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Estimated original oil in place variation due to porosity determination technique

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ABSTRACT

Original oil in place underpins field appraisal, development, and management and at early appraisal stage, static volumetric technique had been used for estimation. One of the key variables in this technique is porosity; therefore the technique use for porosity determination will influence the estimated original oil in place magnitude. The evaluations of zone-average porosity in the net-pay intervals in a single well have accuracy of approximately 5 to 25 % of total porosity. This is largely the result of systematic uncertainty. Through this research paper, it is inferred that, the effect of averaging the porosity is more imminent on an inter-bedded reservoir rather than a clean sand reservoir. This is because the averaging effect is not accounting the porosity changes in smaller scale, as it is wrongly assumed; changes in smaller area of reservoir are negligible. This fundamental approach is proven to be incorrect. Though in clean sand this averaging method is still applicable, it is proven that an averaging method is not suitable to be used in a laminar or inter-bedded reservoir. The difference that may be introduced is almost 25% of the original oil in place, which may affect the economic model as the potentially producible and sub-economic field or discovery.

1. Introduction

Petroleum reserve or original oil in place estimation underpins field appraisal, development, and management. At the early stages of field development, static volumetric techniques form the basis for estimates of hydrocarbons in place and then ultimate recovery. Petrophysical properties play important role in this critical path through the evaluation of reservoir size, net-to-gross pay, porosity, and hydrocarbon saturation. Therefore one of the key parameter that is being used in the oil and gas industry for calculation of initial hydrocarbon in place is porosity. This indicates that any error on porosity will directly translate into error in original oil in place (OOIP) which is the key parameter in determining the viability of oil and gas prospect.

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A lot of efforts have been made to estimate porosity by correcting the algorithms with considering various parameters impact [1-6]. Some of the method increase the complexity of the estimation and introduce additional uncertainties into the calculation. This calculation method has also made it a bit difficult to have a very handy tool for generating quick porosity estimates. It is a fact that, over light hydrocarbon or gas, the density log porosity estimation is usually too high while neutron value is reads out too low. Thus averaging will compensate for their respective flaws. The porosity can easily be calculated from density logs based on the direct relationship between total or bulk density and the matrix/pore filled volume, if the actual densities of the two materials (matrix and fluid) are known [7].

The evaluations of zone-average porosity in the net-pay intervals in a single well that has accuracy of approximately ± 5.0% bulk volume or total porosity as the result of systematic uncertainty because the random uncertainties. Where core control is not available, these accuracy estimates should probably be doubled. The porosity accuracy in very shaly sands is also more uncertainties because of the associated shale volume where it affects the pay zone estimation. There are many similar study cases about effect of porosity calculation on OOIP determination. However, the study is limited to porosity determination from neutron and density porosity against core porosity [7] though there are many other new methods, such as NMR (Nuclear Magnetic Resonance) [8-10] is available. In most available data, the rock or reservoir volume was not provided and quantification of uncertainties is not easy. Hence, constant reservoir volume and water saturation, Sw were used to calculate the original oil in place (OOIP). Therefore, this paper focused on addressing the effect of porosity determination technique on the original oil in place estimation.

1.1 Oil in Place

Oil in place is the total hydrocarbon content of an oil reservoir and is often abbreviated STOOIP, which stands for Stock Tank Original Oil In Place, or STOIIP for Stock Tank Oil Initially In Place, referring to the oil in place before the commencement of production. Calculating oil or gas in place from petrophysical analysis results is a simple matter of calculating volumes from reservoir thickness, porosity, and water saturation. The original oil-in place (OOIP) volumetric calculations are as expressed in

$$OOIP(m^3) = \text{Rock Volume} \times \varphi \times (1-S_w) \times (1/B_0) \quad (1)$$

where φ = the porosity, S_w = the water saturation and B_o = the oil formation volume factor.

1.2 Porosity

Porosity is the ratio of the void to the bulk volume of the rock and is a measure of the space available for commercial fluids storage within a reservoir rock. Therefore porosity is one of the most important reservoirs properties because it shows a potential storage volume for hydrocarbons.

The porosity of a permeable medium is a strong function of the local pore or grain size distribution, and a weak function of the average pore size. For sandstones the porosity is usually determined by the sedimentological processes under which the medium was originally deposited. For carbonate, the porosity is mainly the result of changes that took place after deposition. Therefore, carbonate rocks are heterogeneous and poses significant challenges to data acquisition, petrophysical properties estimation and reservoir analysis [6]. The porosity can be divided into an interconnected or effective porosity that is available to fluid flow and a disconnected porosity that is unavailable to fluid flow. At the other end of the flow scale is the fracture porosity that expresses the volume fraction of a particular medium that is tied up in large scale voids [11].

Based on geological origin, porosity categorized as primary (depositional, original) or secondary (post-depositional, induced). The former is developed during the deposition of the sedimentary material and the latter porosity develops by geological processes subsequent to original deposition. Based on pores connectivity, porosity categorized as total or effective. Total sum of effective porosity and clay bound water is defined as total porosity, which includes all voids space regardless if the pores are connected or isolated. This void includes any hydrocarbon fluids, mobile water, capillary bound water and clay-bound water [12].

By definition, an effective porosity must be less than the total porosity. For the majority of reservoirs, particularly sandstone, the difference between effective and total porosity is small. However, in some formations, such as those containing significant quantities of sponge spicules, dolomitised carbonates in which much of the porosity may be composed of vugs, or oomoldic limestones, the difference can be very significant. Connected porosity is not necessarily very efficient at transmitting fluids through the formation. For example, vugs can be connected but the connecting pore throats may be so small that flow through them will be difficult.

Although porosity is a very important parameter in the evaluation of a formation but it cannot be measured directly. All the measurement techniques determine some other property, which then must be converted to reservoir porosity. Core measurements determine sample volumes in an environment that is not the same as the reservoir. Logs record some property of the formation such as bulk density, which is then related to porosity by some model of tool response. The indirect nature of the measurements leads to many of the problems with comparisons of porosity. When considering the techniques used to determine reservoir porosity the inclusion or exclusion of clay bound water volume becomes important as the different measurement methods treat it in different ways. The porosity assessment techniques are summarized as shown in Figure 1.

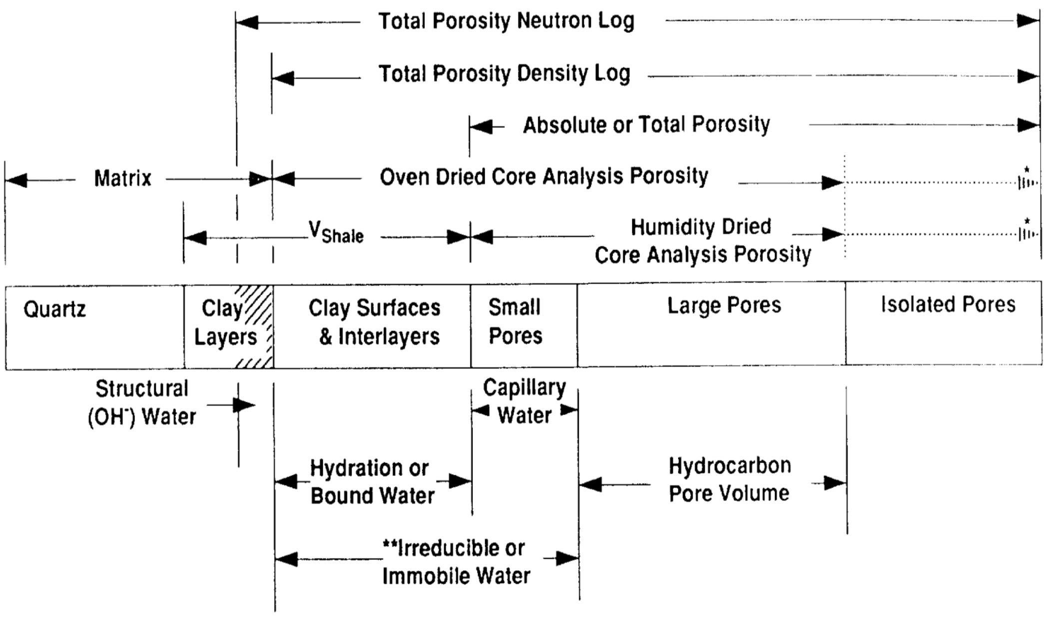

Fig. 1. Pore system relating mineralogy, water content and porosity assessment [13]

Measurement of porosity in the core analysis laboratory essentially consists of taking a sample from the core, extracting the fluids from it and then determining the pore volume, grain volume and bulk volume of the sample. When examining a core analysis report, it is unlikely that any term other than simply porosity will be encountered. The term porosity normally refers to the pore space that can be contacted in the particular technique being used (typically gas injection porosity or fluid re-saturation) or generally refer as an effective porosity.

The porosity of a zone can be estimated either from a single “porosity log” (sonic, density, neutron, or magnetic resonance log) or a combination of porosity logs, in order to correct for variable lithology effects in complex reservoirs. When using a single porosity log, the true porosity is calculated from interpolation between the values for the matrix mineral and the pore fluid; usually equated with mud filtrate, because of the shallow investigation of the porosity tools. The neutron and density logs are responses to pores of all sizes. However, field observation over many years has shown that the sonic log is a measure of inter-particle (inter-granular and inter-crystalline) porosity but is largely insensitivity to either fractures or vugs. This discrimination can be explained largely by the way that the sonic tool measures transit time by recording the first arrival waveform which often corresponds to a route in the borehole wall free of fractures or vugs. When sonic porosities are compared with neutron and density porosities, the total porosity can be subdivided between “primary porosity” (inter-particle porosity) recorded by the sonic log and “secondary porosity” (vugs and/or fractures) computed as the difference between the sonic porosity and the neutron and/or density porosity. Typically, moderate values in secondary porosity are caused by vugs, because fracture porosity does not usually exceed 1 to 2% by volume [14].

While the neutron and density logs are sensitive to all pore sizes, the sonic log porosity does not reflect all the oomoldic pores. The distinction is commercially important because much of the oomolds are poorly connected vuggy pores that cause an increase in resistivity such that water-saturated oomoldic zones can look to be promising hydrocarbon shows and be confused with real oomoldic oil and gas producers. This has been enough of a problem to encourage the specific use of Electromagnetic Propagation Tool (EPT) logging in some wells. The type of porosity logs and their attributes are tabulated (Table 1).

Table 1
Summary of various porosity tools [14]

Attributes	Types of porosity log			
	Density	**Neutron**	**Sonic**	**NMR**
Basic principle	Gamma ray attenuation	“Slowed” neutrons or Gamma ray capture	Transit times	Excitation of hydrogen in pore spaces
Required data	Matrix and fluid densities	Calibration	Matrix and fluid transit times	Hydrogen index
Advantage	Little effect of gas presence in formation	Ability to detect presence of gas in formation; can be used in cased hole	Good compensation for environmental effects; combinable with induction logs	Lithology independent
Disadvantage	Shallow investigation depth; affected by wellbore washouts	Sensitive to irregular borehole; requires calibration	Investigation depth dependent on type of formation	Environmental corrections; tool run speed affects results

3. Methodology

The execution of the study is shown step by step as highlighted in Figure 2. Neutron logs were used to identify the delineation of porous formation and to determine their porosity, while density logs was used to calculate the total porosity of a zone. The neutron and density logs data was studied and interpreted to identify the possible pay zone. The both reading was then averaged. Any indication with a possible 'show' present was shortlisted for more detail study. The porosity of this shortlisted zone was then calculated by using neutron-density method and cross checked with core sample data available.

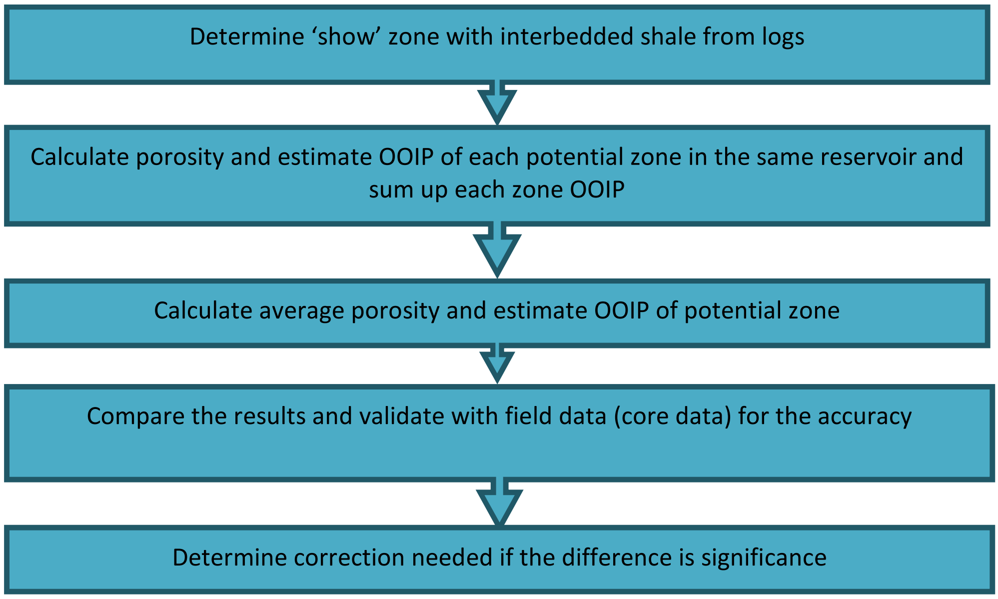

Fig. 2. Methodology flow diagrams

The zones porosity reading were averaged and compared with the core sample reading and average of standard deviation was identified. The differences in zone by zone method were compared to average porosity method by applying those porosity values into OOIP calculation. Later, the discrepancies were studied for improvement in averaging or zone by zone calculations.

3. Results and Discussions

3.1 Studied Well Interpretations

Six wells with seven formation types had been investigated as shown in Table 2.

3.2 Porosity Comparison

The core sample porosity was taken from the laboratory work as control and compared to the logs reading that was interpreted. This is done to ensure that there were no misinterpretation or calculation error was induced on the interpreted logs reading. The porosity difference was calculated, as shown in Table 3 and Figure 3. From the table 3 and figure 5, it is clearly seen that the differences between the core sample and the logs reading mean is less than 5%. Though at some formation the percentage of differences is larger than 5% due to presences of inter-bedded layer where some of the interbedded can be smaller than the resolution of the equipment used for interpretation. There are very few conventional wireline logs that can resolve below 10cm without special inversion–processing methods [15].

However, there is also a need to understand that it is still arguable fact that the access to whole core from the reservoir is intact and undamaged. The question of the degree direct measurement is to be trusted even if the core sample is recovered with a great care. One may profess that all cores are damaged by the coring process, thus no accurate assessment of porosity is possible by coring.

However, X-ray computerized tomography scans, thin sections, and scanning electron microscope examination can verify that grain contacts are unmoved, antigenic pore linings are undamaged, and heavy-weight drilling fluids and/or particles are absent.

Table 2
Wells reservoir summaries

Well	Formation	Total depth (mMRDT)	Total thickness (m)	Reservoir zone thickness (m)	Core sample porosity (%)	Average porosity (%)	Average water saturation (%)	Log zone by zone porosity (%)	Zonal water saturation (%)	Remarks
1	A	3253.0	237.8	141.6	17.1	16.2	98.3	18.4	99.7	Water
				96.2	Na			14.1	96.8	Water
1	B	-	23.3	9.6	15.4	13.8	52.5	14.6	19.8	Oil
				13.7	13.4			12.8	85.2	Residual
										oil
2	C	2470.0	166.6	24	27.8	23.65	58.5	29.4	79.5	Residual
				154.6	16.9			17.9	37.5	oil
										Oil
2	D	-	314.2	143.3	24	21.6	67.45	23.6	49.9	Oil
				171.2	Na			19.6	85	Water
3	D	2149.1	93.2	22.9	39.2	31.8	35	38.8	55.8	Oil
				70.3	23.4			24.8	14.2	Oil
4	A	2514.0	260.7	12	Na	32.8	46.23	47	42.7	Oil
				226	33.7			37.9	38	Oil
				22.7	13.6			13.5	58	Oil
5	E	2739.0	294.1	111.1	20.6	21.05	29.75	21.2	19.6	Oil
				183	17.5			20.9	39.9	Oil
6	F	2905.0	130.7	42.8	23.8	23.55	52	24.8	87	Oil
				87.9	Na			22.3	17	Oil
6	G	-	129.2	63.9	29.2			24.8	10.9	Oil
				35.2	15.8	15.7	34.67	16.6	81.4	Residual
				30.1	Na			17.2	98.1	oil
										Water

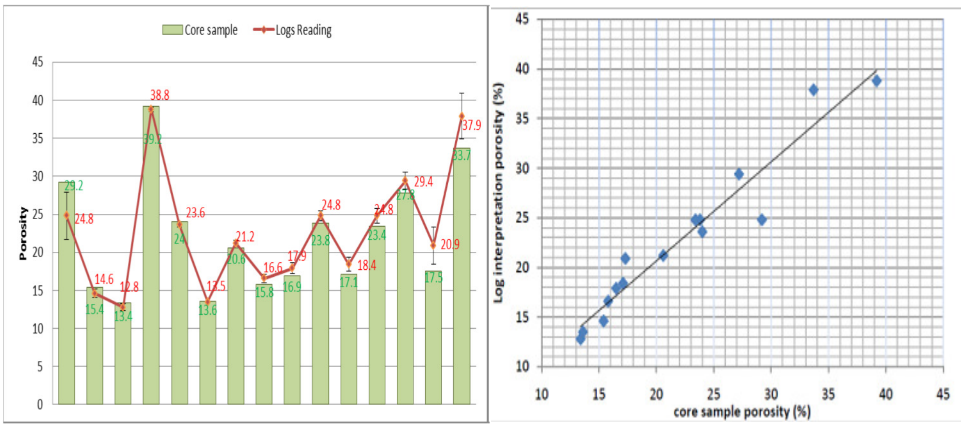

Fig. 3. Core sample and logs interpretation porosity comparison

3.3 OOIP Estimation

The OOIP calculation using Equation (1) is done using the data collected and interpreted. For the entire reservoir, the gross rock area of 10000 m^3 is used. This is to ensure that the differences in OOIP calculation are not being affected by the rock area. However, the interpreted reservoir height is used for each formation, where for the averaging OOIP calculation, the cumulative height of the reservoir is used while for zonal OOIP calculation, and respective reservoir height was used. The shrinkage, $1/B_o$ equal to 1 is used as this research paper is only concentrating on the effect of porosity and water saturation on the oil in place. Table 4 showed the original oil in place calculation for each studied formation.

Table 3
Core sample porosity and interpreted logs porosity summaries

Well	Formation	Core sample porosity (%)	Zonal porosity (logs interpretation) (%)	Porosity differences (%)
1	A	17.1	18.4	-1.3
		N/A	14.1	N/A
	B	15.4	14.6	0.8
		13.4	12.8	0.6
2	C	27.8	29.4	-1.6
		16.9	17.9	-1.0
	D	24	23.6	0.4
		N/A	19.6	N/A
3	D	39.2	38.8	0.4
		23.4	24.8	-1.4
4	A	N/A	47	N/A
		33.7	37.9	-4.2
		13.6	13.5	0.1
5	E	20.6	21.2	-0.6
		17.5	20.9	-3.4
6	F	23.8	24.8	-1.0
		N/A	22.3	N/A
	G	29.2	24.8	4.4
		15.8	16.6	-0.8
		N/A	17.2	N/A

*N/A: Not available (No successful recovery were made)

3.4 OOIP Variation

The calculated OOIP for all the six wells is summarized in Table 5 and Figure 4. The differences then are closely studied to determine the reason of the differences. From the table 5 and figure 4, it is established that well-1 and well-4 in an A formation has the largest percentage of difference while well-2 and well-3 in D formation has the least percentage of differences. The differences of these two reservoirs were studied closely and the characteristic of these two formations is compared.

The detailed study of the A formation and D formation have indicated that the effect of averaging porosity is not huge in D formation since D formation is almost clean sand whilst, the A formation is an interbedded formation (laminar sand). In the A formation, the reservoir primarily consists of thinly bedded shales, siltstones and sand beds. This create the classical low-porosity, low resistivity predicament where quantification of the hydrocarbon saturations and net-to-gross become problematic. When the reservoir is porosity averaged across shale and sand lamina, the element of reserve estimation becomes less significant and efficient.

Table 4
OOIP calculation for all wells

1	A	Average	237.8	98.3	10000	2378000	16.2	0.017	654901.2	0.654
		Zonal	141.6	99.7	10000	1416000	18.4	0.003	78163.2	0.512
			96.2	96.8	10000	962000	14.1	0.032	434054.4	
	B	Average	23.3	52.5	10000	233000	13.8	0.475	1527315	1.527
		Zonal	9.6	19.8	10000	96000	14.6	0.802	1124083	1.384
			13.7	85.2	10000	137000	12.8	0.148	259532.8	
2	C	Average	166.6	58.5	10000	1666000	23.65	0.415	16351374	16.351
		Zonal	24	79.5	10000	240000	29.4	0.205	1446480	18.742
			154.6	37.5	10000	1546000	17.9	0.625	17295875	
	D	Average	314.2	67.45	10000	3142000	21.6	0.326	22090774	22.090
		Zonal	143.3	49.9	10000	1433000	23.6	0.501	16943219	21.976
			171.2	85	10000	1712000	19.6	0.150	5033280	
3	D	Average	93.2	35	10000	932000	31.8	0.650	19264440	19.264
		Zonal	22.9	55.8	10000	229000	38.8	0.442	3927258	18.885
			70.3	14.2	10000	703000	24.8	0.858	14958715	
4	A	Average	260.7	46.23	10000	2607000	32.8	0.314	45975661	45.975
		Zonal	12	42.7	10000	120000	47	0.573	3231720	57.624
			226	38	10000	2260000	37.9	0.620	53105480	
			22.7	58	10000	227000	13.5	0.420	1287090	
5	E	Average	294.1	29.75	10000	2941000	21.05	0.703	43490405	43.490
		Zonal	111.1	19.6	10000	1111000	21.2	0.804	18936773	41.923
			183	39.9	10000	1830000	20.9	0.601	22986447	
6	F	Average	130.7	52	10000	1307000	23.55	0.480	14774328	14.774
		Zonal	42.8	87	10000	428000	24.8	0.130	1379872	17.649
			87.9	17	10000	879000	22.3	0.830	16269411	
	G	Average	129.2	34.67	10000	1292000	15.7	0.653	13252475	13.252
		Zonal	63.9	10.9	10000	639000	24.8	0.891	14119855	15.305
			35.2	81.4	10000	352000	16.6	0.186	1086835	
			30.1	98.1	10000	301000	17.2	0.019	98366.8	

Thus, it is inferred that, the effect of averaging the porosity is more imminent in an inter-bedded reservoir rather than a clean sand reservoir. This is because the averaging effect is not accounting the porosity changes in smaller scale, with the wrong assumption of changes in smaller area of reservoir is negligible. This fundamental approach is proven to be incorrect. Though in clean sand this averaging method is still applicable, it is not accurate to use this averaging method in a laminar or inter-bedded reservoir. The difference that may be introduced is almost 25% of the OOIP, which may affect the economic model as this may affect the potentially producible and sub-economic field or discovery. This averaging porosity methodology and the exceedance probability that may be encountered in an inter-bedded reservoir however, can also be reduced using Monte-Carlo probabilities assessment [16].

Table 5
OOIP variation summary for wells

Well	Formation	Average (Million m^3)	Zonal (Million m^3)	Differences (%)
1	A	0.655	0.512	-21.787
	B	1.527	1.384	-9.409
2	C	16.351	18.742	14.623
	D	22.091	21.976	-0.517
3	D	19.264	18.886	-1.965
4	A	45.975	57.624	25.337
5	E	43.490	41.923	-3.604
6	F	14.774	17.649	19.459
	G	13.252	15.305	15.488

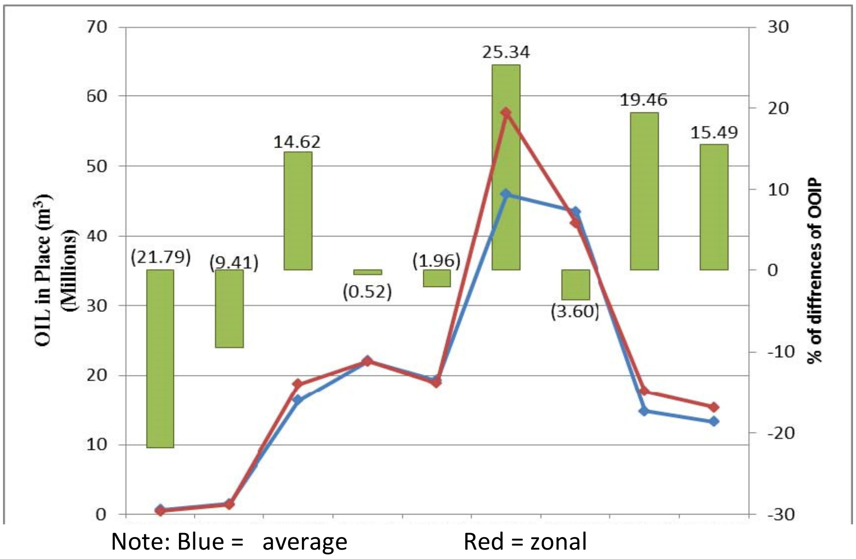

Fig. 4. Original oil in place variation

4. Conclusions

Variation of original oil in place due to porosity estimation technique was studied. It is concluded that original oil in place estimation is significantly influenced by technique used for porosity determination in an interbedded reservoir as compared with a clean sand reservoir. An averaging porosity technique may introduce over or underestimate of original oil in place that may be encountered in an inter-bedded reservoir and this error can be reduced using zonal porosity calculation. The uncertainty of hydrocarbon in place estimation is usually due to uncertainty in average porosity. The averaging of petrophysical properties uncertainty (net to gross ratio, porosity and water saturation) can be reduced by using zonal porosity concept.

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