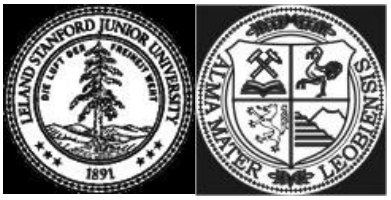
INTERNATIONAL FORUM ON  RESERVOIR SIMULATION

Practical Aspects of Simulation of Fractured Reservoirs

presented by

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Practical Aspects of Simulation of Fractured Reservoirs

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This document accompanies a presentation given at the 2003 International Forum on Reservoir Simulation. It discusses practical aspects of large-scale numerical simulation of naturally fractured reservoirs (NFR) and highlights some experiences in forecasting performance of NFR. A major premise of the presentation is that there is value in incorporating fractures separate from the matrix rock in numerical simulators using dual-continuum models. The presentation will stress the major difficulties in full-field modeling of NFR including 1) understanding and capturing relevant flow processes, 2) turning fracture measurements into credible descriptions of the fracture network, and 3) performing efficient simulation of the system. Many of the ideas presented here are a result of many years of interaction with Dr. Hossein Kazemi at the Colorado School of Mines and I wish to acknowledge his significant contributions to this field of study. Much of the material presented here is a condensed version of an "engineering" chapter to be provided by Dr. Kazemi and myself in an upcoming AAPG Monograph on fractured reservoirs (edited by Dr. Amgad Younes).

Simulation of NFR requires that a number of complex issues come together in a consistent manner. In fact, fractures are often not incorporated explicitly in simulations because they are difficult to describe and difficult to simulate. In NFR, the uniqueness problem is significant and forecasting uncertainty is greater than with conventional reservoirs. The large uncertainty should be addressed, yet because of numerical difficulties, we are often forced to a single realization for history matching or even worse we are forced to ignore the influence of fractures (except for the enhanced permeability aspects). This large uncertainty with a given realization often leads to poor forecasts which leads to further skepticism of the reliability of the simulators.

Major steps in simulating NFR include:

1. Distribute matrix rock properties in 3D. This is the same problem as with conventional reservoirs; however, we normally are only concerned with "pay" and therefore "non-pay" rock acts simply as barriers to flow or is included as net-to-gross ratios.
2. Distribute fracture properties in 3D including intensity, transmissivity, directionality, and pore volume. In this case fractures may be present in both "pay" and "non-pay" possibly creating complex connection between the matrix "pay" intervals. This leads to special considerations when building static 3D models.
3. Average (or upscale) matrix and fracture descriptions in order to reduce the problem to a manageable set of simultaneous flow equations.
4. Chose appropriate simulator assumptions and develop approximations for matrix-fracture fluid exchange.

With all these issues, there may appear to be little hope of getting a unique answer. In fact, for a model to precisely predict the all behaviors of a physical system, the model would need to be more complex than the system itself requiring a precise reservoir description. The question should instead be "can we estimate the range of uncertainty?"

When I think of making prediction of NFR performance, I think of a story given by Peter L. Bernstein in his book *"Against the Gods: The Remarkable Story of Risk"* (John Wiley and Sons, 1996). He refers to World War II weather forecasters who asked to be relieved of duty because they found that their forecasts of next month's weather were no better than numbers out of the hat. The response was "The commanding general is well aware that the forecasts are no good. However, he needs them for planning purposes."

The reservoir simulation industry has much more going for it than with early weather forecasting. Based on seismic, geologic and petrophysical advances, we can get a very reasonable estimation of the pore volume of most systems. Thus unlike the butterfly effect in weather forecasting where small changes in initial conditions lead to large variability in results, we are constrained by volumetric estimates and analogous reservoirs in regard to the upper and lower limits of hydrocarbon recovery. Although issues like viscous fingering and injection fluid breakthrough paths are very difficult to predict and perhaps suited to chaos theory, again the system is generally constrained and well represented by empirical relations like relative permeability and Darcy's Law.

A continuous education process on a given field where flow tests, core measurements, logs, and seismic interpretations are calibrated to field response through simulations is a valuable task. It may not always show what "is" but it does show what "is not" possible. This reminds me of a bumper sticker referring to the high cost of a college education "You think education is expensive, try ignorance" (This aphorism is attributed to Derek Bok, a former President of Harvard). This is often the case I see as a reservoir modeler. The cost and time of reservoir characterization and simulation is often considered to be of questionable value because of the uncertainty of the results. The choice is often made to do very limited or simplified reservoir studies that ignore important data (*e.g.* fractures) in order to save costs. However, the wrong choices in regard to field development can cost orders of magnitude more than the study. Something as "simple" as ignoring the fractures can lead to spending millions of dollars in improper developments. A model that provides bounds on the potential behavior of the reservoir can be very valuable. Of course there is the other extreme where the modeler gets bogged down in the details, defining fracture variability that is not unique simply for the purpose of getting a history match.

The Nature of Fractured Reservoirs

Fractures can significantly affect the mechanism of oil and gas production from petroleum reservoirs. We are all aware of cases where fractures can become channeling paths for flow of water or free gas, causing detrimental early water or gas breakthrough in production wells.

However, fracture flow could be used to one's advantage as in gas-induced gravity drainage of oil, where the gas-oil contact in fractures is pulled down to expose matrix blocks to gas and induce oil gravity drainage. The goal of a reservoir engineer should be to understand how fractures could be used to positively affect production (Nelson, 1985).

The same processes that are active in unfractured systems are important in fractured reservoirs. These include rock compaction, fluid expansion, viscous drive, gravity displacement, and imbibition. However, the degree of importance may be quite different between the two systems. For example, large viscous forces may be difficult to achieve in the matrix component of extensively fractured reservoirs; therefore, capillary and gravity forces may dominate. In such systems, increasing fluid withdrawal rates may cause an increase in water and gas production rates with a lesser effect on oil production rate. Alternatively, decreasing total fluid withdrawal rate may allow little change in oil production rate at reduced water-oil and gas-oil ratios. It is important that reservoir simulators capture and approximate these differences.

In dealing with conventional reservoirs, reservoir engineers can generally provide a reasonable assessment of the reservoir performance by combining information about the reservoir's geologic framework, the rock and fluid properties, and results from well logs, rock mechanic tests, and formation evaluation tests. Furthermore, in the last several years, reservoir-scale seismic information has greatly aided reservoir characterization. However, for fractured reservoirs, obtaining the right data and forecasting the reservoir performance is much more difficult than for conventional reservoirs. To design an appropriate plan of development, one needs a credible reservoir description that includes mapping fractures in terms of size, connectivity, conductivity, and frequency distribution and then turning this information into a reliable fracture network characterization.

Reservoir description should rely on information from many sources including drilling data, core analyses, geologic interpretations, seismic surveys, petrophysical information, and ultimately well tests, such as RFT, MDT, DST, and extended pressure transient tests. In the later stages of reservoir life, historical well performance and non-routine field tests like tracer breakthrough can provide the type of data that can be used to refine the reservoir description. All of the data sets have to inter-relate closely to produce an acceptable description of the reservoir for long-term reservoir evaluation and forecasting. In fact, history matching in various forms (*i.e.*, the classical tank material balance approach or the modern numerical simulation methodology) is the preferred tool used to infer reservoir flow characteristics and to develop a working picture of the reservoir. The measured reservoir characteristics must show consistency with reservoir properties obtained from flow measurements. Direct prediction of flow characteristics from static measurements is still very problematic. So how do we scale the static data to the field in the presence of numerous property variations? Currently the experienced reservoir engineer applies a number of pragmatic approaches. Hopefully, future development will bring a number of easy-to-use, broad-based methods to up-scale measured data from all sources for fluid flow applications.

A major modeling assumption is that in the macroscopic sense, the inter-connected open fractures are assumed to form a continuum in dual-porosity modeling. Similarly, in the dual-porosity/dual-permeability modeling, both fracture and matrix components of the reservoir are considered separate continua in the macroscopic sense. This continuum view should be no more disconcerting that in conventional reservoirs where the microscopic pores are very tortuous and the channel dimensions and flow properties vary drastically from point to point. In this case, the continuum definition of the porous medium flow equations cannot be applied on the pore level scale (Lake, 1989) but must be averaged over some representative pore volume (REV). The flow problem is therefore transformed from the microscopic level to a macroscopic REV scale. At the REV scale, the flow problems are expressed in terms of averages of the microscopic properties (*e.g.*, permeability and porosity) taken over the REV. The size of the REV must be larger than the microscopic heterogeneity size and much smaller than the macroscopic length scale (Royer, et al., 2002).

There are a number of important flow characteristics of fractured reservoirs that are well represented by the dual-continuum "idealization" such as:

- High apparent permeability compared to core measurements
- Early breakthrough of injection fluids or early gas/water coning
- Highly directional flow behavior
- Large variability in well productivities and recoveries
- Potential loss of productivity with time
- Flow comes from a very small portion of the open interval
- Hydrocarbon production rates are not directly proportional to drawdown

While these could also be represented by discrete approximations of fractures, there are a number of reasons that prevent the discrete approach from being widely applied in full-field modeling.

There are a number of issues in regard to the nature of fractures that have significant implications on fluid-flow modeling. For example, whether fractures are a result of shear, extension, or tension, the fact is that they exist generally in vertical or sub-vertical forms. Also the mechanical properties of rocks can vary significantly in various stratigraphic layers of the reservoir. The variation of properties, such as Poisson ratio and shear modulus, would create different horizontal stress in reservoir layers, and different fracture lengths and apertures if fracturing occurs. In many cases, fractures may cluster (Gale, 2002).

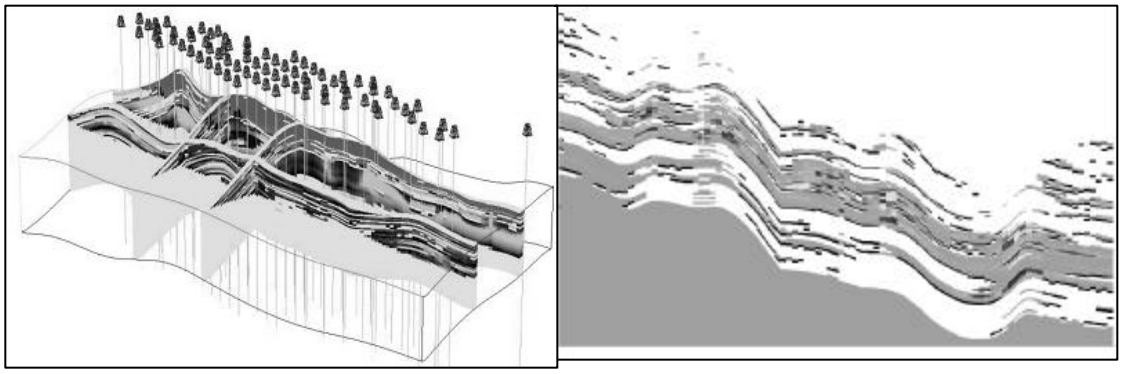
Finally, the morphology (form and structure of fractures) is an issue (Nelson, 1985). Fractures may be open with attendant large permeability, gouge filled with low permeability along and perpendicular to fracture, slickensided with high permeability along the fracture and low perpendicular to it, mineral-filled leading to partial or total fracture closure as well as reduced permeability, and vuggy where vugs are imbedded in the fractures. Knowledge of morphology is

a very important piece of information in fluid flow modeling because models require estimates of fracture spacing, effective permeability, porosity distribution, and permeability anisotropy.

Diagenesis can alter the permeability and porosity of open fractures to the extent that they would not behave like fractures, and fully mineralized fractures could, potentially, become baffles or barriers to flow. Thus, the mere presence of fractures does not require dual-porosity/dual-permeability modeling. Also, a reservoir need not be modeled only as a dual-porosity or single-porosity system. Various parts of the reservoir may be characterized differently.

Quantifying Reservoir Data for NFR Simulation

For dual-porosity simulation, the fracture network is described as a continuum with properties (*e.g.*, permeability and porosity) similar to those defined for the matrix rock. We need to relate rock properties, which are measured in cores or obtained from well tests, to those required for reservoir simulation. For example, porosity and permeability are defined with respect to the bulk volume of the core, not with respect to individual fractures. Combining fracture network flow with characterization of the rock matrix storage allows optimization of recovery schemes, which complement the fracture network. To date, most approaches for quantify the flow properties on the fracture networks are based on empiricisms. In fact, as a reservoir modeler, I would generally be "happy" with a quality assessment of the 3D distribution of fracture network characteristics, such as relative fracture intensity, directional aspects, and whether the fractures are generally open or closed.



In current 3D modeling approaches we need to address the issue of fracture distribution throughout the reservoir volume, not just the "reservoir rock". Fractures may allow significant communication paths throughout the reservoir including "non-pay" intervals.

The empirical approaches use information such as structural data, seismic time surfaces, images logs, and field production performance to estimate the fracture network properties (*e.g.*, Gauthier et al., 2002). The approach is to build both deterministic and stochastic models with these data and validate them by comparing to the field performance (*e.g.*, water and gas breakthrough).

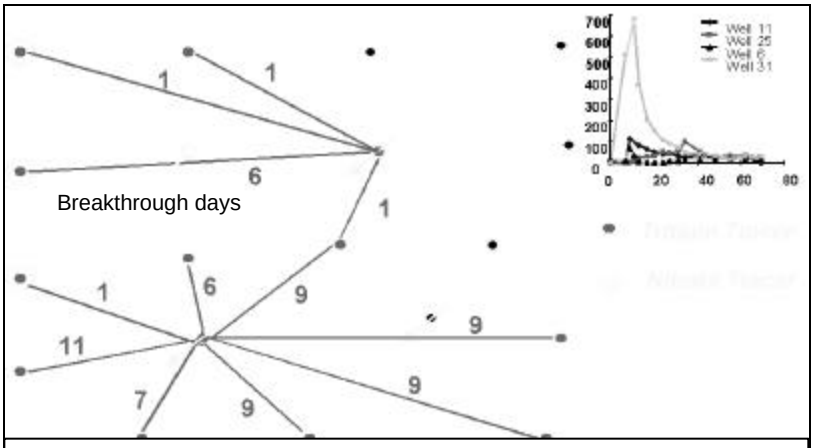
Non-standard dynamic field tests such as tracer tests can be very important for quantifying the fracture heterogeneity. Inferences about fracture volumes and directional tendencies can be made with such tracer tests (Kazemi and Shinta, 1993). Interference or pulse testing can also provide the important information. Araujo et al. (1998) reported a number of practical issues in regard to such field tests. Interference testing can give directional information to compare to FMS and stress relations for calibrating such static measurements. Although such tests can often be difficult to interpret, they can usually provide an estimate of fracture volume from the very rapid pressure response between wells.

Traditional methods of estimating fracture parameters have also included single-well pressure transient testing to estimate fracture conductivity, and cores and image logs to estimate fracture intensity. The theoretical dual-porosity signature of the pressure build-up curve (Warren and Root, 1963) is often missing because of the presence of well bore storage effects. However, comparing the pressure transient permeability to that estimated from matrix permeability can give an indication of the effectiveness of the fracture network.

In an ideal setting, we should be able to estimate fracture network effective permeability from aperture and porosity estimates using parallel plate idealizations (Kazemi and Gilman, 1993). However, the effective fracture permeability for a network of fractures will likely be much smaller than calculated from such relations because fractures are tortuous, may be constricted by mineral deposition, may terminate abruptly, and are not ideal parallel plates. Furthermore, the vertical permeability of an individual fracture could be quite high, however, if the fractures terminate in shale lenses or are of limited height for some other reason, the effective vertical permeability of the network could be quite low. Therefore, permeability is best determined from field tests and not from core-measured fracture widths and spacing. The static data however can be used to derive empirical scaling relations to distribute permeability in 3D.

Permeability in NFR can be highly directional. Considering this highly directional nature, the need for permeability tensors has been widely discussed but not widely applied in field-scale fluid-flow modeling. When the principal permeability directions are not aligned with the standard x-y grid coordinates, the velocity in the x-direction has contributions from both the potential gradient in the x-direction and the y-direction. This similarly applies to the velocity in the y-direction. Such directional permeability can be modeled with a permeability tensor (Scheidegger, 1960). The directional permeability values and the permeability tensor components can be calculated by knowing the principal permeability values (*e.g.*, from pressure interference testing) and the direction angle relative to the x-y coordinate system. Whether such a tensor approach is required is still debated because the actual data required to uniquely define the tensors are not available. Also, the extra computation required means that additional upscaling would be required, reducing other details in the model. Generally aligning the grid system with the directional trends would appear to be adequate for most field scale systems. Provided that grids are aligned with the maximum permeability direction, the use of conventional 5-point finite differences should provide adequate resolution for field-scale flow models. Otherwise, higher order schemes may be required (*e.g.*, 9-point finite difference, Gilman and Kazemi, 1983).

Single-well flow tests, such as a pressure build-up test, cannot decipher permeability anisotropy. The most direct method to calculate permeability tensor is from the interpretation of pressure interference tests conducted in various parts of a field. Haws and Hurley (1992) summarized interference test results from a number of Big Horn Basin fractured reservoirs, where they reported that the maximum to minimum permeability ratio varied from 10 to 1000. These results reflect the permeability anisotropy mainly as related to the diffusive component of flow. On the other hand, tracer tests can provide information on the well-to-well, well-to-fracture as well as the global channeling trends as related to the convective component of flow. Tracer tests, compared to interference tests, could be more time consuming and expensive. However, a tracer test conducted in a naturally fracture reservoir (Kazemi and Shinta, 1993) should provide additional insight on permeability anisotropy. Finally, the most common method used to assess the directional flow tendencies is based on fracture orientation studies of the borehole image logs, oriented cores, outcrops and of course water or gas breakthrough tendencies. Seismic methods are also being investigated as a means to infer fracture anisotropy. These later methods however are not quantitative and still must be calibrated to dynamic data.



Fractured reservoir description can be significantly improved by calibrating to non-standard field data such as tracer tests and pressure interference data.

Methods are being developed to estimate the effective fracture permeability tensor for a REV cube or a grid cell using discrete fracture network (DFN) models based on measured fracture aperture, surface area and the inclination angle normal to the fracture surface. Only the open fractures that contribute to fracture flow should be included (Oda, 1985 and Dershowitz, et al., 2000). This approach is one method for scaling DFN models, image logs and outcrops to equivalent dual-porosity medium (Deshowitz, *et. al.*, 2000).

If fractures close as reservoir pressure declines, then effective permeability could decrease. A number of researchers have derived the expressions for permeability, aperture, compressibility, and porosity of smooth open fractures as functions of pore pressure and stress state in an elastic porous media. However, fracture closure is very difficult to estimate because of the presence of

filler material, or complex stress states of the reservoir. Also at large flow rates, the onset of turbulent flow can create additional pressure drop causing an apparent reduction in permeability. Step rate tests may be required to determine if turbulent flow is important.

Fracture porosity calculations require an estimate of fracture spacing and width, which can be obtained from cores, image logs and outcrops. The local porosity calculated for an individual fracture would essentially be 1.0; however, when calculated with respect to the bulk rock volume in a REV, fracture bulk porosity is quite small (<1.0%). In addition to cores and logs, one can in theory use the effective permeability and fracture spacing results from pressure buildup tests to estimate fracture porosities (Kazemi and Gilman, 1993).

For reservoir characterization and flow modeling, fracture porosity needs to be estimated at all well locations and distributed in the 3-D space. Typically, we do not have image logs or cores at all wells; therefore, we need to estimate porosity from conventional logs (*e.g.* Iwere, 2002) and develop empirical relations to relate fracture porosity to other static information such as flexure, lithology, and other intrinsic and extrinsic rock mechanical characteristics. Researchers have also estimated fracture porosity (and permeability) based on fracture-scaling fractals in terms of fracture width and/or length (*e.g.* Hossain, *et. al.* 2002; Gale, 2002). Under these assumptions, the fracture total permeability is dominated by the largest fracture permeability.

In addition, to the conventional reservoir parameters (porosity, permeability, compressibility, etc. for both fracture and matrix), an additional parameter, the shape factor, is needed for fluid transfer calculation between the matrix and fracture network. This parameter is often represented by the symbol 's' in units of ft^{-2}. This term is best understood from the Warren and Root paper (1963) in which they idealized the system as a stack of "sugar-cubes".

There has been much discussion about the physical meaning and the functional form of the shape factor. From a practical view, it is a second order, distance-related, geometric parameter that is used to calculate the mass transfer coefficient between matrix blocks and surrounding fractures. Shape factor is a function of fracture spacing (or intensity), and is not inherently a time-dependent parameter, but several authors have attempted to treat it as such. Ideally, the shape factor could be calculated from pressure build-up data. Several expressions describing the shape factor have been presented in the literature and some are summarized here.

The pseudo-steady state, analytically derived expression for the shape factor (Kazemi and Gilman, 1993, Chang, 1993, Zimmerman, 1993, Lim, 1995) in terms of fracture spacing (L) in the x, y, and z directions is:

$$s = p^2 \left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2} \right) \qquad (1)$$

while the pseudo-steady state, numerically derived expression for shape factor (Kazemi, 1976, Kazemi and Gilman, 1988) has a coefficient of 4 rather than π. A transient state, analytically derived shape factor was given by Penuela, et al., 2002, but is not generally used in field scale simulations.

A generalized shape factor based on water imbibition experiments (Kazemi, et al., 1992, Zhang, et al., 1996) is:

$$s = \frac{1}{V}\sum_{i=1}^{I}\frac{A_i}{d_i} \tag{2}$$

In the above equation, A_i designates the area of the exposed fracture surface i for the given matrix block with a volume V, d_i is the distance from the center of the block to surface i, and I is the number of exposed fracture surfaces. This equation is also the most general form for upscaling from complex fracture patterns (*e.g.*, DFN network models) to equivalent dual-porosity media for both single- and multi-phase flow.

In practice, shape factor is often considered a history matching parameter, but it is best to start with the above equations using the best estimate of the fracture spacing. The shape factor can vary over the computational grid and is only considered a constant over the REV. Note that the numerical models do not actually require any discrete representation of matrix "sugar cubes". The idealization of sugar cubes is just an artifact for discussion similar to the bundle of capillary tubes idealization used for a single-porosity media. The dual-porosity models are "simply" two overlying porous media with a transfer term directly proportional to shape factor.

As pointed out by Kazemi and Gilman (2003), the power law fractal model can eliminate the need for measuring fracture spacing (Gale, 2002) because for a given fracture aperture w_f the average spacing is $1/F(w_f)$. This method may be a good way to estimate the smallest dimension of the matrix blocks in a fractured reservoir.

Ideally, the shape factor could be calculated from pressure build-up curves for various wells in the field under study. Theoretically, such curves develop two parallel straight-line segments, indicative of dual-porosity behavior (Warren and Root, 1963). The build-up time at the inflection point, on the transition segment between the early and late straight line build-up segments, is related to shape factor and depends on two dimensionless parameters, the storativity and the inter-porosity flow, w and l, which are defined as:

$$w = \frac{(fc_t)_f}{(fc_t)_f + (fc_t)_m} \tag{3}$$

$$l = \frac{s k_m r_w^2}{k_e} \tag{4}$$

The inflection point on the transition between early and late straight-line flow periods depends on the shape factor according to the following relation (time is given in hours):

$$\Delta t^* = \frac{-(f m c_t)_f \ell n(w) r_w^2}{0.0002637 l k_e} \tag{5}$$

In the above equations, k_e, is the effective permeability of the fractured system as calculated from the slope of the build-up curve. The vertical pressure separation (δp) between the two parallel lines is related to ω. Often the customary two straight-line segments do not appear on the pressure build-up curve because of well bore storage or boundary effects; therefore, shape factor cannot be calculated from the test. The time equation given above shows the short time frame for transition to occur in systems with moderate compressibility. Also non-uniform fracturing complicates the transition period. However, the magnitude of effective permeability compared to only the matrix (core) permeability gives an indication of the relative importance of fractures. Fractures must be well connected to give effective permeability much greater than matrix permeability. If the dual-porosity response is not seen, shape factor will need to be inferred from other information (*e.g.* image logs).

Continuum Representation of the NFR Flow Equations

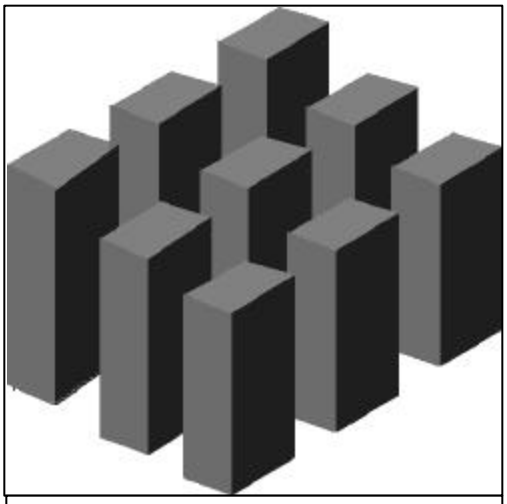
Fluid flow modeling is a most important aspect of the process to decipher the role of natural fractures in reservoir performance, and it is the primary method for optimizing hydrocarbon recovery from the reservoir. For large-scale numerical simulation of petroleum reservoirs, dual-porosity / dual-permeability models are the most widely used idealization. These idealizations have been found to reproduce the behavior of many systems and are a very practical method for large-scale simulation. The industry has used dual-porosity and dual-permeability models to history match numerous fractured reservoirs over many years of history and to predict future performance. In these models, the fracture network is assumed to be well connected and is treated as an equivalent porous medium described by its porosity, permeability (often highly directional), relative permeability, capillary pressure, etc. These properties can vary widely throughout the reservoir. However, this idealization leads to a number of issues in regard to representing the fracture-matrix exchange.

Gilman and Kazemi (1988) and other authors have presented several fracture-matrix arrangements for idealizing dual-porosity flow in naturally fractured reservoir. These idealizations were devised with the goal of developing computationally efficient models and are thought to preserve the salient petrophysical characteristics and the dominant fluid flow features of NFR. These models simplify the complexity of the real fracture network and its connection to the matrix,

but the end product is thought to represent flow in an actual reservoir if consistent mathematical and petrophysical parameters are input into the models.

Three approaches are commonly used to model field-scale fluid flow in naturally fractured petroleum reservoirs. The first approach is a dual-porosity (DP) idealization of the reservoir, where a typical representative elementary volume (REV) of reservoir rock is idealized to contain a large number of equal size matrix blocks separated by interconnected fracture planes. This model is often referred to as the sugar-cube model, where the sugar cubes represent the matrix blocks and the spaces between the sugar cubes represent the fractures. In the numerical simulation of flow, an individual sugar cube is not treated as a discrete grid cell. Instead, for a given grid cell or REV, the set of all interconnected fractures are lumped into one continuum called fracture while the collection of all matrix blocks is lumped into another continuum called matrix. In dual-porosity modeling, the fractures are interconnected as a continuum and form a flow network connected to the well bore. The matrix blocks, on the other hand, are presumed not to interconnect; therefore, there is no matrix-to-matrix flow, but there is matrix-to-fracture flow. The dual-porosity models generally ignore any viscous displacement from the matrix, but methods have been developed (Gilman and Kazemi, 1988) to account for this displacement mechanism. Also gravity effects are generally approximated by a segregated fluid assumption similar to the vertical equilibrium option provided in many single-porosity simulators.

The second approach is a dual-porosity/dual-permeability (DP/DK) idealization of the reservoir, where, contrary to the dual-porosity case, the matrix blocks also communicate with each other; therefore, there is matrix-to-matrix flow in addition to matrix-to-fracture flow. A very pragmatic approach to fluid flow modeling of fractured reservoirs is to assume that the reservoir is composed of a set of vertical columns of matrix blocks surrounded by interconnected vertical fracture planes. These fractures, in the map view, form a two-dimensional network. This approach is a sub-set of the classical dual-porosity/dual-permeability model. Vertical and sub-vertical tension and shear fractures (usually in conjugate pairs) are created in reservoirs as a result of earth stresses. Also, the digenetic changes in the fractures pore space, such as mineral deposition, creates vertical connection between matrix blocks that could lead to film flow of oil between matrix blocks. In the case of multi-phase flow, the fluid density differences create significant gravity forces in the vertical direction, which induce gravity drainage in the matrix. The capillary pressure forces, interact with the gravity force to enhance or oppose matrix drainage.



Many fractured reservoirs can be idealized as vertical fracture sets

The third approach, the discrete fracture network (DFN) flow modeling, is the most recent method, which relies on three-dimensional spatial mapping of fracture planes to construct an interconnected network of fracture surfaces. Any three-dimensional reservoir rock volume, bounded by fracture planes, is, therefore, a matrix block. Contrary to the dual-porosity/dual permeability flow modeling, the DFN approach requires very precise description of fracture network in terms of geometry, conductivity, and connectivity. However, the models have been largely applied in single-phase systems (*e.g.*, aquifers) because of the large computational effort required. Recently, however, emphasis has been placed on the use of the DFN models for upscaling geologic information to the dual-porosity fluid-flow simulation (Bourbiaux, et al., 1999; Dershowitz, et al., 2000). DFN-based models are currently impractical for field-scale simulations of petroleum reservoirs for the following reasons:

- The total number of fracture elements is too excessive for modeling flow in each individual fracture.
- The flow network, consisting of discrete fracture elements in the three-dimensional space, is very difficult to describe reliably, and
- The inter-porosity flow between the matrix and fracture adds much additional complexity because it requires extensive computation that has not been adequately developed for multi-phase, large scale modeling.

For field-scale simulation, dual-porosity/dual-permeability approaches mean that we must average flow behavior over a large volume. This creates special limitations in representing the flow in the fractures and from matrix-to-fractures. The following discussion addresses that averaging by presenting the basic equations for some important recovery process in NFR. The finite difference form is for that of fracture-matrix fluid transfer which is often the constraining condition in regard to efficient recovery in NFR. These equations approximate the proper physics, and so the issue is finding the correct average properties to input into the large-scale models. The most pragmatic approach is to use some sort of static averaging (upscaling) to represent the static variables like shape factor and absolute permeability. These are variables, which in theory, do not depend on the recovery process. Relative permeabilities and capillary pressures are then the parameters that can be used to upscale and approximate the recovery process dependent flow behavior.

In purely single-phase depletion, the dominant recovery mechanism is fluid expansion. In practice, this occurs normally as the first stage of reservoir operations, and fluid recoveries are typically quite low (except for gas systems). In single-phase depletion, oil or gas recovery rate can be much greater in NFR compared to unfractured reservoirs because the high permeability fracture network undergoes rapid depletion and provides large surface areas for reservoir fluid in the low-permeability matrix to expand into the fractures. In multi-phase depletion, fracture flow can lead to free gas flow in the fractures, which, in turn, could invoke gravity drainage of oil from the matrix—leading to very high oil recoveries if the gas-oil gravity drainage process is managed properly.

The equations for a single-phase, dual-permeability model is presented below. The first equation represents the flow in the fractures in addition to a term for flow contribution from the matrix. The second equation represents flow in the matrix. The first term is dropped from this second equation for dual-porosity flow.

$$\nabla \bullet \left(\frac{k_f}{m} \nabla p_f \right) - \frac{s k_m}{m} \left(p_f - p_m \right) + q_f = f_f c_{tf} \frac{\partial p_f}{\partial t} \tag{6}$$

$$\nabla \bullet \left(\frac{k_m}{m} \nabla p_m \right) + \frac{s k_m}{m} \left(p_f - p_m \right) + q_m = f_m c_{tm} \frac{\partial p_m}{\partial t} \tag{7}$$

These equations are commonly discretized in finite-difference form and solved for fracture and matrix pressures at all grid blocks and a given time step (*e.g.*, Kazemi and Gilman, 1993). A one-dimensional, single-phase oil fluid-expansion finite difference form for fracture-matrix transfer is:

$$t_o = 0.001127 \frac{s V k_m k_{ro}}{B_0 m_o} \left(p_{om} - p_{of} \right) \tag{8}$$

From these equations one can see that the important parameters that affect the rate of matrix-fracture fluid transfer during depletion to be shape factor, s, matrix fluid mobility, (*i.e.* $k_m k_{ro} / m_o$ for oil), and fracture-matrix pressure difference, $\left(p_m - p_f \right)$.

Solution of these single-phase equations for low compressibility flow shows that in an ideal closed radial reservoir, producing under constant bottom-hole pressure depletion, a double exponential flow rate decline can develop. Chen, *et al*., (1986) showed the exponential decline characteristics of a number of Austin Chalk wells. A plot of $ln(q)$ versus time should give a straight line during exponential decline. A plot of flow rate versus cumulative recovery also gives a straight line during exponential decline.

Satman (1985) derived equations for the initial flow rate and for the slope of the exponential recovery lines as a function of the inter-porosity parameter, l. Because of the small volume of fluid in the fractures, the initial period may be very short and therefore impractical to measure. For large λ (> 16 r_w^2/r_e^2) only a single straight line will develop because of the nearly instantaneous pressure equalization between the fracture and matrix. The reservoir then responds like an unfractured reservoir with a permeability equal to k_e and porosity-compressibility equal to that of the total system. For highly fractured systems with moderate to good matrix permeability (σk_m > 0.1 *md-ft*$^{-2}$), only one straight line will develop.

In theory, Satman's equations could be used with decline curve analysis to determine reservoir properties for the fracture-matrix system (Chen, *et al*. 1986). In practice this is very difficult

because of variations in bottom-hole pressures, multiphase-flow, offset well interference effects and the long production times required to obtain both exponential decline periods. Also, numerical simulation has shown that the first line is very short lived and the slope is affected by matrix-fracture flow. Therefore, fracture properties are very difficult to determine from decline curve analysis. However, long-term rate and pressure decline can be used with conventional reservoir depletion analysis to determine the effective permeability and total pore-volume of the system (fracture and matrix). The magnitude of effective permeability compared to only the matrix (core) permeability gives an indication of the relative importance of fractures. The above equations show how high fracture intensity (large σ) can lead to efficient depletion of fractured systems with low matrix permeability.

Water imbibition has proven to be an effective recovery mechanism in some NFR. Imbibition in reservoir rock is the process in which water is drawn into a reservoir rock by the action of the capillary forces. This is similar to water rising in a capillary tube when one end of the tube is immersed in a tray of water. The following quasi-linear partial differential equation represents the one-dimensional imbibition processes. Here viscous and gravity flow terms are neglected.

$$\frac{\partial}{\partial x} D \frac{\partial S}{\partial x} = \frac{\partial S}{\partial t} \tag{9}$$

D, the capillary "diffusion" coefficient, has units of length^2/time and is given by

$$D = \frac{k k_r}{\phi \mu} \frac{\partial p_c}{\partial S} \tag{10}$$

Mattax and Kyte (1962), through experimental investigations, found that recovery in such systems could be scaled through the following dimensionless time:

$$t_D = \left[\sqrt{\frac{k}{\phi}} \left(\frac{\gamma}{\mu L^2} \right) \right] t \tag{11}$$

This equation shows that recovery is inversely proportional to the matrix block size squared, L^2. Capillary pressure is indirectly incorporated in the above equation through the interfacial tension, γ, permeability and porosity terms. The above equation can be rewritten in terms of shape factor, σ, by replacing $1/L^2$ with σ as shown in Kazemi, *et al*. (1992) and Zhang, *et al*. (1996).

The experimental data generated by Mattax and Kyte can be described by an exponential time function that indicates fractional oil recovery is inversely proportional to the square of the matrix block size. Kazemi, *et al*. (1992) provide an analytical solution for one-dimensional flow in a fractured systems using such exponential relations. These relations can provide a quick screening tool for scaling laboratory results to field performance.

The important parameters affecting oil recovery from water imbibition are shape factor, capillary pressure and oil mobility, kk_{ro}/m_o. Specifically, oil rate is greater as permeability increases and matrix block size decreases (fracture intensity and shape factor increases). Recovery rate also increases as oil relative permeability increases making it easier for water to imbibe and oil to flow out. Higher capillary pressure increases rate of oil recovery through increased imbibition force. NFR that have undergone waterflood or strong aquifer drive include the Fahud Field (O'Neill, 1988), Ekofisk Field (Hallenbeck et al., 1991), Midale Field (Beliveau, et al., 1993) Ezzaouia Field (Gilman et al., 1996), and Ghawar Field (Phelps and Strauss, 2002). The more than 30% recovery from the Ezzaouia Field is a case that illustrates the effectiveness of water imbibition dominated recovery in some NFR.

The finite difference form for imbibition in a single grid block without gravity reduces to:

$$t_o = 0.001127 \frac{sVk_m}{B_0} \left(\frac{1}{(m/k_r)_{wf} + (m/k_r)_{om}}\right)(p_{cwom} - p_{cwof}) \qquad (12)$$

which again approximates the partial differential equations.

In some highly fractured reservoirs, the gravity drainage rate in a gas-oil system can be approximated as a one-dimensional solution. In one-dimensional gravity drainage in a porous media, the time rate of change in elevation of a constant saturation oil "shock" front (that is, the gas-oil frontal velocity in ft/day) is given by the following equation (Dykstra, 1978; Richardson, 1989):

$$\left.\frac{\partial z}{\partial t}\right|_{S_o} = \frac{7.83x10^{-6} k_v \Delta r_{og}}{f m_o} \left.\frac{\partial k_{ro}}{\partial S_o}\right|_{S_o} \qquad (13)$$

Solution of this equation for a simple 1-D homogeneous system shows that the assumption of vertical equilibrium in the matrix rock is overly optimistic. Therefore the methods used to calculate the gravity term in dual-porosity models should be used with caution.

For the above equation, the frontal velocity can be converted to gas-induced gravity drainage oil rate by multiplying it by the cross-sectional area perpendicular to the flow direction. The important parameters affecting gravity drainage rate are vertical permeability, density difference, and oil mobility. Fractured systems in which gas filled vertical fractures surround a vertically continuous matrix can be represented by this equation. The above equation ignores capillary pressure. Capillary pressure has minimal effect on early rates, but can cause

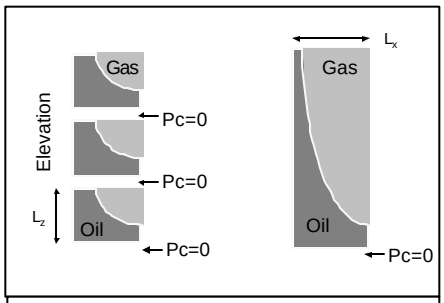


Illustration of saturation profile for gas-oil gravity drainage with and without vertical barriers

hold-up of oil above barriers or horizontal fractures. Permeability variations can affect early drainage rate, but a harmonic average permeability can give a reasonable approximation to the drainage behavior over a limited permeability range. Simulation shows that for matrix block radii of 10's of ft, there is no difference in recovery, showing the insensitivity of this system to fracture spacing. Because the flow is vertical, the areal spacing of the fractures should not be expected to have any effect. (Fracture intensity will however, significantly affect the rates and coning tendency of producing wells with regard to the fracture network). Adding vertical barriers across a matrix column would appear to initially increase drainage rate, because each isolated region can feed into the fractures rather than just flowing vertically through the entire matrix column. However, in actuality, oil will resaturate the lower matrix as drainage occurs, and thus the system with barriers actually drains more slowly. Also, for a case with large capillary pressure and vertical barriers, capillary holdup above the barriers causes long-term recovery to be reduced.

A commonly used finite-difference approximation to calculate the gravity drainage rate, in STB/D, for the dual-porosity idealization and negligible capillary pressure is based on the concept of vertical equilibrium as given by:

$$t_o = 0.001127 \frac{s_{go} V k_{zm} k_{ro}}{B_o m_o} (h_{om} - h_{of} - p_{cogth}) \frac{\Delta r_{og}}{144} \tag{14}$$

Where h_{om} is the multiplication product of the mobile oil saturation in a given matrix grid cell and the matrix block height, L_z. Similarly, h_{of} is obtained by multiplying the mobile oil saturation in the given fracture cell and L_z. The shape factor for gas-oil gravity drainage, σ_{go}, needs to reflect the fact that the process of drainage is primarily vertical. It can be given by the following equation:

$$s_{go} = \frac{2}{L_z^2} \tag{15}$$

Because the oil height terms are proportional to L_z and σ_{go} is inversely proportional to L_z^2, the drainage rate becomes inversely proportional to L_z. Here L_z could be greater than the grid block height and would effectively be the distance between major flow barriers. This form generally over estimates the rate of gravity drainage as previously mentioned.

A more realistic alternative to conventional dual-porosity, pseudo-gravity simulation is to use fine grids and dual-permeability simulation only in the vertical direction and dual-porosity in the other directions. This will provide for a more accurate simulation of the gravity drainage process. Dual-permeability in the vertical direction means that all matrix blocks are allowed to be continuous in the vertical direction. This will then allow oil to drain vertically in the matrix as well as laterally into the fractures. Of course, there is added computational expense because of the dual-permeability approach and the requirement of additional layers.

A common method of assessing effectiveness of gravity drainage is through laboratory centrifuge experiments, which can be directly upscaled to field behavior. Centrifuge experiments are fast, inexpensive, and highly scalable to field behavior both in time and spatial dimensions (Mattax and Kyte, 1962) and can be readily matched using a conventional field-scale reservoir simulator. Predicting the gas-oil gravity drainage behavior is very difficult without proper laboratory data.

In gravity-dominated recovery from NFR, fractures are used as gas flow conduits to invoke gravity drainage from the matrix by controllably lowering the gas-oil contact in the fractures. This procedure is the basis for the concept of "contact management" in fractured reservoirs, which can lead to one of the most effective improved-oil-recovery techniques for fractured reservoirs (Rothkopf and Wadleigh, 1994). NFR that have undergone gas-oil gravity drainage include the Fahud Field (O'Neill, 1988), the Yates Field (Rothkopf and Wadleigh, 1994), the Haft Kel Field (Saidi, 1996), and the Cantarell Field (Arevalo, et al., 1996). In the Haft Kel Field (Saidi, 1996), the calculated water displacement efficiency, supported by field measurements was only about 17%, whereas the calculated gas displacement efficiency, at a reservoir pressure of 1512 psi, was about 32%.

In three-phase systems, consisting of gas, oil, and water, different portions of a given reservoir could undergo different displacement processes leading to complex flow behavior. This usually happens because of the differences in field operations schemes (*i.e.*, water-flooding vs. gas injection) and rock characteristics such as wettability, fracture intensity, permeability variations, layering, structural peculiarities, capillary pressure and relative permeability hysteresis. The oil recovery mechanisms associated with the field characteristics as well as the production schemes in the field are best studied by laboratory experiments and fine-grid numerical simulation. The approximations made by the simulators for coarse-grid full-field models must be verified by these fine-grid studies.

The multi-phase flow equations require the use of relative permeability in both the matrix and fracture. Relative permeability in the matrix is the same as obtained for conventional single-porosity cores (although there is an upscaling issue here because the flow rates are a function of the average saturation in a grid block). On the other hand, fracture relative permeability could be quite different. It is often assumed that fracture relative permeabilites are linear functions of phase saturations. Laboratory experiments have shown this to be true for large fracture sizes (> 50 μm). However, for smaller fractures it has been demonstrated (Maloney, et al., 1997) that relative permeabilities in fractures are non-linear and depend on the fracture flow velocity, direction of flow, and density difference. Other fracture relative permeability concepts have also been presented by a number of authors (*e.g.* MacDonald, *et al*., 1991; Kazemi and Gilman, 1993). There have also been a number of different methods proposed to handle the effect relative permeability for matrix-fracture flow, although the most general method is to use conventional "upstream weighting".

The above discussions refer to water imbibition and gravity drainage, two of the most common methods for enhancing recovery in NFR; however, tertiary recovery, or enhanced oil recovery

(EOR), are processes that produce further additional oil economically over that which can be produced from primary and secondary recovery methods. In NFR, EOR can be viewed as the methods that accelerate oil recovery by altering reservoir fluid and rock properties to better utilize the reservoir's natural energy. The most promising EOR techniques in NFR (Christiansen, *et al*., 1989) include CO_2 (Beliveau and Payne, 1993; Malik and Islam, 2000), heat (Reis and Miller, 1995), surfactants (Chen, *et al*., 2001), and polymers (Sydansk and Moore, 1992).

Addressing Issues of Scale

Fracture characterization often deals with discrete fracture information such as transmissivity, size, orientation, location, and spacing; while for large-scale simulation we need average fracture network properties such as conductivity, intensity, anisotropy, and storage capacity. Although this talk does not directly address the reservoir characterization issue, a brief discussion of upscaling and averaging is warranted. Methods for determining the average data are a major issue. The main question is whether we can determine this average data from rock measurements alone (*i.e.*, without history matching past performance).

Because heterogeneity characteristics are generally measured at small scales (centimeters), as in core plugs, there is a need to upscale such measurements to the scale of computation, *i.e.*, the grid dimension in geologic models (meters) or reservoir models (decimeters). In fact, in the continuum approach of fluid mechanics (Royer, et al., 2002), the flow problem is transformed from the microscopic level to macroscopic scale at which the problem is expressed in terms of averages of the microscopic quantities. The need to know the exact local characteristics of the whole domain is circumvented by the use of these average quantities, which are taken over a representative elementary pore volume (REV). The size of the REV must be larger than the heterogeneity size and much smaller than the macroscopic length scale (e.g., well spacing).

What properties should be used in a grid block of several thousand cubic feet in volume? If we could describe the fractures in detail, then fracture porosity could be directly described. But the fracture distribution may be fractal in nature, with the smallest fractures approaching the size of matrix pores. In a dual-porosity model it is likely that some of these smaller fractures should be grouped into what we call "matrix". Fracture network permeability is again a composite of all the fractures making up the network. Because we could never hope to measure the apertures, roughness, and connections, fracture permeability is best determined by direct measurements (e.g., pressure testing) and then correlated to static data that can be distributed in 3D. Fracture network permeability is often assumed to be the permeability in excess of the matrix contribution.

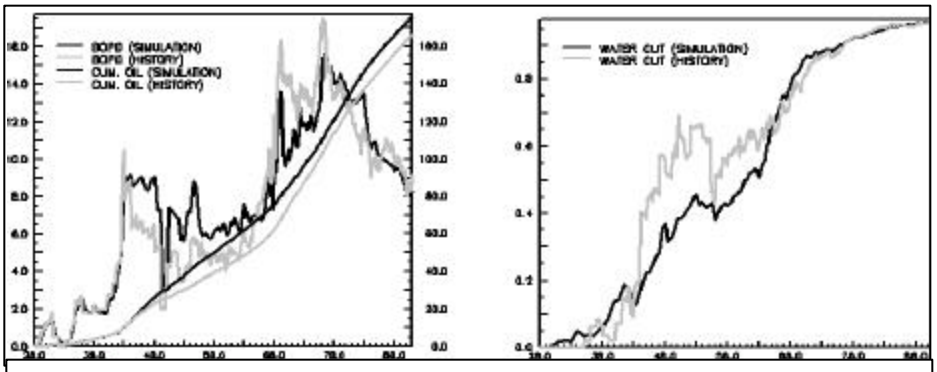
Reservoir flow properties, such as permeability, calculated from pressure transient well tests in heterogeneous porous media are generally non-unique lumped averages (Herweijer, 1997). The reason for this is that pressure transient tests are based on diffusive character of flow. On the other hand, the flow tests that rely on the convective character of flow (e.g., tracer tests) could lead to the delineation of reservoir heterogeneity in a somewhat broader sense.

Scaling issues have been studied for laboratory matrix-fracture fluid transfer experiments (e.g. Kyte, 1970; Zhang, et al., 1996) in homogeneous rocks and have resulted in several viable scaling rules. For heterogeneous rocks much of the research has evolved from a geologic perspective (Pickup and Hern, 2002), where measurements are usually conducted on cores and outcrops and complemented by information from pressure transient tests, well logs and seismic data. The big question is how to scale these data to the reservoir model grid dimensions to create a viable forecasting tool.

One of the most important parameters in dual-porosity models is the apparent matrix block size. Again if we know the fracture distribution, we could determine this as the fracture-matrix area divided by distance from the fractures to the center of the matrix as shown earlier. However, in dual-porosity idealizations, the fractures which are to be included in this calculation should only be those which are well connected for the given flow process. The fractures are anastomosing on a large scale, but a few primary pathways may dominate flow. Damage to these pathways through drilling, completion, stimulation or pressure depletion can be permanent and severely reduce the conductivity of the system. Also, the apparent connectivity can depend on the well placement and the flow process. For example, the effective block size may be different for depletion versus water flood. Under depletion, all the fractures can be quickly depleted of pressure causing matrix fluid to flow through the entire fracture-matrix surface area. Under water flood, water can imbibe only through the matrix surface that is contacted by water. Fractures that are not part of the water flow path will not be flooded by injection water.

Some Generalizations from Field Studies

Long-term performance and modeling of fields with very long histories (> 70 years) has taught us much about the nature of the fractured network, fluid transfer mechanisms and indications of how the effective network properties may relate to more directly measurable properties like image and production logs and pressure transient and tracer tests. However, the characterization and modeling process is still very uncertain and requires extensive calibration with dynamic data. NFR



Dual-porosity models can be effective in matching long-term historical production but the process often requires extensive calibration

simulation, therefore, still relies very much on empiricism and tuning to historical data. This is especially true of the fracture network descriptions because fractures may be enhanced or degraded by diagenesis and other effects.

Initial geologic models are highly qualitative and subjective. The properties that can be directly measured may not hold up at the reservoir scale. Therefore, some degree of uncertainty will always be present. Field production tests (pressure transient, tracers, production tests, etc.) are required in order to validate our idealizations that come from static data. Therefore we will always be limited in our ability to accurately predict behavior without previous history. We need to use knowledge and learning from other studies to bracket the possibilities. The parameters, which affect fluid flow in NFR, are extremely difficult to quantify. NFR in general are very heterogeneous and thus vary widely in behavior (Nelson, 2002). Generalizations for one reservoir do not necessarily apply to another. In fact all reservoirs are heterogeneous. A Texas A&M Study showed that infill drilling for use in secondary water flood resulted in essentially as much oil as from the primary water flood which used a large well spacing (Wu, 1989). The authors own experience has included studies of primary depletion with and without aquifers, water floods, gas-oil gravity drainage, steam pilots, CO_2 huff and puff, dilute surfactant, and polymer floods. Making generalizations about any subject as complex as NFR is probably not a wise thing to do. However, this seems to have wide interest, so a few thoughts will be briefly highlighted here.

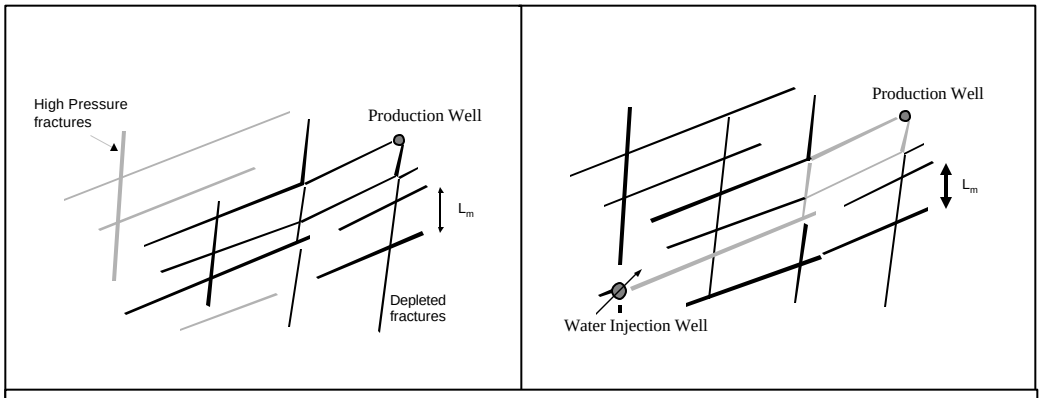
First of all, the author's experience has shown that the effective fracture intensity and degree of connection is difficult to predict. This may be because fractures are often well connected on a large scale, but a few primary pathways may dominate flow. Also, the apparent connectivity can depend on the well placement and the recovery process. Coarse-grid, dual-porosity models for multi-phase flow have historically been too well connected.

Secondly, the fracture network appears much more heterogeneous than first estimated. For example in several studies, the effective fracture spacing appeared to be different for depletion versus waterflood. Under depletion, a near-by producer can deplete many of the fractures, causing matrix fluid to expand through a large fracture-matrix surface area. However, under waterflood, water can imbibe only through the matrix surface that is contacted by water. Fractures that are not continuous along the water flow path will not be flooded by injection water even if they are open and permeable. Recent industry activity has been directed at using discrete stochastic distributions of fractures based on statistical and deterministic information gathered from logs, cores and outcrops to improve understanding of the fracture connectivity. These stochastic realizations may be a means to estimate effective fracture network properties for upscaling into conventional dual-porosity models.

From many simulations, we also often see that the fracture spacing required to match history is larger than estimated from core or outcrop studies. This observation could be caused by inaccuracy of matrix data. For example in the Austin Chalk, matrix permeability may range from 0.01 to 0.0001 (3 orders of magnitude!!!). However, it is more likely because of large scale

averaging of data and associated numerical error or the fact that many of the fractures we see do not inter-connect on a large scale.

However, as opposed to the effective spacing, the apparent fracture volume appears greater than estimated from image logs. This is because many small-scale fractures and vugs can contribute to apparent fracture network volume.



Displacement processes can appear to have different fracture connectivity from depletion processes because of the complex fracture connectivity.

History matching would also suggest that relative permeability in the fractures is not a linear function of phase saturations. This may be because the relative permeability for a fracture network is not the same as for an individual fracture. Also, the large grid sizes we are required to use leads to averaging problems. For example, the fluids may tend to quickly segregate in the fractures over the scale of the grid system, but this is often difficult to approximate in the simulators. Think of a grid typical of today's models – several hundred feet in areal dimension by only a few feet thick. Only a small amount of gas can lead to a large GOR, because we generally assume dispersed flow and fully penetrating wells in the center of the grid block.

In water floods in oil-wet fractured reservoirs, modeling and laboratory work would suggest that viscous displacement from the matrix blocks may be contributing some recovery which is often not accounted for in standard dual-porosity models.

Most emphasis today is being placed on improvements in characterization of the fracture network, however, reservoir flow behavior is very dependent on the effectiveness of matrix-fracture transfer mechanisms. A common method to quantify matrix-fracture transfer for such systems is through history matching. However, matches will be non-unique. Also, for systems where there is no history to match, we have no way to determine the input data. Therefore laboratory experimentation is still very important, but is becoming a "lost art".

It is extremely difficult to predict productivity of individual wells as well as early gas or water breakthrough during injection or under coning. Nelson (2000) has pointed out that NFR have the characteristic of a wide distribution of well recoveries or rates. The author's own experiences

have shown the near impossibility of predicting (not matching) individual well water-cut and GOR's in complex NFR. The simulators thus need to be viewed as a reservoir management tool and not so much as a means to predict short-term individual well performance. Alternative methods of performing history matches thus need to be considered (Campanella, et. al., 2000). In Campanella's study, a major difficulty was modeling of individual well GOR's and water-cuts over a 70-year history for over a 1000 wells. This problem was alleviated by independently controlling historical gas, oil, and water rates in the simulator. The time-dependent fluid-contacts and saturation profiles were used to validate the history match rather than individual well water and gas cuts.

Their study also showed that vertical dual-permeability can be a very effective method for gravity drainage simulation in systems with vertical continuity. One difficulty was properly handling hysteresis in gravity drainage behavior in areas of the field where water had invaded the oil column and was subsequently displaced. Laboratory centrifuge experiments showed the excellent response that was possible for gas-oil gravity drainage in these previously water-invaded areas; however, incorporating the necessary hysteresis was not straightforward with current methodology. This again points to the simple physics in current dual-porosity simulators and the need to tune models to laboratory data. These laboratory data were matched by fine-grid simulations and scaled to large block models. Numerous authors have shown that for gravity drainage, centrifuge experiments can be directly modeled and used for field scale simulation, provided they are properly calibrated to the assumptions inherent in the simulators. For example, capillary pressure is often incorporated into the centrifuge derived relative permeability and thus should not be used in the gravity drainage models. This discussion is intended to stress the fact that laboratory data is a necessary part of understanding field behavior.

Although there have been a number of notable failures, waterflooding can be very effective in NFR. This of course depends highly on wettability and the ability to maintain areal and vertical conformance. Field tests of water and/or gas breakthrough and tracer can be used to characterize the system by identifying water or gas flow paths. Tracers are very effective in identifying directional tendencies and to a lesser extent to estimate fracture volumes. A major problem here is that rate changes during the test can complicate the interpretation.

Early water breakthrough in NFR is very problematic and has been discussed widely. For example Weber (2001) discussed one field example where is was stated that "Complex interaction between fractures, matrix and the highly permeable streak caused a surprising pattern of water breakthrough, which can be explained by a geomechanical model for the heterogeneous natural fracture network." It was explained how the fracture networks were upscaled to a dual-permeability simulator for field-scale multi-phase reservoir simulation and showed how integrating seismic, borehole, well test and production data were used "to constrain and validate such a field-wide model". This is just one of many papers that shows the success of dual-porosity or dual-permeability idealizations to model field performance. The difficulty of course is determining what are the important controls regarding the areal and vertical distribution of the fractures. The authors indicate that the process of integration of all data is very important.

The timing and amount of breakthrough depends on many factors including fracture pore volume, permeability anisotropy, fracture intensity, matrix wettability and pore volume. In gas-water systems, the absolute value of fracture intensity is often not the main variable in early water breakthrough – it is matrix pore volume and wettability, fracture pore volume and the areal and vertical variability of fracturing throughout the reservoir. For example, consider the complexity of the field described by Weber (2001). "The field consisted of three communicating, carbonate reservoirs that were heterogeneously fractured with each reservoir consisting of a dolomite package, sandwiched between two calcite layers. A highly permeable streak sits between the top calcite and dolomite in only one part of the reservoir. According to the authors, water advanced through the streak, but fell out into the fractures below before reaching the wells. Only after some years of production did this fractured matrix become so saturated that water finally entered the well perforations. The timing of water breakthrough in these wells depended on the volume of fractured rock below the streak. Elsewhere in the reservoir, the highly permeable streak is absent, and water breakthrough occurs via coning of bottom water, if it occurs at all." The authors stated, "Knowledge of the fracture distribution and their flow properties was essential for field development".

As a general recommendation for NFR simulation, is it important to identify intrinsic (e.g. lithologic) and extrinsic (e.g. structural) controls on fracture distribution and intensity and relate these to well performance (e.g. productivity and water breakthrough) in order to develop algorithms for distributing the fracture network properties in a 3-D static geomodel. Accurate distribution of matrix properties is also important. The simulation model must honor the variability and not be an overly simplified model. We still rely very much on empiricism and tuning to historical data. NFR models are not very predictive based on static data alone.

Addressing Numerical Instabilities

Because of the highly nonlinear nature of the fluid flow equations, numerical simulators can experience stability problems. Simulation of fractured reservoirs is especially difficult because of the high flow rates occurring through small pore volume nodes, high transmissibility and extreme heterogeneity. Methods to avoid some numerical problems need to be further addressed in the numerical simulators. The “work” required to simulate a NFR can be well over an order of magnitude greater than an equivalent single-porosity system. It is not just a result of the doubling of the number of computational cells – significant non-linearity leads to much smaller time-steps and more work per time-step.

Although most experienced modelers have methods to identify and minimize stability problems in such systems, here is a partial list of items that can create potential stability problems when solving the finite difference equations:

- Large shape factor,

- Low fracture porosity,
- High fracture permeability,
- High well productivity,
- Severe rate changes,
- High flow rates,
- Wellbore crossflow,
- Extrapolation of input data tables,
- Step derivatives (slopes) in input data tables (including hysteresis),
- High fluid mobility, and
- Input data discontinuities.

Obviously all the above items cannot be eliminated and still represent the physical system. However, there may be certain reasonable limits of data beyond which simulation results become insensitive to data changes. For example, modern 3-D geomodeling generally relies on correlations and statistics to relate static data to dynamic flow properties. The methodologies applied can create extreme values, which cause many numerical difficulties in the flow models. These extremes could be truncated in many cases without loss of accuracy. The following items address the stability problems caused by the items listed above and discuss how some problems may be avoided.

1. Fluid transfer between matrix and fracture depends on the matrix shape factor as discussed previously. However, above a certain limit, pressure equilibration between fracture and matrix will occur in a time frame much sorter than the finite difference time-step. Thus increasing the shape factor beyond this value will have no impact on the simulation results. In fact if the shape factor is made too large then the fluid transfer rate becomes sensitive to numerical roundoff. In other words, fluid transfer rates are large for even very small pressure differences. In moderate mobility systems (> 10 md-ft/cp), the simulation will normally become insensitive to shape factor above a value of 0.1 ft^{-2}. A simple way to evaluate this is to perform a fine-grid matrix block simulation to see if equilibrium occurs in a time less than a "typical" time-step (e.g. 10 days).

2. Low fracture porosity can cause stability problems, because very high flow rates through small pore volumes will lead to rapid saturation changes. Theoretically, fully implicit simulators should be able to handle such systems. However, in many causes the Newton-Raphson scheme, which is used to solve the non-linear equations, may converge very slowly or may actually diverge. The remedy is to make fracture porosity as large as possible without affecting the answers significantly. If the majority of the oil comes from the matrix, then “excess” fracture porosity is only significant at early times. Increasing minimum fracture pore volume to 2-3% of total pore volume, should not significantly affect results. Another method to improve stability would be to use slightly higher fracture porosity near wells and use the correct value throughout the rest of the reservoir.

3. High values of fracture permeability (e.g. > 25,000 md) can lead to stability problems in some cases because small changes in pressure lead to large changes in rate. The small changes in pressure might only be due to numerical error. In many situations, fracture permeability can be reduced to a value that provides stability, but has minimal effect on the simulation results. High vertical permeability is an especially difficult problem. The large surface area leads to extremely high vertical transmissibility. A stable limit for horizontal fracture permeability might be 50,000 md, but it might only be 5000 md for vertical permeability. The sensitivity of permeability should be studied for each specific problem. The idea here is not to globally reduce fracture permeability or transmissibility, but to limit the extreme values.

4. High well productivity (injectivity) can be a problem for the same reasons as outlined above. Flow rates from individual layers can change drastically for only small changes in pressure. From a practical point, simulation results will be little affected if pressure drop at the well is 1 psi or 0.001 psi. However, the simulator may have many convergence problems if pressure drop is negligible. Reducing well productivity to a value that gives a measurable pressure drop can greatly improve simulator performance.

5. Large rate changes (e.g. when a new well is brought on line or an existing well is shut in) can cause problems with some simulators. Obviously the fluid withdrawal and injection must be honored in order to represent the system. However, some smoothing of the rate profile may help the simulation run time and may not affect the results. For example, averaging rates over 90 day periods rather than monthly periods early in the life of the reservoir may not significantly affect results at later time. Alternatively, rates could be increased gradually in the simulation model or time steps could be reduced when rates change significantly.

6. When running simulations, the rate of one phase (e.g. oil) is often specified and the other phases are unconstrained. This can lead to very unrealistic rates for the unconstrained phases and thus numerical difficulty. Users should constrain the rates of all phases and also constrain the bottom-hole-pressure to avoid these problems. In fact, for certain situations, the simulator may be much more stable if total liquid rate or total reservoir voidage is specified rather than oil rate. There can be significant differences in model behavior for the two methods of well control. Especially before a history match is obtained.

7. Crossflow can be a difficult problem in NFR because pressure drop between the well and grid block can be very small. Small differences between the pressure gradient in the wellbore and reservoir can lead to significant crossflow in the wellbore. If crossflow is not important to the solution (*i.e.* when vertical permeability allows significant vertical flow in the reservoir), then minimizing crossflow can allow the models to run much better. There are several ways to reduce crossflow in the simulators such as ensuring that zero rate wells are "isolated" from the formation, reducing well productivity so that pressure drop

between the well and grid blocks is larger, changing the method of density calculation in the wellbore, or choosing a simulator option to prevent crossflow. Although in some cases, use of such options can be detrimental to stability. For example an on/off switch for crossflow can cause a layer to oscillate be on/off over each iteration. This on/off switch is highly non-linear, leading to slow convergence of the iterative solution scheme.

8. Some simulators will extrapolate fluid properties and other input data tables outside the range of input data if required. This extrapolation can lead to unrealistic estimates of data and cause severe stability problems. The best way to avoid this is to provide limits in the simulation. For example, maximum injection pressure could be constrained to not exceed the maximum value of pressure in the PVT tables. Economic limits could be set to ensure that vertical flow performance tables are not extrapolated outside the range of input rates, watercuts and gas-oil-ratios.

9. Very steep derivatives of data (e.g. capillary pressure and relative permeability) can lead to highly non-linear relations and thus cause stability problems. Hysteresis is especially difficult because of the frequent flow "reversals" common in NFR simulations. In most cases, answers are affected very little by some smoothing of the data. For example, the imbibition rate is proportional to the rate of change of capillary pressure with respect to water saturation. Near irreducible water saturation, measured capillary pressures can be very steep causing imbibition to be nearly instantaneous over a small saturation range. From a finite difference approximation where time-step sizes are on the order of days, slowing the imbibition rate by reducing the slope of the capillary pressure curve will not significantly affect the simulation results. This is especially difficult in modeling capillary pressure hysteresis and improved methods for handling this in simulators are required.

10. High fluid mobility can cause problems for the same reasons discussed with high permeability (item #3). Gas is especially sensitive because of its viscosity. For example gas-oil ratio might increase from solution gas to 10's of MSCF/STB over a very small gas saturation range. The simulation results again may be little affected by reducing gas relative permeability near critical saturations. Problems can be especially severe in fractured systems where there is a tendency to set phase relative permeability equal to phase saturation. A more gradual increase in gas relative permeability near critical gas saturation can reduce stability problems and in fact provide more physically realistic results. Depletion problems can be especially severe because as free gas evolves it has a tendency to move up structure at extremely high velocities.

11. Convex gas relative permeability curves often result when critical gas saturation is increased for the purpose of matching field historical performance and the remaining portion of the curve is not changed. This can lead to non-monotonic derivatives near the critical gas saturation causing convergence problems.

Even with the changes outlined above, dual-porosity/dual-permeability problems are difficult to solve and many of the numerical solution tolerances that have been established for single-porosity problems may need to be altered. For example, tighter tolerances for the linear solvers can improve stability by providing more accurate pressures for the non-linear iterations improving overall convergence rates.

Summary

In spite of the inherent uncertainties involved and numerical limitations, NFR simulation can be a very effective tool to aid in optimization of hydrocarbon recovery. We still have much work to do in understanding the fluid flow process in NFR and in learning how to efficiently simulate it. As Dr. Kazemi has stated, "characterization and flow modeling of fracture networks is a pragmatic process that relies heavily on experience and empiricism and very little (to date) on systematic approaches". Pilot testing of secondary and tertiary recovery processes in NFR is often required to access the fracture network behavior and the process effectiveness. Reservoir description should rely on information from many sources including static data (well logs, cores, petrophysics, geology, and seismic), and ultimately on dynamic data (formation evaluation well tests, long-term pressure transient tests, tracer tests and longer term reservoir performance).

Maximizing economic recovery from NFR requires a thorough understanding of matrix flow characteristics, fracture network connectivity and fracture-matrix interaction. In primary production, highly permeable fractures reduce pressure gradient in the well bore vicinity, enhance production rate from wells, and, in the absence of gas and water coning, can lead to efficient reservoir depletion. In secondary recovery, management of gas-oil and water-oil contacts and prevention of early water or gas breakthrough are often the key factors for success. For example, when gas-oil contact in fractures is controllably lowered, this can lead to enhanced drainage of oil from the matrix. In fact, this kind of gas-induced gravity drainage is one of the most efficient improved-oil-recovery techniques for NFR. In tertiary oil recovery, injection of steam, surfactant or CO_2 may provide long-term improvements in the ultimate oil recovery from NFR.

Nomenclature

A area, ft^2
B formation volume factor (FVF), RB/STB
c compressibility, $psia^{-1}$
d distance, ft
D capillary diffusion coefficient, ft^2/day;
D depth, ft;
h height or thickness, ft
k permeability, md
L matrix block dimension, ft;
p pressure, psia

q	flow rate, STB/D
r	radius, ft
s	skin factor, dimensionless
S	saturation, fraction
t	time, days
V	volume, ft^3
w	width, mm
x	distance in x-direction, ft
y	distance in y-direction, ft
z	distance in z-direction, ft
Δ	difference or change in values
ϕ	porosity, fraction
γ	density gradient, psi/ft
λ	interporosity flow parameter, dimensionless
λ	mobility, md/cp
μ	viscosity, cp
π	Pi, constant
ρ	density, lb/ft^3
σ	shape factor, ft^{-2}
τ	fracture-matrix flow rate, STB/D
ω	storativity ratio, dimensionless
∂	partial derivative
∇	gradient operator
$\nabla\cdot$	divergence operator for a vector

Subscripts

c	capillary
D	dimensionless
e	effective
f	fracture
g	gas
i,j,k	index
m	matrix
o	oil
r	relative
t	total
th	threshold
v	vertical
w	water
x	x-direction
y	y-direction

z z-direction

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