THE IMPORTANCE OF LITHO-FACIES DISTINCTION IN DETERMINING THE MOST REPRESENTATIVE CEMENTATION FACTORS FOR WELL-LOG EVALUATION: AN OLD ISSUE PERSISTENTLY NEGLECTED

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ABSTRACT

Cementation factor is a parameter always required in any conventional open-hole log analysis leading to determination of water saturation. Considering the central of water saturation in the estimation of hydrocarbon in place and reserves, any error in the use of the parameter may prove fatal. A common practice in the oil industry is that acquisition of laboratory-derived cementation factor has never been given a proper attention. It occurs very often that too few samples – hardly represent the rocks of reservoir of concern – are assigned for laboratory test. The practical use of the parameter in the log analysis also often draw question, in which un-representative cementation factor is arbitrarily used due to lack of the data. The effect of this practice has long been known but is often neglected – with all of its consequences – up to present day. This study tries to revive the awareness through presenting a fact that cementation factor may vary due to differences in litho-facies characteristics. Formation resistivity factor data from forty-seven limestone core-plug samples were taken from a West Java (WJ) field. Visual description over the samples has shown that they belong to several litho-facies types. Results of the study have mainly proved that different litho-facies type may have significantly different cementation factors. An averaging effect is also obvious when data from all samples are processed collectively. The effect of improper use of cementation factor is shown through the application of three water saturation models through which erroneous water saturation estimates are produced. The finding of the study is again hoped to reinforce the awareness of the use of proper and representative cementation factor.

Keywords: cementation factor, improper use, erroneous water saturation, better practice

I. INTRODUCTION

Cementation factor (m) is a parameter that reflects the tendency of how brine-containing pore network in sedimentary rocks influences resistivity magnitudes of the rock bulk itself, under an assumption that the solid parts of the rock are completely electrically non-conductive. It reflects the tortuosity (i.e. twisted-ness) of the pore network in a sense that the more tortuous the network the more restriction given to electrical current that flows through it and therefore the less contribution provided by the brine in the pore on the total rock resistivity, and vice versa. The more permeable a sedimentary rock the less tortuous its pore network and the less cemented it is usually, this provides the name for the parameter. Cementation factor ranges from 1 – 1.3 for unconsolidated sands to 2 – 2.2 for hard sandstones and limestones (Pirson, 1958). Variation in values between the two extremes marks the hardness degree of rocks, the harder the rocks the higher the values.

In the field of formation evaluation and reservoir characterization the cementation factor is regarded as

SCIENTIFIC CONTRIBUTIONS OIL & GAS
VOL. 34. NO. 2, SEPTEMBER 2011 : 139 - 148

a sufficiently important parameter. Up to present day efforts for determining water saturation still mainly rely on the use of water saturation models such as Archie (Archie, 1942) and other Archie-based models (e.g. deWitte, 1950; Poupon *et al*, 1954; Hossin, 1960; Waxman and Smits, 1968; and Fertl, 1975), all of which require cementation factor as one of their input variables. As shown by the following Archie water saturation (S_w) model of

$$S_w^{\ n} = \frac{a}{\phi^m}\frac{R_w}{R_t} \qquad \text{......... (1)}$$

with n, a, R_t, ϕ, and R_w are respectively saturation exponent, tortuosity coefficient, formation resistivity, porosity, and formation water resistivity, erroneous use of m values may results in biased values of water saturation. Inaccurate water saturation values will inevitably result in unreliable estimates of oil or gas initial in place (IOIP/IGIP).

Common day-to-day practice in well-log analysis is that cementation factor is derived from laboratory core resistivity measurements on limited number of core samples ranging as wide as possible in porosity values, often encompassing the whole rock facies in the rock formation. The reason for the limited sample number sent to laboratory is usually related to budget limitation and lack of concern over the importance of the cementation factor data itself. To author's knowledge almost all laboratory testing for cementation factor – at all commercial laboratories including LEMIGAS – are made in this fashion under the pretext mentioned above. The resulting hazard is indeed obvious; oversimplified and un-representative cementation factor with biased water saturation estimates. It is the objective of this paper to show the risk through presenting a real case study.

The case study used in this work is a set of limestone rock samples taken from a producing West Java field (WJ field). The primary reason behind the use is the complexity of the Baturaja reef buildup and platform that make the field's reservoirs and the relatively large number of samples sent to the laboratory. All data is obtained from LEMIGAS Core Laboratory Database with disguised true identity. Using the data, facies-related variation in cementation and its effect to water saturation estimation is studied, through which a more positive attitude towards the importance of cementation factor is appreciated.

II. CEMENTATION FACTOR: A BRIEF REVIEW

Cementation factor is a parameter that represents the twistedted-ness of any rerservoir rocks of concern. For sandstones the grain sands are compacted and cemented in manners differently from one rock to another. Grain sands that are made of quartz and other minerals are compacted, cemented, and lithified to make reservoir rocks. Cementation may take the form silica (e.g. quartz growth or clay cementation) or carbonate (e.g. calcite) grain cementation. The more cementation that may take place the more hardness the rock resulting on the high cementation factor values of around two. On the contrary, the less cemented sandstones the lower values of the factor of values less than two. Pirson (1958) observed that soft sandstones (i.e. loose sandstones) tend to have cementation factor values of 1 – 1.3 whereas hard sandstones have the corresponding values of two or higher.

For limestone reservoir rocks cementation factors are not governed by grain shape, sorting, packing, cementation, and compaction, but rather on the nature of the pore system, whether fractured, vuggy, or connected vuggy system. Despite the difference, relation between the pore passage twisted-ness and electrical current is no different from that for sandstones hence same concept of cementation factor also applies (Archie, 1952). However, more variation in values is certainly to be expected since it is known that limestone porosity is in general more complex than that of sandstone's. Cementation factors of limestones ranges from low values (around 1.3) for fractured limestones up to 2.8 for hard and compact oolitic limestones (Hellander, 1983).

From his laboratory experiment on some sandstone samples Archie derived a relation between formation resistivity factor (F_R) and porosity (ϕ) in the form of

$$F_R = \frac{1}{\phi^m} \qquad \text{......... (2)}$$

or in the form of 'Generalized Humble formula',

SCIENTIFIC CONTRIBUTIONS OIL & GAS
VOL. 34. NO. 2, SEPTEMBER 2011 : 139 - 148

$$F_R = \frac{a}{\phi^m} \qquad \text{......... (3)}$$

with a and m are the tortuosity exponent and cementation factor, respectively. Rearranging the Equation (3) in logarithmic manner, the relation becomes

$$Log(F_R) = -mLog(\phi) + Log(a) \qquad \text{......... (4)}$$

with m as the slope of the resulting F_R versus porosity straight line. As early as in 1942 different m values have been observed to represent different type of rocks when plots are made with the use of a = 1 (1942). This knowledge is well preserved up to the present day but it is usually applied to accommodate potentially different m values of *different* reservoirs, rock formations, or fields but rarely of different litho facies *within* a rock formation. This study emphasizes in observing of m variation in this smaller scale.

III. AN OVERVIEW ON WJ FIELD

The West Java (WJ) field is located in the Northwest Java Basin. This extensively large sedimentary basin extends from the Asri Basin in offshore Southeast Sumatera to the east covering the Ardjuna Basin in the offshore Northwest Java and the onshore Jatibarang Basin. The field is located in the Jatibarang Basin. Stratigraphycally, the field consists of Jatibarang, Talang Akar, Baturaja, Cibulakan, Parigi, and Cisubuh Formations. However, the field's hydrocarbon is mostly accumulated in the Upper Baturaja Formation's reservoirs. The reservoirs are mostly reef buildup that developed in the Early Miocene. Permeability and porosity for the reservoirs' best part were developed through dissolution by meteoric water during sea level low stands. Thickness can reach up to 50 m with porosity and permeability reaching values higher than 30% and 1,000 mD, respectively. The samples assigned to laboratory tests and are used in this study were obtained from this part of rock formation.

IV. LABORATORY DATA

In obtaining the formation resistivity factor, the samples were immersed and vacuumed in synthetic brine that simulates the real formation brine. As the samples were fully saturated with brine electrical conductivity (C_O) of the samples were measured. The formation resistivity factor, F_R, was then calculated using

$$F_R = \frac{R_O}{R_W} \qquad \text{......... (5)}$$

of which the R_O and R_W are sample resistivity at 100% brine saturated (R_O = 1/C_O) and brine resistivity, respectively. Using the relation presented in Equation (3), cementation factor can be obtained through

Table 1
Basic data and cementation factors of samples taken from eleven wells of WJ field.

Well	Sample number	Depth (mss)	Lithology	Porosity (%)	Permeability (mD)	*m*
WJ-05	3	1889.0 – 1895.3	boundstone – packstone	12.9 – 39.6	12 – 392	1.8704
WJ-06	4	1786.3 – 1791.7	packstone	13 – 27	1.4 – 458	1.7005
WJ-07	4	1938.3 – 1943.7	packstone	8 – 15	0.44 – 20	1.7047
WJ-08	2	2024 – 2026	packstone – grainstone	15 - 17	13 – 35	1.7188
WJ-10	4	2072.7 – 2078	packstone – grainstone	13.5 – 20	1.8 – 6.3	1.7812
WJ-13	6	1796.4 – 1803.1	wackestone	6.5 – 20.9	0.23 – 24.8	1.6021
WJ-14	4	1802.6 – 1809	boundstone – packstone	11.9 – 23.6	2.5 – 158	1.8285
WJ-18	5	2185.3 – 2189.6	packstone – wackestone	10.4 – 23.7	2.2 – 42	1.7357
WJ-24	5	1812 – 1819	grainstone – packstone	1.5 – 23.5	4 – 759	1.7998
WJ-31	5	1834.9 – 1837.3	wackestone – packstone	11 – 15	2.4 – 8.3	1.6946
WJ-33	6	1903 – 1911.5	grainstone – packestone	4.4 – 24.4	1.1 – 375	1.7271
Total	47					

plotting formation resistivity factor versus porosity measured in laboratory on log-log graph resulting in a straight line with *m* as its slope.

As previously stated, the WJ field is chosen due to the complexity of its reservoir limestones and the relatively vast amount of cementation factor data taken. Table 1 presents basic data of the forty seven (47) samples taken from eleven wells in the WJ field. Lithologically, the samples range from wackestone to boundstone – according to Dunham classification – that are usually considered as of poor to good reservoir rock quality. The samples from the eleven wells are ready to show that heterogeneity is the characteristics of the WJ field limestones. For instance, packstone samples of WJ – 07 well have similar properties to wackestone samples of WJ – 13 well, even though it is true that wells having boundstone and/or grainstone samples are usually characterized with higher porosity and permeability values.

The results from individual wells are usually presented in an individual manner. Each well has its own cementation factor, as is presented in Table 1. Figures 1 and 2 are two examples presenting plots for WJ – 06 and WJ – 14 samples with cementation factors of 1.7005 and 1.8285, respectively. The two cementation factors are certainly aggregated values of whatever litho-facies present in the two wells. The two cementation factors may be taken as 'representative' for the rock columns in the wells – and therefore 'valid' for any well-log analysis in the two wells – but they are not necessarily representative for the individual rock type in the well. The next section investigates this aspect further.

V. ANALYSIS OF DATA

Cementation factor is usually presented in well-basis manner due to the fact that core analysis is usually made on well basis. This practice also comes from a consideration that the resulted cementation factor has to be regarded as directly representative and therefore usable for any well-log analysis made on the well's log data. On the other hand, whenever required a single cementation factor value can also be generated using all data from all wells regardless of rock facies types. Figure 3 shows the plot that yields cementation factor value of 1.7692. This cementation factor value can be regarded as an averaged value encompassing all presence of heterogeneity and differences.

Following the classification established by Dunham (1962) and Embry and Klovan (1971) (Table

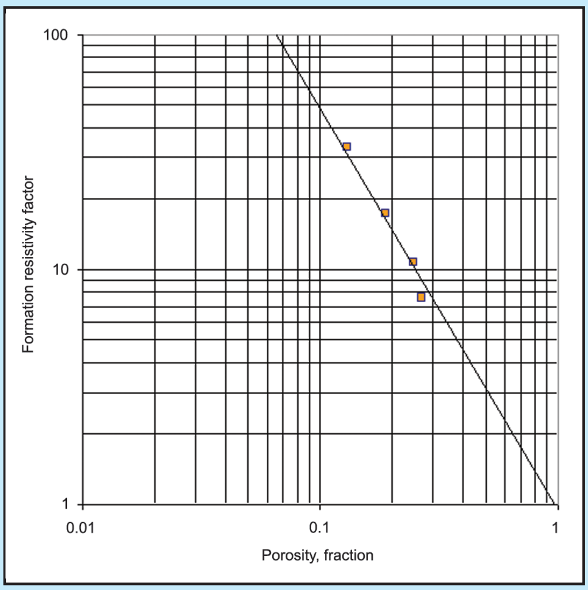

Figure 1
Formation resistivity factor versus porosity plot of WJ – 06 well's samples drawn to a =1 resulting in cementation factor of 1.7005

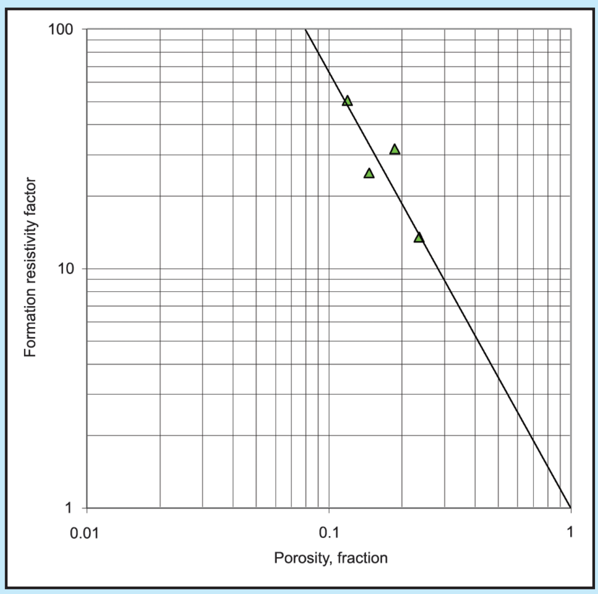

Figure 2
Formation resistivity factor versus porosity plot of WJ – 14 well's samples drawn to a =1 resulting in cementation factor of 1.8285

SCIENTIFIC CONTRIBUTIONS OIL & GAS
VOL. 34. NO. 2, SEPTEMBER 2011 : 139 - 148

Table 2
Modified Dunham classification (from Embry and Klovan, 1972)

<table>
<tr><td colspan="6">Allochthonous Limestone
Original components not organically bound during decomposition</td><td colspan="3">Autochthonous Limestone Original components organically bound during deposition</td></tr>
<tr><td colspan="4">Less than 10% > 2 mm components</td><td colspan="2">Greater than 10% > 2 mm components</td><td rowspan="4">By organisms that build a rigid framework</td><td rowspan="4">By organisms that encrust and bind</td><td rowspan="4">By organisms that act as baffles</td></tr>
<tr><td colspan="3">Contains lime mud (< 0.03 mm)</td><td>No lime mud</td><td rowspan="4">Matrix supported</td><td rowspan="4">Supported by grain components coarsers than 2 mm</td></tr>
<tr><td colspan="2">Mud supported</td><td colspan="2" rowspan="3">Grain-supported</td></tr>
<tr><td rowspan="2">Less than 10% grains (>0.03 mm < 2 mm)</td><td rowspan="2">Greater than 10% grains</td></tr>
<tr><td colspan="3">Boundstone</td></tr>
<tr><td>Mud stone</td><td>Wackestone</td><td>Packstone</td><td>Grainstone</td><td>Floatstone</td><td>Rudstone</td><td>Framestone</td><td>Bindstone</td><td>Bafflestone</td></tr>
</table>

Table 3
Litho facies description of WJ field's limestones. The basic assumption is that reservoir rock quality to range from wackestone as the poorest to boundstone as the best. Also notice that lower quality rocks of wackestone and packstone are associated with micro stylolite and micro fractures leading to lower cementation factor values

Lithology class	Description	Sample number
Boundstone	up to 7 mm vugs, micro x-lin, intra-particle porosity	8
Grainstone	grain-sprtd, vugs, aragonite, bioturb, med-coarse grain	8
Packstone	pp-mott vugs, mud/grain sprtd, bioturb, micro styl	23
Wackestone	pp-mott vugs, mud sprtd, shale lam, micro styl, nat fract	8

2), the 47 samples are grouped resulting in classes as presented in Table 3. The F_R versus porosity plots for the four groups are presented on Figures 4 through 7. Cementation factors for the wackestone, packstone, grainstone, and boundstone groups are 1.5628, 1.7376, 1.7327, and 1.9345, respectively.

The relatively low *m* value of the wackestone group is actually unlikely provided the poor rock quality usually associated with it. The presence of micro stylolite and fine natural fractures (Table 3) can probably be considered as responsible for the low *m* value. For packstone and grainstone groups the *m* values are sensible and similarity in *m* values between the two facies groups are likely to come from the fact that both packstones and grainstones are grain-dominated by nature (Table 2). For boundstones, the relatively high value of cementation factor points out the influence of vuggy pore system that offer tortuous pore paths.

When compared with the cementation factors of the four litho-facies groups the overall cementation factor of 1.7692 appear to lie right in the middle suggesting the effect of averaging. This is also true when the overall value is compared to the well-based cementation factors (Table 1) that range within 1.6021 – 1.8704. Implicitly nonetheless, the narrower range of the well-based cementation factor compared to the facies-based cementation factor range suggests that the well-based cementation factors themselves are essentially also averaged values already.

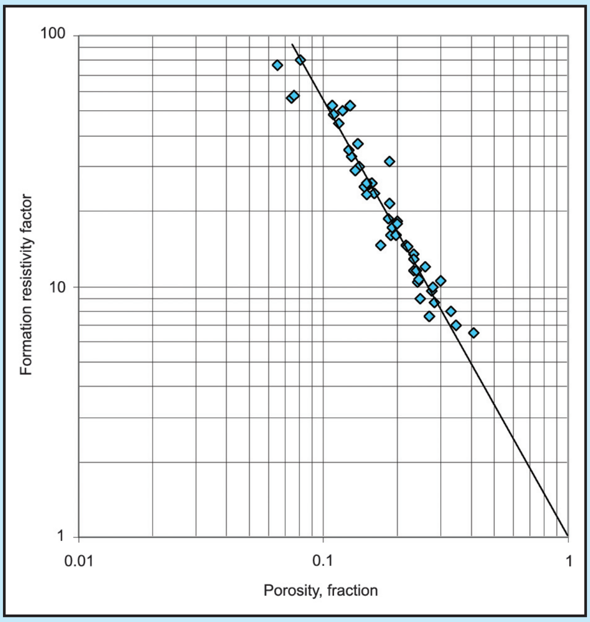

Figure 3
Formation resistivity factor versus porosity plot for all samples drawn to a =1 resulting in cementation factor of 1.7692. All potential differences due to any sources of heterogeneity are 'averaged' nevertheless

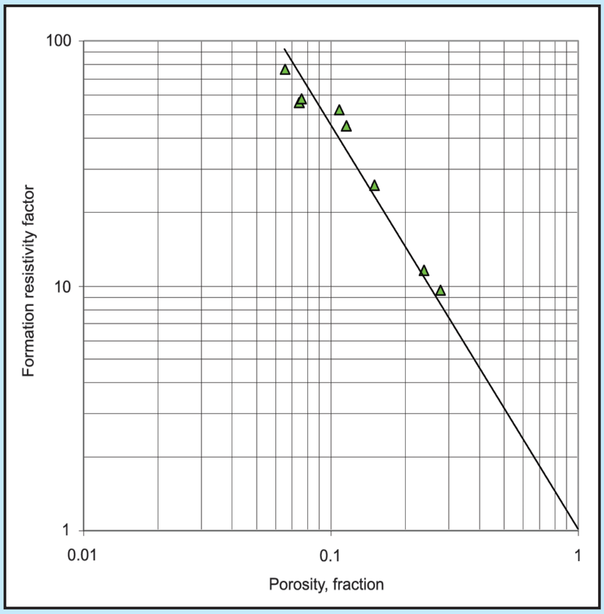

Figure 4
Formation resistivity factor versus porosity plot for wackestone samples drawn to a =1 resulting in cementation factor of 1.5628. The relatively low m value is probably due to presence of micro stylolites and fine fractures

V. VARIATION IN *m* WITH WATER SATURATION ESTIMATES

Variation of cementation factor results in variation in the estimated water saturation. Error in establishing the representative cementation results in unreliable water saturation estimates. To observe the effect of this a test is made using three water saturation models. The first is the Archie model, as described by Equation (1). The second is the Poupon *et al* (Poupon *et al*, 1954) model of

$$S_w^{\ n} = \frac{a}{\phi^m}\left[\left(\frac{1}{R_t} - \frac{V_{sh}}{R_{sh}}\right) \times \frac{R_w}{(1-V_{sh})}\right] \quad .... (6)$$

with V_{sh} and R_{sh} are shale contents and shale true resistivity, respectively. The third water saturation model is the one established by Hossin (1960)

$$S_w^{\ n} = \frac{a}{\phi^m}\left(\frac{1}{R_t} - \frac{V_{sh}^{\ 2}}{R_c}\right) R_w \quad . ... (7)$$

with dispersed clay resistivity (R_c) represented by R_c = 0.4 x R_{sh}. The choice over the two shaly sand models is completely arbitrary and is exclusively meant to serve the observation.

For the observation, a set of assumption is made to include

Water resistivity (R_w) = 0.1 Ohm-m at reservoir condition,
Tortuosity factor (a) = 1,
Shale resistivity = 1 Ohm-m,
Shale contents = 10%, and
Saturation exponent (n) = 2

For the observation, two porosity values are chosen, 10% to represent low porosity and 25% to represent moderate to high porosity. Figures 8 through 13 exhibit the plots. For the porosity of 10% plots for the three water saturation models (Figures 8 through 10) clearly show variation in water saturation estimates with variation in cementation factors. The four curves on each figure represents cementation factors of 1.5628 (wackestone), 1.7327 (packstone/grainstone), 1.7692 (overall data), and

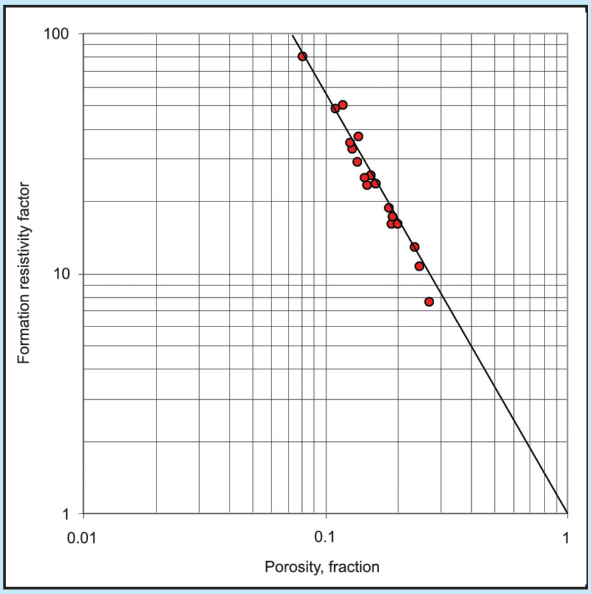

Figure 5
Formation resistivity factor versus porosity plot for packstone samples drawn to a =1 resulting in cementation factor of 1.7376. The effect of micro-stylolite presence appears to be less profound than in the case of wackestone samples

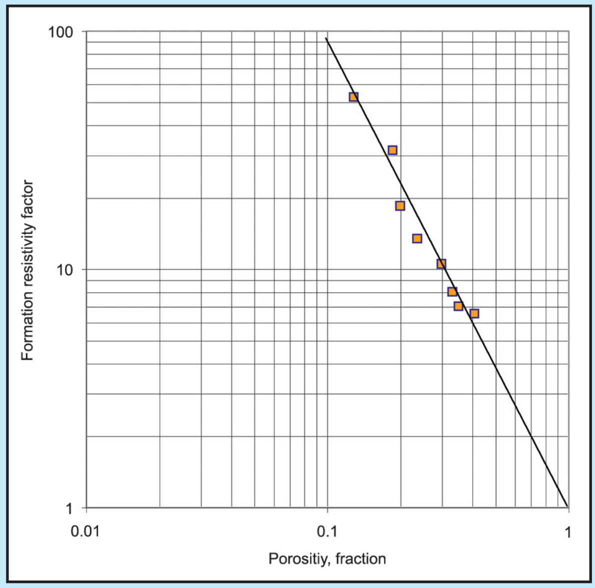

Figure 7
Formation resistivity factor versus porosity plot for boundstone samples drawn to a =1 resulting in cementation factor of 1.9345. The relatively high cementation factor value is likely to be caused by the tortuous vuggy pore system

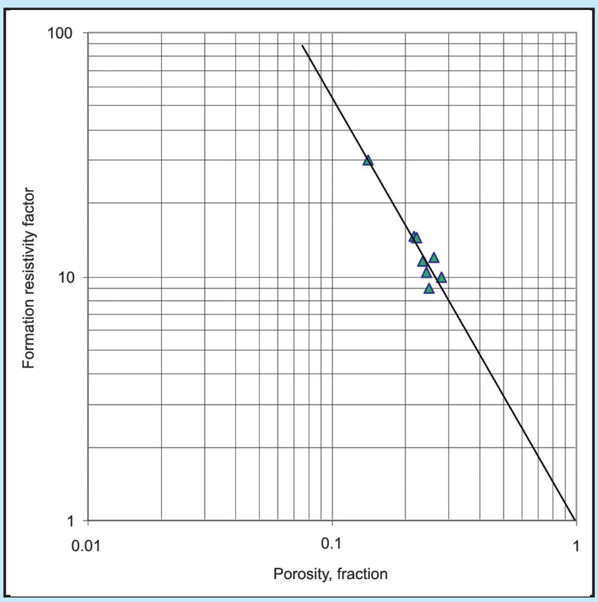

Figure 6
Formation resistivity factor versus porosity plot for grainstone samples drawn to a =1 resulting in cementation factor of 1.7327. Similar cementation factor value to packstone group is probably due to their common grain-supported type of limestones

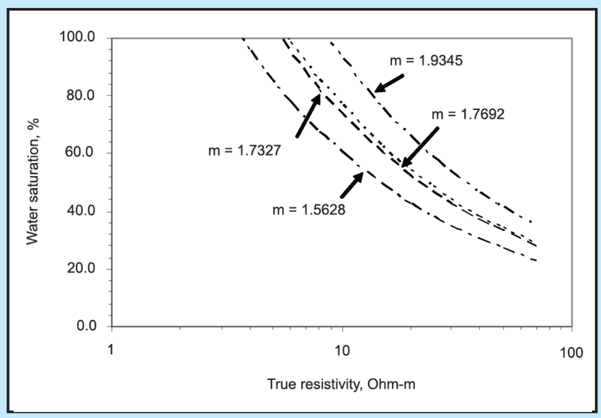

Figure 8
Estimated water saturation from the use of Archie model (porosity = 10%). Potential error due to the use of wrong cementation factor is obvious as clearly shown by the m = 1.5628 and m = 1.9345 curves.

1.9345 (boundstone). Variation in water saturation is noticeable at lower resistivity values. For instance, at resistivity value of 8 Ohm-m the water saturation estimated using Archie model (Figure 8) are 67% and 100% for wackestone and boundstone, respectively.

SCIENTIFIC CONTRIBUTIONS OIL & GAS
VOL. 34. NO. 2, SEPTEMBER 2011 : 139 - 148

For Poupon *et al* and Hossin models the case are also true but becomes narrower at higher resistivity values than the case of Archie model due to the effect of shale correction.

For high porosity case (porosity = 25%) water saturation gap is also visible (Figures 11 through 13) even though narrower than the case of low porosity. This can be taken as a proof that the effect of cementation factor becomes less pronounced for rocks with high porosity. This is due to the increasingly larger contribution of porosity – compared to the cementation factor itself – in the denominator of formation resistivity factor (F_R) in Equations (2) and (3). This occurrence suggests that choice of the right cementation factor is even more crucial in the

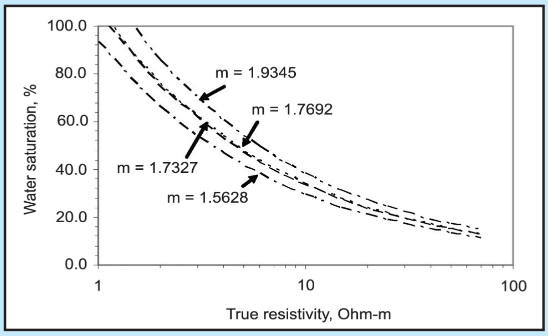

Figure 11
Estimated water saturation from the use of Archie model (porosity = 25%). The difference in water saturation at this relatively high porosity is apparently less compared to the case of low porosity

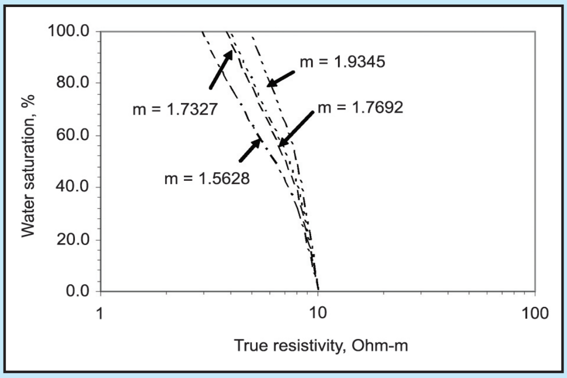

Figure 9
Estimated water saturation from the use of Poupon et al model (porosity = 10%). The gap in water saturation estimates becomes narrower at higher resistivity values

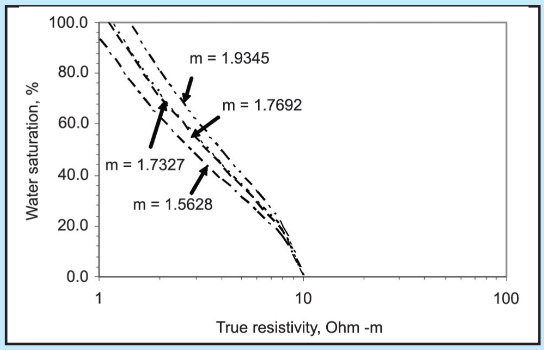

Figure 12
Estimated water saturation from the use of Poupon et al model (porosity = 25%). Similar to the case of Archie model the water saturation gap is also noticeable even though it is not as wide as in the case of low porosity

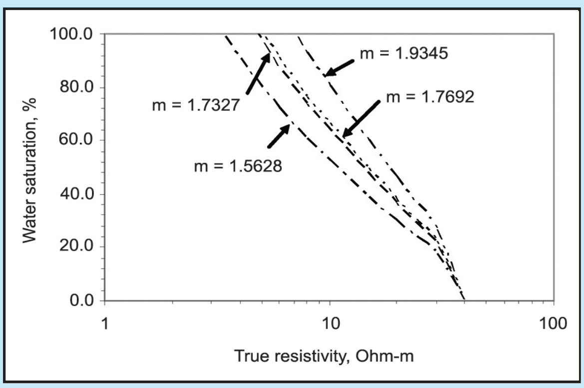

Figure 10
Estimated water saturation from the use of Hossin model (porosity = 10%). The difference in water saturation estimates is as large as in the case of Archie model but is reduced at higher resistivity values

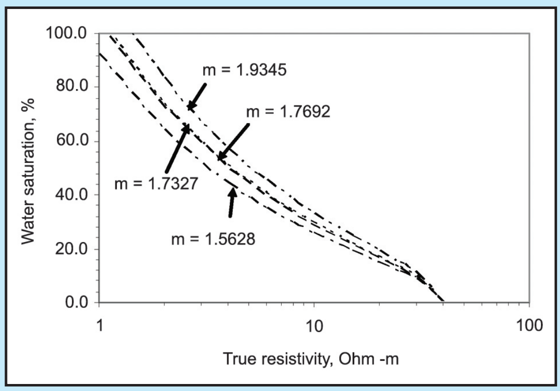

Figure 13
Estimated water saturation from the use of Hossin model (porosity = 25%). Compared to Poupon et al model the water saturation gap is still present at higher resistivity values

SCIENTIFIC CONTRIBUTIONS OIL & GAS
VOL. 34. NO. 2, SEPTEMBER 2011 : 139 - 148

case of reservoirs with poor rock quality. Careless choice for the already marginal reservoirs may result in overlooked or bypassed zones.

VI. FURTHER DISCUSSION

The test and litho-facies based analysis on samples from the same limestone rocks of WJ field have shown that litho-facies grouping is actually specific and ignoring it tends to ends up in unrealistic water saturation estimates. Cementation factor that belongs to wackestone group but is applied to boundstone group certainly lead to error in water saturation estimates. As high as 70% error in water saturation estimate may result when the practice is pursued. If this is applied to calculation of original hydrocarbon in place, a similar error may take place and decision over plan of development of a field can be seriously biased. A serious selection over the most representative cementation factor for a sound and reliable well-log analysis is needed.

From the laboratory point of view, suggestions have to be underlined that sample grouping to be made first so that cementation factors to be yielded meet the litho-facies grouping of the field. Based on this reservoir rock grouping the formation resistivity factor test on the grouped samples is made. Careful and selective use of cementation factors for the appropriate reservoir rocks can be applied, accordingly. In return, reliable and representative estimates of hydrocarbon in place can be produced.

VII. CONCLUSIONS

From the study a set of conclusions have been established:

- A careful reservoir rock grouping has resulted in different cementation factors as shown by the formation resistivity factor test in the laboratory.
- Application of averaged cementation factor for field-wide well-log evaluation tends to produce either underestimated or overestimated water saturation values.
- Application of cementation factor obtained from poor quality reservoir rocks on good quality reservoir rocks tends to yield pesimistic water saturation values. This leads to existence of overlooked or bypassed zones over the already marginal fields.
- The effect of wrong choice of cementation factor has similar effect on both clean and shaly reservoir rocks.
- Wrong choice of cementation factor has more effect on rocks with low porosity. This is due to the relatively low contribution of porosity on the formation resistivity factor relative to the contribution of the cementation factor itself. This has an effect of too high water saturation estimates for the already marginal reservoir rocks.
- The effect of wrong choice in cementation factor decreases with higher resistivity values. Nevertheless, this potential effect has to be balanced with awareness over the tendency of worsening water saturation estimates in the case of tight reservoirs normally associated with high formation resistivity values.

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