Sixth SPE Comparative Solution Project: Dual-Porosity Simulators

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Summary. Two problems are used to compare fractured reservoir models: (1) a simple single-block example, and (2) a more complicated cross-sectional example developed to simulate depletion, gas-injection, and water-injection cases. In selection of the problems for this Comparative Solution Project, some aspects of the physics of multiphase flow in fractured porous media were considered. The influence of fracture capillary pressure on reservoir performance has been addressed by cases with zero and nonzero gas/oil capillary pressure in the fractures.

Introduction

In recent years, interest in the simulation of naturally fractured petroleum reservoirs has increased. For this SPE Comparative Solution Project, reservoir test problems were designed to illustrate some aspects of the physics of multiphase flow in fractured reservoirs and modeling techniques to account for capillary and gravity forces. The approach to the solution of the problems has been limited to dual-porosity models.

An important element in simulating a fractured reservoir with a dual-porosity technique is the proper calculation of the fluids exchange between the matrix blocks and the fractures. In the conventional approach, the transfer term for a particular phase is directly related to the shape factor, σ, fluid mobility, and potential difference between the matrix and fracture.[1] Shape factors have been developed based on first-order finite-difference approximations[2] and by matching fine-grid multiphase simulations of matrix/fracture flow.[3]

In most dual-porosity models, the matrix block heights are assumed to be at the same depth as the corresponding fracture blocks, and therefore, gravity has no explicit effect on the fluid exchange between the matrix and the fracture. Pseudo capillary pressures have been used to account for the effect of gravity.[3] The gravity-segregation concept has also been used to compute the fluid levels in the matrix and fractures to account for the gravity contribution.[4,5] An alternative approach has been presented in Ref. 6 (see the second option) to account for gravity effects.

Dual-porosity models also must account for the saturation distribution in a matrix block. Because the saturation is evaluated at the center of a grid cell, it represents an average value for that cell. The pseudo-capillary-pressure concept has been used to account for both gravity effects and nonuniform saturations within a matrix block.[3,7,8] The method of subdomain discretization has also been applied to this problem.[9,10] In that approach, the matrix is divided into a number of grid cells and pressures and saturations are calculated for each grid cell. The subdomain approach can also take care of transient effects. These effects, however, may not be important in field-scale problems.

Although fracture capillary pressure is assumed to be zero in most dual-porosity models, a recent paper[11] questions the validity of this concept. In selection of the problems for this Comparative Solution Project, the influence of fracture capillary pressure on reservoir performance was addressed by including cases with zero and nonzero gas/oil capillary pressure in the fractures. The nonzero fracture capillary pressures are not based on any actual measurements, but are intended as a parameter for sensitivity studies. The variation of gas/oil interfacial tension (IFT) with pressure has also been incorporated in the problems. Gas/oil capillary pressure is directly related to IFT, and therefore, the gas/oil capillary pressure should be adjusted according to the ratio of IFT at reservoir pressure divided by IFT at the pressure at which capillary pressures are specified.

Problem Statement

We selected two problems to compare fractured reservoir models: a single-block example and a more complicated cross-sectional example developed to simulate depletion, gas-injection, and water-injection cases.

Basic PVT data for the above cases were taken from Ref. 3. The rock/fluid data, with the exception of the matrix water/oil capillary pressure, were also taken from Ref. 3. **Table 1** gives the matrix water/oil capillary pressure data. Matrix-block shape factors have been specified for use in simulators that directly enter this variable (see **Table 2**).

Single-Block Studies. The single-block simulation is a study of gas/oil gravity drainage at 4,500 psig [31.0 MPa] for a cubic matrix block with dimensions of $10 \times 10 \times 10$ ft [$3.05 \times 3.05 \times 3.05$ m]. One-cell, dual-porosity runs were made for this case. Two runs were reported: the first with a zero fracture capillary pressure and the second with a constant fracture capillary pressure of 0.1 psi [0.69 kPa]. These runs were terminated at 5 years.

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TABLE 1—MATRIX WATER/OIL CAPILLARY PRESSURE DATA		
	P_{cwo}	
S_w	psi	kPa
0.20	1.0	6.89
0.25	0.5	3.45
0.30	0.3	2.07
0.35	0.15	1.03
0.40	0.00	0.00
0.45	−0.2	−1.38
0.50	−1.2	−8.27
0.60	−4.0	−27.0
0.70	−10.0	−68.9
0.75	−40.0	−275.0

TABLE 2—MATRIX-BLOCK SHAPE FACTORS*			
Block Size		Water/Oil Shape Factor	
ft	m	ft^{-2}	m^{-2}
5	1.52	1.000	10.76
10	3.05	0.250	2.69
25	7.62	0.040	0.43

*Ref. 3 gives the basis for selection of the shape factors. Participants were given the choice to use a single shape factor for a given block size for both water/oil and gas/oil cases or different values for the two cases. Some techniques do not use shape factors.

Cross-Sectional Studies. The layer description for the cross-sectional studies is given in **Table 3.** In all studies, the injection well was at $I=1$ and the production well at $I=10$. Input data for each study are given below.

Depletion. Depletion runs were carried out to a maximum of 10 years or whenever production declined to less than 1 STB/D [0.16 stock-tank m^3/d]. The production well has a maximum rate of 500 STB/D [80 stock-tank m^3/d] and was limited by a maximum drawdown of 100 psi [689 kPa]. This well was perforated only in the bottom layer.

Two runs were made: the first with zero fracture capillary pressure and the second with fracture capillary pressure data from **Table 4.** These data are reported at the bubblepoint pressure of 5,545 psig [38.23 MPa] and were adjusted for the effect of pressure on IFT.

Gas Injection. For these runs, 90% of the gas produced from the previous timestep was reinjected. The injection well was perforated in Layers 1 through 3. The production well was perforated only in Layers 4 and 5 and was constrained by a maximum drawdown of 100 psi [689 kPa]. A maximum rate of 1,000 STB/D [160 m^3/d] was set. The minimum cutoff rate was 100 STB/D [16 stock-tank m^3/d].

Two runs were made: the first with zero fracture capillary pressure and the second with fracture capillary pressure data from Table 4 adjusted for the pressure effect.

Water Injection. In this run, water was injected at time zero at a maximum rate of 1,750 STB/D [280 stock-tank m^3/d] and was constrained by a maximum injection pressure of 6,100 psig [42.06 MPa]. The production rate was set at 1,000 STB/D [160 stock-tank m^3/d] of total liquid(s) (water and oil). The injection well was perforated in Layers 1 through 5, and the production well was perforated in Layers 1 through 3. A run time of 20 years was reported.

The following data were specified for the two problems to control timestep sizes: maximum saturation change=0.1, maximum pressure change=500 psi [3.45 MPa], and maximum saturation pressure change=500 psi [3.45 MPa]. Maximum timestep increment for the gas- and water-injection cases was set to 0.25 years. Maximum timestep increment for the depletion cases was set to 0.1 year to minimize time truncation error.

"...reservoir test problems were designed to illustrate some aspects of the physics of multiphase flow in fractured reservoirs and modeling techniques to account for capillary and gravity forces."

Reporting Results

For the single-block gas/oil gravity drainage runs, oil recovery vs. time at 0.25-year increments was reported. The following re-

TABLE 3—BASIC DATA

k_{ma}, md	1
ϕ_{ma}	0.29
ϕ_f	0.01
n_x	10
n_y	1
n_z	5
Δx, ft [m]	200 [61]
Δy, ft [m]	1,000 [305]
Δz, ft [m]	50 [15.2]
Initial reservoir pressure (1,1,1), psi [MPa]	6,000 [41.37]
z-direction transmissibilities	multiply calculated values by 0.1

Layer Data

Layer	Effective Fracture Permeability (md)	Block Height ft	Block Height m	J* (res bbl-cp)/(D-psi)
1	10	25	7.62	1
2	10	25	7.62	1
3	90	5	1.52	9
4	20	10	3.05	2
5	20	10	3.05	2

*$q=(k_r J)/(B\mu)\Delta p$, where Δp is in psi, μ in cp, B in RB/STB, and q in STB/D.

TABLE 4—FRACTURE CAPILLARY PRESSURE DATA*		
	P_{cfgo}^{**}	
S_g	psi	kPa
0.0	0.0375	0.258
0.10	0.0425	0.293
0.20	0.0475	0.327
0.30	0.0575	0.396
0.40	0.0725	0.500
0.50	0.0880	0.607
0.70	0.1260	0.869
1.0	0.1930	1.331

*Fracture water/oil capillary pressure is equal to zero. Fracture relative permeability curves are straight lines with zero residuals.
**At the bubblepoint pressure of 5,545 psig [38.23 MPa].

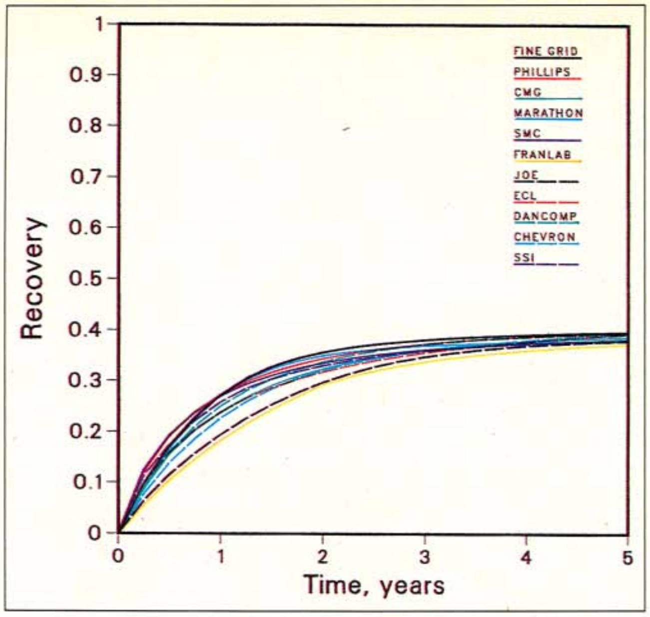

Fig. 1—Recovery vs. time: single block, zero P_{cf}.

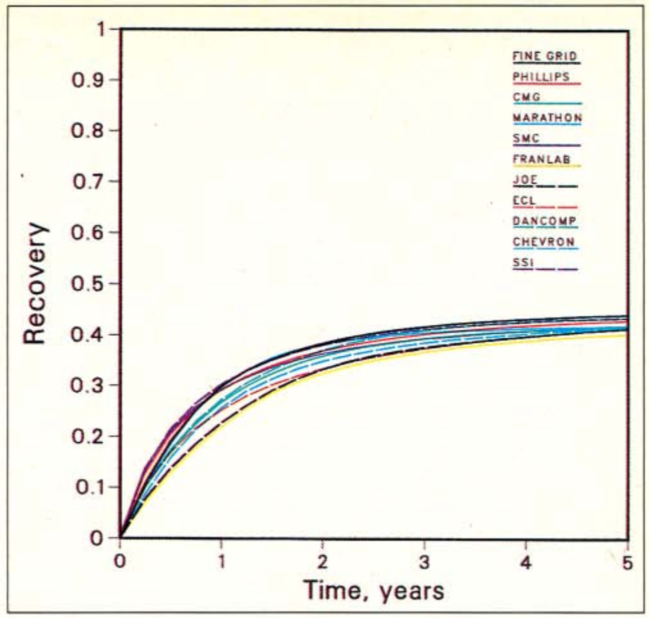

Fig. 2—Recovery vs. time: single block, nonzero P_{cf}.

sults were reported for the cross-sectional runs.

1. Oil production rate, GOR, and pressure at Gridblock (5,1,1) each year for the depletion and gas-injection runs.
2. Fracture and matrix gas saturations at 2, 5, 10, and 20 years for the column of blocks at $I=5$ and $K=1$ through 5 for the gas-injection case with the nonzero fracture capillary pressure.
3. Oil production rate and water cut each year for the water-injection run.
4. Total number of timesteps and global iterations for all runs.

Description of Models

The 10 organizations that participated in the Sixth SPE Comparative Solution Project used the models described below.

Chevron Oil Field Research Co. Chevron used their naturally fractured reservoir simulator, NFRS, to solve the problems of the Comparative Solution Project. This simulator, based on the methodology outlined in Ref. 12, avoids the use of shape factors by using cylindrical matrix blocks that may be discretized in the r and z directions.[9] Fluid exchange between fracture and matrix is allowed through top, bottom, and side faces of the matrix blocks.

Two cells were used to solve the single-matrix problem: one cell contained a gas injector at 0.5 PV/D and the other cell contained a producer at 4,500 psig [31.0 MPa].

A sensitivity analysis showed that vertical discretization of matrix blocks had a strong effect on oil recovery. This effect was strongest in the gas-injection example with zero fracture capillary pressure. As a result of the sensitivity analysis, four matrix-block layers were used in the single-block problem for the depletion and gas-injection cases and the water-injection case was run with undiscretized matrix blocks.

Computer Modelling Group (CMG). CMG used the IMEX model, which is both a single-porosity and a dual-porosity/dual-permeability, four-component, adaptive-implicit reservoir simulator. For the dual-porosity option, IMEX allows the discretization of the matrix blocks into subblocks either in the nested format,[10] for the representation of transient effects, or in the layer format, for the representation of gravity effect.[13]

For the problems of this project, the dual-porosity option with the subdomain approach was used to represent the matrix/fracture fluid-transfer calculations. In this model, the matrix block dimensions are entered directly and no shape factor is required. Because the matrix block is discretized, the fluid transfer between the matrix and the fracture is believed to be represented properly by difference equations. Within a given gridblock, gravity segregation is assumed in the fractures. All runs were performed with five subdomain blocks per grid cell. A five-point differencing scheme with single-point upstream-weighted mobility was used.

Dancomp A/S. Dancomp A/S used its DANCOMP/RISO simulator for the test examples of the project. This is a three-phase, 3D, isothermal model that can run in either black-oil or compositional modes with a dual-porosity/dual-permeability option.

Space discretization is performed by the integral finite-difference technique to avoid reference to a specific coordinate system. The time-integration method is fully implicit, and the timestep is adjusted automatically to maintain a specified accuracy. The resulting nonlinear system of equations is solved by the Newton-Raphson method. The system of linear equations is solved either by a direct band solver or by an iterative sparse matrix solver.

In the DANCOMP/RISO model, the saturation gradients within the matrix blocks for an imbibition process are taken into account. The imbibition is modeled as a diffusion process with capillary pressure as the driving mechanism.[14] The corresponding diffusion equation is solved either numerically or analytically. Recovery from gas/oil gravity drainage is found by considering (1) matrix blocks above the gas/oil contact (GOC), (2) matrix blocks in the GOC zone, and (3) matrix blocks below the GOC. In water/oil cases, a capillary continuity between adjacent horizontal matrix blocks in the same grid cell is assumed.

Exploration Consultants Ltd. (ECL). ECL used the ECLIPSE model in dual-porosity mode. This model required two simulation cells to represent each gridblock volume; one each for the rock matrix and the fracture properties. In the dual-porosity mode, the shape factor in the transfer function term was computed from Eq. 5 of Ref. 1.

ECLIPSE is a fully implicit program and reinjects a fraction of the phase production or reservoir voidage from the current timestep to model pressure-maintenance schemes. This approach has been used in the gas-injection runs rather than reinjecting gas from the previous timestep.

In all the runs, the ECLIPSE iterative solution techniques of nested factorization for the linear equations and Newton's method for the nonlinear equations were used. Drawdown control in ECLIPSE was simulated by converting the maximum drawdown to a maximum liquid rate that may not be exceeded. This target liquid rate was updated at each nonlinear iteration. Limiting the number of iterations for which the target is updated would reduce the number of iterations at the expense of accuracy.

Franlab. Franlab used FRAGOR to simulate the test examples. This model is a three-

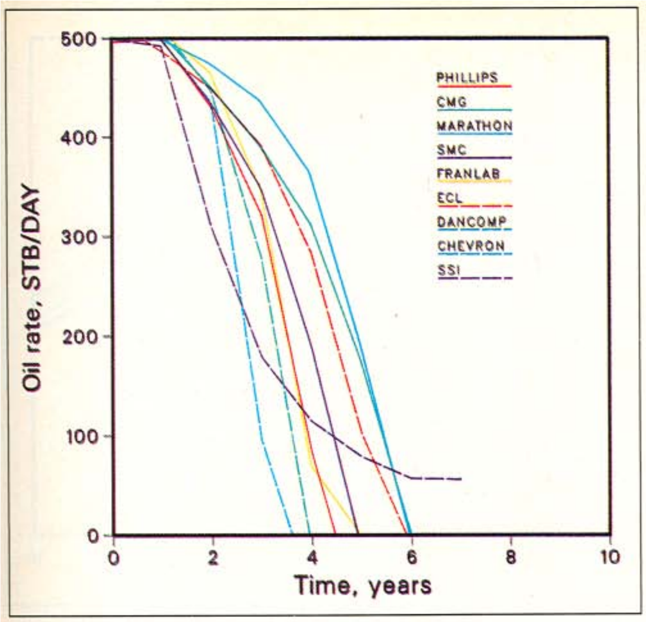

Fig. 3—Oil rate vs. time: depletion, zero P_{cf}.

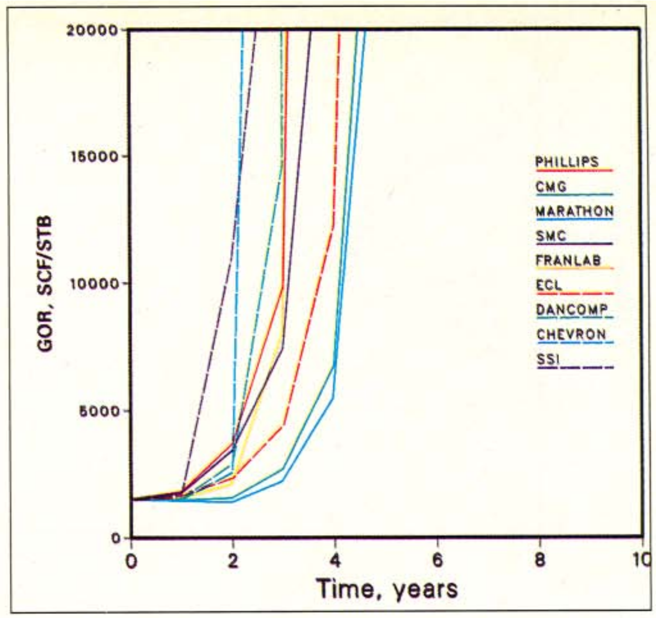

Fig. 4—GOR vs. time: depletion, zero P_{cf}.

phase, 3D, black-oil, pseudo- and fully-compositional simulator with a dual-porosity/dual-permeability option. Ref. 6 outlines the main features of the model.

The matrix/fracture flows are computed through the six faces of the central block of each cell. Gravity, capillary, and viscous forces are included in the dual-porosity options. Numerical solution schemes, such as fully implicit and adaptive implicit techniques, are available in FRAGOR.

In using the FRAGOR model, Franlab made no attempt to introduce any correction factor or pseudofunctions to correct the effects of an undiscretized matrix block.

Japan Oil Engineering Co. (JOE). JOE and Japan Natl. Oil Corp. jointly developed this model. The runs were performed with the fracture/matrix fluid transfer of Ref. 1. The model uses a finite-difference spatial discretization in which flow terms are weighted upstream and applies a fully implicit backward Euler method for the time discretization. Nonlinear iterations are performed with the Newton-Raphson technique. Various options for the matrix/fracture transfer function are currently being tested.

Marathon Oil Co. Marathon's fractured simulator is a fully implicit, three-phase, 3D model. Matrix/fracture fluid-transfer functions for each phase are based on the transmissibilities of Ref. 1 with upstream mobilities. In the example problems of the project, D_f was assumed to be equal to D_{ma}.

In this simulator, pseudo-capillary-pressure curves were used to simulate the gravity forces.[8] For the gas/oil system, a pseudo fracture capillary pressure was found for each block size that would allow a dual-porosity, single-node model to match oil recovery from a vertical, dual-permeability, fine-grid model. This match was obtained at a constant pressure of 4,500 psig [31.03 MPa]. Matrix capillary pressure was unchanged. For all other pressures, the matrix capillary pressure (adjusted by the IFT ratio) was integrated to determine an equilibrium gas saturation for each block height. Pseudo-IFT ratios for the fracture were calculated at each pressure for each block size such that, when multiplied by the maximum base fracture pseudo capillary pressure, the matrix and fracture capillary pressures would be equal at $S_{gf}=1$ and $S_{gma}=S_{ge}$. S_{ge} is the equilibrium matrix gas saturation determined by integration of the capillary pressure curve at each pressure and for each matrix block height. This procedure was used for both the zero- and nonzero-fracture-capillary-pressure cases.

For the water/oil case, pseudo fracture capillary pressures were developed for each matrix block size at 6,000 psig [41.37 MPa] such that a dual-porosity model would give the recovery as determined from fine-grid simulations.

For both water/oil and gas/oil cases, the matrix shape factor was computed from $\sigma=12/L_{ma}^2$.

Phillips Petroleum Co. Phillips' simulator is a fully implicit, 3D, three-phase, single- or dual-porosity model. For dual-porosity simulations, primary flow in the reservoir occurs within the fractures with local exchange of fluids between the fracture system and matrix blocks. The matrix/fracture transfer term is based on an extension of the equation developed by Warren and Root[15] and accounts for capillary pressure, gravity, and viscous forces. Matrix unknowns are implicitly evaluated as a function of fracture unknowns. The matrix/fracture flow equation accurately matches detailed simulations of multiphase flow processes.

Provisions are included for modeling the gravity term, for properly calculating relative permeabilities as a function of both up- and downstream conditions and hysteresis, and for evaluating the appropriate shape factor depending on the environment of the fracture system.

Simulation and Modelling Consultancy Ltd. (SMC). SMC's three-phase, 3D GENESYS simulator is designed to model both fractured and unfractured petroleum reservoirs.

In addition to the viscous and capillary forces, the matrix/fracture exchange terms[5] handle gravity forces with different results depending on matrix block size or matrix block connections. The exchange terms and gravity forces within the exchange terms simulate the behavior of a single matrix block surrounded by fractures that might contain different fluids. Gravity forces were internally calculated as functions of saturation.[5]

Several different choices of discretized time-solution techniques are available in GENESYS. Various sequential and implicit pressure, explicit saturation solutions are obtained as simplified versions of the fully implicit technique. Ref. 16 provides the details of the conservation equations and the solution techniques.

Scientific Software-Intercomp (SSI). SSI used SIMBEST II for this project. This simulator was designed to expand traditional black-oil simulation to include dual-porosity and pseudocompositional behavior. In the dual-porosity option, the fluids-transfer flow is currently modeled through a formulation described in Ref. 1.

SIMBEST II allows automatic accounting of phase pressure differences between the matrix and fracture when the matrix is subjected to capillary equilibrium and the fracture is in vertical equilibrium. Well unknowns are normally treated fully implicitly at all times in SIMBEST II, but for expediency of implementation of the constant-drawdown constraint specified for

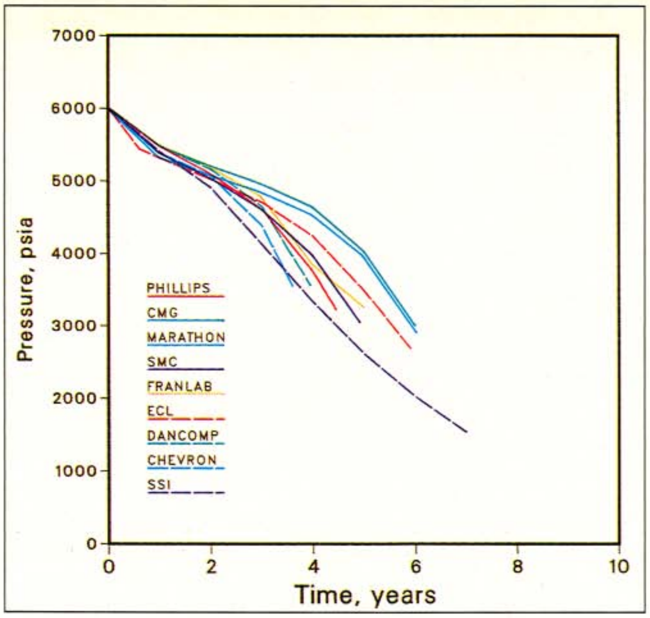

Fig. 5—Pressure vs. time: depletion, zero P_{cf}.

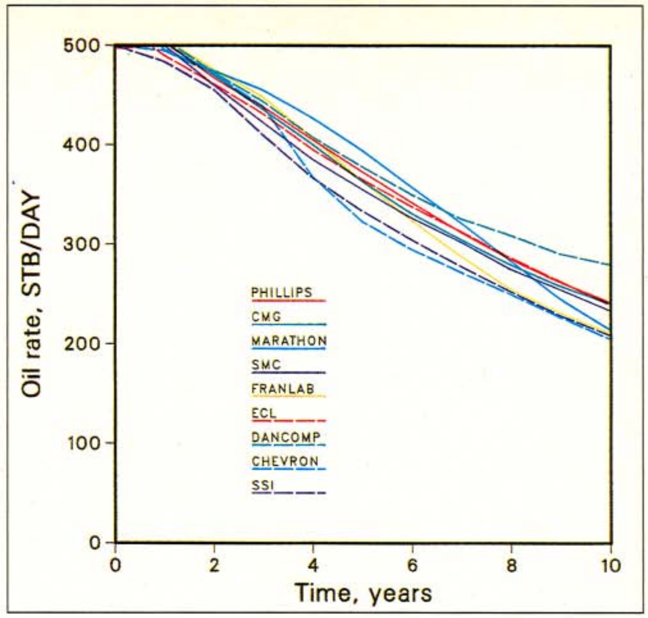

Fig. 6—Oil rate vs. time: depletion, nonzero P_{cf}.

this project, they were modeled explicitly at each nonlinear iteration. As a result, more than twice as many nonlinear iterations were required than would have been the case for other well operating constraints.

SIMBEST II uses both fully and adaptive-implicit nonlinear formulations. For solving the sets of linear equations within each linear iteration, either D-4 Gaussian elimination or a conjugate-gradient iterative solution package can be selected.

SIMBEST II does not have a pressure-dependent gas/oil capillary pressure option. Gas/oil capillary pressures at 4,000 psig [27.60 MPa] were used for the gas injection and depletion runs.

Comparison of Results

In line with the tradition of previous SPE Comparative Solution Projects,[17-21] a minimum of commentary is presented on the results submitted by the 10 participants of this project.

Single-Block Results. Figs. 1 and 2 show the results of single-cell, dual-porosity simulations by all 10 participants and the results of a fine-grid, single-porosity simulation. Fine-grid simulations give a recovery of 40 and 44% when $P_{cf}=0$ and 0.1 psi [0 and 0.69 kPa], respectively, at the 5-year termination. Note that at the end of 5 years, the results of the dual-porosity simulations for all the participants are close to the single-porosity fine-grid simulation.

Cross-Sectional Results. *Depletion.* Figs. 3 through 5 present oil production rate, produced GOR, and pressure as a function of time for the run with zero fracture capillary pressure. **Figs. 6 and 7** show oil production rate and GOR plots for runs that used fracture capillary pressures based on the adjusted data of Table 4 (SSI used gas/oil capillary pressure data at 4,000 psi [27.58 mPa]). With few exceptions, most models show similar trends in the reported results. Comparison of the results for zero and nonzero fracture capillary pressure clearly indicates that capillary continuity has a major influence on the produced GOR and reservoir pressure (reservoir pressure plot for the nonzero-fracture-capillary-pressure run is not shown).

***Reinjection.* Figs. 8 and 9** show oil production rate and produced GOR as a function of time for the gas-injection case when 90% of the produced gas is reinjected. These figures are based on the assumption of zero fracture capillary pressure. **Figs. 10 and 11**

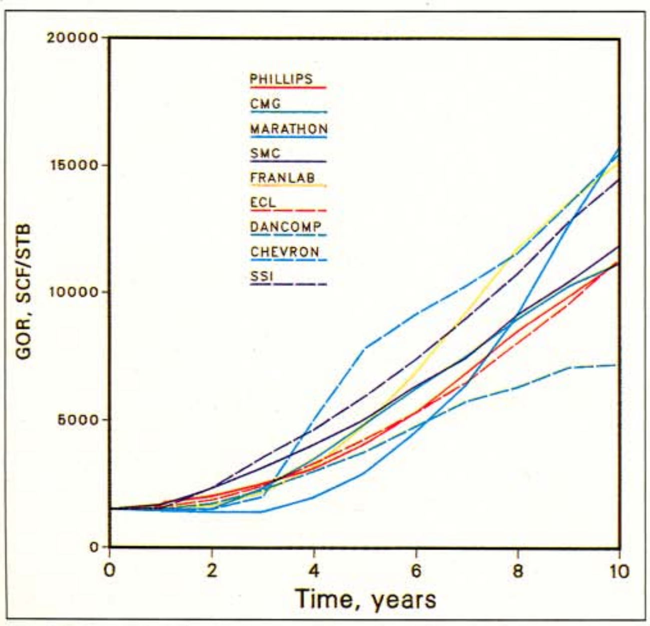

Fig. 7—GOR vs. time: depletion, nonzero P_{cf}.

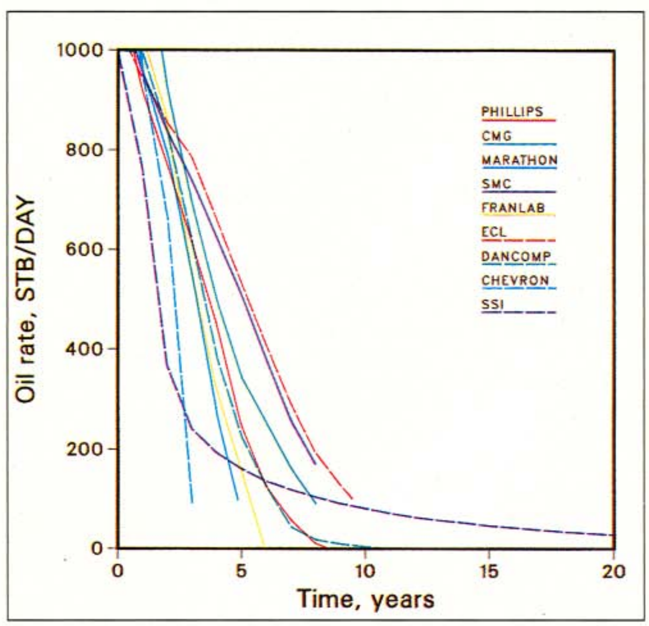

Fig. 8—Oil rate vs. time: gas reinjection, zero P_{cf}.

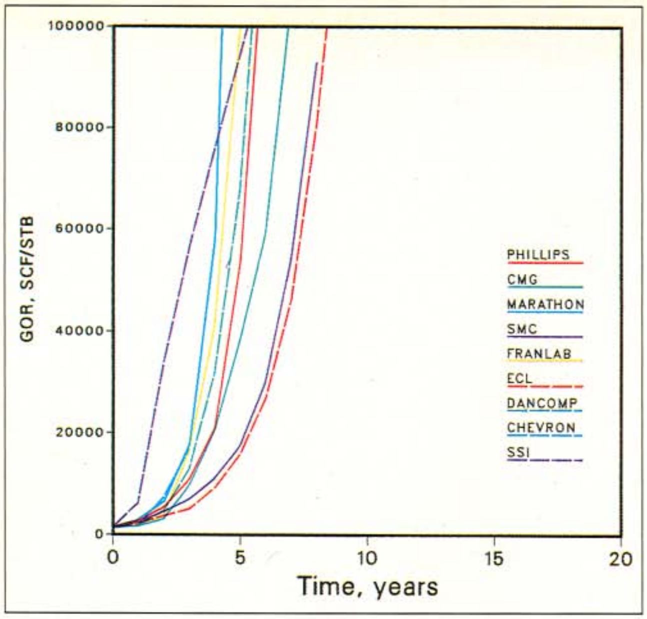

Fig. 9—GOR vs. time: gas reinjection, zero P_{cf}.

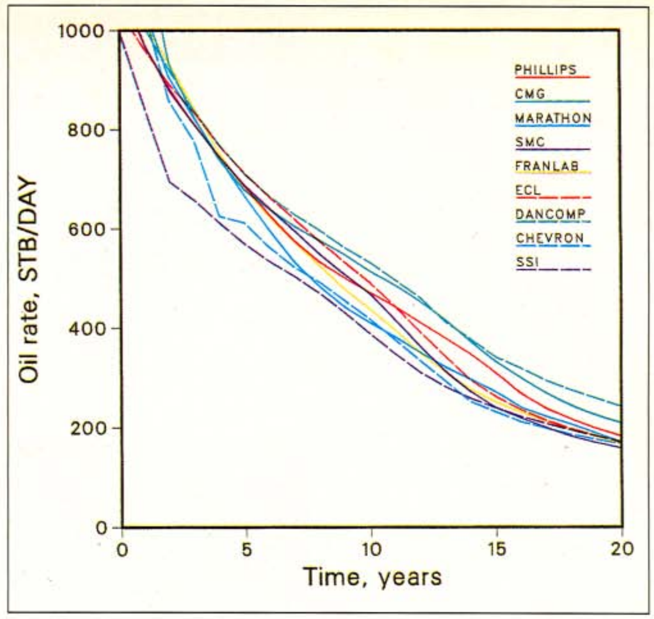

Fig. 10—Oil rate vs. time: gas reinjection, nonzero P_{cf}.

show results for the case of nonzero fracture capillary pressure. As in the depletion runs, a noticeable variation exists between the results of the nine participants.

The reinjection runs also indicate a strong influence of fracture capillary pressure on the results. **Table 5** presents the fracture and matrix gas saturations for all layers at $I=5$ for the run with nonzero fracture capillary pressure. Note that a substantial variation of fracture saturation exists in the top layers at 2 years.

Water Injection. **Fig. 12** shows the oil production rate and water cut as functions of time for the water-injection test example. Unlike the previous runs, the results from all participants are in general agreement.

Timesteps and Iterations. Table 6 lists the number of timesteps and global iterations reported by the nine companies who participated in the cross-sectional runs.

Concluding Remarks

The two problems for this comparative solution project for dual-porosity models of fractured reservoirs were selected to illustrate specific aspects of multiphase flow in fractured porous media. The conventional dual-porosity concept, however, does not model processes such as reinfiltration.[22,23]

The comparison of solutions from various participants indicates that for some examples, there is a noticeable difference in the results. Different formulations for matrix/fracture exchange is the main reason for this difference. The difference between the cases with zero and nonzero fracture capillary pressure indicates the need for further development of the physics and numerical modeling of naturally fractured petroleum reservoirs.

Most of the current techniques in dual-porosity simulation are represented in the results of the participants of this project. We believe that results based on various techniques will be of value in further enhancement of fractured reservoir simulation technology.

Nomenclature

B = FVF
D_f = depth of fracture
D_{ma} = depth of matrix
I = gridblock index in x direction
J = gridblock index in y direction
k = permeability
k_f = effective fracture permeability

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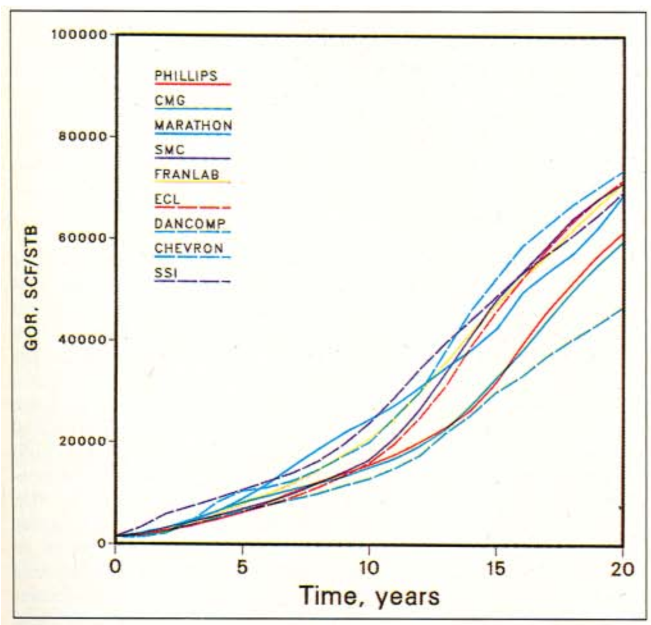

Fig. 11—GOR vs. time: gas reinjection, nonzero P_{cf}.

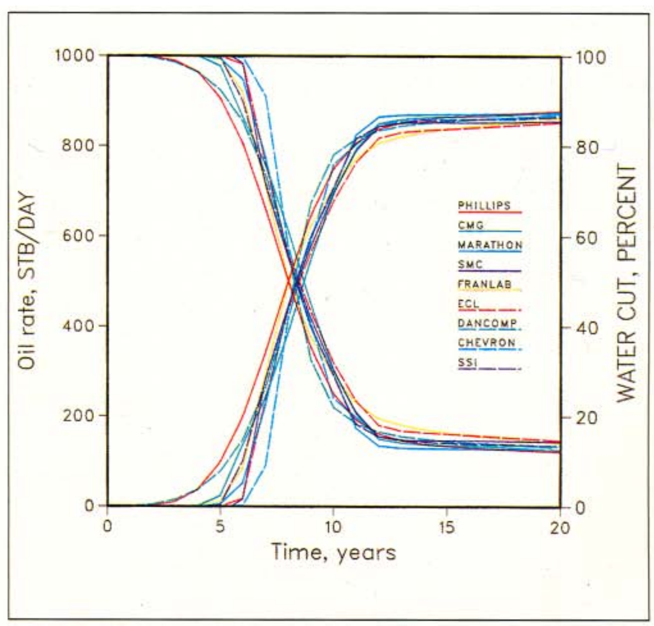

Fig. 12—Oil rate and water cut vs. time: water injection.

TABLE 5—CROSS-SECTIONAL GAS REINJECTION NONZERO-P_{cf} RESULTS*

Time (years)	Layer	Phillips S_{gf}	Phillips S_{gma}	CMG S_{gf}	CMG S_{gma}	SMC S_{gf}	SMC S_{gma}	Marathon S_{gf}	Marathon S_{gma}	Franlab S_{gf}	Franlab S_{gma}	ECL S_{gf}	ECL S_{gma}	Chevron S_{gf}	Chevron S_{gma}	SSI S_{gf}	SSI S_{gma}	Dancomp S_{gf}	Dancomp S_{gma}
2	1	0.194	0.094	0.384	0.111	0.245	0.111	0.617	0.102	0.249	0.090	0.282	0.124	0.065	0.093	0.697	0.076	0.333	0.093
	2	0.174	0.083	0.212	0.061	0.210	0.094	0.519	0.080	0.145	0.068	0.218	0.094	0.078	0.097	0.649	0.062	0.198	0.069
	3	0.146	0.048	0.100	0.034	0.175	0.044	0.144	0.063	0.087	0.065	0.145	0.041	0.135	0.058	0.344	0.029	0.109	0.042
	4	0.022	0.014	0.019	0.041	0.026	0.025	0.004	0.060	0.010	0.030	0.017	0.031	0.008	0.047	0.009	0.035	0.009	0.031
	5	0.017	0.012	0.017	0.039	0.020	0.024	0.003	0.059	0.008	0.028	0.013	0.031	0.007	0.045	0.007	0.034	0.007	0.030
5	1	0.566	0.284	0.650	0.273	0.573	0.290	0.679	0.249	0.665	0.251	0.603	0.295	0.679	0.268	0.789	0.191	0.590	0.270
	2	0.514	0.255	0.595	0.229	0.520	0.261	0.625	0.221	0.610	0.225	0.531	0.256	0.652	0.263	0.754	0.172	0.536	0.231
	3	0.407	0.151	0.454	0.137	0.418	0.168	0.470	0.165	0.453	0.169	0.379	0.144	0.493	0.156	0.505	0.113	0.393	0.142
	4	0.021	0.009	0.049	0.037	0.025	0.012	0.023	0.095	0.025	0.039	0.023	0.023	0.067	0.037	0.019	0.059	0.020	0.027
	5	0.014	0.007	0.038	0.037	0.015	0.011	0.014	0.095	0.015	0.034	0.014	0.022	0.023	0.035	0.011	0.058	0.013	0.026
10	1	0.820	0.436	0.805	0.413	0.873	0.433	0.809	0.396	0.853	0.387	0.871	0.429	0.855	0.400	0.889	0.301	0.843	0.428
	2	0.791	0.413	0.788	0.382	0.830	0.418	0.780	0.371	0.827	0.370	0.829	0.412	0.835	0.390	0.871	0.286	0.773	0.409
	3	0.718	0.334	0.721	0.366	0.824	0.412	0.825	0.360	0.851	0.410	0.791	0.403	0.868	0.416	0.867	0.400	0.681	0.365
	4	0.025	0.004	0.068	0.023	0.122	0.005	0.242	0.089	0.200	0.032	0.083	0.011	0.285	0.019	0.282	0.064	0.032	0.021
	5	0.008	0.002	0.027	0.023	0.007	0.003	0.012	0.055	0.010	0.011	0.008	0.007	0.009	0.015	0.010	0.056	0.013	0.014
20	1	1.000	0.513	0.994	0.508	1.000	0.483	0.992	0.482	0.990	0.468	1.000	0.485	0.995	0.466	0.970	0.400	0.966	0.522
	2	1.000	0.508	0.990	0.501	1.000	0.480	0.982	0.475	0.988	0.464	1.000	0.481	0.994	0.464	0.964	0.393	0.962	0.519
	3	1.000	0.464	0.998	0.463	1.000	0.468	0.997	0.439	0.998	0.453	1.000	0.465	0.999	0.447	0.986	0.448	0.956	0.530
	4	0.527	0.173	0.528	0.170	0.605	0.284	0.770	0.309	0.656	0.309	0.570	0.279	0.619	0.276	0.760	0.290	0.410	0.140
	5	0.007	0.001	0.040	0.013	0.059	0.001	0.060	0.032	0.093	0.003	0.027	0.002	0.008	0.076	0.062	0.047	0.023	0.008

*Saturations at (5,1,1 through 5).

Sixth SPE Comparative Solution Project: Dual-Porosity Simulators

(From Page 715)

k_{ma} = matrix permeability
k_r = relative permeability
K = gridblock index in z direction
L_{ma} = length of matrix block
n_x = number of gridblocks in x direction
n_y = number of gridblocks in y direction
n_z = number of gridblocks in z direction
Δp = drawdown, psi
P_{cf} = fracture capillary pressure
P_{cfgo} = gas/oil fracture capillary pressure
P_{cwo} = water/oil capillary pressure (matrix)
r = radial distance from center of a cylindrical gridblock
S_{ge} = equilibrium matrix gas saturation, fraction
S_{gf} = fracture gas saturation, fraction
S_{gma} = matrix gas saturation
S_w = water saturation
Δx = grid-cell dimension in x direction
Δy = grid-cell dimension in y direction
z = vertical distance for a cylindrical gridblock
Δz = grid-cell dimension in z direction
μ = viscosity
σ = shape factor
ϕ_f = fracture porosity
ϕ_{ma} = matrix porosity

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TABLE 6—TOTAL NUMBER OF TIMESTEPS AND GLOBAL ITERATIONS

Company	Depletion, Zero P_{cfgo} Steps	Depletion, Zero P_{cfgo} Iterations	Depletion, Nonzero P_{cfgo} Steps	Depletion, Nonzero P_{cfgo} Iterations	Reinjection, Zero P_{cfgo} Steps	Reinjection, Zero P_{cfgo} Iterations	Reinjection, Nonzero P_{cfgo} Steps	Reinjection, Nonzero P_{cfgo} Iterations	Water Injection Steps	Water Injection Iterations
Phillips	48	116	103	215	42	114	86	209	92	185
CMG	63	239	103	392	48	317	94	535	100	215
SMC	53	265	91	455	149	745	280	1,400	170	550
Marathon	66	140	106	290	34	119	91	444	96	260
Franlab	60	200	114	344	85	129	199	306	100	240
ECL	63	275	103	369	88	397	87	516	134	383
Chevron	36	196	104	495	22	228	89	576	88	540
SSI	75	308	106	424	106	424	96	384	100	400
Dancomp	50	260	111	359	273	1,201	576	2,499	750	1,505

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SI Metric Conversion Factors

bbl	× 1.589 873	E−01	= m^3
cp	× 1.0*	E−03	= Pa·s
md	× 9.869 233	E−04	= μm^2
psi	× 6.894 757	E+00	= kPa

*Conversion factor is exact.

Provenance

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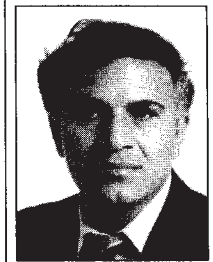
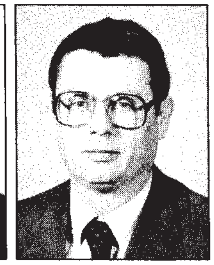


Firoozabadi



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