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UTILIZING CONCEPTUAL MODELING IN THE STUDY OF ONE OF THE IRANIAN FRACTURED CARBONATE RESERVOIRS

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ABSTRACT

A typical Iranian carbonate matrix block surrounded by an open fracture was modeled in order to understand the fracture-matrix interaction and realize how to model the interaction best. The modeling was carried out by using a fine-scaled Eclipse model in the single porosity mode (the fractures were explicitly modeled). The model was extended to a stack of 6 matrix blocks to understand block-to-block interaction under both water and gas injection scenarios. The results and conclusions obtained from the single porosity single block and 6-block model were used in order to optimize the full field model. The simulation results showed that gas injection worked as a major recovery mechanism for medium and good rock types at all block heights and for poor rock type with block heights of more than 2 meters. The oil recovery results were in the same range for the single and six-stack block model, but the delay of oil recovery by gas gravity drainage is clearly seen in the six-stack block results indicating a period of at least 8-10 years required for reaching ultimate oil recovery for typical block heights. The water injection simulations showed that water imbibes drained the matrix block in a short time dependent on water front advancement in the fracture system surrounding the block. From the simulation results, it was concluded that the water imbibition process was a fast recovery mechanism for all block heights dependent on injection rate and fracture volume which had to be flooded to achieve full recovery of the block. The expected recovery factor of drained oil to initial oil in place after water injection was in the range of 15-35 % for poor to good rock types and different block sizes in the range of 1-5 meters. The results were highly influenced by wettability conditions in the reservoir.

Keywords: Iranian Fractured Carbonate Reservoir, Conceptual Modeling, Water Injection, Gas Injection, Drainage and Imbibitions.

INTRODUCTION

Current practices in the numerical simulation of fractured reservoirs rely on the construction of both static and dynamic conceptual models from which one may create an integrated reservoir model to be simulated. Commercial numerical models capable of handling flow in fractured reservoirs have been present in the industry for quite some time. However, the correct application of those simulators for representative reservoir models is not easy. Early dual porosity models include those of Kazemi et al. [1] and Saidi [2]. Saidi modeled a fracture reservoir by dividing it into sectors in

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which the fracture was assumed to have infinite transmissibility. Understanding the main physiccal processes, on which the performance and IOR potential of one of Iranian carbonate reservoirs are based, is one of the main challenges in this evaluation and in general for carbonate fields. The use of conceptual models is a widely accepted method, which can help to improve the estimation of potential IOR attempts. Normally, the physical understanding is based on the single-porosity simulation of the problem on small scale and the results are matched in a dual porosity model on the same scale. Then, pseudo-capillary and relative permeability curves together with recommendations for dual porosity modeling options can be specified for full field reservoir simulation studies.

This paper will discuss parametric ways to improve the construction of representative models by using a fine grid simulation and utilizing it in full field modeling.

Literature Review

In order to investigate the physics of fluid flow in reservoir, small scale simulation is necessary. The models need a high degree of discrepancy and input data on core scale.

Yamamoto was one of the first researchers who made a conceptual model for compositional simulation in one of Iranian hydrocarbon south reservoirs [3]. He concluded that for a given rock type, recovery from a block was a function of block height, environment in the fissures, and the rate of pressure decline in the fissures.

Fung described the effect of block to block processes in naturally fractured reservoirs by utilizing conceptual modeling [4]. He showed that most current dual porosity models use a single matrix block approach to calculate matrix/fracture transfer within a grid block. Kossack described realistic numerical models for fracture reservoirs [5]. In this study a fracture reservoir undergoing a water flood is simulated with a single porosity formulation where the matrix blocks are subdivided into core plug size grid blocks and the fractures are subdivided into even smaller blocks. He concluded that the single porosity simulation of the displacement of oil from a matrix block is sensitive to the size of the numerical grid blocks.

Saidi et al. discussed the gas /oil gravity drainage process in fractured reservoirs in Iran [6]. Early dual porosity models include those of Kazemi et al. and Saidi. Saidi modeled a fracture reservoir by dividing it into sectors in which the fracture was assumed to have infinite transmissibility.

Vidal et al. discussed oil reimbibition between stacked matrix blocks in naturally fractured reservoirs [7]. They concluded that the capillary continuity between blocks tended to minimize the reimbibition of the oil from the fracture to the matrix and consequently could enhance the produced oil flowing in fractures network to the wellbore.

Field Specification

This field is an onshore oil field located in the foothills of the Zagros Mountains in Iran. The Asmari, Pabdeh, and Bangestan reservoirs consist of fractured carbonates with a minor amount of clastic sediments. The production is mainly from the fractured carbonates. The original oil column was some 1000 meters thick, above the original WOC at around 1900 meters (sub-sea). An original gas cap in the Asmari formation overlaid with the oil column and the crest of the structure is around 250 meters (sub-sea). Lithologically, the two main reservoirs, namely Asmari and Bangestan, are composed of carbonates with a well developed fracture system. The oil has a gravity of 30 API.

Procedure

Grid

The simulations have been performed with two main grid types, namely 1-matrix block grid and 6-matrix block grid. The matrix blocks are in each model subdivided into 6 numerical grid blocks in x-, y-, and z-direction. No dip is assumed in the simulations; but the general understanding is that a high dip could improve the recovery of oil from the matrix blocks, especially for the poorer rock types.

One layer of grid blocks on each side, representing the fracture system, surrounds all matrix blocks. Figures 1 to 3 show the outline of the single matrix block and the 6-stacked matrix block models and saturation distribution describeing the modeling of matrix, fracture, and dummy layers in more detail.

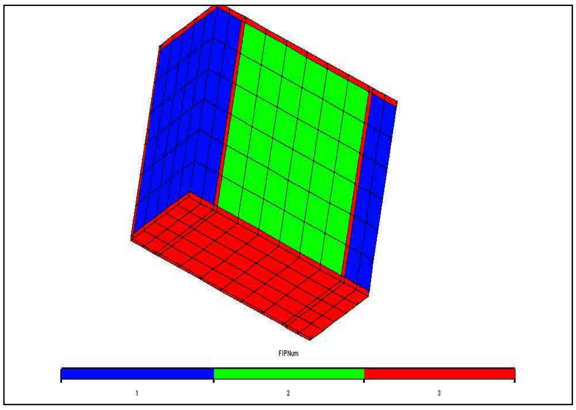

Figure 1: Single matrix block model grid showing the matrix block (green), the fracture system (red), and the dummy layers (blue) at the top and the bottom of the grid with an x-z cross section at y = 6

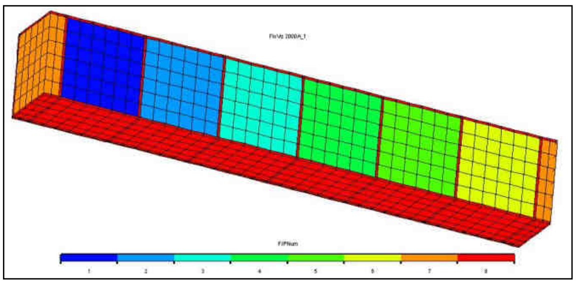

Figure 2: 6-stacked matrix block model showing the numerical grid block division with an x-z cross section at y=6 (dummy blocks, orange; fractures system, red; matrix blocks, remaining colors)

The grid block dimensions and porosity/permeability properties of the matrix block(s) investigated can be found in Table 1 and Table 2, respectively. The effect of grid block dimensions of different block sizes is assumed insignificant in these simulations. The fractures are assigned an effective permeability according to a fracture aperture of 0.3 mm giving a permeability value of 7560 mD. According to parallel plate theory, a fracture porosity of 0.01% and a total porosity of approximately 8% give an effective fracture permeability of 604.9 mD.

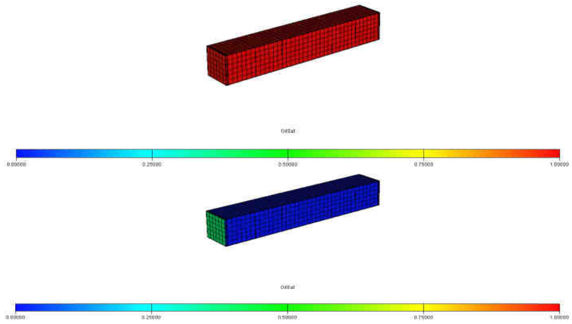

Figure 3: 6-stacked matrix block model showing the 3D saturation in the initial state (a) and after 20 years of production (b)

Table 1: Numerical grid block dimensions for one matrix block surrounded by fractures for all sensitivities (single matrix block and stack of matrix blocks).

Blocksize	DX (meter)	DY (meter)	DZ (meter)
1 meter	0.17	0.17	0.17
2 meter	0.33	0.33	0.33
3 meter	0.5	0.5	0.5
5 meter	0.83	0.83	0.83

The fractures were modeled using fracture grid cells of 3 cm to avoid numerical problems due to high throughput in very small grid cells, and the results were assumed not to be influenced by this modification since the rates of the advance of the WOC (2 meter/year) and GOC (3 meter/year) were modeled approximately equal to the field performance in the fracture system by manipulation of the injection and production rates in the small scale simulations.

PVT Properties

The single block and 6-block models are

assumed to be located in the highly fractured sectors of the reservoir at a depth of 1000 m. Thus the oil is undersaturated under initial reservoir conditions.

Table 2: Matrix and fracture property specifications (porosity and permeability) in single-porosity simulations

Property	Porosity (%)			Horizontal permeability (md) (permz = 0.5 x permx)		
Rock type	poor	medium	good	poor	medium	good
Matrix	6	9	12	0.1	0.5	1.0
Fracture	100	100	100	604.8	604.8	604.8
Dummy block	100	100	100	600	600	600

The model is set up with water, oil, and gas as active phases, and dissolved gas and vaporized oil as options turned on. Therefore, the amount of vaporization of oil in the presence of under-saturated gas is set by default parameters in VAPPARS, and the resolution of gas is set to infinity. The main PVT properties of the oil used in this study are displayed in Table 3 and Figures 4 to 6.

Table 3: Properties of oil used at 160 °F

Bubble point Pressure (psia)	2231
Density of total gas evolved (g/litre)	1.1046
Density of stock tank oil (g/litre)	0.8807
Density of reservoir fluid at Pb	0.7528
Average compressibility factor(5021-pb)	556.5

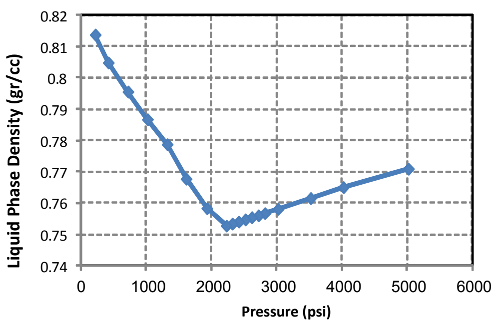

Figure 4: Variation of oil density vs. pressure

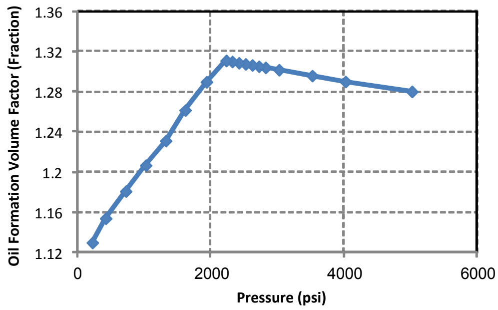

Figure 5: Variation of oil formation volume factor vs. pressure

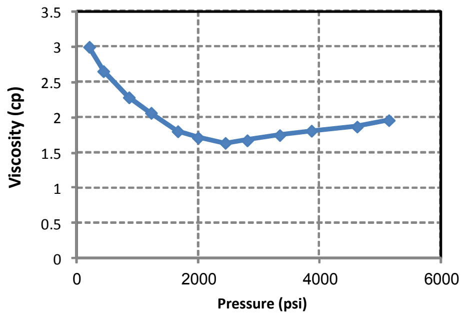

Figure 6: Variation of viscosity vs. pressure

SCAL Data

There are restrictions of data both vertically and laterally. The highest uncertainty on predicting performance in this fields is wettability under reservoir conditions (no wettability measurements of the reservoir rock is available in this field).

The amount for spontaneous imbibition of water has been set to 3, 5, and 7 saturation units for rock types poor, medium and, good respectively in the base case. The forced imbibition part (negative Pcow) was set to a most likely case of mixed-wet rock properties approximating an average condition between oil wet rock and the measured SCAL data for the field (assuming core material was water-wet after cleaning). The water-oil drainage and imbibition and the gas-oil drainage curves are given in Figures 7-12 (medium rock type).

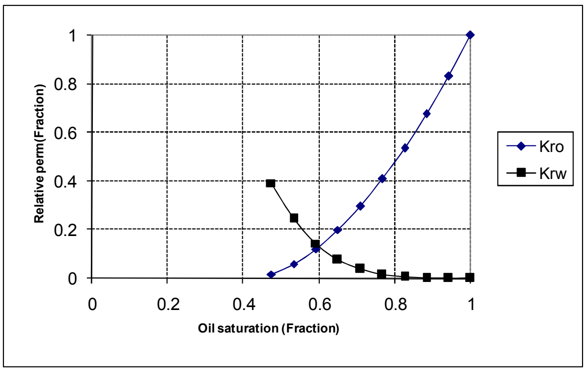

Figure 7: Water-oil drainage relative permeability curve (medium rock type)

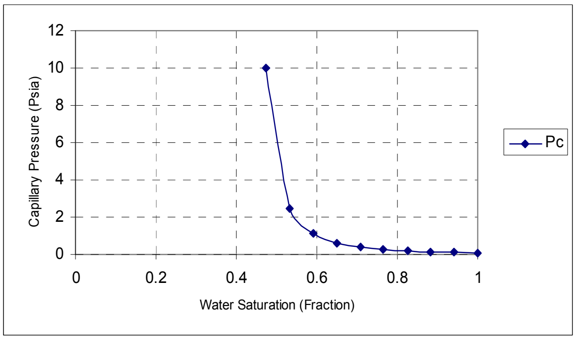

Figure 8: Water-oil drainage capillary pressure curves for medium rock type (threshold pressure= 0.1 psia)

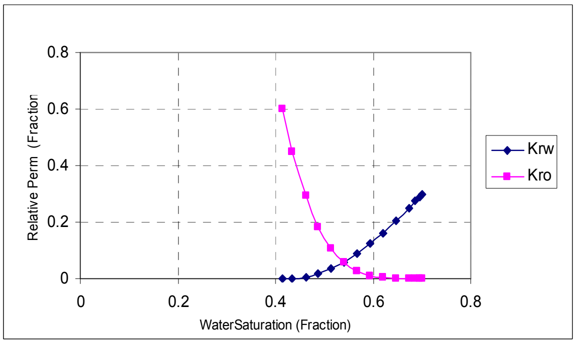

Figure 9: Water-oil imbibition relative permeability curves (medium rock type)

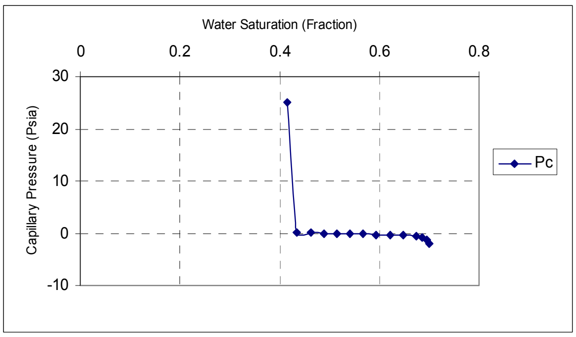

Figure 10: Water-oil imbibition capillary pressure curves (medium rock type)

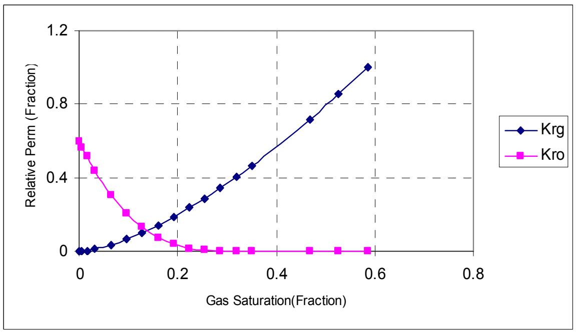

Figure 11: Gas-oil drainage relative permeability curves (medium rock type)

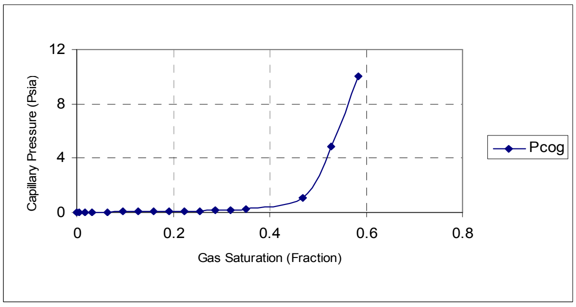

Figure 12: Gas-oil drainage capillary pressure curves for medium rock type (threshold pressure= 0.03 psia)

Water injection simulations have been performed with the hysteresis option switched on. The default hysteresis options have been used in Eclipse. Gas-oil hysteresis has been investigated assuming no imbibition gas-oil capillary pressure curve; however, since no significant differences with the non-hysteresis simulation were observed, this option was turned off for gas injection sensitivities.

Less favorable conditions for water imbibition have also been studied in these models, and the water displacement efficiency is as expected highly dependent on the amount of sponta-neous and forced imbibition specified in the input SCAL curves. Since these parameters are poorly defined in this carbonate rocks due to limited and uncertain data in the SCAL database, water displacement efficiencies in the range of 10-40% for the three rock types in the base case could be considered as normal values for this field. Water displacement efficiency could be very low assuming more oil-wet reservoir conditions; values below 10% are normal in other carbonate reservoirs in the Middle East.

Well Specifications

In all the simulations, 2 wells have been specified: one producer and one injector. When performing gas injection, the injector is placed in the top dummy layer and the producing well is placed in the bottom dummy layer. For water injection sensitivities, the water injector is located in the bottom dummy layers and the producing well is placed at the top of the grid. In order to be able to find stable numerical conditions and mimic the physical conditions during the displacement of oil in the matrix blocks (i.e. the velocity of the flooding fronts), the injection and production rates needed to be adjusted for the various matrix block heights (see Table 4). These injection and production rates imply small pressure depletion during flooding, and the effect of pressure on the ultimate recovery will be checked in the column model and full field model.

Table 4: Specified injection and production rates in the Eclipse runs

Block size	Injection rate (m^3/day)	Production rate (m^3/day)
1 meter	0.0005	0.0005
2 meters	0.001	0.001
3 meters	0.003	0.003
5 meters	0.008	0.008

For all the simulations, the BHP target for the injector is defined as 250 bars. No BHP limit is set for the producer. The simulations were conducted using no lift curves for well performance.

RESULTS AND DISCUSSION

Single Matrix Block Model Results after 7 Years

Table 5 shows the final oil recovery after 7 years of gas injection in the single matrix block model with various block sizes. Saidi et al. discussed the gas/oil gravity drainage process in fractured reservoirs in Iran [6]. Gas gravity drainage is a significantly slow process going on long after the gas has flooded the fracture surrounding the block, and for large blocks the ultimate oil recovery does not reach before 7 years after the start-up of gas injection. Thus the gas-gravity drainage rate is low, and for poor rock types the gas has problems entering the block for all matrix blocks less than 2 meters.

Table 5: Oil recovery factor (drained matrix oil to initial matrix oil in place) for single matrix block after 7 years of gas injection

Single matrix block	Recovery factors (%)
1 meter	
Poor Rock	2.1
Medium Rock	9.4
Good Rock	20.2
2 meters	
Poor Rock	7.0
Medium Rock	22.1
Good Rock	33.2
3 meters	
Poor Rock	7.0
Medium Rock	26.2
Good Rock	35.4
5 meters	
Poor Rock	5.4
Medium Rock	25.8
Good Rock	34.8

The expected oil recovery factor of drained oil to initial oil in place after gas injection is in the range of 10-35% for poor to good rock types and different block sizes in the range of 2-5 meters. The effect of gas injection on oil recovery is governed by the capillary pressure curve given for each rock type and block height. The maximum recoverable oil is to some extent influenced by the residual oil saturation S_{org} given in the relative permeability curves. From the simulation results, it is concluded that the water imbibition process is a fast recovery mechanism for all block heights dependent on injection rate and fracture volume that has to be flooded to achieve full recovery of the block. A typical cubic matrix block is drained in approximately 0.5-2 years (dependent on block size) to residual oil saturation under a typical field water front, advances 1-2 meters per year. The expected recovery factor of drained oil to initial oil in place after water injection is in the range of 15-35% for poor to good rock types, and different block sizes in the range of 1-5 meters. The results will be highly influenced by the wettability conditions in the reservoir.

The 6-stacked Matrix Block Model Results after 20 Years

Table 6 shows the final oil recovery in the 6-stacked matrix block model after 20 years of gas injection. The recovery is reported in the first block below the dummy layers with the gas injector.

Table 6: Oil recovery factor (drained matrix oil to initial matrix oil in place) for 6-stack matrix block model after 20 years of gas injection

6- Stack matrix block	Recovery factors (%)
1 meter	
Poor Rock	2.5
Medium Rock	10.0
Good Rock	21.9
2 meters	
Poor Rock	10.9
Medium Rock	24.4
Good Rock	36.9
3 meters	
Poor Rock	16.0
Medium Rock	31.5
Good Rock	41.9
5 meters	
Poor Rock	17.1
Medium Rock	33.8
Good Rock	44.30

Gas injection works as a major recovery mechanism for medium and good rock types at all block heights; it is also suitable for poor rock type with block heights of more than 2 meters. The oil recovery results are in the same range as for the single block model but the delay of oil recovery by gas gravity drainage is clearly seen in the results indicating at least 8-10 years to reach an ultimate oil recovery for typical block heights.

The re-imbibition process and its consequence of delaying oil recovery in the stack compared with single matrix block recovery have not yet been fully quantified for this field. The simulation results showed that the delay in oil recovery (the time required to reach a specific oil recovery value in a stack) by assuming no dip and no capillary continuity is linear with the number of block assumed contributing to the oil production at the bottom of the stack. This is due to the full re-imbibition of oil from a block into its neighboring block beneath it. Thus the oil from a top block has to drain through all the blocks below it to reach the producer.

Sensitivity Simulation Results in the Gas Injection Case

Grid Sensitivity

It is of theoretical interest to see how the oil recovery from the matrix changes as the discretization of the matrix block becomes coarser. Three additional discretizations were simulated as shown in Table 7. To determine the oil recovery from the regions of the reservoir, a comparison plot of the regional oil efficiency (ROE) from the matrix block vs. time for the four cases is given in Figure 13. As the results show, the single porosity model is sensitive to numerical block size. Grid sensitivity shows that the small grid blocks cause variation in oil recovery. Since a high capillary contrast, the initial flow from matrix to fracture is high.

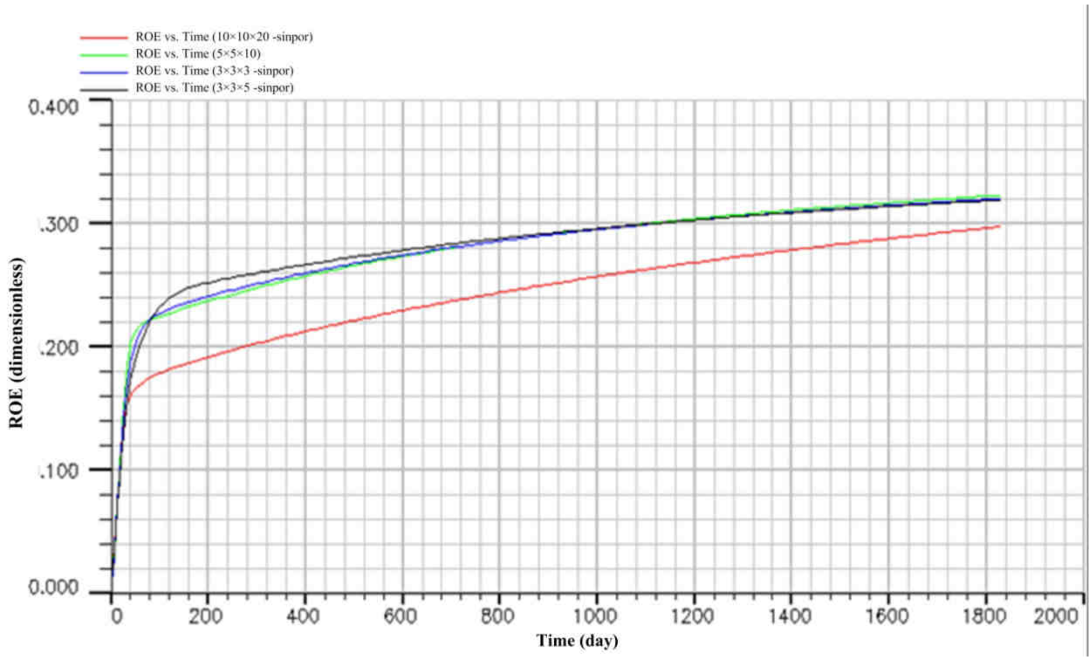

Figure 13: Comparison of oil recovery for various grid refinements in single porosity simulation

Block-to-Block Flow

Oil produced from one matrix block may often flow into, and enter, the under laying matrix block. This oil re-infiltration (often referred to as block-to-block flow) may take place due to actual physical contact between the blocks (permeable contact points), by oil droplets produced from one block falling on top of the next block and entering due to gravity and/or capillary forces, or through liquid bridges and film flow

Table 7: Grids for single porosity simulation

Number of grid cells in matrix	Total number of grid cells in matrix and fracture	Oil recovery at 1860 days
8x8x18	10x10x20	29.8 %
3x3x8	5x5x10	32.2 %
1x1x3	3x3x5	32%
1x1x1	3x3x3	31.2%

Block-to-block flow can easily be modeled in the simulation model by introducing a stack of matrix blocks either completely separated by horizontal fractures or with some degree of contact between them. In the model, with a stack of matrix blocks separated by horizontal fractures, all oil produced from one matrix block will re-infiltrate into the next matrix block (100% block-to-block flow). This results in a significant delay in the oil production, because a whole stack of blocks never has a production rate that is significantly higher than that of a single block. This delay in the recovery is illustrated in Figure 14, which shows the recovery vs. time for various matrix block positions in a stack that consists of 50 matrix blocks completely separated by horizontal fractures.

The time to reach 50% recovery for the top block is 60 days, similar to the single-block base case, since this block is unaffected by the production from the underlying blocks. However, all oil produced from this block flows into the underlying blocks causing a delay in the recovery in the blocks beneath; block number 5 in the stack reaches 50% recovery in about 500 days, whereas it takes more than 5500 days for the bottom block to reach a recovery of 50%. Clearly, the block-to-block flow results in a significant delay in the oil production; however, it should be noted that the ultimate recoveries are not directly affected. This means that in this field, where the estimated oil recoveries from the gas invaded zones are relatively modest (around 30% of IIOP), a delay effect could merely be caused by the re-infiltration; this means there is a significant potential for additional oil recovery.

The cases in Figure 14 represents 100% re-infiltration. It is likely that the degree of re-infiltration is less in the field. Factors that might significantly reduce the block-to-block flow are interbeded layers of non-fractured rock, impermeable fractures (shales and mineral deposits), sloped fractures, and viscous forces (pressure gradients in the fractures).

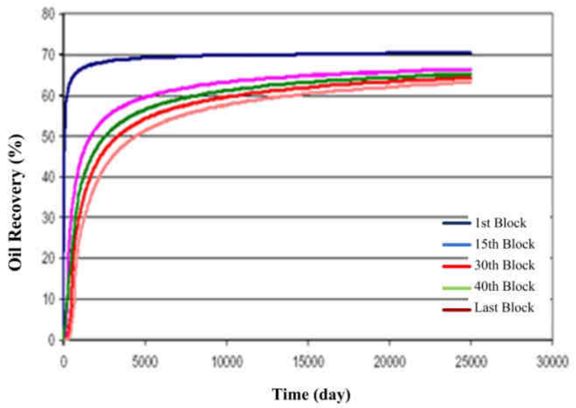

Figure 14: Stacks of 50 matrix block- Oil recovery vs. time for different matrix block position

Matching Single Porosity Results with Dual Porosity/Dual Permeability Models

The single matrix block model is matched in dual porosity mode with a dual porosity/dual permeability grid block model of 1x1x3 blocks, one for the matrix block in the middle and 2 extra blocks for the dummy injector and producer located in the fracture cells above and below. The 6-stacked matrix block model is matched with a dual porosity model with a dimension of 1x1x8 having the same requirement of 6 matrix blocks with fracture connections and 2 dummy fracture blocks above and below for the location of producer and injector.

The water displacement rate and final recovery of a single matrix block under water flooding can be easily matched by tuning the spontaneous imbibition part of the water-oil capillary pressure curve. The same conclusion can be drawn from matching the 6-stacked model. No further pseudoization to obtain correct oil recovery rate and ultimate final oil recovery are observed at this stage; however, additional work has to be done to confirm this conclusion for all matrix block geometries, fracture apertures, and fluid systems.

During gas injection, the single porosity solution of oil rate versus time and ultimate oil recovery in the block cannot be matched with the normal gravity drainage mode set in Eclipse. The invading gas saturation during gas gravity drainage in low permeability matrix blocks does not follow the assumption of vertical displacement. Some components of gas front movements in the horizontal directions at the side faces of the block are observed, and thus the match of the ultimate recovery during gas injection is easily achieved by using the alternative gravity drainage mode in Eclipse. The initial oil rate when the fractures surrounding the block are gradually filled by advancing gas and the gas gravity drainage rate when the matrix block is fully surrounded by gas is not easily matched in the simulations at this stage and further work is needed to find the final solution of this pseudoization problem. The forces and conditions affecting the recovery factor are summarized in Table 8.

The rate of production depends on the transmissibility between matrix blocks and fracture. High stack heights, low interfacial tension, and low capillarity tend to reduce the rate. In the case of gas injection, the residual oil swells, which increases the oil zone thickness and reduces the oil viscosity and hence improves the overall oil production.

Psuedoization in a Single-porosity Model

According to scale up theory, one can modify the rock curves so that the simulation with a coarse grid will match the fine grid solution. To test this theory, a history matching process is made with the 1x1x1 grid case. Here the matrix block is modeled with one numerical grid block 4.9x4.9x4.9 m.

Table 8: The forces and conditions affecting the recovery factor

Mechanism	Gas Flooding	Water Flooding
Capillary Drainage	High Drainage Pc	-
Capillary Pressure Imbibition	-	Low Imbibition Pc Oil Wet Condition
Gravity Forced Drainage	Small Stack high Small Fluid Density Difference	

Adjustments to both the relative permeabilities (Krow and Krw) and the capillary pressure (Pcow) were made. Only a change in the capillary pressure provided a change in the flow, which allowed the match of the oil recovery results. A comparison of the solution oil recovery from the matrix block and the matched result is given in Figure 15.

Psuedoization in a Dual-porosity Model

In this section, attempts were made to match the calculated dual porosity oil recovery from the matrix block with the fine grid single porosity results which were the solution. Attempts were made to match the solution with changes in stack height, relative permeability, sigma, and capillary pressure. In order to study the effects of stack height, 6 different stack height sizes were used in the model. Figure 16 shows the effect of different stack height sizes on oil recovery. In order to study the effects of sigma parameter, 4 different sigma parameters were used in the model. Figure 17 shows the effect of different sigma values.

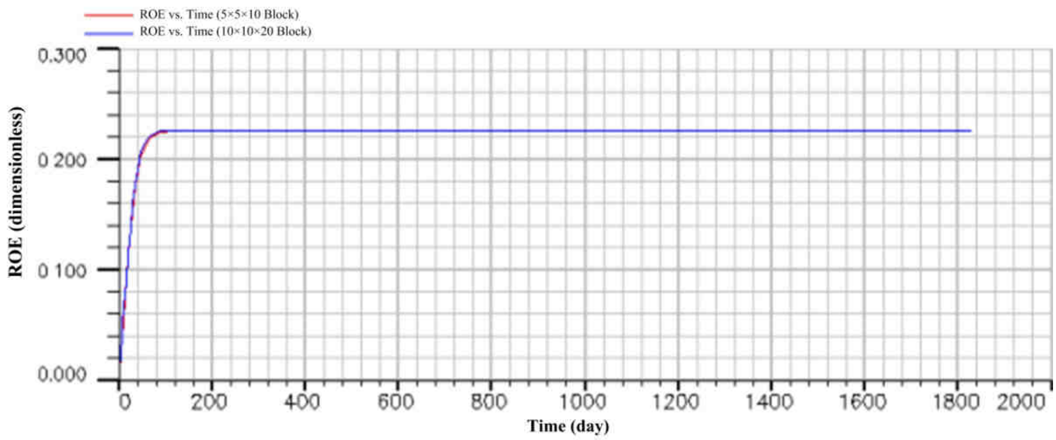

Figure 15: Comparison of oil recovery for various grid refinements in dual porosity simulation

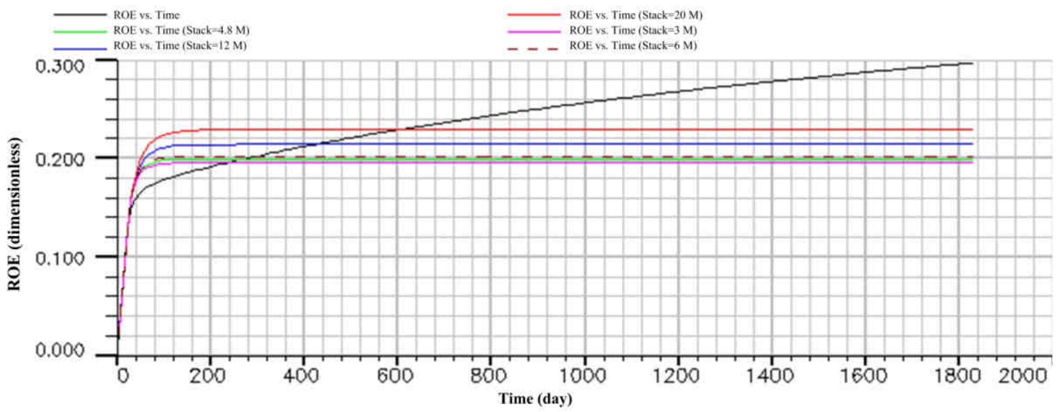

Figure 16: Effect of stack height block on oil recovery

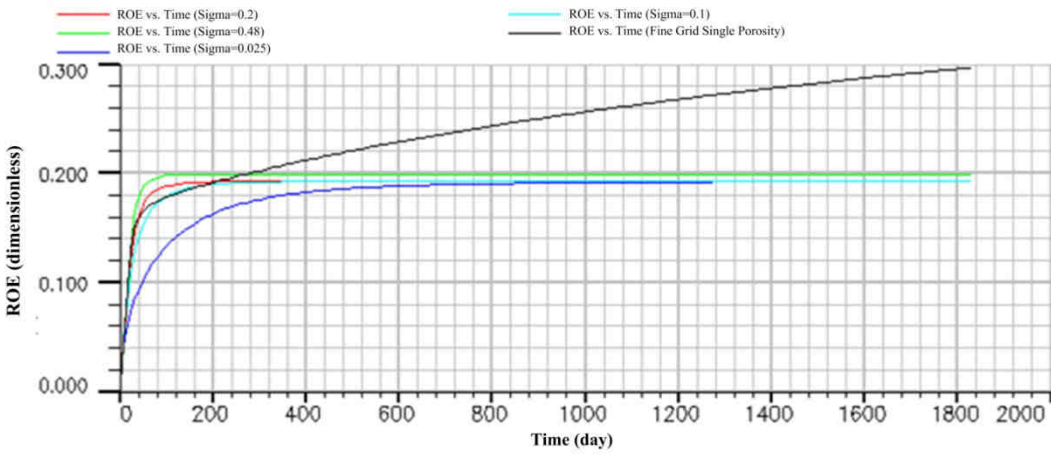

Figure 17: Effect of sigma parameter on oil recovery

CONCLUSIONS

Based on conceptual studies, the following conclusions and recommendations can be drawn for field oil recovery mechanisms.

Block-to-block flow results in a significant delay in the oil production; however, it should be noted that the ultimate recoveries are not directly affected. This means that in this field, where the estimated oil recoveries from the gas invaded zones are relatively modest (around 30% of OIIP), a delay effect could merely be caused by the re-infiltration; this means there is a significant potential for additional oil recovery.

The field performance of matrix oil recovery around 35-38% behind the advancing gas front implies no capillary continuity between individual matrix blocks with block sizes in the range of 2-4 meters. Small matrix block sizes and efficient stack heights of around 2-4 meters is also a possible scenario that will obey the field performance.

Carbonates of poor rock type quality are not drained by gas for matrix block sizes of 1 meter; a minimum block size of approximately 2 meters is necessary to force gas into the block. Expected oil recovery factors in the gas flooded zone is 11% for 2-meter block sizes and 17-18% for 5-meter block sizes for this rock type.

Expected oil recovery factors behind the gas front for medium and good rock types are respectively in the range of 10% and 22% for matrix block sizes of 1 meter and respectively 34% and 45% for block sizes of 5 meters.

The effect of pressure on gas-oil interfacial tension, gas and oil phase densities, and thus the resulting gas-oil capillary pressures in the matrix block during gas displacement decreases the above stated recovery estimates for gas gravity drainage (because of a decline in pressure).

Water imbibition ultimate recovery is expected to be in the range of 15-35% for poor to good carbonate rock with the additional effect of block size. These results are highly uncertain, with a large range of possible outcomes (2-50%) based on available SCAL data and experience from other carbonate fields in the region.

Grid sensitivity shows that the small grid blocks cause variation in oil recovery. Since a high capillary contrast, the initial flow from matrix to fracture is high.

NOMENCLATURE

BHP : Bottom hole pressure

Dx : Block length in x direction

Dy : Block length in y-direction

Dz : Block length in z direction

GOC : Gas oil contact

Krg : Gas relative permeability

Kro : Oil relative permeability

Krw : Water relative permeability

MD : Millidarcy

Pc : Capillary pressure

Pcow : Oil-water capillary pressure

ROE : Regional oil efficiency

SCAL : Special core analysis laboratory

S_{org} : Residual oil saturation in gas oil system

SS : Sub sea

WHS : Wellhead Separator

WOC : Water oil contact

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