Fundamental Study of CFD + XDEM Experimental Impermeable Reservoir Fracturing

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Abstract. Hydraulic fracturing is an essential technique for enhancing hydrocarbon extraction from low-permeability reservoirs, such as shale and tight formations. However, its efficiency is often limited by the complex interactions between fracturing fluids, solid particles, and reservoir matrices. This study investigates the thermal and hydrodynamic effects of hydraulic fracturing using Computational Fluid Dynamics (CFD) and eXtended Discrete Element Method (XDEM) to optimize the fracture behavior and improve the oil production. Simulations were conducted using CMG IMEX to evaluate cumulative oil production and fluid flow rates, along with ANSYS Fluent to analyse reservoir behaviour after hydraulic fracturing. The results reveal that hydraulic fracturing significantly increases permeability and oil flow rates, with production reaching up to 10 barrels per day compared to 2 barrels per day prior to the fracturing. This combination method provides a systematic approach to improving hydraulic fracturing processes, resulting in better economic and operational outcomes in oil extraction.

1 Introduction

This investigation employs a comprehensive thermo-hydro-mechanical framework to model the progression of fractures and the movement of fluids, thereby elucidating the intricate relationships that dictate the development of fracture networks and the transport of proppants [1]. This approach accounts for the coupled phenomena of fluid flow within the induced fractures, mechanical deformation of the reservoir rock, and the subsequent leak-off into the surrounding porous matrix, which are critical for accurate predictive modeling of hydrocarbon recovery [2]. Furthermore, the simulation incorporates the effects of temperature distribution and effective stress-strain behavior, which are essential for understanding the material response under the extreme conditions encountered during

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fracturing operations. The model also considers the impact of pore pressure propagation and cooling stress, which are crucial for optimizing multi-well fracturing treatments [1].
This detailed investigation aims to provide a robust predictive tool for enhancing the efficiency and sustainability of hydraulic fracturing operations, particularly in unconventional reservoirs. This involves evaluating the impact of thermochemical additives on fluid transport and heat propagation within the fracture network to optimize treatment design [3]. The complex interplay between thermal, hydraulic, mechanical, and chemical processes significantly influences the long-term evolution of induced fractures and their conductivity, underscoring the necessity for integrated modeling approaches to predict reservoir performance accurately [4]. This includes assessing how non-uniform proppant distribution within fracture clusters can impact overall fracture conductivity and the efficiency of hydrocarbon recovery [5]. The numerical simulations employed herein incorporate advanced constitutive models for rock deformation and proppant transport, capturing phenomena such as proppant crushing and embedment, which significantly impact long-term fracture conductivity [6].

Moreover, the study delves into the optimization of proppant placement strategies, including the use of advanced proppant materials and clustered proppant designs, to maximize fracture conductivity and ultimately enhance hydrocarbon production [7]. Hydraulic fracturing, often referred to as fracking, is an indispensable technique for extracting hydrocarbons from reservoirs characterized by low permeability, such as shale and tight formations. These reservoirs possess inherently limited natural permeability, posing challenges for conventional extraction methods and often resulting in suboptimal oil and gas recovery. To address this, hydraulic fracturing artificially creates fractures within the reservoir rock, thereby augmenting hydrocarbon flow towards the wellbore and enhancing extraction efficacy [8–10].

The efficacy of hydraulic fracturing, despite its widespread adoption, is often constrained by the complex interplay between fracturing fluids, solid particles, and the reservoir matrix. A primary difficulty in hydraulic fracturing lies in the precise prediction and optimization of fracture propagation within the reservoir. The interaction between fracturing fluids and the rock formation is highly variable, contingent upon fluid properties, pressure, temperature, and the mechanical characteristics of the reservoir rock [11]. Furthermore, the inclusion of proppants, such as silica sand, in the fracturing fluid can introduce complications affecting fracture conductivity and permeability if not optimally managed. Moreover, the severe temperature and pressure conditions typically encountered during fracturing operations can induce substantial thermal stress in the reservoir rock, potentially modifying fracture behavior and fluid flow dynamics. These challenges can result in process inefficiencies, diminished oil recovery rates, and increased operational costs [12,13].

The hydraulic fracturing sector has made significant progress in tackling these challenges, but there is still a need for a deeper comprehension and optimization of the physical process involved. Recent developments in computational methodologies have created opportunities to improve the predictability and efficiency of hydraulic fracturing operations. Computational Fluid Dynamics (CFD) and the eXtended Discrete Element Method (XDEM) represent two advanced simulation approaches that facilitate the detailed modeling of fluid-structure interactions at a granular level. CFD simulations help to analyze the behaviour of the fracturing fluids; meanwhile, Bažant et al., [14] state that XDEM simulations offer valuable insights into the mechanical properties of the reservoir rock and the dynamics of fracture propagation. Yu et al., [15] highlight that these methods collectively offer a comprehensive framework for understanding the complex thermal and hydrodynamic effects associated with hydraulic fracturing.

In this study, the combination of CFD and XDEM advanced simulation tools, such as CMG IMEX and ANSYS Fluent, was used to investigate the thermal and hydrodynamic effects of hydraulic fracturing in low-permeability reservoirs. CMG IMEX, a component of Computer Modelling Group's reservoir simulation software suite, specializes in black oil and compositional reservoir simulation, facilitating precise modeling of cumulative oil production, fluid dynamics, and pressure distribution over time. Previous researchers [16–19] emphasize that its ability to incorporate geomechanically characteristics makes it an invaluable tool for understanding the impacts of hydraulic fracturing on reservoir performance. On the other hand, ANSYS Fluent provides detailed insights into fluid behavior, heat transfer and stress distribution within the reservoir. The capabilities of ANSYS Fluent enable the analysis of thermal gradients, pressure changes, and fluid interactions during the fracturing process, ensuring high precision in simulating complex reservoir conditions. This study aims to develop a more efficient and effective approach to hydraulic fracturing by analysing the impact of these factors influence the oil production rates, thereby addressing the current challenges in the industry.

2 Methodology

2.1 Reservoir modelling using CMG

A reservoir model was created using CMG IMEX with single porosity. The reservoir model was imported from the CMG database. Defined reservoir parameters such as structure and permeability. PVT data was generated using correlation methods. Initial reservoir conditions were then set, followed by the addition of well locations and perforation data. Once completed, the dataset was saved as a base reservoir for the comparison process. Next, the existing reservoir was modified to include hydraulic fracturing for the well with the lowest production rate due to low permeability. This modified version was saved as a new reservoir dataset. Both reservoir models were run simultaneously, and the results were analysed, focusing on cumulative oil production and fluid flow rates.

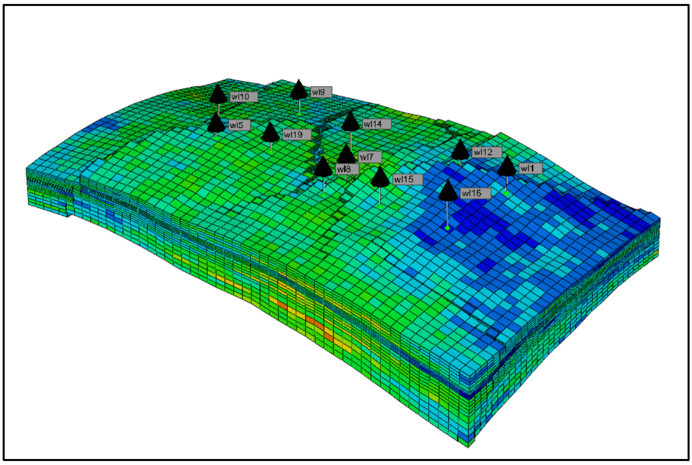

Fig. 1. Reservoir model using CMG IMEX

2.2 CFD couple XDEM modelling using ANSYS FLUENT

A reservoir model with an irregular rock shape was created in ANSYS Fluent using the Design Modeler. After completing the modelling process, meshing was performed to discretize the reservoir into smaller elements for numerical analysis. Qiao et al., [20] stated that careful meshing and refinement were applied to achieve the required number of nodes. Next, the model setup phase was carried out, involving the definition of material properties, boundary conditions, cell zones, and numerical methods. Material properties were manually inserted to ensure the simulation accurately reflected the reservoir's physical behaviour. The initialization phase followed, where initial conditions for the simulations were established, including temperature and pressure inlets for the fracturing fluid.

Once the model was initialized, the simulations were run to compute the results. If calculations did not converge or errors were identified, adjustments were made to the solution data. After completing the calculations, the results were analysed with a focus on temperature distribution and pressure behaviour in the reservoir

3 Results

3.1 Cumulative Oil Production in CMG IMEX

The data presented in Fig. 2 clearly illustrate the substantial impact of hydraulic fracturing on cumulative oil production. A comparison shows that a well without hydraulic fracturing yielded 4630 m^3 of oil, whereas the same well with hydraulic fracturing produced 41500 m^3, representing an 896.32% increase. This dramatic enhancement in production highlights the critical role of hydraulic fracturing in improving hydrocarbon recovery from low-permeability reservoirs that would otherwise be uneconomical [5,21,22]. Khizhniak et al., [23] illustrate that the increase in cumulative oil production demonstrates the impact of fracturing on production efficiency.

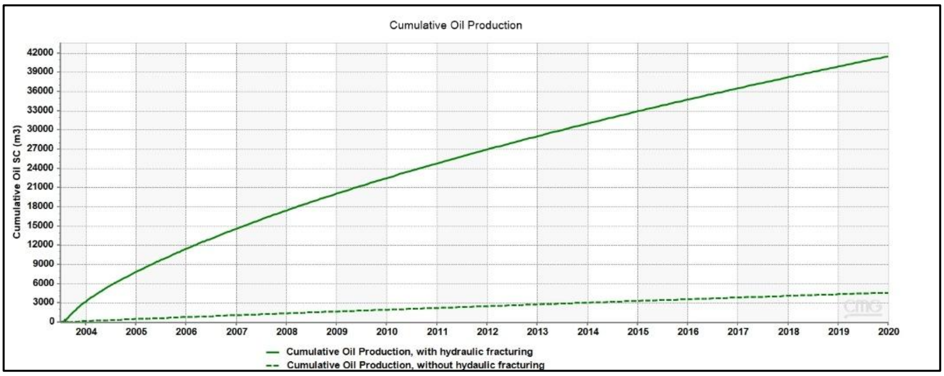

Fig. 2. Graph of cumulative oil production over time in two scenarios in low permeability without hydraulic fracturing (dashed line) and with hydraulic fracturing (solid line)

The primary mechanism behind this significant increase is the creation of artificial fractures within the reservoir rock, which dramatically improves the movement of hydrocarbons towards the wellbore. In low-permeability formations, such as shale and tight sands, natural flow paths are limited, making conventional extraction inefficient [24].

Hydraulic fracturing bypasses these limitations by generating an extensive network of highly conductive pathways, making the economic development of ultra-tight reservoirs possible [25–27].

Several factors contribute to the effectiveness observed:

- Increased Reservoir Contact Area: The induced fractures extend into the reservoir, increasing the surface area through which oil can flow into the wellbore [5]. The creation of a very large man-made fracture network is key to maximizing the reservoir area connected to the wellbore.
- Enhanced Permeability and Conductivity: The fractures are propped open by proppants, for example, silica sand, injected with the fracturing fluid, preventing them from closing once the pumping pressure is released. These proppant-filled fractures create high-conductivity channels that allow hydrocarbons to flow more freely than through the native, low-permeability rock matrix [28,29]. This directly enhances the overall permeability of the reservoir and is crucial for long-term production performance [30].
- Bypassing Flow Barriers and Accessing Isolated Hydrocarbons: Hydraulic fractures can connect isolated pockets of hydrocarbons or natural fractures that were previously inaccessible [31,32]. This effectively expands the drainage area of the well and helps to establish communication between the wellbore and a larger portion of the reservoir, thereby tapping into greater reserves [33].
- Optimized Fluid Dynamics: The presence of these conductive fractures reduces the resistance to fluid flow, allowing oil to be extracted more efficiently and at higher rates over the production period [34]. The improved flow paths facilitate smoother movement of production fluids toward the wellbore.

The effectiveness of hydraulic fracturing relies on the complex interplay between fracturing fluids, proppants, and the reservoir rock. Accurately predicting and optimizing fracture propagation, along with managing extreme temperature and pressure conditions that can alter fracture behavior and fluid flow, are crucial. Therefore, optimizing proppant placement strategies, including the use of advanced materials and clustered designs, is essential for maximizing fracture conductivity and boosting hydrocarbon output. The increase in cumulative production observed is due to engineered fracture networks that overcome the challenges of low-permeability reservoirs.

3.2 Fluid Rates in CMG IMEX

Fig. 3 clearly illustrates the significant enhancement in initial production rates and sustained productivity achieved through hydraulic fracturing. A comparison reveals that a well without hydraulic fracturing starts at 39.81 m³/day and declines to 21.76 m³/day, whereas a hydraulically fractured well begins at a much higher 1000 m³/day and declines to 149.76 m³/day. By the end of the production period, the hydraulically fractured well produces 6.88 times more than the conventional well. This demonstrates that hydraulic fracturing is a critical technique for enhancing productivity in low-permeability formations, not only by boosting initial production but also by influencing the decline curve to sustain higher rates over time. According to Fatahi et al., [35], this enhances the flow regime from radial to near-linear patterns and expands the effective drainage area by linking previously isolated regions.

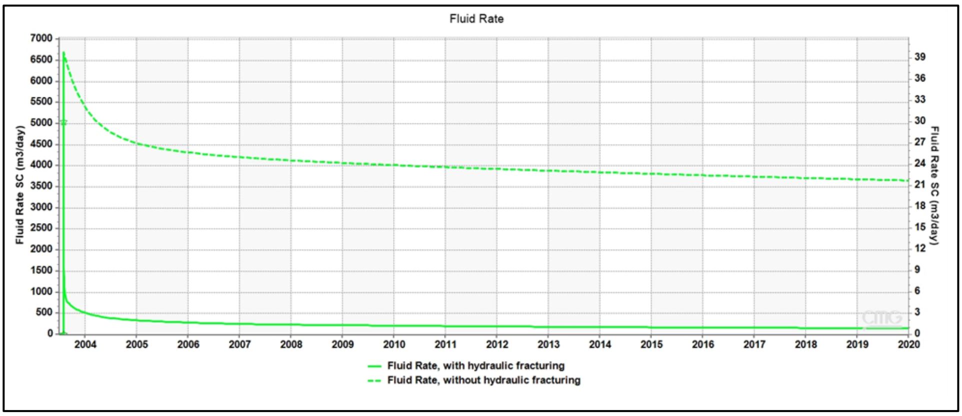

Fig. 3. Graph of fluid rates over time for two scenarios in low permeability with hydraulic fracturing (solid line) and without hydraulic fracturing (dashed line)

This sustained higher production rate in fractured wells, even with natural decline, can be attributed to several factors. The initial high conductivity can create propped fractures, providing an immediate high-conductivity pathway for hydrocarbons to flow to the wellbore, leading to significantly higher initial production rates [29,36]. This initial surge directly results from overcoming the inherent low permeability of the reservoir rock [21,25]. For instance, the permeability of shale can increase from 10^{-18} to 10^{-20}m² to 2×10^{-15}m² immediately after fracture, and further increases by 2–4 orders of magnitude when proppant is included [21].

Meanwhile, an expanded drainage area could hydraulically fracture effectively extend the reach of the wellbore into the reservoir, increasing the drainage volume. This larger contact area with the reservoir rock allows for a greater cumulative recovery of hydrocarbons over the well's lifespan, even as reservoir pressure declines [32,37]. The drained rock volume in hydraulically fractured reservoirs is visualized and significantly affected by the presence of both hydraulic and natural fractures [37,38].

By improved flow dynamics, the engineered fracture network reduces the resistance to fluid flow, allowing hydrocarbons to move more freely and efficiently towards the wellbore. This improved fluid dynamics contributes to higher sustained production rates compared to unfractured wells, where flow is restricted by the natural matrix permeability [34].

In managing production decline, all wells experience a natural decline in production over time. Hydraulically fractured wells are designed to mitigate this decline and sustain higher production rates for longer periods [27]. This is achieved through careful optimization of fracture design, including fracture spacing, proppant type, and fluid injection strategies, which aim to maintain fracture conductivity and reservoir access [39].

The long-term productivity of fractured wells is highly dependent on the sustained conductivity of the propped fractures [29]. Factors such as stress sensitivity, where increasing effective stress during production can compact the conductive medium and reduce seepage capacity, can influence the decline rate, and strategies like optimizing bottom-hole pressure drawdown are employed to manage this [40,41]. Additionally, post-stimulation operations, such as plug drillout and well flowback, also play a significant role in securing long-term well performance as they can affect the hydraulic fracture system.

In certain of economic viability, the dramatic increase in cumulative production, as evidenced by the 6.88 times higher output, directly contributes to the economic viability of extracting hydrocarbons from unconventional reservoirs. Without hydraulic fracturing, the development of many low-permeability and unconventional reservoirs would be significantly challenging, as their natural production rates would be insufficient for economic success.

In essence, hydraulic fracturing transforms a low-producing or non-producing reservoir into a commercially viable asset by establishing efficient flow paths and maximizing the drainage area, thereby accelerating and increasing the total hydrocarbon recovery. Continuous research and optimization in areas such as fracture spacing and overall fracture design are crucial for maximizing oil recovery and project revenue [39]. This includes optimizing fracturing parameters with advanced techniques like machine learning and evolutionary algorithms to predict dynamic production and improve fracturing design, ultimately enhancing long-term productivity and economic returns [42,43].

3.3 Fluid Rates in CMG IMEX

Fig. 4. and Fig. 5. depict the total temperature distribution after fracturing in an impermeable reservoir with velocities of 2 m/s and 10 m/s. The results show that the maximum temperature decreases with the increase of velocity fracturing fluid. The red regions represent areas that have high temperature, while the blue for lower temperature.

Each figure in Fig. 4. And Fig. 5. were divided into two parts at the middle, showing various temperature distributions. The left half shows red regions at the centre bottom, indicating the heat accumulation. In the other part, exhibit orange regions in the same depths and same fluid injection point. This illustrates the differences in reservoir characteristics such as porosity and permeability. The right side of the reservoir has denser and more tightly packed rock structure with few pore throats.

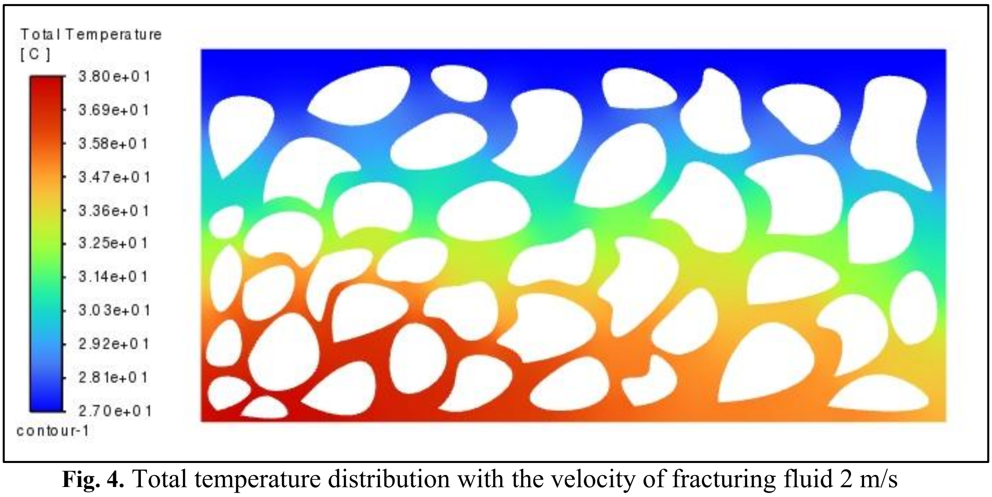

Fig. 4. Total temperature distribution with the velocity of fracturing fluid 2 m/s

3.3.1 Impact of Fluid Velocity on Temperature Distribution

The observation that the maximum temperature decreases with an increase in fracturing fluid velocity (from 2 m/s to 10 m/s) is a critical insight. This phenomenon can be explained by considering the principles of heat transfer during fluid injection into a reservoir. When a fracturing fluid (typically colder than the reservoir rock) is injected, heat transfer occurs primarily through convection. A higher injection velocity means the colder fluid moves more rapidly through the fracture network and the surrounding rock. This increased fluid movement enhances the rate at which heat is carried away from warmer regions of the reservoir. As the colder fluid is advected faster, it has less time to absorb heat from any single point in the reservoir, leading to a more distributed and lower maximum temperature [3].

At lower velocities, the fluid moves more slowly, allowing for a longer residence time in certain areas. This prolonged contact can lead to more significant heat exchange and potential heat accumulation in specific regions of the reservoir, as indicated by the "red regions at the centre bottom" in your description. With higher velocities, the rapid flushing action prevents such localized heat build-up, resulting in a more uniform and generally cooler temperature profile across the fractured zone [3].

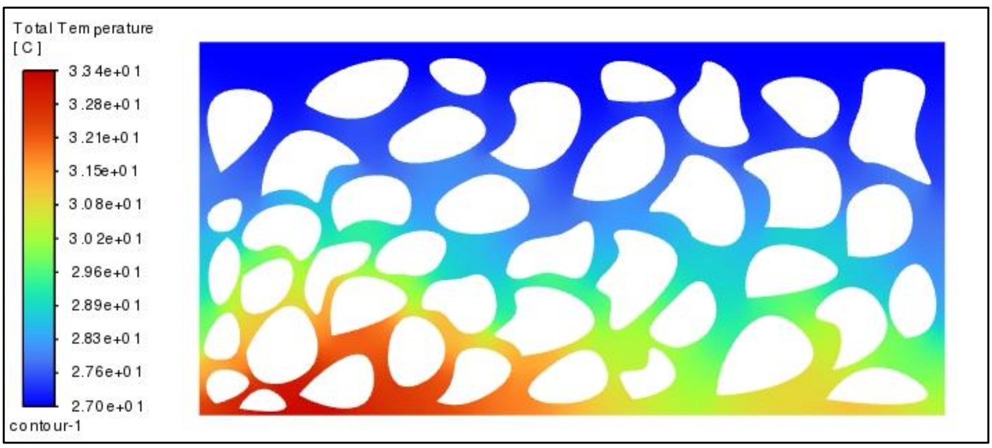

Fig. 5. Total temperature distribution with the velocity of fracturing fluid 10 m/s

While not explicitly stated in your description of Fig. 4 and Fig. 5, the rapid injection of cold fracturing fluid can also induce thermal stresses in the reservoir rock due to thermal shock. The interplay between fluid flow, heat transfer, and rock mechanics is complex and is often studied using thermo-hydro-mechanical models [44,45]. These models consider how temperature changes affect rock deformation, fracture propagation, and fluid flow dynamics [1].

3.3.2 Reservoir Heterogeneity and Temperature Distribution

The division of each figure into two parts, showing different temperature distributions, and your comment that the right side "has denser and more tightly packed rock structure with few pore throats," strongly suggests the presence of reservoir heterogeneity.

The differences in temperature and fluid flow patterns directly reflect variations in the reservoir's petrophysical properties, specifically porosity and permeability.

- Regions with "denser and more tightly packed rock structure with few pore throats" on the right side indicate lower porosity and permeability. In such areas, fluid flow is restricted, leading to less efficient heat exchange between the injected fluid and the rock. This can result in different temperature signatures compared to regions with higher porosity and permeability. For instance, lower permeability can lead to reduced convective heat transfer and potentially higher localized temperatures if the fluid cannot efficiently dissipate heat [46].
- The reservoir rock is denser and less permeable, the injected fluid might struggle to penetrate effectively. This could lead to a less uniform distribution of the colder fluid and, consequently, different patterns of heat dissipation. The "orange regions" compared to "red regions" in different parts of the figures likely visually represent these variations in heat distribution due to varying reservoir characteristics.

Understanding and accurately modeling these heterogeneities are crucial for optimizing hydraulic fracturing treatments [1,36]. Factors like leakoff coefficient, thermal conductivities of the rock and fluid, and porosity are all complex variables that influence the temperature profile and need to be considered. Sophisticated coupled models are necessary to capture the complex interplay between fluid flow, heat transfer, and mechanical responses in heterogeneous reservoirs [47].

In summary, Fig. 4 and Fig. 5 illustrate the intricate thermal responses of an impermeable reservoir during hydraulic fracturing. The inverse relationship between fluid velocity and maximum temperature is due to enhanced convective heat transfer, while the differing temperature distributions within the figures clearly highlight the impact of reservoir heterogeneity, particularly variations in porosity and permeability, on fluid flow and thermal behavior.

3.4 Hydrodynamic Effects in ANSYS Fluent

Fig. 6. represents the hydraulic fracturing in the industry and in the simulation of ANSYS Fluent, where the top diagram shows the process of hydraulic fracturing combined with horizontal drilling, a technique that is used to extract oil and gas from impermeable reservoirs. Horizontal drilling allows greater interaction with the reservoir, while a high-pressure fluid, a mixture of water, chemicals, and proppant, is injected into the wellbore to create fractures in the adjacent rock, as shown in the yellow circle. These fractures increase the permeability, facilitating the movement of trapped hydrocarbons to flow more freely into the wellbore for extraction. The purpose of this method is to access a larger volume of resources than conventional vertical wells.

The bottom diagram in Fig 5 shows a result from ANSYS simulation that provides a detailed view of the fractured regions within the impermeable reservoir. It visualizes the distribution of different phases, such as air, oil, or water, which are represented by colour-coded volume fractions. The red zones indicate the areas with high pressure as fracturing fluid was injected into the reservoir, where the fractures have been induced to improve the permeability. In contrast, the blue zones indicate the areas containing oil at lower pressure, which remain unaffected by fracturing fluid until the fractures extend to reach them, or a pressure gradient drives the oil towards the fractured zones.

This relationship between both diagrams in Fig 5 highlights how the process of hydraulic fracturing (top diagram) influences the reservoir's structure (bottom diagram), increasing the permeability and enabling more effective hydrocarbon extraction from the impermeable formations.

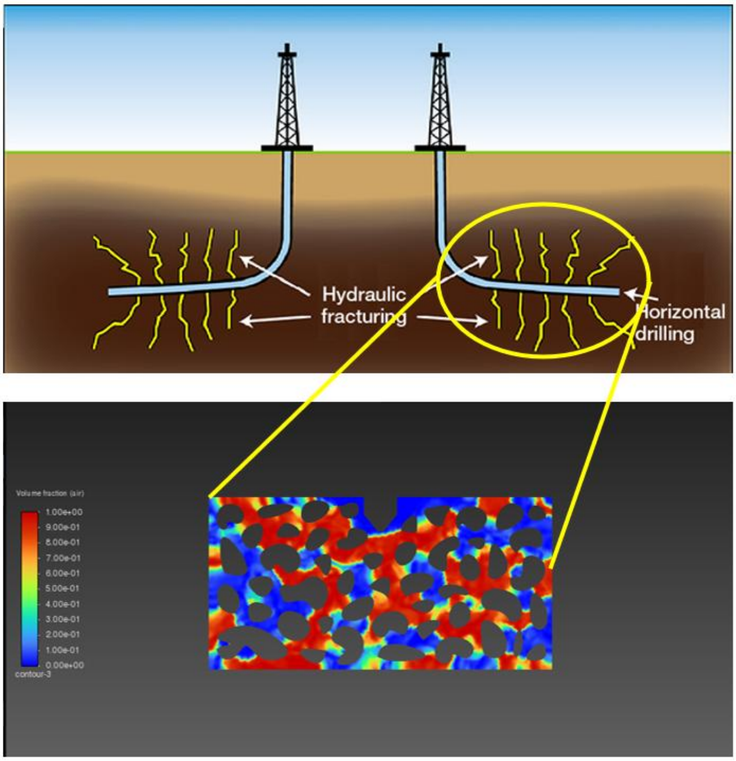

Fig. 6. The hydraulic fracturing in industry and in the simulation of ANSYS Fluent

4 Conclusions

In conclusion, this study focused on enhancing hydrocarbon extraction from impermeable reservoirs through existing methods, the integration of hydraulic fracturing and horizontal drilling. The primary issue tackled as in the low permeability of these reservoirs, which restricts the natural flow of hydrocarbons. The approach involved the use of ANSYS simulations to analyse the fracturing process and its impacts on the reservoir's structure and fluid flow dynamics.

The solution was to inject the high-pressure fracturing fluids into the reservoir to create fractures and improve the connectivity and permeability. Simulation outcomes showed the creation of high pressure that expanded fractured pathways, facilitating the movement of hydrocarbons. The results highlight the effectiveness of hydraulic fracturing in maximizing resource recovery by enlarging the productive areas of the reservoir.

Future research could focus on optimizing the properties of fracturing fluids, selecting proppant materials and refining injection parameters to further enhance permeability and lower the operational costs. Furthermore, the incorporation of advanced modelling techniques, like coupled CFD-XDEM simulations and experimental validation, could provide more insight into fracture propagation and its long-term effects on reservoir performance.

Acknowledgement

Thanks to the Universiti Malaysia Pahang-MOHE FRGS grant scheme with the grant reference of RGS/1/2023/TK08/UMP/02/13, Faculty of Chemical & Process Engineering Technology with the grant reference of RDU230146 and the *Inisiatif Penerbitan Sarjana Muda* (FYP Initiative Scheme) to run the research fundamental study.

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