SCIENTIFIC CONTRIBUTIONS OIL AND GAS
Vol. 41, Number 1, April 2018: 1 of 5
RESEARCH AND DEVELOPMENT CENTRE FOR OIL & GAS TECHNOLOGY LEMIGAS
Journal Homepage:http://www.journal.lemigas.esdm.go.id
ISSN: 2089-3361, e-ISSN: 2541-0520

A CUSTOMIZED QUASI THREE-PHASE DRAINAGE RELATIVE PERMEABILITY MODEL FOR SOME INDONESIAN WATER-WET SANDSTONES

MODEL PERMEABILITAS RELATIF DRAINAGE TIGA-FASE SEMU YANG TELAH DISESUAIKAN BAGI BATUPASIR BASAH-AIR INDONESIA

Bambang Widarsono
"LEMIGAS" R & D Centre for Oil and Gas Technology
Jl. Ciledug Raya, Kav. 109, Cipulir, Kebayoran Lama, P.O. Box 1089/JKT, Jakarta Selatan 12230 INDONESIA
Tromol Pos: 6022/KBYB-Jakarta 12120, Telephone: 62-21-7394422, Faxsimile: 62-21-7246150
E-mail: bambangw@lemigas.esdm.go.id,

First Registered on January 27th 2018; Received after Correction on April 6th 2018
Publication Approval on: April 30th 2018

ABSTRAK

Informasi mengenai karakter permeabilitas relatif dua-fasa – atau bisa dianggap tiga-fasa semu – drainage dari batuan reservoir dianggap sangat penting dalam setiap kegiatan pemodelan reservoir hidrokarbon. Data tersebut mengontrol berbagai proses dalam reservoir seperti ekspansi tudung gas ke zona minyak, ekspansi gas terlarut dalam mendorong minyak, dan pendesakan gas tak tercampur dalam proses enhanced oil recovery (EOR). Proses-proses tersebut adalah mekanisme-mekanisme yang berlaku di reservoir yang secara keseluruhan yang pada ujungnya turut menentukan besarnya cadangan dan kinerja produksi darI reservoir. Meskipun demikian, data yang dibutuhkan tersebut seringkali karena berbagai sebab tidak tersedia. Studi ini mencoba untuk memberikan solusi dengan mengadaptasi model permeabilitas relatif yang sudah ada sehingga dapat memodelkan batuan-batuan reservoir di Indonesia. Model Corey dkk yang dianggap standar dan relatif sederhana dipakai dalam pemodelan atas data dari 32 batupasir basah air yang diperoleh dari 5 sumur minyak di Indonesia. Percontoh-percontoh batupasir yg dipakai mewakili tiga kelompok, yaitu batupasir konglomeratik, batupasir mika berlempung, dan batupasir keras. Korelasi khusus antara permeabilitas dan saturasi air sisa, serta antara rasio permeabilitas dan saturasi air sisa telah dapat dibuat. Penerapan model pada data dari 32 percontoh batupasir juga menghasilkan harga-harga spesifik untuk indeks distribusi ukuran pori (λ) dan parameter saturasi fase pembasah (S_m) untuk ketiga kelompok batupasir, serta sebuah prosedur praktis untuk membuat kurva-kurva permeabilitas relatif drainage di saat data pengukuran dari laboratorium tidak dapat diperoleh. Temuan-temuan lain seperti hubungan antara λ dan permeabilitas serta pengaruh dari ukuran percontoh terhadap pemodelan juga telah dibuat.

Kata Kunci: *Permeabilitas relatif tiga fase semu, ketidak tersediaan data laboratorium, pemodelan, prosedur pemodelan untuk membuat kurva permeabilitas relatif*

ABSTRACT

Information about drainage effective two-phase – i.e. quasi three-phase – relative permeability characteristics of reservoir rocks is regarded as very important in hydrocarbon reservoir modeling. The data governs various processes in reservoir such as gas cap expansion, solution gas expansion, and immiscible gas drive in enhanced oil recovery (EOR). The processes are mechanisms in reservoir that in the end determines reserves and resevoir production performance. Nevertheless, the required information is often unavailable for various reasons. This study attempts to provide solution through customizing an existing drainage relative permeability model enabling it to work for Indonesian reservoir rocks. The standard and simple Corey et al. relative permeability model is used to model 32 water-wet sandstones taken from 5 oil wells. The sandstones represent three groups of conglomeratic sandstones, micaceous-argillaceous sandstones, and hard sandstones. Special correlations of permeability – irreducible water saturation and permeability ratio – irreducible water saturation have also been established. Model applications on the 32 sandstones have yielded specific pore size distribution index (λ) and wetting phase saturation parameter (S_m) values for the three sandstone groups, and established a practical procedure for generating drainage quasi three-phase relative permeability curves in absence of laboratory direct measurement data. Other findings such as relations between λ and permeability and influence of sample size in the modeling are also made.

Keywords: quasi three-phase relative permeability, absence of laboratory data, modeling, procedure for relative permeability generation

How to cite this article:

Widarsono, B., 1, 2018, A CUSTOMIZED QUASI THREE-PHASE DRAINAGE RELATIVE PERMEABILITY MODEL FOR SOME INDONESIAN WATER-WET SANDSTONES, *Scientific contributions Oil and Gas*, 41 (1) pp, 1-15. DOI: 10.29017/SCOG. 41.1.1-15.

I. INTRODUCTION

In various processes that involve reservoir fluids movements in oil and gas reservoirs information over flow characteristics of the reservoir's rock mass is very important. Different rocks with their different interactions with the contained fluids and reservoir conditions tend to exhibit different flow behaviors. This is especially true for reservoir fluids that are usually present in at least two-phase systems of gas-oil, water-oil, or water-gas systems. In gas–oil system, drainage processes like gas cap expansion into oil bank, solution gas drive mechanism, and immiscible gas drive in enhanced oil recovery (EOR) are three examples that work under virtually drainage two-phase flow systems. Therefore, rock petrophysical property (i.e. relative permeability) that governs the two-phase flow behavior has to be properly acknowledged since the above three flow processes are directly or indirectly related to oil recovery. Since the first establishment of relative permeability concept however, needs for drainage relative permeabilty had become a neccessity in any reservoir modeling, and the data is not bound to applications in hydrocarbon flows but also have expanded to other applications. Applications such as acid gas disposal (e.g Bennion and Bachu 2008), CO_2 storage (e.g. Burnside and Naylor 2014; Ott et al. 2015, Reynolds and Krevor 2015), and underground waste movements (e.g Gerhard and Kueper 2003) are some examples.

There are several known methods to obtain information regarding relative permeability rock behavior, from the least direct and reliable approaches such as guessing to the much better approaches such as direct measurements on core samples, as well as even further assisted by combining with other techniques like well testing and core modeling. Undoubtedly, reservoir engineers tend to be more confident in using data from direct measurements for their calculations and reservoir modeling. Nevertheles, the wanted data is not always available for all studies due to various reasons, and furthermore, it is more a rule rather than an exception that different rocks have different relative permeability characteristics. This therefore makes adoption of unrepresentative relative permeability model(s) for the intended purposes risky.

Indonesian reservoir rocks, like many others in the world, are inclined to be heterogeneous hence making generalization in relative permeability modeling unrealistic. This study has been made through application of an existing three-phase relative permeability model on three different water-wet sandstones from several oil fields in Western Indonesia. These three sandstone types will hopefully give some view and sense of representativeness over reservoir sandstones in Indonesia. Some facts are to be encountered, and a procedure for making and applying the model on the three sandstone types is to be established for practical purposes. It is hoped that the procedure can be used to generate customized two-phase drainage relative permeability models in case of absence of direct relative permeability measurement data.

II. METHODOLOGY

The characteristics of multiphase flow in porous media are influenced by at least four major factors namely pore size distribution, wettability, saturation, and saturation history. Pore size distribution and wettability tend to determine fluid distribution in the pore system, in which the wetting phase fluid tends to fill the smaller pores whereas the non-wetting phase inhabits the center parts of larger pores (Figure 1). These occurrence along with mode of fluid movements (saturation history) and fluid phase fractional quantity (saturation) determine shapes and end points of the relative permeability curves versus wetting phase saturation. Further and more detailed information can be found in various references (e.g. Blunt 2017).

In water wet rocks, the fine pores are mostly – if not all – filled with formation brine that is interstitial water or/and connate water. In drainage condition, hydrocarbon moves through the pore network mainly within the middle parts of the greater pores and is hindranced only by the pores' throats allowing it to move faster (i.e. more mobile) than the brine as the wetting fluid. For two-phase fluid system, water is usually taken as the most wetting in either water – oil or water – gas systems whereas oil acts as the wetting phase in oil – gas system. This simplification may be considered true despite the facts that many reservoir rocks are preferentially oil wet.

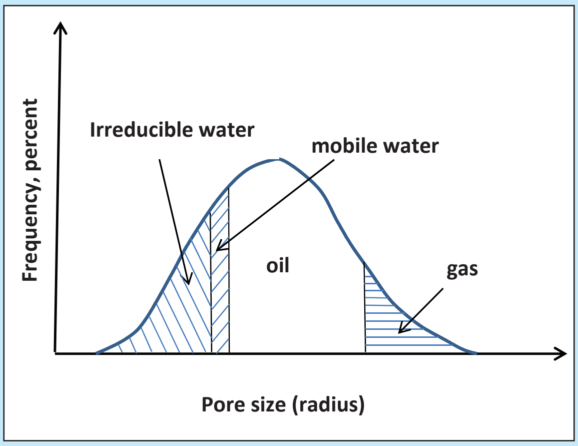

Figure 1
An idealized distribution of the three fluid phases in which the wetting phase water occupies small sizes pores, oil in intermediate-sized pores, and the incoming gas largely in larger pores. When there is no mobile water the system turns into effectively two-phase drainage system.

In 1954, A.T. Corey, as one of the earliest researchers in relative permeability, established a two-phase oil – gas relative permeability equations in porous media modelled on a bundle of tubes. The work was expanded into three-phase relative permeability in Corey et al. (1956). Later these works had been extended in Brooks and Corey (1964) and Johnson (1968) by introducing an empirical factor of λ (lambda) that relates to the intrinsic pore size distribution of the porous media and that is called 'wetting phase saturation parameter'. These two parameters are to play an important part in this study, and serve as the determining factors in the model generation for the sandstones. Some other researchers also offered either alternative or further development models, such as the exponential correlation by Cherichi (1984), fractured rocks by Pruess and Tsang (1990), wettability-incorporating by Huang et al. (1997), the empirical matching LET parameters by Lomeland et al. (2005), and modification of Corey model by Masalmeh et al. (2007). There are also others who have used different approaches for producing relative permeability model, such as Ahmadi (2015) through utilization of artificial intelligence/statistical approach, and Schembre and Kovscek (2003) and Blunt et al. (2013) through the use of X-ray computed tomography (CT) measurements and modeling.

Despite the fairly huge volume of efforts to study and develop models for relative permeability, the Corey et al model is regarded as the standard or classics and is often used for comparison in relative permeability-related studies. Its general robustness and ease in application have given motivation for its use in this study. One important aspect that characterized Corey et al. approach is that same basic methods can be applied to both two-phase and three-phase relative permeability curves. This comes from their comparison of two-phase (oil-gas) and three-phase (oil-gas-water) displacement tests on core samples, from which they concluded that the gas relative permeability curve remains the same regardless two or three phase systems. Furthermore, they also concluded that in an effective displacement of a three-phase system (i.e. gas displacing oil in a sample with irreducible water saturation) there is no oil left leaving water as the only irreducible liquid. In other words, since there is no residual oil left then there is only irreducible water that affects the oil and gas curves. From this simplification, three equations were drawn for normalized water, oil, and gas effective permeabilities (K_w, K_0 and K_g, respectively) of (Standing, 1975)

$$\frac{K_W}{K_W@S_W^*=1} = (S_W^*)^2 \frac{\int_0^{S_W^*} \frac{dS_L^*}{P_C{}^2}}{\int_0^1 \frac{dS_L^*}{P_C{}^2}} \qquad (1)$$

for mobile water,

$$\frac{K_o}{K_o @ S_0^* = 1} = (S_o^*)^2 \frac{\int_{S_w^*}^{S_L^*} \frac{dS_L^*}{P_c^2}}{\int_0^1 \frac{dS_L^*}{P_c^2}} \quad (2)$$

for oil, and

$$\frac{K_g}{K_g @ S_g^* = 1} = (S_g^*)^2 \frac{\int_{S_L^*}^{1} \frac{dS_L^*}{P_c^2}}{\int_0^1 \frac{dS_L^*}{P_c^2}} \quad (3)$$

for gas, where normalized saturations for water (S_w^*), oil (S_o^*), gas (S_g^*), and liquid (S_L^*) are

$$S_w^* = \frac{S_w - S_{wirr}}{1 - S_{wirr}} \; ; \; S_o^* = \frac{S_o}{1 - S_{wirr}} \; : \; S_g^* = \frac{S_g}{1 - S_{wirr}} \; ;$$

and

$$S_L^* = S_w^* + S_o^* = \frac{S_w + S_o - S_{wirr}}{1 - S_{wirr}} = 1 - S_g^* \quad (4)$$

with S_w, S_{wirr}, S_o, S_g, and S_L are water saturation, irreducible water saturation, oil saturation, gas saturation, and liquid saturation, respectively, in fraction. The P_c in Equations (1) through (3) is capillary pressure in psi.

As described further in Standing (1975) the Corey et al. three-phase relative permeability in Equations (1) through (3) can be given solution in expressions of

$$K_{rw} = (S_w^*)^{\frac{2+3\lambda}{\lambda}} \quad (5)$$

$$K_{ro} = K_r^{\circ} (S_o^*)^2 \left((S_L^*)^{\frac{2+\lambda}{\lambda}} - (S_w^*)^{\frac{2+\lambda}{\lambda}} \right) \quad (6)$$

$$K_{rg} = K_r^{\circ} \left(\frac{S_g + S_m - 1}{S_m - S_{wirr}} \right)^2 \left[1 - (1 - S_g^*)^{\frac{2+\lambda}{\lambda}} \right] \quad (7)$$

Lambda (λ) in Equations (1) and (2) is pore distribution index that represents the complexity of rock's pore system, and it can have any dimensionless values above zero. The smaller the index the wider the pore sizes spectrum hence more complex, and in the other hand higher index values relate to more uniform pores. Standing (1975) put that λ values of between 0.5 and 4 represent natural sandstones and limestones. Pore uniformity that conceptually resembles a bundle of tubes may have λ values approaching infinity. Lambda can be determined using capillary pressure data through

$$S_w^* = \left(\frac{P_c}{P_e} \right)^{-\lambda} \quad (8)$$

with P_c and P_e are capillary pressure and pore entry pressure in psi, respectively. Put in logaritmic form, lambda is the recirocal of the slope of log (P_c) vs log (S_w^*) plot. However, in case of absence of capillary pressure data lambda has to be determined using other means.

Permeability ratio (K_r°) in Equations (6) and (7) is basically a normalization factor that converts relative permeability data – both masured and calculated – from basing on intrinsic rock permeability to non-wetting phase fluid maximum effective permeability. For water wet rocks this ratio is between non-wetting phase permeability at irreducible water saturation (K_g@ S_{wirr}) and absolute permeability (K). The use of irreducible water saturation instead of irreducible liquid saturation is again referred to the theory's 'no residual oil' assumption, which leads to the use of to adjust the calculated oil and gas relative permeabilities for the S_{wirr} and not for the residual liquid saturation. In a manner similar to permeability, K_r° is closely related to irreducible wetting-phase saturation (S_{wirr}). Correlation between K_r° and S_{wirr} needs to be established to enable prediction of K_r° from knowledge of S_{wirr}, and consequently therefore correlation between K and S_{wirr} is also needed to produce S_{wirr} when rock permeability is known or assumed. The two correlations are established in this study.

The last parameter in Equations (6) and (7) is the so called 'wetting phase saturation parameter', S_m. This parameter has virtually no physical significance apart from its use for partially controlling the shape of the non-wetting phase relative permeability curve. This parameter's values typically fall around unity, and produces steeper curves for values higher than 1. In the other hand, values of less than 1 shift the curves to the left and yields zero slope at , and starts to yield invalid values when values take place. Careful choice of the most representative values is therefore needed for specific type of rocks. Standing (1975) put that values are usually within 0.9 to 1 range. Different rocks could have it differently, nevertheless, as to be shown in this study.

For the purpose of Corey et al model tests, commercial laboratory measurement reports containing data of 32 sandstone core plug and whole core/full diameter samples taken from 6 oil wells situated in four productive sedimentary basins (North sumatra, Central Sumatra, West Natuna, and Northeast Java basins) in western Indonesia were used. The data contained includes basic parameters (porosity and absolute permeability), and special core analysis data of oil-water-gas drainage relative permeability and wettability (Amott method) measurements. Table (1) presents the wettability test results.

In the gas-oil relative permeability test, the samples were initially fully saturated with synthetic brine, after which the brine saturated samples were flushed with synthetic oil until no longer brine had been expelled. Initial condition for the gas-oil relative permeability test has been obtained with irreducible water saturation in the samples. The samples were then flushed with dehumidified air during which oil and gas volumes expelled were measured and effective permeability to both fluids were calculated (i.e. 'measured' relative permeability). Terminal condition was reached after no longer oil came out from the samples. The gas-liquid relative permeability test followed drainage mechanism but since the flow involved only two fluids – water phase in immobile condition – then the flow mechanism that took place is more two-phase than three-phase system. Effective two-phase or quasi three-phase drainage relative permeability system is the more appropriate term for the process. In this condition the 'mobile water' component in Figure (1) is non-existent, and since water saturation in S_w^* remains S_{wirr} then K_{rw} in Equation (5) remains zero throughout the drainage gas-liquid displacement.

All 32 sandstone samples are of strong water-wet and preferentially water-wet in nature and are actually characterized by a sufficienlly wide

Table 1
Wettability indication for the samples tested for relative permeability data. Samples used for wettability test (Amott test) were in native condition (fresh samples) and taken from adjacent depths. Note that no porosity and permeability data is available for PTB-50 samples

Well	Sample	Porosity (%)	Permea-bility (mD)	Wettability Index		Wettability
				Oil	Brine	
KRA-3X	24	24.5	817	0.0	0.4526	mod. water wet
	25	23.3	5,152	0.0	0.4521	mod. water wet
	49	24.5	617	0.0	0.4655	mod. water wet
PRP-02	1D	25.5	3.9	0.0	0.7692	strong water wet
	3D	11.1	0.5	0.0	0.7059	strong water wet
	5D	28.3	94.7	0.1333	0.3165	pref. water wet
PRP-04	1D	27.5	2.6	0.0	0.4167	mod. water wet
	3D	30.0	9.9	0.0	0.2727	weak water wet
NGL-PA	2	33.7	105	0.0	0.1505	weak water wet
	10	32.9	202	0.0	0.1540	weak water wet
	15	33.7	416	0.0	0.2835	weak water wet
PTB-50	1B	-	-	0.0	0.8979	strong water wet
	2B	-	-	0.0	0.0132	weak water wet
	5B	-	-	0.0	0.8696	strong water wet
	7B	-	-	0.0	0.8966	strong water wet
	8B	-	-	0.0	0.8071	strong water wet
	9B	-	-	0.0	0.9024	strong water wet

range of hydraulic properties. Through lithological description the sandstone samples can be divided into three groups of:

1. **Medium hard – hard conglomeratic sandstones** (15 samples). Light brown to light grey in color and are made of fine grains to very coarse grains, wth some pebbles commonly observed. Grain sorting is commonly poor to medium with grains of angular to subrounded. Slight argillaceus material and carbonate streaks are also seen in some of the somples.

2, **Medium hard micaceous-argillaceous sandtones** (11 samples). Light grey/brown to dark grey in color, with very fine to medium sub-angular to sub-rounded grains. Grain sortings are of poor to medium/well. Impurities in minerals are commonly found mostly in the form of micas and clays/argillaceous minerals. Slight glauconites and carbonate minerals are also found in sveral samples.

1. **Hard sandstones** (6 samples). The sandstones are grey-colored and hard in nature. They are made of very fine to fine grained sub-angular and moderately to well-sorted quartz grains. Slight calcareous and argilaceous materials are also found with some traces of mica in some samples.

On these three groups of water wet sandstones the Corey et al. drainage relative permeability model was applied. All parameters required by Equations (5) through (7) are to be found with the light that there is no laboratory data available to the model's users in the future. A procedure for establishing drainage relative permeability curves – with absence of laboratory measurement data – is therefore needed.

III. RESULTS

Application of Corey et al. drainage gas-oil-water relative permeability model requires all data as shown in Equations (5) through (7). Most crucial is the permeability ratio, K_r°. In a manner shown in Standing (1975), correlation between K_r° and S_{wirr} needs to be established in order to enable determination of K_r° for any predetermined S_{wirr}. All required data for it is available for the 32 core samples. The K_r° - S_{wirr} plot is depicted on Figure (2), from which the following correlation is derived.

$$K_r^\circ = -14.41(S_{wirr})^2 + 3.29\, S_{wirr} + 0.76 \qquad (9)$$

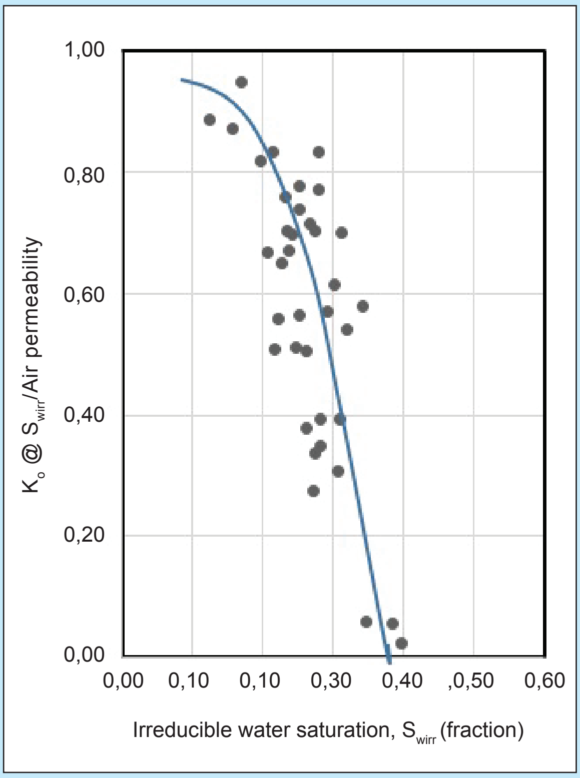

Figure 2
Plot between K_r° (ratio of (K_o @ S_{wirr} / K_{air}) and S_{wirr} for the water wet sandstones used in the study.

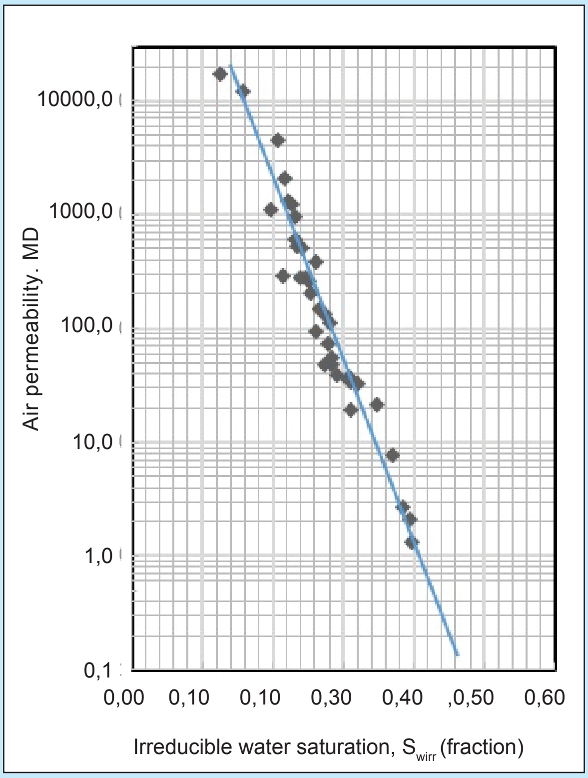

Figure 3
Plot between K_{air} and S_{wirr} for the water wet sandstones used in the study.

However, with more careful examinations the constant of 0.76 in the above general equation are more appropriate as being 0,70, 0.63, 0.65, and 0.72 for conglomeratic sandstones, micaceous-argillacious sandstones (high permeability), micaceous-argillaceous sandstones (low permeability), and hard sandstones, respectively.

With the establishment of Equation (9) K_r° can be determined provided S_{wirr} is known or assumed. As shown in Widarsono (2011), relation between permeability and irreducible water saturation is reciprocal and straightforward. The higher permeability the lower irreducible water saturation, and vice versa. Accordingly, an auxilliary correlation is etablished for the 32 core samples.

$$K = 3 \times 10^6 \, e^{-39.46 * S_{wirr}} \tag{10}$$

The plot between permeability and irreducible water saturation is presented on Figure (3). Any needs for irreducible water saturation data can be obtained whenever permeability of concerned reservoir rocks is known or assumed.

With K_r° and S_{wirr} data available for each sample's data set, calculations were made with sensitivity trials made in S_m until the best fits are obtained between observed/measured and calculated relative permeability data. Table (2) presents an example of calculation showing comparison between observed and calculated relative permeability data. Graphically, three examples are depicted on Figures 4 through 6 for the three sandstone groups. Nonetheless, less satisfactory results are also encountered in the form of too high and too low calculated end points (Figure 7) and too low calculated curve and end point (Figure 8). Despite being minority these occurrences are worth presenting due to their effects to the model validity.

Figures 9 and 10 present comparisons between calculated and measured relative permeability values with the 45° line represent a reference of exact agreement between the two. In general, comparisons on the two figures show fair to good agreements between the two sets of values indicating the effectiveness of the Corey et al drainage three-phase relative permeability model for the sandstone samples used in the

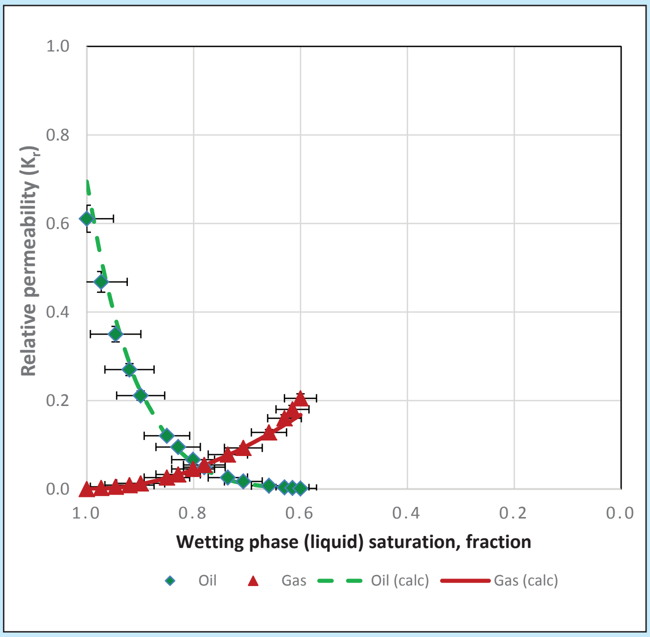

Figure 4
Result of calculated relative permeability (oil, K_{ro}; gas, K_{rg}) curves compared to measured values. Group 2: Med hard micaceous-argillaceous sandstones Well PRP-02, sample 1C, S_m = 1.05 and λ = 0.36.

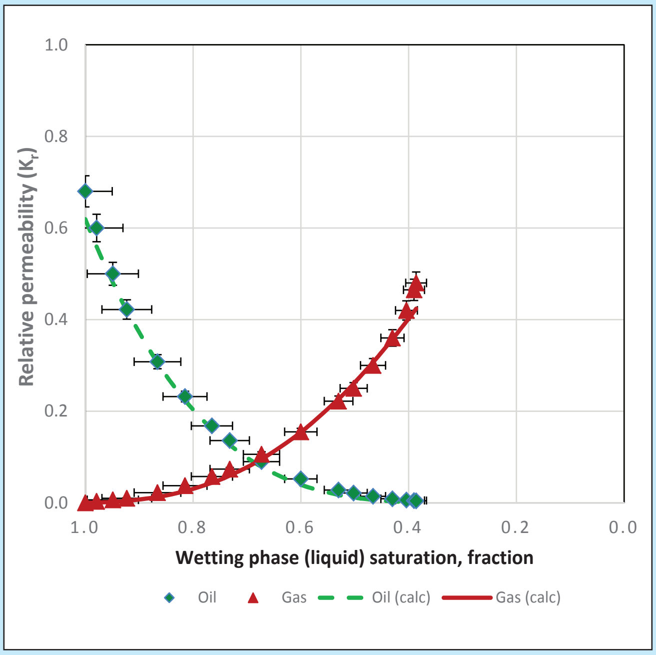

Figure 5
Result of calculated relative permeability (oil, K_{ro}; gas, K_{rg}) curves compared to measured values (with 5% error bars). Group 1: Med hard-hard conglomeratic sandstones, Well KRA-3X sample #12, S_m = 1.1 and λ = 4.0.

Table 2
Example calculation for sample #12 (Group 1: Conglomeratic sandstones) of well KRA-3X, West Natuna basin. Irreducible water saturation (S_{wirr}) is 0.266 and the most appropriate values for S_m and λ that give the best fit are found to be 1.1 and 4.0

Well	Sample	Measured			Calculated							
		S_L (fract)	K_{ro} (fract)	K_{rg} (fract)	S_w^* (fract)	K_{rw} (fract)	$(S_o^*)^2$ (fract)	$(S_L^*)^{\frac{2+\lambda}{\lambda}}$ (fract)	K_{ro} (fract)	$\left(\frac{S_g+S_m-1}{S_m-S_{wirr}}\right)^2$ (fract)	$1-\left(1-S_g^*\right)^{\frac{2+\lambda}{\lambda}}$	K_{rg} (fract)
KRA-3X	12	1.00	0.646	0.000	0.27	0.00	1.00	1.00	0.619	0.014	0.000	0.000
		0.98	0.570	0.003	0.27	0.00	0.94	0.96	0.559	0.021	0.043	0.001
		0.95	0.475	0.007	0.27	0.00	0.87	0.90	0.481	0.033	0.102	0.002
		0.92	0.422	0.010	0.27	0.00	0.80	0.85	0.420	0.045	0.153	0.004
		0.87	0.308	0.022	0.27	0.00	0.67	0.74	0.306	0.079	0.261	0.013
		0.82	0.232	0.038	0.27	0.00	0.56	0.65	0.224	0.117	0.353	0.026
		0.77	0.168	0.058	0.27	0.00	0.46	0.56	0.160	0.161	0.439	0.044
		0.73	0.136	0.074	0.27	0.00	0.40	0.51	0.126	0.195	0.494	0.060
		0.67	0.090	0.106	0.27	0.00	0.31	0.41	0.079	0.262	0.587	0.095
		0.60	0.052	0.155	0.27	0.00	0.21	0.31	0.039	0.359	0.693	0.154
		0.53	0.028	0.222	0.27	0.00	0.13	0.22	0.017	0.467	0.784	0.227
		0.50	0.021	0.250	0.27	0.00	0.10	0.18	0.012	0.514	0.818	0.260
		0.47	0.014	0.300	0.27	0.00	0.07	0.14	0.007	0.578	0.858	0.307
		0.43	0.009	0.360	0.27	0.00	0.05	0.11	0.003	0.645	0.894	0.357
		0.40	0.006	0.399	0.27	0.00	0.04	0.08	0.002	0.696	0.918	0.396
		0.39	0.005	0.442	0.27	0.00	0.03	0.07	0.001	0.725	0.931	0.417
		0.39	0.004	0.456	0.27	0.00	0.03	0.07	0.001	0.733	0.934	0.424

study using the most optimum λ and S_m values. Tables (3) through (5) present most optimum λ and S_m values for individual samples within the three sandstone groups including suggested values to be used in modeling and preparing for relative permeability curves in absence of laboratory measured data.

From the results of drainage two-phase relative permeability model on the three sandstones groups, a procedure for preparing drainage two-phase relative permeability for oil – water system has been established, which is sequentially

1. Determine permeability value(s) for reservoir water-wet (at least preferentially water-wet) sandstones that are considered as being represented by one of the three sandstone groups. The permeability could be pre-set/assumed values or permeability values of core samples that do not have the needed relative permeability data.
2. Determine irreducible water saturation (S_{wirr}) values using regression line on Figure (3) or Equation (10). For broader scales, alternative correlations presented in Widarsono (2011) can also be used.
3. Determine K_r° for the S_{wirr} of concerned using graph on Figure (2) or Equation (9) and its modified constants those belong to the three sandstones groups. From trials, it has been observed that Equation (9) still tends to fail for large values of S_{wirr} (i.e S_{wirr} > 0.35). It is suggested therefore to use K_r° that correlates to S_{wirr} = 0.35 for such high S_{wirr} values.
4. Take the suggested λ and *Sm* values for appropriate sandstone groups in Tables (3) through (5). Suggested values in ranges depict most likely values that may work best for the calculated K_{ro} and K_{rg}.
5. Establish a set of wetting phase (liquid) saturation (S_L) values, and determine normalized water and liquid saturations (S_w^* and S_L^*) using the previously determined S_{wirr} in step 2. Small increments of S_L is advised.
6. Calculate K_{ro} and K_{rg} curves for the liquid saturation values using Equations (6) and (7), respectively.
7. Irreducible liquid saturation - *Swirr* plus

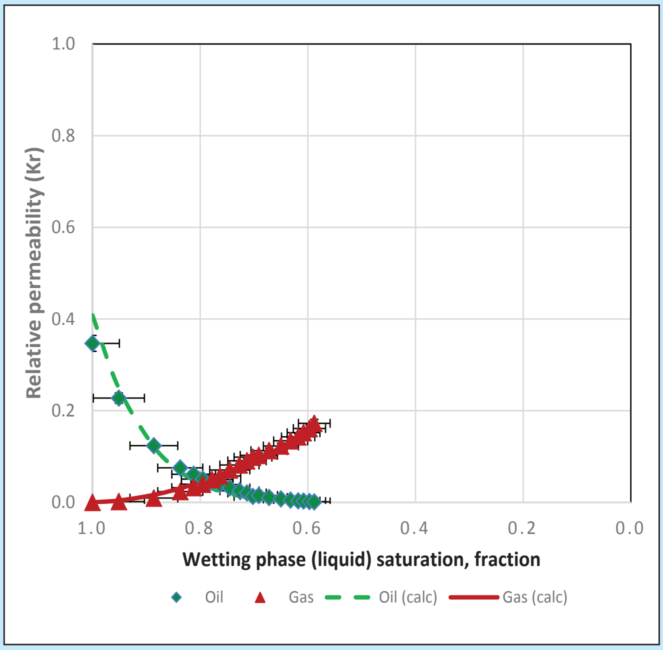

Figure 6
Result of calculated relative permeability (oil, K_{ro}; gas, K_{rg}) curves compared to measured values (with 5% error bars). Group 3: Hard sandstones Well PTB-50, sample #6, S_m = 1.1 and λ = 0.5.

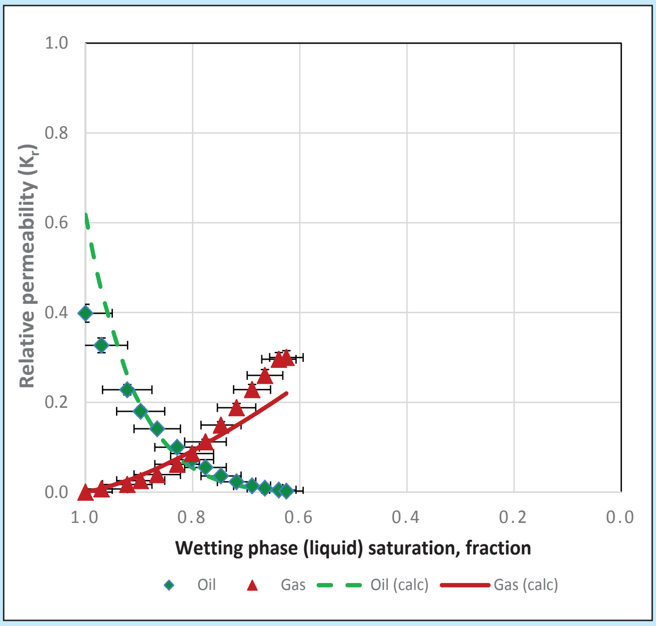

Figure 7
Result of calculated drainage relative permeability (oil, K_{ro}; gas, K_{rg}) curves compared to measured values showing too high calculted end point of K_{rw} curve and far too low end point of calculated curve. Group 2: Micaceous-argillaceous sandstones. Well PRP-02, sample #5C, S_m = 1.22 and λ = 0.43.

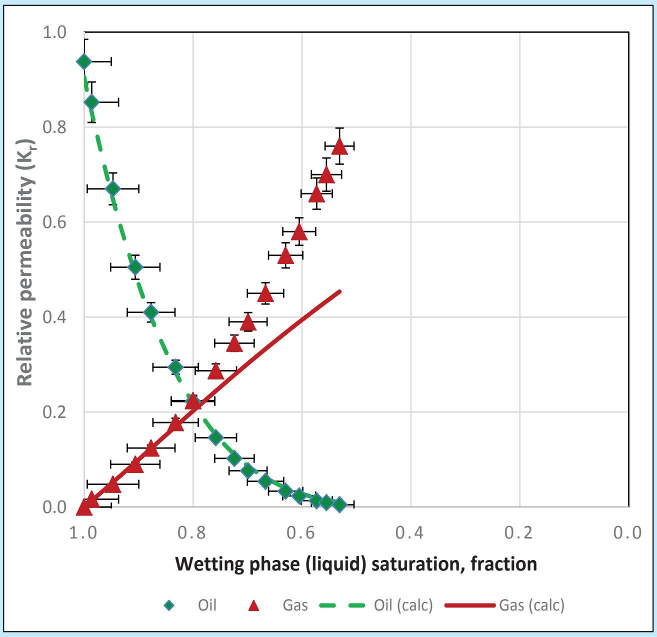

Figure 8
Result of calculated drainage relative permeability (oil, K_{ro}; gas, K_{rg}) curves compared to measured values showing good curve match but too low end point of calculated K_{ro} curve. Group 1: conglomeratic sandstones. Well KRA-3X, sample #4(WC), S_m = 1.4 and λ = 0.78.

$S_o r$ – (i.e. K_{rg} end point) is determined at K_{ro} equal to or approaches zero, with constant S_{wirr} and S_L should not less than S_{wirr}. Adjustments in S_m shall be made to avoid invalid curve.

The established relative permeability curves may not entirely represent sandstones in any reservoir of concerned but they can at least serve as the 'first guess' for populating reservoir model's grid cells or for any other purposes. Interactions with other data and facts (e.g. history matching) may modify the curves into the most representative ones.

IV. DISCUSSIONS

From trials and applications on the three groups of sandstones some issues are worth noting and discussing. First of all is an evidence that the classic Corey et al. drainage three-phase relative permeability model can work for an effective two-phase or quasi three-phase fluid systems, and appear to have worked for the three groups of Indonesian reservoir sandstones. The most notable outcome of the application of this simple and

Table 3
Values of pore size distribution index (λ) and 'wetting phase saturation parameter' (S_m) for Group 1 sandstones. Sample numbers with (WC) code indicate whole core – full diameter samples

Group	Well	Sample No.	Porosity (%)	Permeability (mD)	Lambda (λ)	S_m
Group 1: Medium hard conglomer-atic sandstones	KRA-3X	#25	12.5	17237	0.26	1.34
		#24	20.8	4530	0.53	1.35
		#39	21.8	2100	0.38	1.22
		#74	22.3	1313	0.90	1.14
		#71	22.7	1235	0.78	1.20
		#38	23.2	595	0.20	1.32
		#46	23.4	530	0.76	1.11
		#69	24.1	506	1.90	1.47
		#53	25.3	206	1.25	1.35
		#12	26.6	147	4.00	1.10
		#62	30.9	30.7	1.20	1.20
		#8(WC)	21.4	284	0.42	1.09
		#7(WC)	24.7	278	1.20	1.08
		#9(WC)	23.8	277	0.72	1.24
		#4(WC)	25.2	257	0.78	1.70
	Range				0.26 – 1.90	1.08 -1.70
	Suggested value(s)				0.70 – 1.20	1.10 - 1.30

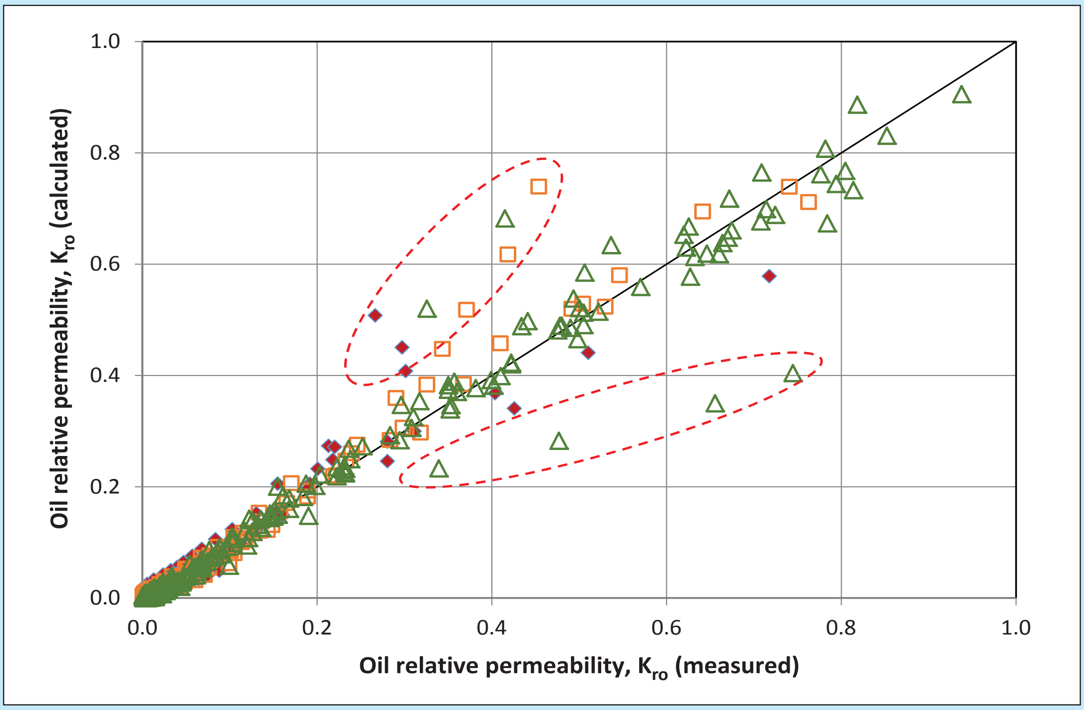

Figure 9
Comparison between masured and caculated oil relative permeability (K_{ro}) values. The 45° line marks complete agreements between the two. Note some significantly lower calculated K_{ro} values in area marked by the dashed envelope.

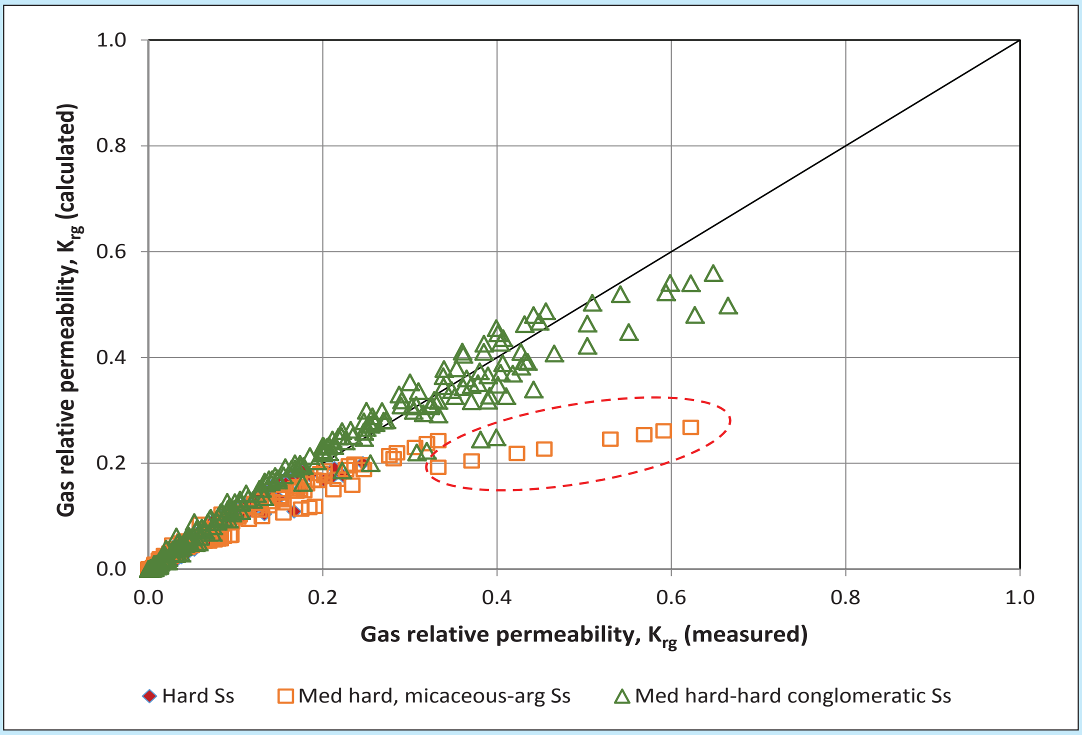

Figure 10
Comparison between measured and caculated gas relative permeability (K_{rg}) values. The 45° line marks complete agreements between the two. Note some higher and lower calculated K_{rg} values in areas marked by the dashed envelopes.

easily applied model is the fairly specific values of pore size distribution index (λ) and wetting phase saturation parameter (S_m) for the three sandstones groups. Fairly specific λ ranges of 0.70-1.20, 0.24-0.40, and 0.50-0.90 are suggested for the medium hard-hard conglomeratic sandstones, medium hard micaceous-argillaceus sandstones, and hard sandstones, respectively.

These values appear to be in line but not exactly within the range of 0.5 – 4 put by Standing (1975) as normally encountered for natural sandstones. This appears true for the three groups even though Group 1 and Group 2 sandstones tend to show lambda values closer to the lower values suggested by Standing (1975), and only one sample in Group 3 that has λ value of 5 (Table 4). This results show that sandstones in the three groups tend to have largely non-uniform pore size distribution. Even when the λ values are related to permeability magnitudes of the rock samples in Tables (3) through (5) no specific differences shown by the samples in the three groups. High, medium, and low permeability values all relate to poor pore size distribution meaning that λ is not the predominant factor in affecting rock permeability.

In his notes on relative permeability Standing (1975) show that the wetting phase saturation parameter (S_m) has no physical significance (i.e. meaning) else than for adjusting the non-wetting phase relative permeability curve – K_{rg} in this case – either to the left or to the right as discussed previously. Standing (1975) put that S_m is usually within the range of 0.9 – 1. However, as shown in Tables (3) through (5) most of S_m values for the 32 samples fall outside of this range, and through thorough trials it has been suggested that the most representative range is 1.0 – 1.4. This range has by and large shown that 1.84 as the highest S_m value, above which no significant upward shift of calculated K_{rg} can longer be expected for matching the obserbed K_{rg} data. On the other hand, S_m values below 1.0 tend to yield theoretically invalid calculated K_{rg} values. The S_m range of 1.0 – 1.4 appears to be the safe guess for S_m.

Equation (9) that is used to estimate K_r° tends to not functioning for large irreducible water saturation (S_{wirr}) of > 0.35. This may be caused by absence of sufficient data. A series of reformulation has been

Table 4
Values of pore size distribution index (λ) and 'wetting phase saturation parameter' (S_m) for Group 2 sandstones. Higher permeability (Higher K) samples are represented by three PRP-02 well's samples (#2C, #6C, and #5C) while the 'Lower K' covers the rest of the samples

Group	Well	Sample No.	Porosity (%)	Permeability (mD)	Lambda (λ)	S_m
Group 2: Med hard-hard micaceous-argillaceous sandstones	**PRP-02**	#2C	19.7	1117	0.18	1.30
		#6C	23.2	972	0.40	1.21
		#5C	26.2	384	0.43	1.40
		#4C	30.7	36	0.25	1.70
		#1C	32.1	19.1	0.80	1.60
	PRP-04	#3A	34.8	21.4	0.35	1.75
		#4A-1	39.8	1.3	0.38	1.65
		#2A	38.4	2.7	0.35	1.84
	NGL-PA	#12	31.0	34.3	0.33	1.65
		#1	26.1	92.4	0.32	1.35
		#5	28.3	47.8	0.36	1.14
	Range				0.18-0.80	1.14-1.84
	Suggested value(s)				0.25-0.40 (lower K)	1.60-1.80 (lower K)
					0.20-0.40 (higher K)	1.20-1.40 (higher K)

Table 5
Values of pore size distribution index (λ) and 'wetting phase saturation parameter' (S_m) for Group 3 sandstones

Group	Well	Sample No.	Porosity (%)	Permeability (mD)	Lambda (λ)	S_m
Group 3:	PTB-50	#1	31.0	34.3	5.00	1.30
Hard sandstones		#2	26.1	92.4	0.40	0.95
		#6	28.3	47.8	0.50	1.10
		#7	27.4	48.8	0.65	1.05
		#8	32.0	32.4	0.94	1.00
		#9	29.1	39.3	0.95	1.25
	Range				0.40-5.00	0.95-1.30
	Suggested value(s)				0.50-0.90	1.00-1.20

performed and resulting K_r° values remain negative leading to negative calculated K_{rg} values. Therefore, for practical purposes it is suggested to use K_r° that correspond to S_{wirr} = 0.35 being used in calculation of K_{rg} in cases of S_{wirr} > 0.35. Adjustments may later be made when there is appropriate production and well testing data available for crosschecking the calculated K_{rg} curves.

Application of three-phase Corey et al. model on the 32 samples in general went well (e.g Figures 4 through 6) indicated by calculation results and measured data that are in good agreement. In cases shown by some samples, nonetheless, calculation results are either too high in K_{ro} and too low for K_{rg} (Figure 7) or too low in K_{ro} (Figure 8). These occurences are also shown in Figures (9) and (10) with data points those deviate from the 45^o lines. This certainly affect the curve's end-points, which have practical implication in reservoir modeling. In these cases no λ and S_m can be used to meet the requirement. (Note that λ and S_m values presented for these samples in Tables 2 through 4 are the best usable ones.) It is probably that these disagreements are related to rock's wettability strength, which is not accommodated in the standard Corey et al. model in a way like one proposed by Huang et al. (1997). However, since wettability data is usually even much scarcer than relative permeability data, hence impractical for field cases with no core measurement data, this potential risk must be faced. Another plausible cause is the averaging effect of the relative scatter (R^2 = 0.61) of K_r° vs S_{wirr} plot shown Figure (2). This is especially related to the mismatch in K_{rg} curves.

One other cause that most probably lies behind the mismatch K_{ro} and K_{rg} curves is the 'no residual oil' assumption. Corey et al. (1956) in their experiment concluded that any possible presence of residual oil in core samples with irreducible water saturation does not affect K_{rg} curves within experimental error. This led to the continuing use of K_r° that is derived from K_r° vs S_{wirr} instead of from K_r° vs irreducible S_L which is essentially S_{wirr} plus residual oil saturasion (S_{or}). In this 'no residual oil' assumption Corey et al. argued that oil that moved earlier to displace mobile water had in its return been displace completely by the incoming gas (i.e. humidified air), which is not neccessarilly correct all the time. This is shown by the data shown by the samples tested for this study that the lowest S_L is always higher than S_{wirr} indicating presence of S_{or}. Attemps have been made to correct and use S_L, instead of S_{wir}, to produce K_r° only to unsatisfactory results due to the very irregular nature of S_{or} in relation to permeability. Therefore, the most practical means to compensate the presence of residual oil is to modify Equation (9) as has been shown earlier to reasonably satisfied results.

Unlike the other two groups Group 1 of medium hard-hard conglomeratic sandstones cover laboratory measurement data for both plug-size and whole core (WC). Modeling using the Corey et al. three-phase relative permeability model on their observed relative permeability data show that in general similar λ and S_m (Table 2) could be in use to yield same curve fitting results. This shows that sample size probably gives only very limited influence to the modeling, and it is the intrinsic pore-scale properties that plays the most important role.

IV. CONCLUSIONS

From the quasi drainage three-phase relative permeability study on 32 sandstones core samples some conclusions have been drawn. First conclusion that can be regarded as very important is that the standard Corey et al. three-phase relative permeability model can still be reliably used to model drainage effective two-phase (quasi three-phase) relative permeability of any sedimentary rocks including Indonesian reservoir sandstones despite geological differences compared to the usually much older reservoir rocks in the Western hemisphere.

Using the Corey et al. model that have been validated through its application on three types of sandstones, with different λ and S_m parameters, a quasi three-phase relative permeability model has been made available for Indonesian water-wet sandstones in absence of any core laboratory measuremnets. One only has to chooce the most appropriate sandstone type for his/her case and use the corresponding λ and S_m values to establish the needed drainage quasi three-phase relative permeability curves. Only permeability data is needed – whether being assumed or belongs to a specific core samples – to begin with the relative permeability calculation. Caution, however, has to be taken for cases with very low permeability and high irreducible water saturation.

Magnitudes of pore size distribution index (λ) values for the three sandstones groups appear to show consistency in its relation with permeability, in which there is there is no regularity between the two rock properties. All samples reveal consistently low despite their wide range of permeability. High permeability sandstone samples in Groups 1 and 2 mostly exhibit λ values of lower than unity indicating non-uniform pore sizes and the very similar λ values are also shown by the lower permeability samples in the three groups. Although the magnitudes are somewhat different to what Standing (1975) put, but the consistency of λ proves its important role to indicate rock's pore heterogeneity hence influencing shapes of calculated relative permeability curves.

In a manner different to λ the wetting phase saturation parameter, S_m , tend to exhibit consistency of greater than one for the three sandstones groups. This certainly provide the much needed simplicity and confidence in attempts to establish relative permeability curves under the 'no data' condition. The range is clearly different to what Standing (1975) had put (= 0.9 – 1.1), and this is most likely due to the relative difference in geological histories between different`geological domains.

ACKNOWLEDGEMENT

The author would like to express his gratitude to LEMIGAS Core Laboratory for allowing the use of its data archive for this study.

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