Sensitivity Analysis of Cumulative Oil Production and Production Rate on Matrix/Fracture Permeability and σ for an Iranian Carbonated Fractured Reservoir

Z.Riazi[i], F.Rashidi[ii]

ABSTRACT

Matrix/fracture permeability and σ play paramount role in the sensitivity analysis and therefore the history matching of cumulative oil production and production rate of carbonated fractured reservoirs. In this study, the influence of these parameters upon cumulative production and production rate of an Iranian fractured reservoir were studied by the usage of a simulator. The aforementioned range of matrix/fracture permeability and σ for the studied reservoir were one tenth to twice of the permeability and σ of the matrix/fracture permeability and σ which used in the history matching during the reservoir simulation. Results show that changing the matrix/fracture permeability and σ greatly affect the cumulative production as well as the production rate. Also, sensitivity analysis reveal that, the variations in cumulative production and production rate happen in a limited range of matrix/fracture permeability and σ.

KEYWORDS

Sensitivity analysis, matrix/fracture permeability, σ, carbonated fractured reservoir.

1. INTRODUCTION

The attainment of a history match between filed data and the response from a computer model has long been an important task. Both matrix and fracture systems play an important role in the production mechanism of the reservoir. History matching for all years of production has successfully done an iterative process between static and dynamic models to ensure the consistency between two models also has aided in prediction of performance of reservoir. In order to reach of this goal, we are using sensitivity analysis.

Sensitivity analysis is the study of how the variation of the output of a model can be apportioned, qualitatively or quantitatively to different sources of variation. The procedure is based on determination of the sensitivity of the value of reservoir parameters used in the simulator. Sensitivity analysis changes each precedent variable at a time and then notes the changes of the resulting variable [1, 2]. In this paper, three reservoir parameters were selected (matrix permeability, fracture permeability and σ), and effects of these parameters on cumulative oil production and production rate of this reservoir were evaluated.

Permeability is one of the major controls for production in fractured basement. It is critical to be able to identify and characterize permeable zones in the basement reservoirs not only for evaluating well producing potential but also for designing perforation, well completion and injection

2. BASIC DEFINITION

Matrix permeability K_m can be determined by conventional methods. Fracture permeability can be defined in two ways:

1-Intrinsic permeability K_{ff} which is related to true fracture width W_f. Under the assumption of laminar flow between smooth parallel walls, the flow equation is

$$Q = W_f H \frac{W_f^2}{12\mu}\frac{\Delta p}{\Delta L} \qquad (1)$$

This can be re-written in the form of Darcy's equation giving:

$$k_{ff} = W_f^2 / 12 \qquad (2)$$

In field units, $k_{ff} = 54\times10^9 W_f^2$ if W_f is in inches and k_{ff} in md. The above equation gives the upper limit for real fracture permeability. Actual k_{ff} is lower because of wall roughness, irregularity of the channel, and partial or complete blockage of the channel with calcite or fines.

[i] z. Riazi, M.S, Department of Chemical Engineering, Amirkabir University of Technology, Tehran, Iran (e-mail:zahra_riazi2000@yahoo.com)
[ii] f. Rashidi, Professor, Department of Chemical Engineering, Amirkabir University of Technology, Tehran, Iran (e-mail: rashidi@aut.ac.ir)

Turbulent flow also effectively reduces the equivalent laminar permeability. Some of these factors will be discussed below.

2- Apparent (conventional) permeability k_f is related to bulk flow area $A_b = H \times B$. If the number and geometry of all fractures intersecting the area are known, then relating the total flow to area A_b yields:[4]

$$k_f = \sum_i k_{ffi} A_{fi} / A_b \quad (3)$$

Apparent permeability is used in simulators as well as reservoir engineering calculations. It depends on:

- Individual fracture permeability, which is a function of its average width and other factors discussed above.
- Fracture density (defined as number of fractures per area in a given direction). In many reservoirs, there is a preferred orientation of fracturing. This can cause fracture density and therefore k_f to be strongly anisotropic.

Finally, it is useful to define the total (or effective) permeability of a fractured reservoir k or k_e by

$$k = k_e = k_f + k_m \quad (4)$$

Again, k_e is directional due to directionality of k_e. In the special case of isotropic or uni-directional fracture density and width, Equation (4) can be expressed as (Kazemi, 1990) [3]

$$k = k_e = k_{ff}\phi_f + k_m \quad (5)$$

The matrix-fracture coupling transmissibility terms that exist between each cell of the matrix grid and the corresponding cell in the fracture grid are proportional to the cell bulk volume, being of the form [6]:

$$TR = CDARCY.K.V.\sigma \quad (6)$$

where by the default:

K is taken as the X-direction permeability of the matrix block,

V is the matrix cell bulk volume, and

σ is a factor of dimensionality $LENGTH^{-2}$,to account for the matrix/fracture interface area per unit volume, that is, the size of the blocks in the matrix volume.

Kazemi has proposed the following form for σ :[5]

$$\sigma = 4\left(\frac{1}{l_X^2} + \frac{1}{l_Y^2} + \frac{1}{l_Z^2}\right) \quad (7)$$

where l_X, l_Y and l_Z are typical X, Y and Z dimensions of the blocks of material making up the matrix volume.(l_X, l_Y and l_Z are thus not related to the simulation grid dimensions). Alternatively, as σ a multiplier on the matrix-fracture coupling, it may simply be treated as a history matching parameter.

3. MEASURING METHOD

The dual porosity theory developed by Barenblatt et al. assumes that all flows take place in the fracture. The matrix acts only as a storage medium for reservoir fluids, where a transfer function describes the flow from matrix to the fracture network. Mathematically, the dual porosity theory assumes that a point in the reservoir is a part of both matrix and fracture continua. Here, the approach is used in computer simulation models, where the matrix is represented by grid cells having the properties of the rock and the fracture by grid cells having properties representative of the fracture. In this project, we applied a dual continuum approach in black oil simulator (ECLIPS 100) [7].

4. MODEL DESCRIPTION

A fine grid simulation studies on Eclipse 100 has been carried in Cartesian co-ordinate system. The matrix blocks in the vertical stack have been separated by horizontal fractures. The system is similar to that of Kazemi model [9]. The matrix blocks have been girded from 30 120 1 to 30 120 18 grid pattern and horizontal fractures have each been girded from 30 120 19 to 30 120 36 grid pattern. The heights of matrix blocks are variable throughout this reservoir [10].

The aforementioned range of matrix/fracture permeability and σ for the studied reservoir began from one tenth of the values for history matching and expanded to fourfold of the history matching value and this was simulated from Jan/2007 to Oct/2017.

5. BASIC ROCK AND FLUID PARAMETERS

The basic rock and fluid parameters considered during this study are shown in Table 1. The reservoir was divided into 8 rock types. Figure 1 and 2 represent the gas-oil primary drainage capillary pressure and the relative permeabilities as a function of water saturation for the reservoir. Zero Oil-Gas capillary pressure and straight line Oil-Gas relative permeabilities with end points as 0 and 1 have been considered for the fracture. The primary production mechanism in this field is gravity drainage accessioned by gas cap expansion drive. Rock compression oil expansion and water influx are all lower in the gas cap. Gas injection into the reservoir gas cap commenced through five well.

6. RESULTS AND DISCUSSION

The results of simulation can be observed from Figures 3,4,...and 8 also Tables 2,3 and 4. These Tables show the results of FOPT until Oct/2017 and the time that reservoir can maintain the proposed production rate (6000 stb/day) relevant to changes that happened in the reservoir parameters. Figure 3 represents FOPT vs. Time and Figure 4 FOPR vs. Time for variation of matrix permeability on total production and rate of production for twice, threefold, fourfold 10%and 50% of the initial value of matrix permeability used in the history matching during the reservoir simulation, respectively . From Figures (3&4) and Table 2 of results it is observed that for matrix permeability bigger than the original one (until up to threefold), the influence of matrix permeability is paramount by increasing the cumulative production as well as the production rate. However, as the matrix permeability is increased, and reaches threefold of the original one, the influence of it is decreased and for the values bigger than threefold the cumulative oil production is decreased. As matrix permeability is increased, the oil production and simultaneous reservoir pressure drop increased and liberated gas has not adequate time to adjoin to the gas cap. So, the total released gas reaches to its critical point and gas is produced from production wells. Again, librated gas invades the matrix and blockade oil in the matrix. Gas is produced from production wells while decreasing total oil production.

With increasing of matrixes permeability, the reservoir can sustain the proposed rate for a longer time. However, as the matrix permeability is increased and reach threefold of the original one, the influence of matrix permeability is decreased and constant production rate is yielded. Then, the reservoir can maintain the proposed production rate (6000 stb/day) during the all of production time.

In the case of fracture permeability, the results of simulation can be observed from Figures 5, 6 and Table 3. Figure 5 represents FOPT vs. Time and Figure 6 FOPR vs. Time for variation of fracture permeability on total production and rate of production for twice, threefold, fourfold 10% and 50% of the initial value of fracture permeability, respectively. From Figures 5&6 and Table 3 it is observed that for fracture permeability bigger than the original one, its influence is paramount by increasing the cumulative production as well as the production rate. However, as the fracture permeability increases and reaches threefold the original one, its influence decreases while the influence of increasing the fracture permeability on production rate is low compared to the matrix permeability. This is because matrix is storage for fractures and it is not changed simultaneous with fracture permeability. Therefore, the influence of increasing the fracture permeability is lower than matrix permeability on *FOPT* and *FOPR*.

In the case of σ, the results of simulation can be observed from Figures 7, 8 and Table 4. Figure 7 represents FOPT vs. Time and Figure 8 FOPR vs. Time for variation of σ on total production and rate of production for twice, fivefold, 5%, 10% and 50% of the initial value of σ used in the history matching during the reservoir simulation, respectively. From Figures (3, 4, 7 and 8) and Tables 2&4 it is observed that the results of change in the σ are similar to matrix permeability but sensitivity of σ is lower than matrix permeability.

The results of variations of the average matrix permeability on cumulative production can be displayed as the following equation:

$$FOPT = X^4 - 0.27X^3 + 0.0213X^2 - 0.3758X + (0.3E-03) \quad (8)$$

where X is the average matrix permeability.

For fracture permeability the equation is :

$$FOPT = -X^4 + 1487.18X^3 - (7.6E+05)X^2 + 156.41X + (2E+11) \quad (9)$$

where X is the average fracture permeability.

And for σ it is:

$$FOPT = X^4 - (3.5E-3)X^3 + (3E-6)X^2 - (1.4E-10)X + (5E-12) \quad (10)$$

And X is the average σ.

Equations 8, 9 and 10 can be used only for this reservoir and adjacent reservoir that these are separated by a huge bake thrust fault. These equations have been acquired by Lagrangian Polynminals method via average reservoir characteristic (matrix/fracture permeability and σ) and *FOPT* (until Oct/2017) for this reservoir.

7. CONCLUTION

Sensitivity analysis reveals that the variations in cumulative oil production and oil production rate occur in a limited range of matrix/fracture permeability and σ (Figure 9&10). This range for matrix/fracture permeabilty extends from threefold the permeability to one tenth used in the history matching during the reservoir simulation and for the σ is limited to fivefold the σ and one tenth one, that used in the history matching during the reservoir simulation.

For the σ (Figure 9&10), it is observed the effect of varying σ on rate of production, is similar to change of matrix permeability.

Influence of increasing the fractures permeability on production rate and total production is low compared to the matrix permeability.

Whenever we require simultaneous variation in cumulative oil production and production rate, variation of the matrix permeability and σ are adequate. But if we require variation in cumulative production with low variation in production rate, variation of the fracture permeability is adequate.

8. NOMENCLATURE

P_i, $Psia$ Initial reservoir pressure.

P_b, $Psia$ Bubble point pressure.

μ_o, cp Reservoir oil viscosity.

μ_w, cp Reservoir water viscosity.

$\rho_w, lb/ft^3$ Reservoir water density.

$\rho_o, lb/ft^3$ Reservoir oil density

$B_o, rb/stb$ Oil formation volume factor.

$B_w, rb/stb$ Water formation volume factor.

$R_s, Mscf/stb$ Solution gas oil ratio.

$\phi_f, \%$ Fracture porosity.

$\phi_m, \%$ Matrix porosity.

K_f, mD Absolute fracture permeability.

K_m, mD Absolute matrix permeability.

W_f Fracture width.

$FOPT, (stb)$ Field oil production total.

$FOPR, (stb/day)$ Field oil production rate.

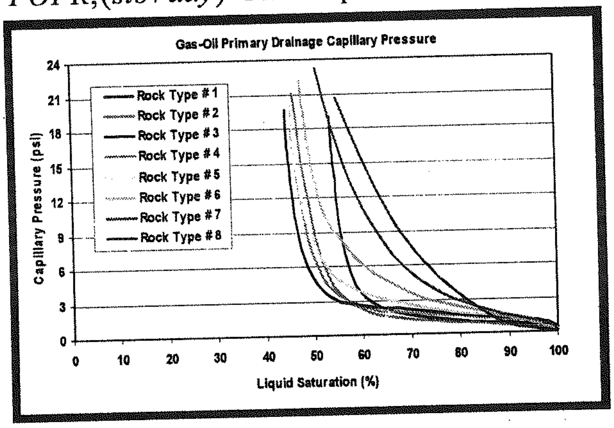

Figure1: Gas-Oil primary drainage capillary pressure.

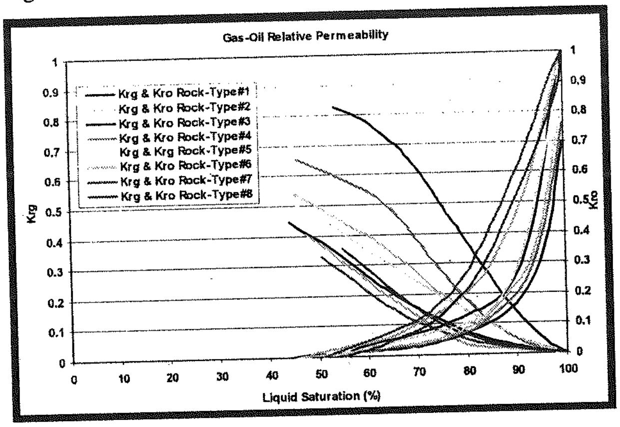

Figure2: Oil and gas Relative permeability VS. liq.saturation.

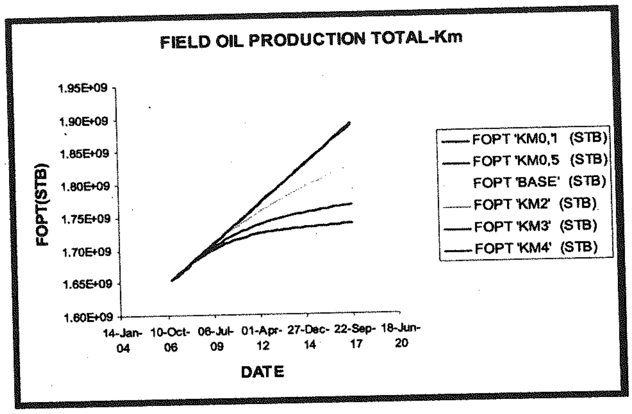

Figure3: FOPT vs Time for simulating matrix permeability effect.

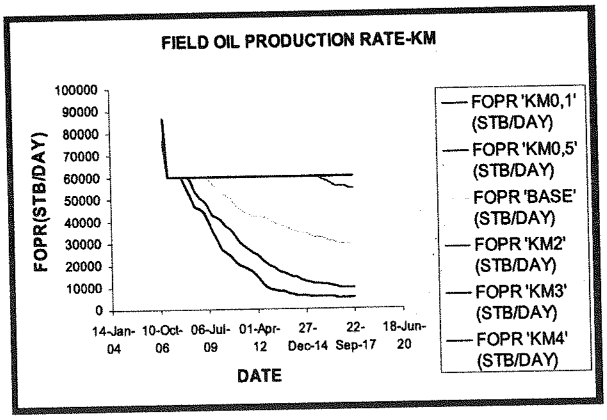

Figure4: FOPR vs Time for simulating matrix permeability effect.

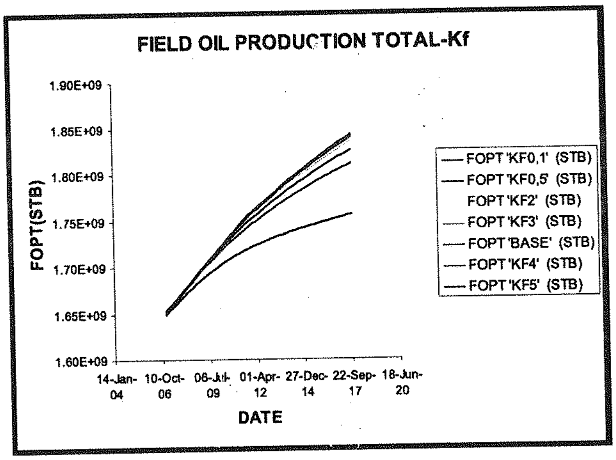

Figure5: FOPT vs Time for simulating fracture permeability effect.

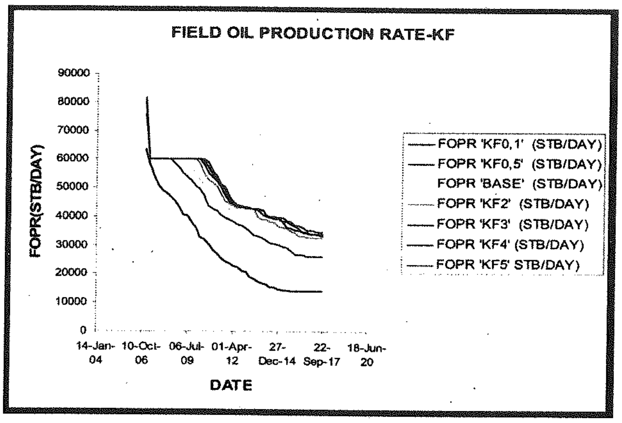

Figure6: FOPR vs Time for simulating fracture permeability effect.

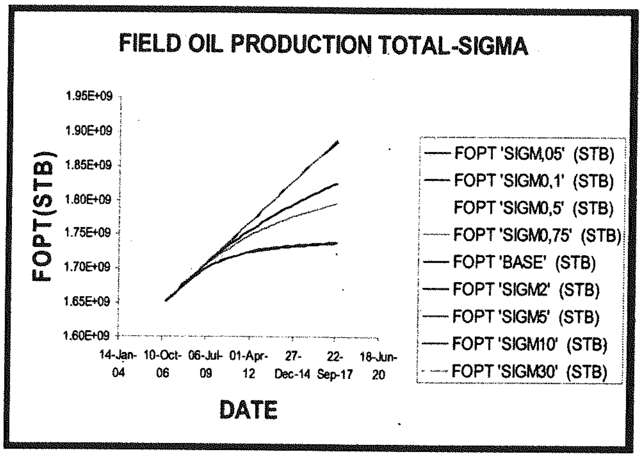

Figure7: FOPT vs Time for simulating σ effect.

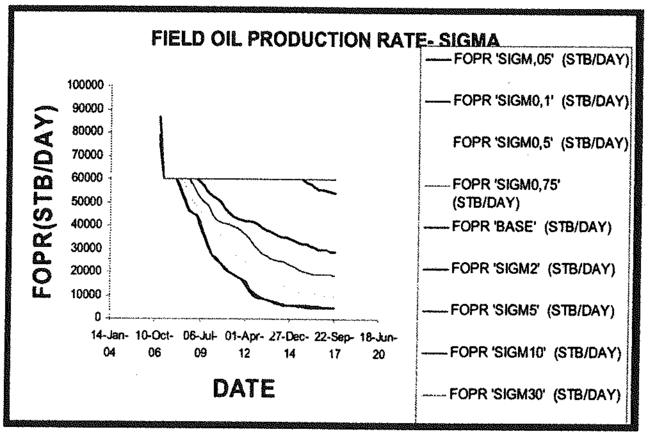

Figure8: FOPR vs Time for simulating σ effect.

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TABLE 1
BASICE ROCK AND FLUID PARAMETERS.

P_i, $Psia$	3645
$P_b, Psia$	2880
μ_o, cp	$0.468 \le \mu_O \le 1.724$
μ_w, cp	0.64
$\rho_w, lb/ft^3$	71.021
$B_o, rb/stb$	1.47
$B_w, rb/stb$	1.01
$R_s, Mscf/stb$	0.775
$\phi_f, \%$	0.3
$\phi_m, \%$	$2.5 \le \phi_m \le 20$
K_f, mD	$150 \le k_f \le 400$
K_m, mD	$0.05 \le k_m \le 0.5$

TABLE 2

The results of sensitivity analysis in various matrix permeabilities.

K_M	0.1	0.5	BASE	2	3	4
$FOPT_{(STB)}$	1737963000	1766106800	1825654400	1886100200	1889327600	1888915300
$FOPR_{(STB/DAY)}$	Apr/08	Jul/08	Jul/09	Jul/15	Oct/17	Oct/17

TABLE 3

The results of sensitivity analysis in various fracture permeabilities.

K_f	0.1	0.5	BASE	2	3	4	5
$FOPT_{(STB)}$	1756207900	1811328800	1825654400	1838922900	1825654400	1841008300	1842646100
$FOPR_{(STB/DAY)}$	Apr/07	Oct/08	Jul/09	Jan/10	Apr/10	Apr/10	Jul/10

TABLE 4

The results of sensitivity analysis in various σ.

σ	0.05	0.1	0.5	BASE	2	5	10	30
$FOPT_{(STB)}$	1738963800	1737964400	1766106800	1825654400	1886100200	1889054200	1889053100	1888912900
$FOPR_{(STB/DAY)}$	Apr/08	Apr/08	Jul/08	Jul/09	Oct/15	Oct/17	Oct/17	Oct/17

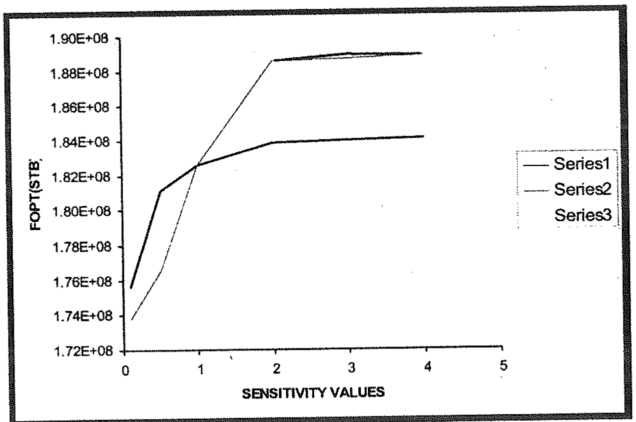

Figure 9: FOPT vs sensitivity values of matrix/fracture permeability and σ. (Series1 is matrix per., Series2 is fracture per. and Series3 is σ)

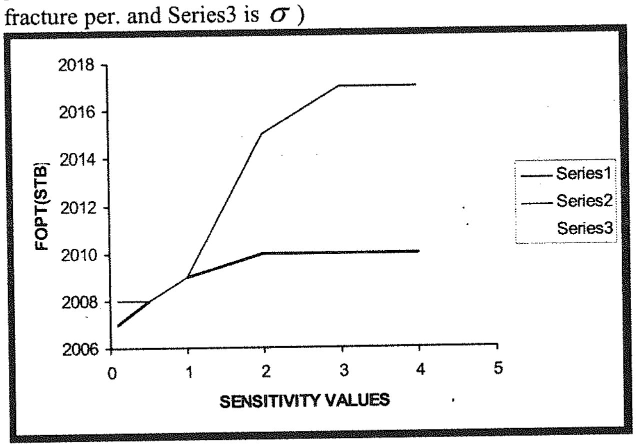

Figure 10: FOPR vs sensitivity values of matrix/fracture permeability and σ. (Series1 is matrix per., Series2 is fracture per. and Series3 is σ) (Series1 is coincided on Series3)