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Naturally Fractured Reservoirs – Modeling and Simulation Methods

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مكامن متشققة طبيعيا ـ طرق نمذجية ومحاكاة

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تلعب التشققات الطبيعية أو التي هي بسبب ما، دوراً حاسما في عدة مكامن نفطية، وبالرغم من أن نسبة صغيرة من النماذج تصف اليوم التشققات أو شبكات التشققات، فإنه يمكن لفرد أن يدعى أن معظم المكامن متشققة عمليا. وبالنظر إلى أهميتها التجارية، رغم تعقيداتها، فقد كانت المكامن المتشققة موضوع دراسات متعددة في العقود الأخيرة.

ستحاول هذه الورقة تقويم الوضع الحالي وتقويم طريقة نمذجة مكامن نفطية متشققة وسيتم التركيز وبصورة رئيسية على تطورات حديثة في مجال نمذجة ساكنة ونمذجة مناسبة ومتحركة لمكامن متشققة، وأثر آخر تقدم في نمذجة قدرات منظومة ساكنة في سير العمل التاريخي القديم وأدخلت تطورات جديدة في مجال محاكاة المكمن.

ومنذ بداية التطور التاريخي لنماذج محاكاة المكمن المزدوج والمفصل تمت إعادة النظر لعدة طرق محاكاة مكامن هيدروكربونية متشققة.

سيتم مناقشة عدة طرق تبدأ من مراجعة صيغ مألوفة ثم تنتقل إلى نموذج المسامية المزدوجة التقليدي ثم إلى نماذج شبكة مفصولة متشققة. وتتمتع كل الصيغ بمميزات ولكن لديها عجز عند وضعها بعضا من خصوصيات المكامن المتشققة.

حاولت صناعة النفط حديثا دمج المعلومات من كل المصادر المتاحة لكي تخلق نماذج شبكة متشققة ونماذج محاكاة مزدوجة ومتصلة، ونال حديثا دمج المعلومات السيزمية ضمن نماذج محاكاة ديناميكية اهتماما كبيرا. وأنعشت التطورات الأخيرة في تقنية التشبيك أمالا يمكن بواسطتها التعامل مع جميع شاذات النفاذية في القريب العاجل.

توجد الشقوق في مناطق محدودة من مكامن متشققة طبيعيا ينعت لها بـ "البقع الحلوة" فقط وتباعا لذلك فإن كل أجزاء نماذج المكمن لا تحتاج معالجة تشقق محددة لنماذج متصلة ومزدوجة.

سمحت أحد الطرق التي تم تقديمها في هذه المقالة بتوليد تلقائي لقطاعات شبكة مستمرة مزدوجة عندما تقترح ميزات النموذج الجيولوجي بهذا العمل. ويطلق على هذا الافتراض نموذج مستمر مزدوج ومكيف حيث أن نتائجه في نماذج المحاكاة المحتوية على قطاعات تشبه الوضع الجيولوجي.

Abstract: *Natural or induced fractures play a crucial role in many petroleum reservoirs. Even though only a small percentage of today's reservoir models explicitly describe the fractures or the fracture networks, one may claim that practically most petroleum reservoirs are fractured. Due to their complexity, but also due to their commercial significance, naturally fractured reservoirs have been the subject to extensive studies during the past decades.*

This paper will try to assess the current situation and methodology for modeling fractured reservoirs. Its main focus will be on recent developments in static and dynamic flow modeling of fractured reservoirs. Especially the latest

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evolution in static modeling software capabilities significantly affected past, historical workflows and initiated new developments in the reservoir simulation area.

Starting from the historical evolution of dual continuum reservoir simulation models, a review is given on various simulation approaches for fractured hydrocarbon reservoirs. Several methods will be discussed, starting from conventional formulations to the traditional dual porosity model, to discrete fracture network models. All formulations have their own advantages, but have deficiencies in describing some other specifics of fractured reservoirs.

Recently, the petroleum industry tries to integrate information from all possible sources to generate fracture network models and dual continuum simulation models. Most recently, the integration of seismic data into dynamic simulation models has received a great deal of attention. Also, latest developments in the gridding technology raised hopes to be able to cope with full permeability tensors in the near future.

In many naturally fractured reservoirs, the fractures are found in limited zones, so called "sweet spots" only. Consequently, not all parts of the reservoir models will typically require explicit fracture treatment with dual continuum models.

One of the methods presented in this paper allows automatic generation of dual continuum grid blocks wherever the attributes of the geological model suggests to do so. This approach is called adaptive dual continuum model and it results in simulation models that contain grids that resemble the real geological situation very closely.

INTRODUCTION

Many petroleum reservoirs are fractured or at least partially fractured. Hence, one of the first questions to be raised is whether or not existing fractures are important for the reservoir behavior under producing conditions. In other words, what is the contribution of the flow in fractures to the overall fluid flow?

Posing this question to a petrophysicist, to a geologist or to an engineer, one can expect different views and answers. As far as the reservoir engineer is concerned, only fractures and fracture networks that affect fluid transportation to and from the wells are of significance. Only when there are fractures with sufficient length of penetration through the reservoir rock, fractures that are interconnected and with sufficient density or spacing, their effects can be observed and measured under dynamic flow conditions.

To assess fracture contributions accurately, a wide range of geological, petrophysical and engineering methods are applied. These methods apply to a large variety of different scales.

The paper will give a brief introduction to multi-continua approaches for modeling fluid flow in porous media. Then, a brief discussion of modeling approaches for naturally fractured reservoirs in static models is given, followed by an overview of available simulation and modeling approaches for fluid flow simulation. This will lead to the definition of a new and flexible method, referred to as the adaptive dual continuum method.

The adaptive dual continuum method can be applied to a large variety of cases. As will be shown in the paper, the approach is especially advantageous if the reservoir appears to be partially fractured, *i.e.* not all areas and regions of the reservoir (different lithologies, facies, aquifer region, *etc.*) contain active fracture networks.

THE MULTI-CONTINUA APPROACH

In the context of this paper, the void space in a fractured porous media is composed of two parts: (1) a network of fractures and (2) blocks of porous medium (called matrix). In principle, the mathematical model that describes the fluid flow through this void space of the porous medium can be stated for every point in the domain. This model would represent a description at the microscopic level, which we cannot solve directly, due to missing information at this detailed level. Therefore, a complete description of the fluid transport problem at the microscopic level is not possible.

We have to transform the problem from the microscopic level to a macroscopic level at which the problem is formulated in terms of averages. The average values are measurable quantities. This is referred to as the continuum approach.

In the continuum approach, the physical domain is replaced by a model in which each component (or phase) acts as a continuum that fills up the entire domain. For every point, average values of component and phase properties are taken over an

elementary volume. Those averages represent the macroscopic values of the considered variables. By moving the elementary volume throughout the entire porous medium domain, we obtain averaged values for all variables that are differentiable functions of time and space.

In the case of porous matrix and fractures, it is possible to classify the various problems related to the scale [3]:

Zone 1: The very near field. Interest is focused on fluid flow and contaminant transport within a single, well-defined fracture.

Zone 2: The near field. Flow is considered in a small domain, which contains a small number of fractures. The location and shape of the individual fractures must be known. However, the definition of the fractures may be statistical.

Zone 3: The far field. Here transport may be visualized as taking place simultaneously, in two overlapping continua. One composed of the fluid within the network of fractures, and the other involving the fluid within the porous blocks. Mass may be exchanged between the two continua.

Zone 4: The very far field. The fluid in the entire fractured porous medium may be regarded as a single continuum.

Local problems such as transport near sources and sinks or a single fracture intersecting a well are represented as a problem of the very near field (Zone 1). A reservoir simulation model could use a single continuum method with very fine grids to explicitly model the fracture. Note that a very detailed knowledge about the fracture is required (length, aperture, orientation). No specialized reservoir simulation models exist to simulate this very near field of naturally fractured reservoirs. Of course, very fine gridded models may be used to accomplish this level of detail.

If the domain of interest is larger (but insufficient for the application of the continuum method), we can construct a near field model (Zone 2) that requires information on every individual fracture. In most cases, information on the fractures is only available in the form of statistics (aperture, length, orientation, spacing, *etc.*) and we can construct different realizations of the domain and study their behavior. In the simulation context, the discrete fracture network (DFN) models [6, 10] consider this approach. The method is based on explicit modeling of fractures that are represented as planes or disks. It requires very detailed descriptions of the network and uses single-phase models to simulate the behavior under fluid flow. However, these statistically based models are not practical when considering fluid flow over large domains and fracture networks, as the inclusion of the total number of fractures in field-scale demands large amounts of input data and computer storage. In addition, the flow simulation on those models is generally performed under single-phase conditions and those models also lack comprehensive description of matrix-fracture fluid transfer. Large, field-scale domains are usually better handled by the far and very far field models described below.

For larger scale problems, the dual continua approach for the far field (Zone 3) may be used. The original concept as proposed by Barenblatt and Zheltov[11] and Barenblatt *et al*[12] is also known as the dual porosity model. In this conceptual model two co-located, but interacting, media represent the porous and fractured medium:

(I) The fractured network and

(II) The porous matrix.

Each is represented by a grid system covering the entire domain. Interaction between the two systems is accomplished by a transfer term that defines the fluid transport between fracture and matrix rock. This type of approach is commonly applied for the simulation of multi-phase fluid flow in naturally fractured reservoirs (Fig. 1).

The interconnected fracture network is represented by a grid system that is co-located with another grid system that represents the intergranular pore space (matrix). Usually, the matrix provides the majority of pore space and storage capacity, but only very limited conductivity. In the idealized dual porosity models, the matrix blocks are treated as sources (or sinks) to the fractures. The network of fractures represented by the fracture grid system provides the major fluid flow conduit and limited storage capacity.

If very large distances (and travel times) are involved, we can use the very far field model (Zone 4) in which we regard the entire domain as a single

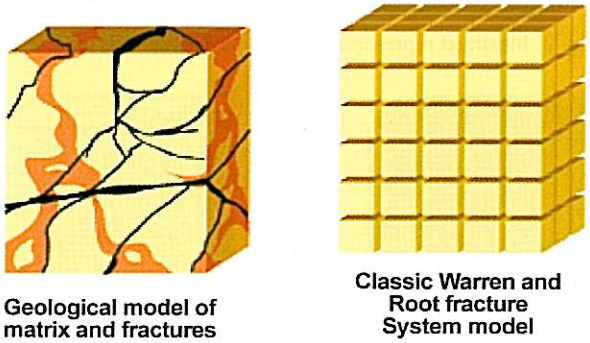

Fig. 1. Idealized grid block representation of naturally fractured rock by a dual porosity model (from Warren and Root, 1963)

continuum. This kind of model is applicable in cases where the system allows sufficient interaction between the fluids in the fractures and in the matrix such that there exists a local equilibrium at every point.

CLASSIFICATION OF NATURALLY FRACTURED RESERVOIRS

For the purpose of reservoir simulation, the classification of naturally fractured reservoirs after Nelson [13,14] or modifications of it[9,18] are used most commonly.

This classification defines the following types of fractured reservoirs:

Type 1: Fractures provide the essential porosity and permeability (Fig. 2)

Type 2: Fractures provide the essential permeability (Fig. 3)

Type 3: Fractures provide permeability assistance to an already producing reservoir (Fig. 3)

In the first case of fractured reservoirs (Type 1), all producible hydrocarbon fluid volumes reside within the fractures. Therefore, this type of fractured reservoirs requires the accurate calculation of fracture porosity, fracture width and fracture spacing. The estimation of these properties will predict whether initial flow rates can be maintained or will drop rapidly within short time after production starts. For this reservoir type, the definition of the fracture network is the decisive factor, whereas the definition of the rock matrix plays a minor role and the application of a dual porosity approach must be questioned.

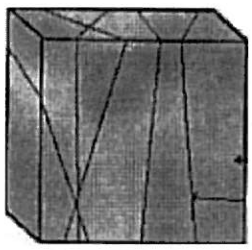

Fig. 2. Idealized representation of type 1 reservoirs.

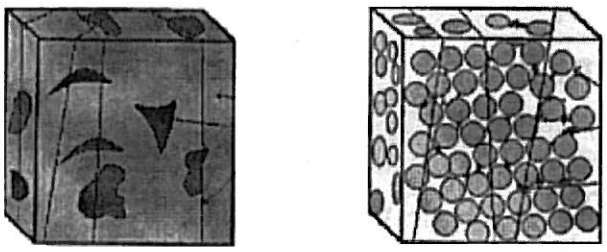

Fig. 3. Idealized representation of type 2 (left) and type 3 (right) reservoirs.

For fractured reservoirs of Types 2 and 3, where the main storage volume resides within the matrix rock volume, early knowledge of matrix-fracture interaction is extremely important. It will determine how efficiently the matrix can be drained by the fracture system. The accurate determination of the fracture porosity will be of less significance in those cases. Usually, a conventional modeling approach will fail for these types of fractured reservoirs, because it is impossible to generate average properties that represent the combined effects of fracture and matrix fluid flow. In most cases, those reservoirs will require explicit modeling of the two continua, matrix and fractures, with distinct property sets.

For all fractured reservoir types, the investigation of fracture orientation will be important in order to capture preferred flow directions. Fracturing may be caused from many possible reasons, but in the end will always represent the stress field of the reservoir and some rock failure associated to this stress.

SPATIAL DISTRIBUTION OF FRACTURES

Since, in most environments, the rock properties vary with location, we should expect the fracturing to do the same. Therefore, the majority of naturally fractured reservoirs will show areas with high fracture intensity just as there will exist areas that indicate no fracturing at all.

It is very likely that the static reservoir model (geological model) can account for the spatial distribution of the fractures and can identify areas with high and low fracture density. Most software packages in this context can relate fracturing to structural elements, lithology or facies types due to the amount and type of data input.

Unfortunately, most dynamic models (simulation models) do not account for the spatial distribution of fractures explicitly. Instead, the dual porosity mode in practically all reservoir simulators operates like a general switch that can be turned on or off. The main problem is that the implementation of dual porosity (or dual permeability) models into reservoir simulators was not appropriately done as true function of location, but as general switch acting globally on the simulation model. This is in conflict with the fracture intensity that most likely appears to be a function of location.

SIMULATION APPROACHES FOR FRACTURED RESERVOIRS

The section will discuss various approaches for the simulation of fluid flow in naturally fractured reservoirs. All methods have their advantages, but have deficiencies in some other specific areas of describing the physics of fluid flow in fractured reservoirs.

The last method presented in this paper allows automatic generation of dual continuum grid blocks wherever the attributes of the geological model suggest doing so. This approach is called adaptive dual continuum model and it results in simulation models that contain grids that resemble the real geological situation very closely.

DISCRETE FRACTURE NETWORK (DFN) MODELS

Discrete fracture network (DFN) models were developed to describe primarily the fracture networks. They are among the models developed most recently. Their focus is on fracture properties and not so much on the description of the rocks' matrix properties. Discrete fracture networks model the fractures as discrete features represented by planes or disks as shown in Figure 4. Contrary to other methods described in this paper, the DFN models require accurate descriptions of the fracture set and its properties. This makes them not very attractive for full field simulation.

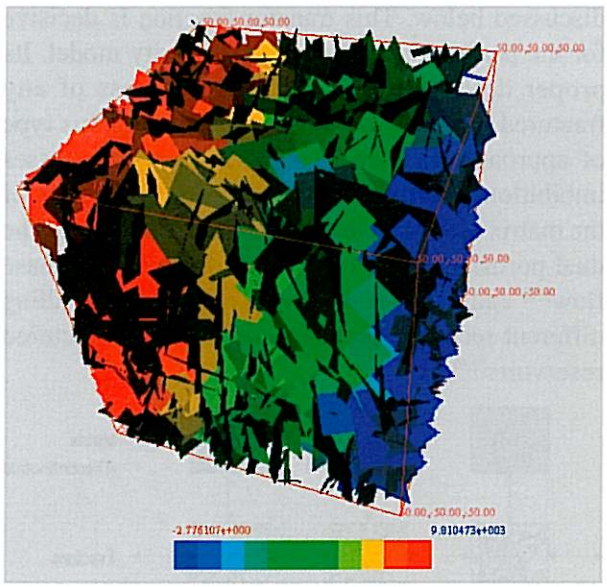

Fig. 4. Discrete fracture network model[15].

The DFN method can be considered a method of the near field or Zone 2. See the discussion on near field models (or Zone 2 models) above. In addition, these models typically perform single-phase calculations and are instructive to obtain fracture properties[6,10] One field of application of these DFN models is the pre-processing or upscaling of fracture information for dual continuum simulation[5].

However, DFN models are very powerful for visualizing the fracture networks. Generally, the DFN approach could be the preferred method for the simulation of fractured reservoirs that are classified as Type 1 according to Nelson[13], whereas their application is limited for reservoirs of Types 2 and 3.

The remainder of this paper describes another group of models that includes the traditional reservoir simulation approaches, where the reservoir is discretized into one rock continuum (single porosity) or two continua (dual porosity/dual permeability models) as first described by Barenblatt, Zheltov and Kochina[2].

SINGLE POROSITY MODELS

Of course, the 'conventional' single continuum simulation approach can be used for modeling fractured reservoirs under certain circumstances.

For example, single porosity methods are frequently used to generate fine grid models in order to investigate matrix-fracture communication on small scale. These high-resolution models are useful for developing generalized matrix-fracture transfer functions that can later on be applied to the field-scale reservoir model. In general, however, they cannot be used for the simulation of the entire reservoir.

One exception may be the fractured reservoirs of Type 1 following the classification by R. Nelson[13], where the fractures provide the main porosity and permeability for the reservoir (*i.e.* they provide the storage volume and the flow paths). In those cases, the single porosity approach may be sufficient to capture the flow behavior of the fracture network.

However, it may be difficult to capture the preferred flow directions, especially when the permeability field (tensor) changes with location and when k_{min} and k_{max} cannot be aligned with the principal co-ordinate directions.

The kPEBI grid proposed by Heinemann *et al.*[11] may be more flexible and powerful to capture those preferential flow directions. However, there are some

limitations with respect to the properties of the permeability tensor that must be considered when constructing a kPEBI grid in the 2D domain (Fig. 5).

An alternative modeling approach that uses a single porosity model is discussed by Saidi[16,17] In his model, the entire reservoir domain is divided into sectors. Those sectors represent also fractures with infinite transmissibility. The sectors are connected with each other. Each sector may contain several rock types that are represented by cylindrical matrix blocks. The fracture pressure and the fluid phase contacts provide the boundary conditions. This model can be considered a special case of the sub domain method of dual porosity models, but does not rely on the concept of shape factors. Saidi claims that this method allows proper handling of block-to-block interaction and re-imbibition processes.

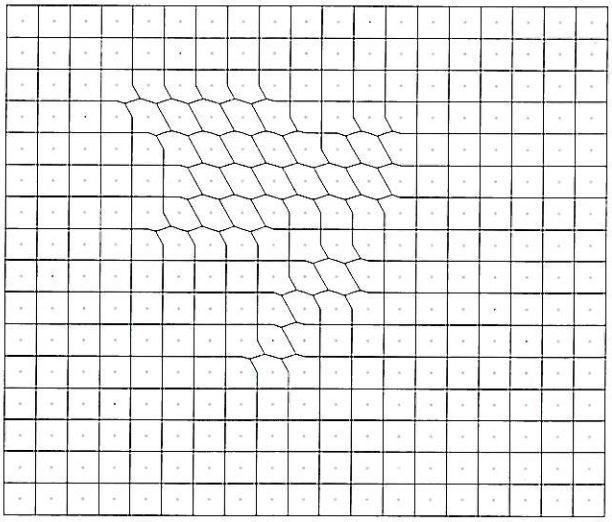

Fig. 5. kPEBI grid for single porosity modeling of fractured reservoirs.

DUAL POROSITY/DUAL PERMEABILITY MODELS

This class of simulation models describes the dual media models that have been introduced by Barenblatt and Zheltov[2] in 1960 and by Warren and Root[19].

In the original publication, the calculation of matrix block pressures assumed no flow between matrix blocks by neglecting matrix permeability. The matrix permeability was only considered in the fluid flow calculation between matrix and fractures. This model is usually named a dual porosity model. It contains a continuous primary medium, the fracture grid system that provides the main flow paths with high permeabilities, but typically low storage volume. The second medium is the matrix rock that is considered non-continuous and acts as a source term for the adjacent fractures. Figure 6 shows an idealized representation of the connections of two grid systems. Only for conceptual purposes, the two grid systems are shown at different locations. In fact, they are co-located.

In other words, the fractures are the boundaries of the matrix blocks. The fracture grid system is truly continuous (indicated by the black arrows between neighboring fracture grid blocks). The matrix grid system in a dual porosity approach has only connections into the fracture system (indicated by the red arrows). Therefore, the matrix grid system is considered discontinuous. Hence, the number of neighbors of the matrix grid block is always one, which is the fracture grid block that surrounds the matrix block. The total number of neighbors for the fracture grid block in a dual porosity model is equal to the total number of fracture neighbors defined by the geometry plus one block, which represents the matrix grid block that is in communication with the fracture grid block (Fig. 6).

Furthermore, the rock matrix in each grid block is idealized as a system of regularly shaped blocks (sugar cubes, see Fig. 1) that are not discretized individually. Instead, all matrix blocks in a grid block are represented by a single grid node, which holds some average value for the variables (pressure, saturations, etc.) of all matrix blocks.

The connection between matrix and fracture continuum that is indicated by the red arrows in Figure 6 is defined by a matrix-fracture transfer term that is discussed below. This transfer function is decisive for the performance of the dual porosity model. Its proper definition is vital to the success of any fractured reservoir simulation study using this type of approach. In particular the recovery processes imbibition, gravity drainage and capillary effects of the matrix blocks have received much attention. The dual porosity concept was extended to multi-phase flow[12] and later refined to be capable of handling different recovery processes occurring in fractured reservoirs[7,9]

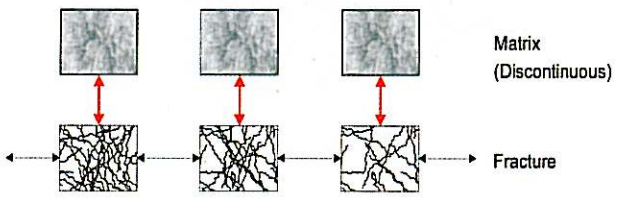

Fig. 6. Grid block connections in a dual porosity model.

When the discontinuous matrix grid system of the dual porosity model is transferred into a continuous grid system by adding the matrix-to-matrix connections, the model is referred to as dual permeability system (Fig. 7). In this case, two co-located media exist and both are continuous. The matrix blocks are no longer isolated, and contribute to the overall fluid flow.

The matrix-to-matrix grid block connections introduce capillary continuity through connected matrix blocks. This may have a significant impact on the recovery for a stack of matrix blocks. It appears that the dual permeability model captures this natural behavior better than the dual porosity model.

However, the dual permeability model comes with additional cost in terms of computation efforts. In a dual porosity model it is possible to pre-eliminate all matrix unknowns from the equation system, thus reducing the size of the Jacobian matrix equal to the size resulting from a model in a conventional single porosity formulation. This pre-elimination step is not possible for dual permeability models, resulting in equation systems that are twice as large in size compared to the size of the linear equation system resulting from an equivalent dual porosity model.

BALANCE EQUATIONS IN DUAL POROSITY AND DUAL PERMEABILITY MODELS

The fluid flow equations discussed in the following are based on a general purpose, compositional formulation, and can be applied to flow processes ranging from single-phase to three phases black-oil cases, or compositional cases using a cubic equation of state with n components.

The formulation of the mass balance equations follows the classical dual porosity/dual permeability approaches with a matrix-fracture transfer term q_{cmf}^{n+1} that is dependent on c , referred to as the shape factor.

First, let us look at a grid block in a conventional (single porosity) model. Then, the molar balance

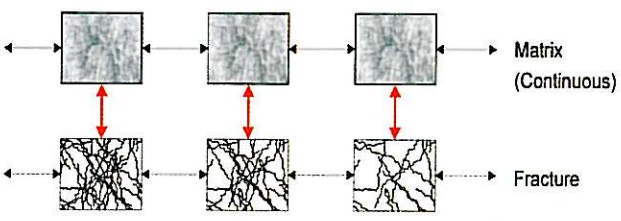

Fig. 7. Grid block connections in a dual permeability model.

equation for a component c in a grid block i is given by Eq. 1.

$$\sum_{j=1}^{N}\tau_{ij}\left[\sum_{p=1}^{P}\left(x_{pc}\lambda_p D_p\right)_{ij}^{n+1}\left(\Phi_{pj}-\Phi_{pi}\right)^{n+1}\right]+\sum_{p=1}^{P}\left(q_p D_p x_{pc}\right)_i^{n+1}=\frac{V_i}{\Delta t}\Delta_t\left[\phi\sum_{p=1}^{P}\left(S_p D_p x_{pc}\right)\right]_i \quad (1)$$

Where

N is the number of neighbors
τ_{ij} is the inter-block transmissibility between i and j
x_{pc} is the mole fraction of component c in phase p
λ_p is the phase mobility
D_p is the specific phase mole density
Φ_p is the phase potential
q_p is the phase production or injection rate
V_i is the block volume of grid block i
Δt is the time step length
ϕ is the porosity
S_p is the phase saturation

This equation is valid as long as the grid is orthogonal, i.e. the line connecting grid blocks i and j is perpendicular to the communicating surfaces between those two grid blocks.

One equation of this type is defined for each component in the reservoir fluid model. Together with other constraints, functions and equations these molar balance equations will yield the linear equation system. The linear equation system is then solved with IMPES, fully implicit or adaptive implicit mode.

In the simulation of fractured reservoirs by dual continuum models (dual porosity or dual permeability) one assumes the existence of two co-located continua, namely matrix and fractures. Eq. 2 defines the molar balance equation for a component c in a fracture block.

$$\sum_{j=1}^{Nf}\tau_{ij}\left[\sum_{p=1}^{P}\left(x_{pc}\lambda_p D_p\right)_{ij}^{n+1}\left(\Phi_{pj}-\Phi_{pi}\right)^{n+1}\right]+\sum_{p=1}^{P}\left(q_p D_p x_{pc}\right)_i^{n+1}+q_{cmf}^{n+1}=\frac{V_{if}}{\Delta t}\Delta_t\left[\phi\sum_{p=1}^{P}\left(S_p D_p x_{pc}\right)\right]_{if} \quad (2)$$

It is worth noting that the sum over the neighbors for the flow term is only over all neighbors in the fracture grid system. The neighborhood connection to the second continuum (the matrix neighbor) is treated in a special transfer term q_{cmf}^{n+1} defined below.

Similarly, for a component c in a matrix block, the balance equation is given by

$$\sum_{j=1}^{Nm}\tau_{ij}\left[\sum_{p=1}^{P}\left(x_{pc}\lambda_p D_p\right)_{ij}^{n+1}\left(\Phi_{pj}-\Phi_{pi}\right)^{n+1}\right]+\sum_{p=1}^{P}\left(q_p D_p x_{pc}\right)_i^{n+1}-q_{cmf}^{n+1}=\frac{V_{im}}{\Delta t}\Delta_t\left[\phi\sum_{p=1}^{P}\left(S_p D_p x_{pc}\right)\right]_{im} \quad (3)$$

The only difference between Eqs. 2 and 3 when compared to the molar balance equation of a single porosity block (Eq. 1) is the additional matrix-fracture

transfer term q^{n+1}_{cmf}. The matrix-fracture transfer term is (by convention) added to the fracture system (Eq. 2) and subtracted from the matrix system (Eq. 3).

The formulae above are valid, if both grid systems are continuous. This is the case for a dual permeability model, but not in the case of the dual porosity model. In the dual porosity model the matrix blocks act as source terms to the fracture system, but have no matrix-matrix connections (compare Fig. 6).

In a dual porosity model, the matrix grid block has no neighbors in the matrix grid system (it is a discontinuous system) and hence the entire flow term within the matrix grid can be disregarded.

If this is the case, then the equation for the matrix blocks (Eq. 3) simplifies (assuming that no well is perforated in the non-continuous matrix grid system) to

$$-q^{n+1}_{cmf} = \frac{V_{im}}{\Delta t}\Delta_t \left[\phi \sum_{p=1}^{P} \left(S_p D_p x_{pc}\right)\right]_{im} \tag{4}$$

because and . Eq. 4 shows why it is possible to eliminate all matrix unknowns from the equation system in a dual porosity system, thus reducing the size of the Jacobian matrix basically to the size of a conventional single porosity model. Of course, this is not possible for dual permeability models, which result in fully coupled and large sized coefficient matrices. Additional CPU time is required to solve those linear systems that stem from dual permeability simulation models when compared to their dual porosity equivalents.

The matrix fracture transfer term is based on the formulation proposed by Kazemi[1,2], following Darcys law. Thus, the total matrix-fracture transfer term (including the molecular diffusion rate) for a component c is given by

$$q^{n+1}_{cmf} = \tau_{mf} \sum_{p=1}^{P} \left(x_{pc} \lambda_p D_p\right)^{n+1}_{mf} \left(\Phi_{pm} - \Phi_{pf}\right)^{n+1} + q^{n+1}_{Dcmf} \tag{5}$$

Here, the matrix-fracture transmissibility is defined to be

$$\tau_{mf} = V_f k c \tag{6}$$

where it is not very obvious what the value for the permeability in this equation should be.

Many attempts have been made in the past to define the shape factor, the classical formula still being

$$\sigma = C \cdot \left(\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2}\right), \tag{7}$$

where C is a constant and varies widely (see for example Table 1 in Boubiaux *et al.*[5]), but typically is between 4 and 12 and l_x, l_y and l_z are the matrix block dimensions.

Usually, the shape factor is multiplied by permeability and volume of the matrix grid block to yield the matrix-fracture transmissibility (Eq. 6).

This approach fails, however, when the permeability in the three co-ordinate directions is different. For this reason, we suggest the inclusion of the permeability, k, into the shape factor and use

$$\sigma = C \cdot \left(\frac{k_x}{l_x^2} + \frac{k_y}{l_y^2} + \frac{k_z}{l_z^2}\right), \tag{8}$$

if l_x, l_y and l_z are the matrix block dimentions.

Using Eq. 8 allows the application of Eq. 9 to calculate the matrix-fracture transmissibility. Then, the matrix-fracture transmissibility must be calculated from

$$\tau_{mf} = V_f c \tag{9}$$

which can be considered superior to Eq. 6. Experience shows that during history matching the transmissibility defined in Eqs. 6 or 9 needs to be modified. Hence, the following equation is used:

$$\tau_{mf} = F \cdot V_f c \tag{10}$$

Where F is a history matching parameter.

Nomenclature

D_p	=	Phase molar density
k	=	Permeability
l	=	Matrix element dimensions
S_p	=	Phase saturation
V_i	=	Block volume
x_{pc}	=	Molar fraction of component c in phase p
τ_{ij}	=	Inter-block transmissibility between block i and j
λ_p	=	Phase mobility
Φ_p	=	Phase potential
Δ_t	=	Time step length
ϕ	=	Porosity
σ	=	Shape factor

ADAPTIVE DUAL CONTINUUM METHOD

Not all parts of a fractured reservoir will typically require dual porosity/dual permeability treatment. Let us assume that the spatial distribution of the fractures is given by Figure 8. The different colors indicate different fracture intensity. Blue indicates no fracturing, green intermediate fracture intensity and red indicates high fracture intensity.

The adaptive dual continuum method takes this aspect into consideration[8]. It allows creating dual porosity/dual permeability cells adapted to user-defined conditions, grid block properties are based

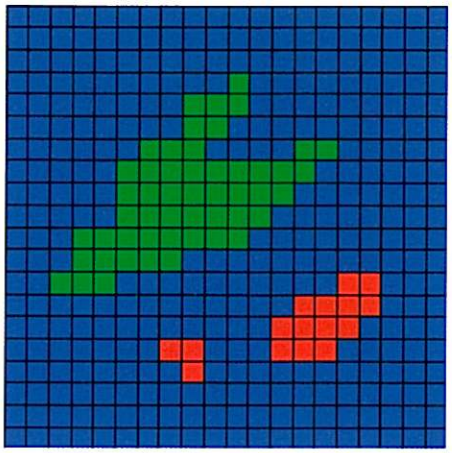

Fig. 8. Spatial distribution of fractures indicated by fracture intensity.

on geological attributes (facies, rock type, fracture intensity, etc.). Dual continuum cells are created only at locations, where those conditions are fulfilled, elsewhere – the unfractured part of the reservoir model – the grid blocks remain conventional single porosity cells. Hence the name adaptive dual continuum method.

Symbolically, the matrix grid blocks are shown in the center, surrounded by the fracture grid blocks. Note, that in fact, both grid systems (matrix and fracture system) are co-located, i.e. at the same location. (Fig. 9).

The standard dual continuum method (dual porosity/dual permeability models) generates dual continuum cells in the entire domain, as shown in left hand side of Figure 9. This means that dual porosity cells are created, even if there should be no fractures in a large portion of the reservoir volume. At times, this will create an excessive amount of additional grid blocks that should not exist in the simulation model. Those grid cells will waste resources of CPU time and computer storage. They may also lead to erroneous simulation results or stability problems during the solution process.

The simulator SURE[21, 22] using the adaptive dual continuum method, is able to generate dual porosity blocks where the fracture intensity is larger than a given threshold value and will convert the single porosity grid block accordingly into a matrix-fracture grid block pair. This is shown at the right hand side in Figure 9.

The dual continuum blocks are generated automatically, if the fracture indicator is available in the simulation model. After this gridding step has been completed, the model contains matrix-fracture grid block pairs only, where the geological model indicates fracturing.

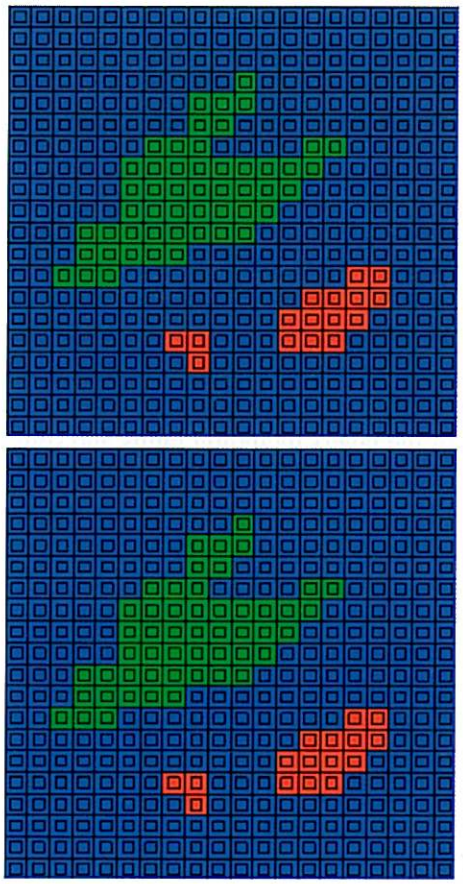

Fig. 9. Modeling naturally fractured reservoirs by standard dual continuum (left) and adaptive dual continuum method (right).

Any block in the simulation model can be set to dual porosity/permeability mode automatically or interactively, if necessary. There are no limitations with regards to any of the other modeling capabilities (like fault modeling or local grid refinement) as a result of those gridding steps. All properties are stored on a cell-by-cell basis and can be modified, correlated or assigned interactively. The shape factors are typically loaded directly from the 3D geological model and assigned to each individual matrix block. However, if requested, it is also possible to correlate shape factors based on matrixblock dimensions l_x, l_y and l_z. Those matrixblock dimensions can be loaded and assigned from maps or geological models and are stored also on block-by-block basis.

The advantages of the adaptive dual continuum method are the following:

- The simulation grid can resemble the geological situation more closely.
- The user flexibility and modeling capabilities are maximized through the advanced gridding processing.
- All fracture properties are stored on a cell-by-cell basis (including the matrix-fracture exchange parameter, "shape-factor").

- The CPU-time and memory requirements for the simulation run are minimized.

Application of Adaptive Dual Continuum Method

The methodology described above has been applied successfully to simulation models running in two-phase gas-water mode, three-phase black-oil mode and ° API models.

Figures 10 and 11 shows a typical application of the adaptive dual continuum method. Figure 10 displays one of the layers including faults and some local grid refinements located at the center of the model. Figure 11 displays a cross section through the model and the different fracturing in the various layers can be observed easily. Layers 2 and 3 are vertically refined in some parts and also the local grid refinement can be seen.

The example shown is the adaptive dual porosity model of a faulted and fractured undersaturated oil reservoir. Note that the fracturing varies with facies and rock types, therefore, a large number of blocks in the model are not fractured and modeled as single porosity blocks.

The fractured areas of the model are using the dual porosity formulation. The total model contains 18368 grid blocks in seven layers, from which 5978 are single porosity blocks, 6195 blocks are fracture, and 6195 are matrix blocks.

Unlike the application shown above, the following example shows how to model a reservoir, where the fracturing is associated with faulting. Figure 12 shows a model with slanted faults, where the fractures are only modeled if the grid blocks are close to a fault. The grid construction follows the PEBI grid construction principles and is fully automated.

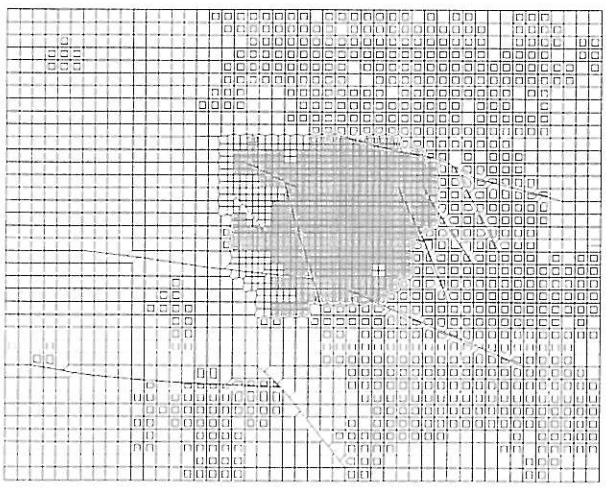

Fig. 10. 2D view of adaptive dual continuum simulation model.

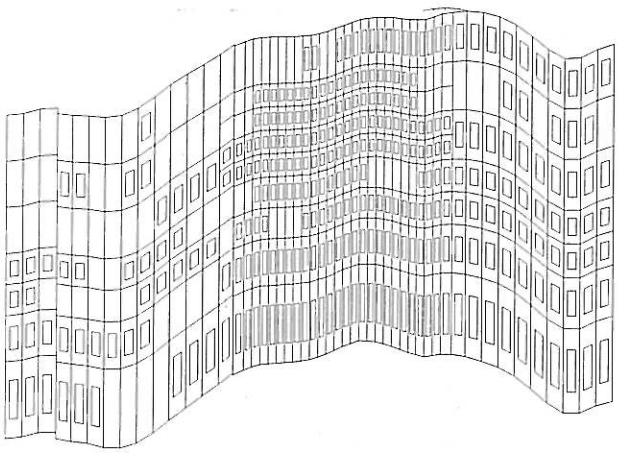

Fig. 11. Cross section through adaptive dual continuum reservoir model.

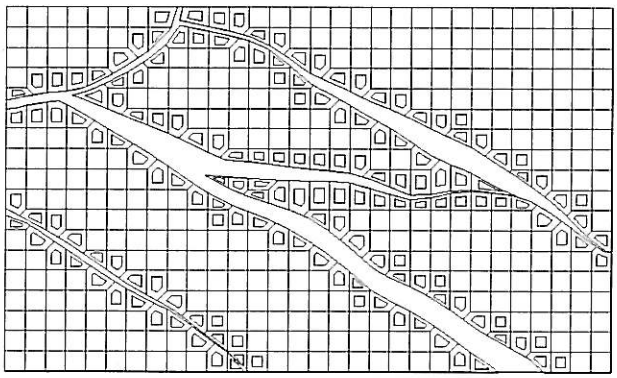

Fig. 12. Adaptive dual continuum model created from distance to fault parameter.

SUMMARY

This paper discusses the current situation and methodology for modeling and fluid flow simulation of naturally fractured reservoirs. Starting from the multi-continua approach different methods for different scales of models are discussed.

Natural fractures are not distributed evenly throughout the reservoir domain. Static models are very well suited to capture those spatial distributions.

Among the simulation models, the application of discrete fracture networks is discussed first. The strength of DFN models lies in the description of the connected fracture networks. Unfortunately, those models require very accurate descriptions of the fracture set and its properties. This makes them not very attractive for full field simulation. However, DFN models are very powerful for visualizing the fracture networks. One field of application of these DFN models is the pre-processing or upscaling of fracture information for dual continuum simulation.

Secondly, the application of single porosity and dual continuum methods is discussed. Single porosity models can be applied to fractured reservoirs under certain circumstances. A new gridding method, referred to as kPEBI grid, may also improve the potential application of single porosity models to special types of fractured reservoirs.

Dual porosity and dual permeability models are commonly applied to simulate the fluid flow in naturally fractured reservoirs. The differences between the dual porosity and the dual permeability models are discussed and the balance equations outlined.

In many naturally fractured reservoirs, the fractures are found in limited zones, so called "sweet spots" only. Consequently not all parts of the reservoir models will typically require explicit fracture treatment with dual continuum models. The last method presented in this paper allows automatic generation of dual continuum grid blocks wherever the attributes of the geological model suggest doing so. This approach is referred to as adaptive dual continuum model. The adaptive dual continuum method results in simulation models that contain grids that resemble the real geological situation very closely. Just like the static fracture characterization methods, the adaptive dual continuum method generates simulation models that represent the spatial distribution of fractures.

The adaptive dual continuum method was implemented in the reservoir simulator SURE. Experience shows that performance and flexibility of this approach are clearly superior to all other methods discussed in the literature. The method is especially powerful when the simulation model is based on a 3D geological model for fracture characterization.

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