SOCIETY OF PETROLEUM ENGINEERS OF AIME 6200 North Central Expressway Dallas, Texas 75206

PAPER INUIBER SPE 5084

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Oil Production from Fractured Reservoirs by Water Displacement

By

Jon Kleppe* and Richard A. Morse, Members SPE-AIME, Texas A&M U.

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ABSTRACT

A study has been made of the flow behavior of fractured oil reservoirs produced by water displacement. A two-dimensional numerical model capable of simulating flow of water and oil in the matrix blocks as well as in the fractures has been developed. The validity of the model has been checked against data from a laboratory experiment involving a matrix-fracture system. Good agreement was observed between the laboratory and simulation results.

By means of numerical simulation, the effects of production rate and fracture flow capacity on the production history and ultimate oil recovery of a fractured system have been evaluated. Results are presented for a single matrix-block system where the block is surrounded by horizontal and vertical fractures. Production rates ranging from 0.05 to 5 times the gravity reference rate of the matrix, and fracture flow capacities ranging from 0.1 to 10 times the flow capacity of the matrix are included in the investigation. At production rates much lower than the gravity reference rate, the system behaves essentially as a nonfractured reservoir. It is also observed that for fracture flow capacities of the order of onetenth of the matrix flow capacity, the effect of *Now with Royal Norwegian Council for Scientific & Industrial Research.

References and illustrations at end of paper.

the fractures is negligible. At higher fracture flow capacities the water-oil ratio performance of the system becomes increasingly more sensitive to production rate. Water production starts much earlier with high fracture flow capacities and high production rates than it does from a nonfractured reservoir, and a large portion of the oil is produced at high water-oil ratios. However, if the additional water can be handled economically, no oil is lost by high rate production. It is demonstrated that for a given fracture flow capacity, the producing water-oil ratio is a unique function of oil remaining in place and present producing rate. Thus, a reservoir can be produced at a high rate until the water-oil ratio becomes too high to handle. Then, reducing the rate causes the water-oil ratio to decrease to the value it would have had if all the oil had been produced at this lower rate.

INTRODUCTION

A significant number of petroleum reservoirs exist where discontinuities such as fractures or joints in the porous rock matrix are the main paths for transmitting fluids to the producing wells. In naturally fractured reservoirs, the matrix rock generally has a low permeability and one or more well-developed fracture systems are present. Normally, the fractures occupy only a small portion of the total volume of the reservoir, and their contribution to the over-all permeability of the reservoir may be of the same order of magnitude as that of the matrix blocks, even though the permeability of an individual fracture is large compared with the permeability of the matrix.

The flow of fluids in fractured reservoirs has received considerable attention over the past 20 years. Numerous papers¹⁻¹¹ hav been published on the behavior of naturally and artificially fractured reservoirs when a single fluid is flowing. These papers have contributed much to the understanding of the effect of fractures in low permeability reservoirs. The majority of these papers have considered vertical fractures only, and in most cases assumed infinite fracture flow capacity.

When more than one fluid is present, the flow paths become much more complex, and the flow behavior of such systems is presently not fully understood. Mathematical modeling of twoand three-phase flow in fractured reservoirs is extremely difficult because of the discontinuities in permeability and capillary pressure between matrix blocks and fractures. It has been recognized that capillary imbibition may be one of the most important factors controlling the production of oil from the matrix blocks. Brownscombe and Dyes¹² made a laboratory study of the rate of water imbibition in Spraberry cores and found that oil could be recovered successfully by imbibition, but the rate of production was too slow to be economical. Elkins and Skov¹³ studied pilot tests in the same field and found that, when water was injected at rates higher than the imbibition rate, a decline was observed in oil production rate. They hypothesized that the injection of water at rates higher than the imbibition rate interferred with the countercurrent ilow of oil. Mattax and Kyte¹⁴ presented an experimentally determined imbibition function for flow of water through fractures, and found that the time required to recover a given fraction of the oil from the matrix is proportional to the square of the distances between fractures. Blair¹⁵ used numerical techniques to solve the differential equations describing imbibition in linear and radial systems. Braester¹⁶ presented an analytical solution for simultaneous flow of two immiscible fluids through fractured media, and represented the fluid exchange between fractures and matrix blocks by a source function including imbibition and pressure gradient as well as gravitational effects. Birks17 studied matrixblock behavior for gas-oil and oil-water systems and developed analytical functions for oil recovery based on capillary theory and relative permeability theory. Aronofsky et al. 18 studied oil-water systems and developed an abstract model fitting the production data of one particular field. Freeman and Natanson19 investigated

the production behavior of the highly fractured Kirkuk field by means of an electric analyser and by application of the model developed by Aronofsky et al. Andresen et al.²⁰ presented a mathematical model that applies to the fractured Asmari field. Graham and Richardson²¹ used a synthetic model to scale a single element of a fractured reservoir. Cyclic water pulsing was investigated by Owens and Archer.^{22*} They showed that this can be an effective technique for recovering oil from some reservoirs. The same conclusions were reported by Felsenthal and Ferrell.²³ Raza²⁴ studied water and gas cyclic pulsing and found that a combination of the two may overcome some of the limitations of each and improve oil recovery. Yamamoto et al.25 present an oil-gas compositional model for a single matrix block, with a fracture located along the middepth of the block. The fracture represents the boundary conditions around the block, and flow along the fracture is not simulated.

The aim of this work is to investigate the quantitative effects of fracture flow capacity and production rate on the production performance and ultimate oil recovery of a fractured oil reservoir produced by water displacement. In order to perform this str ', a numerical model capable of simultaneously calculating flow in the matrix and the fractures was developed. Recently developed techniques ²⁸⁻³¹ for solving the flow equations are employed in the model.

FORMULATION OF THE PROBLEM

The physical problem under investigation is the flow behavior in a fractured oil reservoir produced by water displacement. The system may consist of a network of fractures surrounding porous blocks, as shown in Fig. 1A. A proposed schematic representation of this system suited for numerical simulation is shown in Fig. 1B. The fractures are represented by horizontal and vertical flow channels of high flow capacity surrounding the low permeability matrix blocks. Due to the small width of the fractures, they only account for a small portion of the total volume, but provide for low resistance transmission of fluids through the reservoir. Three mechanisms contribute to the exchange of fluids between matrix blocks and fractures. They are dynamic pressure gradients, capillary pressures, and gravitational forces. The relative importance of each will depend on the rate at which the reservoir is produced as well as the spacing of the fractures.

Governing Equations

The following assumptions are made: (1) only oil and water present, (2) laminar flow, both in matrix and fractures, and (3) no capillary pressures in the fractures.

Based on these assumptions, the equations describing the flow of fluids are as follow.²⁶ All symbols in equations are defined in Table 4.

Oil equations:

$$u_{0_{\mathbf{x}}} = -k \frac{k_{\mathbf{r}_{0}}}{\mu_{0}} \left(\frac{\partial P_{0}}{\partial \mathbf{x}} \right) \dots \dots \dots (1a)$$
$$u_{0_{\mathbf{y}}} = -k \frac{k_{\mathbf{r}_{0}}}{\mu_{0}} \left(\frac{\partial P_{0}}{\partial \mathbf{y}} - \rho_{0} g \right) \dots \dots (1b)$$

Water equations:

$$u_{\mathbf{w}_{\mathbf{X}}} = -k \frac{k_{\mathbf{r}_{\mathbf{W}}}}{\mu_{\mathbf{0}}} \left(\frac{\partial P_{\mathbf{W}}}{\partial \mathbf{x}} \right) , \dots \dots (1c)$$

$$\mu_{\mathbf{w}_{\mathbf{y}}} = -k \frac{k_{\mathbf{r}_{\mathbf{w}}}}{\mu_{\mathbf{w}}} \left(\frac{\partial \mathbf{P}_{\mathbf{w}}}{\partial \mathbf{x}} - {}^{\rho} \mathbf{w}^{\mathbf{g}} \right) \dots (1d)$$

The continuity equations for each phase:

ðу

$$\frac{\partial}{\partial \mathbf{x}} \left(\frac{c\mathbf{u}_{\mathbf{0}\mathbf{x}}}{B_{\mathbf{0}}} \right) + \frac{\partial}{\partial \mathbf{y}} \left(\frac{c\mathbf{u}_{\mathbf{0}\mathbf{y}}}{B_{\mathbf{0}}} \right) - q_{\mathbf{0}} = \frac{\partial \left(S_{\mathbf{0}} / B_{\mathbf{0}} \right)}{\partial t} - \frac{\partial}{\partial t} + \frac{\partial}{\partial \mathbf{y}} \left(\frac{c\mathbf{u}_{\mathbf{w}}}{B_{\mathbf{w}}} \right) - q_{\mathbf{0}} = \frac{\partial}{\partial \mathbf{x}} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{x}}}{B_{\mathbf{w}}} \right) + \frac{\partial}{\partial \mathbf{y}} \left(\frac{c\mathbf{u}_{\mathbf{w}}}{B_{\mathbf{w}}} \right) - q_{\mathbf{0}} = \frac{\partial \left(S_{\mathbf{w}} / B_{\mathbf{w}} \right)}{\partial t} - \frac{\partial \left(S_{\mathbf{w}} / B_{\mathbf{w}} \right)}{\partial t} - \frac{\partial}{\partial t} = \frac{\partial \left(S_{\mathbf{w}} / B_{\mathbf{w}} \right)}{\partial t} - \frac{\partial}{\partial t} = \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} = \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} = \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} = \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{u}_{\mathbf{w}\mathbf{w}}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{w}\mathbf{w}\mathbf{w}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{w}\mathbf{w}\mathbf{w}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{w}\mathbf{w}\mathbf{w}\mathbf{w}}{\partial t} \right) - \frac{\partial}{\partial t} \left(\frac{c\mathbf{w}\mathbf{w}\mathbf{w}\mathbf{w}}{\partial t}$$

The relationships between pressures and between saturations of the two phases are

$$P_{\mathbf{W}} = P_{\mathbf{o}} - P_{\mathbf{c}} \qquad (3a)$$

$$S_{\mathbf{o}} + S_{\mathbf{w}} = 1 \qquad (3b)$$

By combining these equations, the final differential equations become

$$+q_{\mathbf{w}} = \phi \frac{\partial}{\partial t} (1-S_0)/B_{\mathbf{w}} \dots \dots \dots (5)$$

THE NUMERICAL SOLUTION

For simplicity in development, the equations will here be derived for a one-dimensional, vertical oil-water system. The difference equation for oil flow may be written as^{27-31}

$$\frac{1}{\Delta Y} \left[\left(ck \frac{k_{r_0}}{B_0^{\mu_0} \Delta Y} \right)_{i-1/2} (P_{0i-1} - P_{0i}) \right] \\ -\rho_0 g \Delta h_i^{-} + \left(ck \frac{k_{r_0}}{B_0^{\mu_0} \Delta Y} \right)_{i+1/2} (P_{0i+1}) \right] \\ - P_{0i} - \rho_0 g \Delta h_i^{+} \right]^{n+1} + q_{0i} = \left[\phi_i S_{0i} \frac{d(1/B_0)}{dP_0} \left(\frac{P_{0i}^{n+1} - P_{0i}^{n}}{\Delta t} \right) \right] \\ + \frac{\phi_i}{B_0} \left(\frac{S_{0i}^{n+1} - S_{0i}^{n}}{\Delta t} \right) , \dots \dots (6)$$

and the water equation may be written as

$$\frac{1}{\Delta Y} \left[\left(ck \frac{k_{\mathbf{rw}}}{B_{\mathbf{w}}^{\mu} w \Delta Y} \right)_{i-1/2} \left(P_{0i-1} - P_{0i} \right) \right]$$

$$- P_{ci-1} + P_{ci} - \rho_{\mathbf{w}} g \Delta h_{i}^{-} \right]$$

$$+ \left(ck \frac{k_{\mathbf{rw}}}{B_{\mathbf{w}}^{\mu} w \Delta Y} \right)_{i+1/2} \left(P_{0i+1} - P_{0i} \right)$$

$$- P_{ci+1} + P_{ci} - \rho_{\mathbf{w}} g \Delta h_{i}^{+} \right]^{n+1}$$

$$+ q_{\mathbf{w}i} = \phi_{i} \left(1 - S_{0i} - \frac{d(1/B_{\mathbf{w}})}{dP_{\mathbf{w}}} \right) \left(\frac{P_{0i}^{n+1} - P_{0i}^{n}}{\Delta t} \right)$$

$$- \frac{dP_{c}}{dS_{0}} \frac{S_{0i}^{n+1} - S_{0i}^{n}}{\Delta t} \right)$$

$$+ \frac{\phi_{i}}{B_{\mathbf{w}}} \left(\frac{S_{0i}^{n+1} - S_{0i}^{n}}{\Delta t} \right) \dots \dots \dots (7)$$

The superscripts - and + refer to the negative and positive directions, respectively, and n and n+1 represent old and new time levels. The relative permeabilities K_{ro} and K_{rw} , which are functions of saturations, are the factors changing most rapidly and thus controlling the mobilities. Therefore, to improve the stability of the solution and insure rapid convergence, they will be represented in the following implicit form: 28-30

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The derivatives, dk_{ro}/dS_0 and dk_{rw}/dS_0 , are chord slopes estimated from the relative permeability curves. The capillary pressure terms in the water equation are treated in a similar manner:

$$P_{c}^{n+1} = P_{c}^{n} + \frac{dP_{c}}{dS_{o}} (S_{o}^{n+1} - S_{o}^{n})$$
 (8c)

Since the formation factors, B_0 and B_w , and the viscosities, μ_0 and μ_w , undergo on', small changes during one time step, extrapolated values of these, based on the pressures of the two last time steps, are used. When the above relations are substituted into Eqs. 6 and 7, several nonlinear terms are produced. Thus, the equations cannot be solved directly for saturations and pressures. However, the equations may be modified to overcome this problem. Two different models have been developed for obtaining the solutions and will be presented separately.

Model 1. The Sequential Solution

This model solves for pressures and saturations sequentially. First, the mobilities and capillary pressures are extrapolated at the new time level and substituted into Eqs. 6 and 7, leaving pressures only as unknown variables on the left-hand side of the equations. The two equations are then combined to eliminate the right-hand side saturation terms. The final equation then becomes

$$O_{x}^{+} (P_{o_{i+1}} - P_{o_{i}})^{n+1} + O_{x}^{-} (P_{o_{i-1}})^{n+1} - P_{o_{i}})^{n+1} + A9 = A2 \left(\frac{P_{o_{i}}^{n+1} - P_{o_{i}}^{n}}{\Delta t}\right), (9)$$

where O_x^+ and O_x^- represent the combined flow coefficients in the two directions, A⁹ contains production and injection terms, gravity terms, and capillary-pressure terms, and A² the compressibility terms. This equation can be solved implicitly for pressures at the new time level. The pressures are then substituted back into Eqs. 6 and 7. The extrapolated values of relative permeabilities and capillary pressures used for the pressure solution are now replaced by the implicit forms of Eq. 8. Either one of the

resulting equations can be solved implicitly for saturations. The oil equation will be shown here:

$$\frac{1}{\Delta Y} \left[\left(\frac{ck}{B_{0}\mu_{0}\Delta Y} \right)_{i=1/2} \left(\Delta P_{0y} \right)_{i=1/2} \right] \left[k_{r}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(S_{0}^{n+1} - S_{0}^{n} \right) \right] i_{l}^{n} + \left(\frac{ck}{B_{0}\mu_{0}\Delta Y} \right)_{i+1/2} \left(\Delta P_{0y}^{n} - P_{0g}\Delta h^{+} \right)_{i+1/2} \left(\left(\Delta P_{0y}^{n} - P_{0g}\Delta h^{+} \right) \right)_{i=1/2} + q_{0i}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(S_{0}^{n+1} - S_{0}^{n} \right) \right] i_{l}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(\frac{d(1/B_{0})}{dP_{0}} - \frac{\Delta P_{0y}}{\Delta t} \right)_{i=1/2} + q_{0i}^{n} + \frac{\phi_{i}}{B_{0i}} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n+1} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{n}}{\Delta t} \right) + \frac{\phi_{i}}{\Delta t} \left(\frac{S_{0}^{n} - S_{0}^{$$

The subscripts i1 and i2 refer to the blocks from which the fluid is flowing; i.e., subscript i1 may represent Block i or j-1 and subscript i2 Block i or i+1, depending on the direction of flow. The final form of Eq. 10 is

$$A_i S_{o_{i-1}} + B_i S_{o_i} + C_i S_{o_{i+1}} = D_i$$
 . . . (11)

Eqs. 9 and 11 are solved by the same solution method, a modified Gaussian elimination technique. After each saturation solution, new values are assigned to pressure- and saturationdependent parameters of Eq. 9 and the equation can again be solved for pressures. This process is repeated until a specified convergence criterion on pressures or saturations is reached. Normally two to four iterations are sufficient.

Model 2. The Simultaneous Solution

Simultaneous solution of pressures and saturations are provided for in this model. Including all terms, Eqs. 6 and 7 may be written

$$\frac{1}{\Delta Y} \left(\frac{ck}{B_{0}\mu_{0}\Delta Y}\right)_{i-1/2} \left(P_{0i-1} - P_{0i}\right)$$

$$- \rho_{0}g\Delta h_{i}^{-} \left[k_{r_{0}}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(S_{0}^{n+1} - S_{0}^{n}\right)\right]_{i1}$$

$$+ \frac{1}{\Delta Y} \left(\frac{ck}{B_{0}\mu_{0}\Delta Y}\right)_{i+1/2} \left(P_{0i+1} - P_{0i}\right)$$

$$- \rho_{0}g\Delta h_{i}^{+} \left[k_{r_{0}}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(S_{0}^{n+1}\right)\right]_{i2}$$

$$- S_{0}^{n} \left[k_{r_{0}}^{n} + \frac{dk_{r_{0}}}{dS_{0}} \left(S_{0}^{n+1}\right)\right]_{i2}$$

$$+ q_{0i} = \phi_{i}S_{0i}$$

$$\frac{d(1/B_{0})}{dP_{0}} \left(\frac{P_{0i}^{n+1} - P_{0i}^{n}}{\Delta t}\right)$$

When the multiplications above are carried out, several nonlinear terms appear in the equations. The following modifications are made to eliminate these terms.

By substituting these relationships into Eqs. 12 and 13 and manipulating the terms, the equations may be written

A modified version of the solution routine used in Model 1 is used to solve these equations. Due to the approximations introduced by Eq. 14, it is generally required to solve the equations once for saturations and pressures, then update the estimated values used and solve the equations again.

Comparison of Model 1 and Model 2

Both models were tested on various systems of different degrees of complexity. Model 1 was found to perform satisfactorily for most systems and provides rapid solutions. However, in systems exhibiting vanishing pressure gradients (stable cone problems), and frequently in fractured systems, the model proved to be unstable or failed to reach convergence within a reasonable number of iterations. None of these problems have been observed when using Model 2. The model has been applied to a number of reservoir systems and has never failed to converge. It should be pointed out, however, that Model 2 requires about four times the storage area of Model 1. For the problems on which Model 1 could be used, solution times were about half those of Model 2.

The majority of the simulation runs in this study were done on Model 2.

LABORATORY EXPERIMENT

To check the correctness of the numerical models, a laboratory experiment was designed involving flow of oil and water in a fractured system. The core assembly is snown in Fig. 2. A circular Berea sandstone core approximately 4 in. in diameter and 4 ft long was placed in a Plexiglass tube leaving an annular space of about 2.5 mm between the core and the tube. The annulus simulates a fracture surrounding the core. The dimensions of the system and some of the properties of the core and fluids are listed in Table 1. The imbibition relative permeability and capillary-pressure curves for the core were

determined by conventional methods 3^2 and are shown in Fig. 3.

Initially the core was placed in a rubber sleeve, evacuated, and saturated with brine. The core was then flooded with kerosene until the produced oil-water ratio exceeded 100. Saturations were determined by means of resistivity measurements over sections of the core. The electrodes were narrow strips of conductive paint, painted directly on the core. After the core was mounted in the Plexiglass tube, the annular space was filled with kerosene. Brine was injected at a constant rate into the lower end of the tube. The outlet was open to the atmosphere, providing constant pressure production. During each run, the height of the oilwater interface in the annular space and cumulative productions of oil and water were recorted as functions of time. The runs were terminated when the WOR reached about 30. After each run, the core was placed in the rubber sleeve and flooded with kerosene until the produced oil-water ratio exceeded 100.

The laboratory system was simulated on the computer using Model 2. Fig. 4 shows cumulative oil production from the core as a function of cumulative water injected for two injection rates. Good agreement is seen between the experimental data and the simulation data. At the low rate, the displacement of oil from the core is almost piston-like. Essentially, no oil was produced after the oil-water interface reached the top of the core. At the faster rate, water breaks through earlier, and some 20 percent of the movable oil was produced after the oil-water interface reached the outlet.

PRELIMINARY INVESTIGATION - "FIELD" SYSTEM

The general geometry of the system under investigation is shown in Fig. 1B. Before proceeding to the actual investigation, it was desired to find the smallest system (i.e., fewest matrix blocks) that could be simulated and still exhibit the behavior of a fractured reservoir consisting of several matrix blocks separated by fractures. The smallest system possible is a single matrix block surrounded by fractures. Simulations were made of this system, and of systems consisting of two matrix blocks positioned horizontally and two matrix blocks placed vertically. At this point it is convenient to define two parameters used in the following graphs. First. the base production rate used is the gravity reference rate of the matrix. This is the rate at which oil would be produced from a completely oil-saturated matrix subjected to a pressure gradient equal to the difference in gravity heads of oil and water. In equation form this rate may be expressed as

Gravity reference rate = $\frac{kA}{\mu_0 B_0} (\rho_W - \rho_0)$

Hereafter, all rates will be expressed as fractions or multiples of this rate. A second definition needed is that of the conductivity ratio. This is the ratio of the total vertical flow capacity of the fractures to the vertical flow capacity of the matrix.

Fig. 5 shows WOR vs cumulative oil production for the single matrix-block system and for the system of two matrix blocks connected horizontally. Each of the two matrix blocks was the same size as the single block. Although the total fracture flow capacities and actual production rates of the two systems are different, the conductivity ratios and the production rates in terms of the respective gravity reference rates are the same. Only small differences are noted between the two curves. One may therefore conclude that, even if more matrix blocks were present in a horizontal system, the behavior of the system would be essentially unchanged.

In Fig. 6 the single matrix-block system is compared with the system where the two matrix blocks are placed in contact vertically. A large difference in performance is observed when the systems are produced at the same rate. A similar difference can be noted in Fig. 7, where a single matrix-block system of equal height and width is compared with a single matrix-block system where the height is twice the width. Thus, the behavior of a single matrix-block system cannot readily be applied to systems of different block heights or systems where more than one matrix block is placed vertically. Such systems must be simulated separately. However, for the purpose of this investigation, the single matrix-block system shown in Fig. 8 will be chosen. The 50 by 50 ft matrix block is surrounded by fractures of 0.01ft width. The grid break-up shown is the result of a study made of several grid arrangements shown in . 9. For this figure and subsequent figures, the time has been expressed as a product of the matrix permeability in md and real time in days.

The system is initially at capillary equilibrium with the oil-water contact located in the lower horizontal fracture. Water is injected at a constant rate into the lower right-hand fracture block. Fluids are produced from the top left-hand fracture block. To insure nearly uniform water drive, the lower horizontal fracture is assigned a permeability of 1,000 darcies.

The rock and fluid properties of the system are listed in Table 3.

DISCUSSION OF RESULTS - "FIELD" SYSTEMS

The results presented in this section were derived from numerical simulations made by means of Model 2. Production histories were obtained from initial production to a WOR of 100. All calculations were made on an IBM 360/65 computer and solution times ranged from 2.5 to 4.5 minutes, depending on the number of time steps required. Generally, more time steps were required at low production rates.

Produced WOR of fractured reservoirs was found to be very sensitive to production rate and fracture flow capacity. Fig. 10 shows producing WOR as a function of cumulative oil production for a case where the fracture flow capacity is 10 times higher than that of the matrix. Great differences in performance are noted among the three rates shown. At the lowest rate of 0.05 times the gravity reference rate, about 63 percent of the oil in place is produced before water breaks through at the producing block. The WOR increases very rapidly after this point, and only 9 percent of additional oil is produced before the WOR reaches 100. At a production rate of 0.5 times the gravity reference rate, or 10 times higher than the lowest rate, water breakthrough occurs much earlier, but the WOR remains at a relatively low value until some 55 percent of the oil has been produced. The recovery at a WOR of 100 is 5 percent less than at the lowest production rate. If the system is produced at a rate of five times the gravity reference rate, almost instant water breakthrough results at the producing block. Almost no oil is produced before a WOR of 5 is reached. However, a fairly linear increase can be observed until a WOR of 20 is reached. A steep increase is noted after this point, and the recovery at a WOR of 100 is only 61 percent, compared with 72 percent at the lowest rate. The rate sensitivity of oil recovery is much more marked at lower WOR's. If the maximum WOR that can be handled economically in the field is 20, the oil recoveries at the three rates are 68.5, 62, and 42 percent of the oil in place.

At a conductivity ratio of 1.0 (Fig. 11), the difference in performance between the three rates are greatly reduced. Water breakthrough for the three rates does not change much with this reduction in conductivity ratio. However. the WOR's for the two highest rates remain at much lower values for a longer period of time than do those at the higher conductivity ratio. At the lowest rate, the curve is almost identical to the one at a conductivity ratio of 10. This indicates that at such low rates the system behaves essentially as a nonfractured reservoir. At the two highest rates, for a conductivity ratio of 1.0, the recoveries at a WOR of 100 are increased to 68 and 66.5 percent. At this conductivity ratio, a substantial increase in recovery can be observed at a WOR of 20, particularly for the highest rate where 61.5 percent is produced.

Further increases in recoveries can be noted for the case where the fracture flow capacity is 1/10th of the matrix flow capacity (Fig. 12). For all three rates most of the oil is produced before any water production occurs. The difference in oil recovery between the middle and the highest rate is less than 1 percent, and between the middle and the lowest rate about 2.5 percent.

Fig. 13 shows cumulative oil production as a function of time for the highest conductivity ratio. In a nonfractured system the three curves would be approximately evenly spaced. This is not so in a fractured system. For example, at this conductivity ratio the times required to produce 50 percent of the oil in place are 70,800, 17,500, and 9,600 md-days for the three rates, or 194, 48, and 26 years if the matrix permeability is 1 md. Thus, there is a fourfold difference in time between the middle and the highest rates, and only a 1.8-fold difference between the lowest and the middle rates. This also indicates that a further increase in the production rate at this conductivity ratio will not result in a corresponding change in the water-oil ratio performance of the system.

Similar curves are shown in Fig. 14 for a conductivity ratio of 1.0. The curves are more evenly spaced, indicating that the effect of the fractures on the performance of the system is becoming less important. Again, assuming a matrix permeability of 1 md, the times required to produce 50 percent of the oil in place are 194, 37, and 6.6 years, respectively.

At the lowest conductivity ratio (Fig. 15). the curves are almost evenly spaced. Thus, the effect of the fractures at such a low conductivity ratio is small. The times required to produce 50 percent of the oil in place for the three rates are 194, 22, and 2.4 years. Comparing the highest and the lowest conductivity ratio at the highest rate, it is seen that there is more than tenfold difference in the time required to reach 50 percent recovery. This difference is, of course, because much more water had to be produced at the higher conductivity ratio. Fig. 16 shows cumulative water production vs cumulative oil production for the highest conductivity ratio. To produce 50 percent of the oil in place, no water would be produced at the lowest rate. At the two higher rates the water production at 50 percent would be 0.65 and 5.7 pore volumes. At the middle conductivity ratio (Fig. 17), these curves have been shifted downward considerably, and the water productions for the two highest rates to reach the 50 percent points are to 1.1 and 0.4 PV. The differences between the curves are very small at the lowest conductivity ratio (Fig. 18). At the middle production rate only .07 PV of

water is produced at the 50 percent depletion point, and at the highest rate 0.1 PV must be produced. At the highest production rate a change in conductivity ratio from 0.1 to 10 causes a 5.4-fold difference in the amount of water that must be produced to produce 50 percent of the oil in place.

Figs. 19 and 20 show the differences in flooding patterns for these two cases. Fig. 19 shows oil saturation contours in the matrix block at a WOR of 20 for the highest conductivity ratio and the highest production rate. At this stage of depletion, 42 percent of the oil has been produced. Most of the oil remaining is located in the upper middle of the matrix, while the lower parts and the matrix close to the vertical fractures are nearly flooded out. Thus, most of the water entering the matrix from the lower fracture will bypass the oil and be produced through the fractures. A similar graph for the lowest rate and lowest conductivity ratio is shown in Fig. 20. The WCR is again 20, but in this case 69 percent of the oil has been produced. It can be seen from the shape of the contours that the water has moved into the matrix block almost vertically, thus resulting in almost piston-like sweep. This is similar to the performance of a nonfractured system.

At this point it is of interest to know if oil bypassed by water injected at very high rates remains trapped or if it can be recovered at a lower rate of water injection. The next three graphs show the results of simulations made at the highest conductivity ratio. The injection rate was five times the gravity reference rate until a produced WOR of 30 was reached. At this point the rate of water injection was reduced to 0.5 times the gravity reference rate for the rest of the production history. Fig. 21 shows the water-oil ratio performance. As soon as the rate was reduced, the water-oil ratio dropped almost instantly to the low rate curve, and reproduced this curve perfectly to a WOR of 100. Figs. 22 and 23 show this effect on cumulative oil production vs time and cumulative water production vs cumulative oil production. This leads to the important conclusion that oil is not trapped in the matrix by high production rates, but can be recovered successfully by lowering the production rate. The optimum production program for a particular field can be designed according to present value principles.

SUMMARY AND CONCLUSIONS

A numerical model capable of calculating flow of oil and water in fractured reservoirs has been developed. The validity of the model has been proved by laboratory experiments.

Simulations have been performed for a

field-size fractured reservoir. The system simulated was a 50 by 50 ft matrix block surrounded by horizontal and vertical fractures. The production rates ranged from 0.05 to 5 times the gravity reference rate of the matrix, and the vertical fracture flow capacities ranged from 0.1 to 10 times the flow capacity of the matrix.

At high fracture flow capacities, the oil recovery is very sensitive to production rate. At high rates water breakthrough occurs early in the production history and most of the oil is produced at high water-oil ratios. For rates on the order of 0.05 times the gravity reference rate, the system behaves essentially as a nonfractured reservoir. At a WOR of 20 and a conductivity ratio of 10, 27 percent difference in oil recovery is observed between the highest and lowest rates. The difference in oil recovery becomes less at lower conductivity ratios. The effect of the fractures is negligible at fracture flow capacities less than 1/10th of the matrix flow capacity. It is shown that oil remaining in a fractured reservoir produced at a high rate is not lost, but can be recovered at lower rates.

Conclusions of this work on water displacement in fractured oil reservoirs are as follow.

1. A numerical model that simultaneously calculates flow of oil and water in the fractures and the matrix has been developed. The model exhibits completely stable saturation and pressure solutions at all stages of depletion.

2. Ultimate oil recovery from fractured reservoirs is greatly affected by production rate at conductivity ratios higher than 1. Higher rates result in lower recoveries.

3. For fracture flow capacities of the order of 1/10th the matrix flow capacities, the effect of production rate on oil recovery is negligible.

4. At production rates of the order of 0.05 times the gravity reference rate, fractured systems behave essentially as nonfractured reservoirs.

5. Oil is not lost because of high production rates, but can be recovered by reducing rate.

NOMENCLATURE

Capital Letters

- A2 = factor including all compressibility terms
- A9 = factor including production and injection terms, gravity terms and

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| capillary pressure terms | } | |
|--|-------------|--|
| A,C,E,D = matrix coefficients | | <u>Soc. Pet. Eng. J.</u> (June 1967) 221-228. |
| B ₀ = oil formation volume factor | 5. | Parson, R. W .: "Permeability of Idealized |
| OIP = oil in place | | Fractured Rock," Soc. Pet. Eng. J. (June |
| $P_{o} = oil pressure$ | | 1966) 1926–1936, |
| $P_{C} = capillary pressure$ | 6. | Warren, T. E. and Root, P. J.: "The |
| P_w = water pressure | | Behavior of Naturally Fractured Reservoirs." |
| Q_{id} = dimensionless water injection rate | | Soc. Pet. Eng. J. (Sept. 1963) 245-255. |
| $S_{0} = 0il$ saturation | 7. | Russell, D. and Truitt, N. E.: "Transient |
| $S_{a} = Water saturation$ | ļ | Pressure Behavior in Vertically Enactured |
| WOR = water-oil ratio | | Reservoirs," J. Pet Tech (Oct 1061) 1150 |
| $\wedge \mathbf{X} = horizontal call length$ | | 1170. |
| $\wedge \mathbf{Y} = $ wortigel cell length | 8 | Tomme W I Milem D and Quartered David |
| 21 - VELOTORT GETT TEHBOU | | B . Illow to Determine the Tau il a |
| Lavon Gaza Tottana | | Northand Emotions from The Length of a |
| Lower Case Letters | | Production Date " Other in (1.7, 20, 10(2)) |
| a - anortitu | | Production Data," <u>Oilweek</u> (July 30, 1962) |
| g = gravicy | | 13, 24, 35. |
| k = specific permeability | 9. | Prats, M., Hazebroek, P. and Strickler, W. |
| Kro = relative permeability to oil | | R.: "Effect of Vertical Fractures on Reser- |
| $K_{\rm TW}$ = relative permeability to water | J | voir Behavior-Compressible Fluid Case," Soc. |
| q _o = oil flow rate | ļ | Pet. Eng. J. (June 1962) 87-94. |
| q_W = water flow rate | 10. | McGuire, W. J. and Sikora, V. J.: "The |
| t = time | ł | Effect of Vertical Fractures on Well Produc- |
| ∆t = time increment | [| tivity," Trans., AIME (1960) 219. L(1-103. |
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| u, = water flow rate per unit area | | tions," Proc., Fourth World Petroleum |
| \mathbf{x} = horizontal coordinate axis | | Congress, Section IT/E Paper 7 (1955) |
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| $\mu_{\rm u}$ = water viscosity | | Waterflooding the Spraberry Utilizes 'End |
| $\rho_{o} = \text{oil density}$ | 1 | Effects' To Increase Oil Production Rate," |
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TABLE 1 - PROPERTIES OF THE LABORATORY SYSTEM

| Permeability | = 290 md |
|-------------------------|----------------|
| Porosity | = 22,5 percent |
| Diameter of core | = 9.87 cm |
| Length of core | = 122.8 cm |
| Inside diameter of tube | = 10,39 cm |
| Density of oil | = 0.811 gm/cc |
| Density of brine | = 1.02 gm/cc |
| Viscosity of oil | = 2,3 cp |
| Viscosity of brine | = 1.0 cp |
| Pore volume of core | = 2114 cc |
| Volume of fracture | = 1017 cc |

TABLE 2 - PROPERTIES OF THE SINGLE BLOCK SYSTEM

| Oil density | 0.808 gm/cc |
|-----------------------|-------------------------------------|
| Water density | 1.04 gm/cc |
| Oil compressibility | 9.3 x 10 ⁻⁶ vol/vol/psi |
| Water compressibility | 4.05 x 10 ⁻⁶ vol/vol/psi |
| Oil viscosity | 0.51 cp |
| Water viscosity | 1.02 cp |

Water-Oil Relative Permeabilities and Capillary Pressures

| <u>s</u> o | k _{ro} | k _{rw} | Pc |
|------------|-----------------|-----------------|------|
| 0.15 | 0.88 | 0.0000 | 2.75 |
| 0.20 | 0.75 | 0.0050 | 0.66 |
| 0.25 | 0.59 | 0.010 | 0.54 |
| 0.30 | 0.45 | 0.017 | 0.48 |
| 0.35 | 0.33 | 0,023 | 0.42 |
| 0.40 | 0.25 | 0.031 | 0.38 |
| 0.45 | 0.18 | 0.039 | 0.34 |
| 0.50 | 0,12 | 0.050 | 0.30 |
| 0.55 | 0.072 | 0.063 | 0.27 |
| 0.60 | 0.037 | 0.080 | 0.24 |
| 0.65 | 0,016 | U.100 | 0.21 |
| 0.70 | 0.0020 | 0.12 | 0.17 |
| 0.75 | 0.0001 | 0.15 | 9.12 |
| 0.80 | 0.0000 | 0.19 | 0.05 |



Fig. 1 - (A) A porous fractured medium and (B) the schematic flow model.



Fig. 2 - Laboratory core assembly.







Fig. 6 - Effect of matrix blocks placed vertically.









Fig. 9 - Effect of grid break-up.













Fig. 14 - Cumulative oil production vs time (conductivity ratio = 1.0).



Fig. 15 - Cumulative oil production vs time (conductivity ratio = 0.1).



Fig. 16 - Cumulative water production vs cumulative oil production (conductivity ratio = 10).













Fig. 21 - Effect of reducing the production rate on water-oil ratio.

Fig. 23 - Effect of reducing the production rate on cumulative water production.



Fig. 22 - Effect of reducing the production rate on oil recovery.