Use and Misuse of Reservoir Simulation Models

K. H. Coats, SPE-AIME, The U. of Texas at Austin

Introduction

Webster defines "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 sandpack) 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 the oil or gas field, the behavior of a valid model simulates (assumes the appearance of) that of the field.

The purpose of simulation is to estimate field performance (e.g., oil recovery) under a variety of producing schemes. Whereas the field can be produced only once — and at considerable expense — a model can be produced or "run" many times at low expense over a short period of time. Observation of model performance under different producing conditions, then, aids in selecting an optimum set of producing conditions for the reservoir. More specifically, with reservoir simulation the following are possible.

1. We can determine the performance of an oil field under water injection or gas injection, or under natural depletion.
2. We can judge the advisability of flank waterflooding as opposed to pattern waterflooding.
3. We can determine the effects of well location and spacing.
4. We can estimate the effect of producing rate on recovery.
5. We can calculate the total gas field deliverability for a given number of wells at certain specified locations.
6. We can estimate the lease-line drainage in heterogeneous oil or gas fields.

The tools of reservoir simulation range from the intuition and judgment of the engineer to complex mathematical models requiring use of digital computers. The question is not whether to simulate but rather which tool or method to use. There is no general answer to the question as to when the computerized mathematical model should be employed. After some preliminary discussion of the nature of mathematical models and sources of error, some valid and invalid model applications will be illustrated here with specific examples. It should be noted that this discussion is restricted to models for multidimensional, single or multiphase flow in reservoirs. These models apply to dry gas reservoirs and to oil reservoirs undergoing natural depletion or pressure maintenance (such as natural water drive, waterflood or gas injection).

The Mathematical Model

In 1959 Douglas, Peaceman and Rachford[1] proposed the "Leap-Frog" and "Simultaneous Solution" methods for solving two-dimensional, two-phase flow problems. In 1960, Stone[2] and Sheldon[3] described an "Implicit Pressure-Explicit Saturation" method. Since

In reservoir simulation, the question is not whether, but how and how much. The complexity of the questions being asked, and the amount and reliability of the data available, must determine the sophistication of the system to be used.

that time, computer simulation of two-dimensional, two-phase flow has become increasingly efficient as larger, higher-speed computers have evolved with attendant reduced computing costs. Peaceman and Rachford performed a three-dimensional calculation of two-phase flow in a five-spot by the Leap-Frog method[4] in 1962. Three-dimensional, two-phase simulators have been developed and applied, using the simultaneous method, since early 1963.[4] Recent articles describe simulators for three-dimensional, three-phase incompressible[5] and compressible[6] flow.

The mathematical reservoir simulator consists basically of sets of partial differential equations that express conservation of mass and/or energy. In addition, the model entails various phenomenological "laws" describing the rate processes active in the reservoir. Example laws are those of Darcy (fluid flow), Fourier (heat conduction), and Fick (solute transport by diffusion or dispersion). Finally, various assumptions may be invoked, such as those of one- or two-dimensional flow and single- or two-phase flow, negligible dispersion or gravity or capillary effects.

The model equations are generally nonlinear and require numerical solution. A computer program is written to utilize some numerical technique in solving the equations. Required program input data include fluid PVT data — formation volume factors and solution gas (R_s Mcf/STB) as functions of pressure — rock relative permeability and capillary pressure curves, and reservoir description data. This last category usually constitutes the bulk of the input data and is the most difficult to determine accurately.

Computed results generally consist of pressures and fluid saturations at each of several hundred grid points throughout the reservoir. In problems involving heat or solute flow the model will also entail calculation of temperature or concentration at each grid point. These spatial distributions of pressure, etc., are determined at each of a sequence of time levels covering the producing period of interest.

Sources of Error in Computed Results

There are several potential sources of error in computed results.

1. The model itself is usually approximate since it involves certain assumptions that are only partly valid.

2. Replacement of the model differential equations by difference equations introduces truncation error; that is, the exact solution of the difference equations differs somewhat from the solution to the original differential equations.

3. The exact solution of the difference equations is not obtained due to round-off error incurred by the finite word length of the computer.

4. Perhaps most important, reservoir description data (for example, permeability, porosity distributions) seldom are accurately known.

The level of truncation error in computed results may be estimated by repeating runs or portions of runs with smaller space or time increments. Significant sensitivity of computed results to changes in these increment sizes indicates a significant level of truncation error and the corresponding need for smaller spatial or time steps. Compared with errors from other sources, round-off errors generally are negligible.

Error caused by faulty reservoir description data is difficult to determine since the true reservoir description is virtually never known. A combination of core analyses, well pressure tests and geological studies often gives valid insight into the nature of permeability and porosity distributions and reservoir geometry. The best method of obtaining a valid reservoir description is to determine in some manner the particular description that results in best agreement between calculated and observed field performance over a period of available reservoir history.

In many cases, the engineer is less concerned with the absolute accuracy of his reservoir description data and results than he is with the sensitivity of calculated results to variations in those data. The reason for this is that most questions regarding reservoir performance involve comparison of performances under alternative exploitation schemes. Sensitivity to errors in reservoir description data can be determined by performing several runs with variations in those data covering a reasonable range of uncertainty. For example, assume that a computerized mathematical model using a certain reservoir description yields oil recoveries of 57 percent under a flank waterflood and 32 percent under natural depletion. If additional runs, with reservoir descriptions varied over a considerable range of uncertainty, yield small variations (say about 3 percent) in these recoveries, then the estimated recoveries might be accepted as meaningful. In addition, the reservoir description would be considered as "adequate". If, however, reasonable variations (with regard to range of uncertainty) in reservoir description result in large variations (say about 20 percent) in computed recoveries, then attention should be given to obtaining a more accurate reservoir description. Even if calculated recoveries show considerable sensitivity to variations in reservoir description, some meaning might be attached to an essentially invariant difference between computed recoveries by waterflood and computed recoveries by natural depletion.

This discussion of sensitivity of computed results to errors in description data applies equally to sensitivity to errors or uncertainty in any other model input data. Too often we tend to demand accurate determination of all types of input data before we accept the computed results as meaningful or reliable. Actually, interest in accuracy of input data should be proportional to the sensitivity of computed results to variations in those data. If, for example, wide variations in the gas relative permeability curve result in virtually no change in computed oil recovery, then the accuracy of this curve warrants little attention.

The simulation model itself can be useful in allocating effort and expense in the determination of reservoir fluid and rock data. Computer runs may be performed at an early stage of the reservoir study to estimate sensitivity of calculated reservoir performance to variations in the assorted necessary input data. Obviously, effort should be concentrated on obtaining those data that have the greatest effect on calculated performance. For example, in cases where the gravity drainage mechanism dominates oil recovery, the relative permeability curve to oil at low and middle-range oil saturations has a pronounced effect on calculated oil recovery. Gas viscosity and relative permeability and capillary pressure may play virtually no role whatever, and effort expended in determining them is largely wasted.

Educational Value of Simulation Models

Simulation model results frequently have considerable educational value, quite apart from their aid in reaching decisions regarding reservoir operation. The complex interactions of gravity, viscous, and capillary forces in heterogeneous reservoirs often result in seemingly anomalous, or at least unexpected, calculated flow patterns. Verification of the validity of such patterns requires considerable insight into the physics of the situation. Such verification can often be attained by recourse to simpler models. For example, calculated water saturation profiles for a one-dimensional vertical water drive in a heterogeneous pinnacle reef reservoir exhibit pronounced oscillation with vertical distance. These calculated oscillations persist virtually unchanged, despite considerable reduction of spatial and time increments; i.e., they are not caused by truncation error. The oscillations are caused by the dependence of frontal water saturation upon both gravity and viscous forces. The ratio of these forces varies markedly with the permeability of successive layers upward through the reservoir. The simpler Buckley-Leverett model, extended to heterogeneous one-dimensional systems, shows the same oscillations. In high permeability layers, gravity forces dominate viscous forces and a high frontal water saturation develops. However, as this front passes upwards into a low permeability block, viscous forces are dominant and give a low frontal saturation. Upon leaving the tight layer and again entering a loose one, the frontal saturation again jumps to a high value, resulting in an oscillatory water saturation profile at any given time.

Another example of the educational value of simulation models is their application to the question of lease-line drainage. Consider a heterogeneous gas reservoir or undersaturated oil reservoir with given (estimated) kh and ϕh maps. The reservoir consists of a number of leases with various numbers of producing wells in each lease. The problem is that of estimating net drainage rate into or out of each lease for given well producing rates under a semisteady state reservoir depletion. As discussed below, simple examination of the simulator equations allows isolation of that portion of field data that determines these net drainage rates. In fact, under certain conditions, the rates can be quickly determined, quantitatively, without any numerical solution of the simulator equations. In cases like this, the simulator, either by simple examination or by a limited number of computer runs, allows more intelligent formulation of general rules for field operation.

Some Applications of Numerical Reservoir Models

Here we will briefly describe some valid applications of computerized reservoir models. Features responsible for this validity are pointed out. Henderson, Dempsey, and Tyler[7] described a computer simulation of two-dimensional, transient gas flow in a dry gas storage reservoir. The practical problem was that of meeting a required (contractual) deliverability schedule over a 110-day withdrawal period. The peak required delivery rates occurred at the end of the period, when gas in place and hence reservoir pressure and field deliverability were at their lowest levels. The reservoir had 41 wells currently drilled and the problem was to select the number and locations of additional wells to be drilled before the next withdrawal season. The incentive to minimize the number of additional wells was strong, since each well cost about $125,000. On the other hand, the incentive to have enough wells was also strong since the contract specified a penalty of $10 to $100 for each Mcf of contractual gas not delivered.

The numerical model employed simulated two-dimensional (areal) unsteady-state gas flow in a closed heterogeneous reservoir of arbitrary geometry with an arbitrary number of wells arbitrarily located. Model results included pressure distributions in the field at various times covering the 110-day period, and field deliverability (Mcf/D) by well and for the total field at each of these times. Input data specified a gathering system or flowing wellbore pressure. The model was run a number of times for different proposed numbers and locations of additional wells and under different strategies regarding the order in which various wells were brought "on stream". Results indicated that field deliverability depended strongly upon the locations of additional wells and upon the order in which they were turned on during the 110-day period. A somewhat simplified statement of study results is that additional wells should be drilled preferentially in the tighter (lower kh) areas of the reservoir. Further, these tighter wells should be turned on early in the withdrawal period, saving the wells in the high kh portions of the reservoir for the peak withdrawal period.

The well locations and operating strategy recommended on the basis of those model results were largely adopted by the operating company. Recent performance of the reservoir is comparing reasonably well with that predicted by the model.

The practical benefit derived from this application was the elimination of a considerable number of expensive wells that would otherwise have been drilled. That is, the proper locations of additional wells relative to field heterogeneity and an "optimum" operating strategy allowed satisfaction of field deliverability requirements with considerably fewer additional wells.

Features contributing to the benefit of this application are: (1) the clearcut incentive to reduce additional well cost, and (2) the extensive field performance data available over several withdrawal seasons. The critical data in this case (from a standpoint of sensitivity of model results) were the reservoir kh distribution and individual well backpressure curves. These data were fairly well known from the performance data for the existing 41 wells.

Rainbow Field, Alberta

Applications of computerized multidimensional simulators are frequently subject to justification as well as to criticism. The recent pinnacle reef discoveries in the Rainbow field of Alberta offer such an example. For this field the immediate problem is to estimate oil recovery under natural depletion as opposed to various pressure maintenance schemes. The effect of producing rate on recovery is a subsidiary question. The zero-dimensional material balance calculation can be easily modified by including the capillary-gravitational equilibrium concept to yield one-dimensional (vertical) results. That is, an average field oil saturation of 70 percent need not be viewed as a uniform 70 percent saturation from the top to bottom of the reef. Rather the 70 percent can be considered the average corresponding to a nearly segregated fluid column. However, by virtue of this equilibrium assumption, the material balance calculation fixes ultimate recovery at essentially $1 - S_{or}$, where S_{or} is the residual oil saturation at which relative permeability to oil is zero. Equivalently stated, the material balance calculation assumes gravity drainage of oil from behind the declining gas-oil contact to be complete and instantaneous.

This complete recovery predicted by a material balance calculation might be reasonable if reservoir permeability were sufficiently high throughout the reservoir. However, core analyses from wells in most of these fields indicate rather severe heterogeneity with layers of considerable thickness (several feet) having vertical permeabilities of only 1 to 10 md. Fig. 1 shows a permeability distribution through reservoir thickness, typical of these reef reservoirs. One-dimensional (vertical), transient two- and three-phase flow models indicated that gravity drainage was a serious problem in that oil saturations appreciably above residual persisted in tight layers well above the declining, primary gas-oil contact. Fig. 2 shows computed oil saturation vs depth for one of the reef reservoirs after 15 years of natural depletion. This distribution indicates the inadequacy of the complete gravity drainage assumption inherent in the conventional material balance calculation. In this case the conventional material balance calculation is totally incapable of yielding meaningful estimates of oil recovery.

Use of the computerized numerical model in these reef studies can be criticized since the answers obtained are considerably dependent upon the reservoir description (essentially vertical permeability) employed. And in many pools, permeability data are available from only a single well. This scarcity of information about rather critical data required by the model spurred an intensive geological study. The geological work utilized data from many pools in a single area in an attempt to gain a more reliable reservoir description than that of a simple extrapolation over entire pool cross-sectional area from the well core data. The geological work and numerical model studies are discussed in the literature.[8,9]

One justification for application of numerical modeling to these reef reservoirs is simply the fact that it is not possible to estimate recoveries and effects of rate on recovery using conventional material balance calculations. Uncertainties in critical reservoir description data are partly offset by geological study and will be reduced further as performance history becomes available for matching purposes.

Field "X" — Crestal Gas Injection

The question often arises as to when it is necessary to

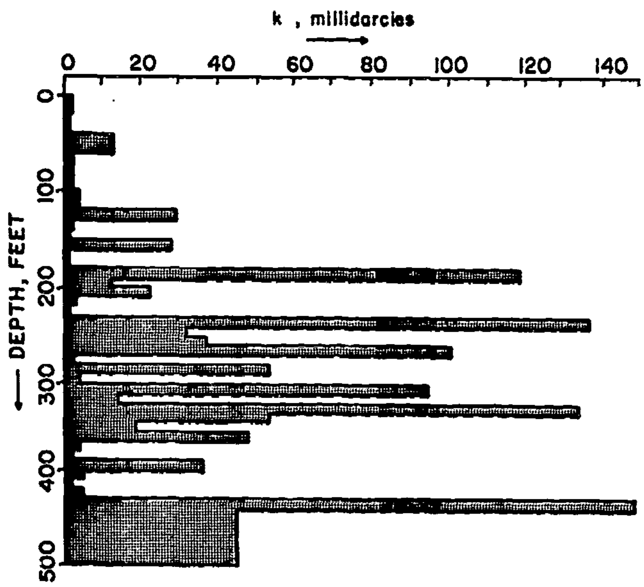

Fig. 1—Reef reservoir description.

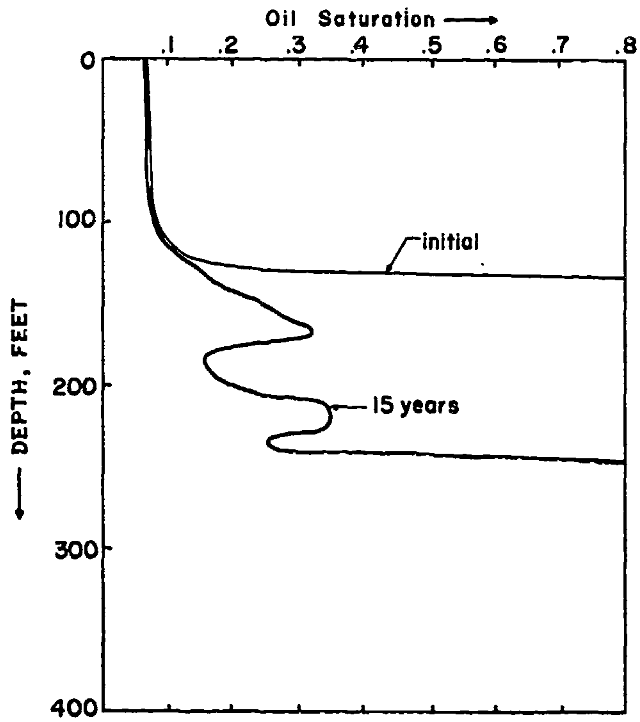

Fig. 2—Reef reservoir prediction.

simulate in three dimensions as opposed to two or even one dimension. Inclusion of flow in the third (nearly vertical) direction is often recommended only if reservoir thickness is "large" in relation to areal extent or if pronounced heterogeneity exists in the vertical direction (if, for example, there is high stratification). The recommendation may be helpful in some cases, but certainly is not binding. The following example of a three-dimensional problem is a somewhat generalized and simplified version of an actual field study. The problem was to estimate oil recovery by crestal gas injection in a steeply dipping reservoir. The reservoir sand was only 40 ft thick and was clean and unusually isotropic (see Fig. 3). Permeability was low at the southern boundary and increased uniformly toward the northern boundary.

Neither gas injection nor oil production wells were equally spaced or symmetrically located. The areal heterogeneity, along with nonuniform well spacing, dictated simulation of flow at least in the two areal (x-y) directions. In spite of the small sand thickness and homogeneity in the vertical direction, simulation of flow in that direction was also required. The reason was the low relative permeability to oil in the low and middle oil saturation range (an example, again, of the gravity drainage problem). The injected gas overrode and bypassed the oil, leaving appreciable amounts of oil behind the gas front. This oil slowly drained downdip and normal to the bedding planes. This vertical gravity drainage of oil was an important mechanism in the recovery and could not be accounted for in an areal, two-dimensional (x-y) calculation.

Field "Y" — Lease-Line Drainage

The question of lease-line drainage leads to an interesting application of the numerical reservoir simulator. Consider the heterogeneous oil or gas field shown in Fig. 4. A two-dimensional grid is superimposed for computing purposes. Estimated values of kh and ϕh are given for each block, along with the locations of producing wells and a lease line. We assume a single-phase, semisteady-state flow regime and a closed reservoir, i.e., a negligible water drive. The semisteady-state assumption implies that at any given time, the rate of pressure decline ($\partial p/\partial t$) is about the same at all spatial points in the field. The first question is: What is the net drainage or flow rate across the lease line for given producing rates of all wells? Examination and elementary manipulation on the finite difference form of the equation describing the two-dimensional flow shows that the answer is entirely independent of the kh distribution or level and of the well locations or individual rates. The answer depends only upon the total producing rates and pore volumes of each lease. In fact, the drainage rate from Lease I to Lease II is simply

$$q_{I \to II} = q_{II} - \frac{V_{pII}}{V_p} q \quad , \quad \ldots \ldots \quad (1)$$

where

q = total field producing rate,
q_{II} = total Lease II producing rate
V_p = total field pore volume, and
V_{pII} = total Lease II pore volume.

Thus drainage is zero if each lease produces in proportion to its pore volume. This same result can be obtained by using Green's theorem in conjunction with the differential equation describing flow in a two-dimensional heterogeneous reservoir. Actually, the result can be obtained by simple reasoning, utilizing the definition of semisteady state, which implies

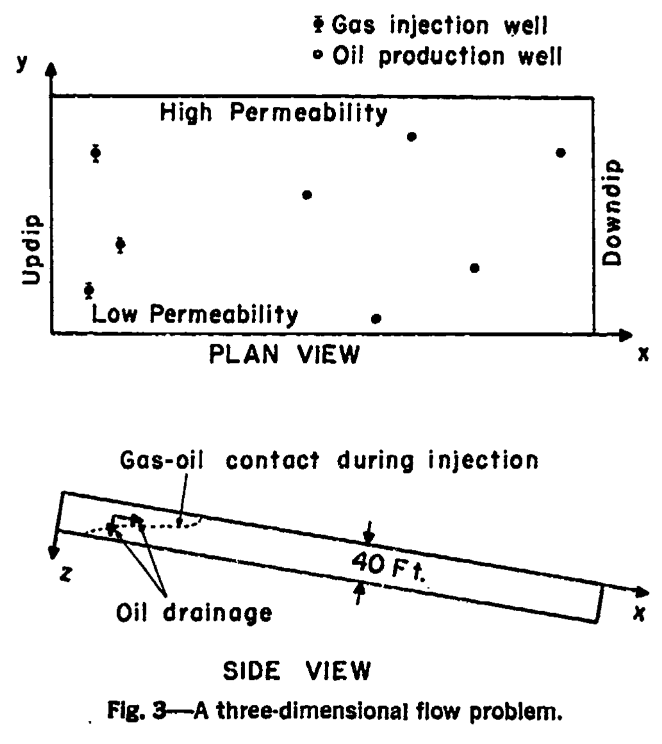

Fig. 3—A three-dimensional flow problem.

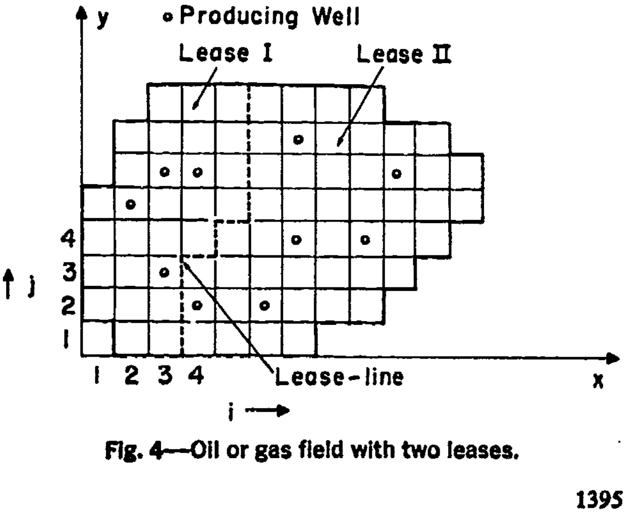

Fig. 4—Oil or gas field with two leases.

a uniform depletion rate per unit pore space over the entire field.

Whereas Eq. 1 appears trivial or immediately obvious, a somewhat more difficult answer to obtain is the net drainage rate for a given backpressure p_w where all well production rates are given by

$$q_{ij} = \alpha\,(kh)_{ij}\,(p_{ij} - p_w) \quad , \quad . \quad . \quad . \quad . \quad . \quad (2)$$

where

q_{ij} = producing rate of well located in Grid Block i, j
α = constant
$(kh)_{ij}$ = kh of Block i, j
p_{ij} = average pressure in Block i, j

Again, the answer is independent of the kh distribution, but is dependent upon the individual $(kh)_{ij}$ values where wells are located. A simple answer cannot be given for this case. However, computer solution of the two-dimensional, single-phase, semisteady-state flow equation gives the answer in less than 1 second of computing time on a high-speed digital computer.

Misuse of Reservoir Models

A kind of "overkill" is the most frequent misuse of reservoir models. Just a few years ago we made decisions regarding reservoir performance using only the tools of judgment and the conventional (zero-dimensional) material balance, or perhaps a one-dimensional Buckley-Leverett analysis. Now, almost overnight it seems, questions regarding reservoir performance can only be answered by performing two- or three-dimensional simulations of two- or three-phase flow, in several thousand blocks. Recently we have been told that even the three-phase (water, "oil", "gas") system is insufficient and should be replaced in many cases by a multicomponent calculation accounting for flow and interphase transfer of 10 or more hydrocarbon components.[10-12] This introduction of multicomponent phase behavior can result in computing times about 100 times greater than those required for the basic three-phase flow calculation.

Too often we automatically apply to a problem the most sophisticated and complex calculation tool available. Typically, grid sizes are used that are smaller than justified by available information concerning reservoir properties. Often the reasons given for fine grid structure have little basis in fact. In short, the overkill referred to here is the application of models accounting for m-phase flow using n grid blocks where questions could be equally well answered using a model describing m-1 or even m-2 phase flow in a grid of $n/2$ or $n/3$ blocks.

This is not meant to imply that there is no need for small-grid-element, three-dimensional simulations, or for multiphase flow calculation accounting for multicomponent mass transfer. There have been well founded three-dimensional studies and ill-conceived one-dimensional simulations and more than one problem has been faced in which a multiphase, multicomponent phase behavior calculation would have been welcome. However, the use of engineering judgment in many cases would dictate the use of a less complex model. Equally valid answers would be obtained at appreciably lower man and machine cost and in a shorter time.

A general rule that should be, but seldom is, followed is "select the *least* complicated model and grossest reservoir description that will allow the desired estimation of reservoir performance". Following is a case in point. A recently discovered oil reservoir with no initial gas cap and negligible water drive has been produced under natural depletion. Pressure has fallen below bubble point. A company is considering drilling one or several additional wells along a lease line to offset drainage believed to be occurring. The problem is to estimate the extent of drainage under current conditions and to estimate the effect of one or more additional wells. Little information is available regarding reservoir heterogeneity normal to the bedding planes. The use of a two- or three-dimensional, two-phase (gas-oil) flow model has been proposed. It appears that a two-dimensional areal (x-y), single-phase flow calculation should be employed in this case, first, because a single-phase flow study is considerably easier to conduct and requires much less computer time than a two-phase flow study, and second, because the extent of depletion below the bubble point has been such that probably only a few percent free gas saturation exists in the reservoir. This free gas, even if above critical saturation (i.e., mobile), should play a negligible role in the direction or rate of oil drainage across the lease line. Strictly speaking, the problem involves two-phase flow. But considering the question being asked, a single-phase flow calculation would undoubtedly be sufficient.

The necessity for a fine grid is sometimes argued on the grounds that accuracy is lost by placing wells in adjacent grid blocks. That is, the grid must be sufficiently fine that at least one "empty" grid block separates blocks containing wells. This is not necessarily true; in fact, in some cases more than one well can be placed in a single block. As an illustration (taken from Ref. 13), Fig. 5 shows two producing wells in a square, closed reservoir, 18,000 ft on a side. Two single-phase, semisteady-state calculations were performed using 9×9 and 3×3 grids. In the former case, two blocks separated those containing the wells, whereas in the latter case, the wells were in adjacent blocks. A common flowing well pressure was specified for both wells. Total field producing rate was specified as 5,000 Mcf/D, and the two-dimensional calculations determined (1) pressure distribution, (2) each well's contribution to the total rate, and (3) the gas in place (or average field pressure level) necessary to meet the required total field rate. The results are summarized in Table 1. The loss in accuracy due to the use of 9 as opposed to 81 grid blocks is clearly negligible.

Often a considerable amount of computing time can be saved in a study if the minimum required definition is determined at the outset. This involves repeated runs using fewer blocks until resolution is lost concerning the facets of field performance being estimated.

Reservoir models are also misapplied when there is gross uncertainty regarding input data that critical-

TABLE 1—EFFECT OF GRID SIZE ON CALCULATED WELL DELIVERABILITY

Grid Size	Deliverability (Mcf/D) Well 1	Deliverability (Mcf/D) Well 2	Gas In Place (Mcf)
9×9	3732.8	1258.1	68,869,784
3×3	3723.1	1274.8	68,897,904

ly affect computed results. Let us take as an example a recent study of oil recovery by gas injection in a dipping cross-section (two-dimensional vertical slice). Initially, relative permeability and other reservoir data were rather crudely estimated and a considerable number of runs were performed to investigate the effect of injection rate on recovery. Subsequent sensitivity studies showed these early computed results to be largely meaningless for the following reason. The answers obtained were entirely dependent upon the oil relative permeability curve employed. And variations of it well within the range of uncertainty gave significantly different estimates of oil recovery. The computed recovery was almost totally insensitive to gas relative permeability and capillary pressure curves and to reservoir porosity. Also, reservoir permeability had an insignificant effect within a reasonable range of uncertainty. Having isolated the particular data of importance (oil relative permeability curve) we performed considerable laboratory work to determine it. Subsequent computer runs were then believed to yield reliable estimates of oil recovery and the quantitative effect of rate on recovery. This overriding importance of the oil relative permeability curve is typical, of course, in problems where oil recovery is dominated by the gravity drainage process.

Erroneous use of reservoir models occasionally occurs in two-dimensional areal studies. The error involves inadequate representation of fluid saturation distributions through the thickness of the reservoir. An areal calculation, as opposed to a three-dimensional calculation is justified in the two limiting cases when (1) fluids are completely segregated (i.e., gravitational-capillary equilibrium exists) throughout the thickness, and (2) no segregation exists (i.e., fluid saturations are uniform throughout the thickness). In the latter case, laboratory-derived rock relative permeability, as well as capillary pressure curves, should be used in the areal calculation. In the former case, pseudo relative permeability curves and capillary pressure curves, reflecting the state of segregation, should be employed.[4] In most cases, the assumption of segregation is more nearly correct than the assumption of uniform saturations, but in many cases neither assumption is valid. If neither assumption is valid, then (1) a three-dimensional calculation should be performed, or (2) totally empirical pseudo curves for areal calculations should be determined. These curves, when used in one-dimensional areal calculations, should result in agreement with two-dimensional cross-sectional calculations using laboratory curves.

Fig. 6 illustrates the error in computed results, caused by the use of laboratory relative permeability and capillary pressure curves in an areal study where the assumption of segregation is nearly correct. This figure shows depth-averaged gas saturation vs distance along a dipping (3°) cross-section. The gas was injected at the crest into the initially oil-saturated formation. The vertical slice is 800 ft long and 25 ft thick. A two-dimensional cross-sectional (x-z) calculation was performed using laboratory relative permeability and capillary pressure curves. The calculated gas saturations were then depth-averaged and plotted as the solid line in Fig. 6. This is the "correct" answer. The triangular points correspond to a one-dimensional calculation that utilized laboratory relative permeability and capillary pressure curves. These curves correspond to the assumption that fluid saturation is uniform throughout the thickness. The circular points correspond to a one-dimensional areal calculation that used pseudo curves reflecting the assumption of gravitational-capillary equilibrium (i.e., segregation) throughout the thickness. The use of these pseudo curves in the areal calculation gives a far more accurate result than does the use of the laboratory curves.

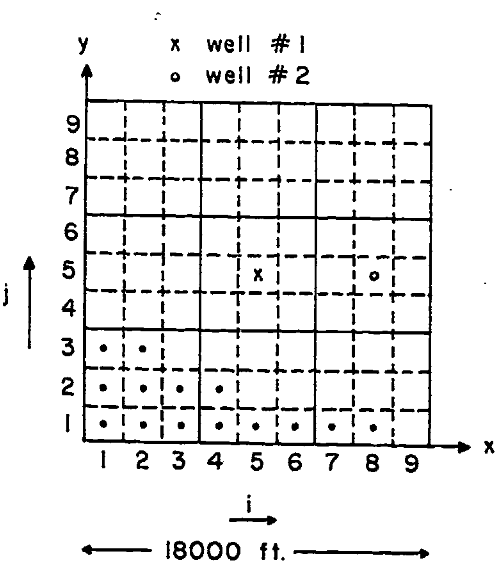

Fig. 5—9 × 9 and 3 × 3 grids.

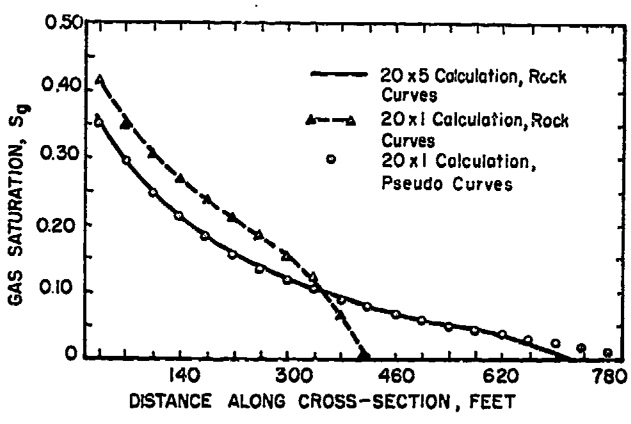

Fig. 6—Comparison of saturation profiles at Time = 360 days for 800-ft × 25-ft cross-section under gas injection.

Conclusions

Error in numerical simulation of reservoir performance results from truncation error and from inaccuracies in reservoir description or other input data. The presence of appreciable truncation error can generally be determined by noting the sensitivity of calculated performance to changes in spatial and time increment sizes. Adequate accuracy of input data is indicated by insignificant variations in computed reservoir performance caused by variations in the input data over the ranges of uncertainty. The mathematical model can be used in many cases to determine which particular input data should be determined accurately.

The complex interactions of capillary, gravitational and viscous forces reflected in the calculated reservoir performance often result in flow patterns or performance characteristics that are of considerable educational value.

Valid application of reservoir simulation models generally possess the following three features: (1) a well posed question of economic importance (such as "Should oil be recovered under natural depletion as opposed to water injection?", "What are the best locations for additional wells to maximize incremental field deliverability per dollar of additional investment?"), (2) adequate accuracy of reservoir description and other required input data, and (3) strong dependence of the answer to the question upon nonequilibrium, generally time-dependent, spatial distributions of pressure and fluid saturations. This dependence renders meaningless the conventional material balance calculations.

A frequent misuse of reservoir models is the application of one that is more complex or sophisticated than the problem warrants, which can greatly increase the required man and machine time. In general, we should apply the least sophisticated model and largest grid size that will yield an adequate estimate of field performance. Application of models in cases where critical input data are poorly known constitutes another misuse. Finally, care should be exercised in respect to the relative permeability and capillary pressure curves employed when using a two-dimensional areal (x-y) calculation to simulate three-dimensional flow in reservoirs.

References

1. Douglas, J., Jr., Peaceman, D. W. and Rachford, H. H., Jr.: "A Method for Calculating Multi-Dimensional Immiscible Displacement", *Trans.*, AIME (1959) **216**, 297-308.
2. Stone, H. L. and Garder, A. O., Jr.: "Analysis of Gas-Cap or Dissolved-Gas Drive Reservoirs", *Soc. Pet. Eng. J.* (June, 1961) 92-104.
3. Sheldon, J. W., Harris, C. D. and Bavly, D.: "A Method for General Reservoir Behavior Simulation on Digital Computers", paper 1521-G presented at SPE 35th Annual Fall Meeting, Denver, Colo., Oct. 2-5, 1960.
4. Coats, K. H., Nielsen, R. L., Terhune, M. H. and Weber, A. G.: "Simulation of Three-Dimensional, Two-Phase Flow in Oil and Gas Reservoirs", *Soc. Pet. Eng. J.* (Dec., 1967) 377-388.
5. Coats, K. H.: "An Analysis for Simulating Reservoir Performance Under Pressure Maintenance by Gas and/or Water Injection", *Soc. Pet. Eng. J.* (Dec., 1968) 331-340.
6. Coats, K. H.: "A Mathematical Model for Simulating Three-Dimensional Three-Phase Fluid Flow in Reservoirs", The U. of Texas, Austin (Nov., 1968).
7. Henderson, J. H., Dempsey, J. R. and Tyler, J. C.: "Use of Numerical Reservoir Models to Develop and Operate Gas Storage Reservoirs", *J. Pet. Tech.* (Nov., 1968) 1239-1246.
8. Coats, K. H.: "A Treatment of the Gas Percolation Problem in Simulation of Three-Dimensional, Three-Phase Flow in Reservoirs", *Soc. Pet. Eng. J.* (Dec., 1968) 413-419.
9. McCulloch, R. C., Langton, J. R. and Spivak, A.: "Simulation of High Relief Reservoirs, Rainbow Field, Alberta, Canada", *J. Pet. Tech.* (Nov., 1969) 1399-1408.
10. Roebuck, I. F., Henderson, G. E., Douglas, J., Jr., and Ford, T. W.: "The Compositional Reservoir Stimulator: Case I—The Linear Model", *Soc. Pet. Eng. J.* (March, 1969) 115-130.
11. Roebuck, I. F., Henderson, G. E., Douglas, J., Jr., and Ford, T. W.: "The Compositional Reservoir Simulator: Case IV—The Two-Dimensional Model", paper SPE 2235 presented at SPE 43rd Annual Fall Meeting, Houston, Tex., Sept. 29-Oct. 2, 1968.
12. Gondouin, M., Canevet, G. and Knizzeff, V.: "A Compositional Three-Phase, Three-Dimensional Reservoir Model", paper SPE 2236 presented at SPE 43rd Annual Fall Meeting, Houston, Tex., Sept. 29-Oct. 2, 1968.
13. Coats, K. H.: "An Approach to Locating New Wells in Heterogeneous, Gas Producing Fields", *J. Pet. Tech.* (May, 1969) 549-588.

JPT

Manuscript received in Society of Petroleum Engineers office Feb. 6, 1969. Paper (SPE 2367) was presented at SPE Gas Technology and Peripheral Waterflooding Symposium held in Liberal, Kans., Nov. 14-15, 1968.