POROSITY VERSUS DEPTH CHARACTERISTICS OF SOME RESERVOIR SANDSTONES IN WESTERN INDONESIA

HUBUNGAN ANTARA POROSITAS DENGAN KEDALAMAN UNTUK RESERVOIR-RESERVOIR BATUPASIR DI INDONESIA BARAT

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ABSTRAK

Porositas adalah sifat petrofisika yang selalu menyita perhatian karena peran pentingnya dalam menentukan kapasitas simpan dari reservoir-reservoir hidrokarbon. Akurasi dalam memprediksi porositas di reservoir sangat berpengaruh terhadap berbagai aktivitas yang berkaitan dengan produksi minyak dan gas bumi. Sesuai dengan hal tersebut, berbagai usaha telah dilakukan untuk mempelajari dan memodelkan porositas batuan, termasuk hubungannya dengan kedalaman. Dalam studi ini, dipakai data porositas dari 4654 percontoh batuan yang terdiri dari 1773 percontoh *full-diameter* dan 2881 percontoh *sidewall*. Percontoh-percontoh tersebut diambil dari 549 sumur di 222 lapangan/struktur yang berlokasi di delapan cekungan sedimen produktif di Indonesia Barat. Hasil utama dari studi ini adalah fakta bahwa model porositas-kedalaman yang diperoleh dari region lain tidak dapat digunakan di Indonesia, sehingga dengan demikian model-model yang tepat dibentuk untuk kedelapan cekungan sedimen tersebut. Kedelapan model porositas-kedalaman ini diharapkan dapat berkontribusi terhadap usaha untuk memahami kecenderungan variasi porositas dengan kedalaman di Indonesia bagian Barat.

Kata Kunci: porositas, kedalaman, kompaksi, sementasi, pemeliharaan porositas, model empiris

ABSTRACT

Porosity is a petrophysical property that always draws attention due to its central role in determining storage capacity of hydrocarbon reservoirs. Accuracy for predicting porosity in reservoir affects much of many petroleum production related activities. Accordingly, various attempts have been devoted to study and model rock porosity including its relation with depth. In this study porosity data from as many as 4654 core samples (1773 full-diameter core plugs and 2881 sidewall core samples) is used. The core samples were taken from 549 wells in 222 fields/structures located in eight producing sedimentary basins in western Indonesia. Main results of the study are facts that existing porosity-depth models derived from data obtained from other regions are not usable for Indonesian cases, and therefore porosity-depth models are established for the eight sedimentary basins. It is hoped that these models can contribute significantly to the understanding of rock porosity trends with depth in western Indonesia.

Keywords: *porosity, depth, compaction, cementation, porosity preservation, empirical models*

I. INTRODUCTION

In reservoir characterization and formation evaluation, determination of petrophysical properties are one of the most important parts. One of those petrophysical properties is porosity. Porosity is known as the most important reservoir rock property in, among others, the determination of original hydrocarbon in place (OHIP) and its corresponding reserves. Magnitudes, types, and distribution of porosity directly affect reserves and the strategy or scenario required for exploiting them.

Indonesia and its complex geological setting is without doubt associated with significant levels of rock heterogeneity in its hydrocarbon reservoirs. The highest the heterogeneity level the more complex porosity distribution both laterally and vertically. In order to understand this heterogeneity in porosity distribution knowledge over local trends is always desired, obtaining which may ease the efforts to model porosity distribution both in regional and local/ reservoir levels. For producing and non-producing reservoirs in mature Indonesia's sedimentary basins this will enhance knowledge over the porosity distribution through various aspects – e.g. judgment on level of porosity heterogeneity and the most likely average porosity values – while, on the other hand, may help in the evaluation of speculative hydrocarbon resources in exploration areas.

In reservoir characterization and formation evaluation, it is generally accepted that porosity decreases variably with depth. This presumption is to some degree used as a guideline in related activities such as well log analysis. Local knowledge over porosity distribution with depth is often used as comparison in judging sensibility of resulting porosity values. This comparison is therefore an indicator whether or not re-analysis is needed and in case of porosity anomalies are indeed in existence, what factors that have possibly caused them.

In Indonesia local knowledge over porosity versus depth is certainly posessed by any local field operators, but usually at structure or field levels and for ones that have reached advanced stages of their production life. For fields that are still at their appraisal stages outside sources that can provide this knowledge is definitely important. This information can be established through data gathering from any available sources at regional or basin scale. This article is to present results of such study through the use of data from thousands of reservoir core samples taken from hundreds of structures/reservoirs in Western Indonesia's eight productive sedimentary basins. It is hoped that this information can be of any use for supporting sub-surface studies performed at any stages of a field's development.

II. RELATION OF POROSITY VERSUS DEPTH

Sand grains that have just settled and been buried in relatively short geological time form sandstones that are very porous with porosity above 40%. With the progress of burial and its subsequent physical and chemical processes the sandstones become more compacted and less in porosity values. Basically, porosity is reduced by two independent factors; compaction and cementation. Compaction is marked by decrease in both pore and bulk volumes while cementation is also associated to decrease in pore volume but with constant bulk volume. With some exceptions compaction is regarded as the predominant factor during early stages of burial whereas cementation becomes more important with the increase of depth and burial time.

Characteristics of porosity versus depth can be different from one region to another depending on the different parameters that may affect the two factors. Various parameters have been suggested as the results of various studies. Among others are pre-burrial mineralogical composition and rock texture (e.g. Pittman & Larese, 1991; Ramm & Bjorlykke, 1994), pressure and temperature gradients (e.g. Gautier & Schmoker,1989; Bjorkum et al, 1998; and Bloch et al, 2002), geological age (e.g Ehrenberg *et al*, 2009), timing of petroleum emplacement in reservoir (e.g Bjorkum & Nadeau, 1998; Worden et al, 1998; Barclay & Worden, 2000; Marchand et al, 2001; Bukar, 2013), porosity rearrangement (e.g Giles & de Boer, 1990), fluid-related porosity enhancement (e.g. Ehrenberg and Jakobsen, 2001; and Sattler et al, 2004 (carbonates)), and tectonic lifting (e.g. Ehrenberg et al, 2005). Variations in the parameters may be different for different regions due to differences in local geological setting. Regional tectonics events, depositional environments, thickness of sediments, nature of petroleum systems, and presence of magmatic intrusions are among the geological features that may produce the differences.

As has previously been stated, porosity tends to decrease with depth. However, it is a norm rather than an exception that porosity values are not always in line with trends, usually in the forms of data scatter and values considerably greater than the trends suggest. Porosity preservation for anomalously high porosity values and excessive cementation for anomalously low porosity values are thought to be the causes. Excessive cementation may be caused by various factors. Loucks et al, (1977) suggested some mechanisms such as massive quartz overgrowth and development of sparry pore-fill calcite cement. Creep process due to high clay – or other ductile materials – contents may also result in excessive porosity reduction (e.g. Beard and Weyl, 1973; Renard et al, 2000; Gratier et al, 2013). On the other hand, porosity preservation at great depths may be caused by various ocurences. Among others are influence of grain size and grain sorting (e.g. Nagtegaal, 1978), early presence of hydrocarbon prior to cementation (e.g. Marchand et al, 2001; Wilkinson et at, 2006; Wilkinson and Haszeldine, 2011; Bukar, 2013), quartz cement growth inhibition through dissolution of sponge spicules (Osborne & Swarbrick, 1999), continuous subsurface leaching of some particular minerals (Loucks et al, 1977), and grain-coating by micro-quartz cement (Aase et al, 1996), and overpressure that reduces effective stress (e.g. Bloch et al, 2002).

Relative domination between the two porosity modification factors varies from one place to another. For instance, cementation levels may vary significantly for sandstones in the same formation, depths, and geographical locations. For example, Ramm et al, (1997) showed a case in Central Graben (North Sea) in which some Upper Jurassic sandstones from similar depths ($\pm$ 4000 m) exhibit considerable porosity variation.

Variation in the domination between the two factors can also be seen from its potential in generating scatter in the porosity – depth relation. For a particular rock group in a particular geographical location, it can be said that compaction factor plays the main role in porosity reduction (primary reduction) and cementation reduces the porosity further (secondary reduction). This suggests that for a particular depth level, the highest porosity is associated with the least cemented. As Ehrenberg and Nadeau (2005) put, this is often associated with lithologies that can preserve original porosity (e.g. clean sandstone). On the contrary, the lowest porosity in the group indicates the highest level of cementation. Through these assumptions, the degree of scatter in porosity values can therefore be regarded as reflecting variations in the intensity of cementation.

Efforts to understand relation between porosity and depth have been spent for long time. As put by Gluyas and Cade (1997), two approaches are usually taken, through laboratory experiments and through the use of field data. As early as in 1968, Vesic and Clough published their results of laboratory compression tests on some sandstone samples and concluded that relation between porosity and stress is by nature linear. This conclusion was later supported Atkinson and Bransby (1978) who stated that this linear porosity – stress relation is indeed true as long as there is no presence of over-pressured intervals. A similar laboratory study on deep sea sediments using porosity rebound concept also managed to construct porosity-depth profiles (Hamilton, 1976). Later laboratory studies, such as one by Scherer (1987) managed to model porosity versus depth with taking into equation parameters of grain sorting, percentage of quartz grain, and geologic age. Nevertheless, availability of data for the supporting parameters may impose problem for any practical use.

By using data published by Vesic and Clough (1968) and Atkinson and Bransby (1978), Gluyas and Cade (1997) has drawn a mathematical correlation between porosity (ϕ) and depth (D) of

$$\phi = 50\exp\left(\frac{-10^{-3}D}{2{,}4+5\times10^{-4}D}\right) \qquad (1)$$

with porosity in percent and depth in meter.

Graphically, Figure 1 depicts the porosity-depth expression in Equation 1 with porosity data, mostly obtained from North Sea reservoir rocks, that in general represents sandstones with moderate degree of cementation. The model represents behavior of this type of sandstones under compaction, which tend to show non-linear porosity-depth trend under lower overburden stress at depths closer to the surface and become more linear at greater depths due to compaction under larger loads. This model represents a burying process that involves limited mechanisms other than compaction under overburden load.

The search for establishing porosity-depth relation has also been performed using field data (e.g. log analysis data). In the same study Gluyas and Cade (1997) observed porosity values greater than the values predicted by the correlation, and they stated that this is caused by overpressure. In the cases of overpressure compaction process is hindered by higher than normal pressure (i.e. hydrostatic pressure) resulting in lower effective overburden and tectonic loading.

Sandstones that undergo overpressure bear the same effective stress to other sandstones having subjected to hydrostatic pressure only but at shallower depths. The difference in depths – between the effective and the true depths – is proportional to the magnitude of overpressure. This can somehow be used as indicator of severity of the overpressure. Gluyas and Cade (1997) put that effective depth for a sandstone that is subjected to overpressure can be estimated using

$$D' = D - \left(\frac{u}{(\rho_r - \rho_w) g (1 - \phi)} \right) \tag{2}$$

with D' = effective depth, ρ_r = density of rock column (kg/m^3, normally 2650 – 2700), ρ_w = formation water density (kg/m^3, 1050 for brine), g = gravity force (m/s^2, 9,8), ϕ = porosity (fraction), and u = overpressure (MPa). They also noted that Equation 2 works well with using average porosity of 0.2 for depths 2000 – 4000 m with clay contents of 15 – 25%. For shallower depths and unusually higher clay contents in reservoirs more representative average porosity values have to be determined.

In a similar manner earlier but with using field data as support, Ramm and Byorlykke (1994) studied porosity-depth trends in Viking Grabben and Haltenbanken areas in offshore Norway using porosity data from 110 wells, supported with mineralogical and log data as well as well test-derived pressure data. For the first estimation they suggest to use the linear equation of

$$\phi = 42.7 - 6.9 * Z \tag{3}$$

with (ϕ) in percent and Z in km. This linear equation applies only for compaction factor only, and after which the resulting porosity values have to be analysed with taking inti considerations factors such as pore pressure, hydrocarbon saturation, and mineralogical compositions. Through analyzing the influence of these factors deviations from Equation 2 can be estimated.

Despite the great volume of works throughout the world that have been spent into studying the characteristics of porosity trends with depth, not much studies – in the form of published articles – have been devoted to this issue for Indonesian cases. A study of Ehrenberg et al, (2009) utilized a huge amount of data including average porosity values of more than 36,000 producing reservoirs throughout the world encompassing from Precambrian-Silurian to Pliocene-Pleistocene Ages. The basic data is a combined core and log analysis data sampled for average values (i.e. P50 values) at every 0.5 km of depth intervals. The study produced global porosity-depth depth trends of the various geological ages, including data from Tertiary reservoirs, mostly in western Indonesia. However, since data from Indonesian reservoirs constituted only a minor part to the total volume of data no relevant information can be obtained from the results. Therefore, in the light of this requirement this study on exclusively Indonesian data is made.

III. DATA PREPARATION

In this study, data from 4654 core samples has been used. The core samples are made of 1773 core plugs taken from full-diameter whole cores (termed FD-plugs) and 2881 percussion sidewall cores (termed SWC). All data has been obatained from LEMIGAS archieve (oldest report used is dated December 1972 and the newest is dated September 2013). The core samples were taken from 222 fields (including exploration areas) through 549 wells located in eight main producing sedimentary basins in Indonesia; North Sumatra, Central Sumatra, South Sumatra, West Natuna, West Sunda/Asri, Nortwest Java, Northeast Java, and Kutai. Figure 1 shows locations and approximate coverage of the eight basins, while Tables 1 through 8 present background details regarding the data including formations, fields, number of wells, depth ranges, number of samples and their types, and number of vertically averaged data number used for deriving porosity-depth models.

Due to their different nature of coring, selection of FD-plugs and SWC data also take different approaches. For FD-plugs, due to their limited coverage the approach of selection is thrugh emphasizing samples that reflect the reservoir rocks' heterogeneity. Therefore, for the usually limited vertical interval covered the data has to represent maximum variety in porosity values. On the other

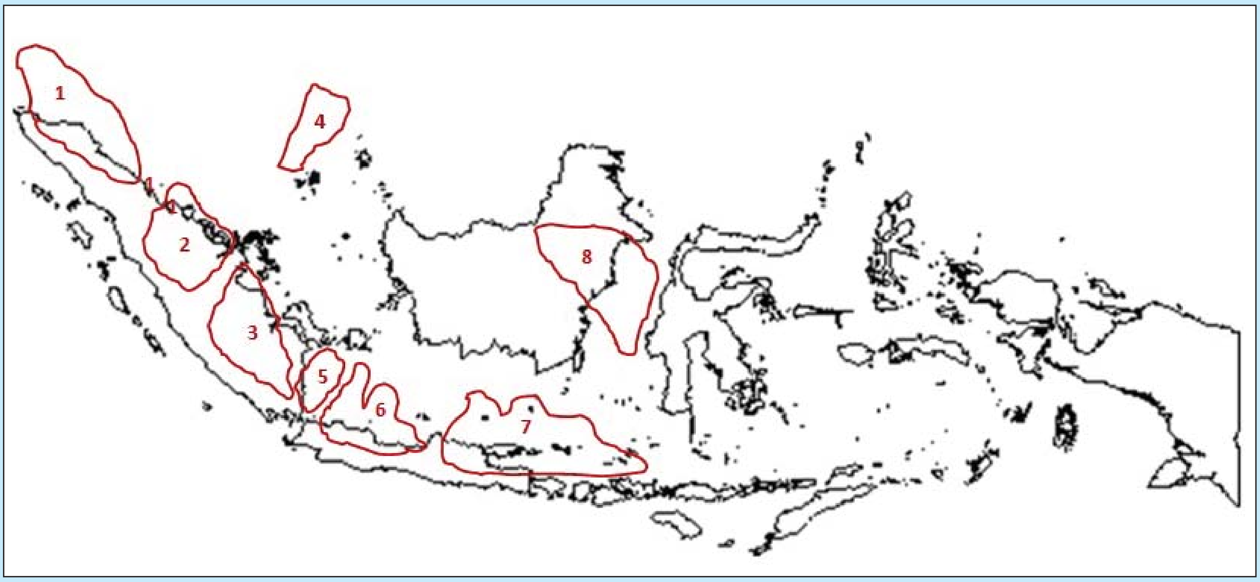

Figure 1
Tertiary sedimentary basins, the place of origin of the sandstone core samples used in this study: (1) North Sumatra basin, (2) Central Sumatra basin, (3) South Sumatra basin, (4) West Natuna basin, (5) West Sunda/Asri basin, (6) Northwest Java basin, (7) Northeast Java basin, and (8) Kutai basin

Table 1
Data and its field of origin, North Sumatra Basin.

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
North Sumatra Main formation(s): Seurulla, Keutapang, Belumai	Onshore: Basilam (2), Batumandi (1), Gedondong (1), Gurame (1), Kuala Simpang Barat (1), P Tabuhan Barat (1), Paluh Sipat (1), PRP (4), P Tabuhan Timur (1), Rantau (7), Lhok Sukon (2), Serang (1) Total wells = 23	271.0 – 2996.0	105 Full-diameter core (horiz. plug) = 90 Sidewall core = 15	30

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

hand, for the vertically far more extensive SWC the focus in data selection is through data picking for roughly every 25 m interval whenever possible. This is to avoid unneccessary data redundancy and statistical bias due to huge data number of similar porosity values. Furthermore, due to the nature of the percussion SWC, special caution has also been made to avoid as much as possible SWC data taken from samples with possible occurence and defects such as sample insufficiency, mud contamination, and fracture creation during testing. Since not all data includes measurement under overburden pressure, only porosity without overburden pressure is used.

As part of Routine Core Analysis, helium porosity measurement has been performed following American Petroleum Institute (API) Recommended Practice No. 40. The second edition of the guideline can be seen in API (1998). Following the recommended practice samples are cleaned using solvents in order to both extract hydrocarbon and leach all salts contained by the core samples. The cleansed samples are then dried in carefully controlled oven. For SWC samples, some irregularity in shape is solved through the use of sample mounting. The dried samples are the tested, which porosity is obtained using Boyle's law as the guiding principle.

IV. PLOT OF DATA

In evaluating the porosity and depth trends, despite the scatters, plot of all FD-plugs and SWC porosity values shows that in general porosity decreases with depth (Figure 2). Both FD-plugs and SWC data shows the same trend, and since the two groups overlap to each other there is seemingly no significant disparity between magnitudes of the two groups in general. However, comparison between the two may differ when made at lower levels, e.g. at basin level or even at field level.

Another occurence that may easily be observed on Figure 2 is a fact that the Gluyas and Cade (1997) porosity-depth model deviates significantly from the general trend of the porosity cluster. Considering the nature of the deviation, it is obvious that same occurence is likely to take place when compared to porosity-depth data at lower levels. This prompts to the need to see the data at lower level and models that fit them.

Porosity-depth relation at lower (i.e. sedimentary basin) level appears to have similarity in general to the one shown on Figure 2. Figures 3 through 10 exhibit the porosity-depth data plot for sandstones in the eight sedimentary basins in western Indonesia. In a manner similar to the general trend shown by the all data plot (Figure 3) the tendencies exhibited by porosity data in the individual basin are, despite the scatter, apparently to decrease with depth.

In order to obtain a more obvious picture over the porosity-depth trends, representative porosity values are established for depths ranging from the shallowest data point to the deepest. In Ehrenberg et al, (2009) averaging was made on log analysis data at every 0.5 km interval for data throughout the world. Following

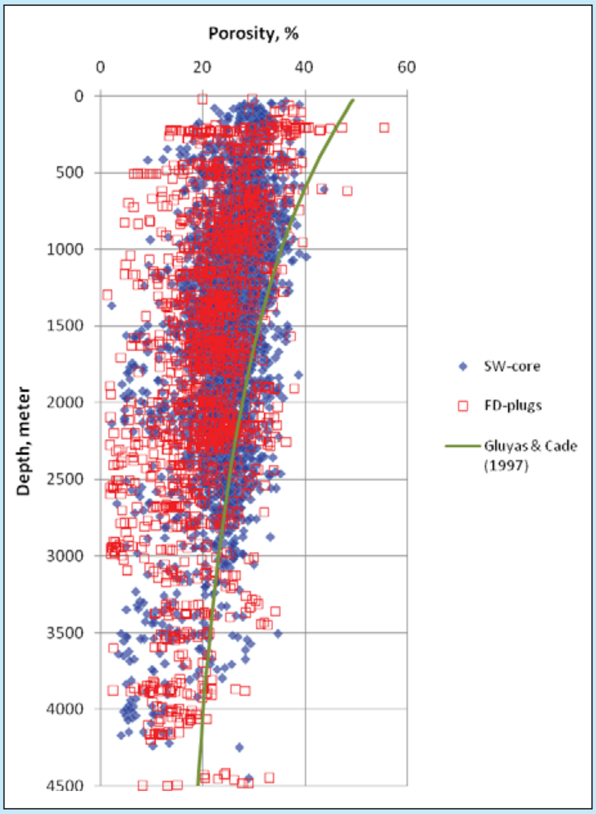

Figure 2
Porosity versus depth for all porosity data

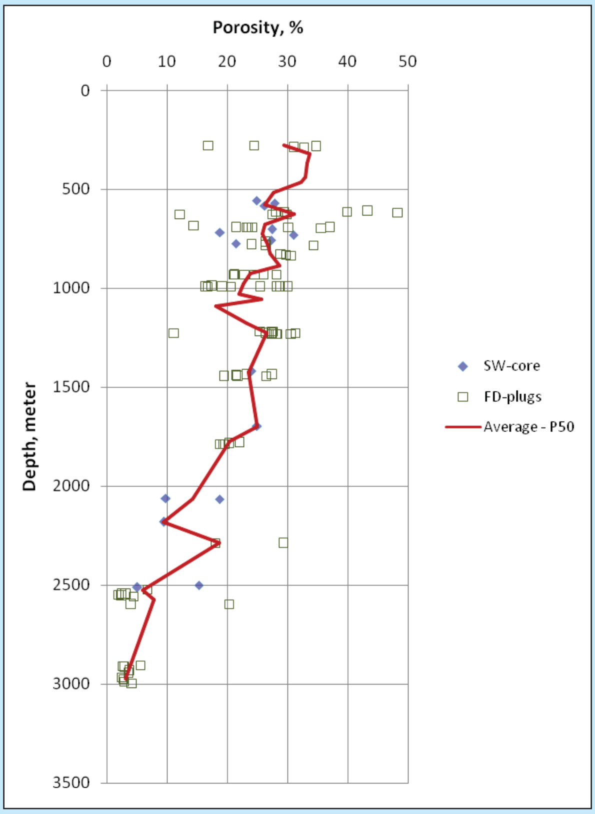

Figure 3
Porosity versus depth for data from North Sumatra basin (90 FD-plugs and 15 SW-cores), including the curve representing average values

Table 2
Data and its field of origin, Central Sumatra Basin

Basin	**Field/structure (*) (no. of wells)**	**Depth range (m, ssl)**	**No. of core samples**	**No. of average data values (**)**
Central Sumatra <u>Main formation(s):</u> Pertama, Kedua, Duri, Bekasap, Bangko, Telisa, Petani	<u>Onshore:</u> Balam South (3), Bangko (4), Bekasap (5), Beruk (4), Binanga (1), Duri (5), Jorang (3), Kopar (3), Kotabatak (9), Kulin (2), Libo (1), Libo SE (3), Minas (4), Pager (1), Pedada (2), Pematang (1), Petani (6), Petapahan (2), Pinang (1), Pudu (2), Puncak (1), Pungut (3), Pusaka (1), Rantau Bais (4), Selat Panjang (1), Talang South (1), Tambusai (1), Tanjung Tiga (1), Telinga (1), Zamrud (5) Total wells = 82	94.8 – 3907.0	420 Full-diameter core (horiz. plug) = 409 Sidewall core = 11	51

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

Table 3
Data and its field of origin, South Sumatra Basin.

Basin	**Field/structure (*) (no. of wells)**	**Depth range (m, ssl)**	**No. of core samples**	**No. of average data values (**)**
South Sumatra <u>Main formation(s):</u> Gumai, Talang Akar, Air Benakat, Muara Enim,	<u>Onshore:</u> Abab (1), Bajubang (3), Benakat (1), Beringin (3), BRC (1), Budi (1), E Benakat (1), E Kayuara (1), E Karangagung (1), Ganesha (1), Gemuruh (1), Ginaya (1), Gunung Kemala (2), Jirak (3), Kalalili (1), Karangagung (1), Karangdewa (1), Kenali Asam (4), Kerumutan (1), Ketaling Barat (2), Leko (1), Lembak (1), Limbur (1), Lirik (1), Lupak (1), Manduru (1), Mentawak (1), Merbau (3), Meruap (1), Molek (1), Ogan (1), Panerokan (3), Pinang (1), Raja (1), Ramba (4), Sekamis (1), SWA (1), Tabuan (1), Talang Akar (1), Talang Jimar (5), Tanjung Tiga (2), Tanjung Tiga Timur (1), Tapus (3), Tempino (2), Tanjung Miring Timur (1), Tuba Obi East (1), W Air Komering (1) Total wells = 74	23.7 – 2796.0	586 Full-diameter core (horiz. plug) = 438 Sidewall core = 148	53

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

the approach used in their study ('P50 points' for the averaged porosity values in accordance to Ehrenberg et al, 2009) averaging is also performed at smaller intervals of 50 m to 100 m depending on the core data availability. For depth intervals with plenty data points averaging is made at 50 m intervals, and averaging is made at greater intervals of up to 100 m for intervals with scarcer data points. For 'no data' intervals of greater than 100 m no porosity avaraging is made, and the corresponding trend line sections are

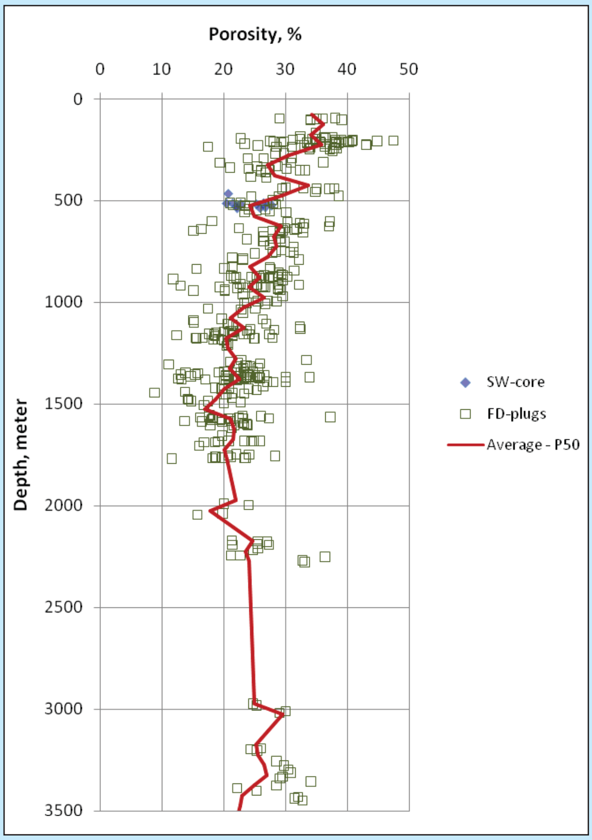

Figure 4
Porosity versus depth for data from Central Sumatra basin (409 FD-plugs and 11 SW-cores), including the curve representing average values. Notice the relatively high porosity values at great depths probably due to porosity preservation effects

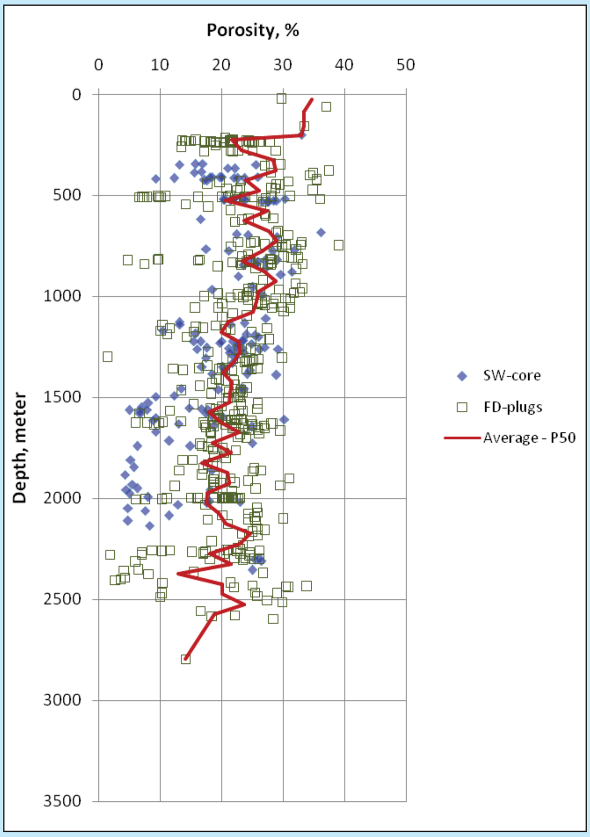

Figure 5
Porosity versus depth for data from South Sumatra basin (438 FD-plugs and 148 SW-cores), including the curve representing average values

made straight through connecting one averaged data to the nearest ones. The resulting trend lines are also depicted on Figures 3 through 10.

From the trend lines shown on Figures 3 through 10 the tendencies are clearer in showing the decrease in porosity with depth, with some deviations at great depths. For the purpose of providing some practical use to the porosity-depth trend lines, empirical mathematical models have been establihed. Through modifying the Gluyas and Cade (1997) model, the model is transformed into the form of

$$\phi = a\exp\left(\frac{bD}{c + dD}\right) \qquad (4)$$

with a, b, c, and d are constants specific to different data sets belonging to the porosity-depth data of the eight sedimentary basins. Summary of the constants for the modified Gluyas and Cade (1997) model is presented in Table 9. Comparisons between tha porosity-depth P50 trends and the respective porosity-depth models are presented on Figures 11 through 18.

V. DISCUSSION

In petrophysics, porosity values derived from FD-plug is in general regarded as more reliable than porosity values obtained from measurements on sidewall core (SWC) samples, especially the percussion (SWC) samples. This pressumption is indeed justified considering the method in which the percussion SWC samples are retrieved in the wellbore. Craft and Keelan (1985) in their study using large number of comparisons from Gulf Coast formations revealed that FD-plug and SWC samples tend to show similarity in values for rocks with moderate

Table 4
Data and its field of origin, West Natuna Basin

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
West Natuna Main formation(s): Lower Gabus, Upper Gabus, Arang,	Offshore: 'A' structures (4), Anoa (1), Bandeng (1), Belanak (4), Belut (3), Binturong (1), Hiu (1), Kakap (1), Kerang (1), Krapu (2), Kuda Nil (1), Porel (1), SAL (1), Sembilang (1), Sepat (1), Tembang (2), Tenggiri (1), Teri (1), Terubuk (1), Tiram (1), Todak (8), Udang (8) Total wells = 39	108.0 – 5852.0	306 Full-diameter core (horiz. plug) = 173 Sidewall core = 133	67

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

Table 5
Data and its field of origin, West Sunda Basin.

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
West Sunda Main formation(s): Gumai, Talang Akar	Offshore: Cinta (7), Farida (7), Gina (1), Gita (1), Karmila (3), Kartini (2), Krisna (9), Lastri (1), Lucia (1), Maya (1), Nani (1), Rama (4), Rena (1), Selatan (2), Sundari (4), Titi (5), Veritas, (1), Wanda (7), Yani (1), Yvonne (2), Zelda (9) Total wells = 77	826.9 – 3256.8	464 Full-diameter core (horiz. plug) = 73 Sidewall core = 391	46

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

Table 6
Data and its field of origin, Northwest Java (NW Java) Basin

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
Northwest Java (NW Java) Main formation(s): Talang Akar, Cibulakan	Onshore: Akasia Bagus (1), Bojong Raong (1), Cemara Barat (4), Cemara Selatan (1), Cemara Timur (4), Haurgeulis (1), Jati Keling (1), Jatinegara (1), Karang Degan 91), Karang Luhur (1), KRG (1), Melandong (2), MLP (1), Pondok Tengah Raya (1), Pegaden (1), Pondok Makmur (2), Pondok Tengah (3) Offshore: Arimbi (13), Arjuna (61), Bima (9), NW Corner (6) Total all wells = 118	156.0 – 3134.0	1293 Full-diameter core (horiz. plug) = 205 Sidewall core = 1088	59

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

Table 7
Data and its field of origin, Northeast Java (NE Java) Basin

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
Northeast Java (NE Java) Main formation(s): Ngrayong, Ledok	Onshore: Arusbaya (1), Banyu Urip (1), Cendana (2), Kawengan (1), Ledok (1), Lengowangi (1), Nglobo (5), Semanggi (1) Offshore: Kepodang (1), Poleng (1) Total all wells = 18	33.8 – 2824.9	86 Full-diameter core (horiz. plug) = 36 Sidewall core = 50	28

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

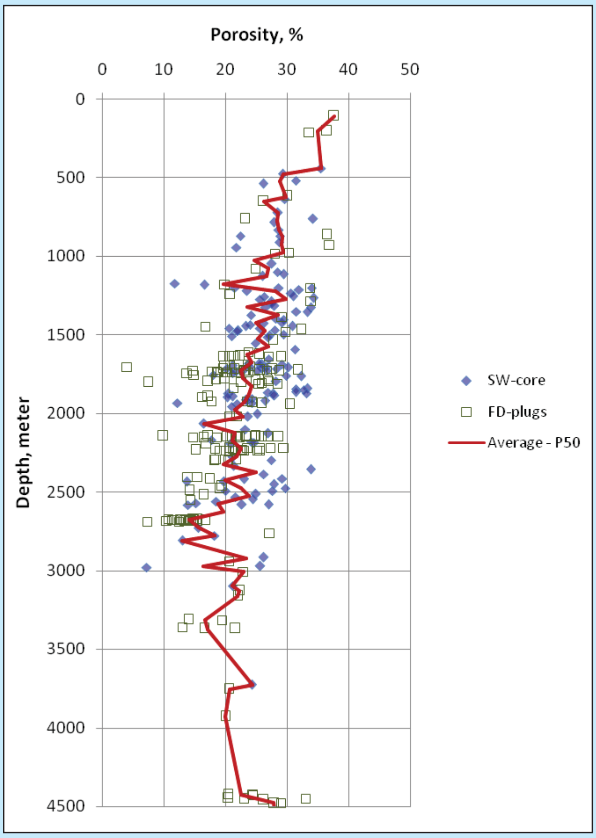

Figure 6
Porosity versus depth for data from West Natuna basin (173 FD-plugs and 133 SW-cores), including the curve representing average values. The bottom part of the data exhibits relatively high porosity values indicating porosity preservation effects

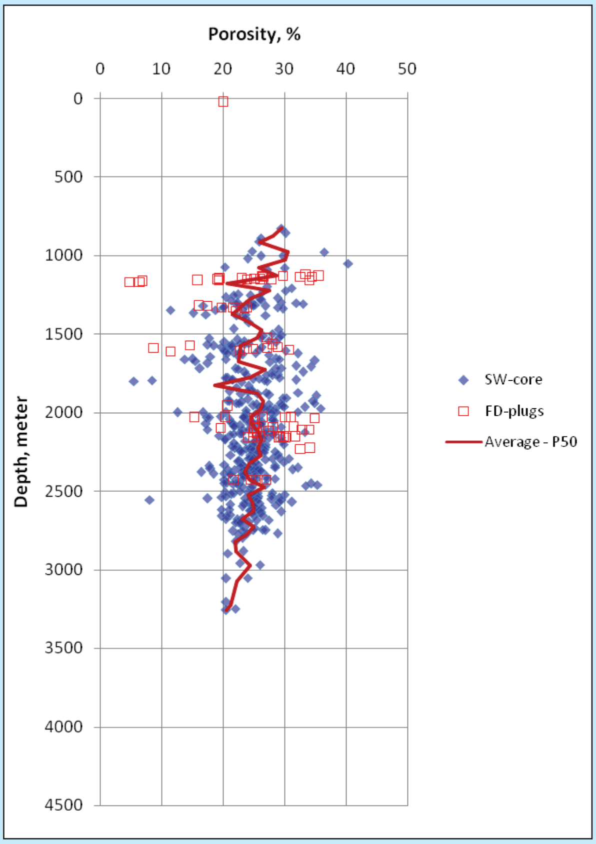

Figure 7
Porosity versus depth for data from West Sunda basin (73 FD-plugs and 391 SW-cores), including the curve representing average values

Table 8
Data and its field of origin, Kutai Basin.

Basin	Field/structure (*) (no. of wells)	Depth range (m, ssl)	No. of core samples	No. of average data values (**)
Kutai Main formation(s): Balikpapan, Kampung Baru,	Onshore: Badak (17), Blambangan (1), Belonak (1), Bongkaran (2), Buat (1), Dondang (1), E Manpatau (1), Kejumat (1), Kemang (1), Kembang (2), Keruing (1), Lamaru (1), Lampake (1), Mengatal (1), Mentawir (1), Meranti (1), Mutiara (6), N Mumus (1), Nenang (1), Nilam (9), N Kutei Lama (1), Pamaguan (10), Parangat (2), Penajam (2), Prangat (1), Punjung (1), Riko (1), Runtu (1), Samboja (2), Sanga-sanga (16), SBT (1), Sebulu (1), Semberah (6), Separi (1), Seturian (1), Tambora (9), Tembesi Bay (1), Terap (1), Tutung (1), UKM (1), W Nilam (2), W Santan (1), Wailawi (1) Offshore: Attaka (13), Bekapai (2), Handil (6), Kerindingan (1), Merah Besar (1), N Handil (1), Nubi (3), NW Peciko (2), Peciko (3), Sisi (2), Tunu (21), W Nubi (1), W Sisi (1), Yakin (1) Total all wells = 118	32.0 – 4561.0	1394 Full-diameter core (horiz. plug) = 349 Sidewall core = 1045	90

(*) Including exploration area(s)
(**) Data median (average, P50) in intervals of 50 – 100 m depth

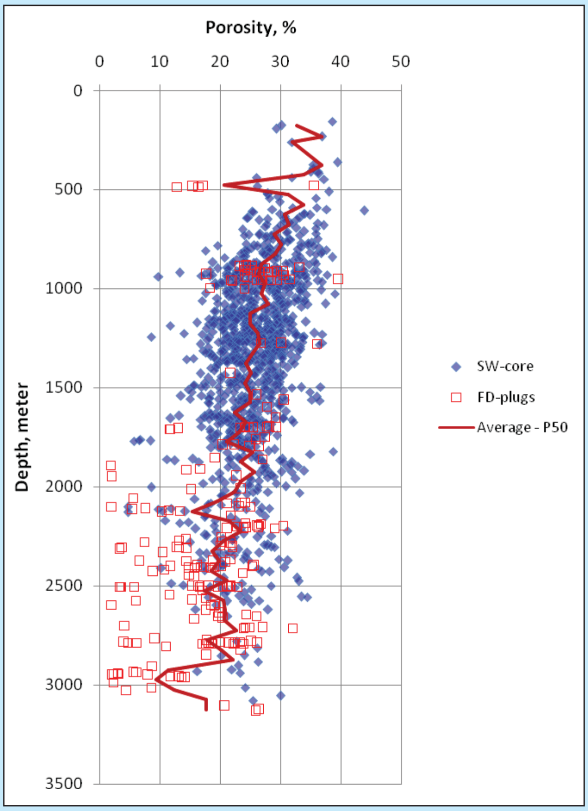

Figure 8
Porosity versus depth for data from Northwest Java basin (205 FD-plugs and 1088 SW-cores), including the curve representing average values

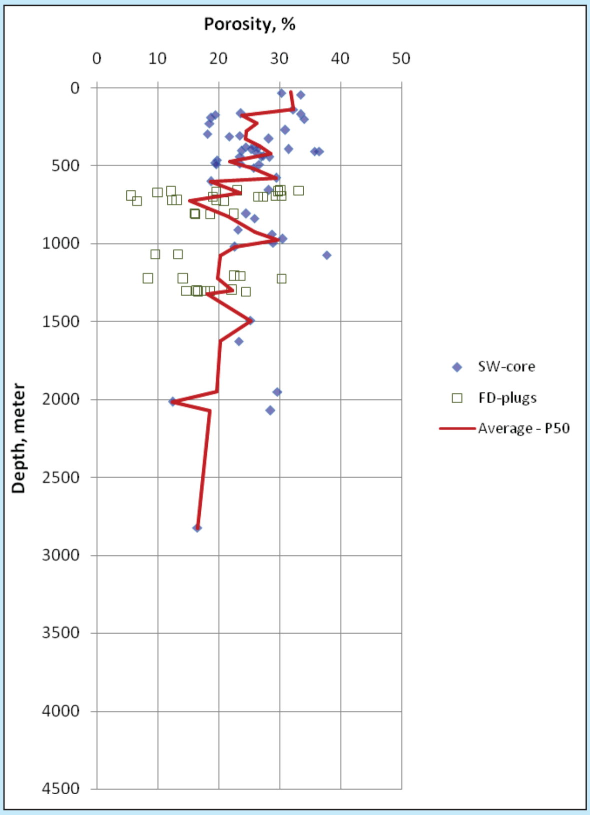

Figure 9
Porosity versus depth for data from Northeast Java basin (36 FD-plugs and 50 SW-cores), including the curve representing average values

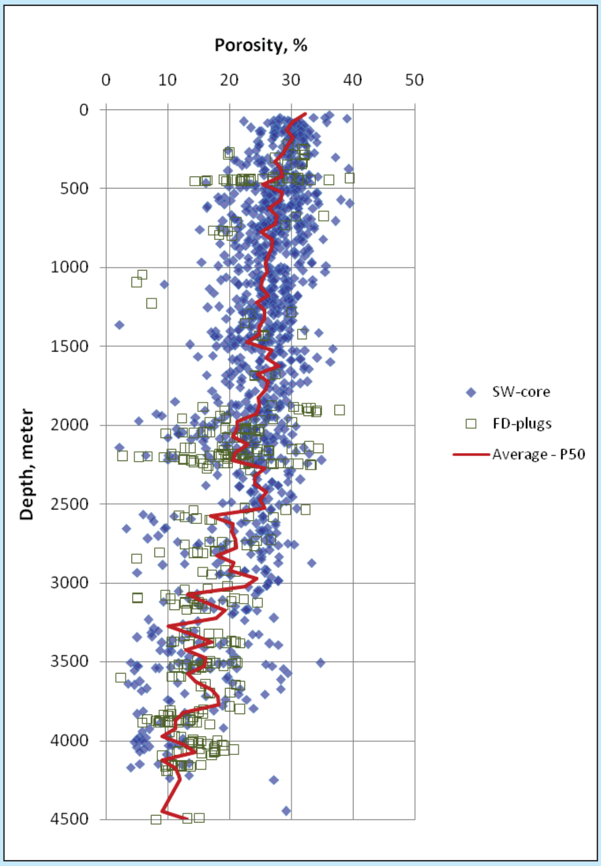

Figure 10
Porosity versus depth for data from Kutai basin (349 FD-plugs and 1045 SW-cores), including the curve representing average values. The lower part of the trend (P50) curve (depth > 2500 m ss) shows gentler slope indicating presence of compaction

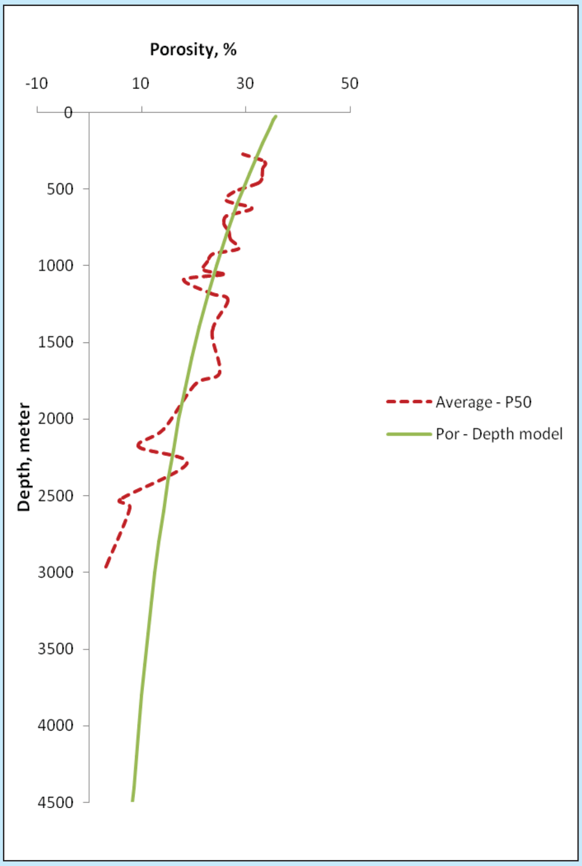

Figure 11
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 30) for North Sumatra basin data

porosity values (porosity of 27% - 33%). For rocks with porosity higher than 33% (i.e. soft rocks) the SWC-derived porosity tends to show lower values than FD-plug values due to impact of compaction on the relatively soft. On the other hand, rocks with SWC-derived porosity lower than 27% the reverse is true due to possible cracking on the retrieved samples (i.e. shattering effect). Measures normally taken (i.e. sample mounting and wrapping) are usualy considered as inadequate to preserve the original porosity.

From the plot shown on Figure 2, however, FD-plug and SWC derived porosity values has shown similarity in general. Clusters of the porosity values of the two groups appear to overlap to each others. Observation over plots at lower level (i.e. at sedimentary basin) show the same occurence except for data from NW Java basin (Figure 8) and NE Java (Figure 9), eventhough for NE java basin the number of data may be considered as to small. The sufficiently large number of NW Java appears to confirm the finding presented by Craft and Keelan (1985), eventhough caution has been made to avoid data representing fractured or insufficient samples. In general, therefore, this study has shown that there is no much differences between the two sources of porosity data. This fact is important for validity of the overall porosity data used for generating the porosity-depth models.

Comparisons between porosity-depth trend for all data and the trends for data at basin level appear to exhibit similar occurences. The porosity tends to decrease with the increase of depth. No firm suggestions show that the trends indicate that the main mechanism that affect the porosity decrease with depth is caused solely by overburden (i.e.

Table 9
Summary of alternative constants to the coefficients in the Gluyas & Cade (1997) model for the eight sedimentary basins in western Indonesia

Basin	*a*	*b*	*c*	*d*
North Sumatra	36	-10^{-3}	2.4	$1.5x10^{-4}$
Central Sumatra	35	-10^{-3}	2.1	$5x10^{-4}$
South Sumatra	32	-10^{-3}	3.4	$5x10^{-4}$
West Natuna	39	-10^{-3}	2.6	$5x10^{-4}$
West Sunda/Asri	32	-10^{-3}	5.9	$7x10^{-4}$
Northwest Java	37	-10^{-3}	2.9	$5x10^{-4}$
Northeast Java	29	-10^{-3}	3.9	$5x10^{-4}$
Kutai (upper part)	36	-10^{-3}	6.4	$1x10^{-4}$
Kutai (lower part)	32	-10^{-3}	7.4	$-8x10^{-4}$

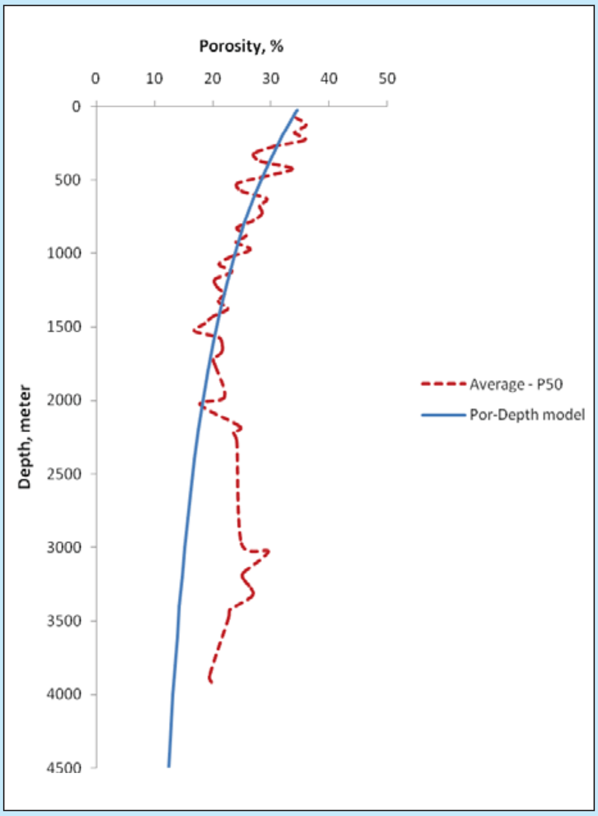

Figure 12
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 51) for Central Sumatra basin data. Notice eveidence of the pressumably porosity preservation at the lower part of the P50 curve

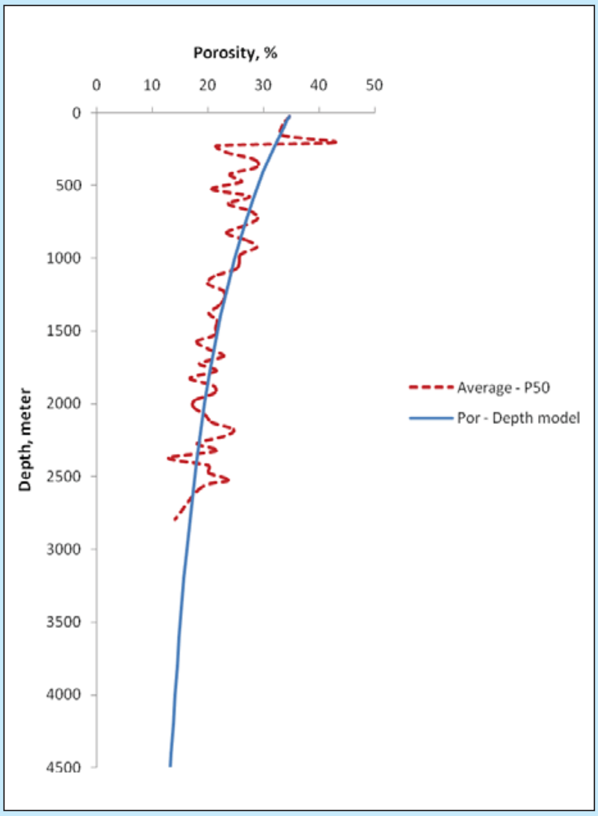

Figure 13
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 53) for South Sumatra basin data.

burrial) effect. Further investigation at lower levels than basin level – field level or lower – may suggest differently, in which non burrial mechanisms such as cementation and porosity preservation prevail. Nevertheless, noticeable occurences are observed for Central Sumatra and West Natuna data (Figures 4 and 6 or Figures 12 and 14, respectively). In these two cases, porosity tends to deviate and be higher than the overall trends indicating porosity preservation as suggested by, for instance, Ehrenberg and Nadeau (2005). On the other hand, signs of porosity reduction at great depths are shown by Kutai basin data (Figures 10 and 18). At depths deeper than 2500 m ss porosity decreases at a tendency stronger than the original trend as, for instance, suggested by Gratier et al (2013). These two occurences have shown that all mechanisms are apparently at work in the eight sedimentary basins.

All models for the eight sedimentary basins (Figures 19) show variety of trends in porosity decrease with depth. Some are similar like in the case of South Sumatra and Central Sumatra data whereas some are sufficiently different when North Sumatra and West Natuna gradients put into comparison. This indicates that each sedimentary basin may have followed similar process in the burial but may have also been differentiated by various mechanisms depending on intrinsical factors within the individual basin. Mineral compositions, hydrocarbon entry, levels of quartz cementation, temperature gradients, tectonic activity, and other factors can both be similar and different for the basins. Nonetheless, a significant difference is exhibited by the Gluyas and Cade (1997) model both in magnitudes and trends. The model represents higher overall porosity values and steeper porosity reduction with depth compared to the

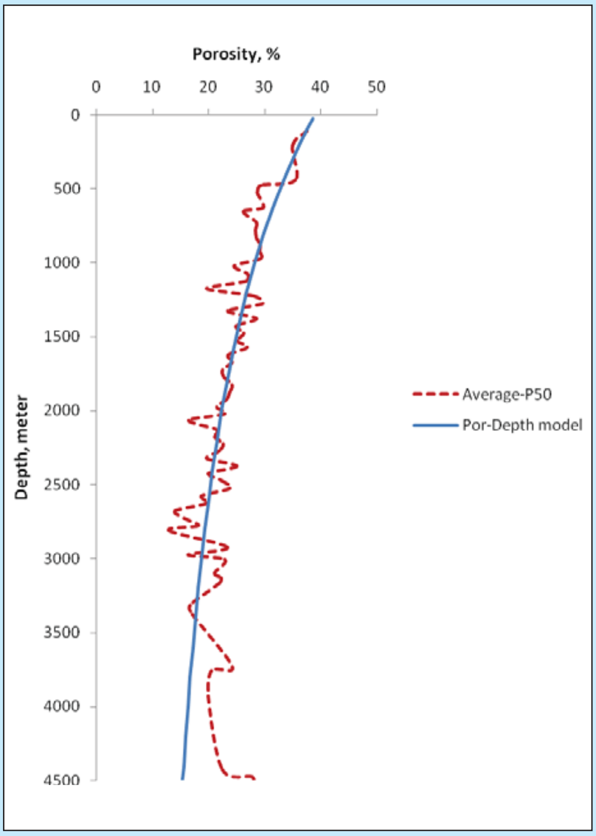

Figure 14
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 67) for West Natuna basin data.
Sign of porosity preservation at great depths are also visible

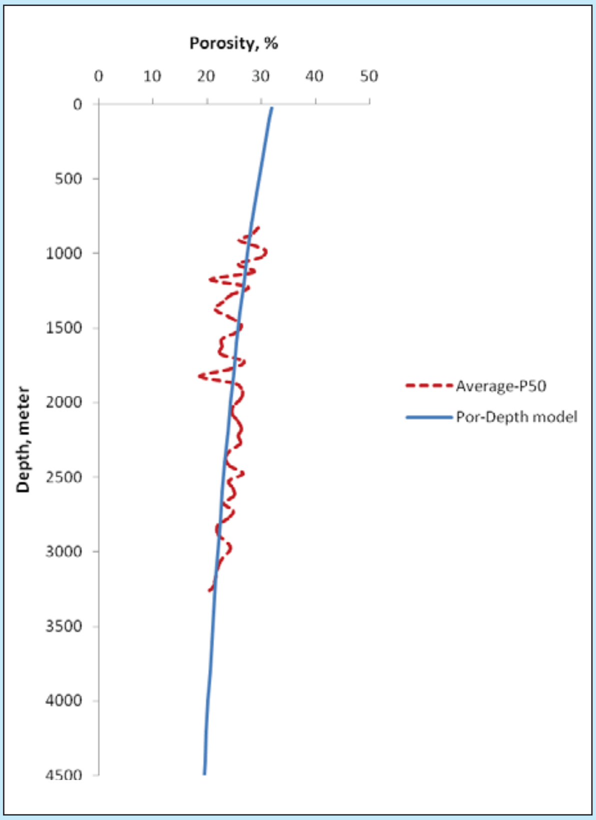

Figure 15
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 46) for West Sunda/Asri basin data

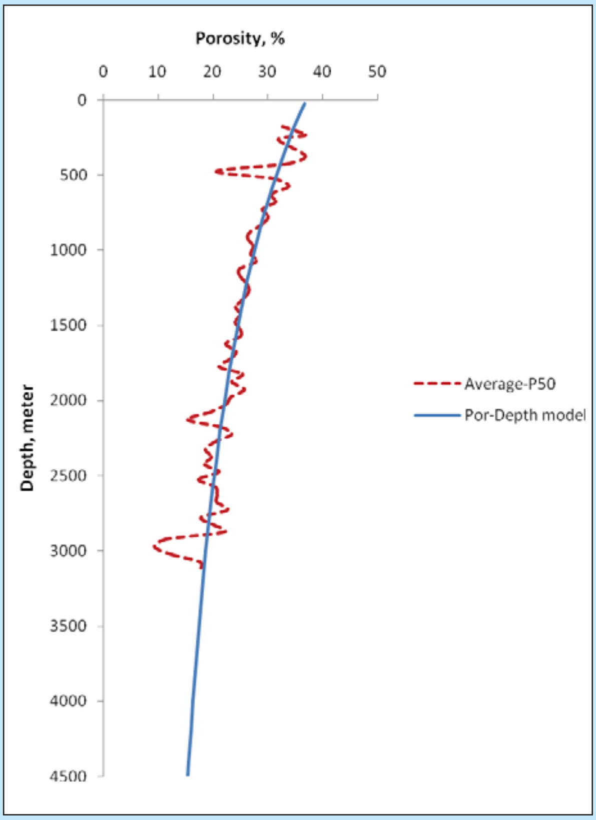

Figure 16
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 59) for Northwest Java basin data

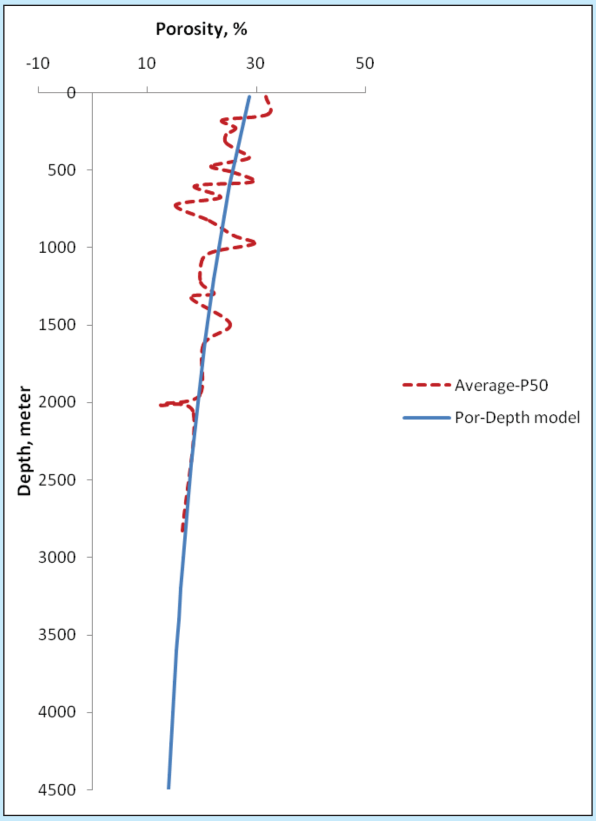

Figure 17
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 28) for Northeast Java basin data

western Indonesian models. Diferences in geological setting and ages between the two world regions are likely to enhance the differences in the above factors.

The porosity values used in the study were measured without overburden loading. This may lead to a consideration over the validity of the porosity-depth models for any practical uses. There is no intetion whatsoever to regard the eight models as the true representative of the porosity variation with depth *in situ*. The models should be regarded as general indicators in judgements over the likely average porosity at field levels and potential anomalies that may be encountered. Therefore, since the differences between overburdened and non-overburdened porosity values are likely to be small (data available indicates maximum difference of just one-twentieth of the non-overburdened porosity values), and certainly far smaller than data scatters, the issue of model practicability should not be to overemphasized.

Due to data availability, distribution of data quantity among the eight sedimentary basins is not even. For instance, the Kutai basin is represented by 1394 samples while the Northeast Java basin has only 86 samples considered suitable or fit to the purpose. For basins with limited samples available like Northeast Java (86 samples) and North Sumatra (105), this condition can lead to a question over the validity of the models representing them. However, when a comparison is made between the models representing the two basins and an average model representing all eight basins, the comparison shows more agreement to the average model than to the Gluyas & Cade (1997) model. This indicates that, despite the data limitation, the models of North Sumatra and Northeast Java basins have at least some extent of validity due to its resemblance to the all other basins represented by the average model. The two models can therefore still be regarded as representative at large for the two basins.

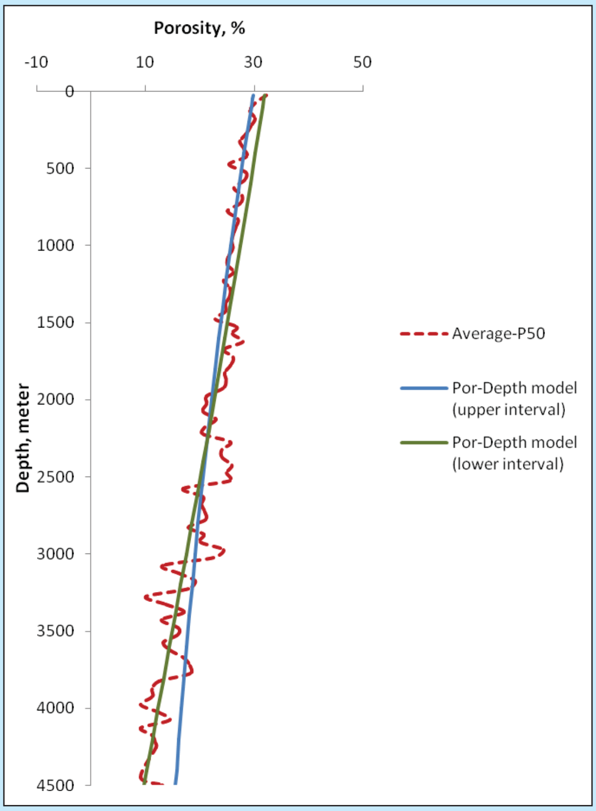

Figure 18
Porosity-depth model fitting on averaged P50 porosity data (P50 point number = 90) for Kutai basin data. Signs of compaction at lower part of the porosity-depth column leads to a separate porosity-depth model

VI. CONCLUSIONS

From the study using porosity data from eight sedimentary basins in western Indonesia, a set of conclusions has been drawn:

As occur in other places in the world, reservoir sandstone porosity in the western part of Indonesia also exhibits reduction with depth. This general occurrence takes place in all eight sedimentary basins in spite of differences in geological conditions.

Despite the differences, trends shown by the porosity-depth models for the western Indonesia sandstones are relatively similar when compared to the Gluyas and Cade model that was drawn using data obtained from the North Sea. The big difference show clearly over vast differences in geological setting between the two world regions. This also emphasizes that a porosity-depth model derived from one region cannot always be applied to other regions.

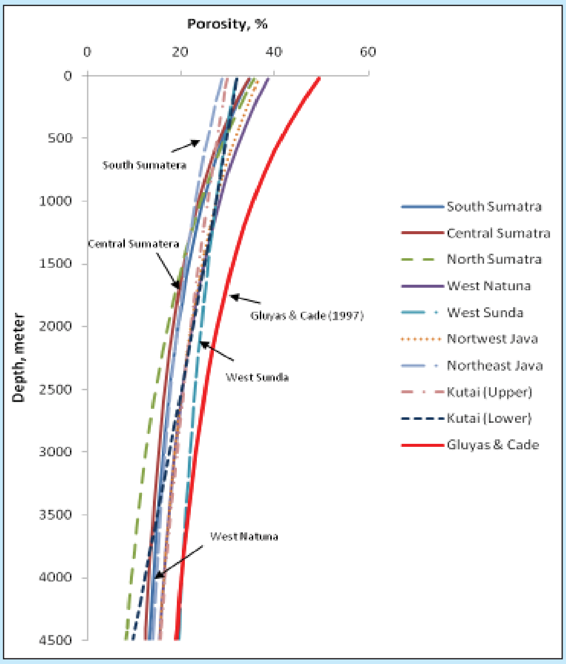

Figure 19
Porosity-depth models of the eight sedimentari basin in western Indonesia. The significant difference shown by Gluyas & cade (1997) model leads to a conclusion that the

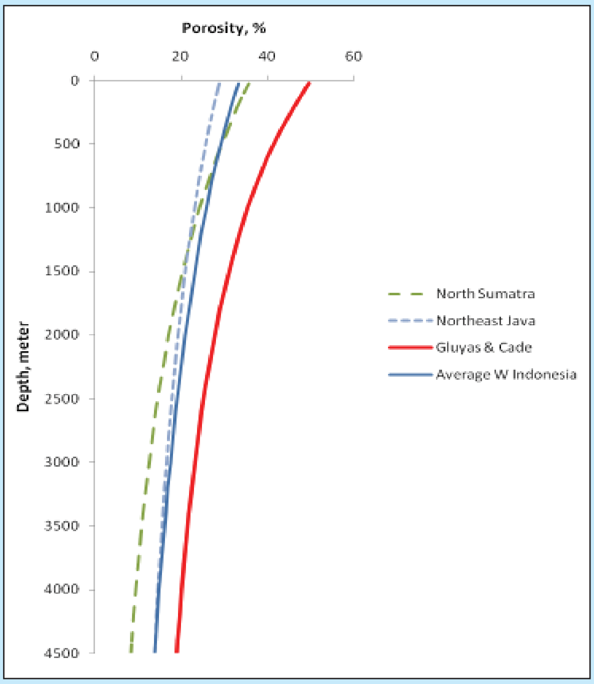

Figure 20
Comparison between North Sumatra/Northeast Java models and average western Indonesia model (average values). The two models appear to be more in agreement with the average model than with Gluyas & Cade (1997) model indicating some extent of validity for the two models

Similarity in trends between the eight sets of porosity-depth data indicates similarity in geological conditions and ages. This leads to similarity in the way mechanisms affecting porosity trends with depth work.

Although the porosity-depth trends – based on averaged porosity values – show gradual porosity reductions with depth, deviations from the trends in the forms of porosity preservation and porosity compaction at great depths also take place. At observation levels lower than basin scale (e.g. field level), this occurrence may be more prevalent judging from the scatters generally depicted by the porosity-depth data.

Unlike what is commonly believed, comparisons between porosity values from full-diameter core and percussion sidewall core samples show reasonable agreement in general. This is due to careful selection over sidewall core data to be used. However, comparisons at smaller scale (e.g. well level) may prove differently.

Data limitation for North Sumatra and Northeast Java basins does not appear to negate validity of the porosity-depth models derived for them. Strong similarity to the porosity-depths models of the other western Indonesian basins and the large difference to the foreigh Gluyas & Cade porosity-depth model seem to confirm the validity.

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