Reservoir monitoring and performance using Simbest II Black Oil Simulator for Middle East reservoir case study

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PROFESSIONAL PAPER

New techniques, capable of characterizing reservoirs in real time, are needed to utilize the dynamic nature of upstream oil operations and minimize the degree of uncertainty around existing reservoir models using high density of data continuously generated by smart technology. The primary objective of a reservoir study is to predict future performance of a reservoir and find the ways and means of increasing ultimate recovery.

Simulation uses a lot more than just the design and use of a good reservoir model to analyze a process, be it an oil reservoir system or a network-switching problem. More realistically, simulation is a process where engineer integrates several factors to produce information and on the basis of that managers can make reliable decisions. At all points along the way engineer should be on the top of situation.

Reservoir simulation technology is being constantly improved and enhanced. New models, able to simulate more and more complex recovery schemes, are proposed continuously. In this study waterflooding of five-spot pattern has been used to increase recovery and maintain pressure to sustain the required production rate.

Key words: mathematical modeling, reservoir development, water flooding

1. Introduction

Webster's dictionary defines the verb "simulate" as to assume the appearance of without the reality. Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior. The model itself is either physical (for example, a laboratory sand-pack) or mathematical. A mathematical model is simply a set of equations that, subject to certain assumptions, describes the physical processes active in the reservoir. Although the model itself obviously lacks the reality of a true oil and/or gas reservoir, the behavior of a valid model simulates (assumes the appearance of) that of the reservoir.[2]

The purpose of simulation is the estimation of reservoir performance (e.g., oil recovery) under one or more producing schemes. Whereas a reservoir, through its entire lifetime, can produce only once at a considerable expense, a model can "produce" or run many times at low expense over a short period of time.[2] Observation of a model performance under different producing conditions aids selection of an optimal set of producing conditions for the reservoir.

The primary objective of a reservoir study is to predict future performance of a reservoir and find ways and means of increasing ultimate recovery. Simulation uses a lot more than just the design and use of a good model to analyze a process. More realistically, simulation is process where an engineer integrates several factors to produce information on the basis of which managers can make reliable decisions. At all points along the way the engineer is on the top of situation. Nothing what the simulation process does can improve the quality of his work, but it can certainly give him a great insight into the interrelationships of the processes which are occurring in his project.[1] Reservoir simulation technology is being constantly improved and enhanced. New models able to simulate more and more complex recovery schemes are being proposed all the time.

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1.1 Necessity for Simulating

The classical approach to problem solving has been to formulate the problem and then trying to make as many simplifying assumptions as possible to produce a new problem that is manageable.[4,12] In this work is illustrated how numerical simulation can come to play a role since it does not require simplifying assumptions, and can produce more realistic solutions of the problem.

1.2 What Questions Can a Computer Model Answer

Computer models can be used to answer many questions asked by petroleum engineers. Some of them are the following:[1]

1 - How should a field be developed and produced in order to maximize the economic recovery of hydrocarbons?

2 - What is the best enhanced recovery scheme for the reservoir? How and when should it be implemented?

3 - What type of laboratory data is required? What is the sensitivity of model predictions to various data?

4 - Is it necessary to do physical model studies of the reservoir? How can the results be scaled up for field applications?
5 - What are the critical parameters that should be measured in the field application of a recovery scheme?
6 - What is the best completion scheme for wells in a reservoir?
7 - From what portion of the reservoir is production coming?

1.3 Modeling Approach

Models are basically of two types, physical and mathematical ones. The best example of this is the potentiometric model used to predict reservoir flow by capitalizing on the one-to-one correspondence between flow in porous media and the flow of ions in an electric potential field.[7] Mathematical models are systems of mathematical equations describing the physical behavior of the process under investigation. The technique of mathematical modeling and the role played by the engineer can be visualized by the block diagram shown in Fig. 1.

2. Reservoir Simulation

The area of reservoir simulation applies the concepts and techniques of mathematical modeling to the analysis of the behavior of petroleum reservoir systems. Simulation of some petroleum reservoir problems including single phase and two-phase, also simulates the flow behavior for water flooding and compares simulator results with available analytical solutions. Reservoir simulation with computers allows a more detailed study of the reservoir by dividing the reservoir into a number of blocks and applying fundamental equations for flow in porous media to each block.[3] In the description of computer modeling terms like mathematical model, numerical model, numerical simulator, grid model, finite difference model, and reservoir simulator are used almost interchangeably.[10] The origin of the simulator and the synthesis into a coherent whole are shown in Fig. 2.

The difference between the problem that is studied and simulated solution of the same can be attributed to the changing of fluid properties in the set of input data for simulation, and as well to the so-called "truncation error". One of the sources of errors that occur in numerical simulation is truncation error. This error is introduced by truncating the infinite Taylor series that is in mathematical model represented only by the first and second derivatives.[7] Equation 1 shows central difference formula for the first derivative and equation (2) shows central difference formula for the second derivative:

$$f'(X) = \frac{f(X+\Delta X) - f(X-\Delta X)}{2\Delta X} + O(\Delta X^2) \quad (1)$$

$$f''(X) = \frac{f(X+\Delta X) - 2f(X) + f(X-\Delta X)}{\Delta X^2} + O(\Delta X^2) \quad (2)$$

We can use implicit or explicit method to solve and minimize this error, but if we use explicit solution method it will give reasonable result if the value selected for ($\Delta t/\Delta x^2$) is less than 1/2. Although explicit method is simpler, it requires selection of small time steps (Δt) or decrease of distances between simulation elements in all x, y, z direc-

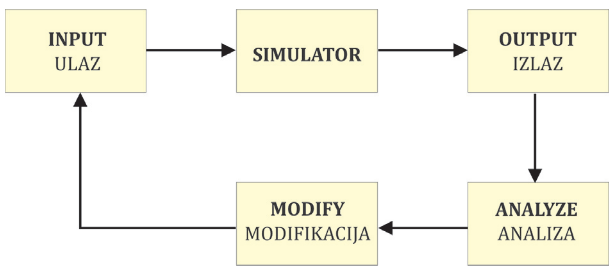

Fig. 1. Mathematical modeling
Sl. 1. Matematičko modeliranje

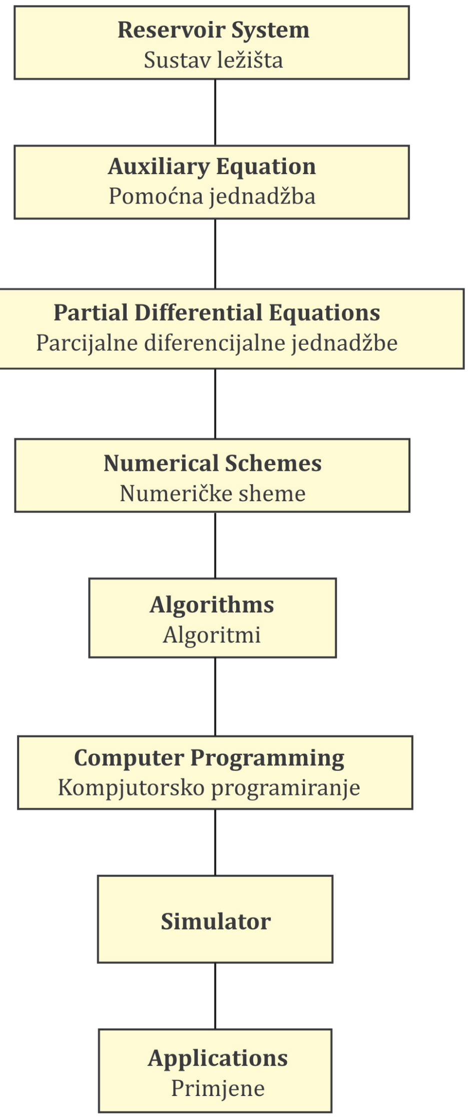

Fig. 2. Flow chart of the simulation
Sl. 2. Dijagram toka simulacije

tions, i.e. increase the number of elements. Otherwise, the solution becomes unstable, but we must remember the implicit method is unconditionally stable.[2,8] Equation (3) shows explicit method formulation, and equation (4) shows implicit method formulation.

$$\frac{P_{i-1}^{n} - 2P_{i}^{n} + P_{i+1}^{n}}{\Delta X^{2}} = \frac{P_{i}^{n+1} - P_{i}^{n}}{\Delta t} \quad (3)$$

$$\frac{P_{i-1}^{n+1} - 2P_{i}^{n+1} + P_{i+1}^{n+1}}{\Delta X^{2}} = \frac{P_{i}^{n+1} - P_{i}^{n}}{\Delta t} \quad (4)$$

3. Simulation of Waterflooding

Waterflooding is used to increase recovery, and to maintain pressure with purpose to sustain the required production rate. In this study we have used "5-spot" pattern, (four injection wells and one production well) with the aim of detection of maximum oil recovery scenario from the reservoir that we have investigated. This reservoir model contains two layers, and between these layers is an impermeable (i.e. k_z = 0.0) layer. Among the results, we need to show the change in water saturation, oil and water relative permeabilities, pressure in simulation elements at different times, oil recovery, and regarding to recovery, what quantity of oil can be produced. Table 1 shows input data, i.e. sets of initialization and recurrent data, for simulation of waterflooding for the considered reservoir.

4. Results and Conclusion

During running the case study of the reservoir model several pictures were created by simulator. Fig. 3 shows simulation run-time monitoring diagram for oil and gas rates, reservoir pressure, gas oil ratio, and water cut. Figs. 4, 5, and 6 show water saturations in different years for different simulation cells. High water saturation can be observed in the first year in the vicinity of water wells only, but after three and five years it increased in other cells of the model due to the continuation of water injection. Fig. 7 shows changes of average pressure with time. At the beginning average pressure is fairly high and immediately after it quickly decreases. Fig. 8 shows changes of oil, water, and gas rates and cumulatives with time. Note also two humps in the oil and water production rates. The first hump is due to water breakthrough in layer 2 (k = 300 mD), followed by the second hump due to water breakthrough in layer 1 (k = 200 mD). Fig. 9 shows percentages of the oil recovery with time for layer 1, and Fig.10 shows the same for layer 2. Fig.11 shows 3D presentation of water saturations in one quarter of five-spot pattern at January 1st, 1997.

In conclusion, in this study we study the relationship between the pressure and time, pressure and radius of the two models, simulator models and line source solution models. The results indicate differences which arise in reservoir model during simulation due to changes in fluid properties, and due to "truncation error". We can decrease the effect of truncation error by decreasing all values of Δx and Δy, or to decrease Δt, or both. Water injection, using 5-spot pattern, will maintain the pressure at a good level, also it will give us high recovery. High-rate injection results in a short life of simulated oil production.

Table 1. Input data for simulation of waterflooding

Input units for simulation	English standard
Fluid phases	oil, gas and water
Initial reservoir temperature	93.33 °C (200 °F)
Standard reference pressure	0.101 MPa (14.7 psia)
Standard reference temperature	60 °F (15.5 °C)
Oil gravity	875 kg/m³ (30 °API)
Bubble point pressure	27.680 MPa (4 014.7 psia)
Under-saturated oil compressibility	2.30E-05 psi^{-1} (3.34E-04 bar^{-1})
Under-saturated oil viscosity slope	4.30E-05 cP/psi (6.2E-04 cP/bar)
Gas gravity	0.65 (air = 1.0)
Density at standard conditions	62.4 lb/ft³ (999.552 kg/m³)
Compressibility	2.8E-6 psi^{-1} (4.1E-5 bar^{-1})
Viscosity	0.3 cp
Oil FVF at initial reservoir pressure	1.02 bbl/STB (m³rc/m³sc)
Maximum pressure	10 000 psi (68.94 MPa)
Irreducible Water Saturation	0.11 fraction
Critical gas saturation	0.05
Residual oil saturation to water	0.18
Residual oil saturation to gas	0.18
Rel. perm. to oil at irreducible water saturation	1
Rel. perm. to gas at res. oil saturation	0.98
Rel. perm. to gas at res. water saturation	1
Pore size distribution index	2
Capillary entry pressure – water/oil	0
Capillary entry pressure – gas/oil	0
Constant compressibility for matrix rock	3E-6 psi^{-1} (4.4E-5 bar^{-1})
Grid type	Regular grid
Number of layers	2
Grid angle (X-axis)	0
Number of X-increments	30
Size of X-increment	100
Number of Y-increments	30
Size of Y-increment	100
Structure tops of layer 1	-5 000 ft (-1 524 m)
Structure tops of layer 2	-5 030 ft (-1 533 m)
Structure bottoms of layer 1	-5 025 ft (-1 532 m)
Structure bottoms of layer 2	-5 050 ft (-1 539 m)
Vertical gross thickness of layer 1	25 ft (7.62 m)
Vertical gross thickkness of layer 2	20 ft (6.09 m)
Vertical net thickness of layer 1	25 ft (7.62 m)
Vertical net thickness of layer 2	20 ft (6.09 m)
X permeability of layer 1	200 mD
X permeability of layer 2	300 mD
Y Permeability of layer 1	200 mD
Y Permeability of layer 2	300 mD
Z Permeability of all layers	0.000 1 mD
Porosity of all layers	0.3
Pressure at bubble point for all layers	4 014.7 psia (276.8 bar)
API gravity for all layers	30 ° (875 kg/m³)
No. of production wells	1
No. of injection wells	4
Oil rate	10 000 STB/d (590 m³/d)
Total rate of water injection	6 000 STB/d (954 m³/d)
First time point date	January 1st, 1995
Last time point date	January 1st, 2002
Time step	1 month

Fig. 3. Simulation run-time monitoring diagram
Sl. 3. Simulaciju dijagrama praćenja vremena izvođenja

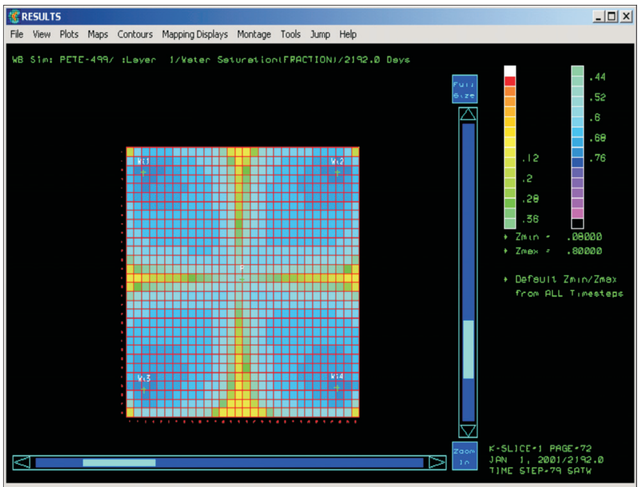

Fig. 6. Water saturation at January 1st, 2001
Sl. 6. Zasićenje vodom na dan 1. siječnja 2001. godine

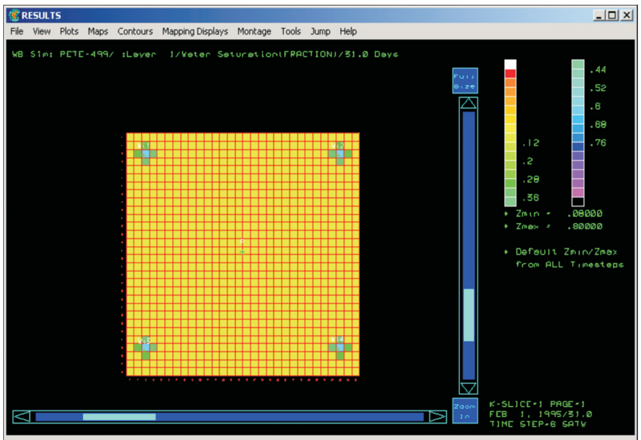

Fig. 4. Water saturation at February 1st, 1995
Sl. 4. Zasićenje vodom na dan 1. veljače 1995. godine

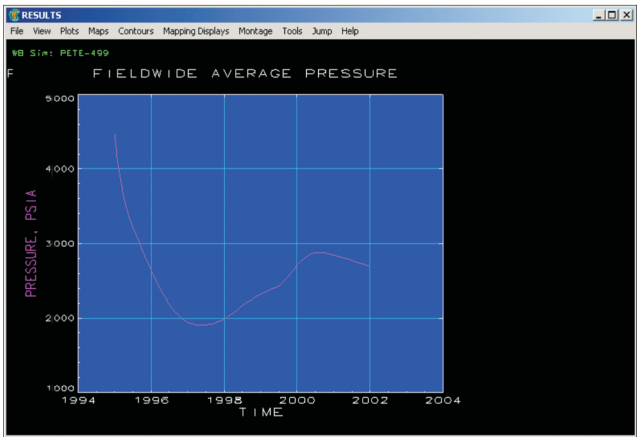

Fig. 7. Average pressure vs. time
Sl. 7. Srednji tlak u odnosu na vrijeme

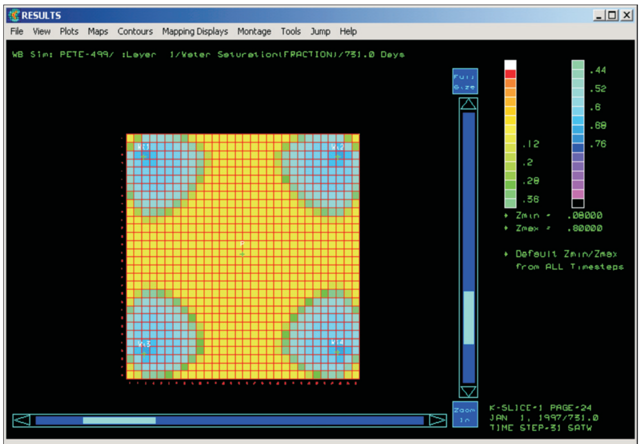

Fig. 5. Water saturation at January 1st, 1997
Sl. 5. Zasićenje vodom na dan 1. siječnja 1997. godine

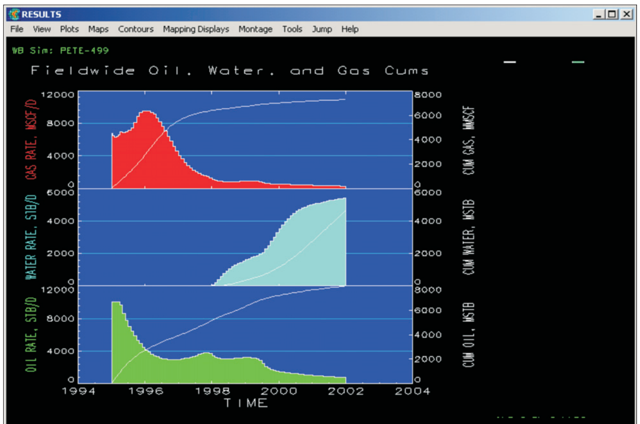

Fig. 8. Oil, water, and gas rates and cumulatives vs. time
Sl. 8. Promjene količine nafte, vode i plina i ukupne količine u odnosu na vrijeme

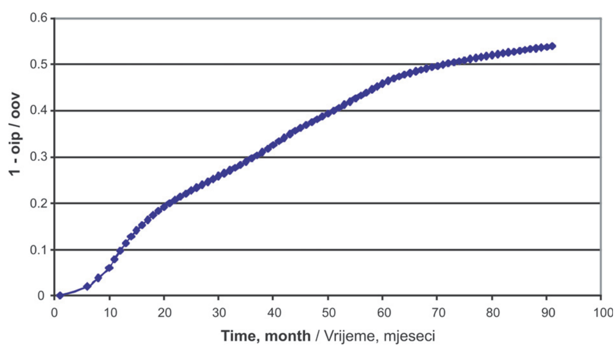

Fig. 9. Oil recovery from layer 1 vs. time.
Sl. 9. Iscrpak iz sloja 1 u odnosu na vrijeme

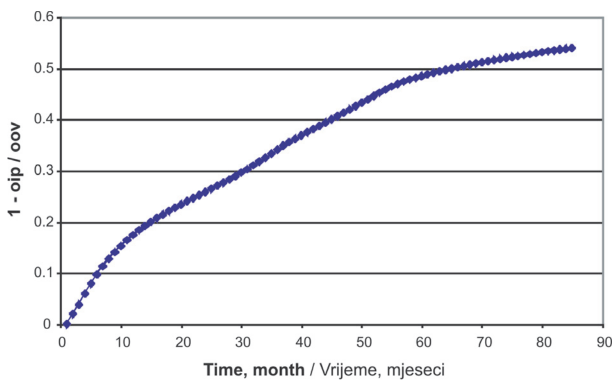

Fig. 10. Oil recovery from layer 2 vs. time.
Sl. 10. Iscrpak iz sloja 2 u odnosu na vrijeme

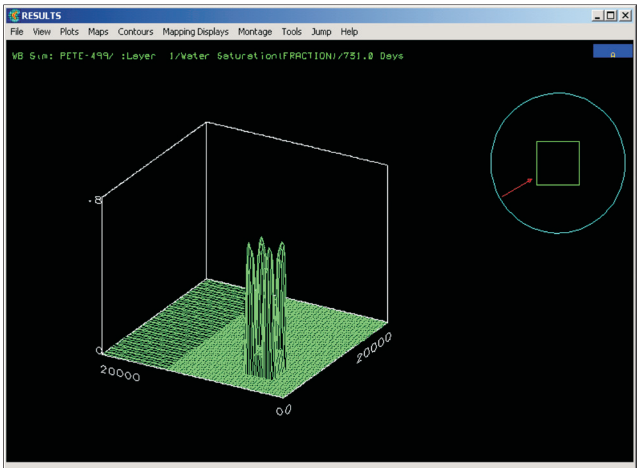

Fig. 11. 3D presentation of water saturation at January 1st, 1997.
Sl. 11. 3D prikaz zasićenja vodom na dan 1. siječnja 1997. godine

Nomenclature

B	formation volume factor, bbl/STB (m^3rc/m^3sc)
C	compressibility, psi^{-1} (bar^{-1})
h	thickness, ft (m)
k	permeability, mD
p_D	dimensionless pressure
p_i	initial pressure, psi (Pa)
p_{wf}	well flowing pressure, psi
q	flow rate, bbl/day (m^3/d)
r_w	wellbore radius, ft (m)
r_D	dimensionless radius
t	time, hr
t_D	dimensionless time
S_w	water saturation, fraction
μ	viscosity, cP
ϕ	porosity, fraction

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