Reservoir Description using Hydraulic Flow Unit and Petrophysical Rock Type of PMT Carbonate Early Miocene of Baturaja Formation, South Sumatra Basin*

Jaka Radiansyah[1], Teddy E. Putra[1], Rienno Ismail[1], Ricky Adi Wibowo[1], Efri E. Riza[2], and Medy Kurniawan[2]

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[1]Upstream Technology Center, PT. PERTAMINA PERSERO, Jakarta, Indonesia (jaka.radiansyah@pertamina.com)
[2]Paku Gajah Development Project, PT. PERTAMINA EP, Jakarta, Indonesia

Abstract

Carbonate reservoirs commonly have a wide range of porosity and permeability. Porosity and permeability relationships are commonly derived from wireline log base and are core-calibrated. Both Hydraulic Flow Unit (HFU) and Petrophysical Rock Type (PRT) analysis was completed predominantly using porosity and permeability core data. The HFU identification was carried out by classifying the reservoir base on its cumulative flowing capacity using the Stratigraphic Modified Lorenz Plot (SMLP) methods, while PRT identification was based on the Flow Zone Indicator (FZI) concept from modified the Kozeny and-Carmen equation and Windland R35 plot. The analysis result shows there are six HFUs. HFU 1, HFU 2, HFU 3, and HFU 5 have a good flowing capacity while HFU 4 and HFU 6 are baffles.
Petrophysical analysis results mainly show three groups of PRT based on pore types and pore sizes. PRT 1 microfacies is largely foram bioclastic wackestone, PRT 2 is largely foram bioclastic wackestone and benthic bioclastic wackestone/packestone association, PRT 3 is benthic bioclastic wackestone/packstone. Based on DST results, HFU units 1, 2, 3, and 5, and PRT 1, which is largely foram bioclastic wackestone, have the most productive reservoirs. The data shows that petrophysical rock types are in line with capillary pressure profiles and thus will give different water saturations at high above free water level (HAFWL) and will affect the hydrocarbon pore volume (HCPV).

Methodology

Forty core plugs were taken and represent various depositional environments of Early Miocene Carbonate of the Baturaja Formation. The samples were taken for petrographic or thin section analysis and were measured for its porosity and permeability. Thin section samples were impregnated with blue dyed epoxy. Amaefule et al. (1993) presented the method for the use of hydraulic flow unit to divide rock facies, because of considerable variation of permeability in well define rock type. In this research, HFU identification was carried out by classifying the reservoir base on their cumulative flowing capacity using SMLP methods (Gunter et al., 1997), while PRT identification was based on FZI and Windland R35. Capillary pressure measurement using mercury injection was also employed to identify the character of each petrophysical rock type based on its capillary pressure.

Geologic Setting

The South Sumatra basin was formed by three major tectonic phases (Figure 1):

1) Extension during late Paleocene to Early Miocene forming north-trending grabens that were filled with Eocene to Early Miocene deposits;
2) Relative quiescence with late normal faulting from Early Miocene to Early Pliocene;
3) Basement-involved compression, basin inversion, and reversal of normal faults in the Pliocene to Recent forming the anticlines that are the major traps in the area.

The South Sumatra Basin consists of Tertiary sediments that unconformably overlies basement. The Lahat Formation is the First sediment unconformity above basement, this sediment is part volcanic and part fluvial-lacustrine in a graben system. Next, the Talangakar Formation was deposited, part of this formation unconformably overlies basement and part is unconformably overlies volcanic sediment of the Lahat Formation. Transgression continued until Early Miocene when the environment changed to shallow water. The Baturaja Formation consists of limestone was deposited at this time. Above the Baturaja Formation is the Gumai Formation, which marked the end of transgressional phase in the South Sumatra Basin. The Air Benakat Formation and Muara Enim was deposited during the end of transgression phase becoming a transition zone and deltaic system (Figure 2).

The Baturaja Formation was deposited during transgressive and highstand system tracts. Early Lower Baturaja Formation records a major sea level drop that made an excellent quality reservoir. The transgression rate increased during late Early Miocene that caused the drowing of carbonate buildups.

Depositional Setting

The Baturaja Formation mainly consists of homogeneous microfacies deposited in a shallow-water environment. Based on petrographic thin section from core and cuttings, the occurrence of millioids can be interpreted as an open lagoon environment on an isolated carbonate platform. Carbonate isolated platforms is controlled by tectonics during the transgression phase. Tectonic extension created local high areas as a place for carbonate (reefal) to grow (carbonate factory). The carbonate factory supplied bioclastic sediment to the Black Reef (lagoonal). The occurrence of millioid and aggradational phase suggests that the depositional environment of PMT field was open lagoon.

Hydraulic Flow Unit (HFU)

The hydraulic flow unit (HFU) concept has been developed to identify and characterize rock types, based on geological and physical parameters at pore scale. The HFU is defined as a mappable portion of the total reservoir and affect the flow of fluids are consistent and predictably different from the properties of the other reservoir rock volume (Ebanks et al., 1992). The stratigraphic modified Lorenz plot (SMLP) can be used to determine the number of HFU, it is a plot of flow capacity and storage capacity, the change in slope indicates a new flow unit, while a flat trend can be treated as a barrier where no flow occurred. PMT Carbonate shows the SMLP for PMT-3 well can determine at least six HFU with two barriers (Figure 3). Figure 4 Shows that about 50% of the fluid flow has occurred from 1,465 ft to 1,466 ft. The heterogeneity of the reservoir of PMT Carbonate is considerably varied along the well. From about 1,465 ft downward the reservoir can be treated as heterogeneous; however, from about 1,465 ft. upward the heterogeneity of reservoir decreases due to the decrease in separation between storage capacity and flow capacity lines.

Petrophysical Rock Type (PRT)

Amaefule et al. (1993) developed a practical and theoretically correct methodology to identify reservoir interest. The flow unit using FZI and RQI function is given as follow:

$$FZI=RQI/Øz,\ RQI=0.0034*(K/Ø)^{0.5}$$

Windland (1972) carried out regression analyses on 322 sandstone sample to develop an empirical relationship between porosity, permeability, and pore-throat size. He found the best fit at 35% mercury saturation. The Windland equation has the following form:

$$\text{Log } R35 = 0.732 + 0.588 \log K - 0.864 \log Ø$$

Based on FZI and Windland R35 (Figure 5), three petrophysical rock types (PRT) are identified from all depositional facies but not all PRT's were available in one particular depositional facies. Those PRT's are:

1) PRT-1 - large foram bioclastic wackestone.
2) PRT-2 - large foram bioclastic wackestone and benthic bioclastic wackestone/packestone association.
3) PRT-3 - benthic bioclastic wackestone/packstone.

PRT-1 (Large foram bioclastic wackestone). PRT-1 has the best rock type properties among others, the porosity varies from 22% - 28.3% and permeability varies from 62.8-214 mD. The microfacies of this rock type mainly large forams with touching vuggy and moldic porosity.

PRT-2 (Large foram bioclastic wackestone and benthic bioclastic wackestone/packestone association). PRT-2 has similar pore association with PRT-1 and PRT-3. The porosity varies from 17% - 21.9% and permeability varies from 10.2-40.1 mD. The microfacies of this rock type is mainly large foram and small benthic, also the occurrence of milliolids. The porosity type is vuggy and moldic porosity.

PRT-3 (Benthic bioclastic wackestone/packstone). PRT-3 has porosity range from 8% - 16.9% and permeability varies from 7-12.1 mD. The microfacies of this type is dominantly small benthic with occurrence of milliolids. Type of porosity is vuggy and moldic.

Discussion

PMT Carbonate reservoirs have a wide range of porosity and permeability. PRT-1 is the best reservoir quality and PRT-3 is the poorest reservoir quality. The data represented shows that all rock types have specific porosity and permeability relationship; capillary pressure (PC) profiles should also be unique for each reservoir rock type. Capillary pressure data from mercury injection is the best way to quantify pore geometry, pore size and pore-throat size. Six mercury injection capillary pressure (MICP) analyses are available to validate the rock types. Figure 6 shows the difference of capillary pressure profile for each rock type. DST from PMT-1, PMT-2 and PMT-3 has a conclusive result while we test on PRT-1.

Conclusion

Rock type will help in determining porosity and saturation height functions. 3D static reservoir models will be easier to compute while rock type is provided to construct consistent geological models and play in controlling porosity population and permeability prediction as well as water saturation determination (Figure 7). Different geological settings, different depositional environments and different proses (diagenetic) may result in different pore geometry, pore size, and pore-throat distribution. Therefore, the HFU and PRT described in this paper should identify the properties occurrences based on available data.

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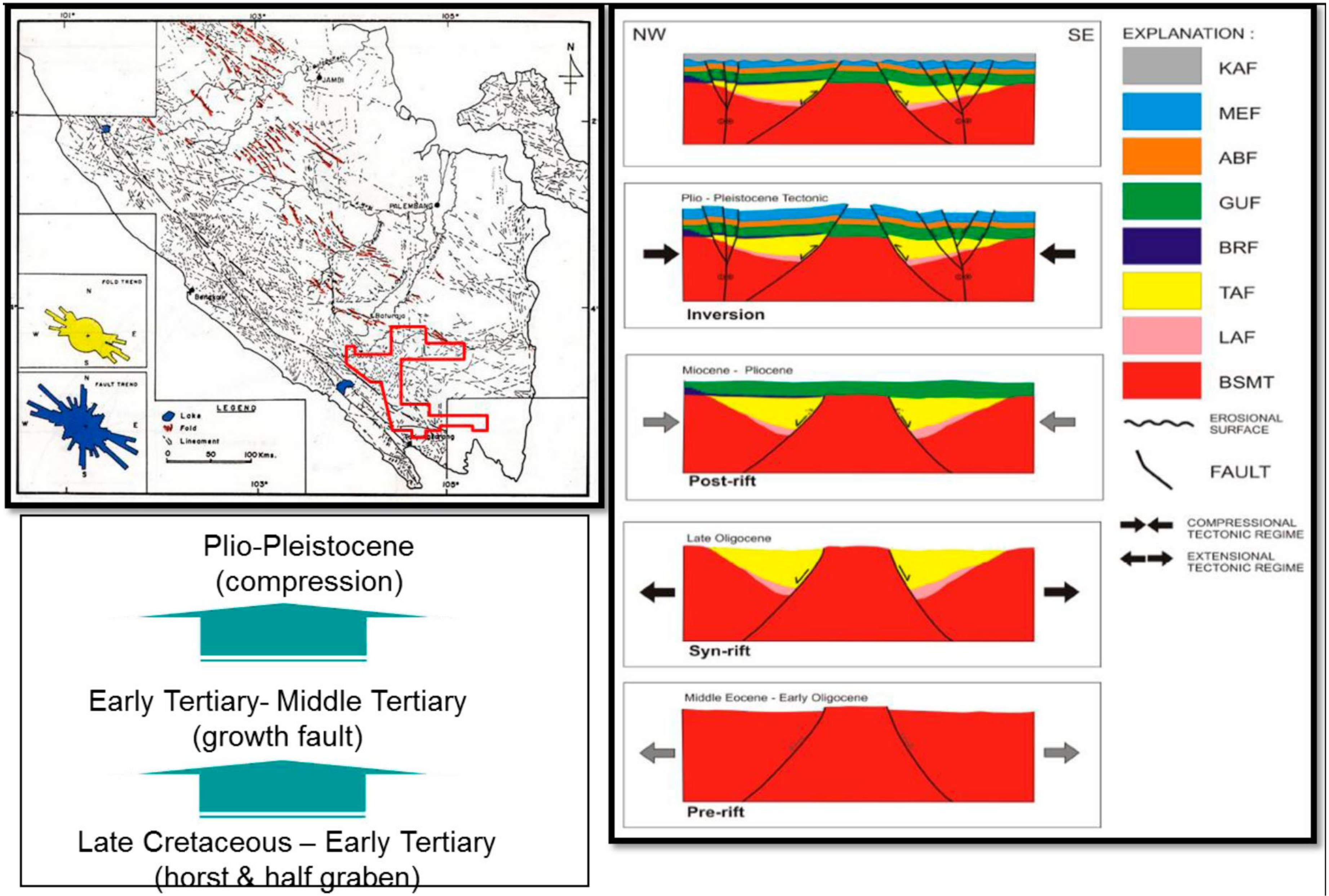

Figure 1. Regional tectonics of the South Sumatra Basin.

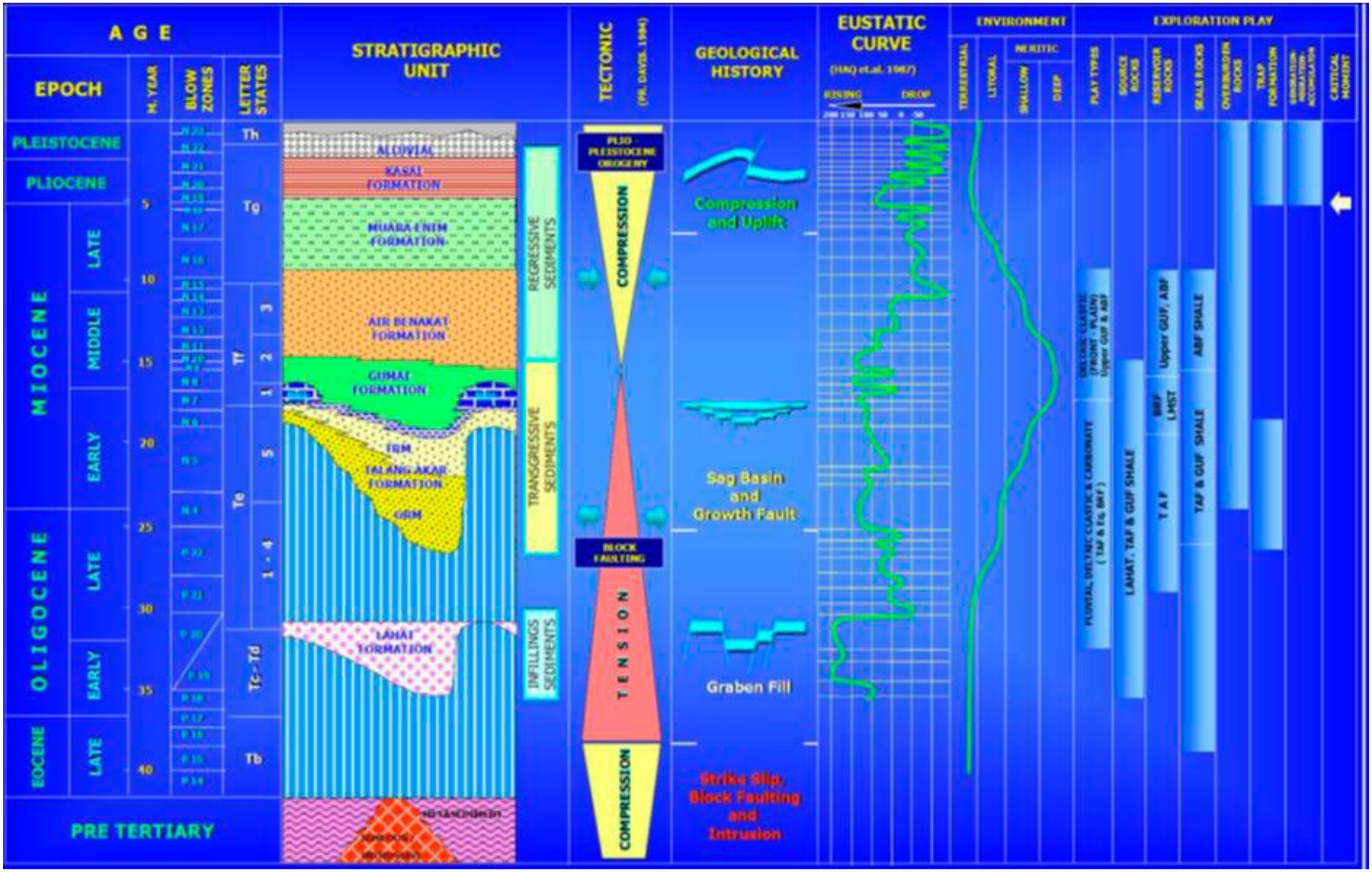

Figure 2. Regional stratigraphy of the South Sumatra Basin.

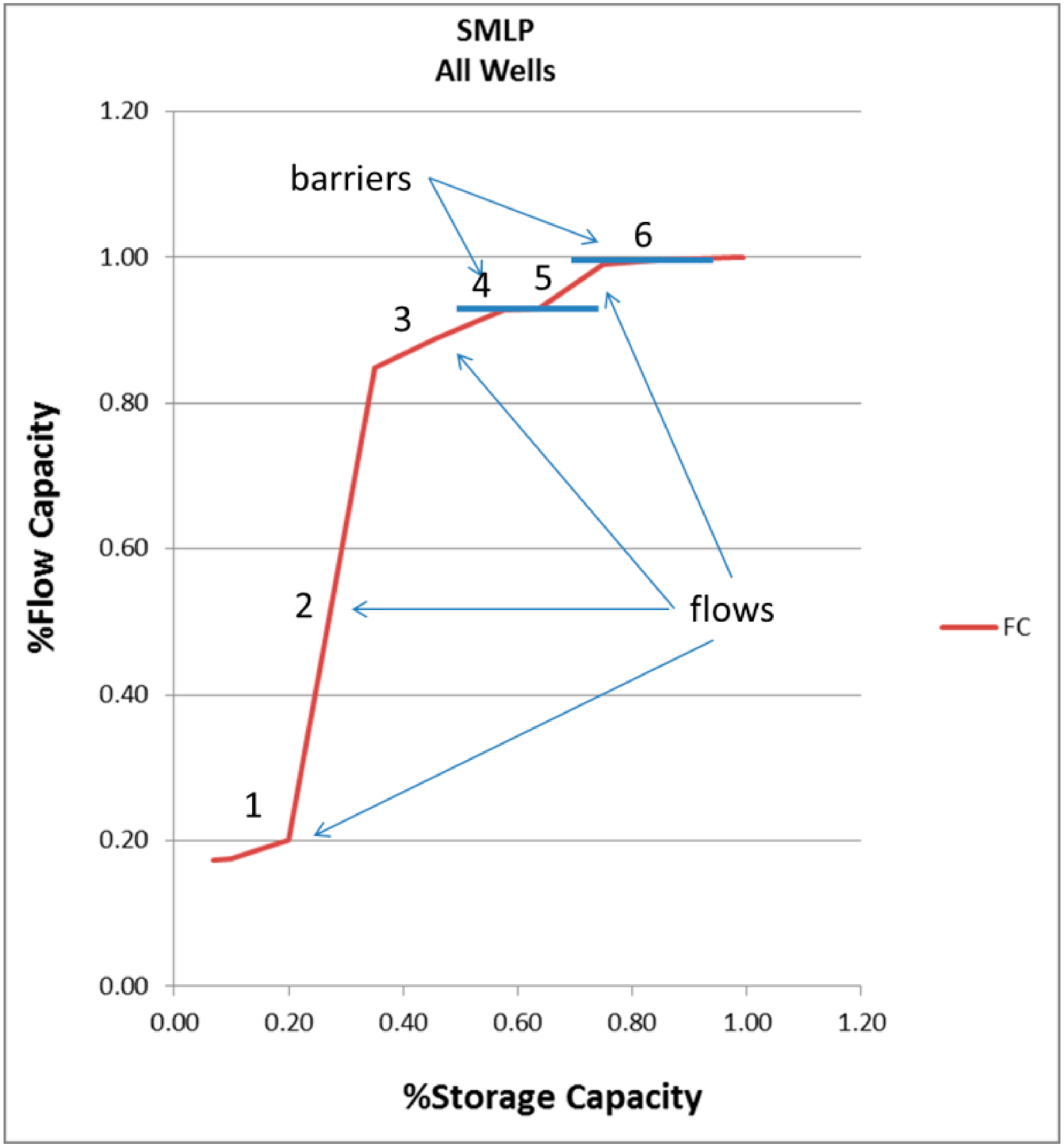

Figure 3. Hydraulic flow unit in PMT Early Miocene Carbonate.

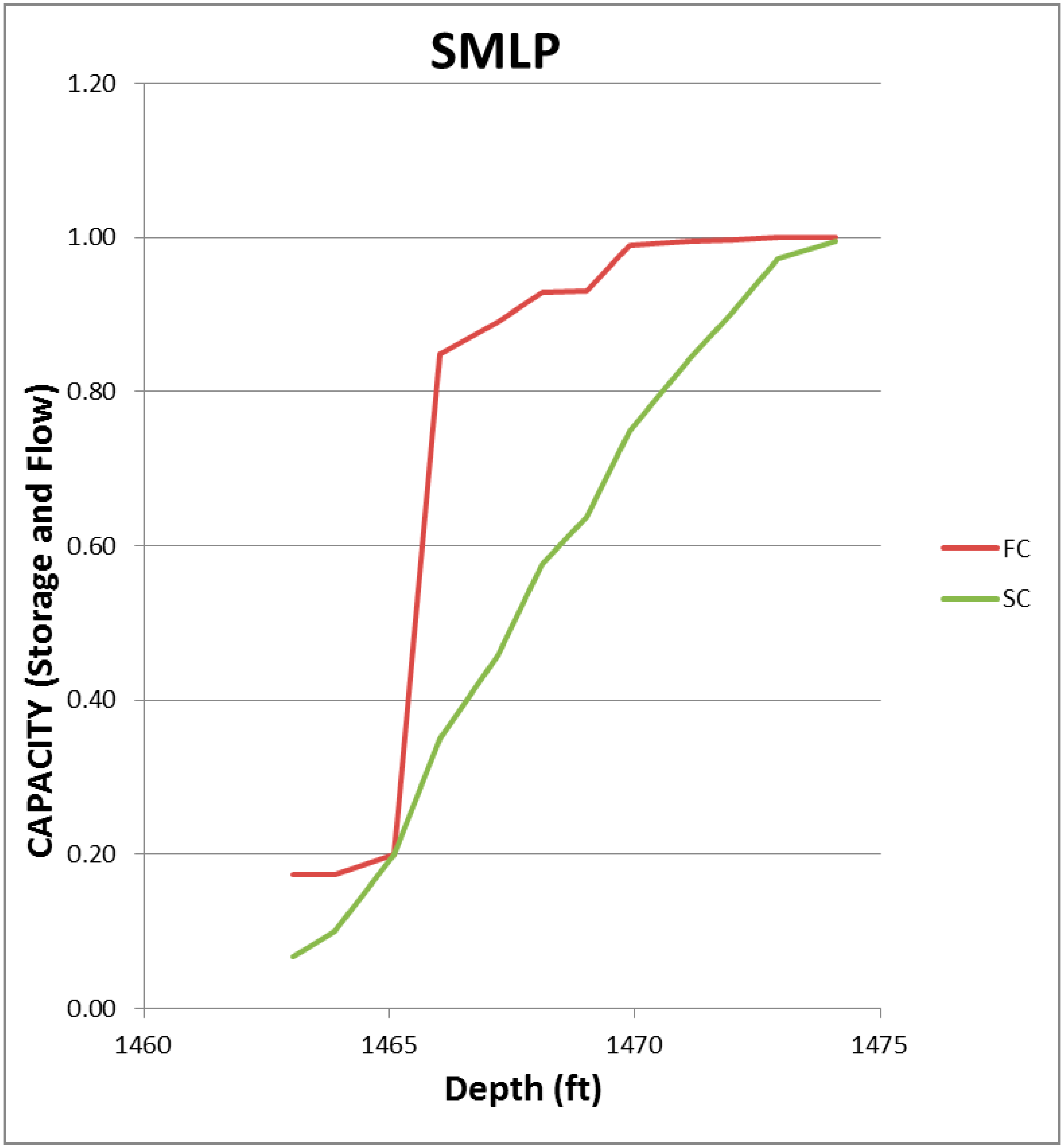

Figure 4. Stratigraphy modified Lorenz plot of PMT Early Miocene Carbonate.

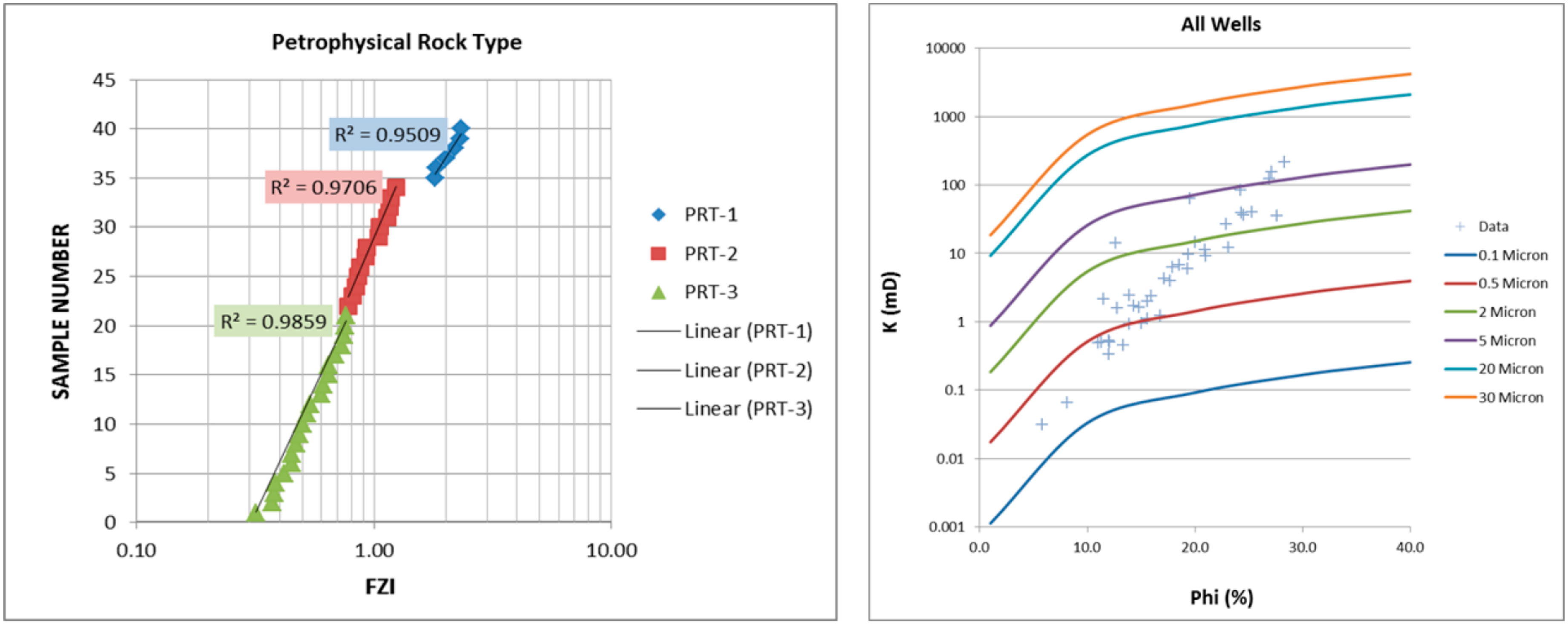

Figure 5. Petrophysical rock type based on FZI and Windland (1972).

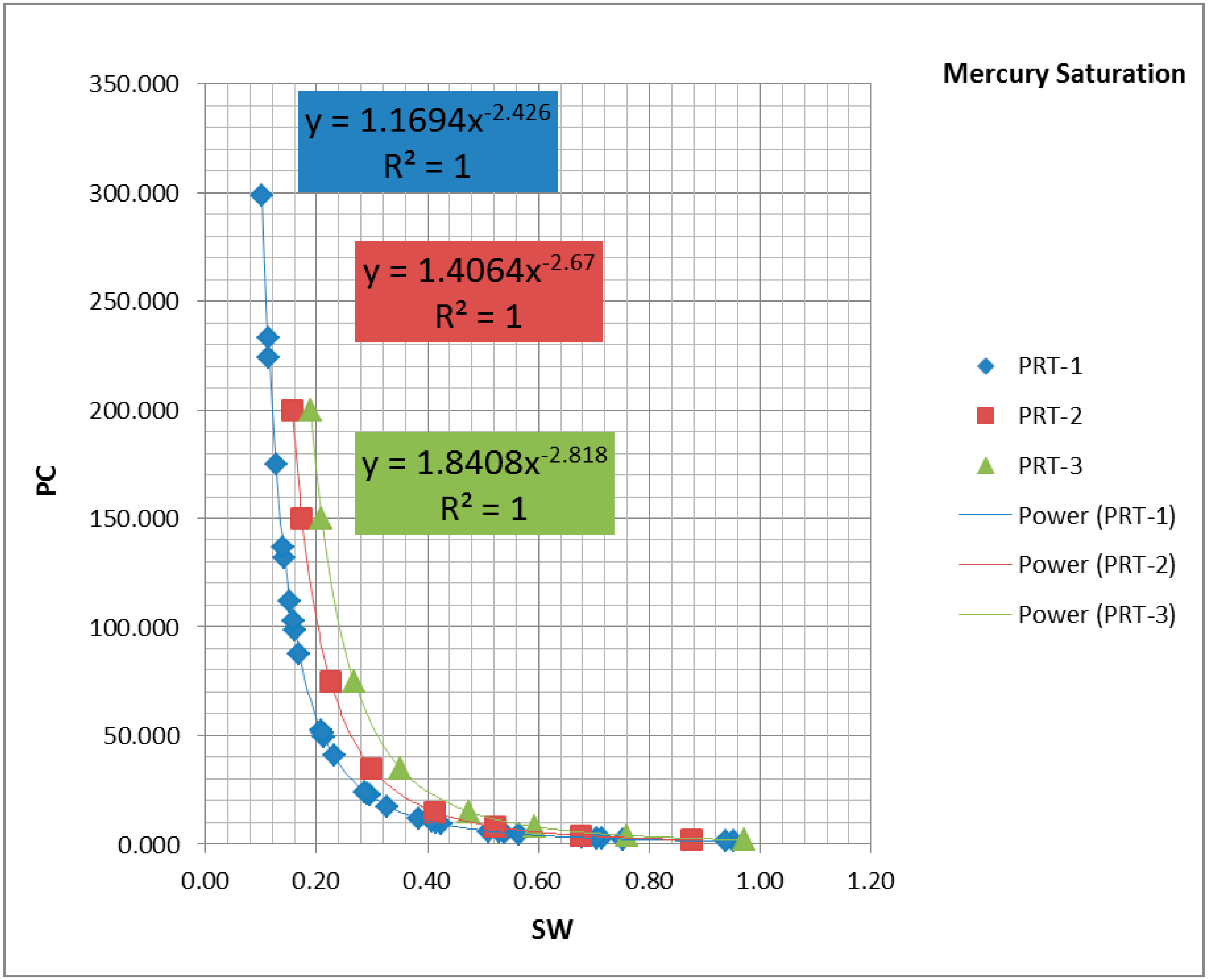

Figure 6. Mercury injection capillary pressure data for every PRT.

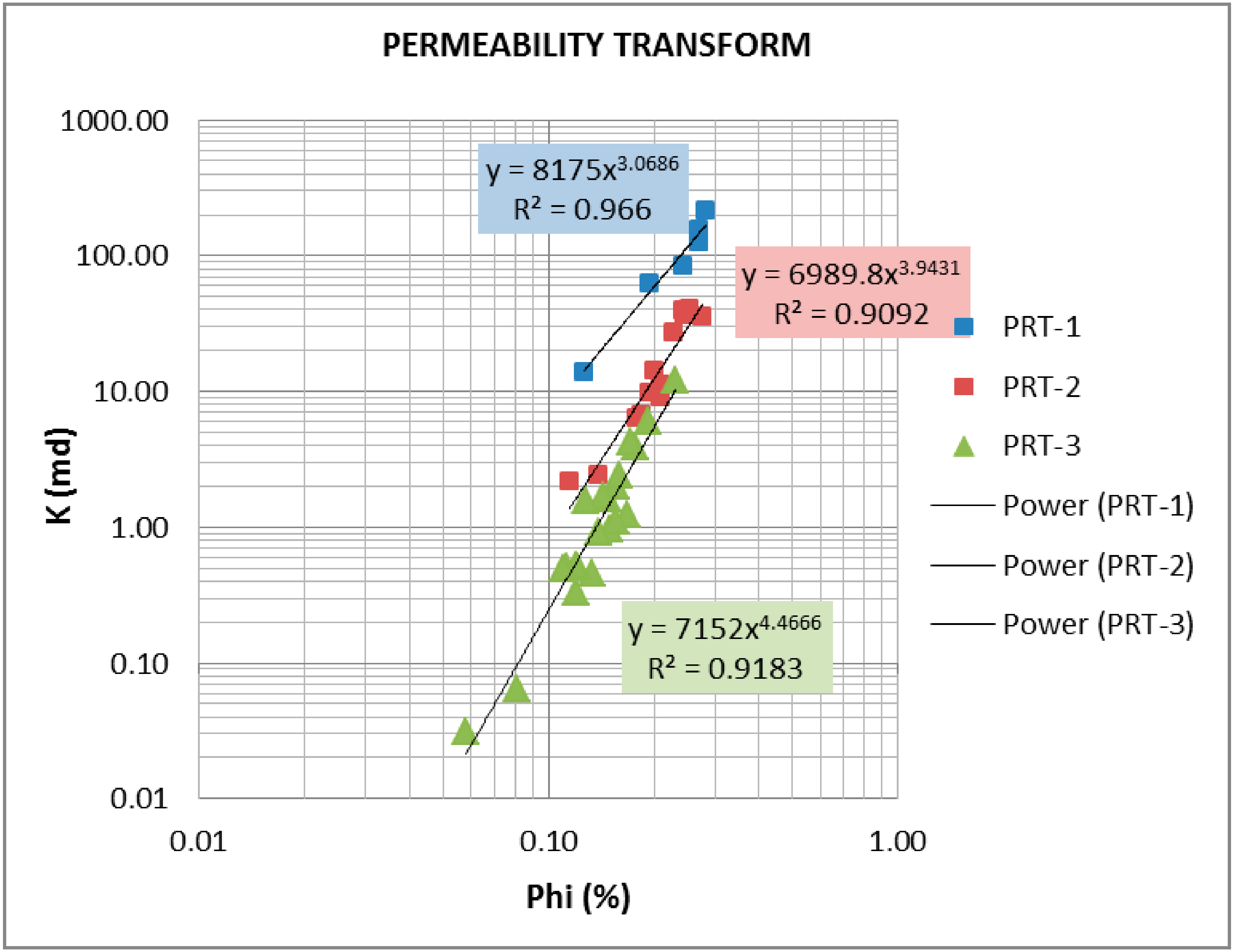

Figure 7. Permeability prediction for each rock type.