EDFM - Literature review update

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1 Introduction

Modeling fractures in numerical flow simulators has been a theme of interest for researchers for many years.

From the 1990s and on, methods embedding fractures in effective higher dimension continua have evolved. The advantage being the ability to use existing commercial simulators with little or no low level code updates. As a matter of fact, many of the proposed methods may be classified as preprocessors.

From early 2010s and on, the naming EDFM (Embedded Discrete Fracture Modeling) has been used frequently while referring to this class of methods. Recent papers show that the method is accurate, and embedding lower dimensional features in higher dimensional numerical elements can be done in many fashions.

2 Objective

This manuscript provides an update of the EDFM technique and its diverse forms, while describing advantages and disadvantages of each from the readers perspective. A decision making process will follow, directing development effort to the more interesting approaches reported.

3 Background

Before beginning any research on fractures, we need to settle some fundamentals. Authors diverge on the understanding of nuances, especially in a field with so much disjoint efforts globally. The following sections introduce terms and ideas in the context of this work, supported by arguments and references.

3.1 Choosing the best modeling technique

Holling and Walters (1978) and Starfield and Cundall (1988) discuss role of modeling as a guide to the understanding and to the decision making in a project. The first step is to qualitatively classify the process according to 2 axes: data availability and understanding (see Fig 1). In region 1 (good data, little understanding), we should try statistics. In region 3 (good data, good understanding), accurate models can be built. In regions 2 and 4, data is scarce or poor in quality. It is clear that most reservoir problems fall inside those data-limited regions. Even mature fields, one can argue, large volumes of data are available, but they are either spatially loose or low in resolution. Latest efforts try to push reservoir models towards region 3, but we cannot be sure to be there yet.

As a response to the lack of good data, Starfield and Cundall (1988) identified a trend to add more and more complexity to the models. As of now, we see academic and industry work spending energy and computer power in complex models. Is that right? The author brings good arguments against complex models: (1) it is futile ever to expect to have enough good data to model rock masses accurately ; and (2) as more detail and complexity is added to the models, we see a decline in intellectual control of the model.

Fracture networks models are even scarcer in data availability and quality when compared to intact rock masses. As we can sample rock masses, and reasonably reproduce in-situ conditions in the lab, sampling fractures and rock joints is more difficult. Recent work try to mimic the fracturing processes in the laboratory and image the joints geometries and hydraulic attributes. Results show high variability and fractal behavior throughout many scales, from millimeters to several meters.

Narr et al. (2006) suggests a straightforward classification of naturally fractured reservoirs, according to the role of the fracture network in the fluid flow (Fig. 2). Pressure tests and early production must be designed to provide such classification. It is likely that fluid flow in Type 1 reservoirs rely mostly on the fractures, whereas in Type 3 the fractures provide a secondary flow paths.

The term *fracture denial* has been introduced by Nelson (2001), while the author is concerned with oversimplification of the problem and its economical consequences (loss of recovery factor, inefficient capital expenditure, improper assessment of opportunities). The reason behind the fracture denial would be related to the desire of technical teams reduce reservoir assessment cycle time by avoiding highly uncertain complexity.

Which assumptions must a practical useful fracture model rely on? Primarily, it must deal with uncertainty, instead of focusing in single realizations. It must recognize data scarcity and avoid over-simplification of the problem. Secondly, we must realize fracture models are being systematically avoided in engineering workflows, for their complexity and high design cycle times. Finally, most fracture-aware workflows in place are normally using classic W&R sugar-box assumptions (Warren and Root, 1963). Novel approaches must advance from this point, offering improvements in forecast uncertainty, performance or history match cycles.

3.2 Numerical fractures as effective hydraulic networks

Viswanathan et al. (2022) reviews the latest efforts to produce quantitative predictions of fracture behavior. According to the authors, *fractures are breaks or mechanical discontinuities (...) complex in shape and often filled with mineral precipitates or transported materials*. While fractures have dynamic behavior (propagation, shear and aperture mechanical response to depletion), for now we are only concerned with the flow behavior of a static fracture network.

Fracture geometry descriptions include (1) roughness, (2) aperture, (3) contact area, (4)

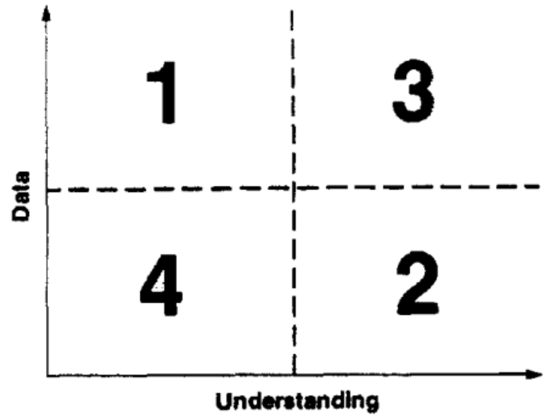

Fig. 1. Holling's [1] classification of modelling problems.

Figure 1: Classifying the target problem in one these regions provide directions on the best modeling technique.

TABLE 1.1—CLASSIFICATION OF NATURALLY FRACTURED RESERVOIRS, MODIFIED FROM NELSON (2001)

Types of Fracture Reservoirs

NFR Type	Definition	Examples
Type 1	Fractures provide essential porosity and permeability.	Amal, Libya Edison, California Basement fields, Kansas
Type 2	Fractures provide essential permeability	Agha Jari, Iran Haft Kel, Iran Sooner trend, Oklahoma Spraberry trend area, Texas
Type 3	Fractures provide a permeability assistance	Kirkuk, Iraq Dukhan, Qatar Cottonwood Creek, Wyoming Lacq, France

Figure 2: Naturally fracture reservoirs classification. (Narr et al., 2006)

fracture network character and (5) non-planarity. A common approach for fluid transport along fractures is the so called cubic law, which is relates aperture and roughness to an effective permeability (Witherspoon et al., 1980). However, more recent work has shown that the assumptions supporting the cubic law are two restrictive for actual field cases, and the resulting fracture transmissibility is significantly higher then what is observed in field conditions (Frash et al., 2019).

Roughness can be described by self-affine fractals across many scales, as small fractures tend to develop first and coalesce into larger fractures (Candela et al., 2012). The resulting non-uniform contact area sets different anisotropic flow paths in a single fracture (see, for example, Fig. 3 and 4). Frash et al. (2019) discusses shear fracture, as *shear is most often the large-scale mechanism for failure of rocks under compression.*

Pyrak-Nolte et al. (1987) shows this complexity moves the cubic law away from reality. She says that: *most of the experiments that have substantiated the cubic relationship have been done either on surfaces prepared by machine or artificially induced tensile fractures. In the former case, the variability in the actual aperture because of imperfectly planar nature of the surfaces can be expected to be small. (...) Natural fractures that have been subjected to any degree of shear motion or alteration are not only far from perfectly planar but the topography of the opposing surfaces fail to register. Therefor, contact between natural surfaces will occur at asperities, corresponding to mutual topographic highs. (...) The experiment shows that the cubic relationship between fixed flow and mechanical fracture displacement does not hold at either high or low stresses (...)*

Viswanathan et al. (2022) concludes that *a method of predicting subsurface permeability based on knowledge of rock type, fracture type, fracture history and stress condition remains elusive and maybe unachievable due to variability at multiple scales.*

To integrate the fracture hydraulics into a reservoir model, Long et al. (1982) looks for the conditions when the fracture can be modeled as an effective porous media. Referring to Snow (1965), they conclude that fractures change significantly the full permeability tensor of a given cell. They can be integrated as long as the control volume is large enough, the fracture are high in density and their orientations are distributed. Most simulation workflows use structured meshes and simplify the permeability tensor to the principal directions (tensor is zero off-diagonal). When that is the case, it is important to estimate approximation errors, as embedding fractures will likely increase significantly rotate the tensor principal direction (non-zero off-diagonal terms).

Note that fractures may be cemented, closed of filled with thin material, which creates flow barriers. That means that a fracture corridor may have negative impact in the permeability tensor of a given element, reducing the fluid transport. This behavior, however, is local and can be incorporated in the upscaling procedure, with no impact on global fluid transport.

With all this background in mind, we can conclude that:

- Although estimating fracture permeability is not in our work scope, we must be aware that its correlation to aperture is complex, and that the assumptions behind the cubic law are too simplistic to most field cases. Whenever the cubic law is used, we may expect resulting permeabilities order of magnitude higher than reality.

- Working on hydraulic characterization of individual fractures is unproductive due to the

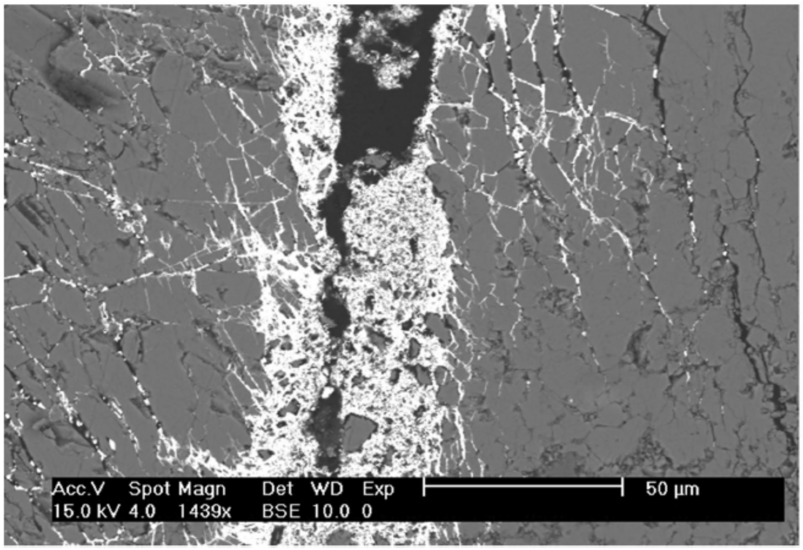

Figure 4. Scanning electron microscopy image of barium carbonate in a fracture network obtained from an induced shear experiment (shear fracture runs vertically through the specimen) involving dissolution of a carbonate-rich shale and precipitation of $BaCO_3$ (bright white) in response to coupled injection of $BaCl_2$ solution (after Menefee et al., 2020).

Figure 3: Example of fracture as a nonplanar fractal, with chemical precipitation, showing high geometrical complexity.

large number of uncertain variables. Upscaling to equivalent fracture networks makes more sense as it simplifies the analysis, reduces the number of parameters and increases the designer control of history matching cycles and uncertainty parameterization.

- Moreover, a single fracture will hardly be long enough compared to a typical model element size (50-200m). However, fractures interconnects in corridors or long networks, and those may provide high transmissibility plus low storage fluid transport pathways (Long et al., 1982).

- Considering the limitations of laboratory characterization of joints, analog field data must be investigated to provide bounding limits for embedding fracture networks in reservoir models.

3.3 Capillary effects must be considered

Multiphase fluid flow in porous media is usually controlled by small scale capillary effects. These effects are upscaled and lumped in relative permeability curves, so that they can be dealt as viscous flow in the large scales (Cense and Berg, 2009).

Regarding fluid flow in fractures, the capillary effects are routinely ignored, and the relative permeability curves are assigned as straight lines. However, considering fractures networks are combinations of void spaces spanning many scales, that assumption might need to be relaxed.

This is left as future work in this report.

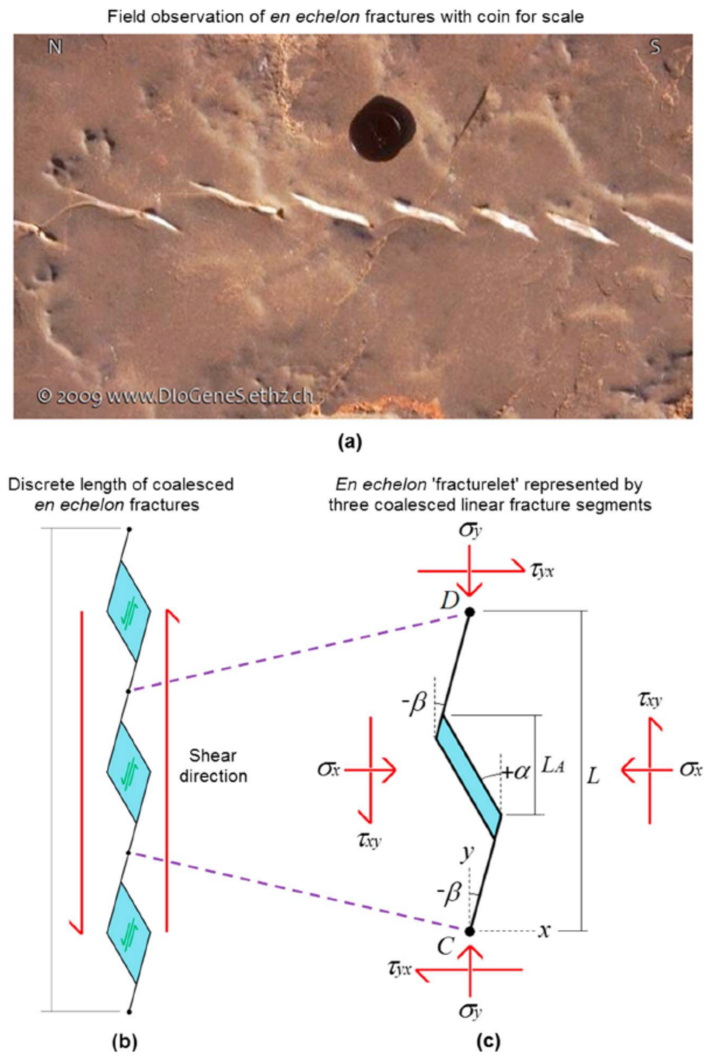

Figure 1. (a) This photograph from J. P. Burg (2000) shows an example of a coalesced en echelon fracture in the field. We represent this general structure with (b) a series of linear fracture segments and (c) an elementary subset of this series with a "fracturelet" composed of three coalesced linear fracture segments. Shearing the depicted fracturelet ($\alpha > 0$) will induce anisotropic aperture with the center segment opening while end segments slip.

Figure 4: Complexity and anisotrpy of shear fractures. (Frash et al., 2019)

3.4 Classification and limitation of fracture numerical models

Naming the fracture models categories and its sub-categories is not uniform in the literature. For the sake of this manuscript, we divide models primarily in two classes: either the fractures are modeled discretely (Discrete Fracture Models, DFM) or they are embedded as effective continua (Continuum Fracture Models - CFM).

As thin entities, one dimension of the fracture is orders of magnitude smaller than the other two. While the hydraulic width of an effective fracture is measured in micrometers to millimeters, the length and height is on the tens to hundreds of meters. Besides, fluid flow and pressure drop inside the fracture is not expected along the thin dimension. That means the fracture flow can be modeled discretely, in reduced dimension, as boundaries of the porous media continua. This is the basis for what we called DM.

However, to keep control of the computational complexity, the fracture count must be limited, and the fractures must be conformed to the mesh. Unstructured mesh have been used in relevant papers, but have been unable to address field-scale models. To our best knowledge, the main limitation is geometrical complexity of the mesh, preprocessing and limited availability of simulators for unstructured meshes.

Moreover, as effective fracture attributes are highly uncertain, fracture model realizations would incur potentially in distinct meshes, with unacceptably large analysis loop.

Continuum Fracture Models look for equivalent fracture behavior in the porous media dimension by (1) enhancing a single mesh (single porosity or single continuum) ; (2) adding a secondary fracture mesh to represent the fracture effective hydraulics (dual porosity, or dual continua) ; or (3) adding numerous fracture meshes, representing independent effective fracture networks.

3.5 Setting the research ambitions

Before deciding on new implementations, it is important to set goals and ambitions. Novel numeric simulation algorithms have been designed, but most of them are not long lasting nor extended. The first step is to decide the target clients for any enhanced algorithm or knowledge.

Novel algorithms must prove its own benefits so they can influences designers of simulators to replicate the idea. Novel knowledge rely on existing software and intend to influence workflows and challenge current practices.

The first set of target users are the industry-level reservoir engineers. They currently use commercial simulators, most likely W&R sugar-box fracture models or no fracture model at all. They will be interested in proven faster workflows with minimum training. But they won't be able to update the software. If they understand and buy the idea, they can influence the simulator designers.

The issue with reservoir engineers is whether they recognize limitations on the way fractures are modeled today. We can agree that there is high uncertainty on the fracture parameters, but as discussed previously, there is little we can help on experimentation and field monitoring to improve parameters. For that, it would be desirable to put together field data and work on quantifying the fracture contributions on overall pressure and production. The challenge would be to get hold of such data, as most companies wouldn't provide them.

A second set of users are the simulator designers. The goal would be to test and prove new algorithms which offer performance or accuracy advantages. Differently from the previous case, we would have more lower level flexibility, as working with finished commercial simulators would not be a contraints.

Both approaches are interesting, and from an academic perspective, it would be better to focus in the second set of users, with less constraints. The task would be to find opportunities of improvement, using latest versions of UTCOMP as the starting point for novel ideas.

4 Fractures as continuum - from 1950 to early 2000s

5 EDFM technique to 2014

6 Recent development

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