

Deep Insights for Optimizing Hydraulic Fracturing Designs to Maximize Productivity in Horizontal Wells within Unconventional Reservoirs

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Abstract

This study investigates the impact of various reservoir and fracture parameters on the productivity of horizontal wells using Schlumberger's PIPESIM software to conduct a comprehensive numerical simulation. The parameters analyzed include fracture length, width, porosity, permeability, and number of fractures. A series of simulations is conducted to systematically examine the effects of each parameter. The results show that fracture half-length and permeability have the greatest positive impact on well productivity, with the optimal fracture length being 4921.3ft and the optimal fracture permeability being 1000md. These two factors enhance the reservoir's ability to efficiently absorb and transport fluids, thus enhancing production rates. Additionally, fracture width and porosity show a moderate impact on productivity, highlighting their role in fluid flow dynamics. Interestingly, the number of fractures exhibits a nonlinear relationship with productivity, indicating that increasing the number of fractures initially leads to higher production rates; however, diminishing returns occur after a certain threshold is reached. The optimal number of fractures is 250, beyond which diminishing returns occur. These results provide valuable insights for improving hydraulic fracturing designs to maximize productivity in horizontal wells, especially in unconventional reservoirs, and to support more informed decision-making in field applications.

Keywords:

Hydraulic fracturing, Horizontal wells, Halfaya oil field.

DOI: [10.33899/injes.v26i4.56130](https://doi.org/10.33899/injes.v26i4.56130), ©Authors, 2026, College of Science, University of Mosul.This is an open-access article under the CC BY 4.0 license (<http://creativecommons.org/licenses/by/4.0/>).

1. Introduction

Hydraulic fracturing, often referred to as "fracking", has generated a lot of attention lately. This process involves creating new or enhancing existing cracks in rock formations to extract oil and gas, or petroleum hydrocarbons. The fractures created in the rock serve as pathways that allow oil and gas to flow from the rock into the well for production (Fig. 1).

Simulations and computer models predict the expected dimensions (length and height), azimuth orientation, and distribution of fractures resulting from different techniques designed to create the most effective and cost-efficient fracture system (Abbas et al., 2022; Hamid et al., 2023; Abdalmohi et al., 2025). Accurate post-fracture

assessments of production rates over time generate economic margins, based on accumulated experience, that inform future fracture treatments (Abdulmajeed and Awadh, 2022). Evaluating the overall performance of current wells helps determine the best locations for future wells in the formation to maximize production efficiency (Al-Bazali et al., 2008; Al-Delfi et al., 2023; AlHusseini and Hamed-Allah, 2023).

Hydraulic fracturing and horizontal wells are long-standing technologies in the oil and gas sector. The initial fracturing experiment occurred in 1947, with the process gaining commercial acceptance by 1950 (Bell, 2003). Horizontal wells were introduced in the 1930s, and by the late 1970s, they had become widely used (El-Dessouky et al., 1995; Faidhllah and Hamd-Allah, 2023; Faraj and Abdul Hussein, 2023).

The Saadi Formation (Late Turonian-Early Campanian) sequence, which is the thickest and most extensive formation in the Halfaya oil field (Al-adliy et al., 2024), is studied in the current research. The Saadi Formation consists of two distinct units: the non-reservoir Saadi A and the reservoir Saadi B, which is the primary tight oil reservoir of the field and 77 meters thick (Bell, 2003). It is located above the Tanuma Formation and below the Hartha Formation, and is mostly made up of limestone (Farman and Abdulmir, 2014).

This study aims to determine the effect of length, width, and number of hydraulic fractures on the productivity of a horizontal well in the Halfaya oil field.

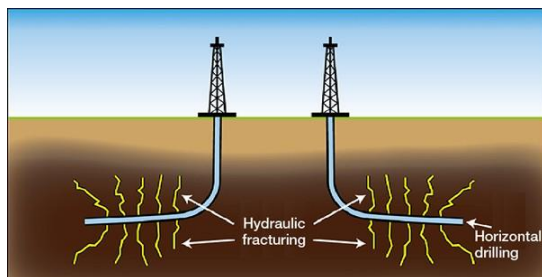


Fig. 1: Fracturing the rock formation for production (Farman and Abdulmir, 2014).

2. Geological Setting

The Halfaya oilfield is located about 35 km southeast of Amarah City (the center of the Missan Governorate) and 320 km southeast of Baghdad as shown in figure (3). Found in 1976, it covers an approximate area of 288 km² (Jreou, G. N. 2012). The youngest, thickest and most extensive formation of the Late Turonian-Early Campanian sequence is the Saadi Formation located within this area. The type section of the formation was originally defined on well Zubair-3 by Owen and Nasr (1958). Subsequently, Chatton and Hart (1961) and Ditmar and the Iraqi-Soviet team (1971 and 1972) modified its definition and age, the latter including in the Saadi Formation exposures of the Pilsner Formation. The Saadi Formation is composed of 300 m of white chalky argillaceous and globigerinal limestone capped by a well-developed 60 m thick marl bed. Distal to the type section, the upper part of the formation also includes organo-detrital limestone (Bellen et al., 1959; Farouk and Al-Haleem, 2022; Holditch, 2006; Jreou, 2012). The Halfaya field is an anticline oriented in a northwest-southeast

direction and only covers an area of around 30 km in length by 10 km in width (Khalili and Ahmadi, 2023; King, 2012; Mansourizadeh et al., 2016).

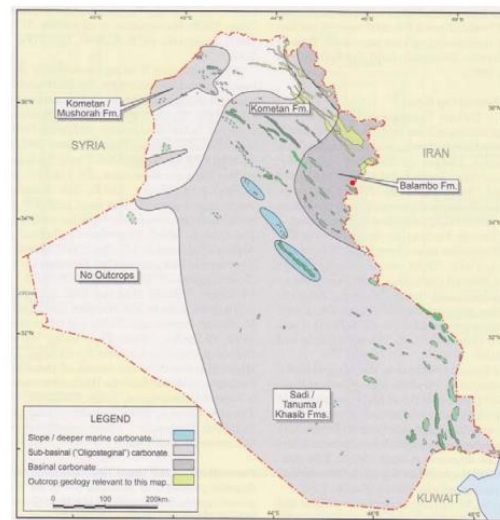


Fig. 2: Late Turonian-early Campanian palaeogeography of Iraq (Mansourizadeh et al., 2016).

3. Methodology

Data from the HF007 in Iraq's Halfaya oilfield are analyzed to determine optimal hydraulic fracture parameters for enhancing horizontal well productivity using Pipesim software. The study incorporated the following datasets:

1. Wellbore Design and Geometry

Total Wellbore Length: Combined vertical and horizontal sections from the surface to the reservoir.

Horizontal Section Length: Portion of the wellbore traversing the productive reservoir zone enhancing exposure to fractures.

Depth: Total distance from the surface to the well's bottom including vertical segments.

Wellbore Radius: Internal diameter influencing pressure dynamics, flow rates and fracture dimensions.

True Vertical Depth (TVD): Vertical measurement from the surface to the reservoir aiding in assessing vertical reach.

Deviation/Inclination: Angles of the horizontal wellbore section affecting fracture geometry and fluid flow.

2. Tubing and Casing Configuration

Casing Diameter: Size of the pipe stabilizing the wellbore and isolating formations.

Tubing Diameter: Inner pipe size impacting production fluid flow and friction losses.

Perforation Details: Location, density and type of casing perforations enabling reservoir-to-well fluid transfer.

3. Hydraulic Fracture Parameters

Fracture Length: Extent of fractures within the reservoir, directly influencing reservoir contact area.

Fracture Width: Opening size dictated by proppant volume and injection rates affecting flow capacity.

Fracture Conductivity: Efficiency of fluid transport through fractures, determined by proppant type, width and rock permeability.

Proppant Properties: Type (e.g., sand, ceramic) and quantity injected to hold fractures open, impacting conductivity.

Injection Data: Pressure and rate profiles during fracturing operations, critical for simulating fracture propagation.

4. Reservoir Characteristics

Reservoir Pressure/Temperature: Key drivers of fluid flow and viscosity.

Permeability/Porosity: Rock properties governing fluid mobility and hydrocarbon storage capacity.

Oil: API gravity, viscosity and composition.

5. Production Metrics

Production Rates: Initial and declining hydrocarbon output over time.

Pressure Data: Bottomhole (BHP) and wellhead pressures, critical for flow and reservoir health monitoring.

Fluid Composition: Oil, gas and water ratios to diagnose production challenges.

Decline Trends: Long-term production patterns guiding stimulation strategies.

6. Completion Design

Completion Type: Open-hole, cased-hole, or perforated configurations influencing fluid entry and fracture initiation.

Completion Tools: Packers, safety valves and tubing ensuring operational integrity.

7. Methodology Workflow

Pipesim software integrated these datasets to model fracture-wellbore-reservoir interactions. Sensitivity analyses tested fracture dimensions prioritizing configurations that maximized

productivity while balancing economic and operational constraints. Historical production data validated model accuracy ensuring realistic optimization outcomes (Sissakian et al., 2023).

This structured approach aimed to reduce trial-and-error in fracture design offering actionable insights for the Halfaya field's development.

4. Results and Discussion

A. Effect of fracture half- length

It is observed that increasing length of fractures significantly enhances productivity due to the increased surface area for the fluid to invade fracture. However, the incremental gain diminishes beyond a certain length due to pressure drop along the wellbore and flow resistance. Therefore, an optimal length must be determined based on economic and technical factors (Savari et al., 2020).

When increasing fracture length (XF) as shown in figure (3), it essentially:

- will increase surface area for the fluid to invade the fracture.
- shortens the distance, so the slow and constrained oil must flow through dense stone.

So initially:

- a little XF goes a long way in achieving higher flow rates and pressure.
- getting an access to new and untapped reservoir that was never connected before.

However, after a certain XF (e.g. >3000 ft), the fracture has already linked most of the productive area. You've depleted the rock tone with the least overhead. New XF extensions may only extend to low-permeability or tight rock. That additional length might not be booking much new oil.

Reservoir depletion and interference

The farther out from the reservoir, the weaker the pressure support is. It takes time for those far-flung spots to contribute flow not always fast enough to matter at high rates. Longer fractures can also develop internal pressure losses.

After a certain point, the benefit of greater contact is offset by lower pressure in the fracture itself and diminishing returns. While continue to spend money and effort to lengthen the fracture, as the amount of additional fluid you obtain per foot of fracture decreases, it becomes economically inefficient.

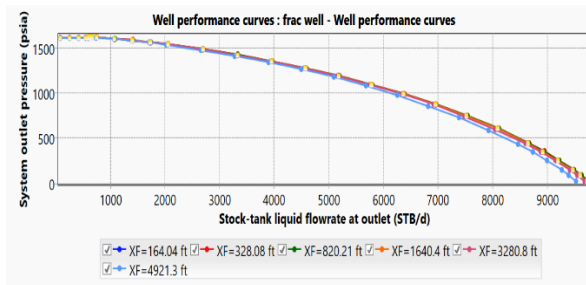


Fig. 3: Effect of fracture half- length

B. Effect of Fracture Width

The results of horizontal well performance curves as shown in figure (4) when changing fracture width indicate that this variable is a key factor in increasing production rates. In cases where fracture width is very small (for example, 0.019685 inches), pressure drops rapidly, and production decreases to very limited quantities, not exceeding tens of barrels per day. This reflects the limited flow path and high flow resistance. When width increases to intermediate values (0.03937 and 0.19685 inches), the well's production capacity improves significantly as the achievable flow rates increase at the same pressure levels, although the improvement remains less than that of larger widths.

In the case of larger widths (0.31496 and 0.3937 inches), performance shows a significant improvement with production rates exceeding 500 barrels per day, with a slower gradual decrease in pressure compared to previous cases. This indicates that fracture width provides better paths for fluid flow and enhances hydraulic communication between the well and the reservoir reducing pressure loss within the fracture and increasing recovery efficiency.

From these observations, it can be concluded that the relationship between fracture width and productivity is directly proportional. However, the effect of increasing width does not persist to the same degree. The improvement is significant when moving from very small to medium values, while the effect decreases as the value increases, which is consistent with the concept of diminishing returns. This also confirms that fracture width,

despite its importance, is not the only factor determining performance. Length, extension and the number of fractures may play a greater role when width reaches high levels.

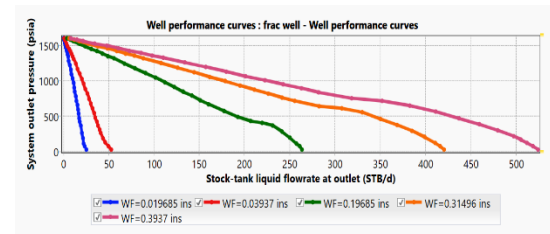


Fig. 4: Effect of Fracture Width.

C. Effect of fracture Porosity

Porosity has a secondary impact compared to permeability or fracture characteristics. It primarily determines the reservoir's storage capacity rather than its flow capacity. Thus, in tight formations, even high porosity does not guarantee good productivity without effective stimulation techniques (Mezaal et al., 2023).

In Figure (5), porosity variation (between 0.05 and 0.2) has little effect on well performance. The performance curves are almost identical indicating that porosity has a little effect on flow rate and pressure behavior in this scenario. In contrast, factors such as permeability and fracture properties have a greater impact.

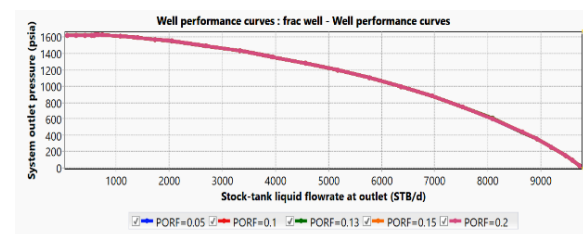


Fig. 5: Effect of fracture Porosity.

D. Effect of fracture Permeability

Permeability is found to be one of the most influential parameters for productivity. It directly governs the reservoir's ability to transmit fluids to the wellbore. Higher permeability results in increased production rates making it a key performance indicator, especially in conventional reservoirs (Khalili and Ahmadi, 2023).

In figure (6), the effect of KF (fracture permeability) is revealed.

Low KF (50–100 md): Bad performance, sudden drop of pressure and low flowrate.

Moderate KF (250–500 md): Massive improvement, way better flow and ability to handle pressure.

High KF (800–1000 md): Super performance, but returns begin to flatten out → little return.

Higher fracture permeability gives a better production, but the added benefit becomes trivial after a certain point (about 800 md).

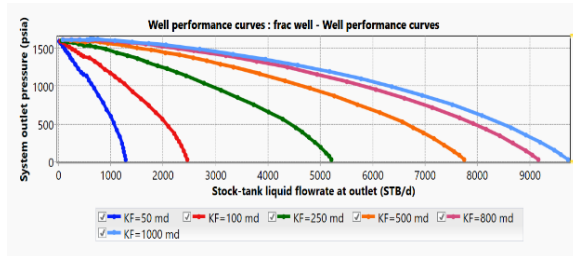


Fig. 6: Effect of fracture Permeability.

E. Effect of Number of Fractures

The analysis shows that increasing the number of hydraulic fractures significantly improves productivity by stimulating a larger reservoir volume and creating more drainage paths. However, excessive fracture density may result in fracture interference reducing the overall efficiency. Hence, optimized spacing and distribution are critical (Hussain and Al Mahdawi, 2019).

In figure (7), as the number of fractures (NF) increases (from 10 up to 2000), the well can deliver higher flowrates with less pressure loss.

The performance boost is noticeable at first, especially between NF = 10 and 100, but the curves begin to converge beyond NF = 500.

More fractures = more flow paths = better reservoir drainage.

Each added fracture improves fluid access to the wellbore and enhancing production.

After around 500–1000 fractures, performance gains slow down.

Additional fractures contribute less likely due to overlapping drainage zones and flow interference.

Between NF = 10 and 100, there's a major performance jump.

Between NF = 500 and 2000, the improvement is less dramatic.

Increasing fracture count significantly enhances production at first, but after a certain point (around NF = 500–1000), the impact levels off as fractures begin to interact and their effectiveness reduces.

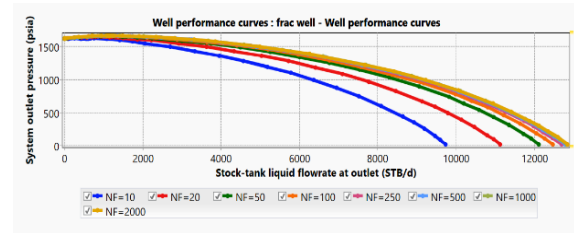


Fig. 7: Effect of Number of Fractures.

Summary of results as shown in Table 1 below

Table 1: Summary of results

Parameter	Impact on Productivity	Technical Notes
Horizontal Well Length	~35%	Diminishing returns beyond optimum
Fracture Width	~20%	Limited by stability and proppant flow
Fracture Porosity	~10%	Affects storage, not flow capacity
Fracture Permeability	~25%	Directly influences fluid flow
Number of Fractures	~30%	Spacing must be optimized

5. Conclusion

Increasing fracturing length increases reservoir contact and improves production, especially in low-permeability rocks.

Fracturing width is directly related to permeability within the fracture, which affects the rate of fluid flow into the well.

The number of fracturing units must be carefully selected to avoid interference and ensure effective reservoir coverage.

Permeability within a fracture is the primary factor in fluid transport and flow efficiency.

Porosity plays a supporting role in temporary fluid storage and takes on additional importance when natural fractures are present.

Optimal design requires a careful balance between these factors, based on a detailed geological assessment of each reservoir.

6. Conflict of Interest

The authors declare that they have no conflict of interest.

7. Funding Statement

This research received no external funding.

8. Author Contributions

Huda J. TH. AL-Hillali, conceived the manuscript and wrote the paper; took the samples and analyzed the data; prepared figures and tables.

Faleh H. M. Almahdawi, provided the writing ideas and supervised the study.

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رؤى متعمقة لتحسين تصميمات التكسير الهيدروليكي لتحقيق أقصى قدر من الإنتاجية

في الآبار الأفقية داخل الخزانات غير التقليدية

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الملخص

تبحث هذه الدراسة في تأثير مختلف معلمات المكمن والكسور على إنتاجية الآبار الأفقية باستخدام برنامج PIPESIM من شركة شلمبرجير لإجراء محاكاة رقمية شاملة. تشمل المعلومات التي تم تحليلها طول الكسر وعرضه ومساميته ونفاذيته وعدد الكسور. أجريت سلسلة من عمليات المحاكاة لفحص آثار كل معلمة بشكل منهجي. أظهرت النتائج أن طول الكسر ونفاذيته لهما التأثير الإيجابي الأكبر على إنتاجية البئر حيث أفضل طول للكسر هو 4921.3 قدم، وأفضل نفاذية للكسر هي 1000 ملي دارسي. يعزز هذان العاملان قدرة المكمن على امتصاص ونقل السوائل بكفاءة، مما يعزز معدلات الإنتاج. بالإضافة إلى ذلك، أظهر عرض الكسر والمسامية تأثيراً معتدلاً على الإنتاجية، مما يبرز دورهما في ديناميكيات تدفق السوائل. ومن المثير للاهتمام أن عدد الكسور أظهر علاقة غير خطية مع الإنتاجية، مما يشير إلى أن زيادة عدد الكسور تؤدي في البداية إلى ارتفاع معدلات الإنتاج. ومع ذلك، يحدث تناقص في العائدات بعد تجاوز حد معين وان أفضل عدد للكسور هو 250، وبعد تجاوز هذا الحد يحدث تناقص في العائدات. وتقدم هذه النتائج رؤى قيمة لتحسين تصميم التكسير الهيدروليكي لتحقيق أقصى قدر من الإنتاجية في الآبار الأفقية، وخاصة في الخزانات غير التقليدية، ودعم اتخاذ قرارات أكثر استنارة في التطبيقات الميدانية.

الكلمات المفتاحية:

التكسير الهيدروليكي، الآبار الأفقية، حقل الحفافية النفطية.

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