INTRODUCTION

The most common stimulation technique of shale production is a multistage hydraulic fracture. This process involves pumping large volumes of water with different types of proppants, and other additives into the rock at high pressures. Slick water-based fracturing fluid is usually used in this process by injecting
produced or freshwater at a high injection rate with adding friction reducers (Ibrahim and Nasr-El-Din 2019). Polymer and foam-based fracturing fluids can also be used (Emrani et al. 2017).

The most important factors governing hydraulic fracture propagation are completions and treatment design, in-situ stresses, and reservoir heterogeneity at different length scales (including natural fractures and bedding planes). In an ideal situation, all fractures in the same stages should be of similar size and conductivity. In the conducted hydraulic fracture operations and simulation, even keeping the same fluid and proppant design, the created fracture system will not be ideal (Spain et al. 2015). It has been well documented that in depleted reservoirs, stress changes arising due to reservoir drainage significantly affect the growth of fractures and attract them towards the depleted regions (Agrawal and Sharma 2018). This stress alteration allows the child well fracture to interact with multi-stress zones, which ultimately affects the growth rate and final geometry of the fracture. The result is a nonuniform growth profile of the child well fracture (Guo et al. 2017, 2018). During hydraulic fracturing, tip energy is usually diverted towards the parent well, due to the reduction of localized stresses caused by production, which may lead to a direct communication event. However, a direct communication event is not always the case (Mayorga and Coenen 2019).

Estimating fracture geometry and stimulated reservoir volume (SRV) is a focal parameter to judge the fracture operation and predict the well performance. Different techniques can be used to evaluate the fracture operations such as radioactive chemical tracers (Scott et al. 2010, Tian et al. 2016). In recent years, chemical tracer has been applied in hydraulic fracture diagnosis to provide a local measurement of the fracture at the wellbore. Many projects used this technique to evaluate the contribution of each fracture stage to the total hydrocarbon production in a multistage horizontal well and to understand the communication between the fractured wells (Tian et al. 2016). However, the application of chemical tracer to estimate fracture volume is limited. Real-time microseismic monitoring (Gutierrez Murillo et al. 2010), and fiber optics (Pakhotina et al. 2020) are other methods that can be used for fracture geometry diagnostics and image the fracture from far-field. Microseismic fracture mapping and downhole tiltmeter are far-field techniques which can provide image and details about fractures orientation and dimensions by detecting induced microseisms and deformation. However, the limitation of these techniques is that they can only map the total extent of hydraulic fracture growth, not the effective propped fracture length or conductivity. Additionally, the resolution will be affected by fracture treatment, reservoir properties, and the distance to the detected wells.

**Fig. 1** show two different fracture system in a single stage with five clusters per stage (Spain et al. 2015). Due to the stress shadow effect and stress changes, the created fracture for each cluster was not the same. The complex fracture systems in the current study were used in the same profiles.

Rate transient analysis (RTA) and pressure transient analysis (PTA) are indirect methods that can be used for fracture diagnostics and estimate the fracture and formation parameters.
This study investigates the performance of shale gas wells with different fractures systems with the same fracture surface area. RTA and PTA were used to analyze the production and the shut-in data to estimate the effective production surface area for each fracture system.

**Methodology**
A numerical simulator was used to generate production and pressure build-up data for a multi-fractured horizontal well in shale formation. Different scenarios were used in the fracture completion with one stage length of 200 ft and five clusters per stage. The total fracture length was 1000 ft. **Table 1** shows the grids size and formation properties. A simple model (uniform fracture length), and Complex (Varies fracture length) model scenarios were used with keeping the total fracture length constant. **Fig. 2** shows the different completion scenarios.

The fracture surface area (FSA) can be calculated as follows.

$$FSA = 4 \times h_f \times \sum_{1}^{N_f} X_f$$

(1)

Where; $h_f$ is the height of the fracture, $N_f$ is the number of fractures, and $X_f$ is the fracture half-length. As the total fracture length in the different scenarios was the same, the FSA in the different scenarios was the same and equals to 9.18 Acre.

<table>
<thead>
<tr>
<th>Table-1 Formation and fluid properties for the simulation cases.</th>
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<tbody>
<tr>
<td>Stage length, ft</td>
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![Figure 2 - Schematic for the different completion scenarios, A-simple fracture system (Case 1), B, C-complex fracture system (Case 2, 3), and D- conjugated fracture system.](image-url)
Rate Transient analysis was conducted on the production data to estimate the completion and the formation properties based on the available flow regimes.

Pressure transient analysis was conducted on the buildup data. The diagnostic plot was used to identify the flow regime in each scenario, and the data were matched to estimate the effective fracture half-length using Kappa Software.

**Fig. 3** shows the cumulative gas production from different scenarios. Even for the same fracture surface area (FSA), the cumulative gas production for cases 2, 3, and 4 were higher than the production from case 1 by 10.7, 28, and 10.5%, respectively.

![Figure 3](image-url)
RTA

In RTA for gas wells, bottom-hole pressure, \( p_{wf} \), was converted to pseudo pressure, \( m(p_{wf}) \). The pseudo pressure difference was then normalized using the gas production rate. The normalized pseudo pressure difference and linear superposition time (super-\( t \)) were used to plot the RTA for \( A_c \) characterization (Malallah et al. 2007a, 2007b). Normalized pseudo pressure and linear superposition time were calculated as follows.

\[
\text{Normalized pseudo pressure difference} = \frac{[m(p_i) - m(p_{wf})]}{q_g} 
\]

(2)

Where \( m(p) = 2 \int_0^p \frac{dp}{\mu z} \)  \( \mu \) and \( z \) are the gas viscosity and compressibility factor, respectively. \( n \) is the time step at which Super - \( t \) is calculated, and \( j \) is the time step from 0 to \( n \).

\[
\text{Super} - t = \left[ \sum_{j=1}^{n} \frac{q_j - q_{j-1}}{q_n} \sqrt{t_n - t_{j-1}} \right]^2
\]

(4)

Fig. 4 shows a diagnostic plot that identifies the linear flow with half slope straight line. Fig. 5 is a specialized and more definitive plot to identify the linear flow behavior (Ibrahim and Wattenbarger 2006). Straight-line was found in the Cartesian plot with a slope (m). \( \sqrt{k}A_c \) can be calculated from the line slope (m) (El-Banbi and Wattenbarger 1998).

\[
\sqrt{k}A_c = \frac{8.032427}{\sqrt{\phi \mu_g c_t m}} \frac{\Sigma}{m}
\]

(5)

where \( \phi, \mu_g, c_t \) are the formation porosity, gas viscosity, and total compressibility, respectively. \( T \) is temperature, \( k \) is the formation permeability, and \( A_c \) is the stimulated area. The estimated area from RTA represents the effective production surface area (PSA) that contributes to the well productivity.
The calculated PSA from RTA was found to be 6.06 Acre which is less than the FSA by around 33%. One possible reason for this behavior is the interference between the created fractures. Fig. 6 shows the pressure distribution in case 1. During the production period, fractures mainly drained the area between the fracture with interference with each other with slight production from the surrounding area.
A similar analysis was conducted for cases 2, 3, and 4 as shown in Figs. 7 and 8. In the diagnostic plots, the pressure difference for the four cases was almost the same, however, the derivative curves showed the early deviation of case 1 from the linear flow regime followed by cases 4, 2, and 3, respectively. Fig. 7 presents the linear flow analysis for the four cases. The slope for the linear flow regime increases from case 1 to case 4, which indicates an increase in the PSA.
Table 2 summarizes the RTA analysis results for the four cases. The effective production surface area in case 4 with natural fractures increased by 8% compared to case 1, however it increased in case 3 by 27%, and the reduction in the PSA comparing to FSA was reduced to 14.6%.

Fig. 9 presents the change in the pressure distribution with the different fracture systems. Cases 2, and 3 showed less interference between the fractures, as a result, the effective production surface area was higher than PSA in Case 1. Hence, the drainage area and cumulative gas production increased. After three-years of productions, Case 3 has the highest drainage area comparing to cases 1 and 2.

Table 2- Summary for RTA analysis results for the different cases.

<table>
<thead>
<tr>
<th>Case</th>
<th>$\sqrt{kA_c}$, md$^{0.5}$ ft$^2$</th>
<th>$A_c$, Acre</th>
<th>(Complex- Simple)/Simple %</th>
<th>(PSA-FSA)/FSA %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>8331</td>
<td>6.05</td>
<td>-</td>
<td>32.8</td>
</tr>
<tr>
<td>Case 2</td>
<td>9692</td>
<td>7.04</td>
<td>16.34</td>
<td>21.8</td>
</tr>
<tr>
<td>Case 3</td>
<td>10583</td>
<td>7.68</td>
<td>27.03</td>
<td>14.6</td>
</tr>
<tr>
<td>Case 4</td>
<td>9002</td>
<td>6.53</td>
<td>8.05</td>
<td>27.4</td>
</tr>
</tbody>
</table>
Figure 9 – Pressure distribution in the different fracture system scenarios after a year and three-year production.
Effect of Permeability
To examine the effect of permeability on the single-stage performance with different fracture systems. Case 1 and 3 were repeated with the permeability of 0.0001 md. RTA analysis in Figs 10 & 11 shows that the two cases almost have the same performance with low interference between the created fracture on each cluster. The estimated PSA were 8.6 and 8.3 Acres which are 6, and 9% less than the FSA for case 3 and 1, respectively.

![Figure 10](image1.png)
Figure. 10 – RTA diagnostic plot for cases 1 and 3 at low permeability.

![Figure 11](image2.png)
Figure. 11 – Square root time Linear flow analysis for cases 1 and 3 at low permeability.
PTA
Pressure transient analysis was conducted in the buildup data for the simple and complex cases to estimate the fracture geometries. Fig. 12 shows the pressure derivative plot for the pressure build-up in cases 1 and 3. A clear half-slope line was observed in a simple fracture system, however, the linear flow for the complex fracture system was masked due to the uneven fracture length created in each cluster. Fig. 13 shows the square root time plot for the build-up data. The estimated PSA from the buildup analysis was found to be 7.9 and 8.5 Acres for cases 1 and 3, respectively.

Figure. 12 – Pressure derivative plot for the pressure build-up in cases 1 and 3.

Figure. 13 – Square root time plot for the build-up data in cases 1 and 3.
Conclusions
This study investigated the performance of single frac stage with different fracture system. Fracture surface area is the sum of hydraulic and natural fracture with good connection to wellbore. More fracture surface FSA will lead to more high stage productivity index. The FSA is higher than PSA with around 30% in productivity index. It is important to know how to characterize the single frac stage geometry which will help in well spacing. The integration between RTA and PTA allow us to characterize single stage properties from fracture half length, fracture conductivity, fracture face skin and fracture interference.

Nomenclatures

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
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<tbody>
<tr>
<td>$A_c$</td>
<td>Cross-sectional area to flow, ft$^2$</td>
</tr>
<tr>
<td>$c_t$</td>
<td>Total compressibility, psi$^{-1}$</td>
</tr>
<tr>
<td>FSA</td>
<td>Fracture surface area, Acre</td>
</tr>
<tr>
<td>$h_f$</td>
<td>fracture height, ft</td>
</tr>
<tr>
<td>$k$</td>
<td>Formation permeability, md</td>
</tr>
<tr>
<td>$m$</td>
<td>Slope of the cartesian plot, fraction</td>
</tr>
<tr>
<td>$m(p_i)$</td>
<td>Pseudopressure at initial reservoir pressure, psi$^2$/cp</td>
</tr>
<tr>
<td>$m(p)$</td>
<td>Pseudopressure at reservoir pressure (p), psi$^2$/cp</td>
</tr>
<tr>
<td>$N_f$</td>
<td>number of fractures</td>
</tr>
<tr>
<td>$P_i$</td>
<td>Initial reservoir pressure, psi</td>
</tr>
<tr>
<td>$P_{wf}$</td>
<td>bottom-hole flowing pressure, psi</td>
</tr>
<tr>
<td>PSA</td>
<td>Production surface area, Acre</td>
</tr>
<tr>
<td>$T$</td>
<td>Formation temperature, R</td>
</tr>
<tr>
<td>$q_g$</td>
<td>Gas flow rate, Mscf/d</td>
</tr>
<tr>
<td>Super-t</td>
<td>Superposition time, hrs</td>
</tr>
<tr>
<td>$X_f$</td>
<td>fracture half length, ft</td>
</tr>
<tr>
<td>$\phi$</td>
<td>Porosity, fraction</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity, cp</td>
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References


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Malallah, Adel, Nashawi, Ibrahim Sami, and Algharaib, Meshal Kh. 2007b. Constant-Pressure Analysis of Oil Wells Intercepted by Infinite Conductivity Hydraulic Fracture Using Rate and Rate Derivative Functions. Presented at the SPE Middle East Oil and Gas Show and Conference, Manama, Bahrain. 2007/1/1/. https://doi.org/10.2118/105046-MS.


