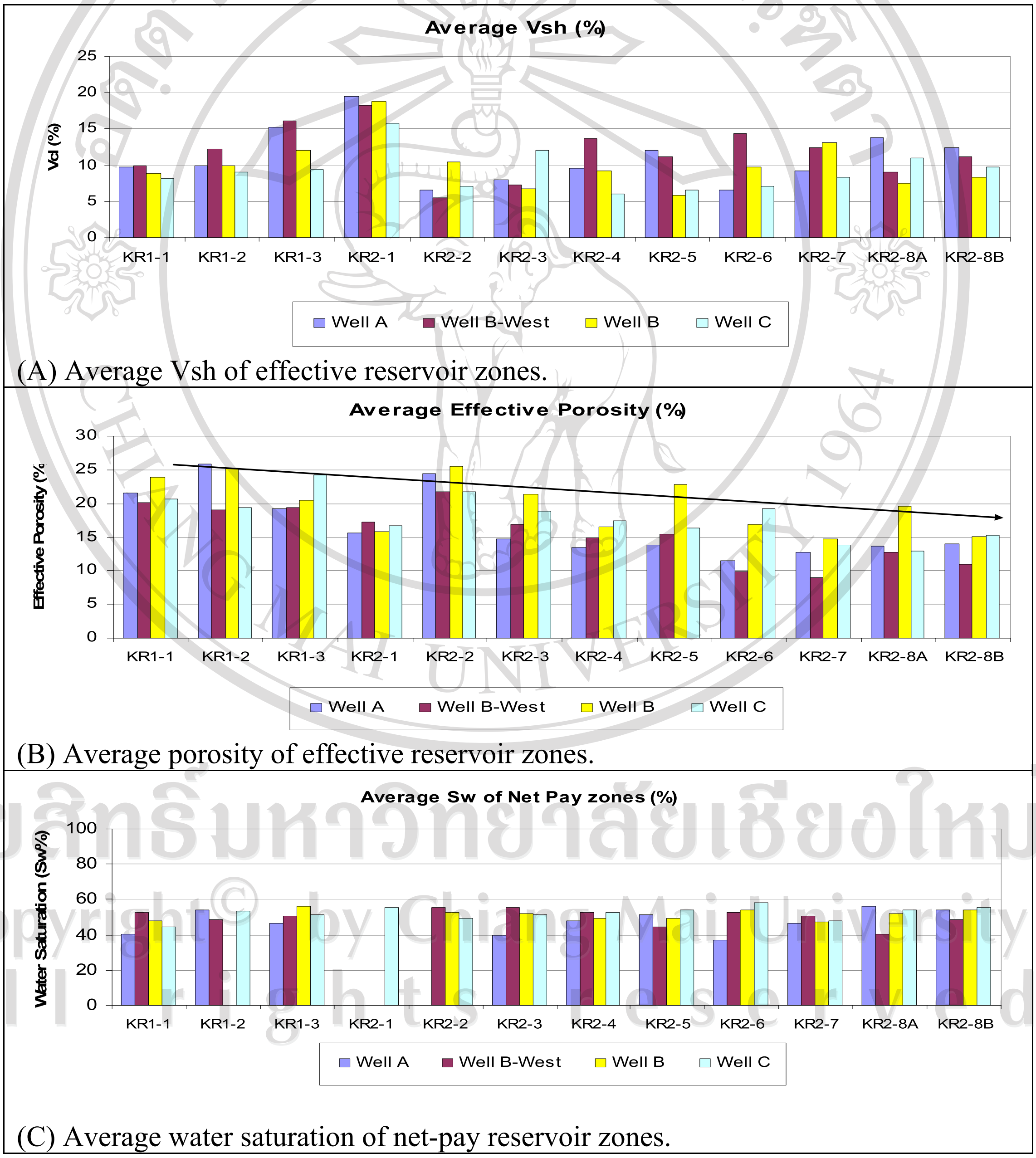
5.2 Physical properties of reservoir units

- Reservoir units are dipping to south-east and the well A is shallower in the north and well C is deeper to the south.

- "Vsh" generally increases with burial depth and laterally increases southward for each of effective reservoir units (Figure 5.1A). The maximum 20% and minimum 6% of "Vsh" were calculated for mean average of effective reservoir units.
- The "ϕe" of effective reservoir zones decreases with burial depth. There is not much lateral variation within each reservoir unit (Figure 5.1B). The mean average of "ϕe" in effective reservoir units ranges from 9% to 26%.
- The estimated "Sw" by dual water model was mostly consistent for all units except for unit KR2-1. Not more than 37% - 56% of "Sw" was used as boundaries for net pay reservoir units (Figure 5.1C). Unit KR2-1 was out of reservoir by a cut-off value of 60% "Sw" and effective thickness.
- The studied intervals for wells A, B-West, B and C are 201 m, 205 m, 205 m, and 207 m in true vertical thickness respectively. The intervals of studied units are comparable in terms of gross thickness; the reservoir units KR2-6 to KR2-8A are gradually thicker southward in all wells (Figure 5.2A).
- The effective thickness of reservoir units varies with the degree of "Vsh" and "ϕe". They were verified by cut-off value of 30% of "Vsh" and greater than 8% of "ϕe". The effective thickness increases with depth for each reservoir units. Generally, the lower division is thicker with depth and laterally thicker southward (Figure 5.2B).
- Net reservoir zones were modified with less than 60% of "Sw" to effective reservoir thickness. The variation of net-pay thickness relies on cut-off values. The cut-off values of 30%, 8% and 60% of "Vcl", "ϕe" and "Sw" were reasonably applied for the net-pay thickness. Figure 5.2C describes the net-pay thickness. The

lower division, unit KR2-8A and KR2-8B, shows the maximum thickness of cumulated hydrocarbon.

- Figure 5.2D explains the factor of hydrocarbon accumulation at bore-hole scale. The reservoir unit KR2-8A of wells B-west and B give the most attractive estimation of hydrocarbon volume. The lower division is most bulk accumulation of hydrocarbon in the study area.

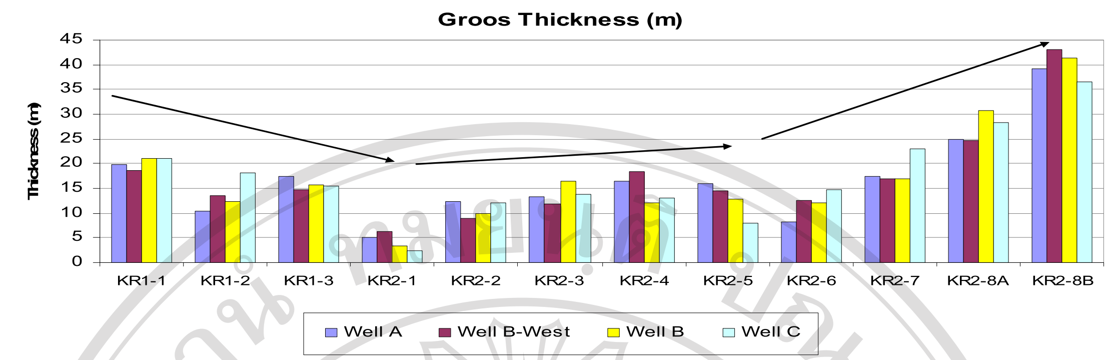


(A) Average Vsh of effective reservoir zones.

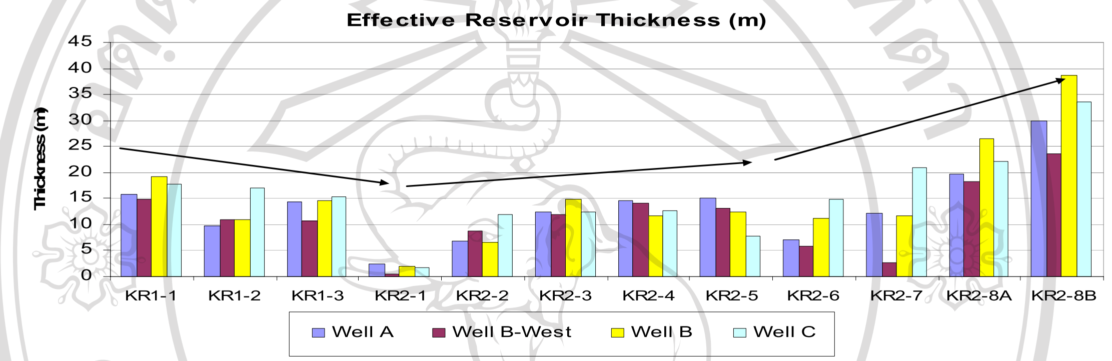
(B) Average porosity of effective reservoir zones.

(C) Average water saturation of net-pay reservoir zones.

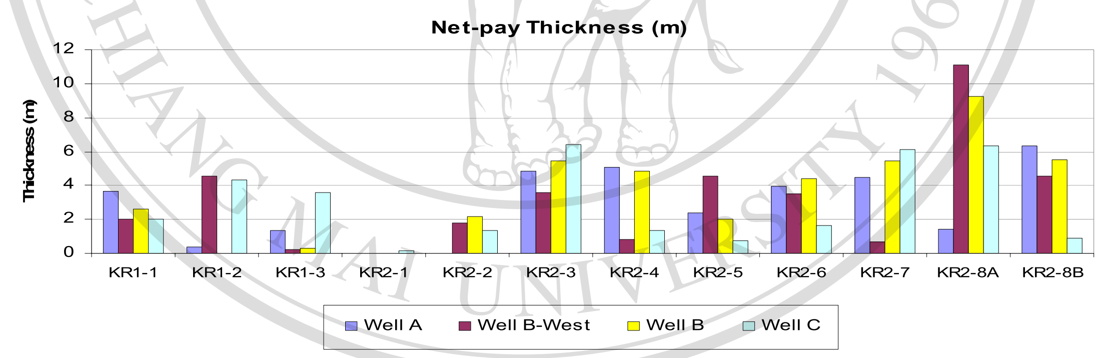
Figure 5.1 Average of Vsh and effective parameters in reservoir zones.



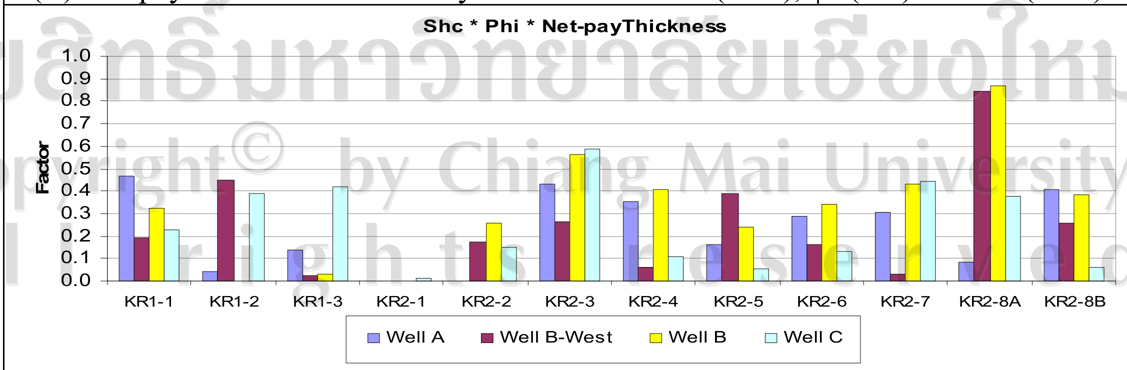
(A) Gross thickness of reservoir units, determined on top and bottom of units.



(B) Effective reservoir thickness by cut-off value Vsh (30%) and ϕe (8%).



(C) Net-pay reservoir thickness by cut-off value Vsh (30%), ϕe (8%) and Sw (60%).



(D) Hydrocarbon volume factor (S_{HC}*ϕe*Net-pay Thickness) in bore-hole scale

Figure 5.2 Comparison of thickness between Gross reservoir, effective reservoir and net-pay reservoir with hydrocarbon volume factor.

5.3 Reservoir distribution

The gross thicknesses of reservoir units are relatively consistent. Moreover, their effective thickness is changeable with internal features which were governed by the heterogeneities of reservoir qualities and depositional environments. The heterogeneities of reservoir were exposed by the characteristics of electrofacies. Wellbore-scale (microscale) heterogeneity to area-scale (macroscale) heterogeneity are possible in successions where sandy bodies and floodplain characters are stratigraphically well recognized. Microscale heterogeneity suggests the vertical variation in grain size, texture and properties of reservoir.

Three divisions of facies were classified based on well-log patterns. The upper division is predominated by coarsening-upward patterns with internal blocky shapes. Blocky top with bell shapes are more significant in the northern area while blocky-based and fining-upward patterns in the southern area. The depositional energy increases northward. The effective thickness lessens increasing "Vsh" with depth in upper division. The middle division does not much vary in effective thickness (Figure 5.2B). Therefore, the middle division is attractive for reservoir quality.

The middle division is dominated by irregular block shapes (stack pattern) with internal fining- and coarsening-upward patterns. The coarsening upward sequence is mainly in the lower part of this division and blocky-based with fining-upward patterns are more developed in the upper part. The effective thickness is a maximum in the middle part and decreases toward upper and lower parts. The thickness of the middle part increases in units KR2-3, KR2-4 and KR-5. The fining-upward bell shapes with blocky-bases and block patterns have considerable effective reservoir thickness in the middle division.

The lower division is interpreted to be the main reservoir with adequate thickness. The gross thickness increases with depth and southward. Stacking patterns are chiefly identified in this division. Moreover, in the northern area (well A) blocky-based and fining upward patterns are predominant, and typical stacking patterns are found in the middle part of division (wells B-West and B). A sharp top and gradual-based block patterns were observed in southern area (well C). The effective thicknesses were generally increases southward following the gross thickness (Figure 5.2-A, B). The block patterns with acceptable thickness are encouraging as effective reservoirs.

5.4 Petrography

Coarse lithic fragments compose the largest proportion of clast types and matrix varies with depth. Siliciclastic grains especially quartz are composed between 27% of minimum to 85% of maximum with carbonates and some metamorphic fragments. Using Dott's classification, the samples are classified as Lithic Arenite with few samples of Lithic Graywacke. Very small amounts of feldspar and clastic fragments such as siltstone and mudstone were observed. Grain sizes vary with lithology. Very angular to well rounded and moderate to very poor sorting grains were observed. The grains are mainly matrix supported. Very fine clasts filled intergranular pores.

Lithic fragments are a mixture of recrystallined dolomitic limestone, limestone, polycrystalline quartz and monocrystalline quartz, schist (or phyllite), and chert. Secondary growth of calcite coats on dolomitic limestone. Monocrystalline quartz is more dominant and aggregated quartz fragments with polycrystalline quartz also occur as main framework. Matrix mixtures with clay especially kaolinite, illite and chlorite mostly filled intergranular pores and spread out around lithic fragments. Kaolinite is the most abundant clay variety under SEM. Uppermost division of reservoir units were mainly comprised of structural shales. Laminated shale and few amount of dispersed shale were observed in middle and lower divisions. Minor amounts of biotite, muscovite and carbonate grains are present.

In the lower part of the reservoir section, lithic fragments are grain supported and partly matrix supported. Very low to moderate effect of diagenesis is encountered and therefore, visual porosity under petrographic analyses could be estimated.

5.5 Diagenesis

A number of diagenetic alterations have been observed with various intensities. The porosity of effective reservoir shows acceptable ranges, for this reason the diagenetic alterations was probably not severe and there was no significant reservoir enhancement. The following events were interpreted based on thin section and SEM.

- Overgrowth of calcite on grains
- Calcite cementation and dissolution
- Precipitation of authigenic clay minerals
- Replacement of hydrocarbon
- Microfractures in feldspar and quartz

The diagenesis that affects porosity was calcite replacement in poor sorting frameworks and coating to grains. Most of the grains especially dolomitic limestones and chert were coated by secondary calcite. Although a distinctive recrystallization was formed by the overgrowth, the rounded outlines of detrital grains are still visible. Therefore, that reaction began only at the time of deposition under stable condition. The calcite cement was major responsible for grain packing and pore filling. Minor dissolution was observed under thin sections.

Clay filled intergranular pores are attributed to alteration of feldspar and Arkosic lithic fragments. Such alteration took place during the secondary stage of diagenesis. Moreover there is not many trace of strong diagenetic phenomena that degraded porosity.

The evidence of microfractures in feldspar and quartz suggests slight compaction during burial. The grains mostly float in matrix with generally point contacts to line contacts. The grains were rarely interlocked. Mineral overgrowth probably partly hindered compaction.

The hydrocarbon residues were examined in intergranular pores and within clay matrix. The replacement of hydrocarbon probably took place after clay precipitation.

5.6 Conclusion

The studied wells are located in an area about 1.6 km by 0.4 km. The well spacing ranges from 0.4 – 1 km.

Petrographic analyses (pore-scale) and petrophysical interpretations (borehole scale) to well to well correlations (area-scale) are trustworthy to establish the effective characteristics of potential reservoirs.

The gross intervals of reservoirs were classified into 3 divisions with 12 sub units based on the characteristics of gamma ray and sonic logs. The reservoir units are deeper to south and south-east and shallower to north and north-west.

Volume of shale is a critical parameter in the estimation of effective porosity because the quality of reservoir is sensitive with shale/clay distribution in study area.

Sensitivity analysis for cementation factor by Pickett plot concluded the value "m" of 2.15 appropriate for these reservoirs. Mean value 0.85 ohm.m of resistivity of formation water (Rw) is a normalized value between varying "Rw". Only dual water saturation can identify the hydrocarbon pay intervals for those formations.

Cut-off values, "Vsh" 30%, "ϕe" 8% are realistic to classify effective thickness. Moreover, permeability and production analyses firmly support the cut-off values for net-pay thickness together with well-log parameters "Vsh", "ϕe" and "Sw". The cut-off value, "Sw" of 60% is a proposed figure for the study area.

The units KR2-8A and KR2-8B are primary potential reservoir and the units KR2-3 to KR2-5 are favorable for second potential reservoir. The Figures 5.1 and 5.2 exhibit the spacial and vertical distribution of reservoir properties.

Diagenesis does not affect much of the reservoir quality.