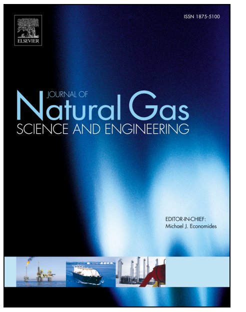

Optimising well orientation in hydraulic fracturing of naturally fractured shale gas formations

Joseph Sherratt, Amin Sharifi Haddad, Filip Wejzerowski, Roozbeh Rafati

PII: S1875-5100(21)00343-7

DOI: https://doi.org/10.1016/j.jngse.2021.104141

Reference: JNGSE 104141

To appear in: *Journal of Natural Gas Science and Engineering*

Received Date: 4 May 2021

Revised Date: 5 July 2021

Accepted Date: 7 July 2021

Joseph Sherratt: Investigation, Methodology, Software, Validation, Visualization, Writing - Original Draft. **Amin Sharifi Haddad:** Conceptualization, Methodology, Funding acquisition, Supervision, Formal analysis, Project administration, Writing - Review & Editing. **Filip Wejzerowski**: Formal analysis, Validation, Writing - Review & Editing. **Roozbeh Rafati**: Supervision, Formal analysis, Validation, Writing - Review & Editing.

Optimising well orientation in hydraulic fracturing of naturally fractured shale gas formations

Joseph Sherratt, Amin Sharifi Haddad*, Filip Wejzerowski, Roozbeh Rafati

School of Engineering, University of Aberdeen, King's College, Aberdeen, UK, AB24 3UE

Abstract

Complex interactions between hydraulic fractures and natural fractures often result in highly complex fracture networks that might lead to bypassed resources damaging the economic viability of developments. In this study the impact of natural fractures of the formation on production from hydraulically fractured wells is studied using a recently developed fracture upscaling method (FUM). By capturing the distribution of complex fracture networks using FUM, a novel idea of changing the well orientation to optimise recovery is proposed. It is shown that with a natural fracture spacing of 15 m a small change in well orientation up to 30° from the standard orientation can increase the recovery by up to 15% for natural fractures at an angle of at least 60° with σ_{hmax}. The increased recovery is a result of the natural fractures and stress orientation complementing each other to assist the propagation of hydraulic fractures deeper into the formation. It is also shown that as natural fracture density increases (fracture spacing decreases) the effect of changing the well orientation becomes more significant. Changing the well orientation when there are two perpendicular planes of natural fractures is also investigated. However, no optimal orientation can be found in these cases, suggesting there needs to be a strong average directionality of the natural fractures in the reservoir to support a beneficial well orientation change. A simple economic analysis shows a small well orientation change can allow a larger well spacing which could lead to a direct reduction in the cost of developing a shale reservoir. The results also show the positive effect this has on the NPV of

* Corresponding author: Amin Sharifi Haddad, Email: amin.sharifi@abdn.ac.uk, Tel: +44 (0)1224 272977 Fax: +44 (4) 1224 272497

the project with different gas prices, and a rapid positive NPV status reducing the risk of investment.

Keywords: Hydraulic fracturing, Horizontal well orientation, Natural fractures, Optimisation

1. Introduction

The development of horizontal drilling and hydraulic fracturing unlocked vast quantities of hydrocarbon resources that were previously inaccessible. However, the high cost of completion and falling hydrocarbon prices have also been a major concern for the shale industry. Therefore, there is now an increased demand to optimise this process as much as possible.

Shale resources in North America have been developed rapidly using a 'Factory Drilling' process which aimed to drill lots of wells quickly with a similar design which massively reduced drilling and completion costs (Rexilius, 2015). Wells should be located close enough together to recover the hydrocarbons as quick as possible without overlapping the drainage areas of neighbouring wells to avoid over-capitalisation (Lalehrokh & Bouma, 2014). In the past, wells have been drilled close together to maximise early production and net present value (NPV). Following the recent drop in hydrocarbon prices there has been an interest in increasing the efficiency of these operations even further rather than prioritising early production.

Early studies aimed primarily at the design of single wells and models only focussed on recovery from single wells. These have been used to determine optimal completion design but fail to capture the interaction and interference between multiple wells in close proximity such as in the development of shale resources. Modelling recovery from multiple wells in close proximity is more difficult and not always possible using conventional simulators. Analytical modelling has shown that reservoir permeability and the fracture area are the most important factors to consider when optimising the well spacing (Lalehrokh & Bouma, 2014). Numerical studies have also shown the challenges of determining optimal stage and cluster spacing when considering complex geological models (Cullick et al., 2014). In a study conducted by Sahai et al, numerical simulations have been used to model the recovery from large areas to determine optimal spacing focussing on the production from stimulated reservoir volumes (SRV) and external reservoir volumes (XRV) (Sahai et al. 2012). This study showed that production from XRV is irrelevant when considering shale gas production. It has been shown that as oil/gas pricing increases a tighter well spacing can be justified and vice versa (Belyadi & Smith, 2018).

The distribution of proppant within the fractures has also been shown to be important when considering the optimal well spacing and interference between neighbouring wells. Frac hits are defined as when a hydraulic fracture propagates into an existing well or fracture of a neighbouring well. These are often used to determine the efficiency of the fracturing as they give an indication of the extent of fractures. Some studies have concluded that frac hits negatively affect overall recovery and determined that frac hits should be minimised by increasing well spacing (Yaich et al., 2014; Malpani et al., 2015). It has also been suggested that frac hits do not necessarily indicate that well spacing could be increased as proppant is unlikely to have filled the fractures and the wells may not exhibit interference during later stages of production (Cao et al., 2017). The effect of frac hits has also been investigated in highly complex formations containing natural fractures and it was found that frac hits can result in high interference allowing multiple completed wells to be produced from a single well head representing a reduction in required surface equipment and associated costs (Yu et al. 2017a).

Hydraulic fractures propagate in the least energy configuration. In a homogenous formation this is in a plane perpendicular to the minimum principal stress. In most shale formations the maximum principal stress is vertical and therefore hydraulic fractures propagate in a vertical plane. To achieve the most efficient recovery, wells are drilled perpendicular to the maximum horizontal stress (i.e., in the direction of the minimum horizontal stress) resulting in fractures propagating perpendicularly away from the well (Wang, 2016). Drilling wells in this orientation also ensures the wells are mechanically stable and avoids costly well collapses and failures during the drilling process.

Microseismic event data has shown that fractures do not always propagate in a planar manner away from the wells, and it was inferred that more complex fracture networks are generated during hydraulic fracturing. This is because shale formations are not homogeneous. A major contributing factor to this effect is the presence of planes of weakness in the formation such as natural fractures. Because the hydraulic fractures propagate in the configuration that requires the least amount of energy, they often exploit these weaknesses resulting in highly complex fracture networks. This has been demonstrated numerically with a single stage of demonstrating the impact of different cluster spacings, injection pressures and natural fracture geometries on the fracture network complexity (Wu & Olson, 2016). Other factors such as stress shadow effects also add to this complexity. This results in highly complex fracture networks which many previous studies have simplified when studying production and determining optimal well and stimulation design. Further studies showed that complex natural fracture networks are formed when a low in-situ differential stress and a high density of poorly cemented natural fractures exist (Jamison & Azad, 2017). It has been shown that the fracture cluster positions can be optimised considering hydraulic-natural fracture interactions (Wang & Olson, 2020). Computational studies have also determined the critical role of in-situ differential stress on the influence of natural fractures for the propagation of hydraulic fractures (Zou et al., 2016). In Zou et al.'s study, it was found that in-situ differential stresses greater than 10 MPa lead to simple transverse fractures instead of complex fracture networks.

While there have been many studies on the propagation of the hydraulic fractures in naturally fractured formations, most of the previous studies have investigated the optimisation of production from such formations using simplified fracture geometry in models and simulations such as simple planar features extending from wellbores. Simulators are now able to capture the complex mechanics of fracture propagation and represent more realistic fracture networks. These complexities can be incorporated by using different approaches such as Embedded Discrete Fracture Model (EDFM) methods, or grid upscaling methods e.g., Fracture Upscaling Model (FUM) developed by Sherratt et al. (2020) that are computationally fast.

Previous research has shown the significant impact of natural fractures on the propagation of hydraulic fractures and concluded that natural fractures can cause hydraulic fractures to deviate from the direction of maximum horizontal stress (Sherratt et al., 2020). In the same study, the investigators demonstrated that the angle between the plane of the natural fractures with the orientation of maximum stress can hinder hydrocarbon recovery from a single well up to 20%. In another study conducted by Olson and Taleghani (2009), it was reported that fracture path complexity is greatest when the horizontal differential stress is low and natural fractures are at a large angle with the favored hydraulic fracture direction which maximised the number of interactions. Furthermore, Yu et al. (2017a) investigated the effect of well spacing on complex hydraulic fracture networks in the presence of natural fractures using the standard well orientation (Yu et al., 2017a). They investigated the flow and interference between neighbouring wells through both complex hydraulic fracture networks and open natural fractures in the reservoir. It was concluded that connecting hydraulic fracture networks result in significant interference between wells compared to connecting natural fracture networks where interference was minimal. Therefore, it was reported that well spacing is the most important element of well design for maximizing production. They also demonstrated tight well spacing in naturally fractured formations can lead to significant interference between wells, and production can be optimized by producing from only one well at a time. However, there has been no investigation on the effect well orientation and its optimisation on hydrocarbon recovery when natural fractures are present in a shale reservoir.

Gas recovery from hydraulically fractured wells relies on gas diffusion and flow from matrix blocks toward hydraulic fracture networks. When wells are placed close together the recovery will be high as the average distance between the centre of the rock matrix block to fracture networks is short. However, this massively increases the development costs i.e., hydrocarbon recovery is maximised, but economics are not optimum. Optimisation requires finding a balance between lowering the field development cost by increasing the well spacing and the delayed recovery from the stimulated formation between wells.

In this study we ask the question; if a formation is naturally fractured, and we drill wells in a different orientation, can the recovery be increased? And if so, how much can a change in well orientation increase the efficiency of the production? Figure 1 shows a schematic of the proposed method in this study to be used instead of the current method for fracturing and development of naturally fractured shale reservoirs.

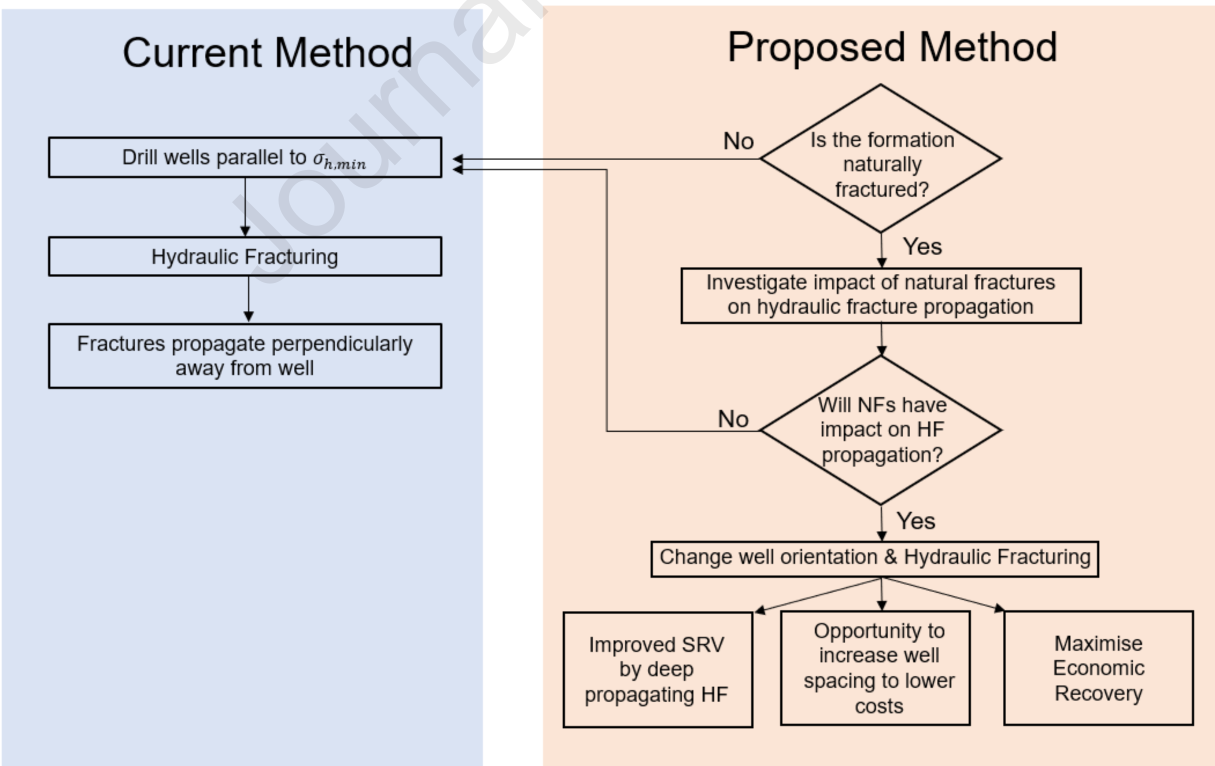

Figure 1 – Schematic of the proposed and current method for developing naturally fractured shale reservoirs

Therefore, to answer the above questions we have used numerical tools and demonstrated that changing the well orientation in naturally fractured formations could lead hydraulic fractures to propagate deeper into the formation allowing the well spacing to be increased and lowering the costs of development. Compared to the case with standard well orientation this represents an opportunity to increase the economics of a project without decreasing expected recovery from a formation. These outcomes could also benefit the oil-bearing tight formations developments where the recovery factor of enhanced oil recovery processes depend on the matrix block sizes, solvent diffusion rates among others to optimise the production (Sherratt et al., 2018, Zhu et al., 2020, Sheng, 2019). In the rest of this study, we explain the details of these findings.

This study is divided into different sections. In the next section, we present the method used to model hydraulic fractures and simulate production from the wells. Then after, in the results and discussion section, firstly the impact of the orientation of natural fractures on production is demonstrated while keeping the well orientation constant and perpendicular to the maximum horizontal stress, σ_{hmax}. Then the impact of rotating the well is investigated to determine an optimised solution for maximising the recovery. In addition, the effect of different natural fracture spacings is elaborated. Furthermore, we investigate the effect of natural fracture and well orientations on recovery when there are two sets of natural fracture planes perpendicular to each other. Finally, a brief economic analysis that shows the potential impact of changing the well orientation in shale gas field development is presented, and it is followed with the summary and conclusions section.

2. Method

The focus of this study is to investigate the effect of well orientation on the gas production from hydraulically fractured wells in shale formations that contain natural fractures. We evaluate natural fracture characteristics to develop an approach to determine the best well orientation to maximize recovery and/or efficiency which can be of benefit to oil and gas companies and practicing engineers in field development plans. To achieve this, a method is required for modelling hydraulic fracture propagation in naturally fractured formations and the production from the resulting fracture networks. The Fracture Upscaling Method (FUM) is used to capture the complex flow behaviour of discrete fracture models in a dual-permeability finite difference-based reservoir simulator (Sherratt et al., 2020). This enables the coupling of complex finite element based hydraulic fracture simulators with conventional reservoir simulators. In this study Schlumberger Kinetix is used to model hydraulic fracture simulation using the unconventional fracture model (UFM) (Petrel Kinetix, Schlumberger, 2017). This can capture complex interactions between neighbouring propagating fractures, interactions with natural fractures, stress shadow effects, fluid leak-off and proppant transport within the fractures (Kresse et al., 2013). FUM could be used with other fracture propagation simulators to study effects that are not captured by this software.

The fracture networks generated are output as discrete fracture models describing the geometry and distribution of properties such as aperture and proppant concentration along the fracture. These fracture networks are exported as text files containing the fracture geometry and properties ensuring that no data is lost between the fracture modelling and upscaling. FUM was developed in C++ which combines these discrete fracture objects with a dual permeability finite difference-based reservoir simulation grid. The details of this method have been presented and tested against field data in a previous study (Sherratt et al., 2020). The FUM uses a numerical method to change the properties of the grid to capture the effect of the discrete fracture network they contain. It calculates the fracture permeability of a cell, $\boldsymbol{k_f}$ containing a section of the hydraulic fracture network as follow:

$$\boldsymbol{k_f} = \alpha \frac{w_f^2}{12} \begin{pmatrix} |\widehat{\boldsymbol{n}}_{\boldsymbol{f}} \times (\boldsymbol{e_x} \times \widehat{\boldsymbol{n}}_{\boldsymbol{f}})| \frac{A_{fx}}{A_x} \\ |\widehat{\boldsymbol{n}}_{\boldsymbol{f}} \times (\boldsymbol{e_y} \times \widehat{\boldsymbol{n}}_{\boldsymbol{f}})| \frac{A_{fy}}{A_y} \\ |\widehat{\boldsymbol{n}}_{\boldsymbol{f}} \times (\boldsymbol{e_z} \times \widehat{\boldsymbol{n}}_{\boldsymbol{f}})| \frac{A_{fz}}{A_z} \end{pmatrix} \quad (1)$$

The fracture is characterised by the aperture, w_f, and the average plane normal vector, $\widehat{\boldsymbol{n}}_{\boldsymbol{f}}$. The coefficient $\alpha = 2 \times 10^{-5}$ is used to represent the effect of proppant on fracture permeability (Yu et al., 2017b). A_{fx}, A_{fy} and A_{fz} are the area of intersection between the fracture plane and the cell faces. The other terms all account for properties of the grid cell. A_x, A_y and A_z are the cell face areas in each grid axes direction and the unit vectors in Cartesian coordinates are $\boldsymbol{e_x}$, $\boldsymbol{e_y}$ and $\boldsymbol{e_z}$. When cells contain multiples fractures, the effects of all fractures contained by the cell can be summed for each fracture as follows:

$$\boldsymbol{k}_f = \sum_{i=1}^{n} \boldsymbol{k}_{f_i} \quad (2)$$

where *n* is the number of fractures contained in the cell.

FUM can be used with a complex 3D grid with a distribution of reservoir properties but in this study a simple single layer grid is used with a homogeneous distribution of properties.

This finite difference-based grid can then be imported into any conventional reservoir simulator to model production. In this study, CMG-GEM, a multiphase flow reservoir simulator, is used.

To evaluate the performance the stimulation and production of a representative section (250 m of the well) between two parallel wells, W1 and W2, is considered as shown in Figure 2. The well orientation is expressed as the angle (θ_w) between the well and the maximum horizontal stress (σ_{hmax}) direction. The wells in Figure 2 have the standard well orientation (the base case in this study) perpendicular to σ_{hmax} with an angle $\theta_w = 90°$. This study investigates the effect of recovery using different orientations which are always expressed relative to the orientation of σ_{hmax}. A well spacing, S_w of 300 m is used for all simulations except when stated in section

3.5 for the economic analysis. Hydraulic fracture stimulation is performed up to the Simulation Boundary which is shown as a green region in Figure 2. The simulation boundary is large enough that it is beyond the maximum extension of hydraulic fractures. Production is then modelled from the region between the two wells, the production volume, represented by the orange region in Figure 2. The production volume and simulation boundary are different because full fracture propagation is modelled but to increase the computational efficiency of the production model, only production from the region between the two wells is considered. This approach limits the number of fracking stages to be modelled and also reduces the size of the production model which decreases the time required to run many simulations but can still be used to determine the recovery performance between two wells which is representative of a full well model.

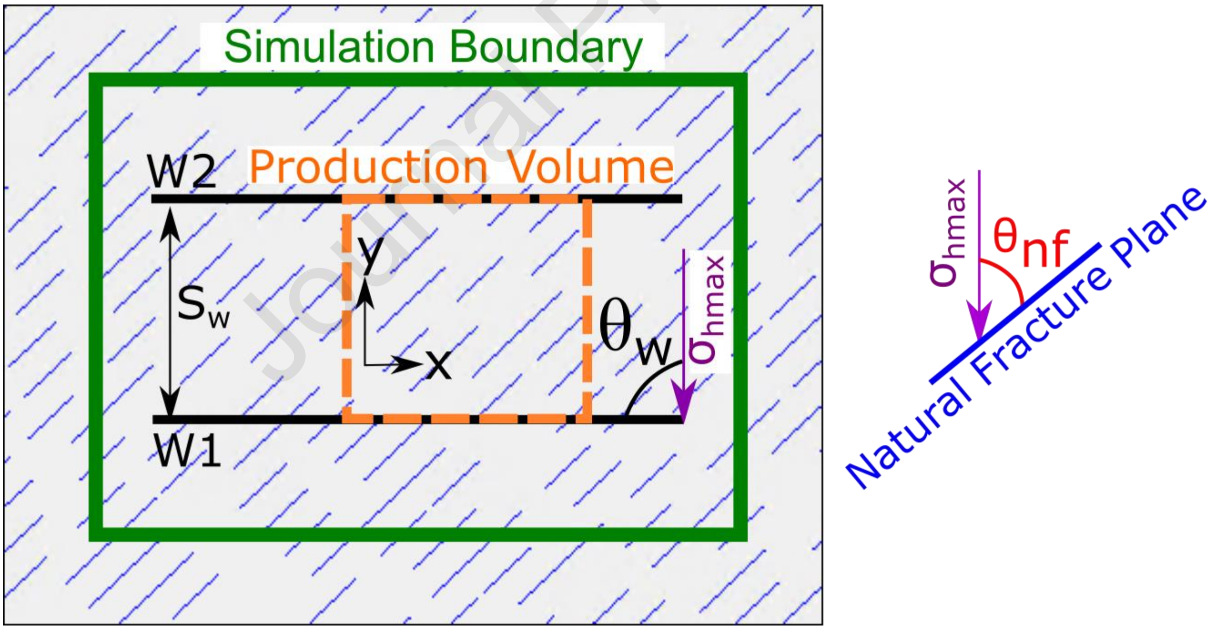

Figure 2 – Schematic of the region being investigated for hydraulic fracture stimulation modelling and production modelling

The reservoir is assumed to contain natural fractures in a vertical plane that fully intersect the target shale formation. These are described by their length, L_{nf}, spacing, S_{nf} and their orientation θ_{nf} which is expressed as the angle between the plane of the fracture and σ_{hmax} as shown in Figure 2. In this study, a mean natural fracture length, $L_{nf} = 30$ m with a standard deviation of 3 m and the mean natural fracture spacing, $S_{nf} = 15$ m with a standard deviation of 2 m are used (Ma & Holditch, 2015). The impact of the orientation is one of the main parameters investigated in this study. Due to the non-uniqueness of the natural fracture realisations, there can be some variation in the results. We tested the use of multiple realisations for each case and based on the tests, we found that after three realisations the average production has converged, and hence further realizations do not significantly impact the accuracy. Therefore, at least three realisations for each case are created and averaged to increase the accuracy.

Natural fractures are considered to be sealed or partially sealed. Therefore, they represent a plane of weakness in the formation that may be exploited by propagating hydraulic fractures but do not contribute to the ability of the formation to conduct fluid flow unless they are exploited by the propagating hydraulic fractures.

2.1. Hydraulic Fracturing Scheme

By using the unconventional fracture modelling software, Kinetix, we are able to capture complex 3D propagation of hydraulic fractures in addition to interaction with natural fractures, the stress shadow effect between stages and the distribution of proppant within the fracture networks among other phenomenon.

Many different factors such as reservoir properties, well design and stimulation parameters can be defined and incorporated into these simulations. Each well section is completed with 3 stages of hydraulic fracturing 47 m apart, each with 4 perforation clusters 16 m apart and is completed with 1,300 $m^3$of slickwater and 198,000 kg of sand proppant injected at a rate of 9.5 m^3 per minute. The other parameters required to model the hydraulic fracture propagation are detailed in Table 1. The information is based on a field case and are typical values for shale formations in North America (Yu et al., 2017b).

It should be noted that the UFM model also has some limitations such as the maximum fracture height must be constrained which requires consideration of geological boundaries that may stop the growth of fractures. In this study this value is taken from Yu et al. (2017b) and is kept constant throughout all cases. However, if UFM is applied to another field then careful consideration should be given to these values.

Table 1 – Reservoir and fluid properties used to model hydraulic fracture propagation from (Yu et al., 2017b)

Property	**Value**
Permeability (mD)	0.0008
Porosity	0.12
Maximum Horizontal Stress (kPa)	51,200
Minimum Horizontal Stress (kPa)	48,263
Initial Reservoir Pressure (kPa)	31,026
Poisson Ratio	0.23
Young's Modulus (kPa)	2.06×10^{7}
Natural Fracture Coefficient of Fraction	0.6
Natural Fracture Toughness ($kPa \cdot m^{\frac{1}{2}}$)	550
Shale Gas Composition	CH_4

2.2. Production Modelling

CMG-GEM, a compositional multiphase flow reservoir simulator, is able to capture many complexities of flow in shale formations. The reservoir permeability and porosity are detailed in Table 1. A pressure dependant permeability modulus is included to account for the pressure dependant nature of shale formations (Pedrosa Jr., 1986).

$$\boldsymbol{k_m} = \boldsymbol{k_{mi}} e^{-\gamma_m (P_{mi} - P_m)} \tag{3}$$

$$\boldsymbol{k_f} = \boldsymbol{k_{fi}} e^{-\gamma_f (P_{fi} - P_f)} \tag{4}$$

where $\boldsymbol{k_{mi}}$ and $\boldsymbol{k_{fi}}$ are the initial matrix and fracture permeabilities respectively at the initial matrix pressure P_{mi} and fracture pressure P_{fi}. The matrix permeability modulus, γ_m and fracture permeability modulus, γ_f are defined in Table 2 (Zhang & Emami-Meybodi 2020). A non-Darcy modifier is also applied to the fractures using the Forchheimer correction to Darcy's Law (Forchheimer, 1901). The beta correction is calculated as,

$$\beta = \frac{\alpha_g}{(kk_{rg})^{N1p}} \tag{5}$$

where k is the absolute fracture permeability and k_{rg} is the relative gas permeability. The constants α_g and N_{1p} are given in Table 2 (Evans & Civan, 1994). A Klinkenberg correction, P_{kr} is applied to the matrix to account for slip flow (Letham & Bustin, 2016). Gas desorption from the shale is also accounted for using a Langmuir isotherm (Arri et al., 1992, Hall et al., 1994). The number of moles of component *j* absorbed per kg of rock is calculated using the equation below,

$$q_j = \frac{q_{j,max} B_j P}{1 + B_j P} \tag{6}$$

where $q_{j,max}$ is the maximum number of moles of component *j* adsorbed per kg of rock, B_i is the Langmuir isotherm parameter. This has been fit against field data from Yu et al. (2017b) to determine the values in Table 2 (Sherratt et al. 2020). The initial water saturation of fractures and the fracture porosity are also detailed in Table 2.

Table 2 – Reservoir and fluid properties used to model gas production

Property	Value
$Matrix\ permeability\ modulus, \gamma_m\ (kPa^{-1})$	4.35×10^{-6}
$Fracture\ permeability\ modulus, \gamma_f\ (kPa^{-1})$	4.35×10^{-5}

$Maximum\ adsorbed\ gas, q_{CH4,max}\ (\frac{mol}{kg\ of\ rock})$	0.23
$B_{CH4}\ (kPa^{-1})$	2.9×10^{-4}
$P_{kr}\ (kPa)$	500
$\alpha_g\ (m^{-1})$	4.76×10^{9}
$N1_g$ (-)	1.021
Initial water saturation of fracture	1.0
Initial Water Saturation of matrix	0.10
Shale density $(kg.m^{-3})$	1992
Fracture porosity	0.001
Reservoir Temperature (℃)	55

The bottom hole pressure schedule for the wells is shown in Figure 3 which extended from the field case in Yu et al., 2017b for 5,000 days of production. In addition to this the matrix and fracture relative permeabilities are shown in Figure 4.

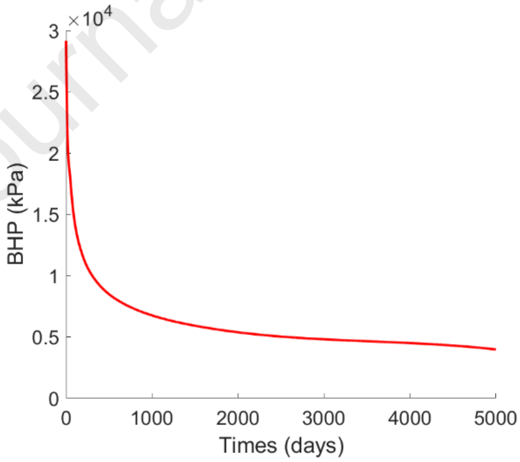

Figure 3 – Bottom hole pressure schedule for wells W1 and W2 during production expressed as days since the beginning of production

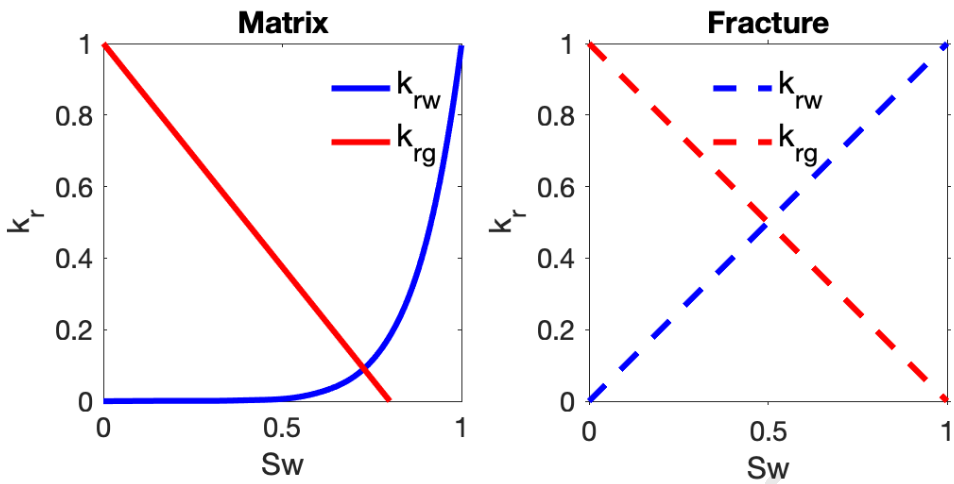

Figure 4 – Relative permeability curves for the matrix and fracture (Daigle et al., 2015)

A previous study tested the sensitivity of FUM with grid cell sizes ranging from 1 m×1 m×25 m to 8 m×8 m×25 m demonstrating results are accurate even with coarse grids (Sherratt et al., 2020). Therefore, in the current study, to capture the complex hydraulic fracture networks in the presence of natural fractures, a fine grid of 2 m×2 m×25 m (less than the minimum natural fracture spacing of 5 m used in this study) can resolve complex fracture geometry and provide accurate results. Thus, a grid cell size of 2 m×2 m×25 m is used throughout this manuscript. This results in models with 125×150×1 grid cells. Simulations were ran using a desktop computer with an Intel Xeon E5645 CPU with 6 cores at 2.40 GHz and 64 Gb RAM. The simulation of hydraulic fracture propagation (Kinetix) takes approximately 30 minutes to run for each case, then the fracture upscaling (FUM) takes less than 5 minutes, and the simulation of 5,000 days of production (CMG-GEM) takes approximately 30 minutes to 1 hour.

3. Results and Discussion

3.1. Impact of Natural Fracture Orientation

To investigate the impact of natural fracture orientation, hydraulic fracture propagation was modelled with different natural fracture orientations. In this section, the well orientation is fixed perpendicular to the maximum horizontal stress ($\theta_w = 90°$) consistent with the current practice in industry (standard orientation). The hydraulic fracture and natural fracture networks ($\theta_{nf} = 0°$ and $\theta_{nf} = 90°$) are shown in Figure 5 in blue and black, respectively. The stimulated reservoir volume (SRV) is shown in yellow for the region between the wells. As discussed earlier, hydraulic fractures propagate in a configuration that requires the least amount of energy, therefore, as they meet natural fractures they often propagate along the natural fracture as this requires less energy. If the fractures are at a high angle to the maximum horizontal stress this can result in highly complex networks that deviate a long way parallel to the well instead of deep into the formation away from the well. This tendency is shown in Figure 5b and results in poor access to the hydrocarbons far away from the well which translates to a lower production. The SRV is clearly much smaller and does not extend as deep into the formation with natural fractures perpendicular to σ_{hmax} in comparison to parallel to σ_{hmax}. It should be highlighted that the presence of a hydraulic fracture does not guarantee a good connection between the well and the formation as the aperture may not be great enough. This implies that full upscaling and production modelling is required to determine the efficiency of each fracture network.

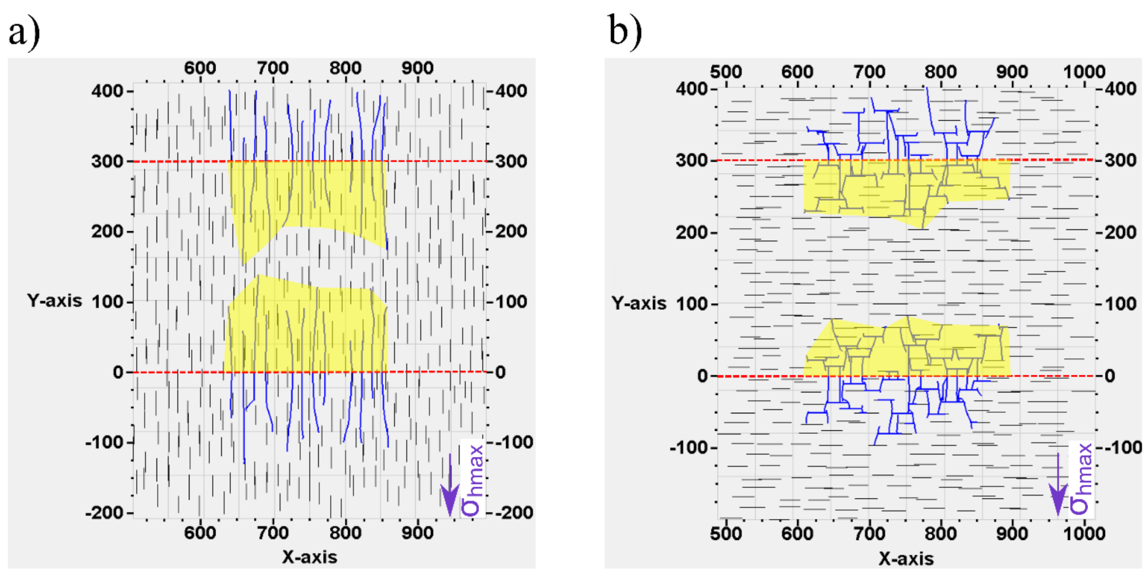

Figure 5 – Fracture networks (blue) and hydraulic fractures (black) with a) $\theta_{nf} = 0°$ and b) $\theta_{nf} = 90°$, with $\theta_w = 90°$, $S_{nf} = 15m$ and $L_{nf} = 30m$. The stimulated reservoir volume is shown in yellow for the region between the wells

For each fracture that propagates away from the well the maximum extension perpendicular and parallel to the well can be estimated to find the average extension in these directions for the network of hydraulic fractures associated with each natural fracture angle as shown in Figure 6. When natural fractures are parallel to σ_{hmax}, $\theta_{nf} = 0°$, the hydraulic fractures can propagate up to 90 m (fracture half-length) perpendicular to the well but this is reduced to less than 50 m when the natural fractures are perpendicular to σ_{hmax}, $\theta_{nf} = 90°$.

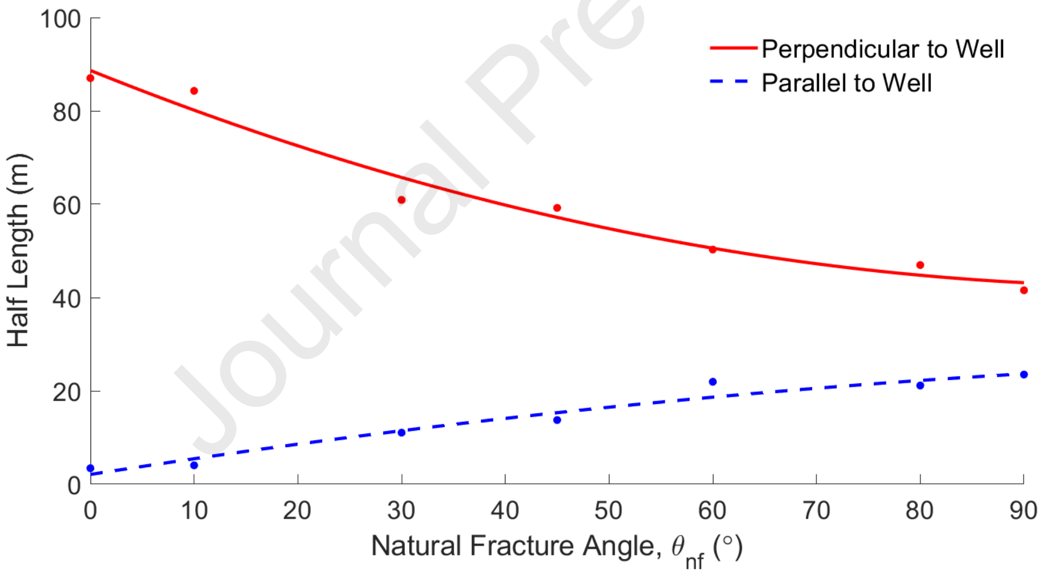

Figure 6 – Average extension of hydraulic fractures perpendicular and parallel to the well with different natural fracture orientations, θ_{nf}, with $\theta_w = 90°$, $S_{nf} = 15m$ and $L_{nf} = 30m$

Using FUM to upscale the hydraulic fractures the cumulative production for different natural fracture orientations is shown in Figure 7. In this study, cumulative production corresponds to the recovery from the production volume shown in Figure 2 from both well segments. Multiple natural fracture realisations are created for each scenario and the production is averaged to plot this graph. This shows that as the angle between natural fractures and maximum horizontal stress (θ_{nf}) increases, the recovery decreases. Based on the cumulative production at different times (after 500 to 2,000 days) that recovery can be decreased by as much as 25-35% due to the negative impact of natural fractures. Therefore, the reduction in recovery in Figure 7 can be associated with the tendency of hydraulic fractures to propagate along natural fractures instead of away from the well into the formation.

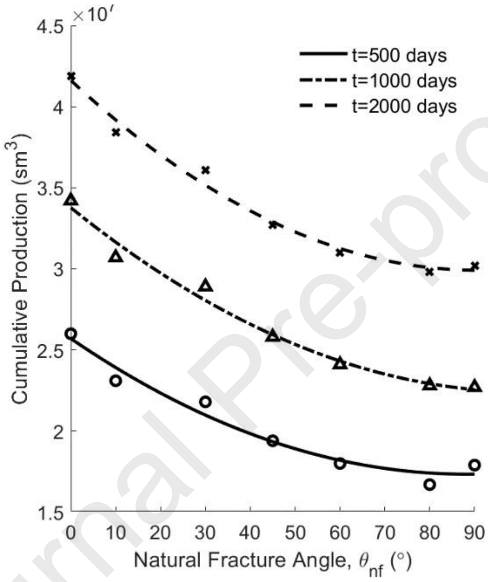

Figure 7 – Cumulative production with different natural fracture orientations and standard well orientation $\theta_w = 90°$ for $S_{nf} = 15\,m$ and $L_{nf} = 30\,m$. Circle, triangle and cross symbols represent the discrete data points after 500, 1000 & 2000 days, respectively

The advantage of propagating fractures deep into the formation away from the well is that a larger volume of the formation becomes connected to the well and as a result a larger volume of hydrocarbons can be recovered. This may also mean that less wells are required to produce the hydrocarbons and as a result well spacing could be increases which represents a large reduction in the cost of producing the resource which is investigated later in this study. An increase in propagation of hydraulic fractures along the direction of the well could indicate that stage/cluster spacing could be increased which may also represent a reduction in the development costs, but this is not investigated in this study. This has been addressed in a previous modelling study, and it was found that decreasing cluster spacing can increase fracture complexity, but this doesn't necessarily mean recovery will be increased (Zou et al., 2016).

Figure 8 shows the pressure distribution in the formation at different times with natural fractures at 0° and 90° to the maximum horizontal stress. This shows the limited penetration of hydraulic fractures when natural fractures are at a high angle with the maximum horizontal stress, leading to a poor recovery from the formation in the centre between the wells.

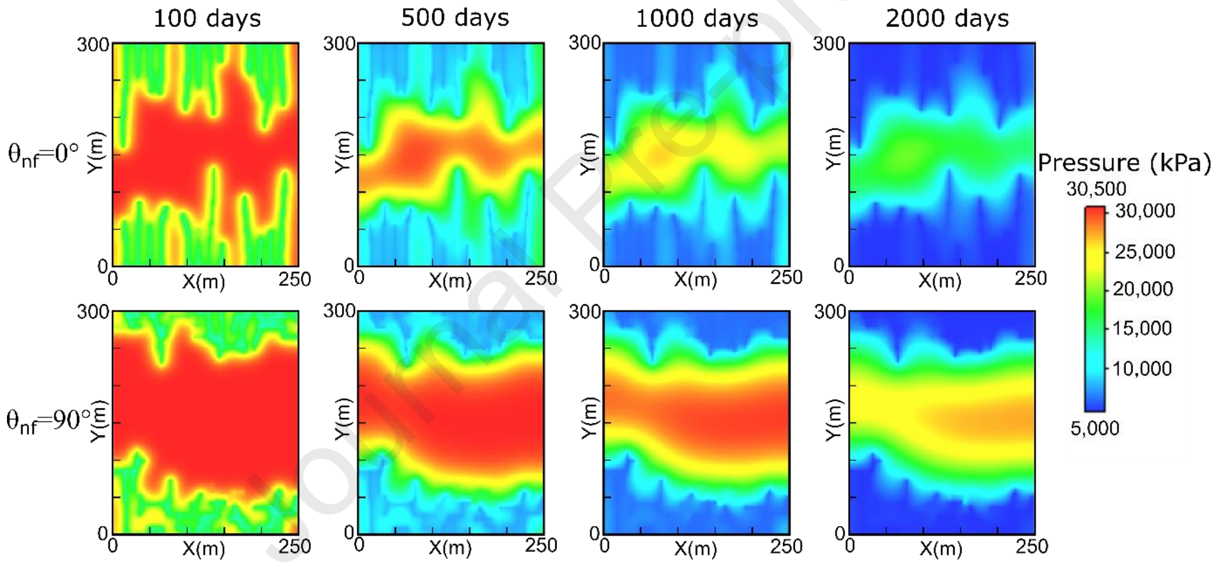

Figure 8 – Reservoir pressure distribution with natural fracture orientations $\theta_{nf} = 0°$ and $\theta_{nf} = 90°$ with standard well orientation $\theta_w = 90°$, $S_{nf} = 15m$ and $L_{nf} = 30m$

The pressure distribution confirms that when natural fractures are at a high angle to the maximum horizontal stress depletion by hydraulic fractures will be limited. Therefore, there is a need to consider the impact of natural fractures on shale gas field development plans to minimise their negative effects on drilling and fracturing costs.

3.2. Impact of Well Orientation

The main aim of this study is to investigate if there is a better well orientation than the current practice in industry (standard orientation) which is parallel to the minimum horizontal stress ($\theta_w = 90°$). The results in the previous section have highlighted that the orientation of the natural fractures can have a large impact on recovery as hydraulic fractures tend to propagate along natural fractures. Successful hydraulic fracturing results in a good connection between the shale formation and the well. This requires the hydraulic fractures to propagate deep into the formation away from the well to connect large volumes of hydrocarbon containing shale reservoirs to the well in addition to high fracture conductivity. Therefore, the directionality of the natural fractures may hinder the ability of hydraulic fractures to propagate deeply into the formation away from the well. In this section we test if a change in well orientation, as shown in Figure 9 may be more optimal and increase recovery from between the wells. As the well orientation is decreased from the standard orientation, $\theta_w = 90°$, such that natural fractures will become more perpendicular to the wells, the component of the maximum horizontal stress parallel to the well hinders the fracturing in theory, but the weak natural fractures will help propagate the fractures away from the well. Therefore, the change in the well orientation results in hydraulic fractures propagating deeper into the formation which may have a dominant positive effect than the negative effect of the component of the maximum horizontal stress parallel to the well. However, with further decreasing θ_w the efficiency of changing the well orientation may diminish. This is tested in this study to determine the well orientations that show an increase in recovery.

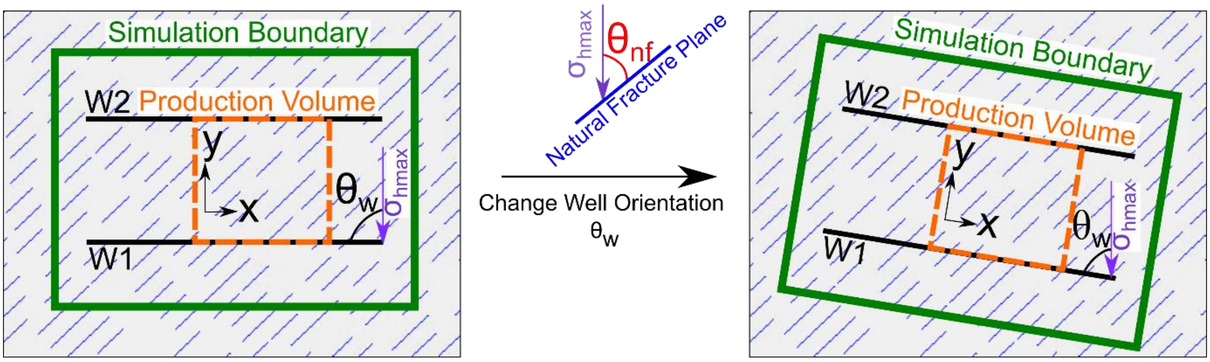

Figure 9 – Diagram showing the simulation schematic of the proposed change of well orientation

Three different natural fracture orientations are investigated; $\theta_{nf} = 80°, 60°, 40°$. For each natural fracture orientation fracture stimulation is simulated using a range of well orientations starting from the industry standard orientation $\theta_w = 90°$ through $\theta_w = 0°$. In this study the horizontal well orientation is rotated in the direction so that fractures become more perpendicular to the well. It is expected that a rotation in the other direction would result in hydraulic fractures more parallel to the well which is likely to hinder the ability of hydraulic fractures to propagate deep into the formations and therefore not investigated in this study. Once the hydraulic fracturing has been simulated the fracture networks are exported and upscaled using FUM so that production can be simulated.

Figure 10 (a) and (b) show the fracture networks with the standard well orientation $\theta_w = 90°$ and a small rotation $\theta_w = 70°$, respectively. The fracture networks in Figure 10 (b) show the effect of hydraulic fractures propagating further towards the neighbouring well when the orientation is changed.

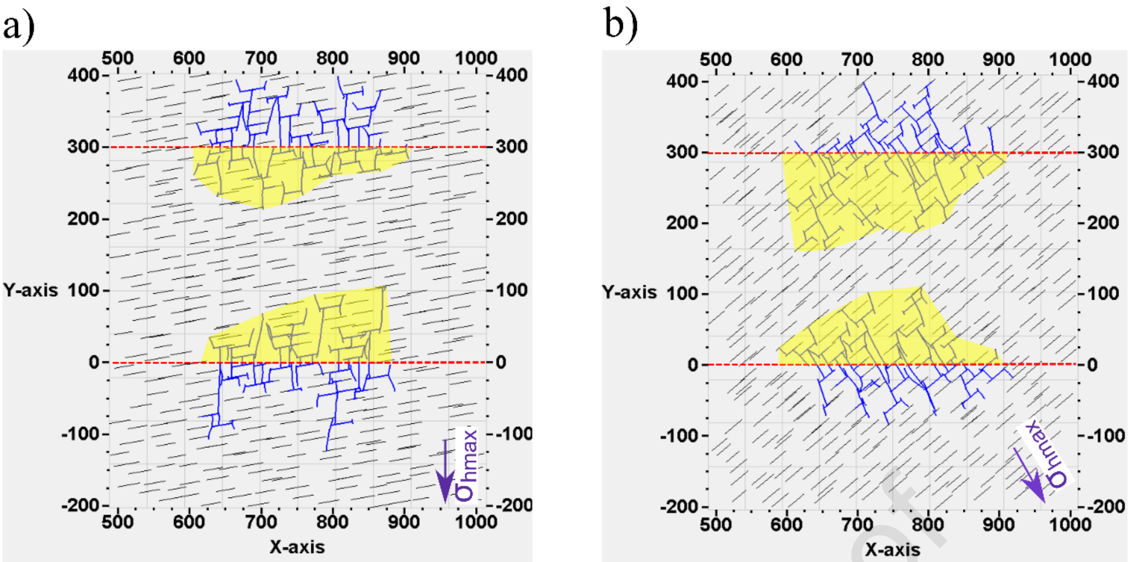

Figure 10 – Fracture networks with $\theta_{nf} = 80°$ a) standard well orientation $\theta_w = 90°$ and b) a rotated well with $\theta_w = 70°$, with $S_{nf} = 15m$ and $L_{nf} = 30m$. The stimulated reservoir volume is shown in yellow for the region between the wells

The reservoir pressure distribution for the standard well orientation $\theta_w = 90°$ and $\theta_w = 70°$ is shown in Figure 11. This demonstrates the tendency of hydraulic fractures to propagate further away from the well in which results in a larger stimulated reservoir volume is created and the recovery would be higher.

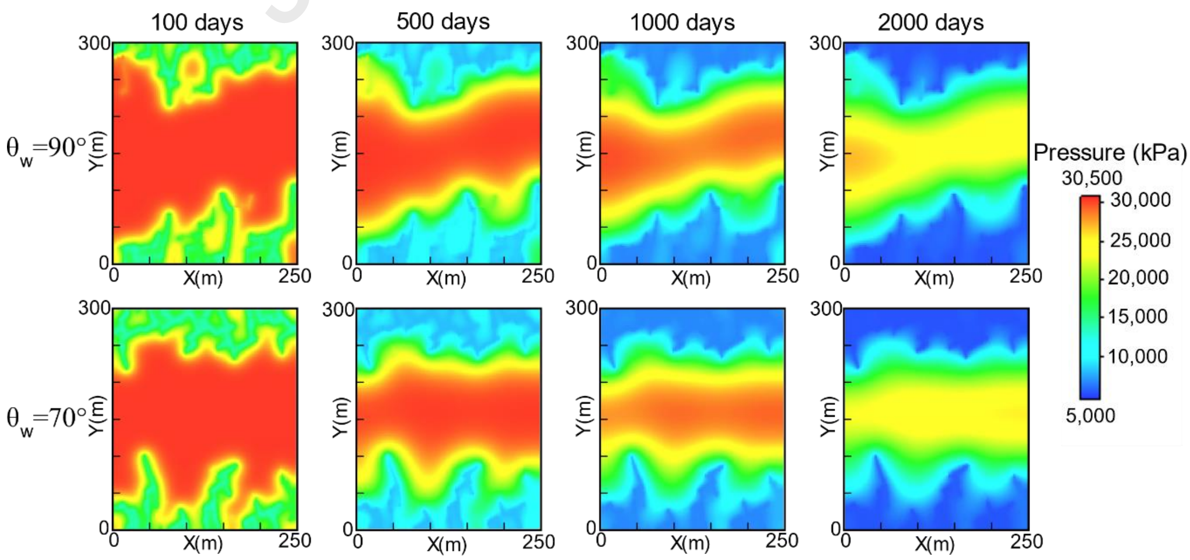

Figure 11 - Reservoir pressure distribution with the standard well orientation $\theta_w = 90°$ and changed by 20 degrees $\theta_w = 70°$ with $S_{nf} = 15m$ and $L_{nf} = 30m$

Therefore, this shows the recovery could be increased by simply changing the well orientation requiring no significant extra investment.

Figure 12 shows cumulative recovery after 500, 1,000 and 2,000 days of production with varying natural fracture orientations, θ_{nf} and well orientations, θ_w. It can be concluded that the maximum recovery is not always achieved with the standard well orientation perpendicular to the maximum horizontal stress, $\theta_w = 90°$. The term recovery multiplier (RM) is defined below as the ratio between recovery at a given well orientation in comparison to the standard well orientation $\theta_w = 90°$.

$$RM = \frac{Recovery\ at\ \theta_w}{Recovery\ at\ \theta_w{=}90°} \tag{7}$$

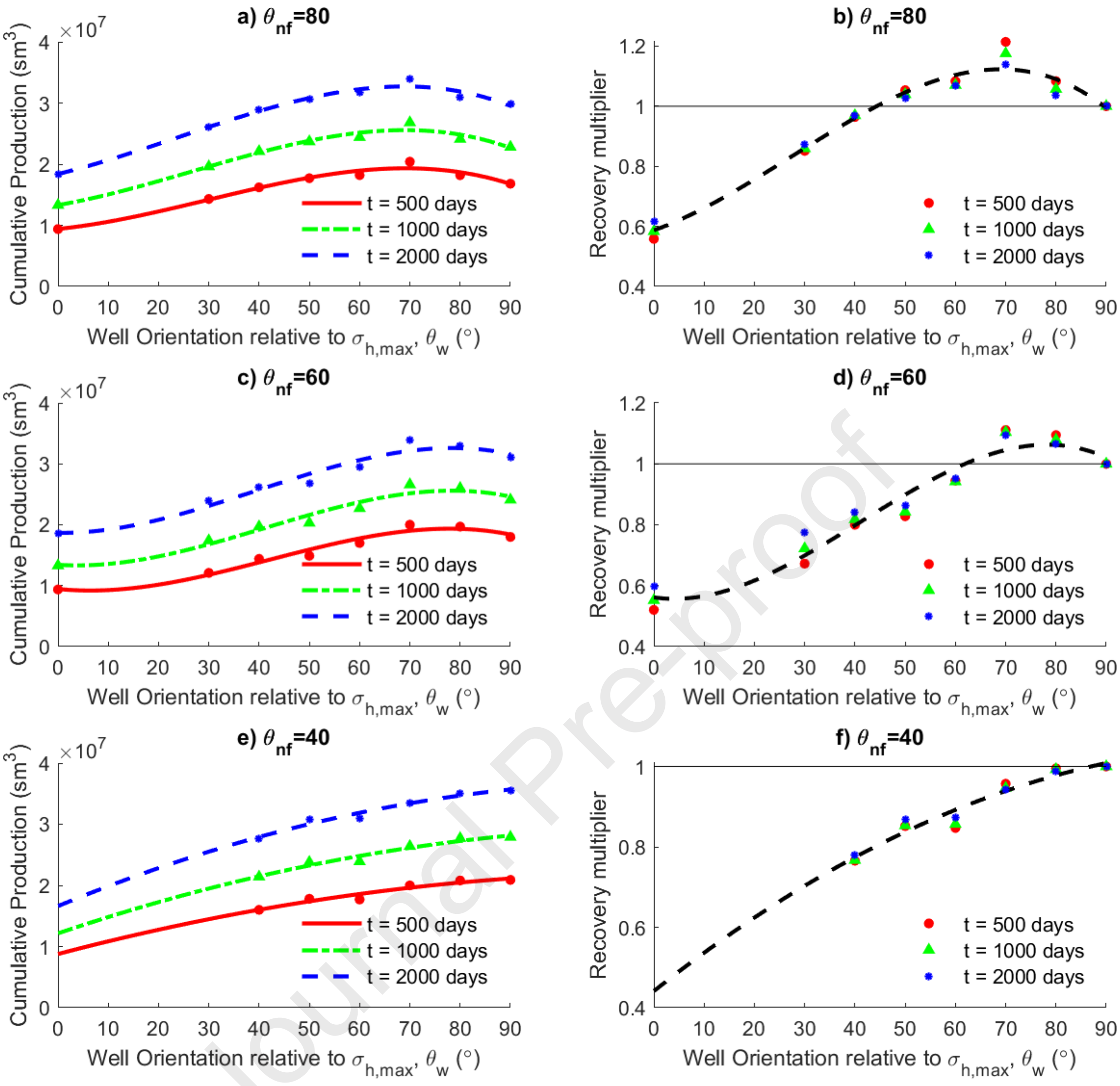

Figure 12 – Cumulative production with different well and natural fracture orientations and the recovery multiplier to the standard well orientation $\theta_w = 90°$ with $S_{nf} = 15m$ and $L_{nf} = 30m$

Figure 12 (a) and (b) show that when the natural fractures are nearly parallel to the minimum horizontal stress ($\theta_{nf} = 80°$) recovery can be slightly increased by up 10-20% with a change of well orientation to $\theta_w = 60°\ to\ 80°$. However, once the well orientation is changed beyond this, there is no increase in recovery and there is a decrease in recovery in comparison to the standard well orientation $\theta_w = 90°$. This is due to the dominance of the maximum horizontal stress component parallel to the well that forces hydraulic fractures to propagate more laterally along the well rather than towards the neighbouring well. It can be seen that for $\theta_{nf} = 60°$, similarly, a small change in well orientation to $\theta_w = 70°$ increases recovery up to 10%. A smaller range of well orientations show an increase in recovery with a non-standard well orientation for $\theta_{nf} = 60°$ than $\theta_{nf} = 80°$. And when the natural fractures are more parallel with the maximum horizontal stress, $\theta_{nf} = 40°$, there is no orientation that shows an increased recovery. This suggests that in this case the orientation of the maximum horizontal stress is still a major dominating factor determining the propagation of hydraulic fractures on a macro scale.

Therefore, these results indicate that when natural fractures are more perpendicular to the maximum horizontal stress there is a greater chance that a change in the well orientation away from the standard orientation to be beneficial. As highlighted in section 3.1 when natural fractures are more perpendicular to the maximum horizontal stress production is impacted to most severely with the standard orientation. Therefore, the worst cases also present the best opportunity to increase production by changing the well orientation.

There are also limitations to the method used in this study which should be noted. The efficiency of rotating the well orientation has only been tested under a single geological and stress condition in this study. Both of these can affect the propagation of hydraulic fractures and under different circumstances the results may be different. In this study, the differential in-situ stress is small and the natural fracture planes are weak. Both of these factors make it easy for hydraulic fractures to propagate along the natural fractures and therefore well orientation change is more likely to be favourable. When natural fractures are tougher, or the differential stress is higher then hydraulic fractures will require more energy to propagate along natural fractures and it is more likely that they will cross over natural fractures instead of propagate along them. In this scenario the effect of changing the well orientation is unlikely to increase recovery or efficiency. In addition to this, other effects such as fracture reorientation from the perforations may also restrict flow from the fractures into the well reducing recovery. This study has focused on the fracture propagation into the formation and not around the wellbore. Therefore, these effects have not been captured but to verify these conclusions they should be considered when changing the well orientation. However, these results demonstrate that on a macro-scale the tendency of hydraulic fractures to propagate along natural fractures could increase recovery which warrant further investigation such as laboratory or field tests.

3.3. Impact of Well Orientation with Different Natural Fracture Spacings

The results in section 3.2 showed that changing the well orientation can increase the recovery. In a previous study it has been shown the natural fracture spacing can also have a large effect on hydraulic fracture propagation, while natural fracture length has less of an effect (Sherratt et al., 2020). Therefore, in this study we elaborate on the effect of changing the well orientation with different natural fracture spacings. To investigate this effect, three natural fracture orientations $\theta_{nf} = 40°, 60°, 80°$ with natural fracture spacings of *S* = 5, 10, 15 and 20 m, were used to model hydraulic fracture stimulation and recovery with various well orientations.

The effect of well orientation on cumulative recovery with various natural fracture orientations, θ_{nf} and natural fracture spacings S_{nf} is shown in Figure 13. Three natural fracture realisations were generated and averaged for each point in each graph.

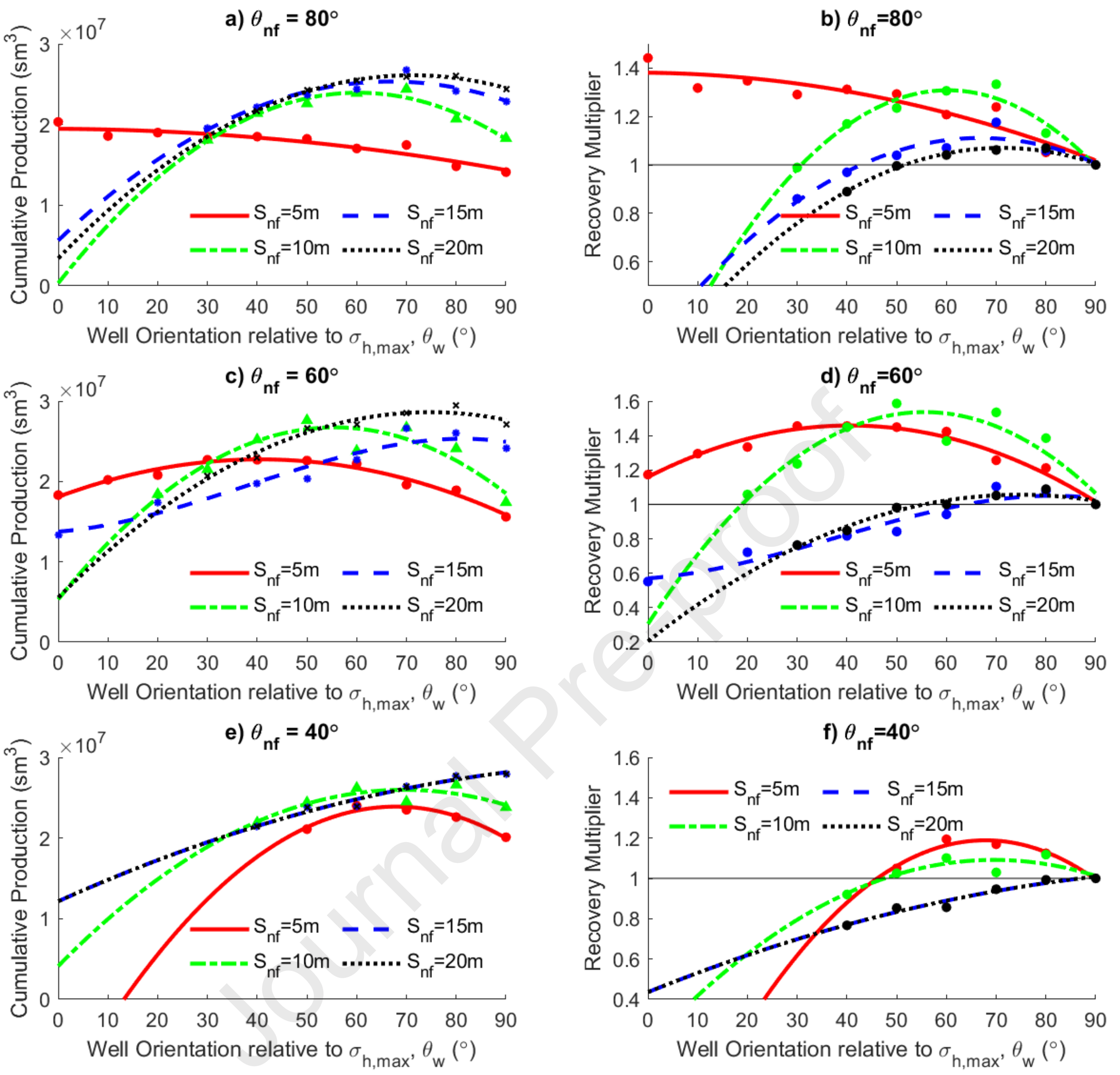

Figure 13 – Cumulative production with different well and natural fracture orientations and the recovery multiplier to the standard well orientation $\theta_w = 90°$ for different natural fracture spacings $L_{nf} = 30m$

For natural fractures that are almost parallel to the standard well orientation, $\theta_{nf} = 80°$, it was previously shown that with $S_{nf} = 15\ m$ the recovery was only increased with a small change in well orientation and with well orientations $\theta_w < 60°$ recovery was negatively impacted.

However, Figure 13 shows that when S_{nf} is decreased and fracture density is higher, the recovery is increased at more significant well orientation changes. In particular, when $S_{nf} =$ 5 m the results show that recovery is greatest when $\theta_w = 0°$ which is completely perpendicular to the standard well orientation. In addition to this, the maximum recovery multiplier (RM) increases with higher fracture density and small natural fracture spacing S_{nf}. This suggests that as the fracture spacing reduces, their effect on hydraulic fracture propagation stays dominant for a wider range of well orientations, over the negative effect of the maximum horizontal stress component (parallel to the well orientation). In section 3.2 the maximum observed increase in recovery was less than 20%. However, with decreased natural fracture spacing this is increased to 40%. The results also show that an increase in recovery is observed with a small orientation change for all natural fracture spacings up to 20 m.

With $\theta_{nf} = 60°$ the observed trend is similar to $\theta_{nf} = 80°$. However, with a natural fracture spacing 5m the increase in recovery does not keep increasing as the well orientation is changed from $\theta_w = 90°$ to $\theta_w = 0°$ and instead the peak recovery and optimal well orientation is about $\theta_w = 40°$. However, even at $\theta_w = 0°$ recovery is still greater than the standard well orientation.

With $\theta_{nf} = 40°$ and natural fracture spacing $S_{nf} = 15$ m in section 3.2 there was no well orientation that increased recovery compared to the standard well orientation. However, Figure 13 (d) and (f) show that changing the well orientation can achieve an increase in recovery of approximately 5% with a natural fracture spacing of 10 m and approximately 17% with a natural fracture spacing of 5 m.

In summary, these results elaborate that fracture spacing plays a large role in the propagation of hydraulic fractures. As highlighted before, changing the well orientation increases recovery by combining the competing effects of the stress orientation and the natural fractures to propagate hydraulic fractures away from the well and deep into the formation. When the natural fracture spacing is decreased, it would increase the dominance of the natural fractures on the propagation of hydraulic fractures and decreases the dominance of the maximum stress orientation, therefore, the well orientation can be changed to a greater amount.

It should be noted in our study, geomechanical properties such as fracture strength and differential stress are kept constant. These properties could impact the ability of hydraulic fractures to propagate along natural fractures and therefore have an impact on the results and should be investigated further if real field data is available. As previously highlighted, other fracture properties such as length will also impact the effectiveness of changing the well orientation. Overall, the results in this study suggest that changing the well orientation could be beneficial in naturally fractured formations where there can be a marginal increase in recovery with no extra investments. Geological uncertainty in the reservoir also presents significant challenges as these results show that changing the well orientation does not always increase recovery. If the geological properties such as natural fracture spacing, orientation or fracture toughness vary away from the well the results may not be as expected.

3.4. Two Perpendicular Planes of Natural Fractures

In previous sections, we have only considered a single set of natural fracture planes. As discussed, hydraulic fractures tend to propagate along the natural fractures, this results in fracture networks aligned with the orientation of the natural fractures. In this section, we further investigate the impact of recovery when there are two sets of natural fracture planes at 90° to each other as shown in Figure 14. As the natural fractures are perpendicular to each other there is no need to define the orientation of both sets and instead just the orientation of one set can be defined. We assume both sets have the same properties and the length $L_{nf} = 30$ m and spacing $S_{nf} = 15$ m. All other properties are defined in Table 1 and Table 2.

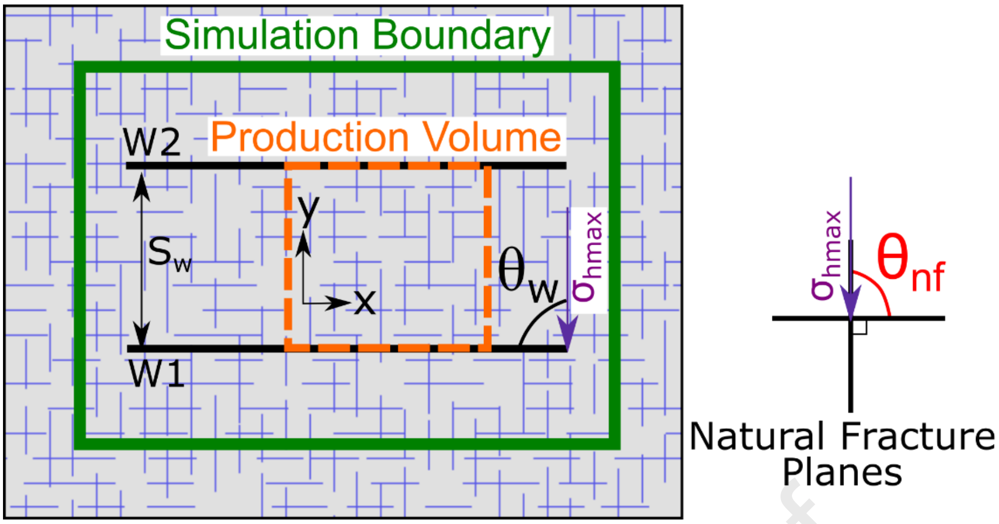

Figure 14 – Schematic of the wells and two perpendicular planes of natural fractures with equal properties

The cumulative production with different natural fracture orientations is shown in Figure 15. Three realisations for each scenario (θ_{nf} and θ_w) are generated and the average cumulative production for each case is taken. This suggests that recovery is slightly increased when one set of natural fractures is closely perpendicular to the well and that recovery is most negatively impacted when both the fracture sets are 45° to the well orientation. This can be explained as when one set is almost perpendicular to the well, the propagating hydraulic fractures are aided by the set that is nearly perpendicular to the well. When the angle is greater, the propagating hydraulic fracture interacts with lots of the natural fractures which all propagate greatly along the direction of the well rather than into the formation. Recovery is not maximum when $\theta_{nf} = 0°$ because the propagating hydraulic fractures are highly unlikely to intersect the fractures perpendicular to the well and therefore cannot easily propagate along them, i.e., natural fractures parallel to the well hinder the propagation of hydraulic fractures.

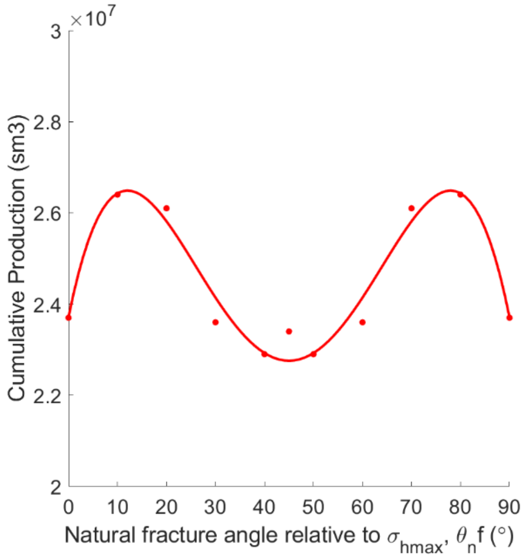

Figure 15 – Cumulative production with different orientations of the two natural fracture planes, θ_{nf} with $\theta_w = 0°$, $L_{nf} = 30m$ and $S_{nf} = 15m$

The cumulative production with different well orientations, θ_w and natural fracture orientations θ_{nf} is shown in Figure 16. This shows the general trend of recovery decreasing as the well orientation is changed and therefore there is no optimal orientation other than the standard well orientation $\theta_w = 90°$.

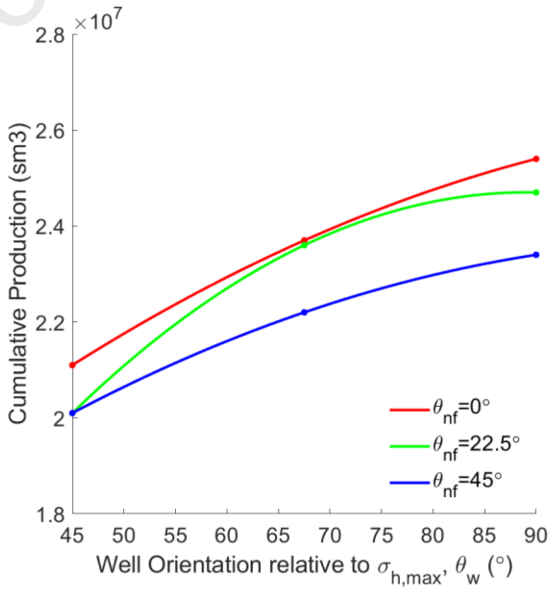

Figure 16 – Cumulative production with different well orientations, θ_w and different natural fracture orientations θ_{nf} with $= L_{nf} = 30m$ and $S_{nf} = 15m$

In sections 3.2 and 3.3, the results showed that production could be increased by changing the well orientation to utilise the tendency of hydraulic fractures to propagate along natural fractures to ensure hydraulic fractures propagate deep into the formation. However, when there are two sets of natural fracture planes perpendicular to each other the effects of each set cancel out each other and therefore no change in well orientation can result in an increased recovery.

The two sets of natural fracture planes scenario in this study is an extreme case and there will be cases when there are two sets of natural fractures with a smaller angle between them. In such cases, the effects might complement each other, resulting in a directional tendency. Therefore, the smaller angle between the sets of natural fractures could result in a higher chance of being able to increase recovery by changing the well orientation, however this requires further studies.

3.5. Economic Analysis of Increasing Well Spacing

The results in this study have shown that under many conditions the recovery can be increased by changing the well orientation. The recovery factor achieved after 5,000 days for the standard well orientation ($\theta_w = 90°$) and the optimised well orientation ($\theta_w = 70°$) with natural fracture angle $\theta_{nf} = 60°$ with different well spacings is shown in Figure 17. This shows that a higher recovery factor is achieved using the optimised well orientation and this increase is limited when well spacing is decreased. This also demonstrates that by changing the well orientation the same recovery factor can be achieved using a larger well spacing representing a reduction in the cost of developing the resource.

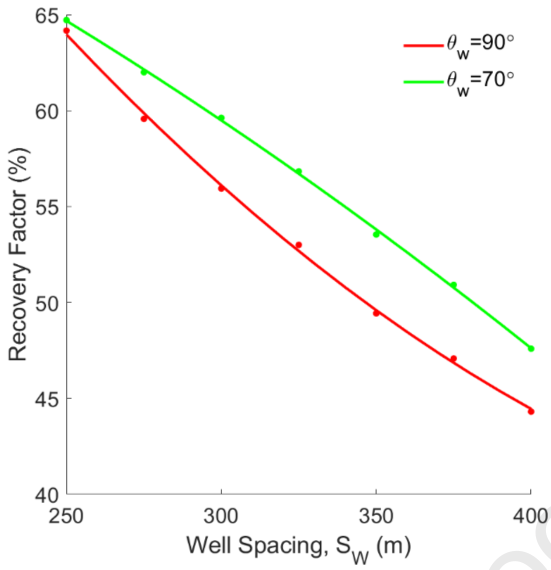

Figure 17 – Recovery factor after 5,000 days with different well spacings $S_{nf} = 15\ m,\ L_{nf} = 30\ m$ and $\theta_{nf} = 60°$ for well orientations $\theta_w = 90°$ and $\theta_w = 70°$

Figure 17 shows that the same recovery factor can be achieved by using the standard well orientation ($\theta_w = 90°$) and $S_W = 300\ m$ as a well orientation of $\theta_w = 70°$ and $S_W = 350\ m$. We can use these two scenarios to perform a simple economic analysis of changing the well orientation. Considering a reservoir section of 2,400 m × 2,100 m × 25 m. With the standard well orientation and $S_W = 300\ m$ a recovery factor of 55% can be achieved over 5,000 days would require 8 wells for the reservoir section of 2,400 m. However, achieving the same recovery factor with $\theta_w = 70°$ only requires 7 wells in the same time period. Typical costs for lease accusation (LA), royalty costs (RC), site preparation (SP), drilling and completion costs (D&C), operating costs (OPEX) and taxes are taken from a previous economic study and detailed in Table 3 (Eshkalak et al., 2014).

Table 3 - Economic parameters used for the economic analysis (Eshkalak et al., 2014).

Property	**Value**
Shale reservoir dimensions (m)	$2{,}400 \times 2{,}100 \times 25$

Cost of single well: drilling, completion, stimulations ($)	3,444,882
Target recovery factor (RF) after 5,000 days (%)	55
Gas price ($/MMBtu)	3.00, 4.00
Operating Costs: OPEX ($/Mscf)	1.00
Site preparation costs: SP ($/well)	40,000
Lease Acquisition Cost: LA ($/acre)	3500
Royalty Costs: RC (%)	15
Tax Rate: Federal + State (%)	45
Discount rate, r	0.1

The main savings will come from the reduction in costs of drilling and completing an extra well. A simple analysis of the reduction in costs is shown in Table 4. This shows that the profit per square metre can be increased by optimising the well orientation from $47.31 to $48.00. This may appear to be a small increase, but it requires no extra investment to achieve which makes this small increase significant when we develop an entire field in which hundreds of wells are drilled.

Table 4 – Simple economic comparison between standard and optimised well orientation

Property	**Standard Well Orientation**	**Optimised Well Orientation**
Well Spacing required for target RF (m)	300	350
Number of wells required	8	7
Total cost of drilling ($)	27,559,056	24,154,174
Revenue from Gas (4$/MMBtu) ($)	228,013,841	228,013,841
Simple profit ($)	238,457,092	241,901,974
Profit per square metre ($\$/m^2$)	47.31	48.00

The simple analysis in Table 4, only takes into account the drilling & completion costs and doesn't take into account the net present value (NPV) of cash flows, OPEX, royalty costs or taxes. A more in-depth economic analysis can be conducted by determining the capital expenditure as the sum of the lease accusation, site preparation and drilling and completion costs,

$$CAPEX = LA + SP + D\&C \tag{8}$$

The net present value (NPV) is calculated using the equation below,

$$NPV = \sum_{t=0}^{N} \frac{Revenue_t - CAPEX_t - OPEX_t - RC_t - taxes_t}{(1+r)^t} \tag{9}$$

Where t is the number of years from the beginning of production and N is the total number of years production is simulated for. A discount rate of $r = 0.1$ is used in this study. This analysis is based on two gas prices of 3.00 \$/MMBtu and 4.00 \$/MMBtu (1 MMBtu ≈ 28,26 sm^3). The actual gas price will have a big impact on any economic analysis and fluctuation in the gas price over the 5,000 days of production is not accounted for in this study. Other variables needed for this analysis are detailed in Table 3. The NPV with time following the beginning of production is shown in Figure 18 for the different well orientations for two different gas prices.

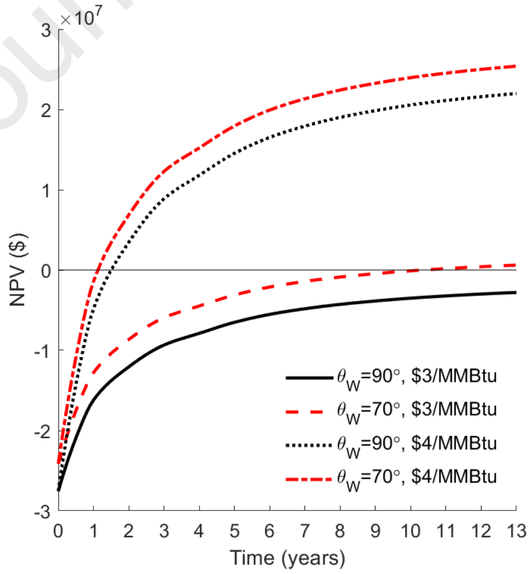

Figure 18 – NPV of the case with the standard well orientation ($\theta_w = 90°$) and $\theta_w = 70°$ with two different gas prices

This shows that changing the well orientation and increasing the well spacing can increase the NPV of shale gas developments. The main difference is the reduction in CAPEX costs from \$27.56 million to \$24.15 million due to less wells being required. The time to which the NPV becomes positive is also decreased by up to several years just by changing the well orientation to $\theta_w = 70°$ which decreases the risk of investment. This analysis does not consider the economics of operating and maintaining a smaller well stock, however this would further increase the economic benefit of changing well orientation and increasing well spacing. This analysis also assumes a large rectangular reservoir. The same results may not be achieved with more complex reservoir geometries or smaller reservoirs as the orientation of the wells may limit the number of wells that can be drilled. The method used in this study also has limitations as each part of this workflow have been independent. A more complete economic analysis could include dynamic adjustments after each stage as the fracture design may be optimized by changing the fluid and proppant schedules with different orientations.

4. Summary and Conclusions

This study highlights the impact of natural fractures on the propagation of hydraulic fractures creating complex hydraulic fracture networks and can be summarized as the following points;

- Hydraulic fractures exploit and propagate along weak natural fractures which may not be in the direction of the maximum horizontal stress. This can result in fractures propagating in a direction lateral to the well in addition to perpendicularly away from the well. As a result, deep regions of the formation between wells can be poorly connected to the well via fractures.
- Changing the well orientation in naturally fractured formations from the standard direction perpendicular to the maximum horizontal stress can combine the effect of

natural fractures and in-situ stress orientation to force hydraulic fractures to propagate deeper into the formation between wells increasing the SRV and volume of hydrocarbons accessed by each well increasing recovery.

- The effect of changing the well orientation is greatest when natural fractures are at a high angle with the maximum horizontal stress and fracture spacing is small.
- The effect of changing the well orientation is only tested in a single geomechanical scenario with low differential stress and fracture strength. This does not suggest this result will be universal and further research is required to determine the geomechanical scenarios that favor changing the well orientation.
- When natural fractures exist in two perpendicular planes with equal distributions there is no well orientation that results in an increase in recovery compared to the standard direction perpendicular to the maximum horizontal stress.
- A simple economic analysis demonstrates the savings that can be made by changing the well orientation and increasing well spacing. This also shows that the time taken for NPV to become positive is also reduced which decreases risk of investment.

Acknowledgments

The authors would like to thank the School of Engineering at the University of Aberdeen for financial support and providing the required facilities to complete the study. Support from the Computer Modelling Group and Schlumberger for the use of their software packages is greatly acknowledged. This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

References

Arri, L.E., Yee, D., Morgan, W.D. and Jeansonne, M.W. 1992. Modeling Coalbed Methane Production With Binary Gas Sorption. Presented at the SPE Rocky Mountain Regional Meeting, Casper, Wyoming, USA, May 1992. doi: 10.2118/24363-MS.

Belyadi, H. and Smith, M. 2018. A Fast-Paced Workflow for Well Spacing and Completions Design Optimization in Unconventional Reservoirs. Presented at the SPE/AAPG Eastern Regional Meeting, Pittsburgh, Pennsylvania, USA, October 2018. doi: 10.2118/191779-18ERM-MS.

Cao, R., Li, R., Girardi, A., Alejandro, G., Chowdhury, N. and Chaohui, C. 2017. Well Interference and Optimum Well Spacing for Wolfcamp Development at Permian Basin. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Austin, Texas, USA, July 2017. doi: 10.15530/URTEC-2017-2691962.

Cullick, A.S., Carrillo, M., Clayton, C. and Ceyhan, I. 2014. Well-spacing Study to Develop Stacked Tight Oil Pay in Midland Basin. Presented at the SPE Unconventional Resources Conference, The Woodlands, Texas, USA, April 2014. doi: 10.2118/168992-MS.

Daigle, H., Ezidiegwu, S. and Turner, R. 2015. Determining Relative Permeability In Shales By Including The Effects Of Pore Structure On Unsaturated Diffusion And Advection. Presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, USA, September 2015. doi: 10.2118/175019-MS.

Eshkalak, M.O., Aybar, U. and Sepehrnoori, K. 2014. An Economic Evaluation on the Re-fracturing Treatment of the U.S. Shale Gas Resources. Presented at the SPE Eastern Regional Meeting, Charleston, West Virginia, USA, October 2014. doi: 10.2118/171009-MS.

Evans, R.D. and Civan, F. 1994. Characterization of Non-Darcy Multiphase Flow in Petroleum Bearing Formations. Contract No. DE-AC22-90BC14659.

Forchheimer, P. 1901. Wasserbewegung durch Boden. Z. Ver. Deutsch. Ing 45: 1782-8.

Hall, F.E., Chunhe, Z., Gasem, K.A.M., Robinson, R. L. and Dan, Y. 1994. Adsorption of Pure Methane, Nitrogen, and Carbon Dioxide and Their Binary Mixtures on Wet Fruitland Coal. Presented at the SPE Eastern Regional Meeting, Charleston, West Virginia, USA, November 1994. doi: 10.2118/29194-MS.

Jamison, W. and Azad, A. 2017. The hydraulic fracture – natural fracture network configuration in shale reservoirs: Geological limiting factors. Journal of Petroleum Science and Engineering 159: 205-29. doi: https://doi.org/10.1016/j.petrol.2017.09.017.

Kresse, O., Weng, X., Gu, H. and Wu, R. 2013. Numerical Modeling of Hydraulic Fractures Interaction in Complex Naturally Fractured Formations. Rock Mechanics and Rock Engineering 46 (3): 555-68. doi: 10.1007/s00603-012-0359-2.

Lalehrokh, F. and Bouma, J. 2014. Well Spacing Optimization in Eagle Ford. Presented at the SPE/CSUR Unconventional Resources Conference – Canada, Calgary, Canada, September 2014. doi: 10.2118/171640-MS.

Letham, E.A. and Bustin, R.M. 2016. Klinkenberg gas slippage measurements as a means for shale pore structure characterization. Geofluids 16 (2): 264-78. doi: 10.1111/gfl.12147.

Ma, Y. and Holditch, S. 2015. Unconventional Oil and Gas Resources Handbook: Evaluation and Development, 1st edition: Gulf Professional Publishing.

Malpani, R., Sinha, S., Charry, L., Sinosic, B., Clark, B. and Gakhar, K. 2015. Improving Hydrocarbon Recovery of Horizontal Shale Wells Through Refracturing. Presented at the

SPE/CSUR Unconventional Resources Conference, Calgary, Canada, October 2015. doi: 10.2118/175920-MS.

Olson, J.E. and Taleghani, A.D., 2009. Modeling simultaneous growth of multiple hydraulic fractures and their interaction with natural fractures. Paper presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, January 2009. doi: https://doi.org/10.2118/119739-MS.

Pedrosa, O.A., 1986. Pressure Transient Response in Stress-Sensitive Formations. Paper presented at the SPE California Regional Meeting, Oakland, California. doi: 10.2118/15115-MS

Petrel Kinetix Schlumberger, Release Date: March 2017, Kinetix Shalre for Petrel 2016.1, version 5.0

Rexilius, J. 2015. The Well Factory Approach to Developing Unconventionals: A Case Study from the Permian Basin Wolfcamp Play. Presented at the SPE/CSUR Unconventional Resources Conference, Calgary, Canada, October 2015. doi: 10.2118/175916-MS.

Sahai, V., Jackson, G., Rai, R.R. and Coble, L. 2012. Optimal Well Spacing Configurations for Unconventional Gas Reservoirs. Presented at the SPE Americas Unconventional Resources Conference, Pittsburgh, Pennsylvania, USA, June 2012. doi: 10.2118/155751-MS.

SHENG, J.J., 2019. Enhanced Oil Recovery in Shale and Tight Reservoirs. Cambridge, MA, USA: Gulf Professional Publishing.

Sherratt, J., Sharifi Haddad, A. and Rafati, R., 2018. Hot Solvent-Assisted Gravity Drainage in Naturally Fractured Heavy Oil Reservoirs: A New Model and Approach to Determine Optimal Solvent Injection Temperature. *Industrial & Engineering Chemistry Research,* **57**(8), pp. 3043-3058.

Sherratt, J., Sharifi Haddad, A., Rafati, R. and Manzari, M.T. 2020. A fracture upscaling method (FUM) for hydraulically fractured reservoirs: From discrete fracture modelling to finite difference simulations. Journal of Natural Gas Science and Engineering 83: 103611. doi: https://doi.org/10.1016/j.jngse.2020.103611.

Wang, H. 2016. Numerical investigation of fracture spacing and sequencing effects on multiple hydraulic fracture interference and coalescence in brittle and ductile reservoir rocks. Engineering Fracture Mechanics 157: 107-24. doi: https://doi.org/10.1016/j.engfracmech.2016.02.025.

Wang, J. and Olson, J.E. 2020. Auto-Optimization of Hydraulic Fracturing Design with Three-Dimensional Fracture Propagation in Naturally Fractured Multi-Layer Formations. Presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Virtual, July 2020. doi: 10.15530/urtec-2020-3160.

Wu, K. and Olson, J.E. 2016. Numerical Investigation of Complex Hydraulic-Fracture Development in Naturally Fractured Reservoirs. SPE Production & Operations 31 (04): 300-9. doi: 10.2118/173326-PA.

Yaich, E., Diaz De Souza, Osvaldo Cesar, Foster, R.A. and Abou-sayed, I. 2014. A Methodology to Quantify the Impact of Well Interference and Optimize Well Spacing in the Marcellus Shale. SPE/CSUR Unconventional Resources Conference – Canada September 2014. doi: 10.2118/171578-MS.

Yu, W., Xu, Y., Weijermars, R., Wu, K. and Sepehrnoori, K. 2017a. Impact of Well Interference on Shale Oil Production Performance: A Numerical Model for Analyzing Pressure Response of Fracture Hits with Complex Geometries. Presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition January 2017. doi: 10.2118/184825-MS.

Yu, W., Hu, X., Wu, K. Sephrnoori, K. and Olson, J.E. 2017b. Coupled Fracture-Propagation and Semianalytical Models to Optimize Shale Gas Production. SPE Reservoir Evaluation & Engineering 20 (04): 1004-19. doi: 10.2118/175109-PA.

Zhang, F. and Emami-Meybodi, H. 2020. A Semianalytical Method for Two-Phase Flowback Rate-Transient Analysis in Shale Gas Reservoirs. SPE Journal 25 (04): 1599-622. doi: 10.2118/201225-PA.

Zhu, C., Guo, W., Wang, Y., Li, Y., Gong, H., Xu, L. and Dong, M., 2020. Experimental study of enhanced oil recovery by CO2 huff-n-puff in shales and tight sandstones with fractures. *Petroleum Science,* doi: https://doi.org/10.1007/s12182-020-00538-7 .

Zou, Y., Zhang, S., Ma, X., Zhou, T. and Zeng, B. 2016. Numerical investigation of hydraulic fracture network propagation in naturally fractured shale formations. Journal of Structural Geology 84: 1-13. doi: https://doi.org/10.1016/j.jsg.2016.01.004.

Highlights:

- Hydraulic fractures (HFs) can extend along natural fractures (NFs)
- This can cause bypassed resources and reduced recovery factor
- The well orientation can be optimised to allow deeper penetration of HFs
- The well orientation change is useful when NF planes are parallel to σ_{hmin}

Declaration of interests

☒ The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☐The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: