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UPSCALING OF PERMEABILITY AND POROSITY FOR A SANDSTONE AND A CARBONATE RESERVOIRS

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Abstract. Various upscaling techniques are used to reduce the number of grid blocks in geologic models to produce simulation models. Nevertheless, the number of grid blocks still amounts to hundreds of thousands of grid blocks, thereby incurring high computing costs. Some upscaling techniques require major programming changes to a simulator. The main objective of this study is to reduce the number of grid blocks in a reservoir simulator by using simple averaging methods on porosity and permeability. Since porosity and permeability proportionally are related, the effects of using different averaging techniques on the two properties were investigated. In this study, the black oil, three-phase-three-dimension option of the Eclipse simulator was used. The reservoirs simulated were a heterogeneous sandstone model that consisted of 43,200 grid blocks (60X40X18) and a heterogeneous carbonate model (60X22X16) with dead oil as the reservoir fluid system. Simulation was repeated on the sandstone model using live oil system. The optimum number of grid blocks was defined as the minimum number of grid blocks that produced errors less than 10% in field oil rate, field gas rate, field water cut, field average pressure and field gas-oil ratio. Sensitivity analysis was conducted to find the optimum condition and two averaging techniques were tested, arithmetic averaging and geometric averaging. For both techniques, permeability showed more influence than porosity. The analysis also shows that geometric averaged permeability and arithmetic averaged porosity gave smaller errors. The optimized sandstone model was 15X40X18, a reduction of 75% from the original model, with 3.48% error. The carbonate model managed to achieve up to 50% reduction (30X22X16) with 3.89% error. Simulation using live oil also resulted in the same number of grid blocks for sandstone but caused a higher error that is 5.1%.

Keywords: Upscaling; grid block; reservoir simulation

Abstrak. Pelbagai teknik penaikan skala digunakan untuk mengurangkan bilangan blok jejaring pada model-model geologi untuk menghasilkan model-model penyelakuan. Namun, bilangan blok jejaring masih berjumlah ratusan ribu blok jejaring, dengan demikian menyebabkan kos perhitungan yang tinggi. Beberapa teknik penaikan skala menghendaki perubahan pengaturcaraan yang besar pada penyelaku. Matlamat utama kajian ini ialah untuk mengurangkan bilangan blok jejaring dalam penyelaku reserbor dengan menggunakan kaedah-kaedah pemurataan sederhana pada keliangan dan ketertelapan. Disebabkan keliangan dan ketertelapan berhubungan secara perkadaran langsung, kesan-kesan penggunaan teknik pemurataan yang berbeza pada kedua sifat itu disiasati. Dalam kajian ini, pilihan minyak hitam, tiga-fasa-tiga-matra penyelaku Eclipse digunakan. Reserbor yang diselakukan ialah model batupasir tak homogen yang terdiri daripada 43,200 blok jejaring (60X40X18) dan

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model karbonat majmuk (60X22X16) dengan minyak mati sebagai sistem bendalir reserbor. Penyelakuan diulangi pada model batupasir dengan menggunakan sistem minyak hidup. Bilangan optimum blok jejaring telah ditakrifkan sebagai bilangan minimum blok jejaring yang menghasilkan kesilapan kurang daripada 10% ke atas kadar pengeluaran minyak lapangan, kadar pengeluaran gas lapangan, potongan air lapangan, tekanan purata lapangan dan nisbah gas-minyak lapangan. Analisis kepekaan dilakukan untuk menemukan keadaan optimum dan dua teknik pemurataan diuji, pemurataan aritmetik dan pemurataan geometrik. Bagi kedua-dua teknik, ketertelapan mempertunjukkan pengaruh yang lebih besar daripada keliangan. Analisis itu juga mempertunjukkan bahawa ketertelapan yang dipuratakan secara geometrik dan keliangan yang dipuratakan secara aritmetik memberikan kesilapan-kesilapan yang lebih kecil. Model batupasir yang dioptimumkan ialah 15X40X18, pengurangan 75% daripada model asal, dengan kesilapan 3.48%. Model karbonat memberikan pengurangan sehingga 50% (30X22X16) dengan kesilapan 3.89%. Penyelakuan menggunakan minyak hidup juga menghasilkan bilangan blok jejaring yang sama bagi batupasir tetapi menyebabkan kesilapan yang lebih tinggi iaitu 5.1%.

Kata kunci: Penaikan skala; blok jejaring; penyelakuan reserbor

1.0 INTRODUCTION

Reservoir simulation has become indispensable and more sophisticated than ever in oil and gas industry. With the increased resolution in reservoir characterisation, efficient and accurate upscaling techniques are crucial to transforming a detailed geologic model (mm scale) to a coarser-grid simulation model so that the fluid flow behaviours in the two systems are the same. Accurate upscaling consists of gridding and averaging. Gridding intends to capture the global geologic features of a geologic model, and averaging focuses on preserving the local geologic details within a coarse grid block. Even with the presence of increasingly fast computers, upscaling is still necessary to allow full field simulation to be completed within a reasonable time.

According to Tchelapi *et al.*, [1], a coarser model may be used to study various aspects of reservoir performance without compromising the results provided one actual fine model is used as the basis for comparison. One geostatistical study has shown that a coarser model can preserve heterogeneity and maintain the general behaviour of a reservoir. This study treated the heterogeneity as variations of permeability and porosity and therefore, averaging of these properties would affect the characteristics of the original model. The challenge was to minimize the effects.

A similar attempt was made in 1993 by Quandalle [2]. According to him, in the 8th SPE Comparative Solution Project 1993, the participants were asked to reduce the number of grid blocks as much as possible using flexible gridding technique, while respecting the two following constraints on both producers, that is, the gas breakthrough time predicted with the flexible grid model had to match within 10% the breakthrough time of the 10X10X4 grid model; at the time that the 10X10X4 grid model reached a gas oil ratio (GOR) value of 10,000 SCF/STB the flexible grid model had to predict a GOR within 10% of the 10,000 SCF/STB. In this study, the tolerance was also chosen to be 10%.

Hagedorn *et al*., [3] applied locally refined gridding approach to optimize the number of grid blocks. This approach put more emphasis on area in the vicinity of the wells by assigning smaller grid blocks to this area, while coarser gridding was applied to other areas. The advantage of locally refined gridding approach is that the variability of the rock properties can be handled more efficiently. However this model did not necessarily have the least number of grid blocks.

Christie and Blunt [4] reported that in the Tenth SPE Comparative Solution Project 2001, GeoQuest used single-phase upscaling in which porosity was averaged with the usual volume-weighted arithmetic average and permeability upscaled using arithmetic-harmonic method, harmonic-arithmetic method and power averaging (with power = 10^6 to extract maximum permeability). The outcome was a grid block reduction of 68%. Other companies (Landmark, Phillips and Coats) which applied pseudo method (flow based, regression based for relative permeability) could achieve up to 95% reduction.

In this study, permeability and porosity variation were studied since heterogeneity of a reservoir is mainly caused by these two properties. Permeability also has a proportional relationship with porosity. Therefore, the question of whether reservoir behaviour will be affected if the two properties were averaged differently was of interest. Sensitivity analysis was performed to study how influential the two properties were on the output parameters, that is, field oil rate, field water cut and field average pressure. Two simple averaging techniques – arithmetic and geometric – were applied. Due to their simplicity, no major changes to a simulator are necessary. Details of the reservoir model studied are provided in Appendix A.

2.0 STATIC UPSCALING

Two main methods of upscaling are available. Dynamic scaling involved the use of pseudofunctions that usually average relative permeabilities, and static method that average absolute permeabilities and other rock properties. Since pseudofunctions are valid for only the conditions of reservoir flow that were used in the derivations, any change to the reservoir flow condition may cause significant errors. Furthermore, properties such as absolute permeability and porosity are also averaged when pseudofunctions are used. Consequently, this work considers only the averaging of static properties.

Averaging [5], one of the key components of upscaling, calculates the effective properties for a course simulation grid that preserve fine-grid fluid flow dynamics (including pressure and flow rate) within the coarse grid block. When the rock properties are uniform and the variations are small at a certain distance, the distribution of these properties is clearcut. However if the variations are significant at close distance for influential rock properties, special attention must be given to obtaining the best average value for each grid block to preserve the actual performance of the reservoir model.

Averaging methods range from the simple averages (arithmetic, harmonic and geometric means) to numerical simulation methods (pressure solver). Intermediate methods are, for example, power-law averaging and renormalisation. Simple and intermediate methods are fast but less accurate, while numerical simulations are accurate but time-consuming. A fast and accurate averaging method is paramount to upscaling of very large geologic model.

Two simple averages, arithmetic and geometric were observed to study their effectiveness and robustness in upscaling. The formulas of arithmetic and geometric averages are respectively as follows [6, 7]:

$$X_{arith} = \frac{\sum_{j=1}^{n} X_j h_j}{\sum_{j=1}^{n} h_j} \quad \text{... 1}$$

$$X_{geom} = \sqrt[n]{X_1 X_2 X_3 \ldots X_n} \quad \text{... 2}$$

The various types of averages has been studied extensively by engineers and researchers faced with the problem of averaging core permeabilites [5]. Cardwell and Parsons [8] were the first to suggest that limits on reservoir performance might be expressed in terms of different averages of permeability, k. They pointed out that the arithmetic mean k (weighted for thickness, if necessary) should represent the upper bound of performance and the harmonic mean should represent the lower limit. In a physical sense the arithmetic average is equivalent to the effective k of a completely stratified system composed of parallel layers, while harmonic mean is equivalent to the effective k of a system in which samples are arranged in series. Reservoirs composed of samples arranged randomly could be expected to have performance intermediate between these two extremes.

Katz and Tek [9] tested the hypothesis with a mathematical model. Warren *et al.*, [10] tested it by use of pressure buildup data. Katz and Tek [9] concluded that the weighted arithmetic average represented the upper bound under both steady state and unsteady state conditions provided there was infinite vertical k and therefore, complete crossflow. Stratification with no crossflow was a better representation of the lower bound that is the series configuration represented by the harmonic mean. They also concluded that no single constant mean k that can be used to represent the performance of a stratified system for all values of time. The work of Warren *et al.*, [10] showed that the average k computed from buildups usually fell somewhere between the arithmetic mean and the harmonic mean, as Cardwell and Parsons [8] anticipated. This work also showed that there was good correlation between the geometric mean k and k from the pressure buildup.

Mattax *et al.*, [11] claimed that the use of the suitable averaging technique was dependent on the distribution of k when sedimentation process took place and also how the permeability was altered by secondary process.

3.0 METHODOLOGY

As mentioned earlier, through sensitivity analysis, the influence of rock properties (ϕ and k) on output parameters (*i.e.* field oil rate, field water cut and field average pressure) were studied. Sensitivity analysis was done in two stages. First, arithmetic averaging was applied to obtain mean values for ϕ and k based on a few possible models. When ϕ was averaged, k was assigned one value throughout and vice versa. This was repeated using geometric averaging technique. The simulated results based on this input were analysed and compared with the base cases. Then the best model as a result of both techniques was identified together with the % error they incurred for comparison so that the better averaging technique could be determined. In addition, the most suitable averaging technique for the rock properties needed to be studied in-depth as well. Hence, a model of the smallest possible number of grid blocks, with the most suitable averaging technique applied to each rock property and with the least error resulted in the end. The simulation procedure was performed on a sandstone and carbonate model with dead oil system and a sandstone model with live oil system.

4.0 RESULTS AND DISCUSSIONS

4.1 Sandstone Model (Dead Oil System)

Figures 1 and 2 show field-oil-rate results for different models as a result of arithmetic averaging, in which porosity values are averaged (constant k) for the former; and permeability values averaged (constant ϕ) for the latter. Figures 3 and 4 show field-oil-

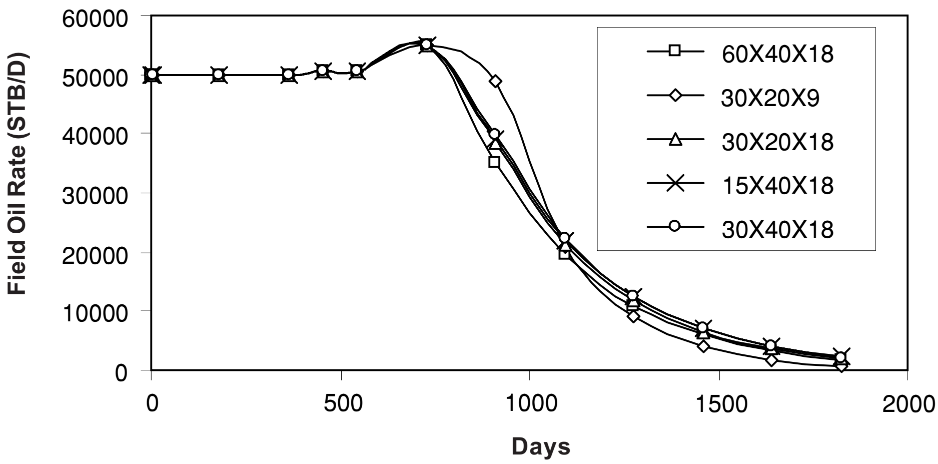

Figure 1 Comparison of field oil rate for constant k case using arithmetic averaging

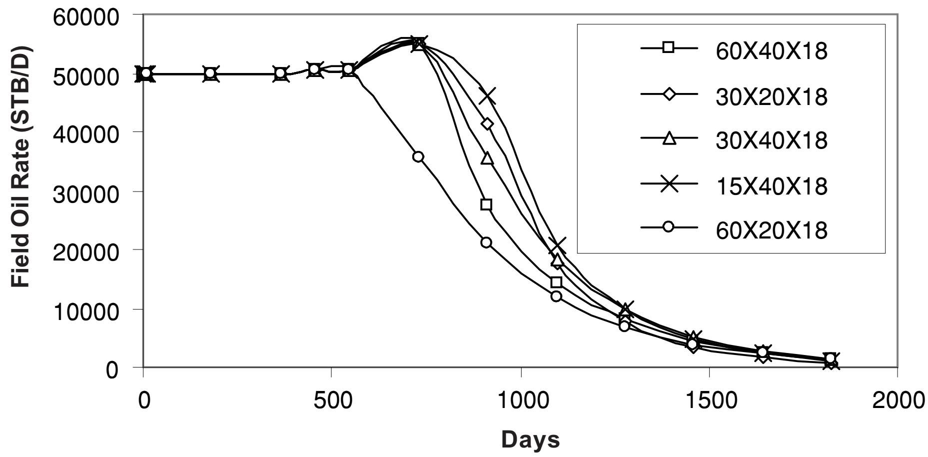

Figure 2 Comparison of field oil rate for constant ϕ case using arithmetic averaging

rate results using geometric averaging technique. Generally, for constant ϕ cases, the simulated results based on models with lesser grid blocks deviate significantly from the base case (Figures 2 and 4), with 60X20X18 showing the greatest error, 37%, attributable to the significant variability of permeability in Y dimension. As for constant k cases, generally the results are not as deviated (Figures 1 and 3), with error ranging from 4% to 20%. In fact, most of them show results close to the base case, except for 30X20X9. This indicates that permeability is relatively more influential than porosity. Geometric averaging is more suitable for permeability while arithmetic averaging is more suitable for obtaining mean porosity values which do not vary much over a certain distance. This is shown by the smaller error resulted.

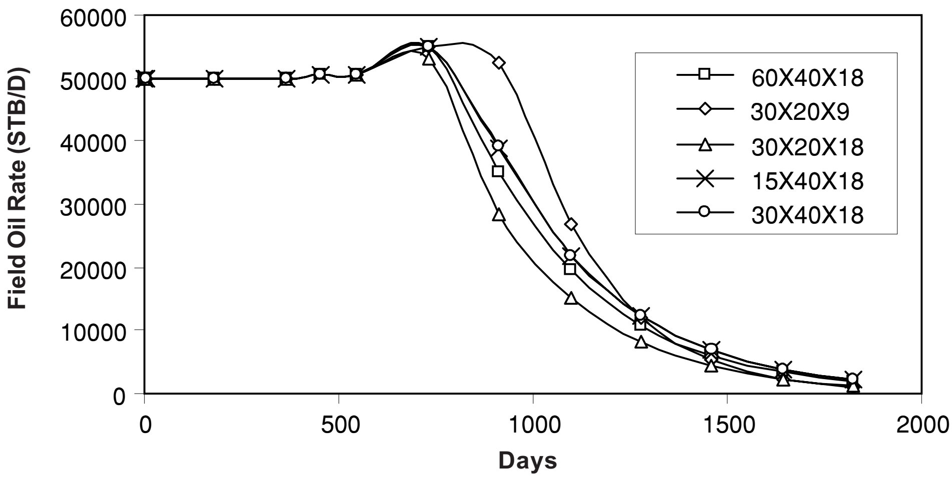

Figure 3 Comparison of field oil rate for constant k case using geometric averaging

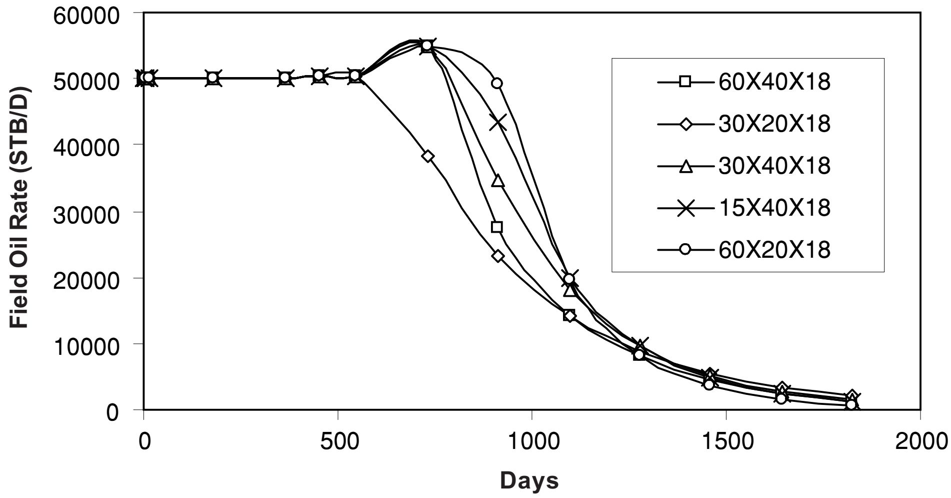

Figure 4 Comparison of field oil rate for constant ϕ case using geometric averaging

Therefore, the optimised model for constant permeability (averaging porosity) cases is 30X40X18 with 4% error only using arithmetic averaging compared to 22% error if geometric averaging is used to average porosity. Geometric averaging used to average permeability for constant porosity cases managed to reduce 60X40X18 model to 30X40X18 with 8% error compared to 13% error if arithmetic averaging is applied.

For field water cut, simulation results show similar phenomena discussed for field oil rate case. However, for field average pressure, there is a slight difference (Figures 5 to 8). The optimised model for constant permeability cases is 15X40X18, a lesser number of grid blocks with 4.6% error. Again, arithmetic averaging is the best to

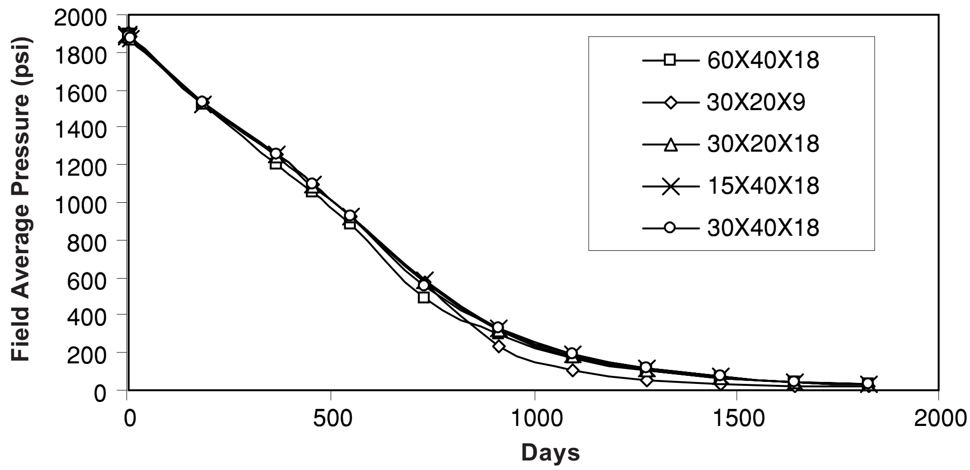

Figure 5 Comparison of field average pressure for constant k case using arithmetic averaging

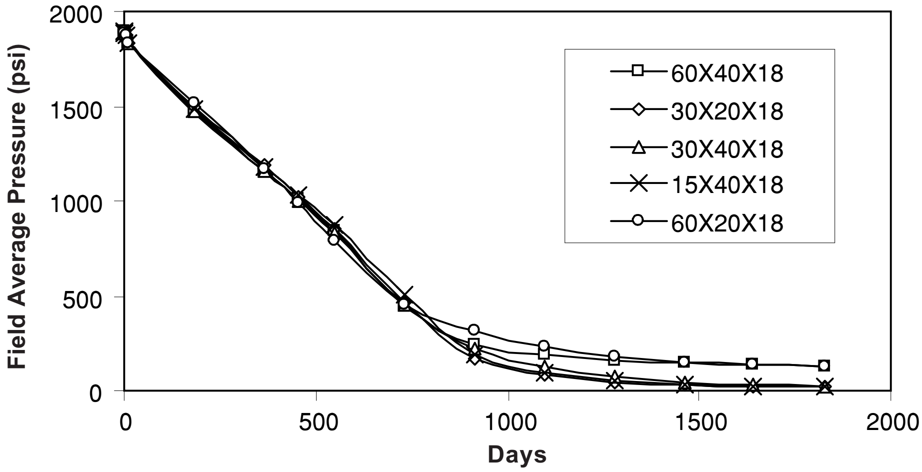

Figure 6 Comparison of field average pressure for constant ϕ case using arithmetic averaging

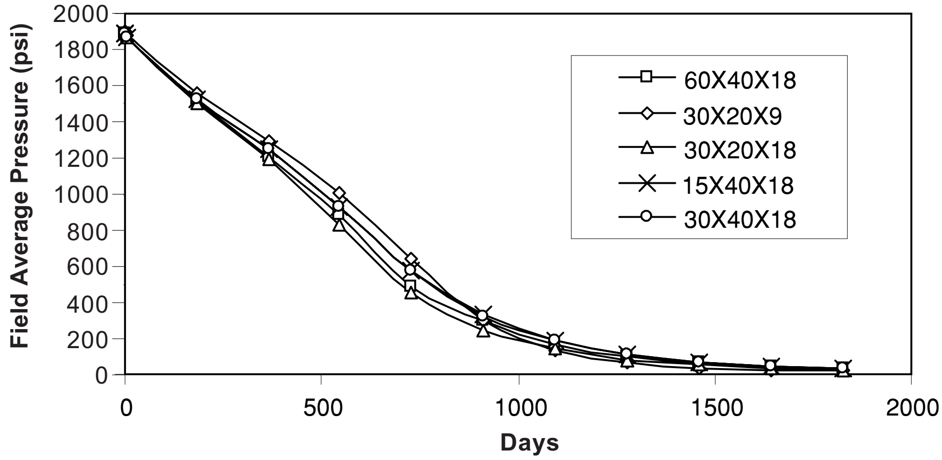

Figure 7 Comparison of field average pressure for constant k case using geometric averaging

average porosity values. As for constant porosity cases, 30X40X18 is the least with 6% error using geometric averaging. A bigger error 22% results when 60X20X18 is tested in spite of the same number of grid blocks.

It is easier to observe that permeability effect is more significant than porosity in Figures 5 through 8, in which porosity variations show small error (<10%), except for 30X20X9 model, which can be explained by the excess coarsening in both X and Y directions simultaneously. It is observed that rock properties along these two directions vary significantly over short distance. Note that when arithmetic averaging is used for constant porosity cases, the errors are way outside the ±10% tolerance. Possible

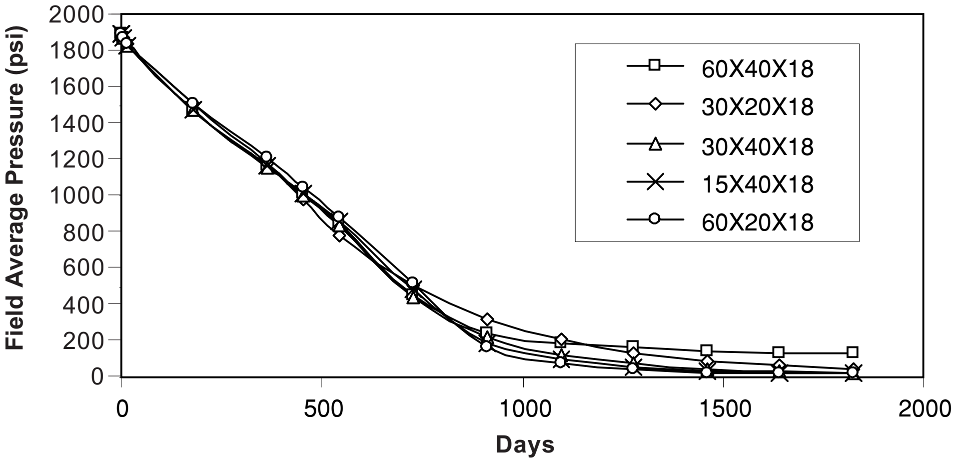

Figure 8 Comparison of field average pressure for constant ϕ case using geometric averaging

explanation is that arithmetic averaging overestimates the permeability, causing the prediction of the field pressure that is too low than it should be.

Up to this stage, we at least know permeability is more influential to the output than porosity; geometric and arithmetic averaging are better for permeability and porosity respectively; and the most possible optimised model are 30X40X18, 15X40X18 and 30X20X18. Next, we are confident to proceed to the simulation of real cases by averaging porosity and permeability simultaneously. Both averaging techniques give the same optimised number of grid blocks – 15X40X18. What differentiates them is a smaller error given by arithmetic, 3.7% compared to 5.5% by geometric.

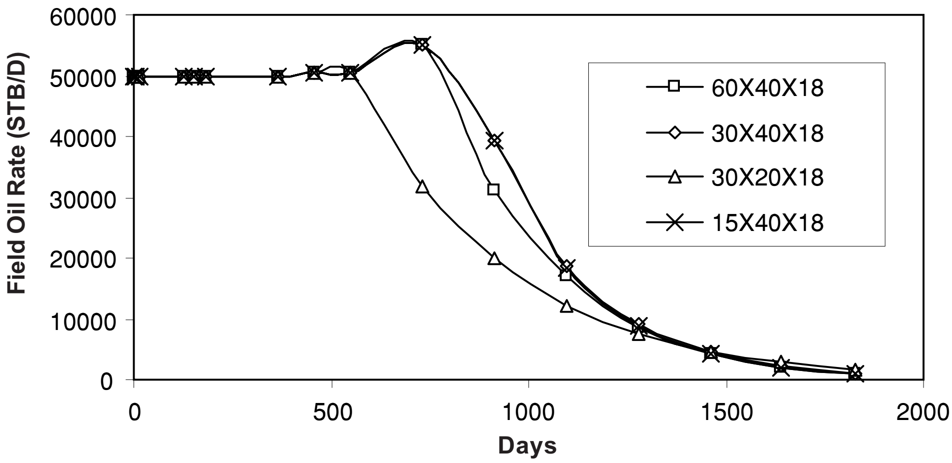

Figure 9 Comparison of field oil rate using geometric averaging for k and arithmetic averaging for ϕ (sandstone model)

Finally, in an attempt to further reduce the model, geometric and arithmetic averaging are applied on permeability and porosity respectively. The average values of these two properties are simultaneously imported into the simulator. Indeed, the resulting optimised model (15X40X18) has a smaller error, 3.48% for all the output parameters studied as shown in Figures 9 through 11. In short, the reservoir model is successfully reduced from 60X40X18 to 15X40X18 (75% reduction from the original model) with only 3.48% error.

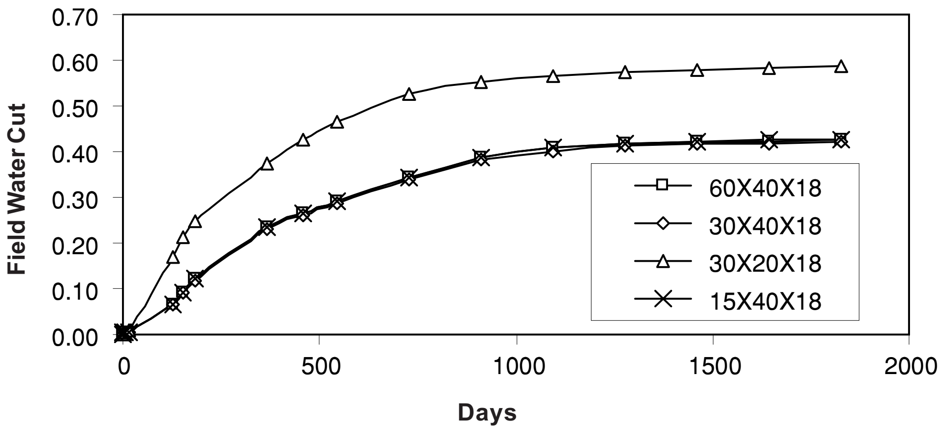

Figure 10 Comparison of field water cut using geometric averaging for k and arithmetic averaging for ϕ (sandstone model)

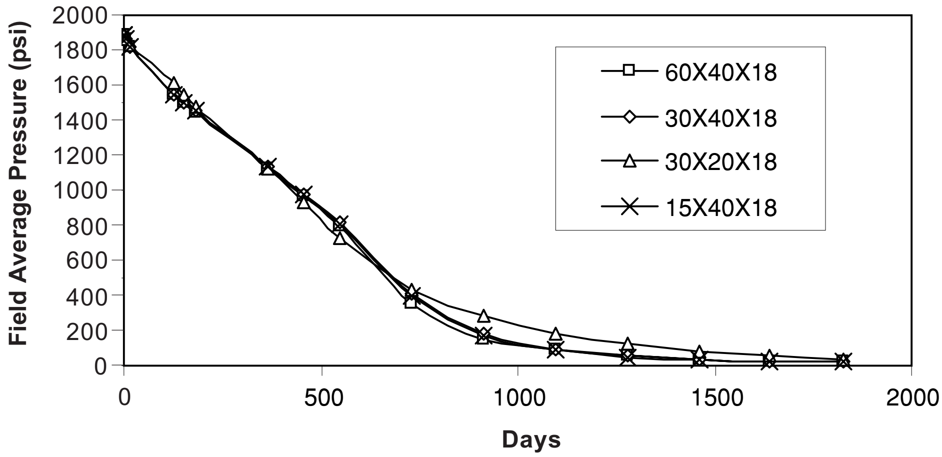

Figure 11 Comparison of field average pressure using geometric averaging for k and arithmetic averaging for ϕ (sandstone model)

4.2 Carbonate Model (Dead Oil System)

A carbonate reservoir was also studied due to its lithology which differs from sandstone. Therefore, a method that works for sandstone may not be suitable for carbonate.

For a carbonate model, k has more influence than ϕ on all the parameters studied, that is, field oil rate, field water cut and field average pressure. Geometric averaging is more suitable for averaging k while arithmetic is more efficient for averaging ϕ. Of the three parameters, field oil rate is most sensitive to averaging. ϕ values are not that heterogeneous (0.15 – 0.24) in Y direction.

For real cases where k was averaged by geometric and ϕ by arithmetic, the most optimum model obtained was 30X22X16, 3.89% error – a reduction of 50%, from 21,120 grid blocks (60X22X16) to 10,560 grid blocks (30X22X16). Detailed analyses showed that field oil rate gave the greatest error, 8.6% followed by field water cut, 2.65% and field average pressure, 0.41%. If it has not been for the oil rate, the most optimised model would have been 15X22X16.

Unlike sandstone, the carbonate model is more sensitive to averaging. The main reason is that the k values are too heterogeneous in Y and Z direction. A possible explanation is that ϕ and k distributions for carbonate reservoir are not only subject to sedimentation but also secondary processes, like vugging, fracturing and etc. The real case results are as shown in Figures 12 to 14.

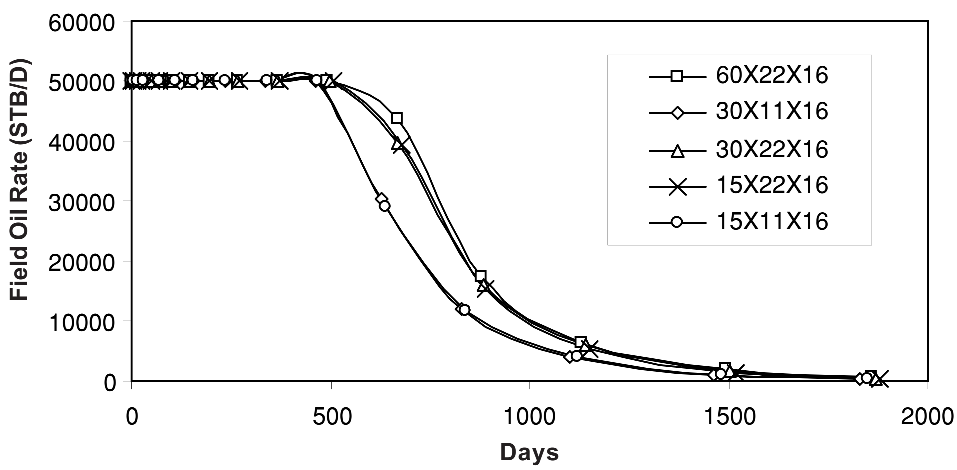

Figure 12 Comparison of field oil rate using geometric averaging for k and arithmetic averaging for ϕ (carbonate model)

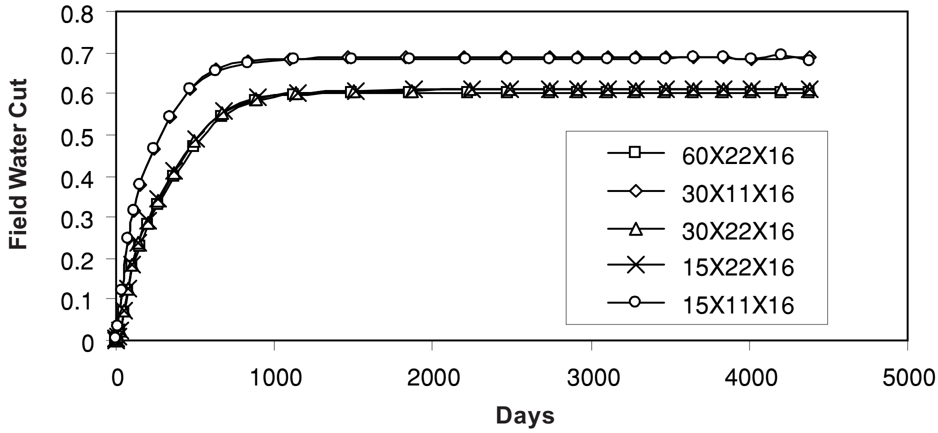

Figure 13 Comparison of field water cut using geometric averaging for k and arithmetic averaging for ϕ (carbonate model)

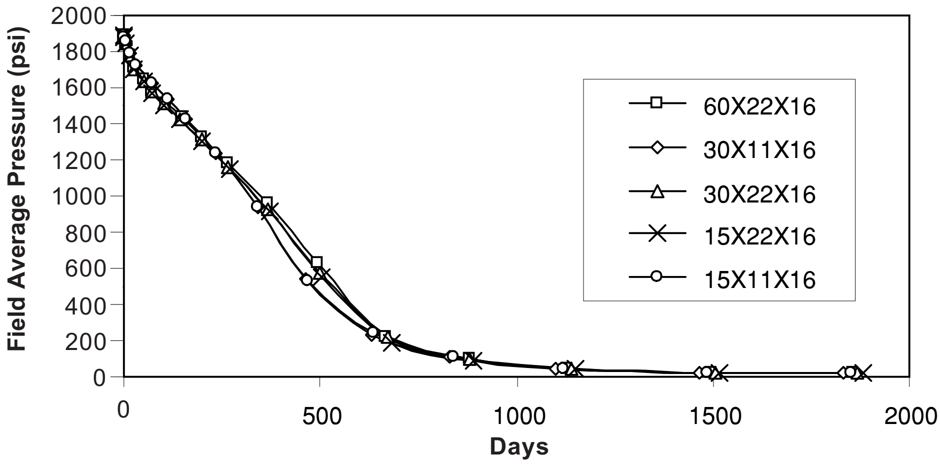

Figure 14 Comparison of field average pressure using geometric averaging for k and arithmetic averaging for ϕ (carbonate model)

4.3 Live Oil System

In an attempt to study if the presence of live oil system affects the optimisation results, the sandstone model in the previous section is now substituted with live oil system. Only the optimised model from the previous section is tested for this purpose. Of all the four parameters studied, field gas-oil ratio gives the smallest error and field average pressure gives a greater error. This is due to the presence of dissolved gas in live oil when the pressure is below the bubble point. This causes non-linear pressure depletion which also influences field oil rate results as well as oil recovery.

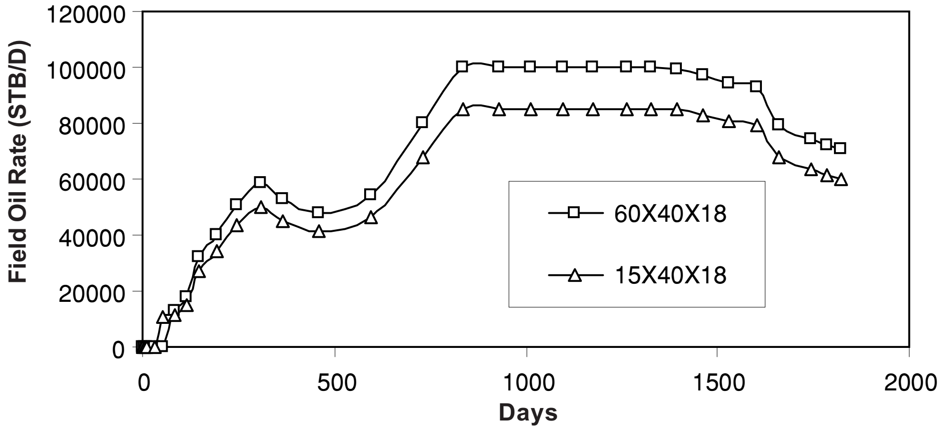

Figure 15 Comparison of field oil rate for live oil system in sandstone model

The most optimised model obtained is still 15X40X18, except that the error is higher, 5.1% compared with 3.48% in dead oil system. The results are as shown in Figures 15 to 18.

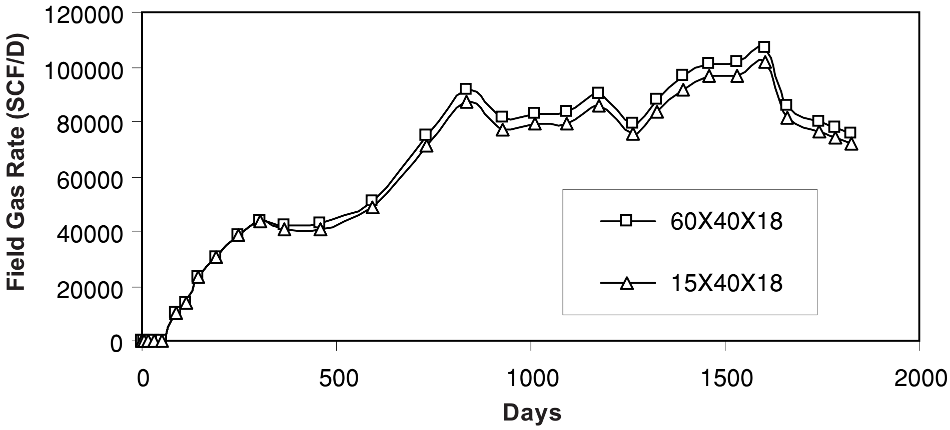

Figure 16 Comparison of field gas rate for live oil system in sandstone model

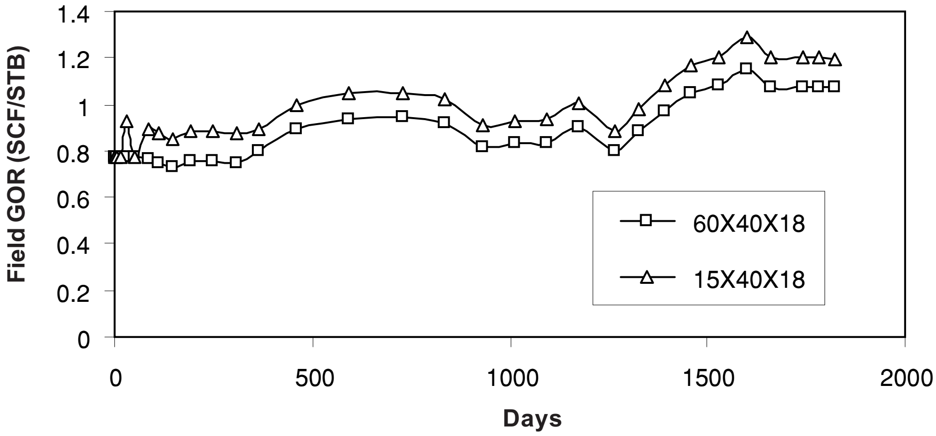

Figure 17 Comparison of field gas-oil ratio for live oil system in sandstone model

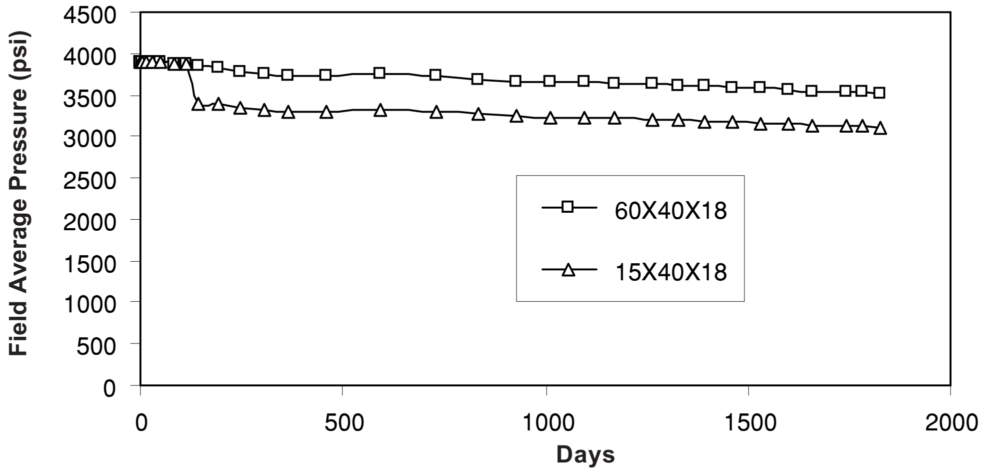

Figure 18 Comparison of field average pressure for live oil system in sandstone model

5.0 CONCLUSIONS

Based on the simulation results and analyses shown above, several conclusions are made as follows:

(1) Different averaging techniques for k and ϕ are found to produce a better upscale model than using the same method.
(2) For the reservoir studied, permeability has bigger effects than porosity on simulation results.
(3) For both sandstone and carbonate models, geometric averaging is more suitable for averaging k while ϕ is better averaged using arithmetic.

(4) The optimised sandstone model is 15X40X18, a reduction of 75% from the original model (with only 3.48% error). For carbonate model, a reduction of 50% is achieved, from 60X22X16 to 30X22X16 with 3.89% error.
(5) The presence of live oil in the sandstone model still gives the same optimised model – 15X40X18. However, the error was greater, that is, 5.1% compared with 3.48% in dead oil system.

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NOMENCLATURE

B	= formation volume factor
c	= compressibility, psi^{-1}
GOR	= gas oil ratio, SCF/STB
h	= thickness of layer, ft
k	= permeability, mD
p	= pressure, psi
S	= saturation, fraction
X_{arith}	= arithmetic mean
X_{geom}	= geometric mean
X_j	= sample
ϕ	= porosity, fraction
μ_p	= viscosity, cp

Subscribe

c	= capillary
g	= gas
i	= initial
o	= oil
r	= relative
w	= water

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APPENDIX A – DETAILS OF THE RESERVOIR MODEL STUDIED

This model has a simple geometry [12], with no top structure or faults. It was originally a very fine geological model scale described on a regular Cartesian grid, which consists of 60 X 220 X 85 cells. Its dimensions are 1200 X 2200 X 170 ft^3. The top 70 ft (35 layers) represent the Tarbet formation, and the bottom 100 ft (50 layers) represent Upper Ness. The fine-scale cell size is 20 X 10 X 2 ft^3. The model consists of part of a Brent sequence. The top part of the model is a Tarbet formation and is representation of a prograding near-shore environment. The lower part (Upper Ness) is fluvial.

Water properties are $B_w = 1.01$, $c_w = 3.10^{-6}$ psi^{-1}, and $\mu_w = 0.3$ cp. The dead oil pressure/volume/temperature (PVT) data are shown in Table A.1.

There are only two wells, one water injector and one producer. All wells were vertical and completed throughout the formation. The injector has an injection rate of 10,000 B/D (reservoir conditions) and a maximum injection bottomhole pressure of 5,000 psi. The producer produces at 800 psi bottomhole pressure.

Table A.1 Dead oil PVT data

p (psi)	B_o	μ_o (cp)
300	1.05	2.85
800	1.02	2.99
2,000	1.01	3.00

APPENDIX B – LIVE OIL DATA

Fluid Density at standard condition: oil density = 39 lb/cuft, water density = 63.25 lb/cuft, gas density = 0.0677 lb/cuft, bubble point pressure = 3800 psi, datum = 3431 ft, S_{oi} = 0.88 and S_{wi} = 0.12.

Table B.1 Water PVT data

p (psi)	B_w	c_w (cp)	GOR
3800	1.0231	3.10E-06	0.137

Table B.2 PVT data of live oil and dry gas

p (psi)	B_o	μ_o (cp)	GOR	B_g	μ_g (cp)
1200	1.17	1.970	0.137	13.947	0.0124
1400	1.20	1.556	0.195	7.028	0.0125
1600	1.22	1.397	0.241	4.657	0.0128
1800	1.24	1.280	0.288	3.453	0.0130
2200	1.28	1.095	0.375	2.24	0.0139
2600	1.32	0.967	0.465	1.638	0.0148
3000	1.36	0.848	0.558	1.282	0.0161
3400	1.40	0.762	0.661	1.052	0.0173
3800	1.45	0.691	0.770	0.89	0.0187

Table B.3 Saturation function

Water			Oil			Gas		
S_w	k_{rw}	p_c (psi)	S_o	k_{row}	k_{rog}	S_g	k_{rg}	p_c (psi)
0.1	0	20	0.3	0	0	0	0	0
0.16	0.0005	9	0.36	0.032	0.001	0.05	0	0.03
0.22	0.004	5	0.42	0.089	0.008	0.09	0.032	0.1
0.28	0.0135	4.1	0.48	0.164	0.0275	0.18	0.089	0.3
0.34	0.032	3.3	0.54	0.253	0.064	0.27	0.164	0.6
0.4	0.0625	2.6	0.6	0.354	0.125	0.36	0.253	1
0.46	0.108	2	0.66	0.465	0.216	0.45	0.354	1.5
0.52	0.172	1.5	0.72	0.586	0.343	0.54	0.465	2.1
0.58	0.256	1.1	0.78	0.716	0.512	0.63	0.586	2.8
0.64	0.365	0.8	0.84	0.854	0.729	0.72	0.716	3.6
0.7	0.5	0.6	0.9	1	1	0.81	0.854	4.5
0.8	0.667	0.3				0.9	1	5.5
0.9	0.833	0.1						
1	1	0						