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Numerical Sensitivity Analysis of Matrix Permeability and Parent–Child Well Interaction on Estimated Ultimate Recovery in Unconventional Reservoirs

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ABSTRACT - Unconventional shale reservoirs hold vast hydrocarbon resources, but productivity is constrained by ultra-low matrix permeability and complex fracture behaviour. While horizontal drilling and hydraulic fracturing are essential for commercial production, optimizing estimated ultimate recovery (EUR) remains challenging due to coupled interactions among permeability, pressure depletion, fracture effectiveness, and well interference. This study uses compositional reservoir simulation to numerically investigate how hypothetical matrix permeability enhancement and parent-child well interactions affect cumulative gas production. Models were built using Eagle Ford shale properties with multi-stage hydraulic fractures and geomechanical effects. Matrix permeability was increased by factors of 10× and 100× relative to the base case, and bottom-hole pressure (BHP) was optimized across 100 synthetic scenarios. Results show that matrix permeability is the primary control on long-term production, with higher permeability significantly improving matrix-to-fracture fluid transfer. The optimal single-well scenario produced approximately 9.8×10^8 ft³ of gas. Geomechanical analysis revealed uneven strain distribution around fractures, indicating non-uniform stress redistribution. In the parent-child configuration, strong pressure interference was observed; notably, the child well outperformed the parent well under simulated conditions, likely due to greater pressure drawdown and enhanced fracture connectivity. This study establishes theoretical upper-bound recovery limits through hypothetical permeability scenarios rather than proposing field-ready technologies. The findings emphasize that maximizing EUR requires an integrated evaluation of permeability, fracture effectiveness, pressure management, geomechanics, and well spacing.

Keywords: unconventional reservoir, shale gas, matrix permeability, parent–child well, hydraulic fracturing, cumulative production, EUR, geomechanics.

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1. Introduction

The increasing global demand for energy and the decline of conventional hydrocarbon reserves have accelerated the development of unconventional resources such as shale gas and shale oil reservoirs. Among unconventional resources, shale formations are among the largest potential energy sources due to their extensive areal distribution and substantial hydrocarbon content. However, shale reservoirs are characterized by ultra-low matrix permeability, nanoscale pore systems, low porosity, complex natural fractures, and strong geomechanical heterogeneity, which significantly restrict hydrocarbon mobility and production performance (Fan et al., 2018). Typical shale permeability ranges from the nano-Darcy to the micro-Darcy scale, causing hydrocarbons to remain trapped within the organic-rich matrix. Consequently, commercial production from shale reservoirs strongly depends on advanced technologies such as horizontal drilling and multi-stage hydraulic fracturing (King et al., 2010).

Unlike conventional reservoirs, shale formations commonly serve as source rock, reservoir rock, and seal rock simultaneously, resulting in unique hydrocarbon storage and flow mechanisms that require advanced stimulation technologies for commercial production (Junira & Wibowo 2016). In addition, shale formations generally have permeability below 0.1 mD and porosity below 10%, making natural hydrocarbon flow extremely difficult without stimulation technologies (Junira & Wibowo 2016). Therefore, horizontal drilling and hydraulic fracturing have become the primary methods for increasing reservoir contact area and improving hydrocarbon productivity from shale formations (King et al., 2010; Junira & Wibowo 2016). Experience from unconventional developments in North America further indicates that fracture-network complexity, hydraulic-fracture conductivity, and geomechanical behavior are key parameters that control the sustainability of shale production (Winderasta 2017).

Hydraulic fracturing is applied to establish highly conductive flow pathways between the reservoir matrix and the wellbore through the creation of complex fracture networks that enlarge the stimulated reservoir volume (SRV). The effectiveness of these hydraulic fractures is strongly influenced by fracture conductivity, stress redistribution, fracture propagation behavior, and matrix–fracture interaction (Taghichian et al., 2018). In unconventional reservoirs, the primary objective is to maximize the contact area between the fracture system and the reservoir while maintaining economic feasibility. Therefore, understanding the interaction between hydraulic fractures, matrix permeability, and geomechanical behavior is essential for improving estimated ultimate recovery (EUR).

Matrix permeability is recognized as one of the most influential parameters controlling long-term shale production performance. Although hydraulic fractures dominate early-time production, hydrocarbon transfer from the matrix toward the fracture network governs long-term recovery. Fan et al. (2018) emphasized that accurately determining shale matrix permeability remains a significant challenge because induced microfractures during core retrieval and transportation can alter laboratory permeability measurements. This uncertainty may lead to inaccurate forecasting of production performance and reservoir recovery.

Hydraulic-fracture propagation is also strongly influenced by reservoir stress conditions and geomechanical behavior. Warpinski & Teufel (1987) demonstrated that in situ stress conditions are the dominant factors controlling fracture propagation, compared with lithological boundaries and variations in elastic properties. Similarly, King (2010) explained that stress redistribution surrounding hydraulic fractures may significantly alter fracture geometry and long-term production behavior. Therefore, understanding the interaction between hydraulic fractures and geomechanical deformation is essential for improving shale recovery performance.

The orientation of hydraulic fractures is strongly affected by the intersection angle between the wellbore trajectory and the principal horizontal stress direction. Lolon et al. (2009) demonstrated that fracture spacing, fracture conductivity, and horizontal well orientation significantly affect production performance in unconventional formations. In addition, Le Calvez et al. (2007) showed that microseismic monitoring can provide valuable insight into fracture propagation and stress evolution during stimulation treatments. These findings indicate that successful unconventional reservoir development requires an integrated understanding of hydraulic fracturing and reservoir geomechanics.

Recent developments in unconventional reservoir engineering have highlighted that parent–child well interaction is controlled not only by well spacing but also by fracture-driven communication, depletion shadow, and stress redistribution around pre-existing wells. Wang et al. (2021) reported that pressure interference between parent and child wells can significantly alter production performance and EUR prediction, particularly in tightly spaced unconventional developments. Similarly, Liu et al. (2026) demonstrated that fracture-hit behaviour becomes increasingly severe under tight well-spacing conditions, leading to dynamic fracture propagation and pressure communication between adjacent wells.

The Eagle Ford shale reservoir, located in South Texas, United States, was selected as the case study in this research because it represents one of the most productive unconventional shale plays in North America. Eagle Ford shale has experienced rapid development following the success of Barnett, Haynesville, and Marcellus shale reservoirs (Tian et al., 2014). According to the U.S. Energy Information Administration (U.S. Energy 2011), the Eagle Ford shale contains approximately 21 Tcf of recoverable natural gas and 3 billion barrels of recoverable oil. The reservoir depth ranges from 2,500 to 14,000 ft, while permeability varies between 1 and 800 nano-Darcy (Inamdar et al., 2010; Stegent et al., 2010). These characteristics make Eagle Ford shale highly sensitive to hydraulic-fracture design, pressure depletion, and reservoir-stimulation strategies.

Several previous studies have investigated the influence of matrix permeability, stimulated reservoir volume, and fracture conductivity on the performance of unconventional reservoirs. While Al-Rbeawi & Al-Kaabi (2020) demonstrated that stimulated matrix permeability and non-Darcy fracture flow significantly influence pressure depletion and the productivity index, their study did not consider geomechanical coupling or parent-child well interactions, leaving key questions about coupled effects unanswered. Cipolla (2009) further showed that reducing fracture spacing can substantially improve gas recovery by increasing fracture-network complexity and reducing matrix drainage distance. Modern studies have also revealed that gas transport mechanisms in shale reservoirs differ substantially from those in conventional Darcy-flow systems due to nanopore confinement and stress-sensitive permeability behaviour.

Recent geomechanical studies have emphasized that permeability evolution and fracture conductivity may change dynamically during depletion processes. Bui (2023) explained that stress-sensitive permeability and fracture-conductivity degradation are critical parameters that control long-term unconventional reservoir productivity. Similarly, Heydari et al. (2024) demonstrated that geomechanical deformation and reactive transport processes within shale microfractures can alter fracture aperture and the evolution of permeability during production depletion.

The objective of this study is not to propose a field-scale permeability enhancement technology. Instead, the work investigates hypothetical permeability multipliers as numerical sensitivity scenarios to quantify theoretical upper-bound recovery limits and understand the relative contribution of matrix-to-fracture mass transfer on long-term shale production.

This study presents a comprehensive, integrated simulation framework for unconventional shale reservoirs that simultaneously evaluates hypothetical matrix permeability enhancement, BHP optimisation, anisotropic geomechanical behaviour, and parent–child well interference within a unified Eagle Ford shale model. Unlike previous studies that investigated these parameters separately, this work quantitatively evaluates the coupled relationship between matrix-flow capacity, stress redistribution, fracture-driven communication, and long-term cumulative production performance. The study also provides insight into the interaction between shear-strain evolution and production imbalance in parent–child well configurations.

1.1 Literature review

Although matrix permeability enhancement has frequently been investigated in numerical studies, achieving uniform permeability increases of one or two orders of magnitude in field-scale shale formations remains technically challenging. Therefore, the present work does not propose a deployable permeability enhancement technology. Instead, matrix permeability multipliers are employed as hypothetical numerical sensitivity scenarios to establish theoretical recovery limits and investigate the contribution of matrix-to-fracture mass transfer under various depletion conditions.

Shale reservoirs are categorized as unconventional hydrocarbon resources due to their ultra-low permeability, nano-scale pore structures, and highly heterogeneous rock properties. Despite containing enormous hydrocarbon potential, shale formations generally exhibit poor natural productivity because fluid mobility within the matrix system is extremely limited (Fan et al., 2018). Therefore, advanced stimulation technologies, such as horizontal drilling and hydraulic fracturing, are required to achieve economically sustainable production (King et al., 2010).

Junira & Wibowo (2016) explained that shale reservoirs differ significantly from conventional reservoirs as they simultaneously act as source rock, reservoir rock, and seal rock. In addition, shale reservoirs commonly have permeability below 0.1 mD and porosity below 10%, making hydrocarbon extraction extremely difficult without artificial stimulation. The study emphasized that horizontal drilling and hydraulic fracturing are the key technologies enabling commercial shale development worldwide. Furthermore, lessons learned from North American unconventional developments indicate that fracture-network complexity and stimulation effectiveness are critical factors governing the sustainability of shale production (Winderasta 2017).

Matrix permeability governs the rate of hydrocarbon transfer from the nanoporous shale matrix to the hydraulic-fracture network and therefore represents a critical parameter controlling long-term unconventional reservoir recovery. Although hydraulic fractures create highly conductive flow pathways, the shale matrix remains the primary hydrocarbon storage medium. Consequently, hydrocarbon recovery strongly depends on the matrix's ability to transport fluids toward the fracture network. Although Fan et al. (2018) emphasized the challenge of accurately measuring permeability, their study did not evaluate how uncertainty in matrix permeability affects EUR predictions across various well-spacing scenarios.

Modern studies have also reported that gas transport mechanisms in shale reservoirs differ substantially from those in conventional Darcy-flow systems due to nanoscale pore confinement and stress-sensitive permeability behaviour. Ghanbarian et al. (2020) demonstrated that gas relative permeability in unconventional reservoirs is strongly influenced by nano-pore structures and pressure-dependent permeability evolution. The study indicated that unconventional gas-flow behaviour may deviate significantly from conventional flow assumptions, especially during depletion processes in ultra-tight formations.

Hydraulic fracturing creates SRV, which becomes the main productive region surrounding the horizontal wellbore. The performance of the SRV depends on fracture conductivity, fracture spacing, stress redistribution, and matrix-fracture interaction. Taghichian et al. (2018) reported that fracture propagation and fracture aperture behaviour are strongly controlled by stress conditions and rock toughness. Similarly, Lolon et al. (2009) demonstrated that horizontal well orientation, fracture spacing, and fracture conductivity significantly affect unconventional reservoir productivity.

Several studies have investigated the influence of fracture spacing and fracture-network complexity on shale production performance. Cipolla (2009) demonstrated that reducing fracture spacing substantially improves gas recovery by accelerating hydrocarbon drainage from the matrix toward the fracture network. The study also suggested that highly complex fracture networks may partially compensate for ultra-low matrix permeability conditions. Al-Rbeawi & Al-Kaabi (2020) further developed a hybrid unconventional reservoir model incorporating anomalous diffusion, stimulated matrix permeability, and non-Darcy fracture flow. Their results demonstrated that increasing stimulated matrix permeability significantly reduces pressure drop and improves productivity index.

Geomechanical behaviour is another important factor controlling fracture propagation and long-term production sustainability in unconventional reservoirs. Warpinski & Teufel (1987) explained that in situ stress conditions are the dominant factors governing hydraulic fracture propagation, compared with lithological discontinuities or variations in elastic properties. King (2010) also reported that hydraulic fracturing may alter local stress conditions and redistribute stress around the fracture network, potentially affecting fracture conductivity during long-term production.

Recent geomechanical studies have emphasized that permeability evolution and fracture conductivity change dynamically during reservoir depletion. Bui (2023) explained that stress-sensitive permeability and fracture-conductivity degradation are critical parameters that control long-term unconventional reservoir productivity. Similarly, Heydari et al. (2024) demonstrated that geomechanical deformation and reactive transport processes within shale microfractures can alter fracture aperture and the evolution of permeability during production depletion. These findings indicate that geomechanical deformation strongly influences fluid-flow behaviour and fracture sustainability in unconventional reservoirs.

Real-time fracture monitoring has also become increasingly important for evaluating the effectiveness of hydraulic fracturing and the evolution of stress. Le Calvez et al. (2007) demonstrated that microseismic monitoring can provide valuable information on fracture propagation and reservoir stress redistribution during hydraulic fracturing operations. Such monitoring technologies are useful for optimizing fracture geometry, fracture spacing, and stimulation efficiency.

Another major challenge in unconventional reservoir development is parent–child well interference. Parent wells refer to existing producing wells, while child wells are newly drilled infill wells located near depleted parent wells. As unconventional developments become denser, hydraulic fractures from adjacent wells may interact, creating fracture-driven communication or “frac-hit” phenomena. Wang et al. (2021) reported that pressure communication between parent and child wells significantly affects production forecasting and EUR optimization in unconventional reservoirs. Similarly, Liu et al. (2026) demonstrated that fracture-hit behaviour becomes increasingly severe under tight well-spacing conditions, leading to dynamic fracture interactions and production interference between adjacent wells.

1.2 Parent–Child Well Interference mechanism

Parent–child well interaction has become one of the most critical technical challenges in modern unconventional reservoir development. As shale developments mature, operators increasingly adopt infill drilling strategies, placing new horizontal wells (child wells) adjacent to previously producing wells (parent wells) to maximize reservoir contact and improve field recovery. However, long-term production from parent wells alters the reservoir pressure distribution and local stress state, which may significantly influence the performance of subsequently drilled child wells. Consequently, the production behaviour of child wells is controlled not only by well spacing but also by complex interactions involving depletion shadow, stress shadow, fracture shielding, and fracture-driven communication mechanisms (Wang et al., 2021).

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In addition to pressure depletion, production from the parent well also modifies the local geomechanical environment through stress shadow development. Reservoir pressure reduction increases effective stress in the rock matrix and alters the distribution of minimum horizontal stress surrounding existing hydraulic fractures. As depletion progresses, the local stress field becomes increasingly heterogeneous, potentially affecting the propagation path of fractures generated during child-well stimulation. Soliman et al. (2019) reported that depletion-induced stress changes can significantly influence fracture geometry and stimulation efficiency, particularly in tightly spaced unconventional developments where hydraulic fractures from adjacent wells are likely to interact. Consequently, the performance of child wells depends not only on reservoir pressure but also on the evolving geomechanical conditions shaped by the parent well's production history.

Another important mechanism is fracture shielding, which occurs when preexisting hydraulic fractures alter the local stress field and impede the propagation of newly formed fractures. Under fracture-shielding conditions, child-well fractures may be unable to effectively access unstimulated reservoir rock, resulting in reduced stimulated reservoir volume (SRV) and lower hydrocarbon recovery. Fracture shielding is Another important mechanism is fracture shielding, which occurs when preexisting hydraulic fractures alter the local stress field and impede the propagation of newly formed fractures. Under fracture-shielding conditions, child-well fractures may be unable to effectively access unstimulated reservoir rock, resulting in reduced stimulated reservoir volume (SRV) and lower hydrocarbon recovery. Fracture shielding is particularly severe in densely developed shale plays where inter-well spacing is limited and hydraulic fractures from adjacent wells overlap significantly. This mechanism has been identified as one of the principal causes of child-well underperformance in many unconventional reservoirs (Ajisafe et al., 2019).

Despite the commonly observed depletion-shadow and fracture-shielding effects, recent studies have demonstrated that parent–child interactions do not always result in child-well underperformance. Under certain reservoir and completion conditions, depletion-induced stress redistribution may create favourable pathways for fracture propagation toward depleted regions surrounding the parent well. This phenomenon is commonly referred to as fracture-driven interaction (FDI) or frac-hit behaviour. Wang et al. (2021) reported that strong pressure communication between adjacent wells may significantly alter production performance and reservoir drainage patterns. Similarly, Liu et al. (2026) demonstrated that FDI become increasingly severe under tight well-spacing conditions, creating highly conductive pathways that promote dynamic communication between neighbouring fracture systems.

Frac-hit events occur when hydraulic fractures generated during child-well stimulation intersect or establish hydraulic communication with pre-existing fractures associated with the parent well. Such interactions may produce either beneficial or detrimental outcomes depending on reservoir conditions, completion design, and depletion severity. In many field developments, frac-hit behaviour causes temporary production disruption, pressure interference, or accelerated decline of the parent well. However, in some cases, fracture-driven communication may enhance fluid transport efficiency by creating highly conductive fracture networks that improve connectivity between the reservoir matrix and hydraulic fractures (Wang et al., 2021; Liu et al., 2026). These observations suggest that parent–child well behaviour cannot be interpreted solely through depletion-shadow mechanisms but must also consider dynamic fracture propagation and inter-well communication processes.

Figure 1 illustrates the principal mechanisms governing parent–child well interactions in unconventional reservoirs, including FDI, direct frac-hit communication, indirect hydraulic communication through natural fracture networks, and the influence of inter-well spacing on fracture interference. These mechanisms have become increasingly important as operators adopt tighter well spacing and infill-drilling strategies to maximize reservoir contact and improve hydrocarbon recovery (Al-Rbeawi 2020).

As shown in Figure 1a, FDI may occur when hydraulic fractures generated during child-well stimulation propagate toward natural fractures and previously stimulated reservoir volumes associated with the parent well. The presence of interconnected natural fracture systems can significantly enhance hydraulic communication between adjacent wells, thereby altering pressure distribution and reservoir drainage patterns. Wang et al. (2021) reported that such FDI can substantially influence production performance and EUR in unconventional developments.

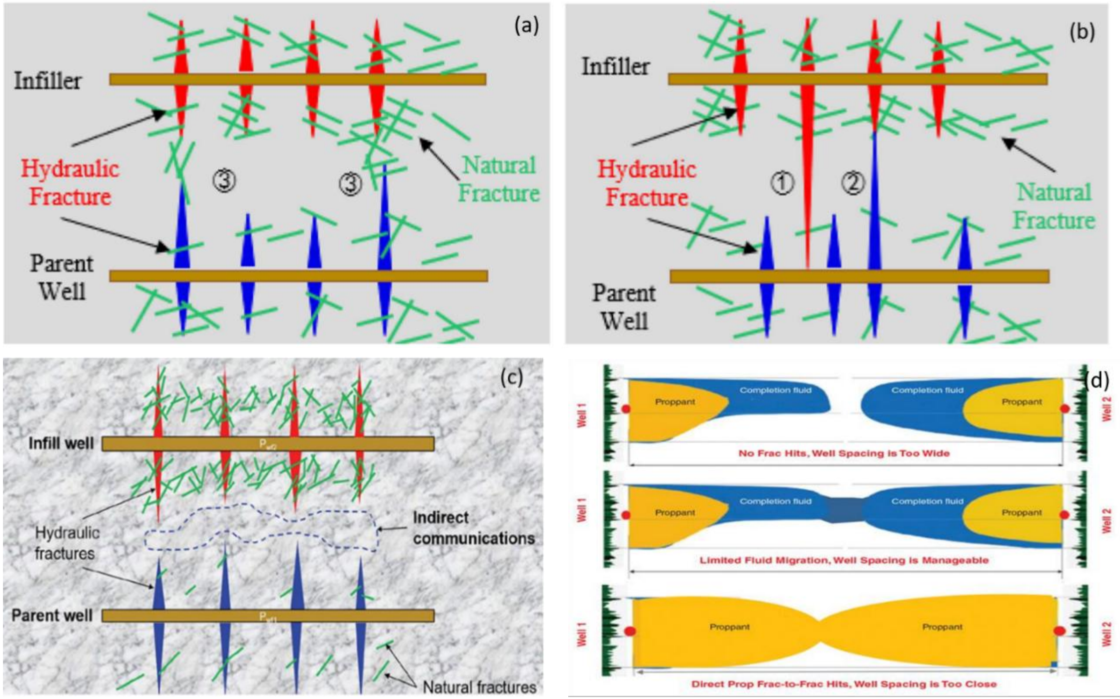


Figure 1.
Conceptual mechanism governing parent-child well interaction: (a). FDI through natural fractures, (b). Direct frac-hit, (c). Indirect hydraulic communication, (d). Well-spacing effect (adapted from Roussel et al (2013), Al-Rbeawi (2020), Wang et al. (2021), and Liu et al. (2026).

Figure 1b illustrates direct frac-hit behaviour, in which hydraulic fractures generated from the child well physically intersect or establish direct communication with pre-existing parent-well fracture systems. Direct frac-hit events may generate significant pressure interference, temporary production disruption, and changes in fracture conductivity. Liu et al. (2026) demonstrated that the severity of frac-hit behaviour increases as inter-well spacing decreases, thereby increasing the likelihood of hydraulic communication between neighbouring wells.

In contrast, Figure 1c illustrates indirect hydraulic communication, in which pressure interaction occurs through interconnected natural fractures and microfracture networks without direct fracture intersections. Under these conditions, pressure signals can be transmitted between wells despite the absence of a continuous hydraulic-fracture connection. Such indirect communication may alter fluid-flow behaviour and influence hydrocarbon drainage efficiency over large portions of the stimulated reservoir volume.

Figure 1d highlights the critical role of well spacing in controlling parent–child well interactions. Excessive spacing may result in isolated fracture systems with limited reservoir communication, whereas overly tight spacing can promote severe frac-hit behaviour and production interference. Intermediate spacing conditions generally provide a balance between reservoir contact and manageable fracture communication. Al-Rbeawi (2020) demonstrated that well spacing and fracture-cluster spacing are among the most influential parameters controlling production performance in unconventional reservoirs.

Although Figure 1 illustrates several fracture-interaction mechanisms, it does not explicitly represent depletion-shadow effects. Depletion shadow is fundamentally a pressure-depletion phenomenon that develops when prolonged production from a parent well creates a localized low-pressure region surrounding the stimulated reservoir volume. The resulting pressure sink may subsequently influence fracture propagation, stress redistribution, and pressure communication during child-well stimulation. Therefore, depletion-shadow effects are more appropriately visualized using reservoir pressure distribution maps rather than fracture geometry schematics.

Collectively, these mechanisms demonstrate that parent–child well performance is governed by a complex interaction among hydraulic fractures, natural fractures, pressure depletion, and geomechanical evolution.

Consequently, the successful development of unconventional reservoirs requires an integrated evaluation of fracture geometry, pressure communication, depletion history, and well-spacing optimization to maximize long-term hydrocarbon recovery.

1.3 Depletion shadow and its impact on child well performance

One of the most widely recognized mechanisms affecting parent–child well performance in unconventional reservoirs is the development of a depletion shadow. A depletion shadow refers to the localized low-pressure region created around a producing parent well as reservoir fluids are continuously withdrawn. As production progresses, reservoir pressure declines in the vicinity of the parent well, creating a pressure sink that may extend beyond the stimulated reservoir volume and influence nearby infill drilling locations (Al-Rbeawi 2020).

The formation of a depletion shadow affects both reservoir-flow behaviour and geomechanical conditions. From a reservoir-engineering perspective, pressure depletion reduces the available reservoir energy that drives hydrocarbon flow toward production wells. Consequently, child wells drilled within a depleted region often experience lower initial reservoir pressure, reduced productivity, and lower EUR compared with parent wells. Numerous field studies have reported significant production degradation in child wells when infill drilling is conducted after substantial depletion of parent wells (Ajisafe et al., 2019; Wang et al., 2021).

From a geomechanical standpoint, pressure depletion increases effective stress within the rock matrix according to Equation 1,

$$\sigma' = \sigma - \alpha P \qquad (1)$$

where σ’, σ, α, and P are effective stress, total stress, Biot coefficient, and pore pressure, respectively. As pore pressure decreases, effective stress increases, resulting in stress redistribution around the parent-well fracture network. This phenomenon is commonly referred to as a stress shadow and may significantly alter hydraulic-fracture propagation during child-well stimulation. Soliman et al. (2019) reported that depletion-induced stress redistribution can cause fractures generated from child wells to be either attracted to or repelled from previously depleted regions, depending on the local stress configuration.

In addition to pressure depletion and stress redistribution, depletion shadows may promote FDI between parent and child wells. The pressure gradient established between newly stimulated child-well fractures and the depleted parent-well region may encourage fracture propagation toward the pressure sink. Under such conditions, hydraulic communication can develop through direct frac-hit events or indirect pressure communication through natural fracture networks. Wang et al. (2021) and Liu et al. (2026) demonstrated that these interactions become increasingly significant as well spacing decreases and fracture networks become more interconnected.

Although depletion shadows are commonly associated with child-well underperformance, recent studies suggest that under specific reservoir and completion conditions, they may also contribute to temporary production enhancement. Severe pressure depletion around the parent well may create strong pressure gradients that accelerate hydrocarbon transfer toward newly stimulated fracture systems. When combined with FDI and favourable geomechanical conditions, this mechanism may result in localized child-well overperformance despite reservoir depletion. Therefore, parent–child well behaviour should not be interpreted solely through depletion-shadow concepts but rather through the coupled effects of pressure depletion, fracture communication, and geomechanical evolution.

Understanding depletion-shadow development is therefore essential for optimising well spacing, completion timing, hydraulic fracture design, and long-term unconventional reservoir recovery. Accurate characterization of depletion patterns can help operators minimize adverse parent–child interactions while maximizing stimulated reservoir volume utilization and hydrocarbon recovery efficiency.

The complex interplay among depletion shadow, stress shadow, fracture shielding, and FDI highlights the importance of integrated reservoir-geomechanical analysis when evaluating parent–child well performance. While conventional field experience generally indicates that child wells tend to underperform due to reservoir depletion, specific combinations of pressure communication, stress redistribution, and fracture-network connectivity may occasionally produce anomalous production behaviour. Therefore, understanding the coupled effects of reservoir depletion, fracture dynamics, and geomechanical evolution remains essential for optimizing well spacing, stimulation design, and long-term recovery strategies in unconventional shale reservoirs.

Table 1.
Review impact matrix permeability on cumulative production.

Experiment	Test effect parameters	Matrix permeability induced	Cumulative production index	Reference
Hybrid model (simulation)	Anomalous diffusion, matrix permeability, non-darcy flow permeability	1-1000 stimulated coeficient	Slightly increased	Al-Rbeawi & Al-Kaabi 2020
Analytical model (simulation)	Stimulated reservoir volume (srv)	Equal to symmetrical constant & varied – asymmetrical srv	No significantly impact	Al-Rbeawi 2020
Forcasting model (simulation)	Matrix permeability, fracture spacing	1-100 x times matrix permeability	Significantly increased	Cipolla 2009

The Eagle Ford shale reservoir has become one of the most productive unconventional reservoirs in North America (Tian et al., 2014). According to the U.S. Energy Information Administration (2011), the Eagle Ford formation contains substantial recoverable hydrocarbon resources. The reservoir permeability ranges from approximately 1 to 800 nano-Darcy (Inamdar et al., 2010; Stegent et al., 2010), making production performance highly dependent on hydraulic-fracture effectiveness, pressure management, and geomechanical stability.

The modelled data for gas-condensate and oil from the Eagle Ford shale reservoir located in South Texas, US, are used for this purpose (Figure 2). Eagle Ford shale has become one of the fastest-growing unconventional developments in the United States following the successful commercialization of the Barnett, Haynesville, and Marcellus shale plays (U.S. Energy 2011). According to reports published in 2009, the estimated natural gas and oil recoverable from Eagle Ford Shale were 21 Tcf and 3 billion barrels, respectively. The reservoir depth ranges from 2,500 to 14,000 ft; the thickness gap ranges from 50 to more than 300 ft; the pressure-gradient gap ranges from 0.4 to 0.8 psi/ft; and the TOC gap ranges from 2 to 9%. In the core analysis, the gas saturation gap ranges from 83% to 85%, and permeability varies from 1 to 800 nD.

Although previous studies have independently investigated matrix permeability enhancement, hydraulic fracture conductivity, geomechanical deformation, and parent–child well interference, limited studies have quantitatively evaluated their coupled effects on long-term EUR optimization using an integrated compositional-geomechanical simulation framework. This knowledge gap motivates the present study. Therefore, this study aims to bridge this gap by investigating the combined effects of hypothetical matrix permeability enhancement and parent–child well implementation on the cumulative production, pressure behaviour, and geomechanical response of the Eagle Ford shale reservoir.

Despite significant advances in understanding matrix permeability, fracture effectiveness, and parent-child interactions individually, no previous study has quantitatively evaluated the coupled effects of hypothetical permeability enhancement, geomechanical deformation, and fracture-driven communication within a unified compositional-geomechanical simulation framework using Eagle Ford shale properties. This gap motivates the present investigation.

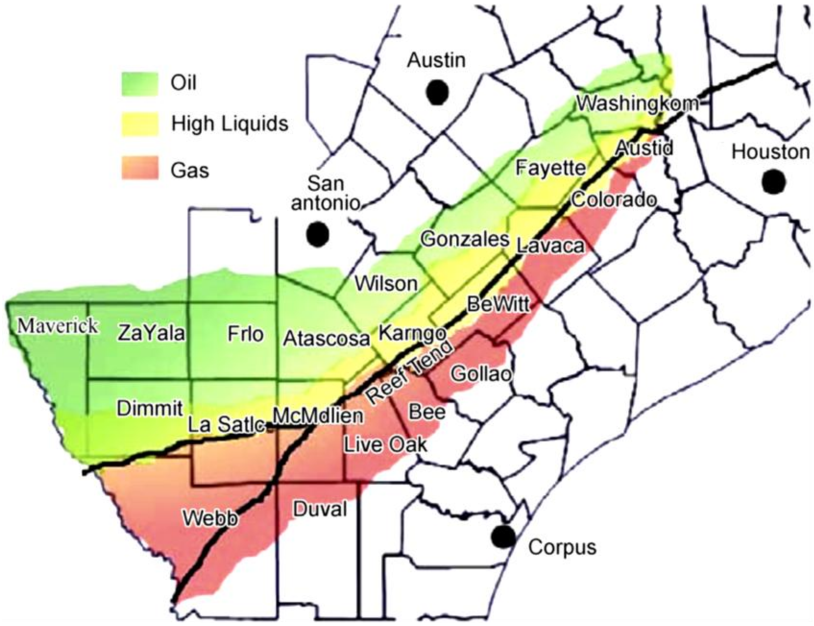


Figure 2.
Lateral extent of Eagle Ford shale reservoir

2. Methodology

2.1 Reservoir model development

This study used a compositional reservoir simulation approach to evaluate the influence of hypothetical matrix permeability enhancement and parent–child well interactions on the EUR of an unconventional shale reservoir. The simulation integrates hydraulic-fracture modeling, production sensitivity analysis, and geomechanical evaluation using the GEM simulator and CMOST optimization tools. The Eagle Ford shale reservoir was selected as the case study because it is one of the most productive unconventional shale formations, with ultra-low permeability and extensive use of hydraulic fracturing (Tian et al., 2014; Inamdar et al., 2010; Stegent et al., 2010). The methodology also accounted for the unconventional characteristics of shale reservoirs, including ultra-low permeability, nanoscale pore systems, stress-sensitive fracture conductivity, and complex geomechanical behaviour, as discussed by Junira & Wibowo (2016). In shale formations, the matrix simultaneously serves as a hydrocarbon source rock and a storage medium, leading to hydrocarbon flow behaviour that differs significantly from that in conventional reservoirs. Therefore, an integrated evaluation of fracture-network performance, matrix permeability evolution, and stress redistribution is essential for understanding unconventional reservoir productivity (King et al., 2010; Junira & Wibowo 2016).

A conceptual reservoir model was developed to investigate the interaction between hydraulic fractures, stress redistribution, and production performance in horizontal wells. Two simulation scenarios were constructed. The first scenario consisted of a single horizontal well with multi-stage hydraulic fractures, while the second scenario involved a pair of horizontal wells representing the parent–child well configuration. The comparison between the two models was intended to evaluate the impact of interwell interference, pressure depletion, and fracture interaction on cumulative production and geomechanical behaviour (Wang et al., 2021; Al-Rbeawi 2020).

The reservoir model utilized a Cartesian grid system of 211×211×5 (Figure 3). The reservoir top depth was defined at 11,800 ft with a total thickness of 100 ft. Reservoir properties included matrix porosity of 0.05 fraction, fracture porosity of 0.05 fraction, matrix permeability of 0.0075 mD, and fracture permeability of 0.00075 mD. The initial reservoir pressure was set to 10,000 psi at a depth of 12,000 ft, with the water-oil contact at 13,000 ft. These reservoir conditions were selected to represent the typical characteristics of Eagle Ford shale reservoirs (Tian et al., 2014; U.S. Energy 2011).

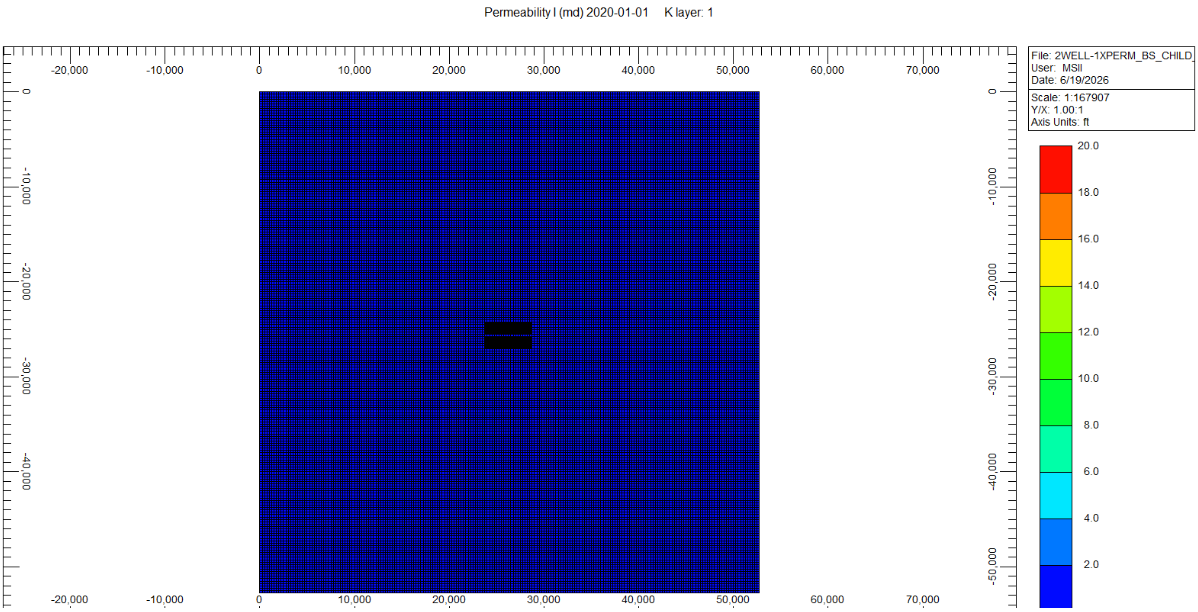


Figure 3.
Global cartesian grid used in the parent–child well simulation model

Table 2.
Initial condition of gas cap condensate

Component	Z Gas
N2	0.03
C1	0.65
C2	0.104
C3	0.103
C4-6	0.07
C7+	0.07
Total	1.00

2.2 Fluid characterization

The reservoir fluid system was modelled as a gas-condensate system using compositional fluid analysis. The fluid composition included hydrocarbon and non-hydrocarbon components such as N2, C1, C2, C3, C4–6, and heavy fractions (C7+, C11+, C15+, and C20+) (Table 2 and Table 3). The compositional properties included molecular weight, specific gravity, acentric factor, critical temperature, critical pressure, and critical volume for each component (Heydari et al., 2024). The Peng–Robinson equation of state (EOS) was used to model fluid property variation under reservoir conditions during depletion and production.

2.3 Single well modeling

The first stage of the study focused on a single horizontal well equipped with multi-stage hydraulic fractures (Figure 4 and Figure 5). The well was completed with 20 hydraulic fractures distributed symmetrically along both sides of the lateral section. The fracture half-length was set to 500 ft, and the fracture width was 50 ft. Fracture permeability near the wellbore was assigned as 20 mD, whereas fracture-tip permeability was reduced to 5 mD to represent conductivity degradation away from the wellbore. The fracture behavior and conductivity distribution were designed based on unconventional fracture-network concepts discussed in previous studies (Winderasta 2017; Lolon et al., 2009; Cipolla 2009).

Table 3.
Compositional data of Eagle Ford oil (Kamari et al., 2018).

Composition	MW	Specific gravity	Acentric factor	Tc, R	Pc, Psia	Vc, cft/lbm
C1	16.064	0.35	0.013	343.3	673.1	1.5658
N2	28.01	0.808	0.04	227.2	492.3	1.4256
C2	30.07	0.48	0.0986	549.8	708.4	2.3556
C3	44.1	0.5077	0.1524	665.8	617.4	3.2294
CO2	44.01	0.8159	0.225	547.6	1071.3	1.5126
IC4	58.12	0.5631	0.1848	734.6	529.1	4.2127
NC4	58.12	0.5844	0.201	765.4	550.7	4.1072
IC5	72.15	0.6248	0.2223	828.7	483.5	4.9015
NC5	72.15	0.6312	0.2539	845.6	489.5	5.0232
NC6	86.18	0.6641	0.3007	914.2	439.7	5.9782
C7+	114.4	0.7563	0.3739	1060.5	402.8	7.4093
C11+	166.6	0.8135	0.526	1223.6	307.7	10.682
C15+	230.1	0.8526	0.6979	1368.4	241.4	14.739
C20+	409.2	0.9022	1.0456	1614.2	151.1	26.745

Table 4.
Compositional data of Eagle Ford condensate (Stegent et al., 2010).

Composition	MW	Specific gravity	Acentric factor	Tc, R	Pc, Psia	Vc, cft/lbm
C1	16.04	0.35	0.013	343.26	673.08	1.5658
N2	28.01	0.808	0.04	227.16	492.32	1.4256
C2	30.07	0.48	0.0986	549.774	708.35	2.3556
C3	44.1	0.5077	0.1524	665.82	617.38	3.2294
CO2	44.01	0.8159	0.225	547.56	1071.3	1.5126
IC4	58.12	0.5631	0.1848	734.58	529.06	4.2127
NC4	58.12	0.5844	0.201	765.36	550.66	4.1072
IC5	72.15	0.6248	0.2223	828.72	483.5	4.9015
NC5	72.15	0.6312	0.2539	845.64	489.52	5.0232
NC6	86.18	0.6641	0.3007	914.22	439.7	5.9782
C7+	112	0.7527	0.3673	1051.39	408.59	7.261
C11+	175	0.8201	0.5491	1245.9	296.89	11.2083
C15+	210	0.8424	0.6435	1327.59	259.01	13.435
C20+	250	0.8612	0.7527	1405.81	226.28	16.0488

A horizontal well model was developed using the Prosper simulator to generate the tubing curve (Figures 6 and 7) and employed the Kuchuk and Goode correlation. The objective of this well model is to optimize well productivity (Al-Rbeawi & Al-Kaabi 2020; Ghanbarian et al., 2020).

2.4 Bottom-hole pressure sensitivity analysis

A horizontal well model was developed using the Prosper simulator to generate the tubing curve (Figures 6 and 7) and employed the Kuchuk and Goode correlation. The objective of this well model is to optimize well productivity. A sensitivity analysis was then performed using CMOST experimental design to evaluate the influence of pressure drawdown on cumulative production performance. The optimization process utilized 100 experimental datasets with bottom-hole pressure (BHP) values ranging from 3,000 psi to 10,000 psi at approximately 70 psi intervals, generating 100 distinct scenarios. CMOST optimization identified the BHP that maximized cumulative gas production while maintaining wellbore stability constraints (minimum BHP = 3,000 psi). The objective of this sensitivity analysis was to determine the optimum operating condition capable of maximizing cumulative gas production while maintaining stable reservoir performance. Previous studies reported that pressure-management optimization plays an important role in unconventional reservoir productivity and parent–child well performance (Le Calvez et al., 2007; Wang 2025).

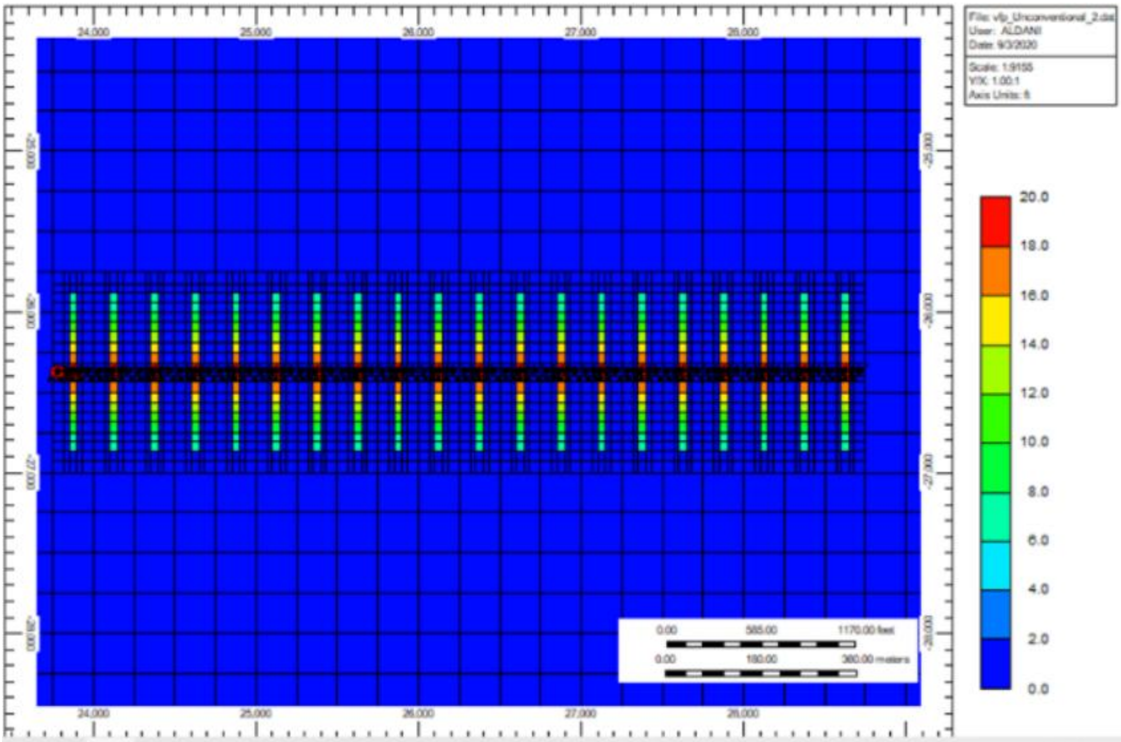


Figure 4.
Multi-stage hydraulic -fracture configuration of the single horizontal well model.

- Shear Stress and Shear Strain Analysis
  Geomechanical behaviour surrounding the hydraulic fractures was investigated by analyzing shear stress and shear strain distributions in selected grid blocks. The stress–strain evaluation was conducted in the IJ, JK, and IK directions to assess anisotropic deformation induced by hydraulic fracturing and reservoir depletion. Previous studies demonstrated that stress redistribution strongly influences fracture propagation, fracture conductivity, and permeability evolution in unconventional reservoirs (King et al., 2010; Taghichian et al., 2018; Bui 2023; Heydari et al., 2024).

Three-dimensional visualization of stress and strain distributions was also performed to identify deformation patterns around the horizontal well and the fracture network. This geomechanical evaluation was intended to investigate the coupling effect between hydraulic-fracture propagation, stress redistribution, and production depletion. Recent studies have indicated that stress-sensitive fracture deformation may significantly influence long-term unconventional reservoir productivity and the evolution of permeability (Bui 2023; Heydari et al., 2024). Subsequently, two additional models were developed by increasing matrix permeability by factors of 10 and 100 relative to the base case.

The next stage is to evaluate BHP sensitivity in the base cases of the three models. The CMOST simulator is used to perform the sensitivity analysis, saving time when running the model. The sensitivity uses 100 different BHP datasets, ranging from 3,000 psi to 10,000 psi in 70 Psi Increments. In this case, the experimental designs used are the same as those in the 100 ID and 100 BHP datasets.

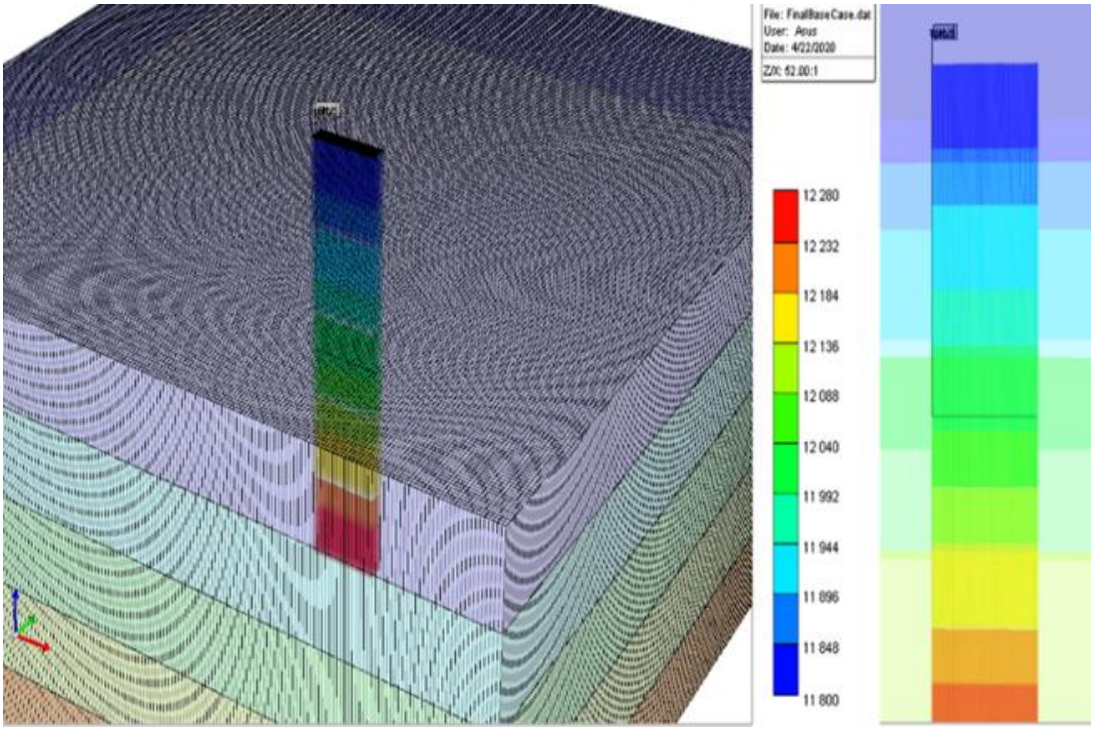


Figure 5.
Location of the well in the model

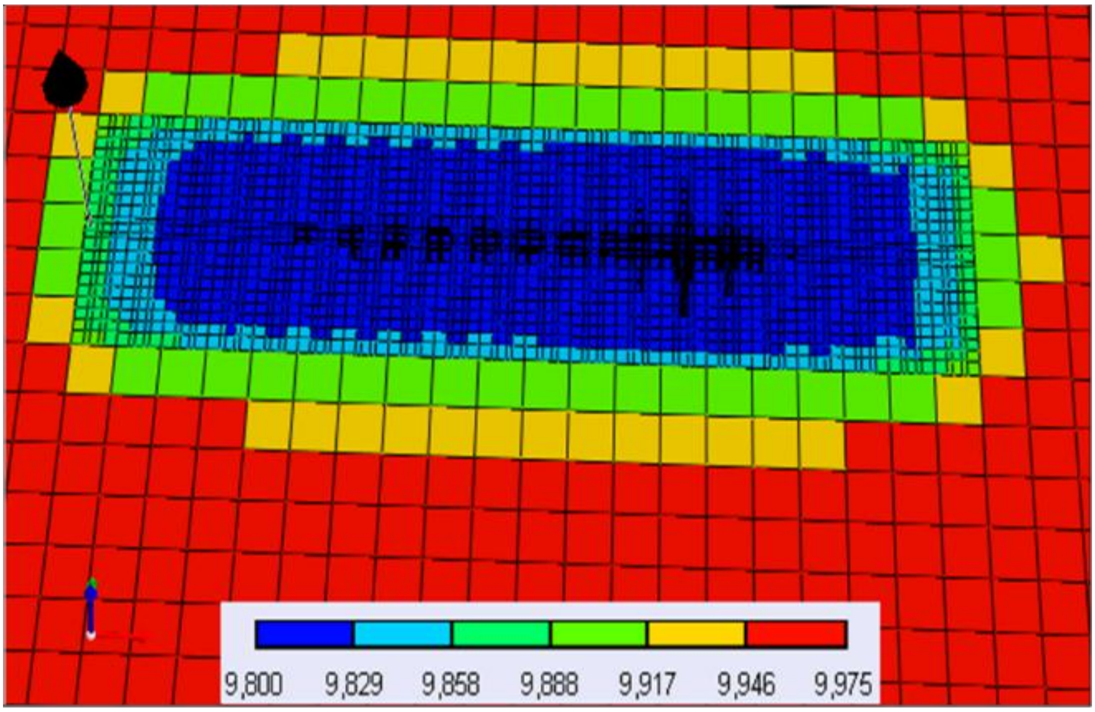


Figure 6.
Pressure distribution in the single model

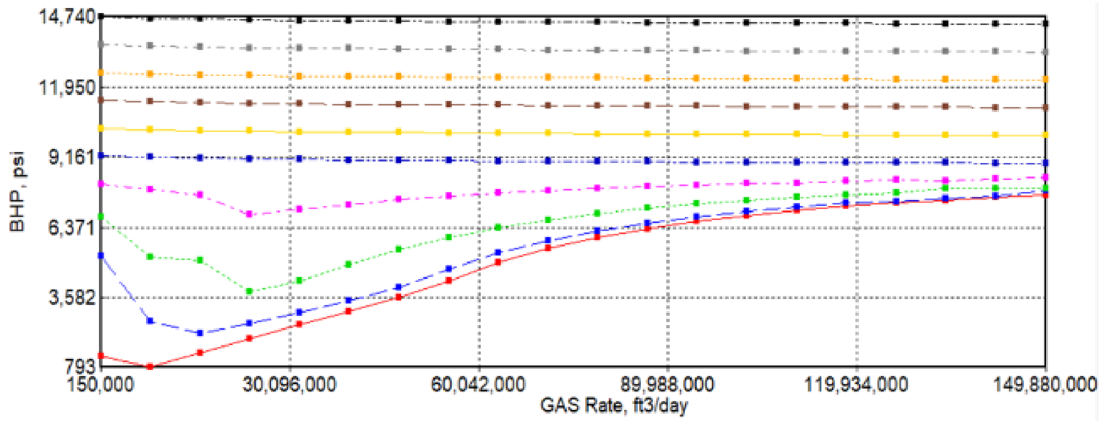


Figure 7.
Tubing performance plot

The primary geomechanical outputs include shear stress and shear strain distributions evaluated at 6, 12, 60, and 120 months. The grid blocks investigated in the model are shown in Figure 7.

106 102 3
106 103 3
106 104 3 } **IJ, IK & JK**
106 105 3
106 106 3

Figure 8.
Grid name for shear strain and shear stress investigation

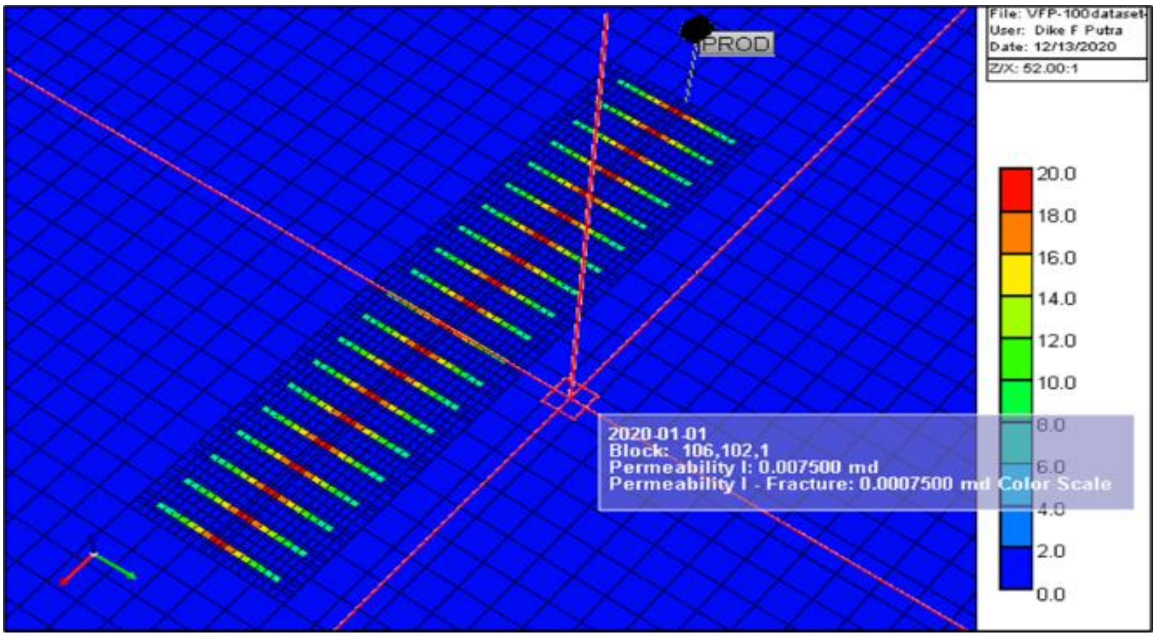


Figure 9.
Grid blocks location for stress and strain investigation

Figure 7 and Figure 8 show one of the grids that was investigated for shear strain and shear stress. From the optimum solution, the shear strain and shear stress are investigated in certain grid blocks. For example, grid block 106 106 3; Figure 9 exhibits the shear strain in block 106 106 3 in three directions. The shear strain in the IJ direction is positive (Figures 10 and 11). Oppositely, the shear stress in the JK direction is negative. Meanwhile, the shear strain in the IK direction changes direction from negative to positive.

Figure 12 and Figure 13 show the different Figure 12 and Figure 13 show the differences between the toe and the heel of the well in the IJ direction. One side of the heel measures positive shear stress, while the toe measures negative shear stress. Oppositely, the phenomenon occurs in an opposite way on the other side.

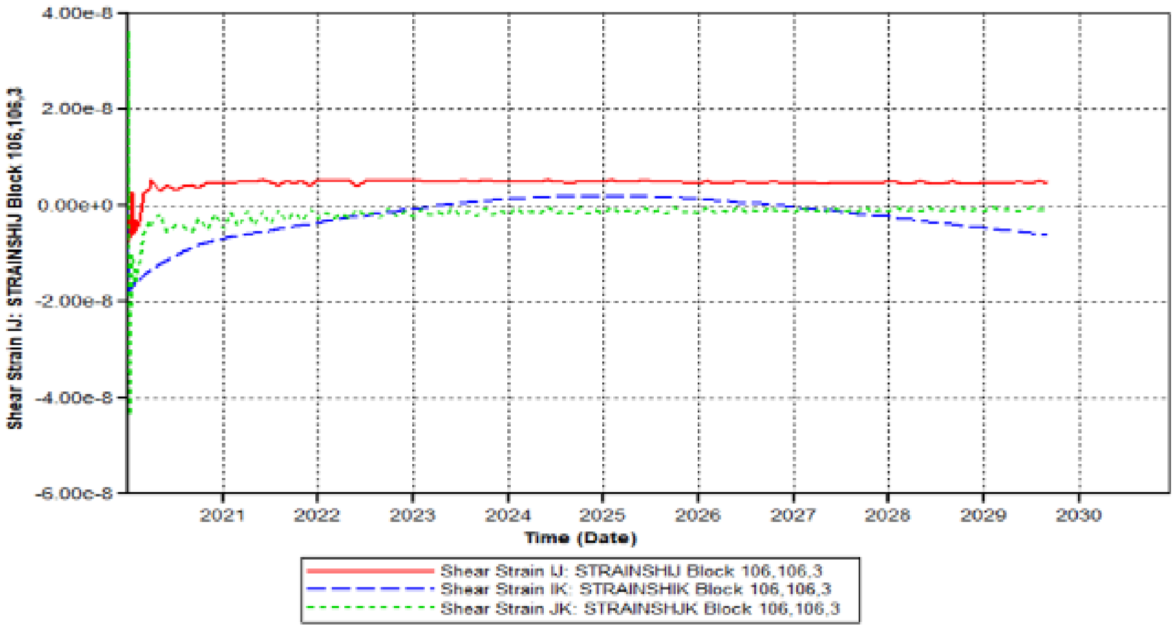


Figure 10.
The shear strain in block 106 106 3

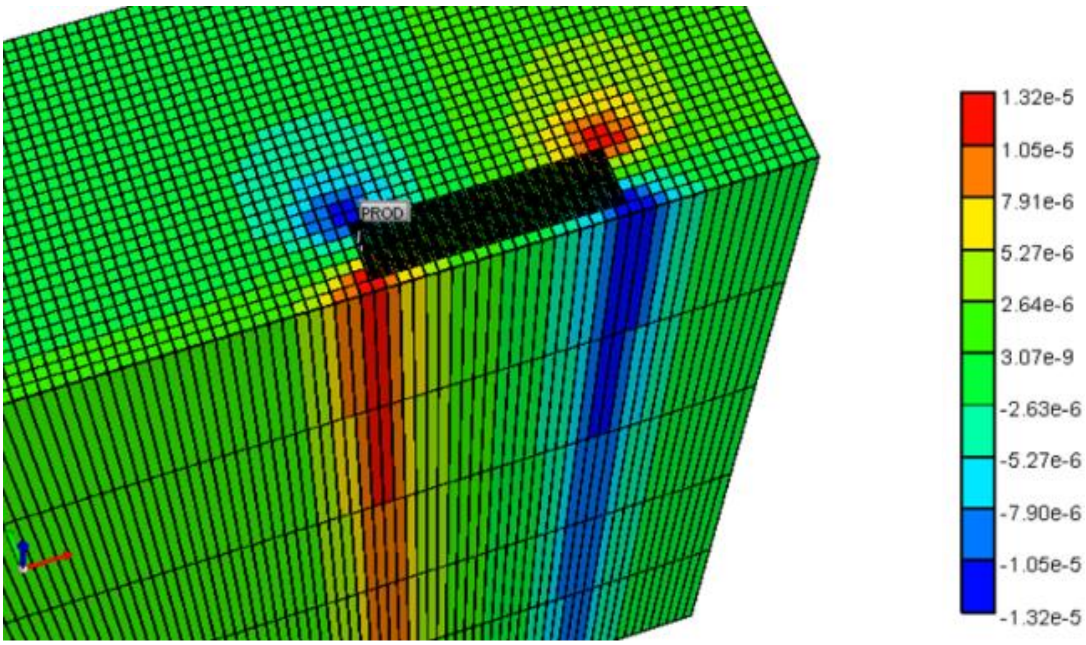


Figure 11.
The 3D virtual of shear strain in the IJ direction

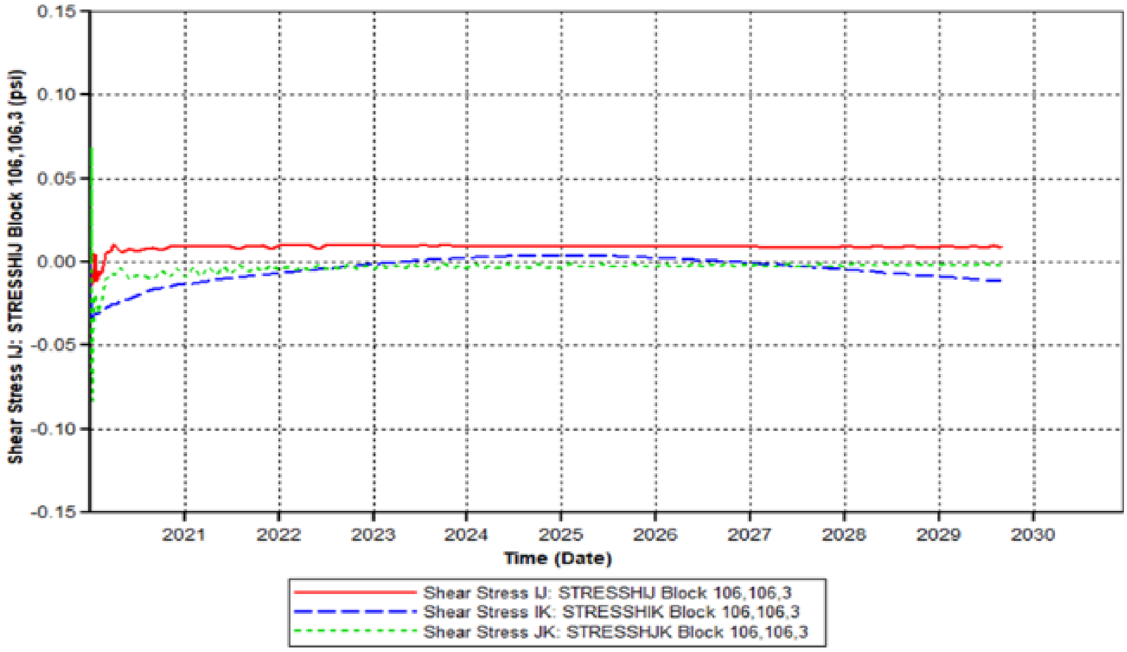


Figure 12.
Shear stress in grid block 106 106 3

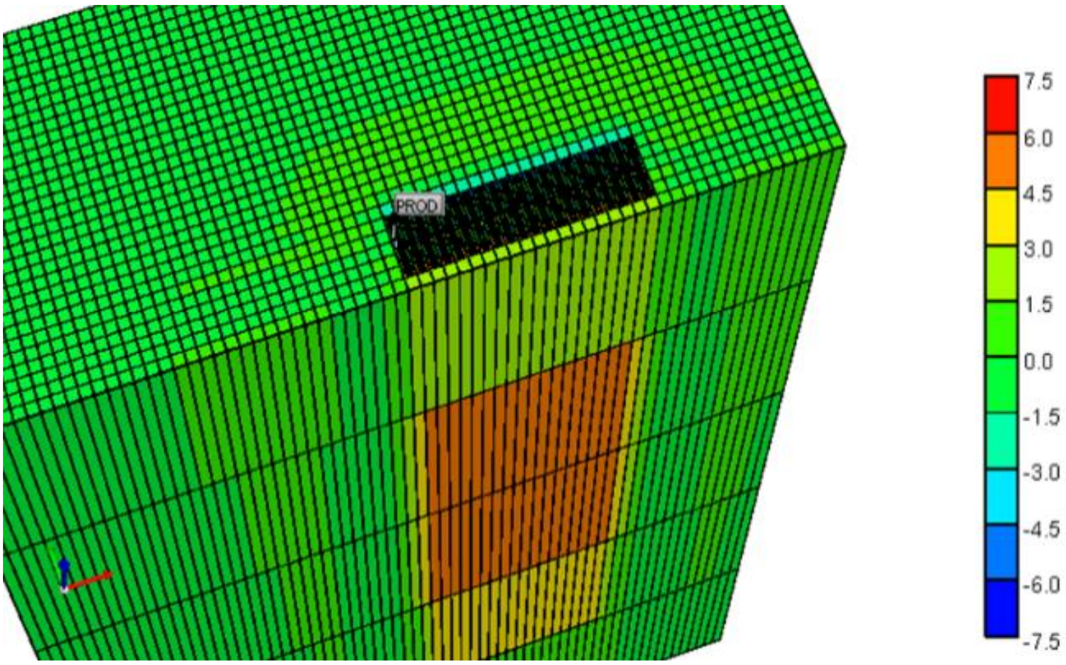


Figure 13.
The 3D virtual of shear stress in the IJ direction

2.5 Parent–child well model

The second stage of this study investigated the interaction between adjacent horizontal wells using a parent–child well configuration. The parent–child well configuration was designed to evaluate fracture-driven communication and pressure interference under relatively tight well-spacing conditions. Previous studies reported that closely spaced unconventional wells may experience fracture-hit behaviour, stress-shadow effects, and dynamic fracture interaction during production and stimulation operations (Le Calvez et al., 2007; Wang et al., 2021, Al-Rbeawi 2020).

A second horizontal well, referred to as the child well, was positioned parallel to the parent well with a spacing of 1,500 ft between wellbores and approximately 500 ft between fracture tips. Both wells had identical completion designs consisting of 20 hydraulic fractures and 5,000 ft horizontal lateral lengths. Gas saturation distribution, cumulative gas production, reservoir pressure behaviour, and wellhead-pressure performance were monitored throughout the simulation period. The parent–child interaction was analyzed to identify production interference, fracture-driven communication, and depletion-shadow effects, which are commonly observed in unconventional reservoir developments (Le Calvez et al., 2007; Wang et al., 2021, Al-Rbeawi 2020).

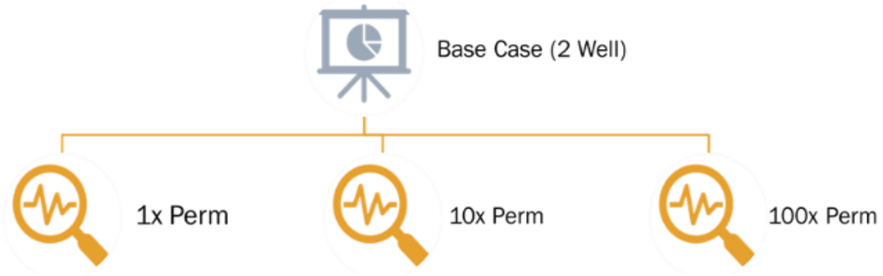


Figure 14.
The second part of case study (parent and child).

The same simulation workflow was applied to all three permeability scenarios, including matrix-permeability variation, BHP sensitivity analysis using 100 hypothetical numerical datasets, and geomechanical evaluation through shear-stress and shear-strain analysis within selected grid blocks (Figure 14).

2.6 Matrix–fracture transfer mechanisms in dual-porosity reservoir systems

The production performance of unconventional shale reservoirs is strongly governed by fluid transfer between the ultra-low-permeability rock matrix and the highly conductive hydraulic-fracture network. Although hydraulic fractures provide the primary production pathways, most hydrocarbons remain stored within the matrix. Consequently, long-term recovery is controlled by the efficiency of matrix-to-fracture mass transfer.

One of the most widely accepted conceptual models describing this mechanism is the dual-porosity model proposed by Warren & Root (1963) and extended by Kazemi et al. (1976). In this formulation, the reservoir is represented by two interacting continuous systems: a low-permeability matrix system that stores hydrocarbons and a high-permeability fracture system that serves as the primary flow conduit toward the wellbore. Fluid transfer between the matrix and fracture systems is expressed as:

$$q_{mf}= \sigma \, (k_m/\mu)(P_m-P_f) \qquad (2)$$

where q_{mf}, σ, km, μ, P_m, and P_f are matrix-to-fracture transfer rate, shape factor, matrix permeability, fluid viscosity, matrix pressure, and fracture pressure, respectively. The relationship in Equation 1 demonstrates that matrix-fracture transfer is directly proportional to the product of matrix permeability and pressure differential. Therefore, any increase in matrix permeability increases hydrocarbon transfer efficiency and accelerates production response.

Kazemi et al. (1976) later extended the Warren–Root concept by introducing transient interporosity flow behaviour. Unlike the pseudo-steady-state assumption adopted by Warren & Root (1963), Kazemi's formulation allows fluid transfer to evolve dynamically as pressure depletion progresses within both matrix and fracture systems. This approach is particularly important for unconventional reservoirs because pressure gradients continuously evolve during production, resulting in time-dependent matrix-fracture communication. The combined Warren–Root and Kazemi frameworks constitute the theoretical foundation of most modern dual-porosity and dual-permeability reservoir simulators, including CMG-GEM. Consequently, matrix permeability is recognized as one of the most influential parameters governing long-term unconventional reservoir performance, as it directly controls the rate at which hydrocarbons migrate from the storage-dominated matrix into the conductive fracture network. Several studies have further demonstrated the importance of matrix permeability in shale-gas production forecasting. Cipolla (2009) reported that matrix permeability significantly affects hydrocarbon drainage efficiency and cumulative recovery, particularly during late-time production periods. Similarly, Al-Rbeawi & Al-Kaabi (2020) demonstrated that stimulated matrix permeability and matrix-fracture interaction substantially influence productivity and pressure-depletion behaviour within unconventional reservoirs. These findings collectively indicate that matrix permeability remains a key parameter controlling long-term EUR in hydraulically fractured shale formations.

2.7 FDI, depletion shadow, and child-well performance

As unconventional developments become increasingly dense, interactions between adjacent horizontal wells have emerged as one of the most important challenges affecting long-term reservoir performance. Parent wells, which are completed and produced first, progressively deplete reservoir pressure within the surrounding stimulated reservoir volume. This depletion creates a localized low-pressure region commonly referred to as a depletion shadow.

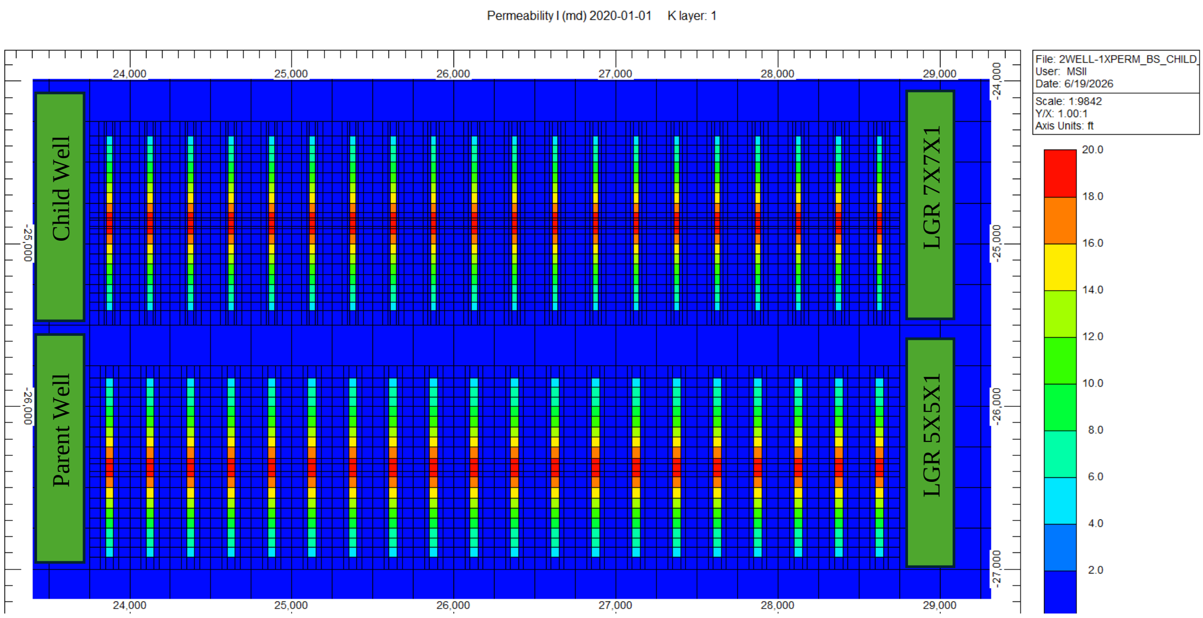


Figure 15.
Local grid refinement (LGR) around parent and child wells

Figure 15 illustrates the implementation of Local Grid Refinement (LGR) around the parent and child wells. The refined grids improve numerical accuracy in regions where strong pressure gradients and FDIs are expected. The use of LGR is particularly important because depletion-shadow and fracture-driven communication occur within a relatively narrow region surrounding the hydraulic fractures.

The depletion-shadow effect is generally associated with reduced child-well productivity because reservoir energy available for hydrocarbon displacement has already been partially consumed by the parent well. Similarly, Ajisafe et al. (2019) demonstrated that depletion-shadow effects often reduce stimulation efficiency and limit access to undrained reservoir volumes.

In addition to reservoir-pressure depletion, production from the parent well alters the local geomechanical environment through stress redistribution. Reducing pore pressure increases effective stress and modifies the local minimum horizontal stress field. This phenomenon is commonly referred to as stress shadowing.

Another important mechanism is fracture shielding, in which previously formed hydraulic fractures modify local stress conditions and restrict the propagation of newly formed fractures. Fracture shielding frequently reduces stimulated reservoir volume and contributes to child-well underperformance. However, recent studies have shown that under certain conditions, depletion-induced stress reorientation may generate the opposite response.

Wang et al. (2021) reported that strong pressure communication between neighbouring wells may create FDI, leading to dynamic communication between adjacent fracture networks. Similarly, Liu et al. (2026) demonstrated that frac-hit behaviour becomes increasingly severe as inter-well spacing decreases, allowing hydraulic fractures to propagate toward depleted regions surrounding parent wells.

Frac-hit events occur when hydraulic fractures generated during child-well stimulation intersect or hydraulically communicate with pre-existing parent-well fracture systems. Depending on reservoir conditions, frac-hit behaviour may either impair or enhance production performance. In some cases, highly conductive communication pathways may develop between fracture networks, creating preferential flow channels that accelerate hydrocarbon transfer and temporarily improve production performance.

These observations indicate that parent–child well performance is governed by a complex interaction among depletion shadow, stress shadow, fracture shielding, and fracture-driven communication. Consequently, understanding the coupled effects of reservoir depletion, fracture propagation, and geomechanical evolution is essential for optimizing well spacing, stimulation design, and long-term recovery in unconventional reservoirs.

3. Result and discussion

The integrated methodology enables comprehensive evaluation of the coupling among reservoir flow physics, hydraulic-fracture performance, pressure behaviour, depletion shadow, and geomechanical response in unconventional shale reservoir development.

3.1 Effect of matrix permeability on cumulative production.

The results of the three models show significant differences in cumulative oil and gas performance (Figure 16 and Figure 17). The simulation results demonstrate that matrix permeability is one of the dominant parameters controlling long-term hydrocarbon recovery in unconventional shale reservoirs. Three permeability scenarios were evaluated: the base-case permeability, a 10× permeability enhancement, and a 100× permeability enhancement. This behaviour confirms that hydrocarbon transfer from the shale matrix toward the hydraulic-fracture network becomes more efficient when matrix-flow capacity improves.

The results suggest that enhancing effective matrix permeability may be as important as increasing fracture complexity. While hydraulic fractures create conductive pathways, long-term production remains governed by the ability of hydrocarbons to diffuse and flow from the matrix toward the fracture network. Consequently, technologies that improve matrix connectivity or stimulate secondary fracture networks may significantly enhance EUR.

In the base-case scenario, production performance remained relatively limited because the ultra-low matrix permeability restricted fluid mobility within the shale formation. Hydrocarbons stored within the matrix could only migrate slowly toward the fracture system, resulting in lower cumulative production and slower reservoir drainage. However, when matrix permeability was increased by factors of 10× and 100×, gas transport to the fracture network became substantially more efficient, leading to higher cumulative gas production and improved EUR. The difference in cumulative gas is up to 400,000 ft3, while the cumulative oil is up to 4,000 bbl. It means the matrix permeability is a key parameter for this model (Figure 18).

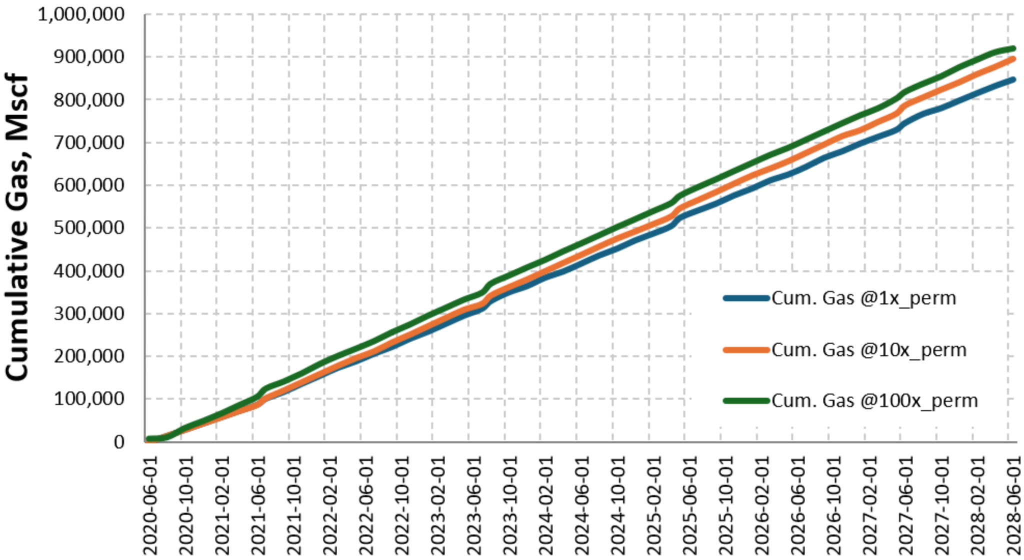


Figure 16.
Comparison of cumulative gas production for the three matrix-permeability scenarios

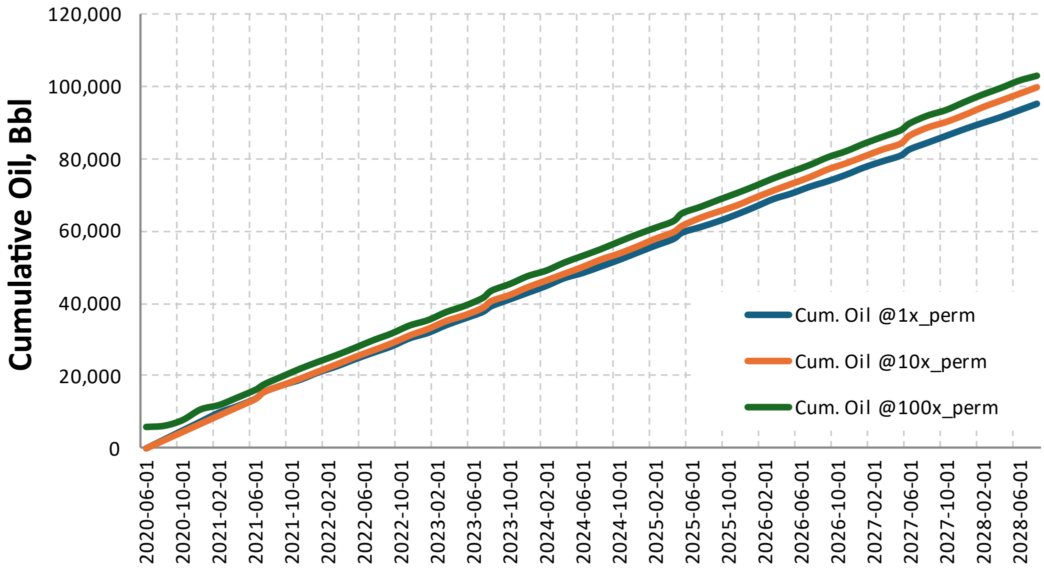
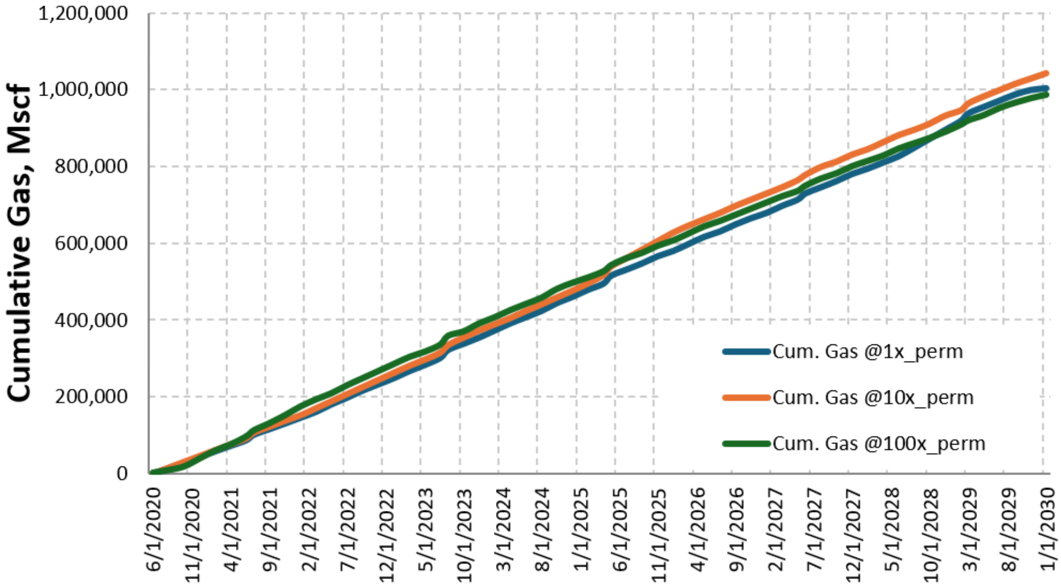


Figure 17.
Comparison of cumulative oil production for the three matrix-permeability scenarios

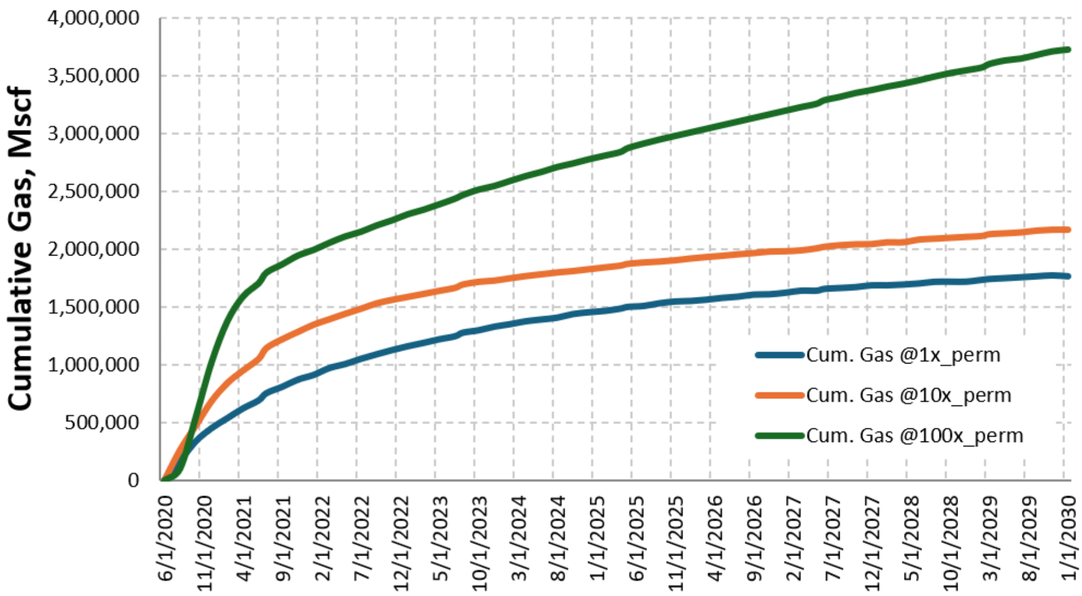
Figure 19 shows gas saturation distribution along both the wellbore and the vicinity near the wellbore. It seems the pressure drawdown in the child well (PROD2) is higher than the parent well (PROD). The impact of pressure drawdown is that gas production from the child well exceeds that from the parent well.

3.2 Theoretical interpretation of matrix permeability sensitivity

The simulation results demonstrate a substantial increase in cumulative gas production as matrix permeability increases from the base-case condition to the 10× and 100× permeability scenarios (Figure 18). Although this trend appears significant, it should be recognised that such behaviour is fundamentally consistent with the governing matrix-to-fracture transfer mechanisms implemented within dual-porosity and dual-permeability reservoir simulators. In unconventional shale reservoirs, hydraulic fractures provide the primary high-conductivity flow pathways, whereas the matrix serves as the dominant hydrocarbon storage medium. Consequently, long-term production performance depends largely on the efficiency of hydrocarbon transfer from the matrix toward the fracture network. According to the pseudo-steady-state formulation proposed by Warren & Root (1963), matrix-fracture transfer is directly proportional to matrix permeability and the pressure differential between the matrix and fracture systems (Figure 20). Similarly, Kazemi et al. (1976) demonstrated that transient matrix-fracture transfer processes strongly influence production behaviour in naturally fractured and dual-porosity reservoirs. Therefore, increasing matrix permeability mathematically accelerates hydrocarbon migration from the matrix to the fracture network, resulting in higher cumulative production and improved recovery efficiency.



Parent well
(a)



Child well
(b)

Figure 18.
Gas cumulative in the parent-child well model

The production enhancement observed in the present study should not be interpreted as evidence of a practical, field-scale permeability-enhancement technology. Instead, the permeability multipliers represent hypothetical numerical sensitivity scenarios designed to establish theoretical upper-bound recovery limits and quantify the relative importance of matrix-flow capacity in unconventional reservoir performance. The results demonstrate that matrix permeability remains one of the most influential parameters governing long-term hydrocarbon recovery, particularly after fracture-dominated early-time production transitions into matrix-controlled depletion.

Furthermore, the sensitivity analysis highlights significant uncertainty in matrix permeability characterisation in shale reservoirs. Because matrix permeability is commonly measured at the nano-Darcy scale and may be affected by core handling, microfracture development, and laboratory testing conditions, production forecasting can vary substantially depending on the assumed matrix permeability value. Consequently, accurate characterisation of matrix permeability remains essential for reliable EUR prediction and reservoir-development planning.

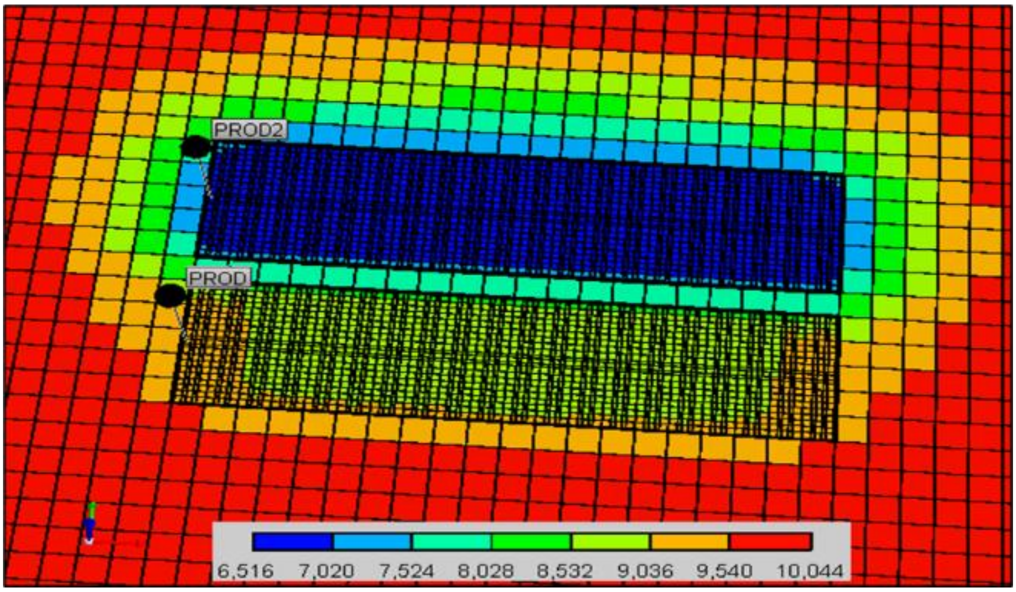


Figure 19.
Gas Saturation distribution illustrating pressure communication between the parent and child wells

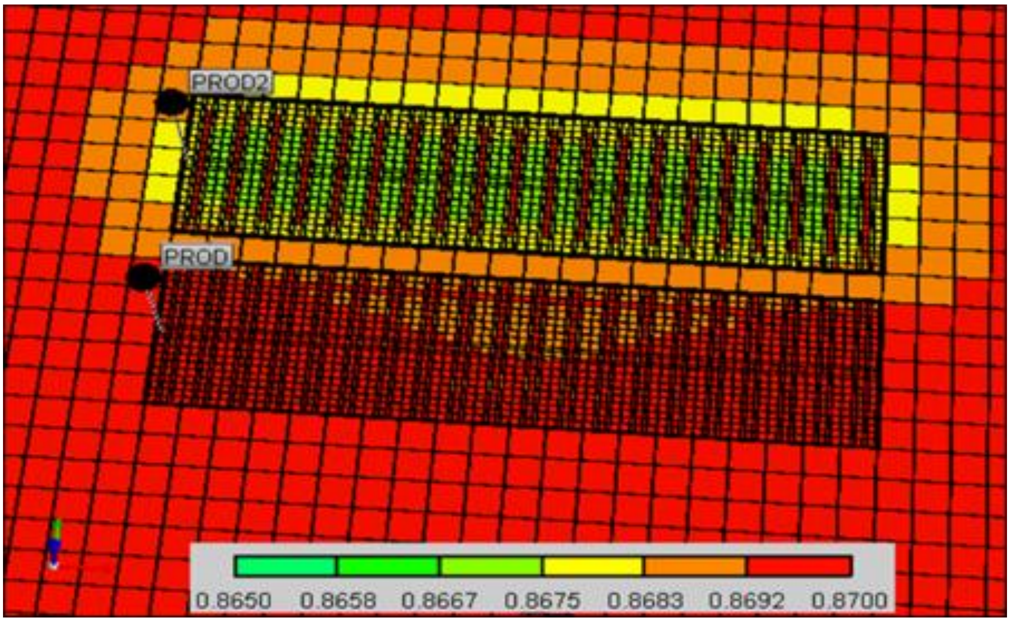


Figure 20.
Pressure distribution in the parent-child well model

3.3 Geomechanical response around hydraulic fractures

In addition to flow-related mechanisms, production performance in unconventional reservoirs is strongly influenced by geomechanical responses induced by hydraulic fracturing and reservoir depletion. Changes in pore pressure alter the effective stress distribution surrounding the fracture network, leading to localized deformation and stress redistribution within the reservoir. As reservoir pressure declines during production, the increase in effective stress may modify fracture conductivity, alter permeability evolution, and influence the mechanical stability of the stimulated reservoir volume (SRV). Consequently, understanding the geomechanical response of the reservoir is essential for interpreting long-term production behavior and parent–child well interaction.

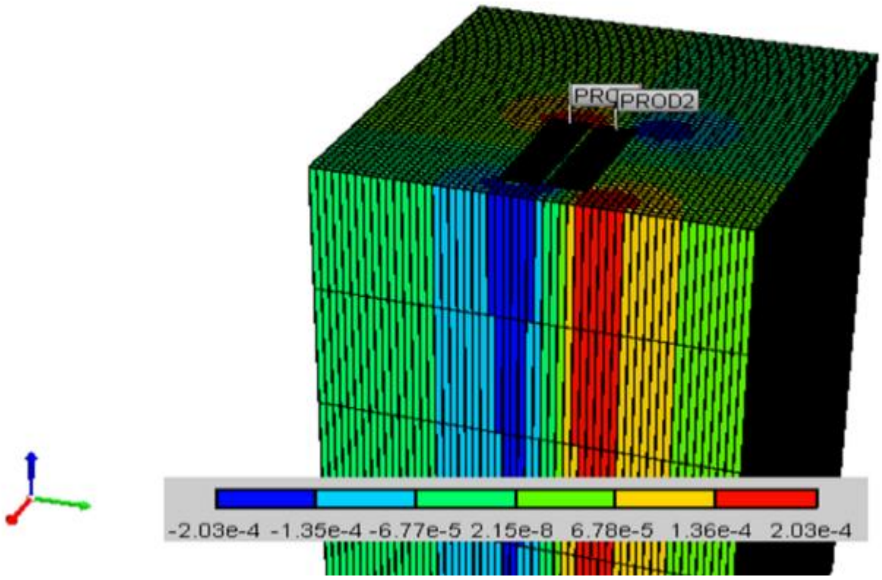


Figure 21.
Three-dimensional shear strain distribution in the parent-child well configuration

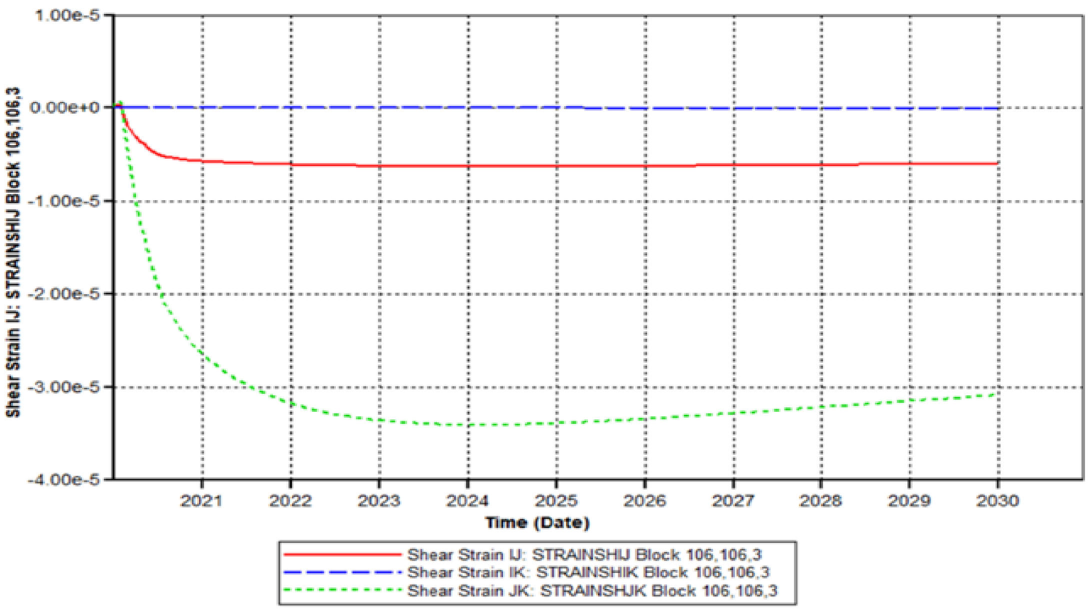


Figure 22.
Shear strain evolution in grid block 106 106 3 for the parent-child well model

Figures 21 and 22 shows the evolution of shear strain surrounding the hydraulic-fracture system. The results reveal significant strain localization near the fracture tips, indicating that reservoir deformation is concentrated in regions experiencing the highest pressure gradients. The asymmetric distribution suggests that hydraulic-fracture propagation and reservoir depletion do not generate uniform mechanical responses throughout the stimulated reservoir volume.

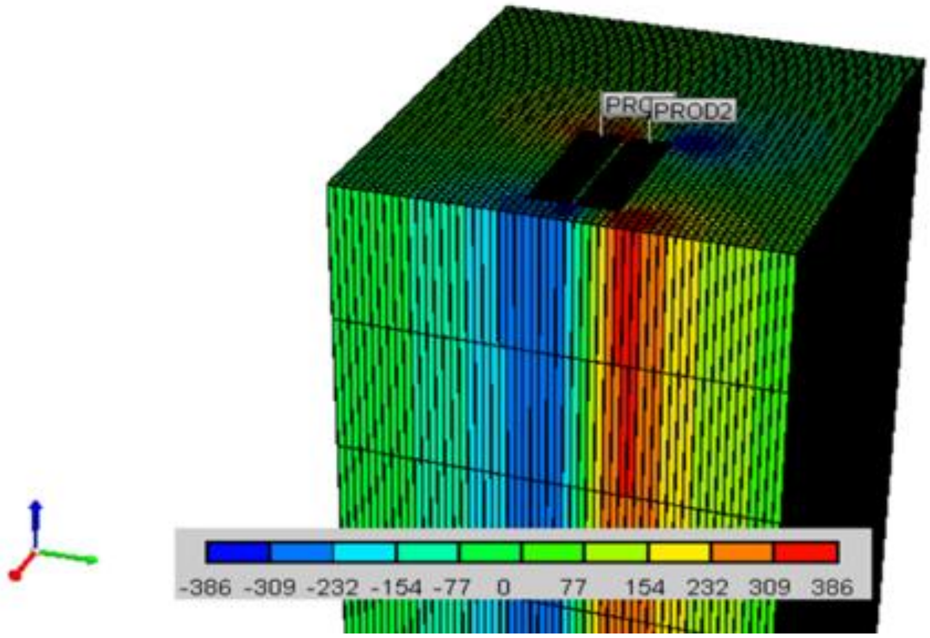


Figure 23.
Three-dimensional shear stress distribution in the parent-child well configuration

Figure 23 presents the corresponding shear-stress distribution. Positive and negative stress values are observed in different regions of the reservoir, indicating complex stress redistribution induced by hydraulic fracturing and pressure depletion. Such behaviour is consistent with stress-shadow development commonly reported in unconventional reservoirs.

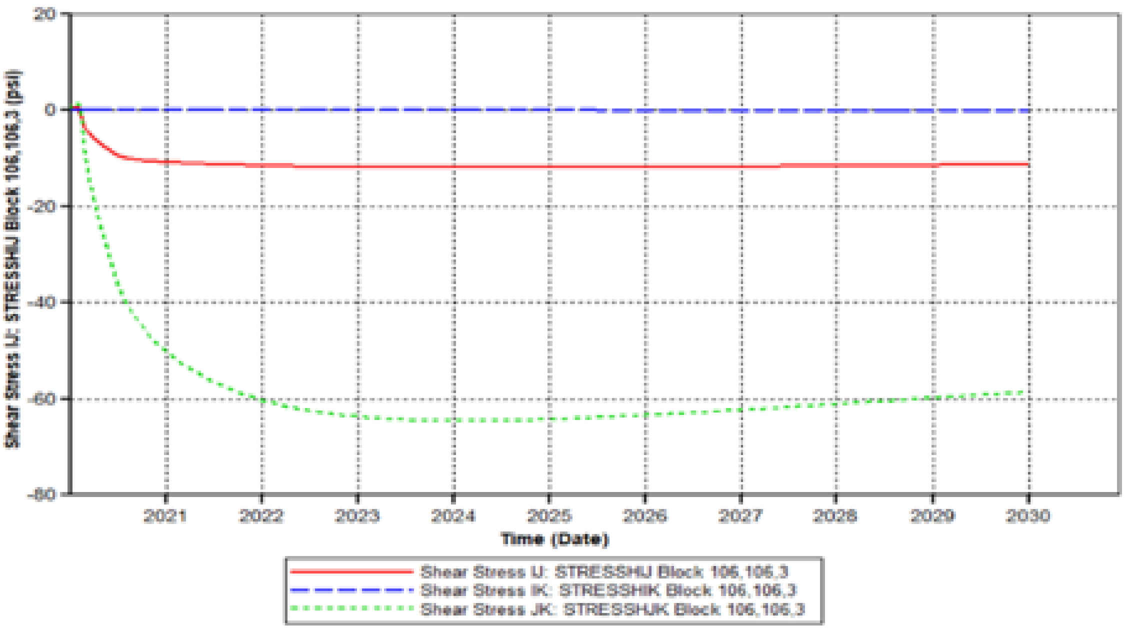


Figure 24.
Shear stress evolution in grid block 106 106 3 for the parent-child well model

The shear stress distributions further demonstrate stress redistribution around the fracture network. Both positive and negative stress regions are observed, reflecting the complex geomechanical interactions between hydraulic fractures, reservoir depletion, and rock deformation. Such behaviour is consistent with the stress-shadow phenomenon commonly reported in unconventional reservoirs, where pressure depletion and fracture development modify the local stress field and influence subsequent fracture growth.

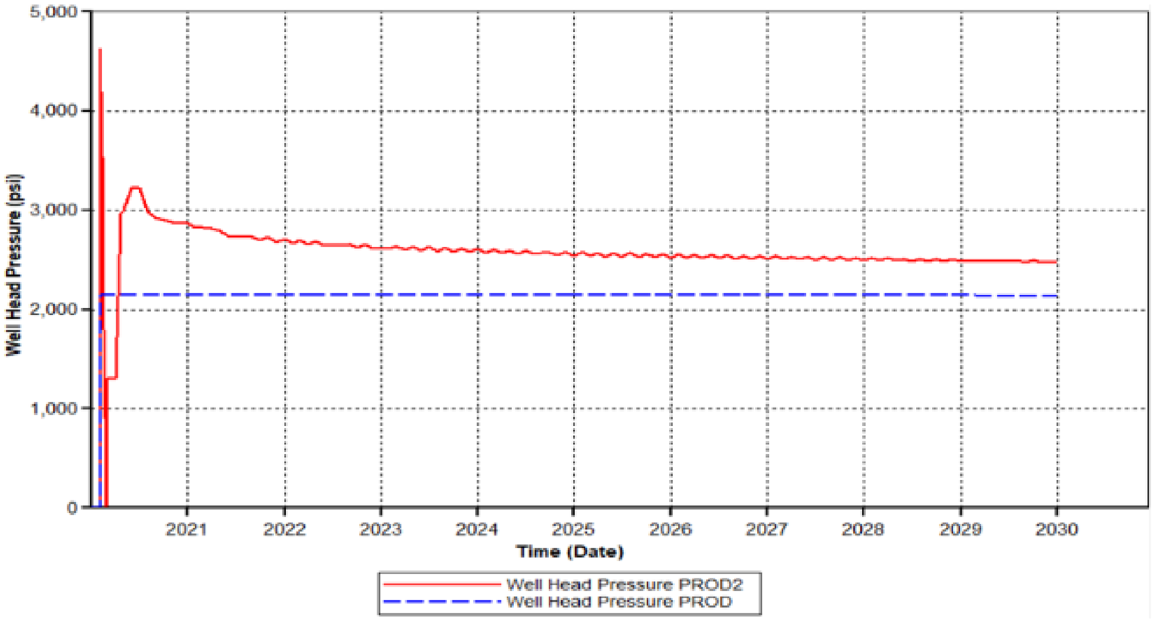


Figure 25.
Comparison of the well head pressure behavior between the parent and child wells

Basically, these two wells are set up using the same method, but the simulation results show that the WHP alteration in the child well exhibits a dynamic rhythm compared with that of the parent well (Figure 25).

Overall, the geomechanical results demonstrate that unconventional reservoir performance is governed not only by matrix permeability and fluid-flow mechanisms but also by the coupled interaction between pressure depletion, stress evolution, and rock deformation. Therefore, integrating geomechanical analysis with production and pressure-distribution evaluation is essential for accurately characterising parent–child well behaviour and optimising long-term hydrocarbon recovery.

Regions exhibiting severe pressure depletion correspond to zones of elevated shear strain and stress concentration. The reduction in pore pressure increases effective stress, resulting in localized rock deformation surrounding the hydraulic fractures. This behavior supports the stress-shadow mechanism commonly reported in unconventional reservoir developments.

3.4 Parent–child well performance and pressure evolution

The parent–child well simulations reveal strong production interference and pressure communication between adjacent horizontal wells. Compared with the single-well scenario, the introduction of a second well significantly altered pressure distribution, reservoir drainage patterns, and fracture-network utilisation. The simulation results indicate that reservoir depletion generated by the parent well creates a substantial pressure gradient that influences the hydraulic and geomechanical response of the subsequently completed child well.

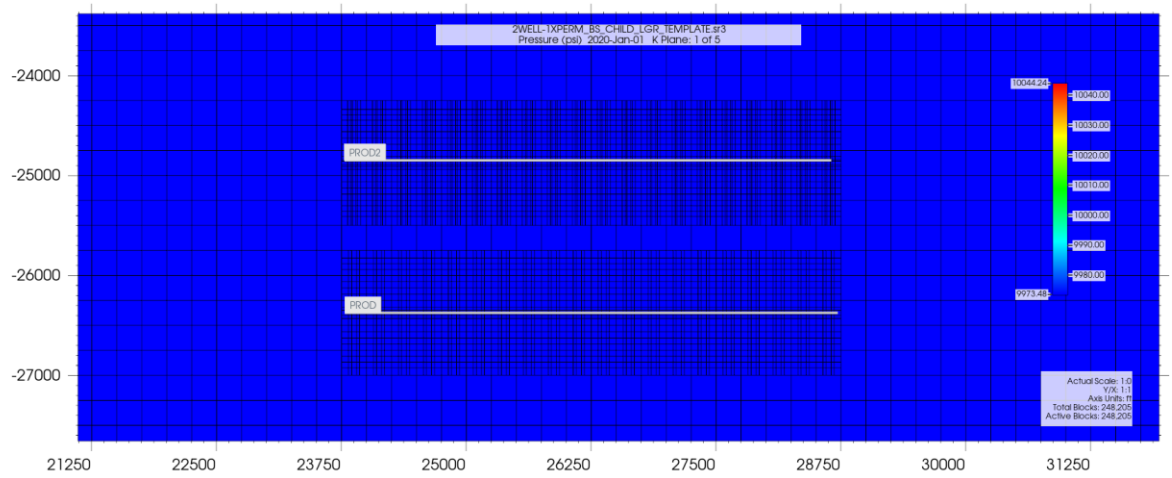


Figure 26.
Pressure distribution immediately before well completion (aerial)

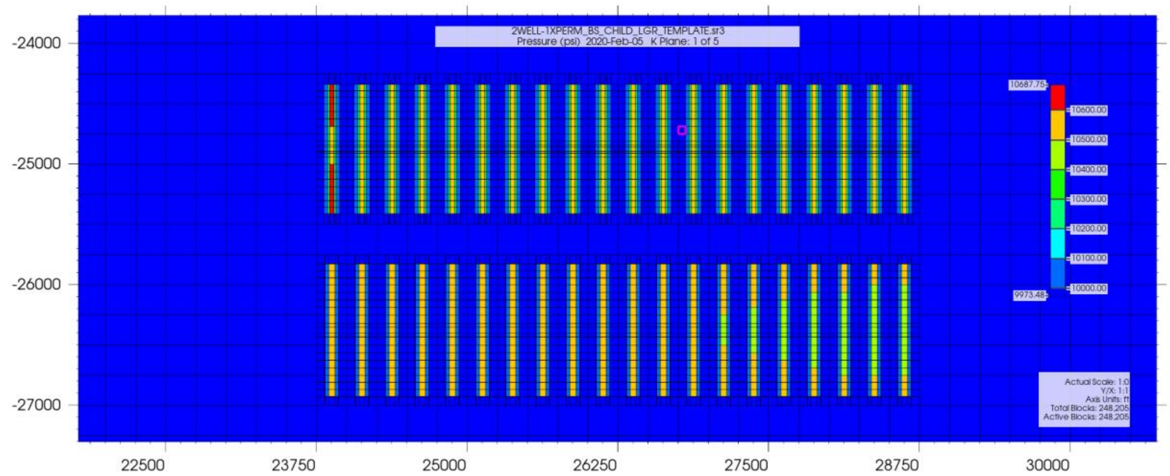


Figure 27.
Pressure distribution immediately before production (aerial)

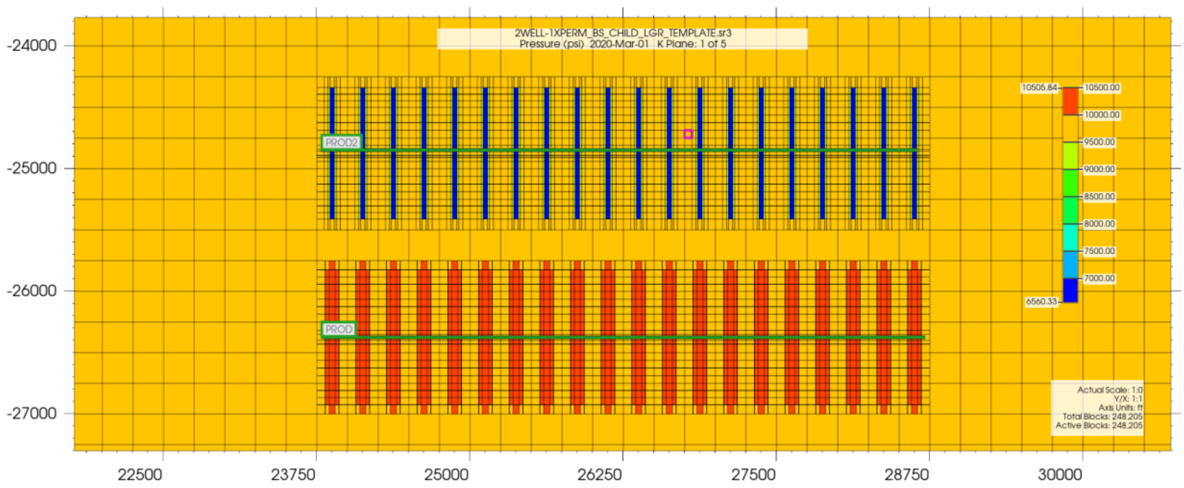


Figure 28.
Pressure distribution 1 month after production (aerial)

Pressure-distribution analysis prior to child-well completion shows the development of a pronounced depletion-shadow region surrounding the parent well. This low-pressure zone serves as a dominant control on subsequent fracture propagation and fluid-flow behaviour. The pressure sink generated by long-term parent-well production modifies local reservoir energy and creates strong pressure communication pathways between neighbouring wells. Such behaviour is consistent with previous studies reporting that pressure interference can significantly influence production forecasting and recovery performance in tightly spaced unconventional developments (Wang et al., 2021).

The pressure-map results further indicate that the depletion-shadow region extends beyond the immediate vicinity of the parent well and influences a substantial portion of the stimulated reservoir volume. Consequently, hydraulic fractures generated during child-well stimulation are subjected to altered stress and pressure conditions compared with those encountered during parent-well completion. These findings demonstrate the importance of considering depletion history and pressure communication when designing infill drilling programs in unconventional reservoirs.

The observed pressure interaction confirms that parent–child well performance cannot be evaluated solely through geometric well spacing. Instead, reservoir pressure depletion, fracture connectivity, and dynamic stress redistribution collectively determine the efficiency of hydrocarbon recovery and long-term field performance.

Figure 18 shows a significant difference in cumulative gas performance. The child well produced more than ten times the cumulative gas volume of the parent well. This behaviour suggests significant pressure depletion around the parent well prior to infill drilling, which altered local stress conditions and promoted preferential flow toward the child well (Figures 26, 27, and 28). Such behaviour is consistent with FDIs reported in unconventional reservoir developments (Figure 20). Dominantly, this is due to the high-pressure drawdown in the child wel.

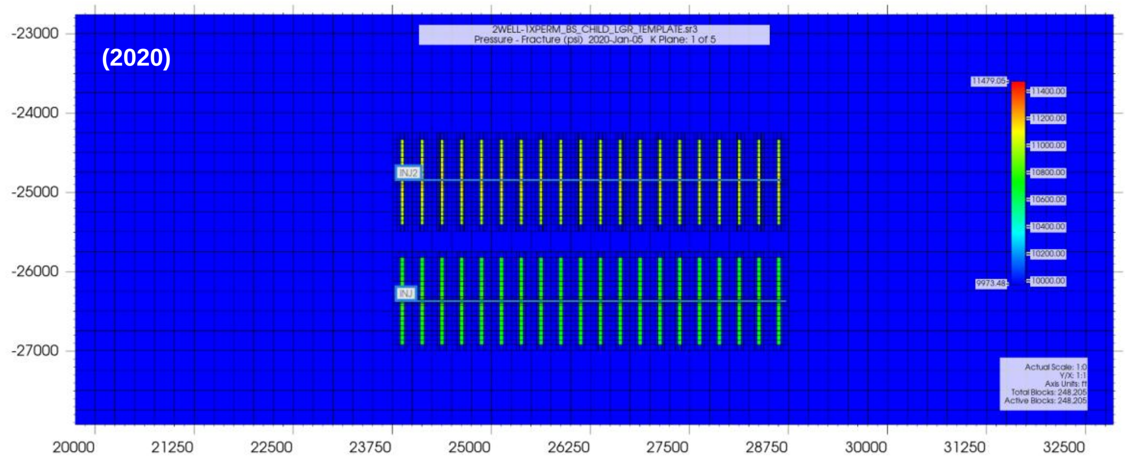
These findings are consistent with Fan et al. (2018), who explained that shale matrix permeability strongly controls long-term unconventional reservoir productivity. Similarly, Al-Rbeawi & Al-Kaabi (2020) reported that stimulated matrix permeability significantly reduces pressure drop and improves productivity index during transient and boundary-dominated flow periods. The results also support the findings of Ghanbarian et al. (2020), who demonstrated that nano-scale pore confinement and stress-sensitive permeability strongly influence gas-flow behaviour in unconventional formations.

The simulation results further indicate that permeability enhancement within SRV improves fluid communication between the matrix system and hydraulic fractures. As permeability increases, pressure depletion propagates more effectively into the matrix region, accelerating hydrocarbon drainage toward the production well. This behaviour confirms that permeability enhancement is critical for sustaining long-term unconventional production.

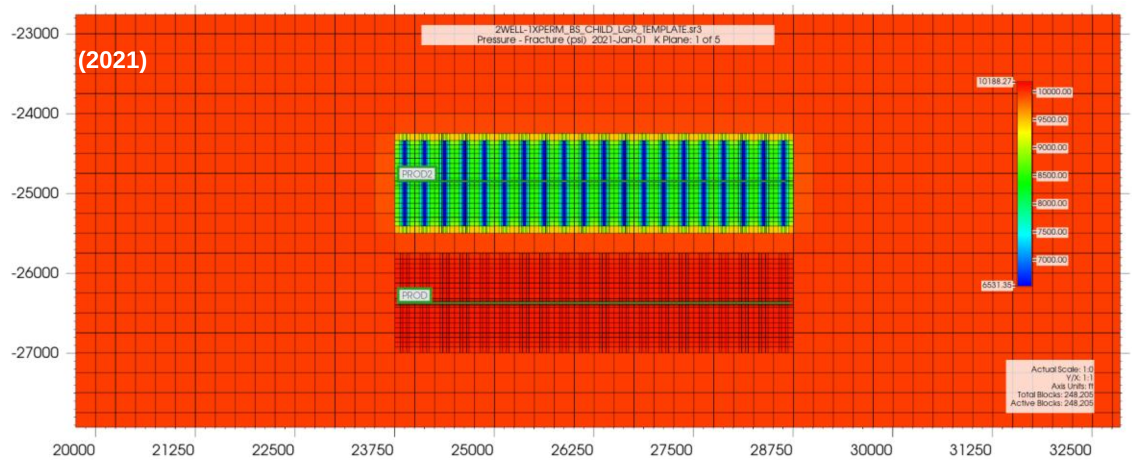
The observed increase in cumulative production is consistent with the fundamental matrix-to-fracture transfer formulation described by Warren & Root (1963) and Kazemi et al. (1976), in which the transfer rate is directly proportional to matrix permeability. Therefore, the present study should be interpreted as defining theoretical recovery limits under progressively improved matrix-flow conditions rather than predicting field-scale permeability enhancement outcomes.

3.5 Long-term evolution of pressure communication

Early Stage (2020–2022): During the early production period, pressure depletion remains concentrated around the parent-well fractures. Hydraulic communication between the wells remains limited, and the depletion shadow primarily forms around the parent well.



(a)



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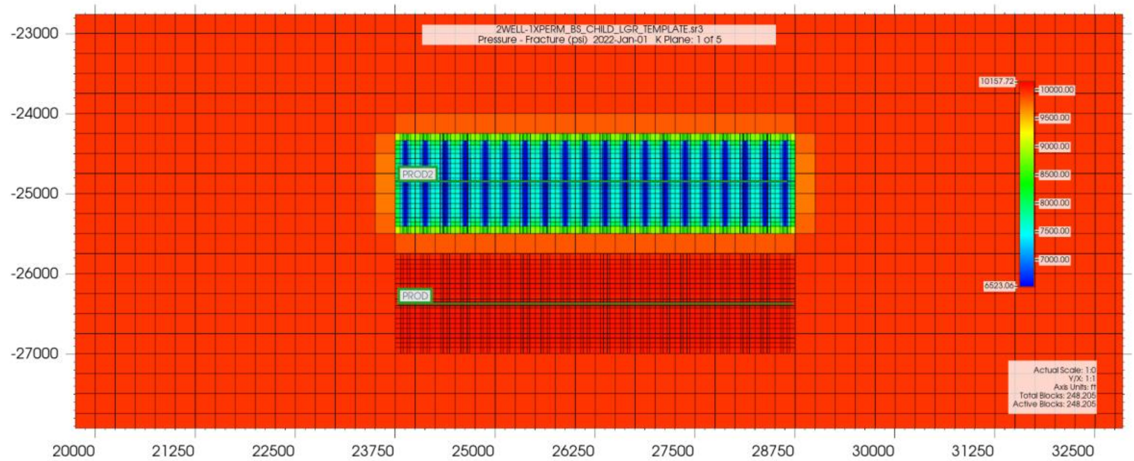
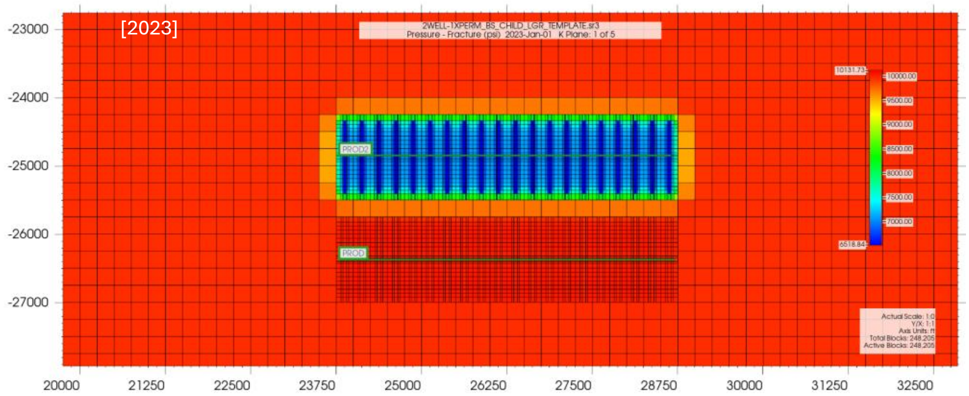


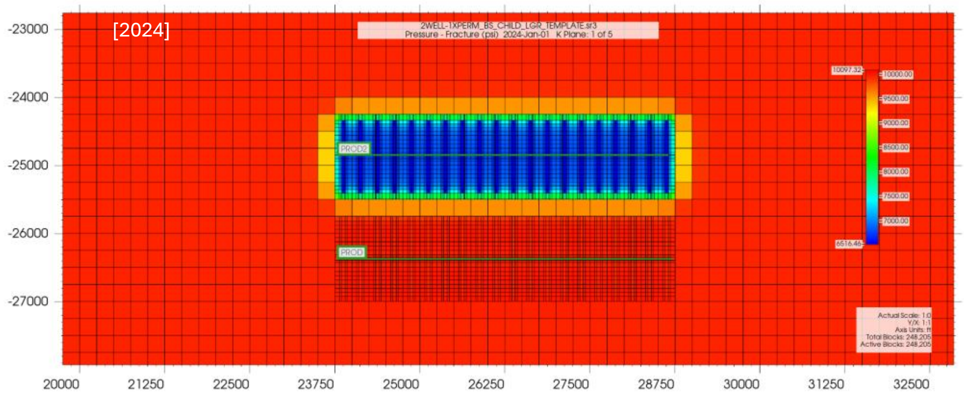
(c)

Figure 29.
Pressure distribution in the parent–child well system (January 2020-2022).

Intermediate Stage (2023–2026) : As production progresses, the depletion fronts expand outward from the parent-well fracture network. The pressure gradients between the wells gradually decrease, indicating increasing pressure communication and reservoir interaction. Late Stage (2027–2030): In the late production stage, the fracture pressure distributions become increasingly interconnected. The pressure field suggests that both wells are partially draining from a shared reservoir volume, leading to stronger parent–child interaction.



(a)



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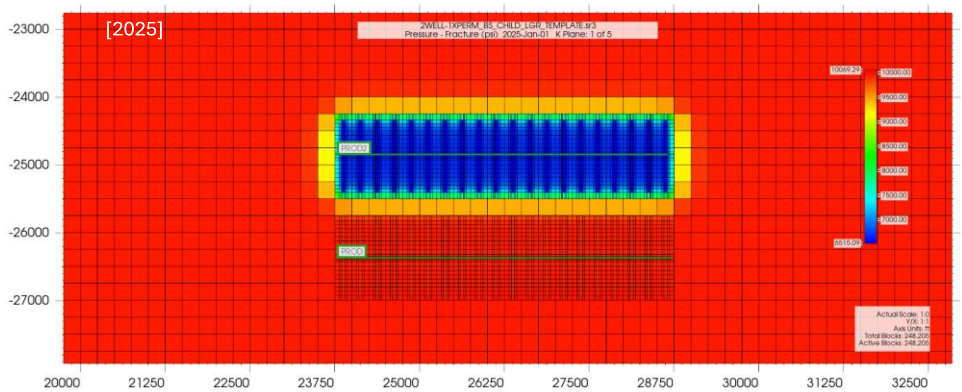

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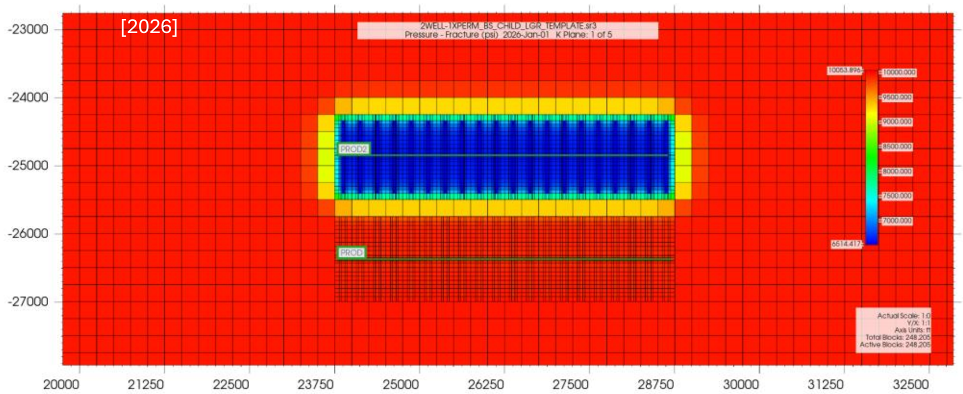


(d)

Figure 30.
Pressure distribution in the parent–child well system (January 2023-2026).

The pressure evolution observed in Figures 29 - 31 validates the need for Local Grid Refinement (Figure 4). Without the refined grids surrounding the hydraulic fractures, the steep pressure gradients and depletion-shadow boundaries would not be adequately captured.

3.6 Influence of hydraulic fracture network and fracture conductivity

The reservoir's production performance is also strongly affected by fracture-network complexity and fracture conductivity. The hydraulic fractures created conductive pathways that connect the low-permeability shale matrix to the production wellbore, thereby enlarging the effective drainage area surrounding the horizontal well.

The fracture system created rapid pressure communication between the reservoir and the wellbore during the early production period. High fracture conductivity near the wellbore accelerated gas transport and improved initial production rates. However, conductivity degradation away from the fracture tips reduced flow efficiency in the outer stimulated region, indicating that fracture conductivity distribution significantly influences cumulative production behaviour.

These observations are consistent with the findings of Taghichian et al. (2018), who reported that fracture propagation and fracture aperture behaviour are strongly influenced by stress conditions and rock toughness. Lolon et al. (2009) also demonstrated that fracture spacing and fracture conductivity significantly affect unconventional reservoir productivity. Furthermore, Cipolla (2009) emphasised that highly complex fracture networks may partially compensate for ultra-low matrix permeability by reducing hydrocarbon drainage distance within the shale matrix.

The present simulation results indicate that fracture-network effectiveness becomes increasingly important during late production periods. As reservoir pressure declines, the fracture system acts as the primary conductive pathway controlling hydrocarbon movement from the matrix toward the wellbore. Therefore, maintaining fracture conductivity stability is essential for sustaining long-term production performance.

3.7 Bottom-Hole Pressure Optimization

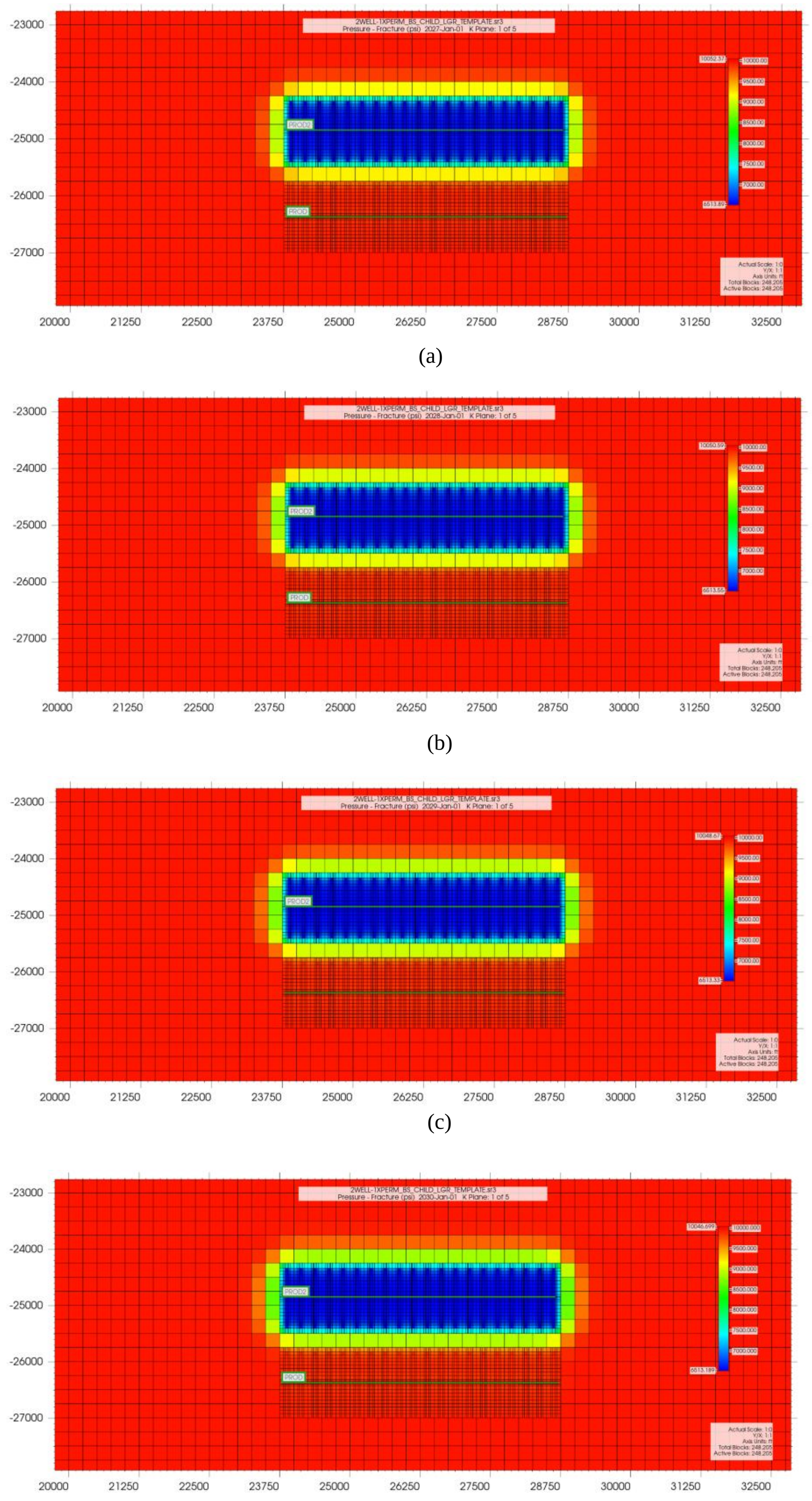
Sensitivity analysis using CMOST demonstrated that BHP strongly affects cumulative gas production and reservoir depletion behaviour. The optimization process utilized 100 experimental datasets with BHP values ranging from 3,000 psi to 10,000 psi. The results indicate that lower BHP values generally increase cumulative gas production because larger pressure drawdown enhances fluid transport from the reservoir toward the wellbore.

CMOST optimisation identified an optimum operating condition yielding a cumulative gas production of approximately 9.8 × 10^8 ft3 under the optimised pressure conditions (Figure 32). The larger pressure differential between the reservoir and wellbore accelerated hydrocarbon drainage from the shale matrix toward the fracture network, thereby improving production efficiency. However, excessively aggressive pressure drawdown may also accelerate stress redistribution and degradation of fracture conductivity. Rapid pressure depletion near hydraulic fractures may induce stress-sensitive permeability reduction and fracture closure. Therefore, pressure optimisation must balance production acceleration with long-term fracture stability.

These findings are consistent with Wang et al. (2021), who reported that pressure-management optimisation significantly affects unconventional reservoir productivity and EUR forecasting. Modern unconventional reservoir developments increasingly integrate production optimisation and geomechanical analysis to minimise fracture degradation while maximising cumulative production (Bui 2023).

3.8 Geomechanical response and shear stress–strain behavior

The geomechanical analysis demonstrated that hydraulic fracturing and reservoir depletion generated significant stress redistribution surrounding the fracture network. Shear stress and shear strain distributions exhibited anisotropic deformation in the IJ, JK, and IK directions, indicating that deformation around hydraulic fractures is highly non-uniform.



(d)

Figure 31.
Pressure distribution in the parent–child well system (January 2027-2030).

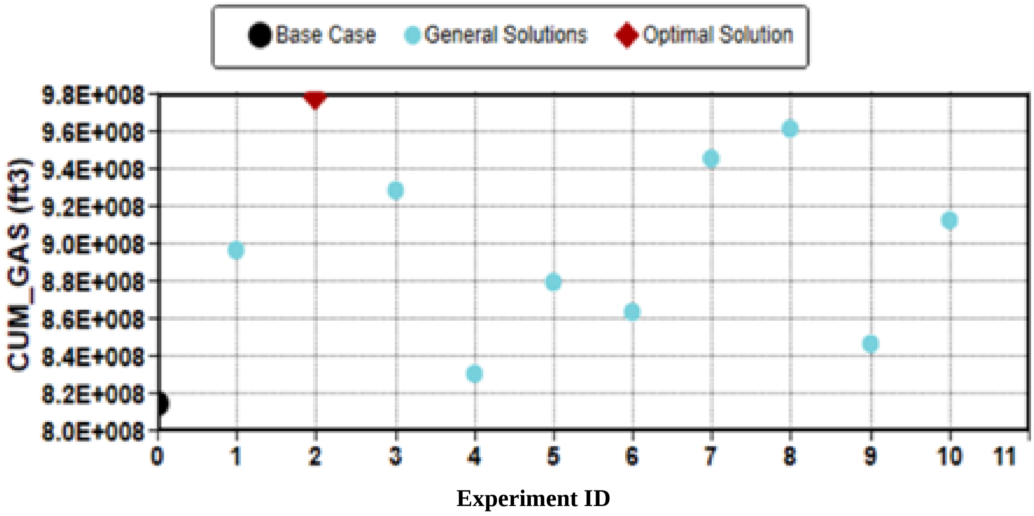


Figure 32.
Experimental design result from CMOST

The highest stress concentration occurred near the fracture regions and surrounding the horizontal wellbore. As production time increased, the magnitude of shear strain also increased due to continuous reservoir depletion and pressure reduction. The deformation behaviour became increasingly pronounced during the late production periods, particularly after 60 and 120 months.

These findings are consistent with those of Warpinski & Teufel (1987), who reported that in situ stress conditions strongly control fracture propagation and fracture geometry. King (2010) also explained that hydraulic fracturing may alter local stress conditions and generate stress redistribution surrounding fracture systems.

Recent geomechanical studies further support these observations. Bui (2023) emphasised that stress-sensitive permeability and degradation of fracture conductivity are critical factors controlling unconventional reservoir productivity. Similarly, Heydari et al. (2024) demonstrated that geomechanical deformation in shale microfractures significantly influences the evolution of permeability and fracture aperture behaviour during depletion.

The present study confirms that geomechanical deformation strongly affects the long-term performance of unconventional reservoirs. Stress redistribution may gradually reduce fracture conductivity and alter the evolution of permeability around hydraulic fractures. Consequently, geomechanical effects should be integrated into unconventional reservoir development planning to ensure sustainable long-term hydrocarbon recovery.

The observed shear-strain concentration near fracture tips suggests local stress redistribution that may contribute to fracture shielding and fracture-driven communication in the parent–child configuration.

3.9 Parent–child well interaction

The parent–child well simulation demonstrated strong pressure communication and FDI between adjacent horizontal wells. The child well exhibited significantly higher cumulative gas production compared with the parent well due to stronger pressure drawdown and more active fracture interaction within the stimulated reservoir volume. However, the simulation also revealed production interference and depletion-shadow effects between the wells, particularly under tight well spacing. These observations indicate that parent–child well performance is strongly influenced by fracture spacing, pressure redistribution, and stress-shadow behaviour.

The production increase in the child well indicates that pressure redistribution between adjacent wells strongly affects fluid-flow behavior in the stimulated reservoir volume. Pressure depletion generated by the parent well altered the stress condition surrounding the child well, influencing fracture propagation and interwell communication behavior.

The simulation also revealed production interference between the parent and child wells. Hydraulic fractures from adjacent wells interacted dynamically, creating fracture-driven communication pathways between the stimulated reservoir volumes. This interaction accelerated hydrocarbon drainage in certain regions while potentially reducing pressure support in others.

These observations are consistent with Wang et al. (2021), who reported that pressure communication between parent and child wells significantly affects production forecasting and EUR optimization. Liu et al. (2026) similarly demonstrated that fracture-hit behaviour becomes increasingly severe under tight well-spacing conditions due to dynamic fracture propagation and stress redistribution.

The results further support Al-Rbeawi (2020), who explained that fracture spacing and well spacing strongly influence pressure interference and productivity behaviour in unconventional reservoirs. Closely spaced wells may experience significant fracture communication, depletion shadow effects, and production rerouting over the long term.

3.10 Implications for unconventional reservoir development

The overall simulation results indicate that the performance of unconventional reservoirs is governed by the coupled interactions among matrix permeability, fracture-network effectiveness, pressure depletion, and geomechanical behaviour. Hypothetical: Matrix permeability enhancement improves hydrocarbon transfer from the shale matrix to hydraulic fractures, while fracture conductivity determines the efficiency of fluid transport to the wellbore.

The study also demonstrates that parent–child well implementation requires careful optimisation of well spacing and pressure management to minimise fracture interference and depletion-shadow effects. Excessively tight well spacing may lead to strong fracture communication and production imbalances between adjacent wells.

Furthermore, geomechanical behaviour plays a critical role in determining long-term fracture stability and the evolution of permeability. Stress redistribution from hydraulic fracturing and production depletion may gradually reduce fracture conductivity and alter reservoir flow behaviour. Therefore, successful unconventional reservoir development requires integrated optimisation involving matrix permeability characterisation, hydraulic-fracture design, pressure-management strategies, and geomechanical evaluation. These integrated approaches are essential for maximising EUR while maintaining sustainable long-term production performance in unconventional shale reservoirs.

3.11 Mechanisms of child-well overperformance under FDI conditions

One of the most notable observations in this study is the substantially higher cumulative production of the child well relative to that of the parent well. Although conventional field experience frequently reports child-well underperformance due to depletion-shadow effects, the numerical simulations indicate that specific combinations of pressure communication, FDI, and geomechanical response may generate the opposite behaviour.

The primary mechanism responsible for this phenomenon is the development of a strong pressure sink surrounding the parent well. Long-term production from the parent well substantially reduces local reservoir pressure, creating a highly depleted region adjacent to the existing fracture network. When the child well is completed and stimulated, the pressure differential between the newly stimulated reservoir volume and the depleted parent-well region generates a strong driving force for fluid migration. This pressure drawdown accelerates hydrocarbon movement toward the child-well fracture network, thereby contributing to elevated production rates. A second contributing factor is depletion-induced stress redistribution. As reservoir pressure decreases around the parent well, effective stress increases, altering the local stress field. Previous studies have demonstrated that hydraulic fractures preferentially propagate toward regions of lower minimum horizontal stress. Consequently, the depleted zone surrounding the parent well may attract newly generated fractures from the child well, increasing the probability of fracture communication and FDI. Such behaviour has been reported in several unconventional developments where fracture propagation becomes increasingly asymmetric as depletion progresses.

The simulation results also suggest that fracture-hit behaviour plays an important role in establishing highly conductive communication pathways between adjacent wells. Once hydraulic connectivity develops between parent- and child-well fracture systems, fluid transport efficiency may increase substantially. Under these conditions, the fracture network acts as an integrated drainage system that accelerates hydrocarbon transfer from the matrix to production wells.

Geomechanical analysis further indicates anisotropic shear-strain behaviour surrounding hydraulic fractures. The observed shear deformation may contribute to localised fracture dilation and temporary increases in effective permeability along fracture surfaces. This mechanism may enhance matrix-fracture communication and improve hydrocarbon drainage efficiency in the vicinity of the child well.

It is important to emphasise that the observed child's well-overperformance should not be interpreted as representative of typical field behaviour. In many unconventional developments, depletion-shadow effects reduce child-well productivity and lead to lower recovery than in parent wells. The behaviour observed in the present study represents a specific numerical scenario characterised by strong pressure communication, FDI, and favourable geomechanical conditions. Therefore, the results should be viewed as a mechanistic investigation of potential parent–child interactions rather than a universal prediction of field performance.

From a reservoir-management perspective, these findings highlight the importance of integrating depletion analysis, fracture-network characterization, geomechanical modeling, and well-spacing optimization during unconventional reservoir development. Failure to account for these coupled processes may lead to inaccurate EUR forecasts and suboptimal infill-drilling strategies.

4. Conclusion

This study investigated the coupled effects of matrix permeability, BHP optimisation, geomechanical behaviour, and parent–child well interaction on production performance in an Eagle Ford unconventional shale reservoir using an integrated compositional reservoir simulation approach. The objective was not to propose a field-scale permeability enhancement technology, but rather to quantify the theoretical upper recovery limits associated with improved matrix-to-fracture fluid transfer and to evaluate the resulting impact on production behaviour and reservoir depletion.

The simulation results demonstrate that matrix permeability is one of the dominant parameters controlling long-term hydrocarbon recovery in unconventional reservoirs. Increasing matrix permeability significantly enhanced fluid transport from the ultra-low-permeability matrix toward the hydraulic fracture network, resulting in substantial increases in cumulative gas and oil production. The sensitivity analysis confirmed that even moderate improvements in matrix-to-fracture transfer efficiency can substantially improve EUR.

BHP optimization further showed that production performance is highly sensitive to pressure drawdown management. The CMOST optimization results identified an operating pressure range capable of maximizing cumulative production while maintaining favorable reservoir depletion behavior. These findings emphasize the importance of integrating reservoir management strategies with hydraulic-fracture design to achieve sustainable long-term recovery.

Geomechanical evaluation revealed non-uniform distributions of shear stress and shear strain around the hydraulic fractures. Elevated deformation was observed near the fracture network, indicating localized stress redistribution and anisotropic rock response during depletion. The results suggest that pressure depletion, fracture conductivity evolution, and geomechanical deformation are strongly interconnected processes that collectively influence unconventional reservoir performance.

The parent–child well simulations demonstrated strong pressure communication and production interference between adjacent wells. Contrary to conventional expectations that child wells typically underperform due to depletion-shadow effects, the simulated child well generated higher cumulative gas production than the parent well under the investigated conditions. This behaviour is interpreted as the combined effect of depletion-induced pressure gradients, FDI, and enhanced hydraulic communication between fracture networks. The findings indicate that parent–child well performance cannot be explained solely by depletion-shadow mechanisms but must also consider stress redistribution, fracture propagation behaviour, and dynamic reservoir communication.

Overall, the study highlights that maximizing recovery from unconventional shale reservoirs requires an integrated understanding of matrix permeability, hydraulic-fracture effectiveness, pressure management, geomechanical evolution, and parent–child well interactions. The results provide valuable insights for optimizing well spacing, stimulation strategies, and production management in future unconventional reservoir developments.

Future research should focus on incorporating explicit FDI modelling, stress-sensitive fracture conductivity, depletion-shadow evolution, and field-scale history matching to further improve the prediction of parent–child well performance and long-term unconventional reservoir recovery.

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6. Declarations

6.1 Author contribution

D.F.Putra: conceptualization, methodology, running model CMG GEM & CMOST, deep analysis, writing result & discussion. I.A. Lukman: Supervision (co), develop model CMG GEM & CMOST, writing literature, visualization. M.H.Putra: Supervision (co), writing introduction, investigation data curation, writing review. F. Hidayat: Supervision (co), methodology, validation, model review. M. Ariyon: Supervision (co), methodology, validation, writing review & editing.

6.2 Funding statement

The authors declare that they have no known competing financial interest or personal relationships that could have influenced the work reported in paper.

6.3 Competing interest

The authors declare that they have known competing financial interest or personal relationships that could have influenced the work reported in paper.

6.4 The use of AI-assisted technologies

The author(s) used Chatgpt to assist, then authors review and edit the content as required. The authors take full responsibility for the publication's content.

7. Glossary of terms and symbols

Terms & Symbols	Description	Unit
k_m	Matrix permeability	mD
k_f	Fracture permeability	mD
ϕ	Porosity	fraction
ϕ_f	Fracture porosity	fraction
q_g	Gas production rate	MSCF/D
q_o	Oil production rate	STB/D
EUR	Estimated Ultimate Recovery	ft^3 or bbl
BHP	Bottom Hole Pressure	psi
WHP	Well Head Pressure	psi
SRV	Stimulated Reservoir Volume	ft^3
USRV	Unstimulated Reservoir Volume	ft^3
P	Reservoir pressure	psi
ΔP	Pressure drawdown	psi
σ	Stress	psi
τ	Shear stress	psi
γ	Shear strain	dimensionless
σ_H	Maximum horizontal stress	psi
σ_h	Minimum horizontal stress	psi
σ_v	Vertical stress	psi
L_f	Fracture half-length	ft
w_f	Fracture width	ft
x_f	Fracture extension distance	ft
h_f	Fracture height	ft
C_f	Fracture conductivity	md-ft
r_w	Wellbore radius	ft
t	Time	day/month/year
S_g	Gas saturation	fraction
S_o	Oil saturation	fraction
μ_g	Gas viscosity	cp
μ_o	Oil viscosity	cp
ρ	Fluid density	lbm/ft^3
TOC	Total Organic Carbon	%
nD	Nano Darcy permeability	nD
mD	Milli Darcy permeability	mD
ft	Feet	ft
psi	Pound per square inch	psi
GEM	Generalized Equation-of-state Model simulator	—
CMOST	Computer Modelling Group Optimization & Sensitivity Tool	—
Frac-Hit	Hydraulic fracture interaction between adjacent wells	—
Parent Well	Existing producing horizontal well	—
Child Well	Newly drilled infill well near parent well	—

Hydraulic Fracturing	Reservoir stimulation by high-pressure fluid injection	—
Non-Darcy Flow	Non-linear flow regime in fractures	—
Drawdown	Difference between reservoir pressure and flowing pressure	psi
Eagle Ford Shale	Unconventional shale formation in South Texas, USA	—
IJ Direction	Grid orientation in x-y plane	—
JK Direction	Grid orientation in y-z plane	—
IK Direction	Grid orientation in x-z plane	—
Grid Block	Numerical simulation cell in reservoir model	—
Horizontal Well	Well drilled laterally through reservoir layer	—
Condensate Gas	Gas reservoir fluid producing liquid condensate	—
Recovery Factor (RF)	Percentage of recoverable hydrocarbon produced	%
Tubing Performance Curve	Relationship between flow rate and pressure in tubing	—
Pressure Depletion	Reservoir pressure reduction during production	psi
Stress Redistribution	Change of in-situ stress due to depletion/fracturing	—
Fracture Propagation	Growth and extension of hydraulic fractures	—
Reservoir Drainage Area	Effective production area connected to the well	acre or ft^2
Cartesian Grid	Rectangular reservoir simulation grid system	—
Well Spacing	Distance between adjacent wells	ft
Fracture Spacing	Distance between hydraulic fractures	ft
Hydraulic Conductivity	Ability of fracture system to transmit fluids	md-ft
Production Interference	Production interaction between neighboring wells	—
Dynamic Interwell Fracture Interaction	Pressure/fracture communication between wells	—

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