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A new upscaling method for fractured porous media

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ABSTRACT

We present a method to determine equivalent permeability of fractured porous media. Inspired by the previous flow-based upscaling methods, we use a multi-boundary integration approach to compute flow rates within fractures. We apply a recently developed multi-point flux approximation Finite Volume method for discrete fracture model simulation. The method is verified by upscaling an arbitrarily oriented fracture which is crossing a Cartesian grid. We demonstrate the method by applying it to a long fracture, a fracture network and the fracture network with different matrix permeabilities. The equivalent permeability tensors of a long fracture crossing Cartesian grids are symmetric, and have identical values. The application to the fracture network case with increasing matrix permeabilities shows that the matrix permeability influences more the diagonal terms of the equivalent permeability tensor than the off-diagonal terms, but the off-diagonal terms remain important to correctly assess the flow field.

1. Introduction

Fractures, either artificial hydraulic fractures or natural fractures, occur at different length scales with different fracture densities in geological porous media. We term systems composed of fractures and geological porous media containing fractures as fractured porous media. Accurate and fast modeling of fluid flow through fractured porous media is important for groundwater resources management, hydrocarbon and geothermal energy resources exploitation, waste disposal and CO_2 sequestration. In conventional reservoir modeling, the fractured porous medium is assumed as a single-continuum or a dual-continuum model and its permeability is represented by the equivalent permeability. However, it is not yet known how best to incorporate the permeability of fractured porous media into conventional reservoir simulators. In this paper we present a new method for computing the equivalent permeability of fractured porous media.

The determination of the equivalent permeability or hydraulic conductivity of fractured porous media, here termed permeability upscaling, has been a problem of interest for many years. Several comprehensive reviews discuss this topic (e.g., [13,16,32,38]. Investigating the permeability of fractured porous rock was pioneered by Snow [36] who related the permeability to the geometry of parallel fractures. Oda [31] developed an analytical method for computing equivalent permeability based on geometric characteristics of fractures with arbitrary orientations; this is popular in reservoir simulation practice [9]. However, the method is less accurate in revealing fracture connectivity [15]. In contrast to the analytical methods, another kind of permeability upscaling is based on solving the flow problem for a discrete fracture model. This is also termed flow-based upscaling, which is considered to be more effective than the analytical upscaling methods, and has been widely used in reservoir simulation. We can further divide flow-based upscaling into boundary integration method and volume averaging method according to the way to compute flow rate and pressure gradient [13,17,40].

Flow-based upscaling is depending on appropriate modeling of fractured porous media. Long et al. [27] initially compute an equivalent permeability by solving the flow problem within fractures under linear boundary conditions using the Finite Element Method. Following this approach, some researchers have considered geomechanical effects on equivalent permeability using the discrete element method [3,29]. Koudina et al. [22] investigated equivalent permeability based on unstructured grids using the Finite Volume method. However, these approaches are based on discrete fracture network (DFN) models [10] in which an impermeable rock matrix is assumed and flow occurs only within fractures. With this limitation the method cannot be applied to different kinds of fractured porous media [30].

Recently, with the development of advanced discretizing methods, more general approaches for calculating equivalent permeability based on discrete fracture matrix models (i.e. including a permeable matrix) have been developed. Lough et al. [28] took matrix permeability into consideration in computing

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equivalent permeability using the Boundary Element method. Bogdanov et al. [5] extended Koudina et al. [22]'s approach by accounting for the rock matrix permeability. Lee et al. [24] introduced a hierarchical approach for modeling the hydraulic effect of fractures in a conventional reservoir simulator. For short fractures, Oda's method has been used; for medium fractures, as an extension to Lough's method, the flow-based upscaling method has been used considering anisotropic rock matrix permeability. For long fractures, they were modeled explicitly as fluid conduits. Karimi-Fard et al. [21] developed an upscaling method for a dual-continuum based on a discrete fracture matrix (DFM) model [20] which was solved by the two-point flux approximation (TPFA) Finite Volume method. Lang et al. [23] used a volume averaging method for finding an equivalent permeability using the Finite Element method in fractured porous media.

In this paper, we applied a recently developed discrete fracture model simulator [34] based on the multi-point flux approximation (MPFA) Finite Volume method and present a new flow-based upscaling method, the multi-boundary fracture upscaling (MFU). The multi-boundary fracture upscaling method is based on the development by Long et al. [27] and Durlofsky [12], which we call here single-boundary fracture upscaling (SFU) method. Both of the two methods belong to the boundary integration upscaling method. The difference lies in a new expression for the flow rate during upscaling. Due to the scale effect, the permeability changes with the scales of measurement in fractured porous media [7]. When the scale of measurement is large, more fractures may be contained in the scale and constitute a fracture network. Reversely, when the scale of measurement is so small that it only contains part of a fracture, a long fracture appears in the scale. Accordingly, the method has been applied to both, a long fracture and a fracture network with different matrix permeabilities.

In the following, we first introduce the governing equations and procedures for the previous single-boundary fracture upscaling method and the new multi-boundary fracture upscaling method. This method is verified then in Section 3. Applications of the multi-boundary fracture upscaling method are shown in Section 4, including upscaling of a long fracture and of a fracture network with different matrix permeabilities. We discuss related problems in Section 5 and come to conclusions in Section 6.

2. Upscaling procedure

Flow-based upscaling involves basically three steps. In the first step, the area of a fractured porous rock is divided into grids in a Cartesian coordinate system. In the second step, we solve the problem of single-phase, incompressible, and steady flow through a fractured porous rock (i.e., discrete fracture model) without sources or sinks in each of the Cartesian grids. In the third step, using Darcy's law, the equivalent permeability for each of the Cartesian grids is computed. After that, the equivalent permeability of the Cartesian girds comprises the equivalent fracture model. The development in this paper is for a two-dimensional discrete fracture model. An extension to three dimensions will be discussed also.

2.1. Governing equations

In a discrete fracture model, mass conservation for single-phase, incompressible and steady-state flow without sources or sinks is given by:

$$\nabla \cdot \boldsymbol{v} = 0, \tag{1}$$

where v is the specific discharge given by Darcy's law:

$$\boldsymbol{v} = -\frac{k}{\mu} \cdot \nabla P, \tag{2}$$

where k is (scalar) fracture or rock matrix permeability, μ is the dynamic viscosity of the fluid and P is the pressure. Specifically, rock matrix is assumed to be isotropic and homogeneous, and fracture permeability can be represented by the cubic law [36]:

$$k = \frac{b^2}{12}, \tag{3}$$

where b is fracture aperture.

Combing Eqs. (1) and (2), the flow equation can be written as:

$$\nabla \cdot \left(-\frac{k}{\mu} \cdot \nabla P\right) = 0, \tag{4}$$

Upscaling is applied for finding an equivalent permeability k^* on Cartesian grids in an equivalent fracture model such that the new solution for pressure P^c on the Cartesian grid is close to that in the discrete fracture model [16]. The flow equation for the equivalent fracture model can be expressed as:

$$\nabla \cdot \left(-\frac{k^*}{\mu} \cdot \nabla P^c\right) = 0, \tag{5}$$

The equivalent permeability k^*, in two dimensions of the $x - y$ coordinate system, is represented as a symmetric, second-rank tensor [12]:

$$k^* = \begin{pmatrix} k^*_{xx} & k^*_{xy} \\ k^*_{yx} & k^*_{yy} \end{pmatrix}, \tag{6}$$

In contrast to effective permeability, which is an intrinsic property based on the observation that a representative elementary volume can be found in heterogeneous porous rock [4], permeability of fractured porous medium should be termed better as equivalent permeability [33]. It may vary with the scale of measurement (e.g., [7], which means that when using equivalent permeability in numerical models and we change the dimension of a grid, e.g., by mesh refinement, the former permeability of the grid may not be applicable to the new refined grids.

2.2. Computing equivalent permeability

We now consider computing equivalent permeability for a two-dimensional Cartesian grid of unit thickness, as illustrated in Fig. 1.

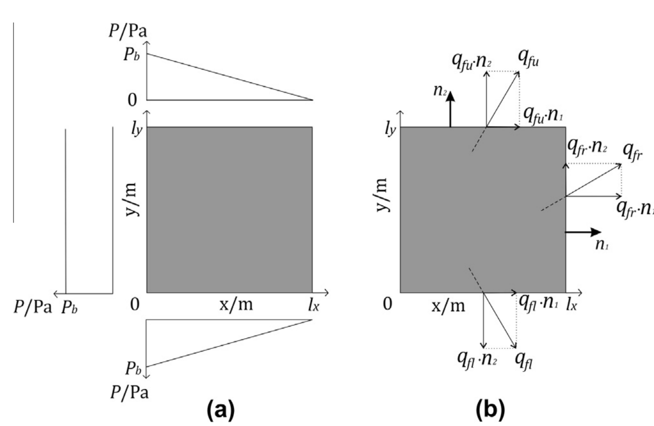

Fig. 1. Cartesian grid for equivalent permeability computation. (a) Linear pressure boundary conditions (b) Possible flow rates out of the boundaries. The dashed lines near the boundaries represent possible fracture orientations. n_1 and n_2 denote the unit vectors along the x and y directions, respectively. q_{fr}, q_{fu}, and q_{fl} represent flow rates in the fractures out of the right, upper and lower boundaries, respectively.