Utilizing Reservoir Model to Optimize Future Oil Production for Hydraulic Fracture Wells in Tight Reservoir

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Abstract
The tight oil reservoir has low porosity and permeability generally suffers from rapid declines in production rates for oil wells, especially in southeast Iraq in the Halfaya oil field of the Sadi Formation, which is considered as tight oil reservoir with a reserve of about 25%; their OOIP accounts for more than a quarter of the total in the H oilfield. Implementing a pilot hydraulic fracture technique was a focus of attention in Iraq to increase the production rates, but the main issue faced in hydraulic fracturing wells was producing with a high oil rate for a short period of time then starting to decline rapidly, so a reservoir dynamic model was utilized to achieve the purpose of this study. The purpose of this study is to predict the production rate to prolong the production stabilization in horizontal and vertical hydraulic fracturing wells in order to avoid highly depleted fracture storage capacity and production below the bubble point. Recognize a practical procedure with horizontal hydraulic fracturing wells to reach stabilization. The reservoir simulator results show that a good history matches till 2021, predicting the rates that stabilize the production with flowing pressure above the bubble point pressure till 2025, producing rates for an eight-stage well with 700 BOPD and 900 BOPD for an eleven-stage well, whereas the rate for a vertical hydraulic fracture well is 225 BOPD. A practical procedure in horizontal hydraulic fracturing wells is achieved by keeping the wellhead pressure constant during the production period to stabilize transient behavior.

Keywords: Reservoir modelling; Hydraulic fracturing optimization; Tight oil reservoir

1. Introduction
One of the Halfaya oil field is the Sadi Formation, which is considered as a giant limestone reservoir. It is located in Missan province in southeast Iraq, about 35 km away from Amara City, the capital of Missan province, as shown in Fig. 1. It has a general NW-SE long axis anticline, and the dip angle of the two central wings is 2–3 °. The Sadi Formation pay zone is divided into three layers: B1, B2, and B3. The original oil in place of the Sadi is 19.14 million barrels, the second reserve after mishrif reserve (the main reserve of Halfaya oil field).
However, the Halfaya oil field met the peak output objective; the contractor company in the field required to sustain peak production according to the contract, although there were comparisons of investment between conventional oil and unconventional oil (Kleinberg et al., 2018), implying production dynamics for tight oil are substantially more rapid. This may lessen the risks associated with locked-in capital and have resulted in a more elastic product, in spite of high capital investment, but Khan et al. (2011) conducted an intensive analysis of the effects of drainage areas on production performance and concluded that a multifracture horizontal well has flow rates many times higher than a vertical fracture well, making it the only decision in an exact tight formation. Also Beyadi et al. (2012) stated that to achieve economic production from shale formations, massively stated that horizontal wells are the most effective in providing access to the formation, also recognizing the following:

a. The behavior of prompt production is organized via the features of the basin interior like the amount, position, and half-length of hydraulic cracks.

b. The exterior reservoir characteristics, particularly fissure permeability and porosity, govern late production.

c. The features of the basin inner during prompt production and the basin external during later production affect the gas desorption.

d. The linear flow's duration shortens with a growth in the number -stages.

e. Boundary effects may be brought on by interfering with other hydraulic cracks and the reservoir external.

On this basis, significant challenges must also be dealt with for their successful development. The first pilot hydraulic fracture research was conducted on a successful pilot hydraulic vertical well in southern Iraq in December-2016, followed by the first pilot horizontal hydraulic fracture well in Iraq.
with a multi-stage (eight-stage) fracture in December-2019, and followed by a multi-stage (eleven-stage) fracture in December-2020, all with the goal of improving well productivity and investigating the overall production mode of the Sadi reservoir. Generally, natural wells in the Sadi formation are produced with a fluctuating low flow rate and shut-in for pressure build-up from time to time due to no flow. Also, production rates drop quickly in hydraulically fractured wells, which is the main problem that needs to be solved. Before hydraulic fracturing was implemented in December-2016, the production contribution was only 0.5% of total oilfield production.

In the previous studies on the Sadi Formation, Farouk and Al-Haleem, (2022) created the fracturing models with the aid of diagnostic fracture injection test (DFIT) analysis to predict that the breakdown pressure of the Sadi B reservoir reflects that this reservoir could easily be fractured by inserting pressure equal to 6250 psi. Also, Fayadh, (2020) stated that when optimizing hydraulic fracture properties for the Sadi reservoir in the southeast of Iraq using simulation software, she discovered the best increase in oil production is achieved with a fracture width of 15 mm and a half-length of 225 to 275 meters. It appears that eight and ten fracture phases are optimal, after which the output surge starts to diminish.

Most of the porosity within the lower part of the Sadi Formation was formed by diagenesis processes described (Myzban et al., 2022). The inner ramp facies of the lower Sadi Formations have the best reservoir quality in terms of porosity and permeability distribution, and these facies reflect the system of shallowing upwards; these facies of this paleoenvironment are evidence of the regression in the lower Sadi Formation. The deposition environment was articulated as part of the homoclinal ramp.

As for other studies, Allan and Qing, (2003) studied the effects of recovery factors by classifying fracture oil sources that have undergone fracturing. Fractures predominate in type: Type one has poor matrix porosity and permeability, storing capacity, and fluid movement paths. Type two has little porosity and permeability of the matrix, but in this case, the matrix serves as a storage medium, and the fractures operate as channels for fluid flow. Microporous reservoirs of type three have high matrix porosity but low matrix permeability, favoring induced fractures over other types of fractures in the direction of fluid flow. Macroporous reservoirs of Type IV have high matrix porosity and permeability; as a result, the matrix supplies flow pathways and storage capacity together, whereas fractures merely increase permeability. Also, the U.S. Energy Information Administration (EIA), (2013) explained that the recovery in the interior of a field or nearby well might differ, as can recovery even within a single horizontal drill hole. This makes it challenging to assess plays and judge the wells' profitability on a specific lease. In order to move the oil toward the borehole and produce oil from tight formations, there must be no less than 15% to 20% of natural gas in the reservoir's pore space. Tight reservoirs that exclusively contain oil cannot be produced profitably, making them more appropriate for fracturing. The U.S. National Committee for Rock Mechanics, (1996) explained that the fracture properties could change during the basin operation due to fluid pressure variations and mineral precipitation. Reduced pressure caused by fluid abstraction from the basin can cause fractures to close. Fluid boosters into the reservoir, on the other hand, can cause pressure to rise, exposing fractures. behavior is hard to forecast because the association between stress and permeability is multifaceted and highly dependent on temperature. The behavior of tight oil reservoirs was comprehended throughout the transient linear flow period, and a theoretical foundation was developed (Selley and Sonnenberg, 2015), as reservoir pressure drops below the bubble point, a two-phase flow develops due to tight oil production combined with high-pressure drawdowns. Several studied on the behavior of production in tight oil reservoir (Tabatabaie and Pooladi-Darvish, 2017; Dong and Wang, 2018; Jalil, 2015; Shahamat et al., 2015; Selley and Sonnenberg, 2015). The prediction of reservoir performance and an explanation of that prediction is considered a model in the field of petroleum reservoir development (Yu and Sepehrnoori, 2018; Ozkan et al., 2011; Barroux et al., 2000; Guo et al., 1997).

The aim of this paper is to study the geological structure and use a dynamic reservoir model to get the fit history matching on hydraulic fracture wells so that we can implement different manually
produced scenarios to conduct the optimum flow rate, which is accepted from an economic and operational standpoint, and also to advise future hydraulic fracture wells to follow a certain procedure of production.

2. The Gridding System

A cartesian grid system is constructed; the X-axis is perpendicular to the field axis, and the Y-axis is parallel. The three-dimensional modeling is done on grids (200 x 320 x 4) in the X, Y, and Z directions. The reservoir is divided into four layers: the Sadi B-1 unit, the Sadi B-2 unit, the Seal rock, and the Sadi B-3 unit on the geological map with a gridding system in 2D and 3D, as illustrated in Figs. 2 and 3, respectively.

![Fig. 2. Grid system for the Sadi reservoir in 2D map](image-url)
3. Formation Characteristics

The Sadi reservoir is a limestone reservoir composed primarily of calcite, dolomite, quartz, and other mineral components (Jassem and Goff, 2006). It is divided into four layers: Sadi A, B1, B2, and B3, as shown in Fig. 3. Sadi A has an average thickness of 50.6 m but contains marl and no oil; Sadi B is the main oil-bearing series, with a total thickness of about 75 m and a top grid of about 2670 m. The Sadi formation was mainly developed in the third-order sequence, with the sea level increasing gradually toward the upper depositions. Sadi B1 and Sadi B2 have apparent "three-section" characteristics for lithology distribution, and the pore types are mainly unconnected intra-fossil pores and inter-crystal micropores. They were deposited in the outer ramp environment, where the water energy was very weak. Sadi B3 mainly comprises oolitic packstone and skeletal intraclasts, packstone with mouldic/dissolution pores, comingled with marlstone. It was deposited in shoal and shoal flank environments with unstable water energy.

4. Environmental Criteria of the Sadi Reservoir

Sadi B1 is on the gentle outer slope, with no large biological debris input and weak hydrodynamic conditions, and belongs to planktonic foraminiferal limestone. Sadi B2 is a planktonic foraminiferal packstone or a packstone with a single biological fossil found on the gentle middle slope of a low-energy debris-generating beach. Sadi B3 is mainly deposited in the inner gentle slope environment and is composed of bioclastic, intraclasts, in-situ organisms, oolitic, and other granular marl. Based on cores and thin sections, the lithology of the Sadi-B formations has been studied (Petrochina Comp., 2012).
The quality of the rock in the Sadi-B formation varies vertically. The cores of Sadi-B1 and Sadi-B2 are still stained with oil despite being relatively tight. The pores in the cores of Sadi B3 are bigger and have a good oil stain. There are three types of Sadi shale: Sadi-A, which is a medium gray, soluble calcareous shale; Sadi-B1, which is mostly bioturbed wackestone; and Sadi-B2, which is mostly bioturbed packstone with pelagic foram chondrites, which are either dolomitized or pyrite cemented. There is shale in Sadi-B3 that contains smectitic rock and pyrite, as well as oolitic and skeletal intraclastic rock. Sadi-B3 also features pebbles, oolitic rock, black grain (pyrite), and chondrite. For more illustration, Fig. 4 depicts the profile of the Halfaya oil field along the structure.

![Fig. 4. Oil reservoir profile along the structural axis of Halfaya Oilfield (PetroChina comp., 2012)](image)

5. Petrophysical Properties

Sadi B1 has an average porosity of 20% and an air permeability of 0.07 mD. Sadi B2 has a porosity of 21% and a permeability of 0.05 mD. Sadi B3 has a porosity of 18% and a measured permeability of 3.2 mD; both porosity and permeability are shown in Figs. 5 and 6. All these properties are input as average values in the reservoir simulator software, However there is some uncertainty, but these properties are almost identical.

The porosity cut-off values were 8% to 12% for Sadi B1 and B2 and 10% for Sadi B3. In general, Sadi B1 and B2 are medium-high porosity and ultra-low permeability limestone reservoirs, and Sadi B3 is a medium-porosity and ultra-low permeability limestone reservoir.
**Fig. 5.** The porosity of Sadi Formation in 3D map

**Fig. 6.** The Permeability of Sadi Formation in 3D map
5.1. Fluid Properties

The reservoir contains subsurface crude oil with a viscosity of approximately 0.81 cp, classifying it as a low-viscosity unsaturated reservoir. The specific gravity of crude oil is 1.17, the formation water has a pH value of 6.30, the sulfur content is 3.70%, the wax content is 1.6%, the crude oil GOR is approximately 868 SCF/bbl, and the total salinity is 220,104 ppm. The reservoir temperature is 87 degrees Celsius, and the initial pressure is 4846 psi. In the Sadi region, the irreducible water saturation of rock phase permeability is 0.07%, whereas the residual oil saturation is 30.96%, as illustrated in Fig. 7.

![Relative permeability of the Sadi Formation](image)

Fig. 7. Relative permeability of the Sadi Formation

5.2. Rock Properties

The rock compressibility assumed that the rock types are not highly compact, so the rock compressibility used in the model was $4.7 \times e^{-0.06}$ 1/psi.

Wettability test method of reservoir rock wettability with the actual characteristics of the Halfaya oil field, it has developed an imbibition flow displacement method (Amott/USBM composite method) from a core depth of 2715 m to complete the following experiment. The wettability of the rock might be classified as weak to medium hydrophilicity, Amott wettability index gave -0.259 (weakly oil-wet), and the USBM wettability index gave -0.004 (weakly oil-wet).

The Capillary Pressure was tested on Sample depth of 2757.30 m, the average pore-throat radius is $-0.1 \mu$m with Measured high Mercury injection pressure. The following draw illustrates more clearly for drainage and imbibition process, as shown in Fig. 8
6. Summary of Wells Data

The available wells completion data utilized till the end of the year 2022 was concluded in the below Table:

Table 1. The Sadi wells completions data

<table>
<thead>
<tr>
<th>Wells</th>
<th>Type</th>
<th>Formation</th>
<th>Completion Interval, m-MDRT</th>
<th>NetPay, m-MD</th>
<th>Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>W-5</td>
<td>Hydraulic fracture</td>
<td>Sadi B2</td>
<td>2926 – 3737</td>
<td>811</td>
<td>Poor Oil</td>
</tr>
<tr>
<td>W-6</td>
<td>Hydraulic fracture</td>
<td>Sadi B2</td>
<td>3051.55 - 4055.8</td>
<td>1004.3</td>
<td>Poor Oil</td>
</tr>
<tr>
<td>W-55</td>
<td>Hydraulic fracture</td>
<td>Sadi B1, B2, and B3</td>
<td>2701 - 2724, 2726-2746, 2749 -2755, 2763 -2769</td>
<td>20, 6, 6</td>
<td>Poor Oil</td>
</tr>
</tbody>
</table>

6.1. Horizontal Hydraulic Fracturing Wells Data

The data used in the simulator for the four hydraulic fracturing wells was first horizontal hydraulic with eight-stages of W-5 with open hole multi-stage fracturing and penetrated the Sadi B-2 formation with a length of 811 m, as shown in Fig. 9, while the fracture properties data provided from PetroChina, 2012, is in Table 2.

Table 2. Horizontal fracture properties of well (W-5)

<table>
<thead>
<tr>
<th>Stage Num.</th>
<th>Fcd mD*m</th>
<th>Kfrac mD</th>
<th>Frac. half-length Ft</th>
<th>Closure width ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stage1</td>
<td>355.52</td>
<td>149378.2</td>
<td>241.08</td>
<td>0.0078064</td>
</tr>
<tr>
<td>Stage2</td>
<td>417.67</td>
<td>152992.7</td>
<td>218.12</td>
<td>0.0089544</td>
</tr>
<tr>
<td>Stage3</td>
<td>434.25</td>
<td>202920.6</td>
<td>162.36</td>
<td>0.0070192</td>
</tr>
<tr>
<td>Stage4</td>
<td>344.75</td>
<td>131584</td>
<td>227.96</td>
<td>0.0085936</td>
</tr>
<tr>
<td>Stage5</td>
<td>375.41</td>
<td>137512.8</td>
<td>211.56</td>
<td>0.0089544</td>
</tr>
<tr>
<td>Stage6</td>
<td>365.47</td>
<td>143885.8</td>
<td>224.68</td>
<td>0.0083312</td>
</tr>
<tr>
<td>Stage7</td>
<td>373.75</td>
<td>166111.1</td>
<td>218.12</td>
<td>0.00738</td>
</tr>
<tr>
<td>Stage8</td>
<td>384.53</td>
<td>188495.1</td>
<td>236.16</td>
<td>0.0066912</td>
</tr>
</tbody>
</table>
Moreover, the second horizontal hydraulic fracture of W-6, which has eleven-stages, penetrated the pay zone with 1004 m, as illustrated in Table 3 and the simulator view in Fig. 10.

**Table 3.** Horizontal fracture properties of well (W-6)

<table>
<thead>
<tr>
<th>Stage Num.</th>
<th>Fcd D*cm</th>
<th>Kfrac md</th>
<th>Frac. half-length Ft</th>
<th>Closure width ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stage1</td>
<td>29.4</td>
<td>117131.474</td>
<td>201.392</td>
<td>0.0082328</td>
</tr>
<tr>
<td>Stage2</td>
<td>29.5</td>
<td>103508.772</td>
<td>210.74</td>
<td>0.009348</td>
</tr>
<tr>
<td>Stage3</td>
<td>29.7</td>
<td>133783.784</td>
<td>211.232</td>
<td>0.0072816</td>
</tr>
<tr>
<td>Stage4</td>
<td>30.4</td>
<td>116475.096</td>
<td>210.084</td>
<td>0.0085608</td>
</tr>
<tr>
<td>Stage5</td>
<td>30.2</td>
<td>108243.728</td>
<td>213.364</td>
<td>0.0091512</td>
</tr>
<tr>
<td>Stage6</td>
<td>30</td>
<td>106382.979</td>
<td>212.544</td>
<td>0.0092496</td>
</tr>
<tr>
<td>Stage7</td>
<td>30.5</td>
<td>108540.925</td>
<td>211.56</td>
<td>0.0092168</td>
</tr>
<tr>
<td>Stage8</td>
<td>30.9</td>
<td>146445.498</td>
<td>213.856</td>
<td>0.0069208</td>
</tr>
<tr>
<td>Stage9</td>
<td>32.1</td>
<td>109931.507</td>
<td>212.052</td>
<td>0.0095776</td>
</tr>
<tr>
<td>Stage10</td>
<td>32.9</td>
<td>112286.689</td>
<td>212.38</td>
<td>0.0096104</td>
</tr>
<tr>
<td>Stage11</td>
<td>33.2</td>
<td>114482.759</td>
<td>211.888</td>
<td>0.009512</td>
</tr>
</tbody>
</table>
6.2. Vertical Hydraulic Fracturing Well Data

The vertical hydraulic fracture properties of the well (W-55) are illustrated in Table 4, and the simulator view is in Fig. 11.

Table 4. Vertical fracture properties of well (W-55)

<table>
<thead>
<tr>
<th>Stage Num.</th>
<th>Fcd</th>
<th>Kfrac</th>
<th>Frac. half-length</th>
<th>Closure width</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>mD*m</td>
<td>mD</td>
<td>m</td>
<td>mm</td>
</tr>
<tr>
<td>Stage 1,2,3</td>
<td>2070</td>
<td>739285.7</td>
<td>22.8</td>
<td>2.8</td>
</tr>
</tbody>
</table>
7. Reservoir Modeling

7.1. History Data Preparation

7.1.1. Flow rate

The oil and gas flow rate was prepared by test separator measurement by monthly periodic scheduling, test separators measured the flow rate for both oil and gas by diverting the well for a 6-hour duration inside the separator then multiple by 6/24 to represent hole day. Oil and gas rate are measured by a flow meter set on the output pipe by 2 inches or 4 inches, depending on the amount of oil or gas entry.

7.1.2. Bottom hole pressure

In order to activate the well head pressure to bottom hole pressure calculation well modelling by converting the pressure and temperature with relative oil and gas rate using the rough approximate method for each well. A simulator well model built by defining four main components that affect a well’s performance, these are:

- The PVT
- The well equipment
- The reservoir inflow data
- And if required, artificial lift data
7.2. History Matching Process

One of the most difficult parts of simulator software is getting the best identical matching in existing high uncertainty in tight oil reservoir because of

- Reservoir heterogeneity,
- Converting the well head pressure to bottom hole pressure by a simulator well model as illustrated in section 9.1.2.
- Flow rate measured through the test separator sometimes does not represent reality due to the operation condition.
- Considering straight fracture length, and the problem of producing Proppant from fracture through production,
- Operation condition (wellhead reading, choke size, and separator test accuracy) all of these are high uncertainty to overcome of it.

The history match of Sadi wells (W-5, W-6, and W-55) till the end of the year 2021 as shown in Fig. 12, 13, and 14 respectively show identical matching with a very small percentage of anomalies and randomness due to the uncertainty.

8. Reservoir Optimization Process

A dynamic reservoir model incorporates a new hydraulic fracture technique to predict production rate with flowing pressure above the bubble point pressure from last production period of year 2022 till 2025, these wells is wells (W-5, W-6, and W-55) as illustrated below:

The well (W-5) shows a good history match till end of production in 2021 then predict to producing with oil rate of 700 BOPD till end of 2024, Fig. 12 shows a constant oil rate with increasing in bottom hole pressure above the bubble point pressure.

![Graph](image)

**Fig. 12.** History matching and producing prediction of well (W-5)
Also, well (W-6) shows a matching in flowing pressure and historical bottom hole pressure, as shown in Fig. 13. However, some historical bottom hole pressure points at the beginning of July-2021 show poor matching, this is because of the gas metering in the test separator gives a high gas rate reading, then after converting the wellhead readings with oil and gas flow rate reading into bottom hole pressure gets an error reading.

Conducting production rate 900 BOPD leads to a little bit of the bottom hole pressure staying in increasing mode only for a half year, and then the flowing pressure decreased to hit the bubble point pressure at the beginning of the year 2025, as shown in Fig. 13. So, there are options to decrease the oil production rate to sustain the pressure above the bubble point pressure or resume to re-evaluating a new oil production rate and put condition to producing above the value of bubble point pressure. Here we can recognize that oil rate 900 BOPD form eleven-stages is greater than eight-stages with 700 BOPD, so increasing the number of fracturing stage lead to increasing the production rate.

![Fig.13. History matching and producing prediction of well (W-6)](image)

Before doing hydraulic fracturing of the well (W-55), there was no identical matching before hydraulic fracturing as shown in Fig. 14, because of the low differential pressure via reservoir simulator to deliver these rates, In contrast, the calculated history bottom hole pressure via well model as illustrated in green balls which consider low. The input formation skin damage before doing hydraulic fracturing is five but still there is no identical matching before doing fracking, while after doing hydraulic fracturing in 21-December-2016, there is a matching with less anomaly in some flowing pressure reading.
Producing oil rate with 225 BOPD by solid yellow line as shown in Fig. 14 which achieve the flowing pressure above the bubble point pressure, the flow rate increases gradually to 225BOPD which consider uneconomically.

The second suggestion is keeping the well producing with last rate of year 2022 which is equal to 385 BOPD as illustrated in green solid line, so high suggested oil rate for vertical hydraulic fracture can not achieved because of the little contact area with pay zone also proppant exit during the production will reduce fracture storage capacity.

![Well Performance Graph](image)

**Fig. 14.** History matching and producing prediction of well (W-55)

### 9. Conclusions

Hydraulic fracture wells in unconventional reservoirs have suffered from a rapid decline in production and flowing pressure, horizontal hydraulic fracturing wells produce a high oil rate at the beginning, then continuously decrease due to high liquid depletion from fracture storage without enough liquid compensation from the reservoir into the fracture.

The optimum flow rate that will satisfy stability from end 2021 until the year 2025 is 700 BOPD for well (W-5) and 900 BOPD for well (W-6), whereas the vertical hydraulic fracturing well producing high oil rates for a short period of time then rapidly declining, most production periods are below bubble point pressure, and the oil rate of 225 BOPD achieves the constraint of producing above the bubble point pressure, but this rate is considered inequitable or keeping the last production rate 385 BOPD with flowing pressure below bubble point pressure. The production rates for horizontal hydraulic fracturing
wells is more than three time bigger the producing from vertical hydraulic fracturing, so it is proper to implementing horizontal hydraulic fracturing technique in the Sadi Formation especially in Sadi B2.

A practical procedure can be used in the absence of the simulator software for extending production as long as possible at economic rates by keeping the tubing head pressure at the surface stable by re-adjusting the choke size every time, once we see the wellhead start decreasing.

References


