

NUMERICAL SIMULATION OF FRACTURE RESERVOIR WITH CONSIDERING EFFECT OF FAULTS IN FRACTURE CREATION IN AN IRANIAN OIL FIELD

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Abstract

One of the top concerns for numerical simulation of naturally fractured reservoir is the distribution and properties of fractures throughout the reservoir; However, most of the times this kind of information is absent between reservoir data. Due to this lack of data, the production rate and pressure in numerical simulation of fracture reservoirs usually could not consistently and accurately match with the actual observed data of reservoir. In this study it's tried to find some specific pattern for fractures' network. Although the fractures may have considerable porosity and permeability, the network of fractures may not continued in the reservoir layers but are concentrated in some specific area such as beside major faults. By this assumption that fractures are created affected by faults, the fracture properties have been defined by attention to orientation of faults and getting a decreasing trend from faults toward the reservoir flanks. For this purpose some correlation are developed for fracture porosity, permeability and shape factor, which is used in a method indicated whether the grid block should be modeled as single porosity or dual porosity. The application of this method could improve the numerical simulation history matching of reservoir clearly in an Iranian fracture reservoir.

Keywords: Naturally fractured reservoir; Numerical Simulation; Dual porosity; History matching; fracture orientation.

1. Introduction

Simulation of naturally fractured reservoirs is very complicated from both of the numerical and reservoir description standpoint. Vast majority of the reservoir pore volume is matrix which is acted as source of the fractures. Fluids flow is mostly from fractures which have high permeability and low porosity with respect to matrix blocks. Hydrocarbon production rate from this kind of reservoir is a function of size and properties of matrix blocks as well as saturation history and pressure of the fracture system [1].

The concept of treating a naturally-fractured reservoir as a dual porosity model was introduced by Warren and Root in 1963, for first time, however Kazemi *et al.* define the dual porosity model with the numerical description. With this definition fracture reservoir modeling could be used in large scale studies [2] as shown in Figure 1.

If the matrix blocks are linked only through the fracture system, matrix blocks are acted as sources and reservoir production could be only from fractures. This model is a dual porosity single permeability model however if the reservoir production is from both matrix and fracture the model could be regarded as a dual porosity dual permeability system [4]. It is important to know that considering whole of a reservoir with some homogeneous properties can cause a lot of inconsistencies. There are some different methods to solve pressure and saturation equations of simulation model such as: Explicit finite difference method, Implicit finite difference method and IMPES method which means solving the pressure equations in implicit and saturation equation in explicit. According to recent studies the most validate and consistent method to solve the pressure and saturation equations in fracture reservoirs simulation is fully implicit

method [5-6]. Totally there are many different methods for simulation of natural fracture reservoirs which is introduced by different persons. These methods are usually based on a discrete 3-D fracture network - DFN - or two different equivalent porous media simulation [7]. However there are still many problems in developing of new models for this kind of reservoirs which can be representative of real reservoirs [8].

In Iran, fracture reservoir developing comes back to 60 years ago and laboratory and fields research about these kinds of reservoir have more than 20 years of experiences with using different simulation techniques. There is a statement in Reiss book about Iranian fractured reservoirs: "No book on fractured reservoirs could be complete without reference to the Iranian experience" [9-10].

In this paper a new method for simulation of an Iranian fracture reservoir is presented and three new correlations are developed for different fracture properties estimation in this offshore fracture reservoir. This method of simulation is confirmed finally by getting acceptable matches between observed data and simulated data in production fluid rates and pressures.

2. Methods and procedures

This work presents a case study of a fracture reservoir simulation in Iran. The reservoir model exported from 3D geological model is in corner point geometry with following characteristics in its up-scaled model: Areal grid size of 100×100 meters however vertical grid size varies from 2.66 to 4.87 meters with average size of 4.12 meter. The model is gridded into 73 cells in X direction, 96 cells in Y direction, and 20 cells in Z direction; making the total number of 140160 grid cells. 3D view of the model and location of well#1 and well#2 are shown in Figure 2.

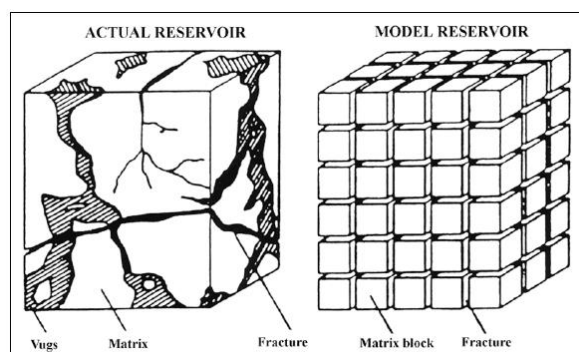


Fig. 1 Actual and simulated fracture reservoir [3]

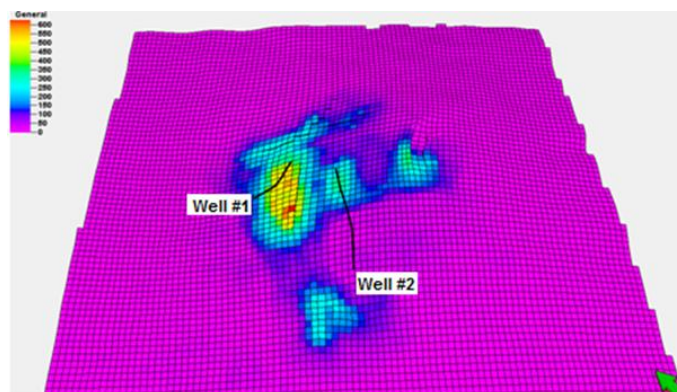


Fig. 2 3D view of the model and location of well#1 and well#2

The nine faults have been picked in this reservoir. The main faults in crest area which makes considerable discontinuity and other faults make minor discontinuity. In construction of coarse grid model these faults which are almost parallel were taken into account and grid orientation was determined accordingly. Average porosity and permeability which are used in the model are 16.4% and 30 mD respectively.

The main challenge in this reservoir simulation is modeling the fracture network and considering its effect on the production. Although the fractures may have considerable porosity and permeability, the network of fractures are not continued in the reservoir layers but are concentrated in the area beside major faults. To quantify the density and the orientation of fractures (Dip and Azimuth), the analysis of image logs and structural analysis of seismic data were applied. The calibration of fracture model depends on the aspects of simulation model and it would be done at that time.

Fracture modeling in the geological model of this reservoir is based on two FMI (Formation Micro Imager) logs run in the reservoir in well#1 and well#2 which is shown in Figure 3, and on seismic attributes.

However, quality and the quantity of available fracture indicators do not allow for a conclusive fracture study. Seismic fault analysis results say that all faults are normal and seem that the origin of them are related to the uplift of the structure, vertical displacement of these faults vary from 2 m to 39 m.

As it is indicated in the Figure 4, the major strike of nearest fault to both wells#1 and #2 are similar to strike of conductive fractures that was recognized in those wells.

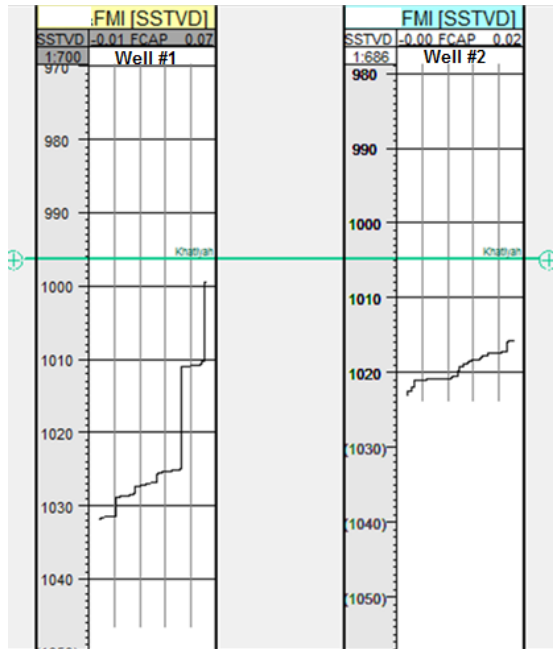


Fig. 3 Aperture log of open fractures in well #1 and well #2

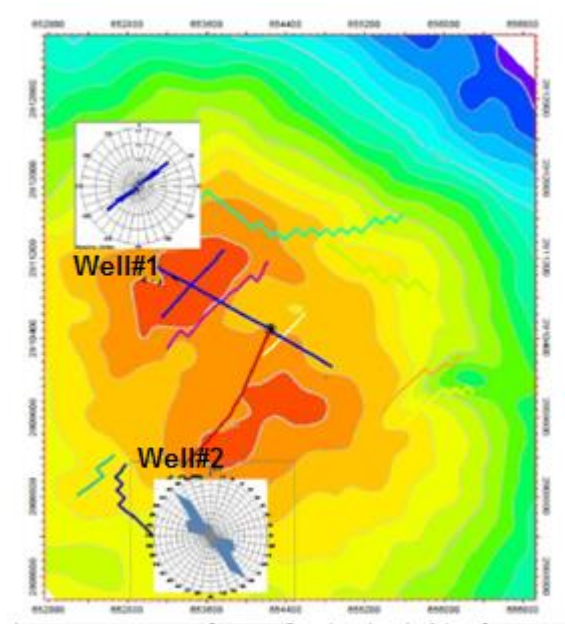


Fig. 4 Rose diagrams show strikes of conductive fractures that approximately similar to seismic fault strikes.

The study and analysis of provided data and structures of analogue dome shows that it can be concluded that fractures in the reservoir occur as fracture swarms that are associated with faults. Bore-hole image (BHI) log of well #2 does not show remarkable fracture in the reservoir while the FMI log in well #1 shows some open fractures in the reservoir. It seems that the preferred orientation of these fractures is parallel to the faults.

It is noteworthy that fracture region of reservoir is defined by a distance function from faults. This distance was set after different try for matching the available observed data of wells. The other concept which is included in defining the properties of fracture region was the orientation of faults. For this purpose the reservoir is divided into different regions according to Figure 5, which in each region the orientation of faults are different. In these regions each of fracture permeability vectors – k_x or k_y - which is in the same direction with the fault would be more than the other one.

According to above information, it was decided to employ extent of dual porosity region method which can be used for a dual porosity, single permeability run to specify regions within the reservoir to be treated as single porosity only. In this method it is indicated whether the grid block should be modeled as single porosity or dual porosity.

The grid block properties for single porosity cells are only required for the matrix cells; the fracture cells are made inactive and ignored. Within single porosity regions, flow is between matrix blocks and Wells may only connect with the matrix blocks in single porosity regions.

Figure 6 shows the final regions of reservoir by separate colors of blue for dual porosity region and red for single porosity region. This assumption for fracture region of reservoir is completely confirmed by available wells production history.

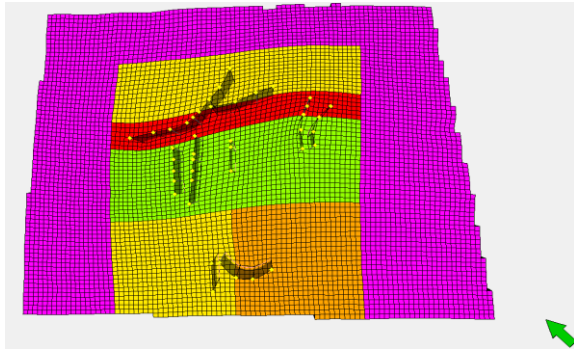


Fig. 5 Reservoir regions according to different faults direction

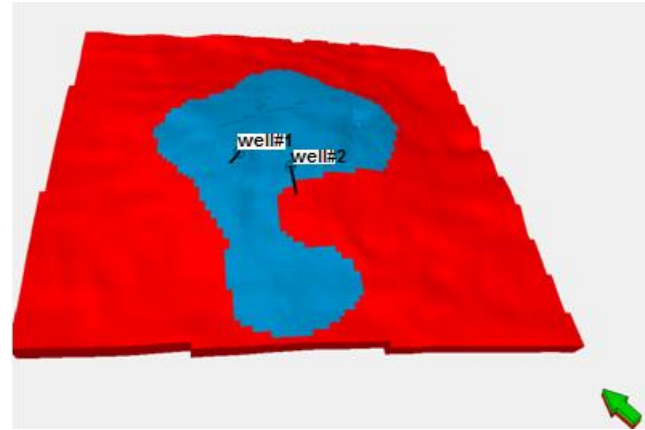


Fig. 6 DPNUM keyword definition in simulation model of X reservoir

In this study it is assumed that each fracture's property has a decreasing trend from faults toward the reservoir flanks. According to this assumption the nearer fractures to the faults, the more significant effect on fluid transmissibility. Correlations No 1, 2 and 3 are developed for different fracture properties. Fracture porosity, vertical dimension of a typical block of matrix (DZmatrix), and shape factor are correlated as following for this Iranian offshore fractured reservoir.

$$\Phi = 0.00025 * \ln(K_f) + 0.0005, \quad (1)$$

which Φ is fracture porosity and K_f is fracture permeability.

$$DZmatrix = -3.5 * \ln(K_f) + 25, \quad (2)$$

which DZmatrix is vertical dimension of a typical block of matrix and K_f is fracture permeability.

$$\sigma = 12 / (DZmatrix)^2 \quad (3)$$

which σ is the shape factor.

Figure 7 and Figure 8 illustrate the reservoir map of fracture permeability and shape factor. It is assumed that the fractures' properties have a decreasing trend from faults toward the reservoir flanks. It means that fractures are stronger near the faults which is an acceptable fact.

Fracture permeability is tuned during the history matching process by applying a decreasing trend in it with increase the distance of cells from faults. Also some weights were set in fracture permeability of different regions by attention to trend of faults in those regions.

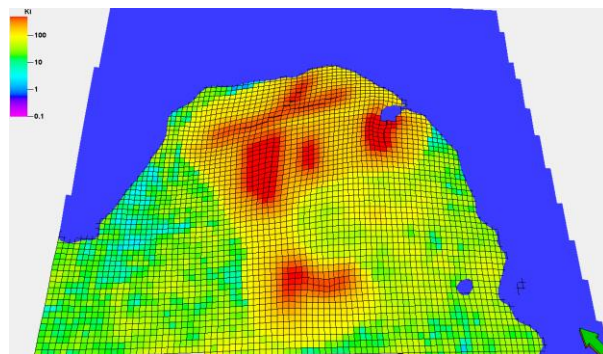


Fig. 7 Fracture permeability map in top of X reservoir

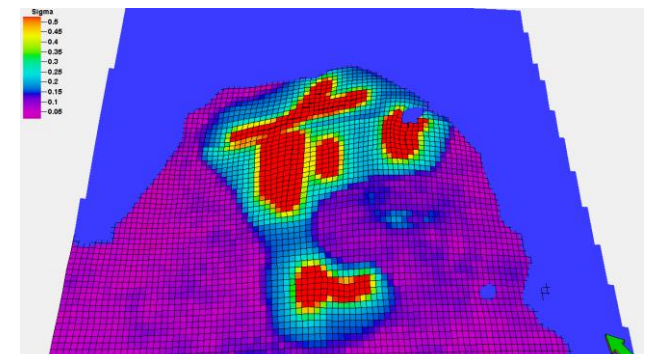


Fig. 8 Fracture sigma map in top of X reservoir

By defining separation of single porosity and dual porosity regions of reservoir and also applying satisfied matrix and fracture properties and using end point scaling method, the history data of the reservoir in different wells, could be matched in simulation model. As it is

mentioned, oil production rate is the basis of this model and it is fully matched in all wells. According to Figure 9 to Figure 14 by applying this method, reservoir history data have been met with the simulation model predicted data with a good accuracy. The level of accuracy in these history matching is remarkable.

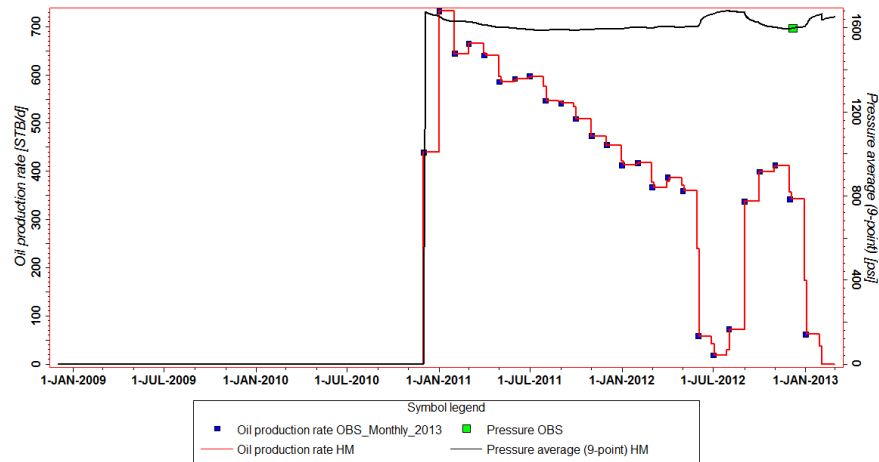


Fig. 9 Comparison of observed and calculated oil production rate and average pressure for well #B.

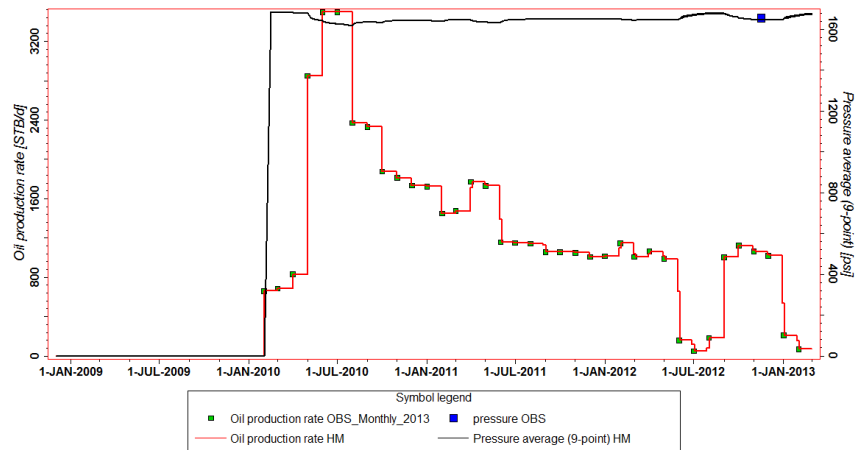


Fig. 10 Comparison of observed and calculated oil production rate and average pressure for well #C.

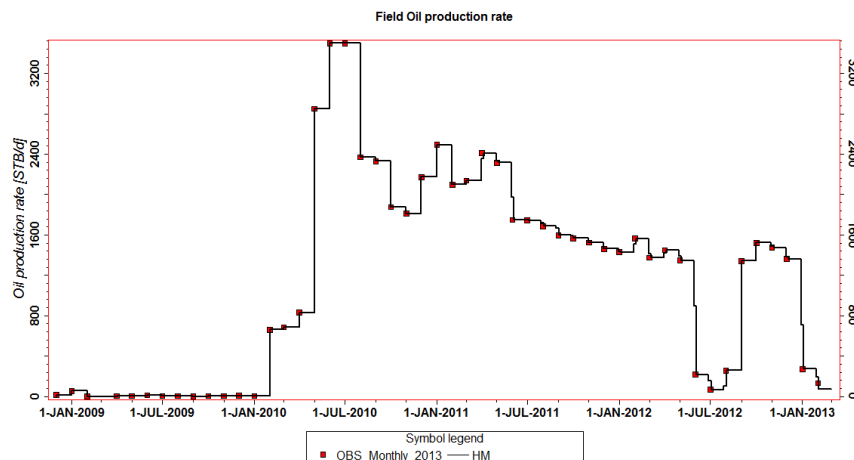


Fig. 11 Comparison of observed and calculated oil production rate for X reservoir.

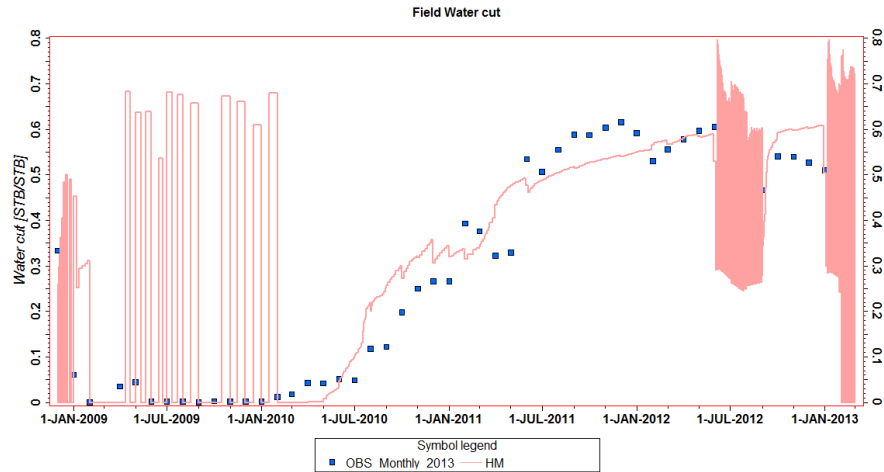


Fig. 12 Comparison of observed and calculated water cut for X reservoir.

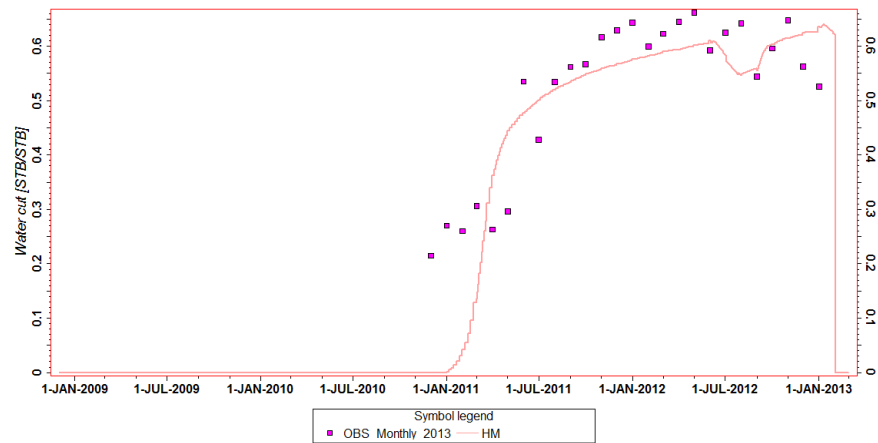


Fig. 13 Comparison of observed and calculated water cut for well #B

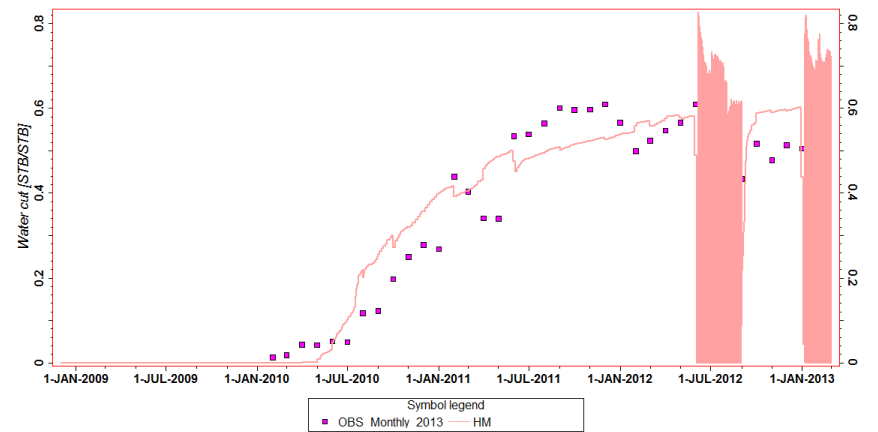


Fig. 14 Comparison of observed and calculated water cut for well #C

3. Results and discussion

In this paper we try to develop a new approach for simulation of naturally fractured reservoirs by a case study. This approach was employing dual porosity model for fractured regions and single porosity model for other regions of our under study reservoir. Also defining fracture region of reservoir by a distance function from faults. The other concept which is included in defining the properties of fracture region was the orientation of faults. Thus, it is assumed that each fractures' property has a decreasing trend from faults toward the reservoir flanks.

According to this assumption the nearer fractures to the faults have the more significant effect on fluid transmissibility. Finally by applying explained approaches, some correlations are developed for different fracture properties such as fracture porosity, vertical dimension of a typical block of matrix (DZmatrix), and shape factor for this Iranian offshore naturally fractured reservoir.

By this method, reservoir history data have been met with the simulation model predicted data with a good accuracy and its note worthy that the level of accuracy in this history matching is remarkable. It is strongly recommended that for modeling and history matching of these kinds of reservoir by applying mentioned assumption and developing appropriate correlations, the better and more real model would be created.

4. Conclusion

This paper presents the numerical simulation of an Iranian naturally fractured reservoir based on some new advancement.

The fracture properties such as porosity, permeability and shape factor are propagate in the reservoir model based on the distance of each grid block from faults also the orientation of nearest fault to that grid. On the other hand, the assumption which fractures are created affected by faults is a good guide to specify each grid block should be simulated as single porosity model or dual porosity model.

Matching simulation data of oil and water rate also bottom-hole pressure with observed data in this case study could be a good indicator for accepting the presented method for building simulation model of a fracture reservoir.

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