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# A workflow for flow simulation in shale oil reservoirs: A case study in woodford shale

Mohammad Sharifi[1]*, Mohan Kelkar[2], Abdorreza Karkevandi-Talkhooncheh[1]

[1]*Department of Petroleum Engineering, Amirkabir University of Technology, Tehran, Iran*

[2]*McDougall School of Petroleum Engineering, The University of Tulsa, Tulsa, USA*

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**Abstract:**
In recent years, with new technologies of long horizontal wells and staged hydraulic fracturing, the development of unconventional oil and gas reservoirs (i.e., shale gas and shale oil) has gained significant momentum. Due to extremely low permeability, these unconventional formations cannot be produced economically without significant stimulation. In the current research, the workflow for shale reservoir history matching that can be used for other shale resources producing from either condensate or oil reservoirs is developed. Production data and well geometry data for nineteen wells were available in Woodford shale. During this work, using the available data, single well simulation models for all the individual wells were constructed and then models were tuned to match the historical data. It has been shown that the fracture half length, shear fracture distribution and the interaction between matrix and fractures should be captured. Also, the results showed that fracture half-length can be longer than 2,000 ft, but the permeability of the fracture is dependent on how far the fracture is from the well. It was found that for multiple well history matching, fracture half-length and the interaction between the wells are the most important factors. Using multiple history matched models, it was shown that multiple models with different fracture distributions could capture the historical data, but they exhibit different future predictions.

## 1. Introduction

The latest Annual Energy Outlook (2020), provides the importance of unconventional shale gas and shale oil production in the U. S. domestic oil and gas production. The latest report by International Energy Agency also has emphasized the critical nature of unconventional resources and showed the importance of investing in upstream oil and gas to compensate for the decline in production from conventional oil and gas reservoirs. Unconventional resources cannot be produced without using massive hydraulic fracturing and horizontal wells. The initial development in horizontal wells and fracturing technology far exceeded the fundamental understanding of how the oil or gas is produced and the mechanisms by which it is produced. Eventually, reservoir engineering analysis is catching up with the technical development in drilling and fracturing. It is assumed that hydraulic fracturing creates a region near the fracture, which is called stimulated reservoir volume and permeability is enhanced in this region. Many researchers have tried to model the mechanisms by which hydrocarbons are produced from an unconventional formation (Blasingame, 2008; Andrade et al., 2010; King, 2010; Moridis et al., 2010; Darishchev et al., 2013; Wang et al., 2015). Many researchers attempted to evaluate the generated fracture properties using hydraulic fracturing (Fredd et al., 2001; He et al., 2018). Meng et al. (2020) proposed a model to estimate the properties of non-uniform fractures by analyzing pressure buildup tests and try to obtain a relationship between fracturing properties and injected volume. While significant advances are being made in stimulating shale oil reservoirs; however many challenges (especially phase behavior, production mechanism and optimization strategy) in modeling of these reservoir remain (Feng et al., 2020; Taghavinejad et al., 2020). Panja et al. (2019) studied the challenges in the production of shale oil and gas-condensate reservoirs. They investigated the effect of the fluid (volatile oil or condensate) and reservoir

*Corresponding author.
*E-mail address*: m_sharifi@aut.ac.ir (M. Sharifi); mohan@utulsa.edu (M. Kelkar); reza.aut89@gmail.com (A. Karkevandi-Talkhooncheh).
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permeability and operating conditions on ultimate recoveries. Some authors have used commercial reservoir simulators to study the gas production from a shale gas reservoir in an integrated workflow (Cipolla et al., 2010). Luo and Kelkar (2013) presented a new approach to predict the expected ultimate recovery of infill well in the tight gas reservoirs. Osholake et al. (2013) investigated the factors that affect the performance of hydraulically fractured well in the Marcellus shale. Adil et al. (2015) proposed a reservoir simulation strategy and the workflow for unconventional gas reservoirs. Zanganeh et al. (2015) investigated the effect of fracturing fluid and fracturing geometry on shale oil performance. All of these methods require reservoir parameters and fracture distribution. One of the biggest challenges is available knowledge about the fracture distribution and fracture permeability and being able to simulate those complex structures using commercial simulators. One of the accepted methodologies in the simulation of unconventional reservoir is focusing on the individual well rather than field-scale model (Ding et al., 2014).

One of the main challenges in history matching is quantifying the uncertainty in possible future production and investigating the main parameters that can affect the quality of history matching. In the case of tight oil reservoirs where wells are hydraulically fractured, the history matching involves adjusting several unknown parameters (i.e., fracture permeability, formation permeability, fracture half length, fracture geometry, relative permeability of fractures and formations, etc.) such that historical performance can be matched. Regarding the fact that in the history matching process we are dealing with an inverse problem and due to the existence of several unknown parameters, matching can be achieved with several scenarios and adjusting different sets of variables. However, these history matched cases, do not provide any information on how wells interfere with each other and how the optimal spacing of these wells can be defined. Our goal is to provide a workflow for history matching of shale oil reservoirs using both single and multiple well simulations and provide a pathway by which the interference between adjacent wells is understood in order to better predict the impact of well spacing and fracture geometry on the reservoir performance.

The overall objective of this paper is to understand the behavior of Woodford shale oil wells by simulating the performance of the wells and matching the historical performance of them using reservoir simulation. In the current work, the workflow for shale reservoir history matching that can be used for other shale resources (Wang et al., 2015) by knowing their reservoir and flow characteristics is developed. First, a brief introduction to Woodford shale and the available data was provided. Afterward, single well simulation models for all the individual wells were constructed and the models were tuned to match the historical data. In the second part, the multiple wells production and the impact of well spacing on production performance were studied. The effect of different variables (i.e., fracture half-length and geometry) on future prediction of well performance was investigated. Different scenarios were discussed to highlight the possible uncertainty in the prediction of future performance.

**Table 1.** Woodford shale reservoir parameters.

| Parameter | Value |
|---|---|
| Net pay | 200 ft |
| Porosity | 4-5% |
| Initial water saturation | 20-25% |
| Initial pressure | 3500 psi |
| Temperature | 140 °F |
| Gas Gravity | 0.65 |

## 2. Woodford shale characteristics and simulation challenges

Woodford Shale is located at a depth between 6,000 to 9,000 ft and the thickness varies from 100 to 300 ft. The shale is of Devonian Mississippian age and depending on thermal maturity, it provides oil and gas as a source rock to many other formations. The thermal maturity of Woodford shale varies and in some locations, the wells in Woodford produce gas only; whereas in some other areas, the wells produce oil or condensates along with rich gas (Curtis et al., 2012). Like many other shale plays, Woodford has its own unique characteristics, including complex layering, faulted blocks and sealed natural fractures (Agrawal et al., 2012).

Typically, any kind of reservoir simulation has a degree of uncertainty. Spatial variation in reservoir properties such as porosity and permeability and viability of structural barriers such as faults are among the most common uncertainties in unconventional reservoir simulation. In this particular case, in addition to these concerns, there are two other important uncertainties. One is the uncertainty regarding hydraulic fracture configuration and the second one is the lack of reliable pilot-run verification test and relative permeability data. The spatial dependency in Woodford shale wells is weak. Adjacent wells have significantly different behavior from each other. The amount of accessed volume by each well is a function of both the oil in place (function of geology) as well as the efficacy of fracturing (function of good engineering). Distinguishing between these two is not easy given the amount of information typically collected from the wells.

Available information in this study consists of the following:

- Well surveys and geometry,
- Well hydraulic fracturing and injection information for most wells,
- Well completion data for most of the wells,
- Laboratory estimation of matrix permeability and porosity,
- Estimation of formation pressure,
- Basic PVT data (gas gravity, reservoir temperature and API gravity).

The typical values that have been used in the simulation model are shown in Table 1.

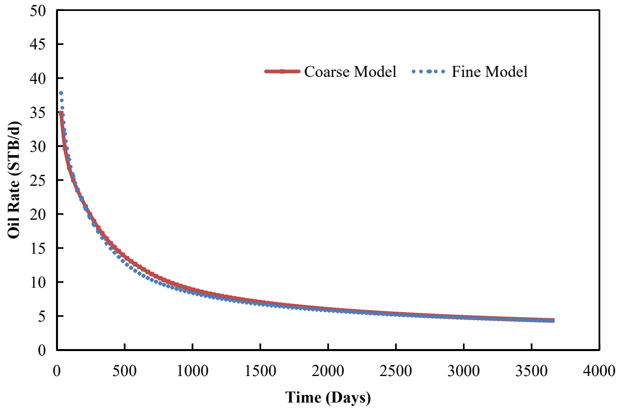


**Fig. 1.** Comparing the oil production in the coarse grid with fine grid size models.

## 3. Modeling

In the first section and after creating a reservoir model, several flow simulation scenarios were conducted but our new contribution was not limited to this part but to develop a workflow to investigate the effect of different fracture parameters (using Fortran programming) on reservoir performance. The proposed modeling is based on the following considerations:

- The main assumption of the current reservoir modeling is that Local Grid Refinement (LGR) is not taken into account. The reason is that, using LGR is more computationally expensive and at the same time it is less flexible for modeling features like shear fractures or multiple well simulations.
- Gas desorption is not considered. From the literature, it was found that the gas desorption is not very important during the early stages of production.
- In addition to primary (tensile) fractures, secondary (shear) fractures are simulated. The shear fracture density decreases as the distance from the well increases. The existence of shear fractures is consistent with micro-seismic data, geological study and also can capture the behavior of some original sealed natural fractures that are activated after the fracturing.
- Only one layer has been used in the simulation model. In other words, when there is a fracture in the model, it means fracture height is the same as the layer height and it penetrates through all of the thickness. This makes the model computationally more efficient. In reality, it does oversimplify the model.
- The fracture permeability value is high close to the well and declines away from the well. This assumption is consistent with the observation that proppant is much better packed near the wellbore than away from the wellbore.
- Due to the lack of accurate PVT data, the exact composition of the reservoir fluids is not available. Based on the provided information, it is believed that the reservoir fluid is black oil with bubble point close to 3,000 psia. Since the initial pressure is close to bubble point, the pressure will fall below bubble point as soon as the production starts.
- Both single and multiple-well simulations are carried out on a simple rectangular grid of size 5,000 ft $\times$ 5,000 ft $\times$ 200 ft using a commercial software. The increments in both $X$ and $Y$ directions are 10 ft, so that 500 $\times$ 500 grid cells are generated. Choosing proper grid size is very important for this case. One of the important considerations about gridding in oil reservoirs is to have small enough grid blocks to capture the change in oil saturation where the pressure falls below the bubble point. For this purpose, different grid sizes for choosing the optimum grid size that can capture the saturation change and at the same time does not significantly increase simulation time is tested. Based on the performed sensitivity study, it is found that having 10 by 10 ft grid block is the optimum size that can be selected. Fig. 1 shows that there is not much difference between production profile of grid size with 10 ft (coarse) and 2 ft (fine) width, so 10 ft width can be used without losing the resolution in production performance.
- One extra assumption utilized in this consideration is that each fracture is independent of the other fracture and the interference between different stages is limited. This may not be true; however, to initially understand the uncertainties in individual parameters and their impact on the reservoir performance, single fracture is studied and then their learning are applied to a multi-stage fractured well. This allowed us to save a considerable amount of time in carrying out the simulation. Fig. 2 shows the schematic of multiple fracture stages and area of one no flow boundary element (as a single stage).

### *3.1 Single well modeling*

In this section, the history matching of a single well is illustrated. Available data include core, well dimension and physical locations and the other physical properties of the field as well as production data.

For modeling and history matching of a single well, the following components are employed:

1) Well location and path,
2) Fractures surrounding the well,
3) Well perforation data,
4) Production data,
5) Basic reservoir petrophysical properties.

In all of the single well modeling, well is located at the center of simulation model. Fig. 3 shows a typical well schematic that used in our simulation. It is worth mentioning that according to our experience, using perforation and casing or using open hole well modeling, will cause a negligible change in the flow simulation result. The reason is that almost all the interaction between well and the reservoir is carried through the fractures.

The next step is to assign permeability, porosity and other necessary parameters for simulation of each grid cell depending on whether it is a matrix or a fracture cell and whether it is tensile or shear fracture cell. These assignments were developed in a workflow that automatically generates

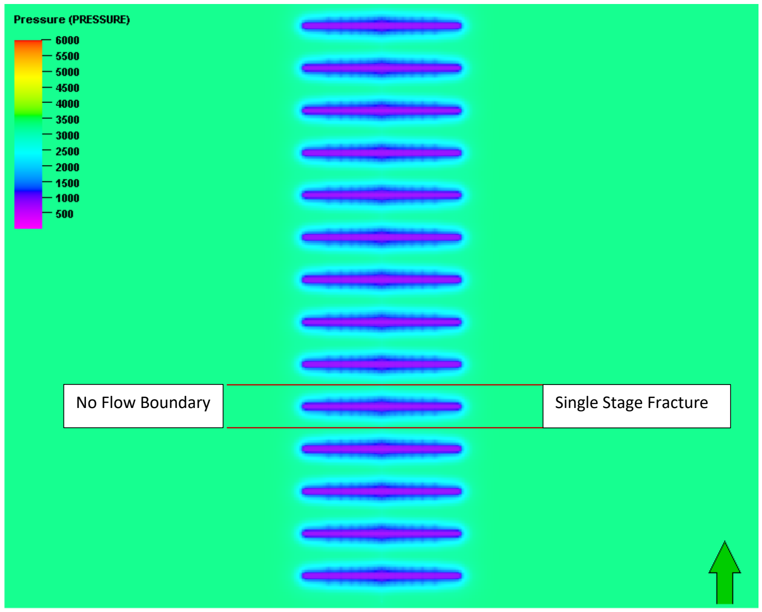


**Fig. 2.** Schematic of no flow boundary between fractures.

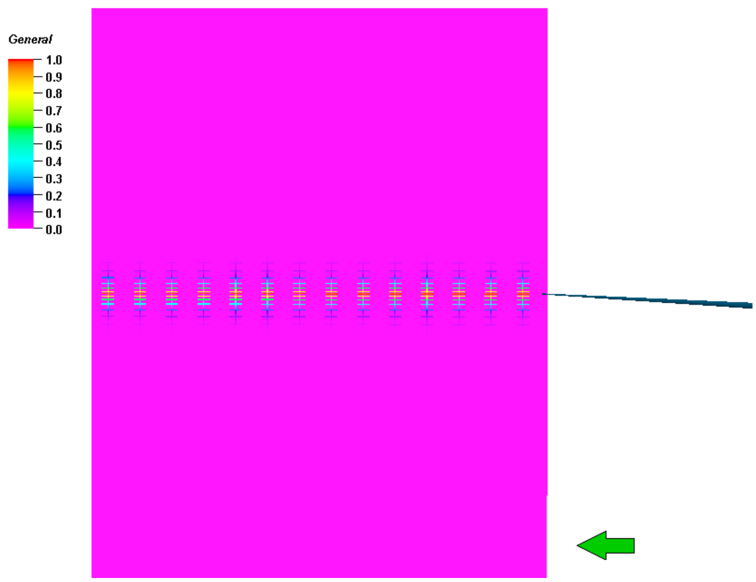


**Fig. 3.** Well schematic of a typical horizontal well (Top View).

porosity and permeability.

### 3.1.1 Example of single well history matching

Well data for nineteen wells is existed and the summary of available wells information is given in Table 2. In this section, the history matching process for well "A" is explained. As previously stated, a general workflow that can be easily applied to other cases is developed. The same procedure was applied for the rest of wells, but history matching results for other wells are not presented in this paper.

To understand the impact of fracture geometry, fracture conductivity, intensity of shear fractures, matrix permeability, and gas and water relative permeabilities, a single well matching is implemented in this section.

Most of our analysis is conducted on a single fracture stage and then is extended to the complete model. In other words, when 20 fracture stages are available, it could be expected that a single fracture should produce $1/20^{th}$ of that total production. In this step, simulation of well "A" with 13 stages and a lateral length of 4,000 ft is investigated.

In a single fracture volume, one segment fracture that consists of 500 by 30 grid blocks is considered. The enhanced permeability has been used for simulating the tensile fractures. For this purpose, a Fortran code is developed that, knowing the position of the well, can generate a desired petrophysical property with different distributions. For example, in this case, the fracture permeability adjacent to the wellbore is 90 md and it decreases to about 0.5 md at the tip of fracture. For the case

**Table 2.** Summary of all available well information in Woodford shale.

| Well Name | GOR Range (MSCF/STB) | Depth (ft) | Length (ft) | Number of Stages | Gas Range (MSCF/D) | Days of Production |
|---|---|---|---|---|---|---|
| 1 | 1-120 | 7400-7600 | 4353 | 14 | 1400-600 | 1080 |
| 2 | 0-70 | - | 4200 | 16 | 2800-800 | 350 |
| 3 | 0-10 | 7900-8100 | 4000 | 15 | 1500-900 | 400 |
| 4 | 0-15 | 8400-8600 | 4997 | 19 | 1600-800 | 250 |
| 5 | 0-30 | 8700-8900 | 4800 | 20 | 2000-1000 | 400 |
| 6 | 0-100 | 8000-8200 | 4200 | 15 | 2500-1300 | 550 |
| 7 | 0-30 | 7200-7400 | 4360 | 19 | | 500 |
| 8 | 0-150 (erratic) | 7500-7800 | 200 | 1 | | 1500 |
| 9 | 0-30 | 6500-6700 | 3256 | 11 | 600-200 | 1400 |
| 10 | 0-80 | 6800-7000 | 4798 | 17 | 2500-1200 | 250 |
| 11 | 0-50 | 5800-6000 | 3453 | 13 | 2000-500 | 1500 |
| 12 | 0-200 | 6800-7000 | 2391 | 7 | 1500-600 | 1400 |
| 13 | Erratic | 8000-8200 | 200 | 1 | | 300 |
| 14 | 0-100 | 7600-7800 | 4000 | 13 | 2500-1300 | 800 |
| 15 | 0-140 | 8200-8400 | 4600 | 20 | 2500-1500 | 300 |
| 16 | 0-120 | 7300-7500 | 3900 | 14 | 2000-500 | 1000 |
| 17 | 1-200 | 7000-7200 | 2683 | 9 | 1200-600 | 1000 |
| 18 | 1-50 | 6100-6300 | 2710 | 10 | 1000-600 | 1080 |
| 19 | 0-16 | 5800-6200 | 4800 | 19 | 1800-1200 | 360 |

of shear fractures, the uniform permeability (1 md) is assigned to model. A shear fracture can help us to get both oil and water matches. Before assigning the permeability and porosity, the reservoir is initialized with water saturation. For initializing the water in the fractures, the higher water saturation near the wellbore and lower water away from the well are used.

In the history matching process, gas production rate is used as a production constraint and oil and water production rates are matched. During this process, it is found that understanding the GOR trend of the reservoir can be very helpful for expediting the process of matching oil rate. For a better understanding of GOR behavior, many sensitivity studies are performed, and results show that the following parameters can increase the GOR:

1) Lower matrix permeability,
2) Smaller fracture half length,
3) Low intensity of shear fractures.

One of the challenges encountered in this study is the fact that in many cases, the GOR behavior of wells were completely different from each other and the length of production history also was different. For quantifying this behavior, a new parameter is defined as follow to represent the change of GOR per day:

$$\triangle \mathrm{GOR} = \frac{\mathrm{GOR}(@t_1) - \mathrm{GOR}(@t=0)}{t_1} \tag{1}$$

where the $t_1$ is the end of production history in days. This number is calculated in the last column of Table 2. Using this value and our knowledge of factors that have the greatest influence on GOR behavior, enabled us to estimate the fracture properties more efficiently. It should be emphasized that the above-mentioned points are only some general guidelines, and for matching each well it is required to look at other parameters and consider the most influential parameters. The summary of tuned reservoir parameters for well "A" is shown in Table 3.

**Table 3.** Well "A" reservoir parameters.

| Parameter | Value |
|---|---|
| Fracture half length | 2,000 ft |
| Fracture permeability | 0.5-100 md |
| Matrix permeability | 100 md |
| Matrix porosity | 4.5% |
| Shear fracture length | 50 ft |
| Reservoir pressure | 3,000 psi |

### 3.1.2 Relative permeability

In this study, it has been observed that the relative permeability is one of the key parameters to capture the production behavior of the reservoir. The typical shape of oil-water and oil-gas relative permeabilities is shown in Fig. 4. In most cases, 20% was considered as the initial water saturation value and the oil relative permeability declined very sharply as the oil saturation decreased.

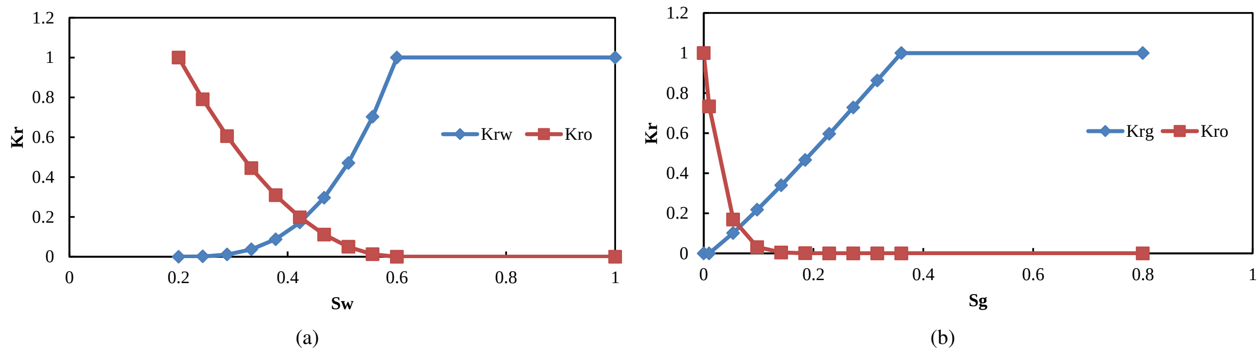


**Fig. 4.** Typical oil-water (top) and oil-gas (bottom) relative permeability in this study.

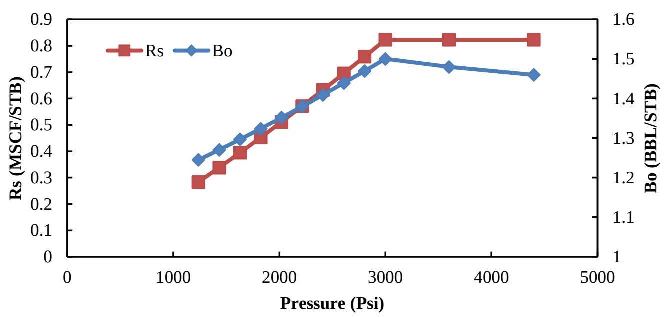


**Fig. 5.** Oil formation volume factor and solution gas of oil sample.

### *3.1.3 PVT modeling*

Another important factor that affects matching the production profile is proper modeling of the reservoir fluid. Regarding the lack of laboratory data, the production data for modeling the fluid is utilized. Also, the initial solution gas is estimated from some of the wells that have almost constant GOR at the beginning of the production. In addition to that, production data tell us that the reservoir pressure is very close to saturation pressure. It is well known that all the reservoirs should be initialized by hydrostatic pressure. Considering these points, the oil sample that used for most of the cases has the bubble point of 3000 psi and the initial solution gas-oil ratio is 830 SCF/STB. The oil formation volume factor and solution gas oil ratio are shown in Fig. 5. Oil viscosity at initial pressure and reservoir temperature is 0.37 cp.

Using all above data, a good match for both water and oil production can be achieved. Fig. 6 shows the history matching results of gas production rate (top), oil production rate (middle) and gas oil ratio (bottom).

### *3.1.4 Well completion and spacing*

This section investigates the impact of fracture density and fracture length on a single well performance. For this purpose, three models with the same fracture volume but different fracture densities are created. Fig. 7 shows the case where three long tensile fractures with fracture half-length of 1200 ft exist. Also, this figure shows six and twelve tensile fractures with fracture half-length of 600 and 300 ft, respectively. To avoid bias, the permeability has been uniformly distributed in

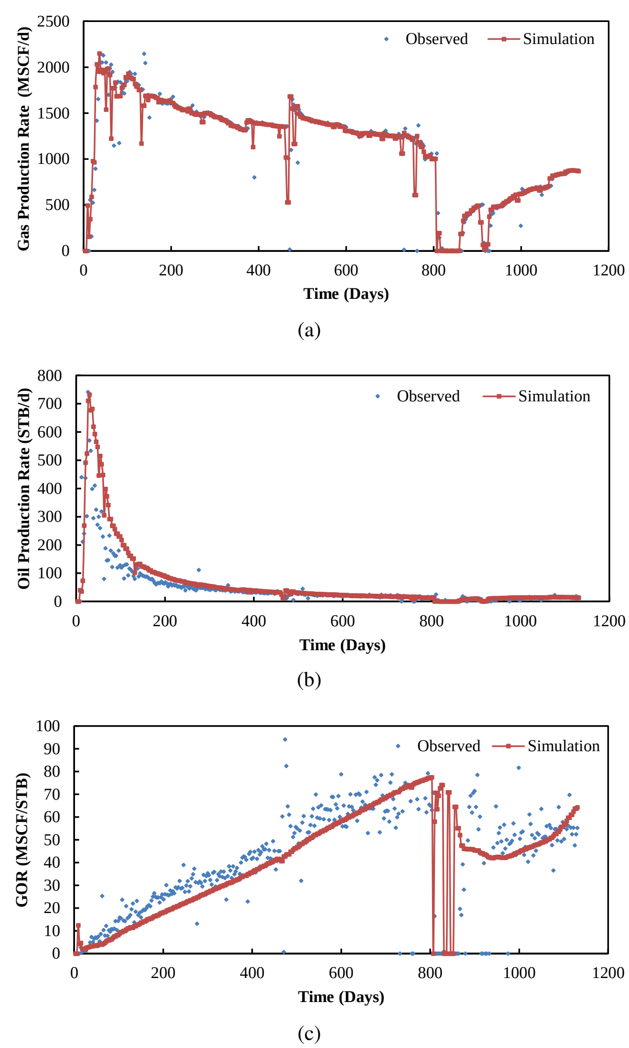


**Fig. 6.** Results of history matching for well "A".

all the cases.

In the next step, simulation models were run for all these three models and the cumulative oil production for all the cases were compared. The results showed that having shorter fractures but more dense fractures can lead to more oil and gas production (twelve short fractures has a 3 and 9 percent production improvement compared to six medium

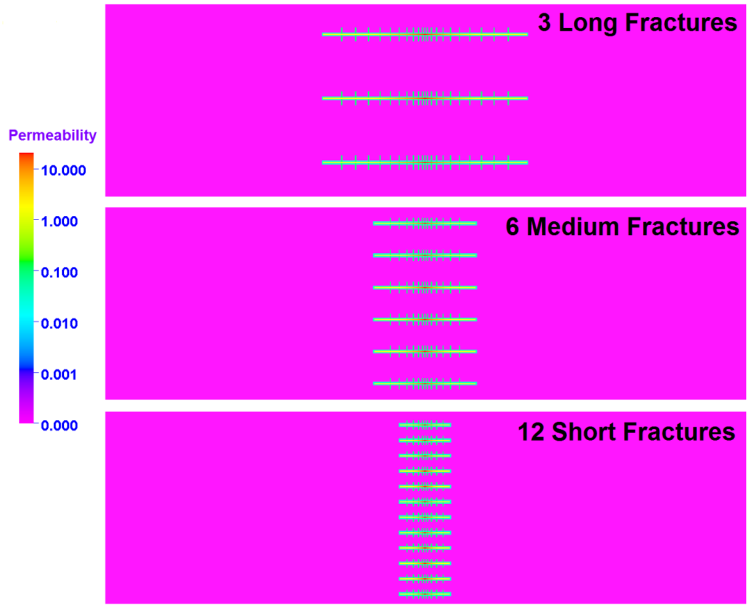


**Fig. 7.** Schematic of 3 long (top), 6 medium (middle) and 12 short (bottom) fractures.

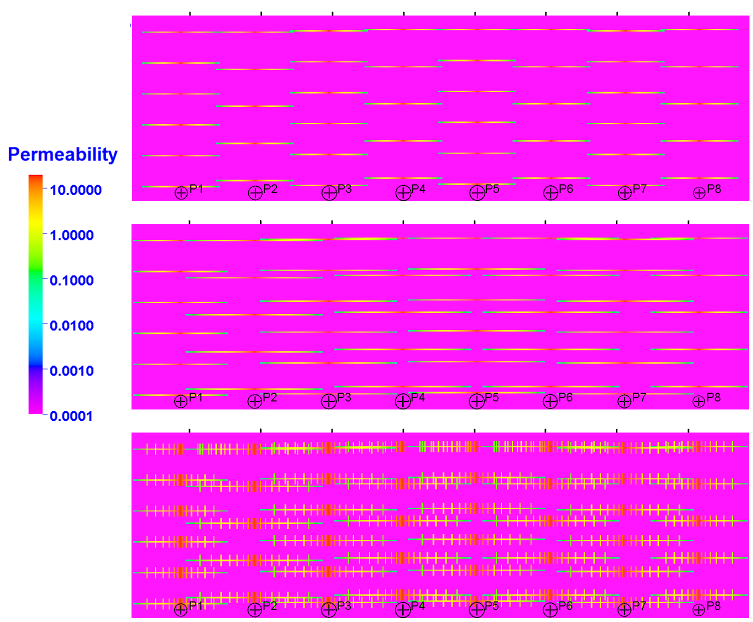


**Fig. 8.** Schematic of 8 wells with FHL = 800 ft (top), 1,400 ft (middle), and 1,400 ft and the existence of shear fracture (bottom).

and three long fractures, respectively). In addition to having higher recovery, smaller fractures also could help us to drill more wells and getting more recovery without unnecessary interference between the wells. This will be discussed in the next section.

## 3.2 Multi-well modeling

The focus of this section is on multi-well modeling. Regarding the lack of multiple well historical data in one segment, our goal is to investigate the performance of multiple well scenarios and find the optimum well spacing under different assumptions. Using the parameters (e.g., fracture length and shear fracture) the sensitivity analysis on the reservoir performance will be examined. This section would provide us with the possible interference between the wells and possible decrease in well Estimated Ultimate Recovery (EUR).

To accommodate multiple wells in a section, a grid dimension of 500 $\times$ 500 $\times$1 is selected. For modeling multiple wells, the FORTRAN code needs multiple-well locations. The wells are oriented in the "J" direction, so the "I" coordinate is provided.

In this section, the well's performance for different fracture spacing and different fracture half-length are assessed. The schematic of 8 wells with different fracture half-length (800 and 1,400 ft) and existence of shear fractures is shown in Fig. 8. As shown at the top of Fig. 9, it can be seen that for the

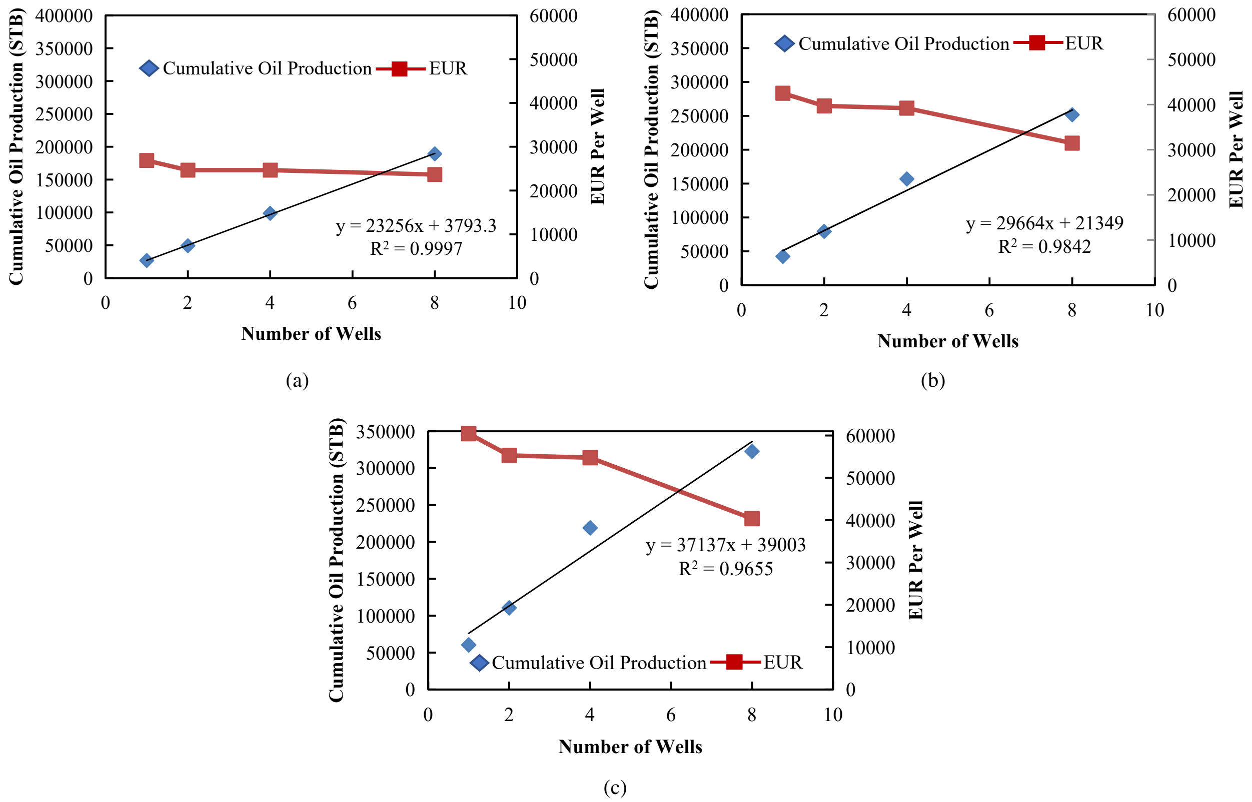


**Fig. 9.** Cumulative Oil production and EUR per well for multiple wells with FHL = 800 ft (top), 1,400 ft (middle), and 1,400 ft and the existence of shear fracture (bottom).

**Table 4.** Effect of different parameters on future well performance.

| Model Name | $K_r$ | $K_m$ (md) | FHL | Fracture Volume | $K_f$ (md) | Comment |
|---|---|---|---|---|---|---|
| S0 | High $S_{or}$ | 80 | 2200 | 657 | 20 | Match |
| S1 | High $S_{or}$ | 270 | 1500 | 465 | 20 | Almost match |
| S2 | High $S_{or}$ | 80 | 1500-shear | 567 | 20 | Almost match |
| S3 | High $S_{or}$ | 80 | 2700 | 651 | 20 | Almost match |

case of smaller fracture length, adding more wells will not reduce EUR per well (red line). However as shown in Fig. 9, for the bigger fracture half length, it can be easily seen that adding more wells will reduce the EUR per well. This observation can be explained by the fact that a larger fracture half-lengths will result in interference between the wells and smaller effective fractured area per well, and consequently the production also will be smaller. This reduction in EUR per well is higher when shear fractures are considered.

In summary, it appears that having a smaller fracture length but more fracture density (smaller fracture spacing), will result in better EUR per section. In conclusion and based on obtained results, smaller fractures with more stages gives better production than longer fractures with fewer stages.

## 4. Uncertainty analysis and future prediction

In this section, the non-unique nature of history matching and its impact on the uncertainty in future production are investigated. The production data of well "B" using four scenarios is matched. In each scenario, different parameters are changed. All cases provide similar production profiles (Fig. 10).

Then, same four models were run to predict the future performance. It has been observed that the uncertainty of future performance is represented by around 10 percent difference between various history matched realizations.

The summary of parameters that have been used in these four models is shown in Table 4.

Looking at Table 4, it can be observed that it is possible to match the performance of a well using multiple parameters combinations. It will get smaller fracture but better reservoir (higher Km) or higher shear fractures to match the data. It should be mentioned that there are certain parameters which cannot be changed where a satisfactory history match in the long run is needed. For example, using lower Sor (residual oil saturation) may provide history matching over a short term but not over a longer time. In summary, four reasonable history matching scenarios for this well are achieved and the

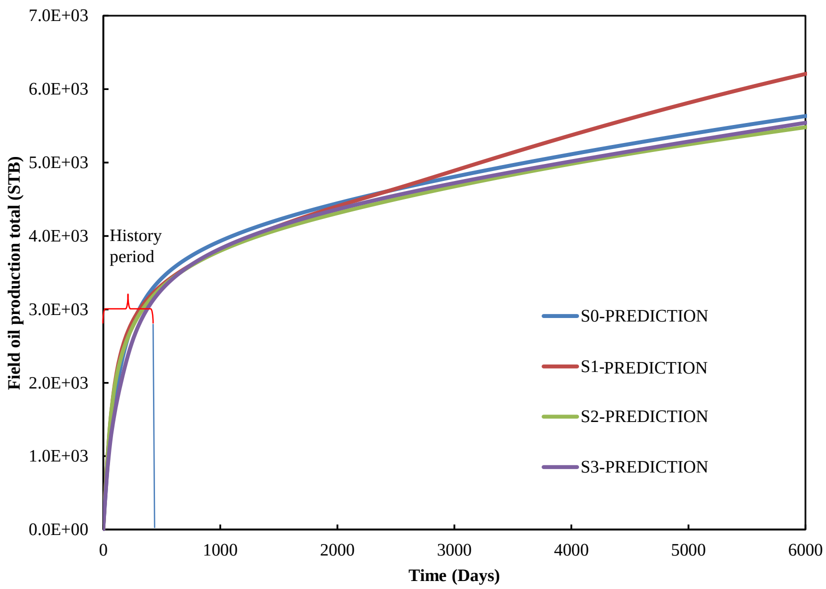


**Fig. 10.** Four possible scenarios for prediction of cumulative oil production from one stage of well "B".

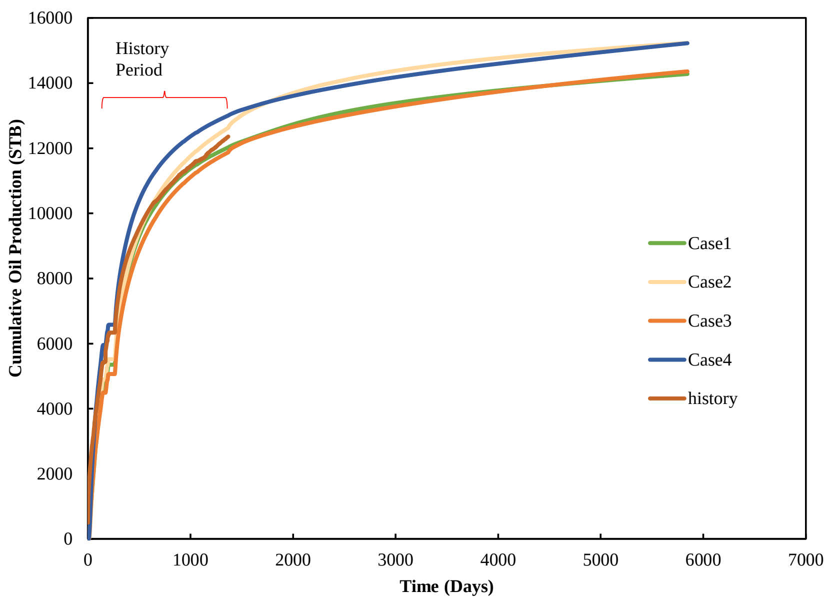


**Fig. 11.** Four possible scenarios for prediction of cumulative oil production of well "C".

specification of each scenario including permeability, FHL and fracture volume are reported in Table 4. In Fig. 11, cumulative oil production (both history and prediction) of these scenarios is depicted. It can be seen that although almost all give a reasonable match for history, but future predictions are different which demonstrate that uncertainty existed in different history matched model. A similar uncertainty analysis is carried out for well "C". As it can be seen in Fig. 11, a reasonable match by different combinations (four combinations) of fracture permeability, matrix permeability, fracture half-length and shear fracture can be achieved. Running future predictions of all possible scenarios provides similar results with about 10 percent difference.

It is worth reporting that uncertainty analysis is mainly performed for a single well model. In a single well model, various combinations of fracture lengths can provide the same future performance; however, that may not be true for multiple well matches. In a section where multiple wells exist, it is possible that fracture length can have a significant impact on the interference between the wells which can result in different observed rates in the future. In fact, degrees of freedom are less when conducting multiple well matches. This is not true for a single well scenario. In addition, the bottom hole pressure data were not available for these wells. In case the bottom hole pressure data is available, matching the Bottom hole pressure can make the models more restrictive and more realistic. Although it is hard to believe that once the match is achieved, the results of the future prediction would be substantially different. It is also important to emphasize that the changes in relative permeability are very difficult to make and still achieve a reasonable history match. In other words, for a given well, there is a very close to unique relative permeability set we need to use to get a good history match.

## 5. Conclusions

In this study, oil production of multiple shale oil wells in Woodford shale is investigated. Many wells were history matched. The observed behavior of the wells can be significantly different even though the wells are physically very close to each other. In some wells the GOR has increased dramatically (200 MSCF/STB) and in other cases, the GOR change was much lower. During this study, it has been shown that this behavior cannot be captured without using the proper rock properties and fracturing parameters.

It was found that the relative permeability with high residual oil saturation (35-45%) has a crucial role for capturing the production data. In addition, the fracture geometry plays an important role in determining the production behavior. It has been shown that the fracture half length, shear fracture and the interaction between matrix and fractures should be precisely captured. In our modeling procedure, the enhanced permeability is utilized to simulate the hydraulic fracture. Also, it can be assumed that the fracture permeability varies along the length with higher permeability at the heel and lower permeability at the toe of the fracture.

The results showed that the well behavior can be captured by using multiple combinations of fracture length, fracture permeability, shear fracture frequency, reservoir permeability and relative permeability. However, once the history match is obtained, the uncertainty in the prediction of future performance is within 10 percent. The importance of understanding the fracture length and fracture frequency on infill well performance is demonstrated in this study. Based on the results, adding more stages with smaller lengths is recommended rather than having longer fractures with fewer stages.

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## Conflict of interest

The authors declare no competing interest.



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