A Fully Integrated Approach for Better Determination of Fracture Parameters Using Streamline Simulation; A gas condensate reservoir case study in Iran

Amir Abbas Askari and Turaj Behrouz*
Research Institute of Petroleum Industry, Tehran, Iran
(Received 6 August 2013, Accepted 29 October 2013)

Abstract

Many large oil and gas fields in the most productive world regions happen to be fractured. The exploration and development of these reservoirs is a true challenge for many operators. These difficulties are due to uncertainties in geological fracture properties such as aperture, length, connectivity and intensity distribution. To successfully address these challenges, it is paramount to improve the approach of characterization and simulation of fractured reservoirs.

In this study, a fully integration of all available data and methods have been used for generating stochastic discrete fracture network (DFN)such as outcrop study, core description, petrophysical and image logs and also for better result validation, streamline simulation has been conducted. In this comprehensive process a real gas condensate fractured carbonate reservoir has been used.

Firstly, three main fracture sets were defined that have fold-related fractures, then the fracture intensity and DFN model using fracture drivers correlation were generated. After that, permeability of the developed DFNs was calibrated with available well test permeability. Then, a streamline simulation was used because of its high computational speed, high accuracy and good visualization for the repeated nature of history matching of a dual porosity model in the gas condensate reservoir. So, with running streamline simulation, three realizations (High, Medium and Low) ranked based on the objective function values. These three realizations are common realization that are well known with optimistic, most likely and pessimistic scenarios. Finally, comprehensive history matching was done for all the three-selected realizations.

The overall goal is to develop a representative fluid flow simulation model for improving gas cycling procedure in gas condensate reservoir. This method has great application in the high resolution fractured reservoir modeling due to using actual fracture parameters. Also, it can be used for model ranking, screening and optimum dynamic model calibration for reduction of the history matching complexity without being manipulated by reservoir engineer.

Keywords: Fracture parameters, DFN model, Fast history matching, Streamline simulation, DST matching

Introduction

Natural fractures play a significant role in subsurface flow and transport of fluids. In recent years, there is a greater need for more robust facture characterization methods that can integrate both static and dynamic data in an efficient manner. Of late, discrete network (DFN) techniques have gained increasing attention in the oil industry. The advantage of the DFN models is the ability to incorporate complex fracture patterns based on field data such as cores, well logs, borehole images, seismic data and geomechanics. Therefore, the DFN modeling has become popular and is often used to fracture model flow path and connectivity. Although the DFN models can reproduce very realistic fracture geometry, it is important to condition these models to dynamic data such as well test, tracer and production data to reproduce the flow behavior in the reservoir.

Standard history matching techniques are often composed of a fixed geological model with global modifications and local adjustment. The limitations of this method are clear. Local adjustments are not always geologically realistic, static uncertainties are not taken into account and only a limited number of models are used for prediction. An important part of uncertain parameters affecting the history match is fracture properties that have a great impact on the reserves estimation and production profile determination.

* Corresponding author: Tel: +98-21- 48252457 Email: behrouzt@ripi.ir

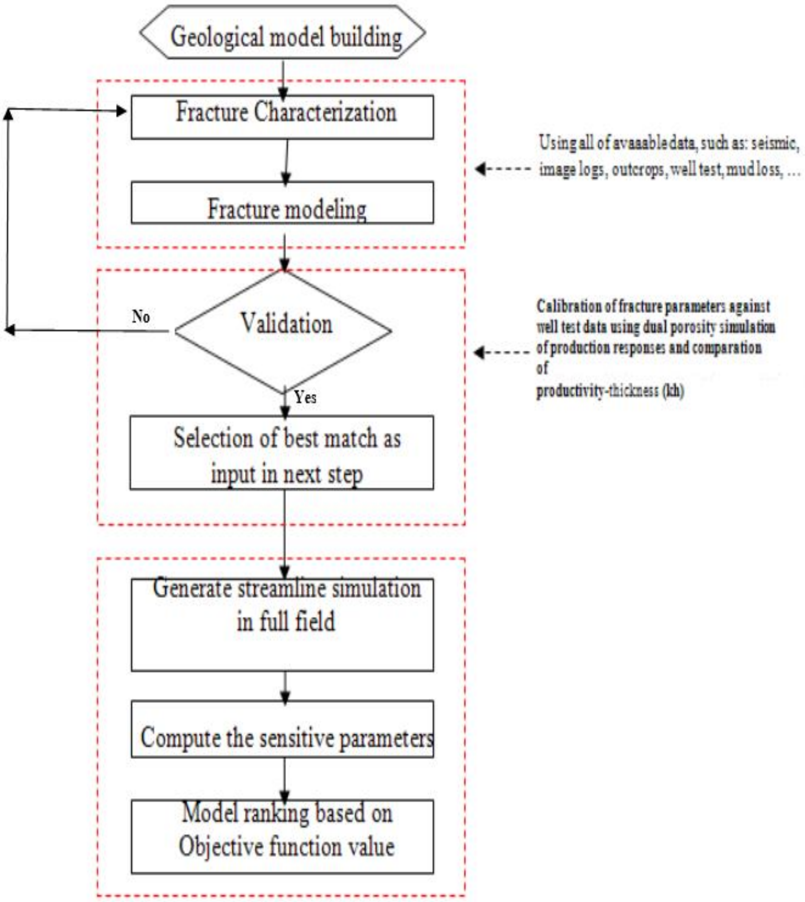

Figure 1: Flowchart of model ranking

We need to conduct history matching of more than one realization. A crucial issue here is to select representative realizations that will adequately represent the uncertainties in the reservoir performance predictions. We will resort to a streamline-based ranking criterion for this purpose. Streamline models have shown great potential in integrating dynamic data into high resolution geologic models.

The organization of this paper is as follows. First, we build a multiple equi-probable stochastic model of the fracture distribution network (DFN). For building this model, data from different sources such as conceptual model, well logs, well tests, seismic and production logs are incorporated. Then these models are validated in surrounding of wells by transient pressure tests, the objective function, which measures the mismatch between the simulated and the observed pressure data, is used for selection of best models. The parameters of selected models are extrapolated into full reservoir. Finally, a great number of multiple realizations with consideration of fracture parameters are built and then using streamline-based dual porosity simulations are ranked. Ranking is based on the comparison between observed and simulated data as an objective function value.

Methodology

The workflow starts by preparing a multiple history matched reservoir model that includes all static uncertainties such as fracture modeling parameters. The delivered results are now probabilistic and the obtained reservoir model is more realistic based on a geological modeling. This methodology can be applied for facilitating

the history matching processes, using all of integrated data from geological study to production, particularly in fractures reservoirs. In this study, we show how all types of dynamic data can improve the characterization of the fracture network either qualitatively or quantitatively. The workflow involves three main steps
(Figure 1):

1. Fracture characterization and modeling
2. Validation and optimization of fracture-network models
3. Model ranking by streamline simulation in the full field model

Step 1: Fracture characterization and modeling

To improve oil and gas recovery in naturally fractured reservoirs, the dominant flow paths must be identified. Identifying, characterizing, and mapping the fracture network in terms of aperture, length, connectivity and intensity distribution are crucial for optimal reservoir management. First, reservoir characterization starts with outcrop, seismic, well logs, core cutting and wellbore images to develop a preliminary description of the reservoir. Then, the fracture controlling (lithology, porosity) are identified and using geostatistical and neural methods are assigned to inter wells. Finally, the discrete fracture network (DFN) modeling has become a desirable starting point.

Step 2: Validation and modification of fracture-network models

Calibration of fracture–network models due to high uncertainty of such models is a very important step. In fact, field experience has shown that the ultimate accuracy of reservoir characterization will depend on the iterative process of calibration against dynamic data. In this section, we define a certain number of grids near wellbore regions inside the reservoir. Fracture distributions are generated stochastically within each region. The dynamic behavior of the fracture-network model is then simulated and compared to the observed production test responses until a satisfactory match is achieved by the appropriate tuning of model parameters.
This fine tuning is done using computation of the equal-probable realizations (about 50) that is iteratively with consideration of different fracture parameters. Finally, a few of these realizations that have optimum objective function value are selected in the condition that their permeability to be consistent with the permeability-thickness (*kh*) of test.

Step 3: Model ranking by streamline simulation in the full field model

A 3D streamline simulator was used in this study to model fluid flow in the reservoir. Under a variety of conditions, the speed of the streamline simulator can be much faster than a conventional numerical simulator and is thus particularly well-suited for large-scale flow simulations and ranking of geologic models. Ranking of multiple realizations due to variety of uncertainty to identify the optimal realization for history matching is important.

With regarding to observed data and comparison with simulation results, best matches have been selected. Achieving these best matches, three mentioned realization have been plotted in recovery factor versus gas in place graph.

The ranking procedure is developed based on the results of production history and flow simulation of streamline as an objective function value. At last, we select three realizations that represent the pessimistic/low, most-likely/medium, and optimistic/high realization for decision making.

Application and results

Case study description

The case study is a gas condensate reservoir in fractured carbonates mainly made up of argillaceous to marly limestone. The field structure shoes up on surface as an anticline with its longitudinal axis orientated N120. The gross reservoir thickness is approximately 200m.Due to poor quality of seismic data, prediction of possibility for faulting existence is impossible. In this field, 12 wells have been drilled over 50 years of production history.

Fracture characterization

Characterization, *i.e.* preparing data for modeling and simulation stage, is the first step of any reservoir study. The aim of natural fractures reservoirs (NFR) characterization is to determine reservoir and fracture properties at well location, as well as correlation and interpolation throughout the inter-well regions. In doing so, it is essential that all available field data at different scales are gathered for a proper rock characterization. These data sources range from seismic and outcrop surveys to different logging tools, wellbore images, core, drilling data and well tests. Unfortunately, in this study it is not possible to use seismic data due to low quality seismic.

Generally, NFR characterization is done in two steps:

1. Processing of data sources for fracture properties determination
2. Analysis and integration of information to establish characteristics, interrelationships and spatial distributions of all fracture properties for the whole reservoir.

Also, the required parameters to define accurately a fracture system at the wellbore scale can be summarized as follows:

- Geometric description (position, orientation and length)
- Fracture aperture, as a significant element of fracture porosity and permeability
- Fracture intensity (density) that is the most important characteristic of a fracture network

First, observations of outcrop analogs and acquired image logs from three wells were analyzed to describe the reservoir fracture network. Outcrop image is at regional scales and it is an important fracture data source. It may establish underground fractures as the surface measurements being extrapolated into subsurface, but always this conversion is not straightforward. There is a difference between surface and subsurface depend on burial stress and weathering.

In this study, orientation of surface maps in the different regions revealed that the fracture system origin of this field is more fold-related than fault related because of not seeing any distinct fault in the reservoir. Also, the maximum horizontal stress is in the NE-SW direction that is the direction of the tension fractures being parallel to anticline axis. In addition, it has been observed that fracture patterns are non-stratbound with length population power-law and spacing of fractures is about of 10cm to 15 m. Figure 2 shows the fracture pattern in one of the outcrops in this field.

Figure 2: An example of outcrop in the field (Shakeriet all, RIPI)

The orientation and dips of sub surface fractures were obtained from core-oriented fracture description and FMI interpretation. Figure 3 shows the fractures in cores and dip-azimuth of fracture in an image log. The consistency of the orientation data in well and in outcrop scale suggested that a continuous fracture population exists between them. Also, fracture aperture size was calculated from image logs in one of the wells that its mean log-normal aperture distribution is 0.2 mm.

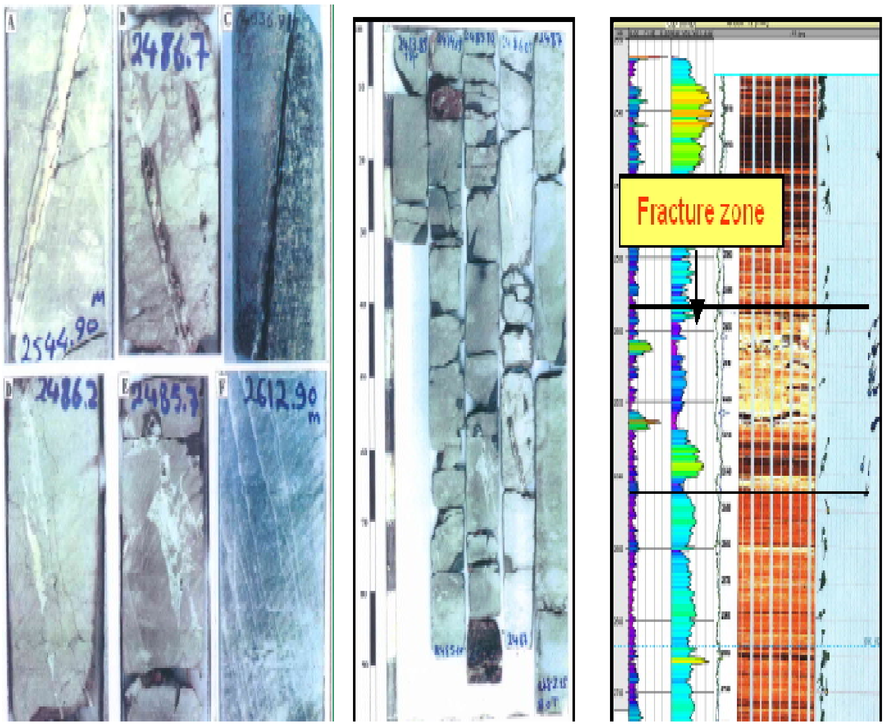

Figure 3: Core data and FMI log in the fractured reservoir

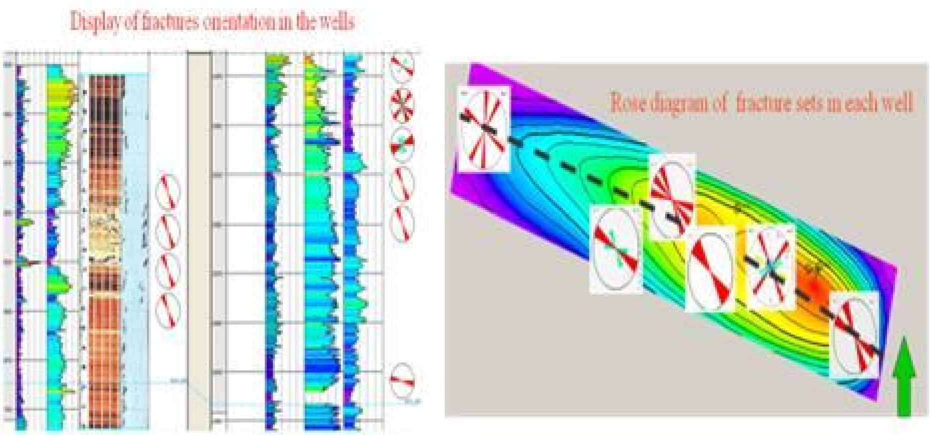

Figure 4: Rose diagram distribution based on image logs and outcrops

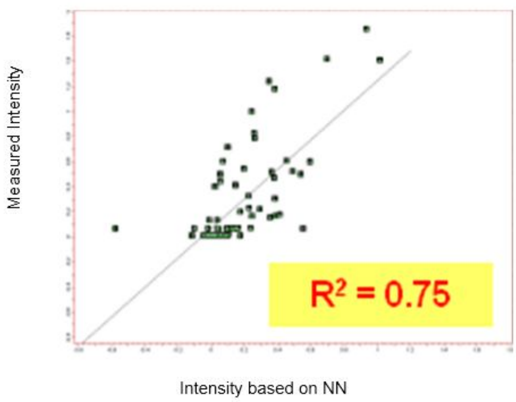

Figure 5: Correlation between intensity log and calculated using neural network

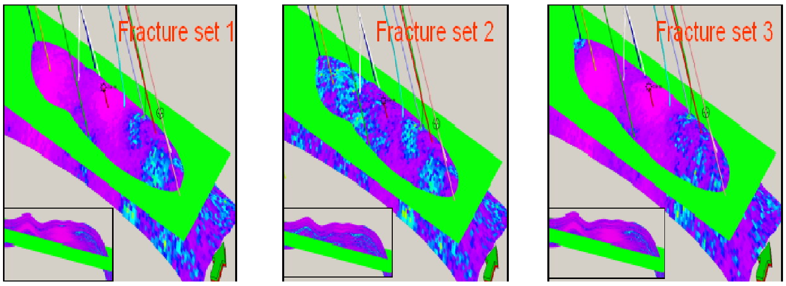

Figure 6: Intensity distribution in each fracture set

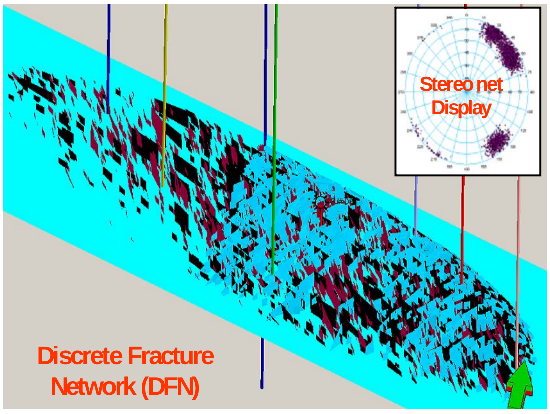

Figure 7: DFN model in full field

With considering of all these information and drawing of rose diagram distribution (Figure 4) three main fracture direction (set) were determined:

1. Parallel to bedding as diagonal with folding axis (N145, dip 80°), shear fractures
2. Perpendicular to bedding as diagonal with folding axis (N55, dip 78°), shear fractures
3. Parallel to folding (N115, dip 75°),tension fractures

The fracture information was analyzed and integrated by statistical, geostatistical and spatial neural methods. The purposes are to determine representative statistics and behaviors of each fracture properties (e.g. location, orientation, length and intensity) and as well as their correlation with other parameters and spatial distribution. The results will be used as inputs in the stochastic modeling of fractures. The orientation and length are obtained from quantitative analysis results in wells and outcrops. Due to sparse data in some wells, it is necessary to estimate the intensity of fractures from some other wells. For this work, a good correlation between intensity log and shale log was identified that with decreasing of shale (ductile zone) in limestone (brittle zone) the fracture intensity increases, then a neural network algorithm was applied for training of available data. Figure 5 shows the good correlation between raw data and calculated data for intensity log. Later, the intensity log in all of wells was estimated. Finally, an intensity distribution map for each fracture set was created stochastically using geostatistical methods. Figure 6 shows the intensity distribution in each fracture set.

Fracture modeling

All data collected were used to define the orientation parameters. Three main fracture sets were detected and assigned to the model showing average dip directions of N145, N55, N115, respectively, with dip angles 80°, 78°, 75°.Also, the distribution of fracture length was described by a power law and the minimum and maximum length with an initial guess about of 20m and 200 m, respectively. Figure 7 shows a view of DFN model in the reservoir. Based on the DFN model, the reduction of fracturization from crest area into flank area can be seen. Also, due to existence of only one dominate fracture set (N145) in the west of the reservoir, a strong anisotropy that associated with a disturbed zone (possibly fault) was seen.

For estimating of fracture parameters (porosity, permeability and sigma factor), we need to have the aperture size and intrinsic fracture permeability. First, the aperture size was calculated, initially, due to relationship between the aperture and its length until their statists consistent with statistics of FMI analysis. Then, the intrinsic fracture permeability as a function was related to the fracture aperture. The intrinsic fracture permeability was considered as a parameter to be matched in the calibration of dynamic data. Finally, the fracture network properties were scaled up within each of cells in the reservoir, but these properties were not in accordance with real data, yet.

Validation

The reliability of DFN model was verified by simulation of the dynamic data in surrounding of wells and by comparison of obtained pressure data, with the pressure response of real data observed. The pressure response taken from well tests has certain diagnostic properties that can be used to help resolve such properties as fracture connectivity, length, scale and permeability.

In this paper, with using of interpretation of drawdown and buildup pressure tests in two wells of the field, initially the matching parameters of fracture (intensity distribution, fracture length, aperture, and intrinsic permeability) were consistent. For this work, first an iterative procedure was defined for simulation of pressure response in the surrounding of two given wells as compositional mode. Figure 8 shows the DFN model in the surrounding of a well, then due to uncertainty of these parameters 50 software runs (different realizations) in different ranges were executed. The permeability-thickness product (kh) obtained from test (ranging between 1000 md.m and 1200 md.m) had to match predicted models, otherwise it would be omitted. Figure 9 shows observed data against simulated data for a transient pressure test. Finally, five realizations of these DFN models that had optimum objective function values were selected for full field model. After extrapolating of selected parameters, in the reservoir, fracture permeability was scaled up in each cell volume (Figure 10)

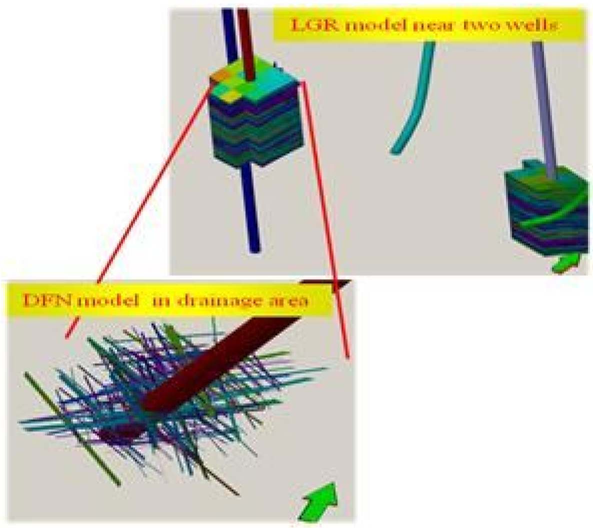

Figure 8: DFN model in the surrounded of a well

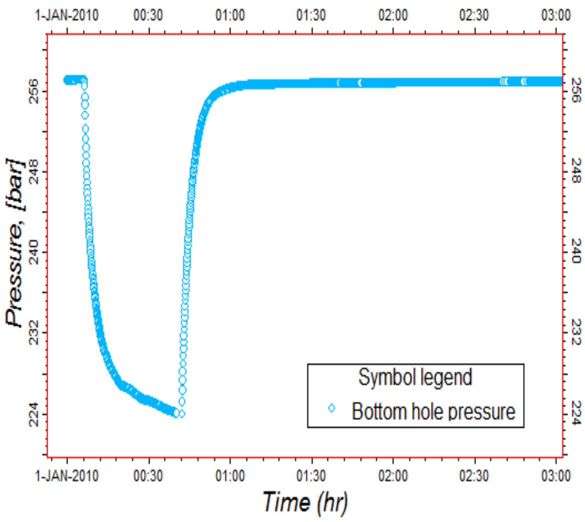

Figure 9: Observed data for a transient pressure test

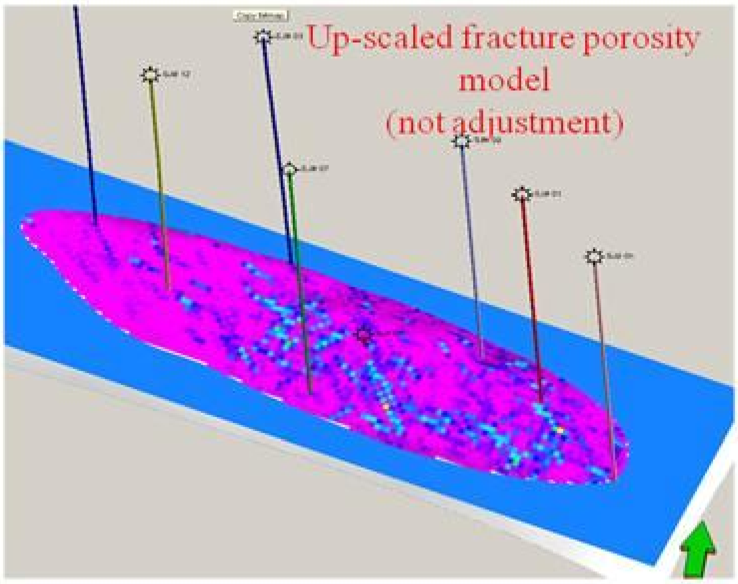

Figure 10: 3D fracture permeability in the reservoir based on DFN model

Prioritizing

The purpose of this part is to prioritize different realizations according to our objective function. The objective function for this study is cumulating produced gas and gas condensate as combination. About45 realizations of different properties such as porosity, matrix permeability, water saturation and also adjusted fracture parameters were constructed. Then, for each of them, OGIP were calculated and subsequently detailed fluid flow simulation scenarios were applied by using streamline simulation. Simulated models based on corner-point geometry with 153*41*71 grid equal to 445000 cells provided 132000 active cells.

The rate of gas production is shown in Figure 11, First, by defining an acceptable threshold range, an appropriate model was selected. P10, P50, P90 realizations were extracted according to three optimistic, most likely and pessimistic attitude. This process is illustrated in Figure 12. These three models can speed up the detailed history matching with minimum modifications for forecast reservoir performance. Three scenarios can be used as reservoir representative model under existing uncertainties. This method will help reduce comprehensive history matching effort and can be a fast screening procedure. Also, Figure 13 shows an example of streamline distribution in the reservoir.

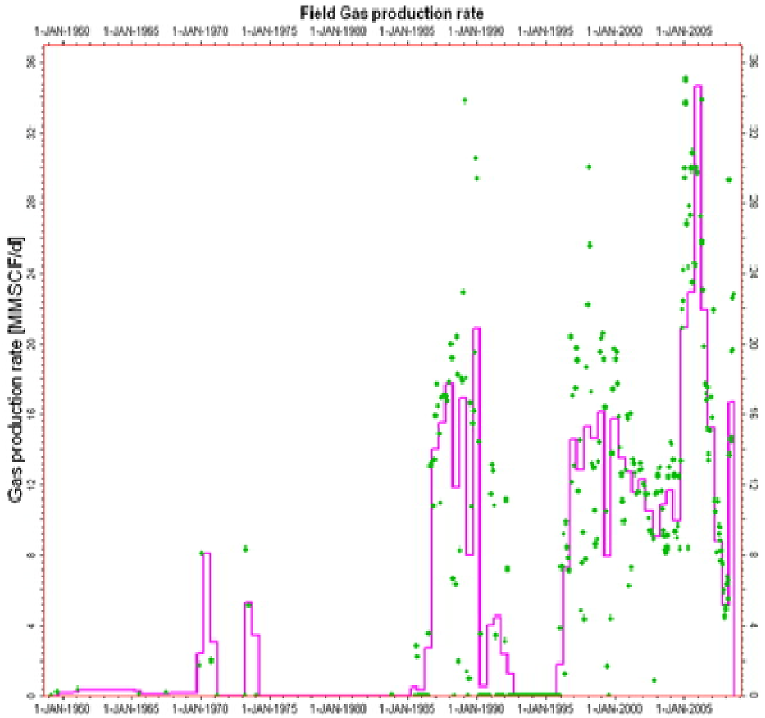

Figure 11: Simplified gas production schedule for the field

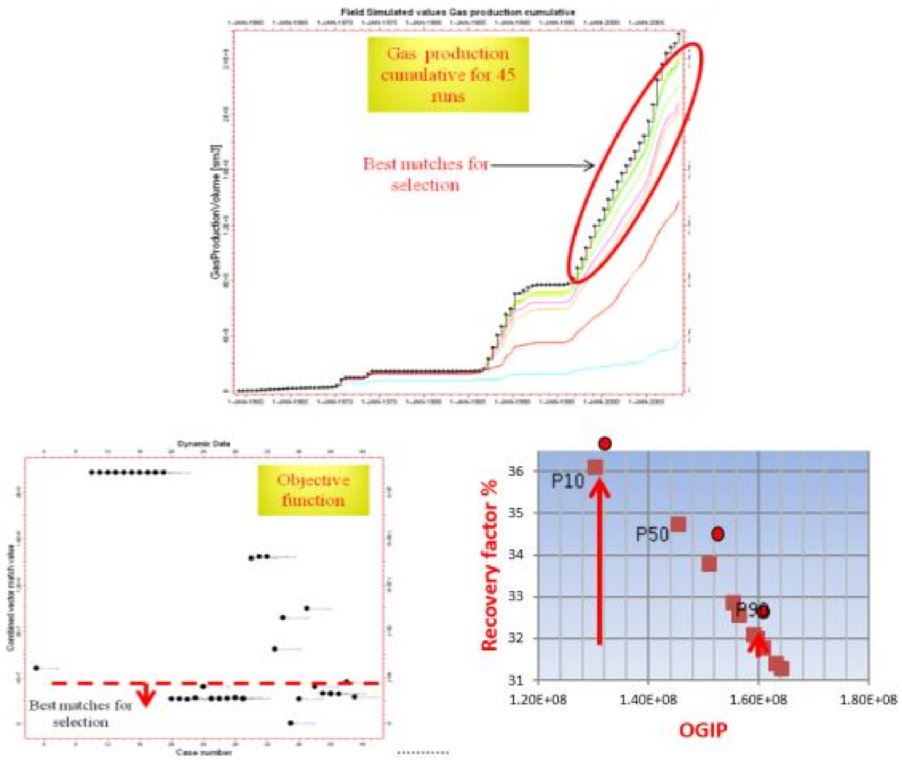

Figure 12: schematic of selecting the best case process

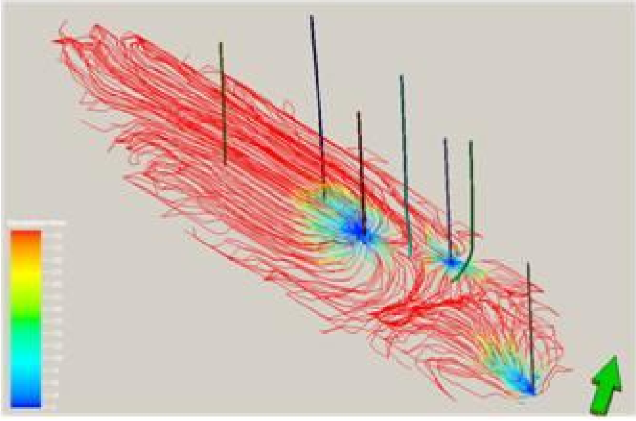

Figure 13: Example for a streamline distribution

Discussion

To illustrate the viability of our approach, first we modeled the characteristic of fractures using a fully integrated data from outcrop study to pressure transient pressure test. Later, for validation and improving of fracture modeling based on variety ranges of uncertainty fracture parameters a series of simulation (as compositional mode) of the dynamic behavior in the reservoir region surrounding wells was performed to reproduce the pressure response recorded during test. Five realizations that have optimum objective function value were selected. Then, streamline simulation as dual porosity was conducted for the 40 realizations that include the five selected realization in fracture modeling. The results of flow simulation were compared with the history production and consequently three realization of best matches were introduced as P10, P50 and P90 in the OGIP distribution for pessimistic, most likely and optimistic attitude.

Conclusion

- Fracture drivers from conventional core, image logs and well logs give predictive tool for fracture distribution
- A representative fracture reservoir model was developed for a gas condensate based on multiple realizations of stochastic DFN methodology by integrating geological and engineering information.
- Multiple realizations of fracture properties (porosity, permeability and sigma factor) can be generated based on variety of fracture parameters (length, aperture and intensity distribution).
- Calibration of the fracture parameters such as fracture intensity and permeability to match the observed dynamic behavior of the formation proved to be an effective way to achieve a better perception of the fracture network characterization that cannot be directly measured.
- Good history match will be obtained for full field model with very minimum adjustment.
- Before starting to study a history match, the uncertainty ranges of fracture parameters possibly impacting the history match, can be defined.
- Here streamline simulation technique, was used to model ranking.
- Successful application of the methodology was the key to achieve a satisfactory history match for the field example with the speed of the streamline-based ranking makes it practical to examine the impact of uncertainty associated with various static and dynamic parameters under realistic field conditions, with minimal adjustments of parameters.

Acknowledgment

This work has been supported by the Research Institute of Petroleum Industry (RIPI) and the authors would like to place on record, their appreciation for the support rendered by Research and Technology Directorate / National Iranian Oil Company, on the research leading to the present article.

References:

1- Aguilera, R. (2003). Geologic and Engineering Aspects of Naturally Fractured Reservoirs. Canadian Society of Exploration Geophysics Recorder (February), pp. 44-49.

2- Acuna, J.A., Ershaghi, I. and Yortsos, Y.C. (1995). “Practical application of fractal pressure-transient analysis in naturally fractured reservoirs.” *SPEFE 173; Trans.,* AIME, 299.

3- Christie, M., Subbey. S., Sambridge, M. and Thiele, M. (2002). Quantifying Prediction Uncertainty in Reservoir Modeling Using Streamline Simulation. 15th ASCE Engineering Mechanics Conference June 2-5, 2002, Columbia University, New York, NY.

4- Datta-Gupta, A. (2000). Streamline Simulation: A Technology Update. JPT 68.

5- Di Donato, G., Huang, W. and Blunt, M.J. “Streamline-based dual porosity simulation of fractured reservoirs." Paper SPE 84036 presented at the Annual Technical Conference and Exhibition, Denver, CO, 5-8 October.

6- Dershowitz, W., *et al. (*2003). “Integration of discrete fracture network methods with conventional simulator approaches,” *SPE Res. Eval. & Eng.*, pp. 165-170, (April 2000).

7- Guerreiro, L. *et al.* (2000). “Integrated reservoir characterization of a fractured carbonate reservoir.” *SPE 58995, SPE Inter. Petroleum Conf. and Exhib.*, Villahermosa, Mexico.

8- Gilman, J.R. et al. (2002). “Statistical ranking of stochastic geomodels using streamline simulation: A field application.” paper SPE 77374 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, 29 September–2 October.

9- Idrobo, E. A. (1999): “Characterization and ranking of reservoir models using geostatistics and streamline simulation.” PhD Dissertation, Texas A&M University.

10- Haldorsen, H.H. and Damsleth, E. (1993), Challenges in reservoir characterization. AAPG Bulletin, 77(4), pp. 541-551.

11- Kazemi, H., Atan, S., Al-Matrook, M., Dreier J. and Ozkan, E. (2005). Multilevel Fracture Network Modeling of naturally fractured Reservoirs. SPE 77741 presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas U.S.A, Jan. 31-Feb. 2.

12- King, M. J. and Datta-Gupta, A. (1998). "Streamline simulation: A current perspective." In Situ,22(1): pp. 91-140.

13- Guttormsen, Li, B., Tran, J. and Hoi, V. (2004). Characterizing Permeability for the Fractured Basement Reservoirs. SPE 88478 presented at the SPE Annual Technical Conference and Exhibition, Perth, Australia, 18–20 October.

14- Milliken, W. J., Emanuel, A. S. and Chakravarty, A. (2001). Applications of 3D Streamline Simulationto Assist History Matching. SPE 74712, SPE Reservoir Evaluation & Engineering, 4 (6), December, 502-507.

15- Nelson, R. A. (1985). Geological Analysis of Naturally Fractured Reservoirs, Gulf Publishing Company, Houston.

16- Reynolds, A. C., He, N. and Oliver, D.S. (1997). “Reducing uncertainty in geostatistical description with well testing pressure data.” in *Proc.*, International Reservoir Characterization Conference, Houston, 2-4 March.

17- Baker, R.O., Kuppe, F., Chugh, S., Bora, R., Stojanovic, S. and Batycky, R. (2002). “Full-field modeling using streamline-based simulation: Four case studies.” *SPE Reservoir Eval. & Eng.*, 5 (2).

18- Tamagawa, T., Matsuura, T., Anraku, T., Tezuka, K. and Namikawa, T. (2002), “Construction of fracture network model using static and dynamic data.” SPE 77741 presented at the SPE Annual Technical Conference and Exhibition, San Antonio, TX, Sept. 29-Oct. 2.

19- Verga, F.M., Giglio, G., Politecnico di Torino, Masserano, F. and Ruvo, L. (2002). Validation of Near-Wellbore Fracture-Network Models with MDT. April 2002 SPE Reservoir Evaluation & Engineering.

20- Wang, Y. and Kovscek, A.R. (2000). “Streamline approach for history matching production data.” *SPE Journal*, (4), pp. 353-362.

21- Zubiri, M. and Silvestro, J. (2007). "Fracture modeling in a dual porosity volcaniclastic reservoir: A case study of the precuyo group in cupen mahuida field, Neuquén, Argentina. AAPG Annual Convention, Long Beach, California, April 1-4.