JOURNAL OF PETROLEUM GEOMECHANICS
(JPG)

Rejuvenation of a Mature Tight Sandstone Oil Reservoir through Multistage Hydraulic Fracturing: A Case Study of a North African Basin

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Received:15 January 2020; Accepted: 14 June 2021
DOI: 10.22107/jpg.2021.215847.1115

Keywords

Unconventional Resources,
Mature Field,
Tight Sandstone,
Multistage Hydraulic Fracturing,
Fracture Conductivity

Abstract

Development of mature oil fields has been increasingly attractive in recent years as a significant amount of world oil and gas production is being extracted from these formations. Hydraulic fracturing (either as a selective corrective stimulation method or as a preliminary completion approach) is a well-established technique in mature oil field rejuvenation to improve productivity and deliverability of such a diminishing field. After many years of successful production in A1 and A2 reservoirs, A3 and A4 reservoirs were developed with only one hydraulically fractured vertical well (Well #1). As the production from well #1 in A3/A4 reservoirs was below the expectation, the well was shut down after 3 years of production. Therefore, the main objective of this research paper is to investigate re-development options for A3/A4 reservoirs due to the low deliverability and productivity of the vertical well #1. Sensitivity analysis for history matching, critical conductivity, and optimum dimensionless fracture conductivity (Cfd) was performed followed by forecasting and multistage hydraulic fracturing. Numerical results showed that there is a critical conductivity beyond which production is insensitive to the conductivity, for a specific propped length and production time. Results also showed that critical conductivity increased with propped length and decreased with production time. After 25 years of forecasting, the recovery factor for the 900m lateral with eight fractures and 110m spacing was the highest at 2.65%. The corresponding values for the 300m and 600m laterals were 2.37% and 2.42%. Therefore, the study suggests that horizontal wells with a longer length and optimized number of fractures and spacing will provide maximum well recovery.

1. Introduction

There has been a dramatic rise since 2006/2007 in the development and exploitation of unconventional resources, particularly shale. We have also seen a revival of oil and gas production in both Canada and the United States due to technological advancements associated with multistage hydraulic fracturing that make it possible for natural gas to be produced from unconventional formations, like shale, tight oil and gas sandstone, in an economical way

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(Abdollahipour et al., 2018). In 2009, the United States became the world's largest producer of natural gas, and this was very much down to application of these new technologies (Ahmed et al., 2016). Unconventional resource plays (URP) have very low permeability and porosity. In contrast, conventional reservoirs exhibit good reservoir quality (high porosity and permeability) and hydrocarbon production from these formations generally do not require a stimulation method (e.g. acidizing or hydraulic fracturing).

Holditch (2006) considers tight gas "A reservoir that cannot be produced at economic rates nor one can cover from it economic volume of gas without large-scale hydraulic fracturing treatment or advance horizontal multilateral wellbores." Differences between unconventional and conventional resources are explained by the resource triangle concept shown in Figure 1 (Masters, 1979).

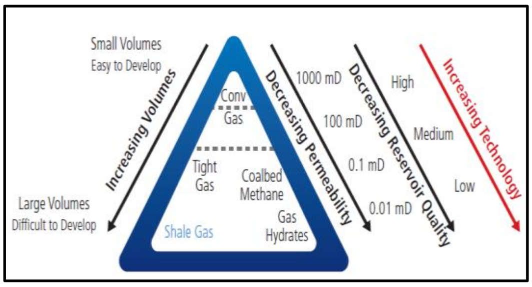

Figure 1. The Unconventional Resource Triangle (Holditch 2006).

As can be seen from Figure 1, conventional resources (e.g. pure gold) are located at the top of the triangle to show high reservoir quality and they are easy to extract but these resources are also hard to discover (they exist in small volume). However, as we navigate deeper into the resource triangle from conventional to unconventional resources (e.g. tight oil, gas sandstone and shale) reservoir quality (permeability and porosity) decreases and technology needed to develop them increases and becomes more complex and difficult; however, these resource volumes are enormous. The Siliclastic sandstone reservoir is classified into two different categories:

- Conventional sandstone formation
- Tight sandstone oil and gas formation

These reservoirs vary considerably based on the following factors:

- Diagenetic evolution
- Reservoir performance
- Depositional environment
- Pore geometry (pore types, pore-throat sizes, pore connectivity)

A tight sandstone reservoir is part of the unconventional reservoir category (see Figure 1) that possess medium to low porosity and low to ultra-low permeability. Table 1 shows the main differences between conventional and unconventional sandstone (tight sandstone formation).

Wang et al. (2016) mentioned that multistage hydraulic fracturing has been established as an extremely effective technique for maximising well productivity and deliverability in development of unconventional resource plays (URP) in the past few decades. Multistage fracturing is a combination of placing hydraulic fractures, either transvers (vertical) or longitudinal (horizontal) fractures, in conjunction with horizontal well length.

Horizontal wells, first attempted in the late 1920s and early 1930s, were first accepted as a water and gas-coning control approach in the 1970s (Pearson, 2013). The first successful multiple fracturing was achieved in a vertical well in 1952, the first multiple fracturing of a deviated well took place early in 1974, and the first multiple fracturing in a horizontal shale well were accomplished in 1988. This combination of deviated and horizontal wells and fracturing technologies has initiated the unlocking of large oil and gas reserves in source rock, tight oil and gas formation and other low-permeability

reservoirs thought to be technically unrecoverable just a few decades ago. Multiple fracturing of wells provides an efficient way to exploit unconventional resources that have very low permeability, while reducing the number of vertical wells necessary to access the same reserves by a factor of two to ten or more (King, 2014).
The oil field modelled in this study possess very low permeability that ranges from 0.1 to 0.001mD, with sandstone as the primary reservoir rock. These characteristics classify the field as a tight formation. The field possesses three natural faults and contains an area of 4 km^2 and consists of four reservoirs: A1, A2, A3, and A4. A1 and A2 reservoirs were successfully developed by multiple wells by an operator. A3 and A4 reservoirs were also developed by one hydraulically fractured vertical well (well #1).
As the production of well #1 in A3/A4 reservoirs was below expectation, the well was shut down after 3 years of production. Therefore, the main objective of this research paper is to investigate re-development options for A3/A4 reservoirs due to low deliverability and productivity of the vertical well #1, in A3/A4 reservoirs.

Table 1. Comparison of conventional and unconventional sandstone reservoirs (courtesy Zou, 2013)

Property	Conventional Sandstone Reservoir	Tight-Sandstone Reservoir
Reservoir rock composition	High quartz grain content, low feldspar and matrix content	Fairly high feldspar and matrix content
Diagenetic evolution	Mostly before stage B of the middle diagenetic phase	Middle to late diagenetic phase
Pore type	Mixed primary and secondary pores	Mainly secondary pores
Pore-throat	Pore-throat connectivity Short pore throats	Sheet and winding
Porosity (%)	12 to 30	3 to 12
Permeability (mD)	>.1	≤0.1
Water saturation (%)	25 to 50	45 to 70
Rock density (g/cm3)	<2.65 2.65 to 2.74	2.65 to 2.74
Capillary pressure	Low	Fairly high
Reservoir pressure	Generally normal to slightly less than normal	Mostly abnormal, high
Stress sensitivity	Weak	Strong

Mature Field Re-development

Martin et al. (2010) suggested several techniques for rejuvenation of a mature field (see Figure 2). He stated that full consideration of these methods should start the basis of a selection process intended for enhancing and maximising the overall value of rejuvenation of mature fields and hydraulic fracturing technique could possibly be applied as a part of a well's initial completion during the development phase.

Hydraulic Fracturing Workflow in a Tight Sand Formation

The analysis of unconventional tight oil formation includes three key stages:

- Resource evaluation
- History matching of the model
- Forecasting

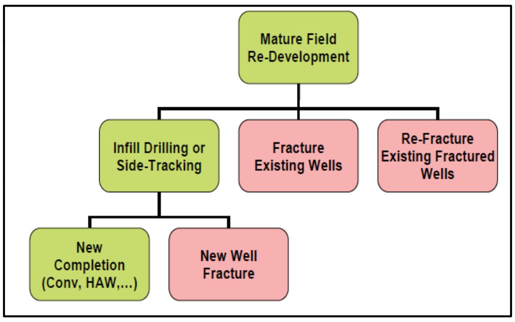

Figure 2. Rejuvenation options for mature field (Economides and Martin, 2007).

The resource evaluation phase involves a multidiscipline approach integrating geology, petrophysics, geoscience, geomechanics and geochemistry to identify the best productive zone or the sweet spot. The main objective of history matching is to obtain and verify a good agreement with the known production and pressure data after running many simulations of the reservoir geomodel and varying the properties of the model. In the forecasting stage, well production future performance (oil rate and cumulative oil) as well as recovery factors are predicted using the history-matched reservoir model. The history matching and forecasting process needs various input data and involves iteration and fast simulators that play a significant role in reducing simulation run-time and accelerating such workflows (Mukundakrishnan et al., 2015).

Hydraulic Fracturing Optimisation

Multiple factors must be carefully considered in hydraulic fracturing optimization (Abdollahipour et al., 2016). These parameters can be classified into four main categories:

- Well placement and horizontal well
- Completion methods
- Fracture numbers and spacing
- Fracture conductivity and geometry (length, width, height, etc.)

Well Placement and Horizontal Length

Wellbore placement and horizontal well length are controlled by a number of factors such as geology of the field, and geomechanical factors (e.g. vertical stress, horizontal stress, Young's modulus, etc.). Other factors that may affect well placement and choice of horizontal well length includes well deliverability, reserves to be developed and also well intervention program. During the past few decades, applying horizontal wells has proven to be an effective and operative method in exploiting unconventional resource plays (URP) by increasing well productivity and deliverability due to maximising reservoir contact with the wellbore.

For example, 3000 ft of 6.25" horizontal open hole provides 456 m^2 of reservoir contact while a single 50 m diameter (radial geometry) hydraulic fracture gives 3927 m^2 of reservoir contact. Even a single really small hydraulic fracture gives reservoir contact that is an order of magnitude greater than any other completion method. Rankin (2010) mentioned that the increasing horizontal length application in exploitation of unconventional resources has positively influenced the economics of oil and gas field development and reduces the environmental affect. At the present, horizontal lengths vary from 1,000 to 10,000 feet. Pedro et al. (2013) stated that in most circumstances the key limitation in horizontal drilling is the applicability of current and future intervention in the wellbore. This limitation could be due to fracture isolation equipment, perforating as well as applying coiled tubing technique.

Completion and Isolation Techniques

The oil and gas industry has developed a wide variety of completion and isolation techniques for horizontal multi-fractured wells (HMF). Each technique, from open hole to cased hole, ball-activated sliding sleeves to pump down plugs and perforation guns, tries to raise operational capability by putting the maximum number of stages in the quickest time. Current multistage sleeve systems are capable of placing dozens of stages in a constant pumping operation (Pedro et al., 2013). Plug-and-perf methods are only restricted by the capability of pumping the plugs and guns down the horizontal length. In the Bakken, for example, operators are now routinely placing as many as 40 stages per lateral using combinations of sliding sleeves and plug-and-perf methodology (Rankin, 2010).

Fracture Spacing and Number of Fractures

Liu et al. (2015) stated that the multistage hydraulic fracturing technique is a combination of both horizontal drilling in conjunction with hydraulic fractures (transvers or longitudinal) placed alongside the wellbore length. Zhao et al. (2016) showed that this technique is very popular and widely used in unconventional reservoir development, and that it can reduce operational costs by simultaneously creating multiple hydraulic fractures. Post production analysis has shown that increasing the number of fractures and optimum spacing between each fracture along the horizontal well length is one of the vital parameters that significantly influence well productivity and deliverability in development of unconventional formations. The productivity and deliverability of these reservoirs clearly correspond to the number of fractures and spacing. The number of fractures and spacing between fractures determines to a large extent the operational cost of hydraulic fracturing and are intern controlled by geomechanical factors like in-situ stress field regime and reservoir permeability.

Generally speaking, reservoir permeability drives everything in unconventional reservoir development. Formation permeability influences the size and shape of the fractures. High permeability reservoirs are generally soft, weak or unconsolidated formations with high skin damage and often it is difficult to place a fracture which is more conductive than the formation. In these formations, hydraulic fractures are designed to be short and very conductive (thick). Factures are designed with the maximum possible conductivity. In contrast, low permeability reservoirs are generally hard formations and easier to fracture than high permeability reservoirs and they show relatively low skin factors. Normally it is very easy to place a fracture which is many times more conductive than the formation. Fractures in these formations are designed for length (very thin and long).

As spacing between hydraulic fractures is reduced, neighbouring hydraulic fractures start to interfere with each other, which could result in decreasing well productivity while costs continue to rise due to the increasing number of fractures. A post economic analysis of multistage hydraulic fracturing carried out by Rankin (2010), and Norris, (1998), showed that economic evaluation controls the optimum spacing where the benefit of increasing hydraulic fractures (transverse or longitudinal fractures) is balanced with the cost of the increased fracture stages along horizontal well length. Pedro et al. (2013) also mentioned that in the Haynesville and Bakken an increased number of hydraulic fractures alongside the horizontal well resulted in increased production and well deliverability. The spacing between fractures along the length of the wellbore significantly influence the productivity of a hydraulically fractured reservoir. The number of fractures and the length of the reservoir control the spacing between fractures. The spacing between fractures is thought to be a major factor in the success of horizontal well completions (Liu et al., 2015).

Fracture Geometry and Conductivity

Determining the desired fracture geometry (e.g. fracture half-length (X_f), fracture width (w_f), fracture half-height (H_t)), and Dimensionless Fracture Conductivity (C_{fd})) are essential parameters for fracture geometry optimization.

Dimensionless Fracture Conductivity (C_{fd}) is a major variable used in fracture design, and it has a significant influence on post-treatment production. Values of C_{fd} >30 are normally considered to have infinite conductivity (Martine et al., 2007). There is a positive relationship between the two factors. This relationship can be explained based on Darcy's equation (Eq.1). Also, Dimensionless fracture conductivity (C_{fd}) is defined in Equation 2.

$$Q = \frac{K\Delta PA}{\mu L} \rightarrow \Delta P = \frac{Q\mu L}{KA} = Pr - Pwf = \frac{Q\mu L}{KA} \quad \textit{(Eq.1)}$$

$$C_{fd} = \frac{k_f w_f}{k X_f} \rightarrow k_f = \frac{k\, X_f\, C_{fd}}{w_f} \quad \textit{(Eq.2)}$$

Where, k_f is Fracture permeability (mD), w_f is fracture width (ft), k is formation permeability(mD), X_f is fracture length (ft) and

$$A = 4h_f * X_f \quad \textit{(Eq.3)}$$

Also, by adding the fracture half height, the Darcy's equation can be represented as follows:

$$P_r - P_{wf} = \frac{Q*\mu*L}{K*4h_f*X_f} \rightarrow Pr - Pwf = \frac{Q*\mu*L*w_f}{k*X_f*w_f*A*C_{fd}} \quad \textit{(Eq.4)}$$

where, A is the fracture flow area and h_f is fracture half height.

In this study after analysis of different parameters sensitivities, the optimum values of each parameter have presented in order to maximize the efficiency of hydraulic fracturing operation.

2. Geological Background

The field is located in North Africa (see Figure 3). North Africa contains several basins including the Trias/Ghadames, Illizi, Hamra, Timmoun, Murzuk, and Reggane, etc. Towards the end of the Ordovician period the basin under study was located on the northern edge of the Gondwana continent in its geological past, which at that time was affected by major glaciation, comparable in scale to that which affects present-day Antarctica (Le Heron et al., 2005).

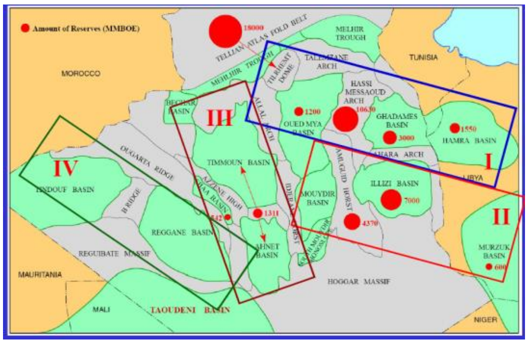

Figure 3. Regional distribution of discovered oil/gas reserves in North Africa.

Natural Fracture

The Ordovician deposits are generally considered a dual-porosity system with natural fractures that enhance the overall permeability. According to Le Maux et al. (2006), the fractures are organised into distinct zones of high-fracture density (“fracture corridors” or “couloirs”). These zones can be identified on seismic logs as faults or “lineaments”—the latter defined as zones of increased curvature without a recognisable offset of seismic reflectors. Figure 4 shows a map of such lineaments in a field that has similar lithology. Fracture density is believed to decrease rapidly away from the fracture corridors to a low “background” density of one fracture every 10 to 20m. The zone of increased fracture density is shown to extend approximately 200 m either side of the seismic lineament. Fracture orientations are described as dominantly NE-SW with locally developed NW-SE strike trends.

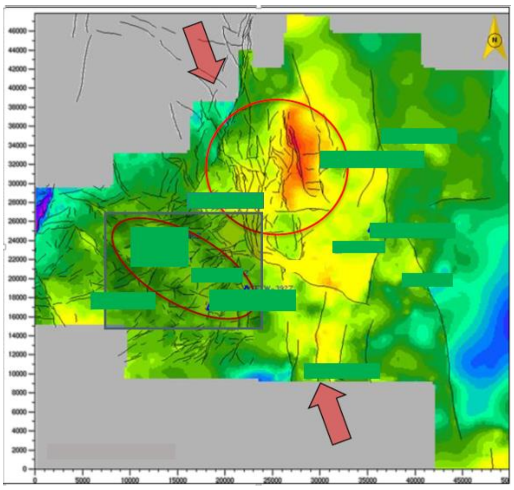

Figure 4. Map showing major seismic lineaments in analogue field, believed to correspond to zones of increased fracture density.

Petrophysical Interpretation

The reservoir production behaviour and dynamic performance of the wells in low to ultra-low permeability formation are largely controlled by the geometry of the petrophysical properties (effective matrix porosity, saturation and permeability), relative permeability of the fluid phases, reservoir pressures and the connected natural fracture density in the drainage area. Figure 5 shows the resistivity, gamma and density logs from a well in the basin that exhibits similar lithology (tight sandstone). It also shows the permeable zone based on the resistivity logs in track-3 and intervals proposed for additional perforation to improve productivity. Table 2 and Figure 6 exhibit PVT and relative permeability of the dynamic model.

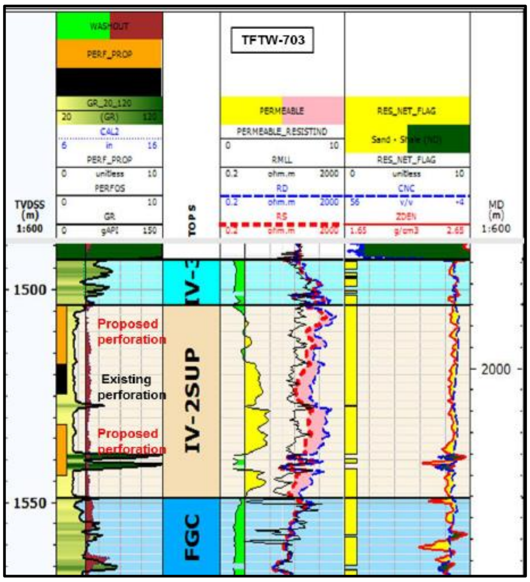

Figure 5. Well log data from analogue well in the basin.

Table 2: PVT and the reservoir properties.

Parameters	Units	Values
Density	kg/m^3	796
Oil Gravity	°API	46
Gas Oil Ratio	Sm^3/Sm^3	12.73
Oil Volume Factor	m^3/m^3	0.5
Connate Water Saturation	%	0.15
Bubble Point Pressure	Bars	22
Oil Viscosity	cp	≤ 1
Reservoir Temperature	°C	80
Kv/Kh	Ratio	0.5
Reservoir Pressure	Bars	110
Average Reservoir Thickness	Meter	30
Average Permeability	mD	0.01-0.001

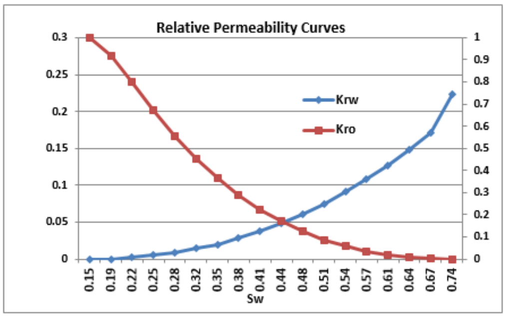

Figure 6. The relative permeability data.

Drilling Direction of the Side-track in the Vertical Well

The drilling direction is assumed to be in the direction of the minimum horizontal stress direction (σhmin) based on provided data (k<0.5mD). Economides & Martin (2007) suggest the initial stimulated rate in a reservoir of permeability <5 mD is obtained by drilling in the direction of σhmin. The likely impact of natural fractures on the stimulations is also considered.

3. Methodology

This study investigated redevelopment options based on multistage hydraulic fracturing for the A3/A4 reservoirs (see Figure 9) as well as the result of low production performance of the existing vertical well (well #1). The static model was created using Schlumberger Petrel/Eclipse. This geological model was then later used to create a dynamic model in Reveal (PETEX). Post-fracture analysis was used for hydraulic fracture design. Initial fracture dimensions are shown in Table 3. Figure 7 represents the fracture design in Reveal.

Table 3: Initial fracture design parameters.

Fracture Descriptions	Symbol	Unit	Value
Half height	h_t	m	30
Half length	h_x	m	37.5
Dimensionless Fracture Conductivity	(C_{fd})		7
Fracture width	w_f	cm	0.02

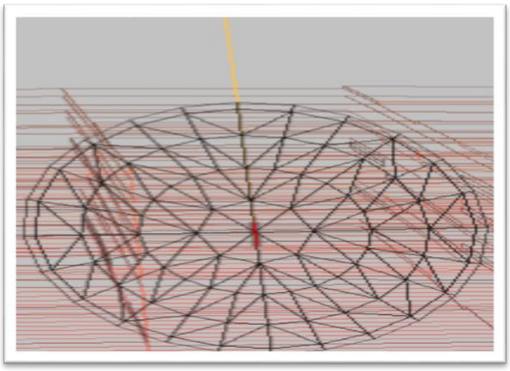

Figure 7. Fracture design in Reveal.

The overall workflow was as follows:

1. Import geological model from Petrel software and review available data; determine in-place hydrocarbon volume for the “study area”
2. Develop PVT / relative permeabilities
3. History match the vertical well performance in REVEAL
4. Model existing fracture stimulation in REVEAL
5. Apply permeability modifiers to the geological model
6. Model well lengths and fracture stimulation scenarios in REVEAL
7. Determine optimum dimensionless fracture conductivity (C_{fd})
8. Develop well trajectories
9. Model fracture stimulations in REVEAL
10. Generate production forecasts

The history matching phase included obtaining and verifying production performance (oil rate and cumulative oil) as well as verifying the bottom hole pressure (BHP). This included inserting existing well properties, fracture properties and three years of production history (oil rate and cumulative oil) and running the simulation for three years. After running three years of production, the oil rate and cumulative oil were matched by choosing oil rate control as well constraint.

However, the bottom hole pressure (BHP) showed a poor match during history matching of the model. Therefore, a series of sensitivity analyses were performed to obtain BHP matched and identifying the best-matched parameter to conduct future forecasting. Table 4 shows parameters and their ranges that were chosen to achieve bottomhole pressure matched.

Table 4: BHP sensitivities analysis.

Parameter	symbol	Unit	Value			
Fracture half length	(X_f)	m	10	20	37.5	60
Fracture conductivity	(C_{fd})	-	0.35	2	7	10
Fracture half height	(h_t)	m	10	20	30	40
Permeability multiplier	-	-	0.35	0.2	0.4	0.9

The critical fracture conductivity (the conductivity to obtain a near-maximum production) was investigated by running a series of analyses based on fracture conductivity ($K_f w_f$) and the propped length (dimensionless fracture conductivities and the fracture half lengths varied from 1 to 10,000 and 10m to 60m respectively.

Table provides a list of variables and their range used for determining dimensionless fracture conductivities. The methodology used in this section was based on work carried out by Ming Gue et al. (2016). The primary-fracture conductivity and the propped length varied from 1 to 10,000 mD/ft and from 32 to 197 ft respectively.

Table 5: List of variables and their range for the parametric study.

Property	Range
Hydraulic fracture conductivity	1-10,000 mD/ft
Hydraulic fracture length	32-197 ft
Fracture spacing	123 ft
Dimensionless fracture conductivity (C_{fd})	1-10,000
No fractures	3
FBHP	40 Bar

Reservoir Model

The oilfield modelled in this study possess very low permeability, ranging from 0.001 to 0.1mD, with sandstone lithology; mainly layers with natural fractures. The static geological model studied in this paper includes a total of 66,690 cells (38, 39 and 45 cells in X, Y and Z directions respectively) representing an area of 4 km^2 on the ground. Other static properties of the model are shown in Table . Figure 8 and Figure 9 show the sector model of the reservoir, the fault positions as well as different reservoirs (A1 A2, A3 and A4 reservoirs) and a cross-section of the field through the existing vertical well.

Table 6: Sector model statistics.

Target reservoirs	**A3/A4**
Faults number	3
A3 OOIP	$20x10^6$bbl
A4 OOIP	$20x10^6$ bbl
Study area	4 km^2
Cells in the statistic model	38x39y45z
Total number of layers	45
Number of layers in A3	40
Number of layers in A4	5
Total number of cells	66690
Number of cells in A3	59280
Number of cells in A4	7410

The following observations were also noted:

- The strike of major faulting system is N60E
- The maximum horizontal stress Sh_{max} orientation is at 330 degrees
- Strike/slip faulting has likely occurred
- Likely stress regime: SH_{max} > Sv > Sh_{min}

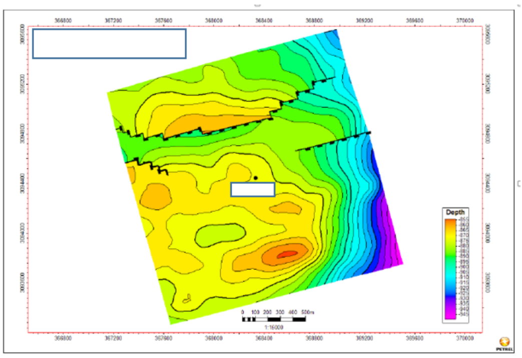

Figure 8. Sector model: Top reservoir structure map.

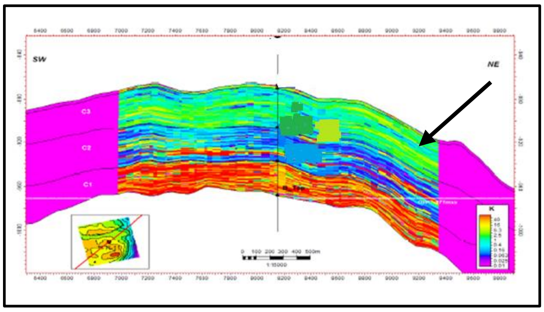

Figure 9. Petrel Cross-Section through the vertical well.

In a strike/slip faulting environment, the SH_{max} is the primary principle stress, the vertical stress (SV) is the middle principle stress, and the minimum horizontal stress is least principle stress. Consequently, hydraulic fractures would be transverse fractures that always propagate perpendicular to the least principle stress (Sh_{min}) because it is the least energy configuration (Zoback, 2007).

4. Results and Discussion

BHP Sensitivity Analysis

- **Effect of Fracture Half Length (Xf)**

Fracture half-length (X_f) and bottomhole pressure (BHP) sensitivities showed a direct relationship. Thus, decreasing fracture half-length (X_f), results in a decreasing bottomhole pressure (BHP) (See Figure 10).

This relationship can be explained based on Darcy's equation as described by equations 3 and 4.

A representation of a fracture geometry and corresponding wellbore radius "r'_w" is shown in Figure11. Decrease in fracture half length (X_f) reduces the fracture flow area (A) Higher pressure drop is as a result of d decreasing the fracture flow area (A). Figure 10 also shows that the fracture half length (X_f) of 20m fracture showed the best bottomhole pressure match among other sensitivities.

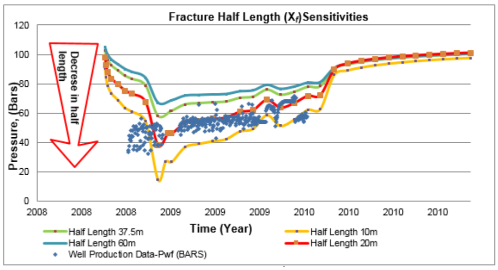

Figure10. Fracture half-length sensitivities.

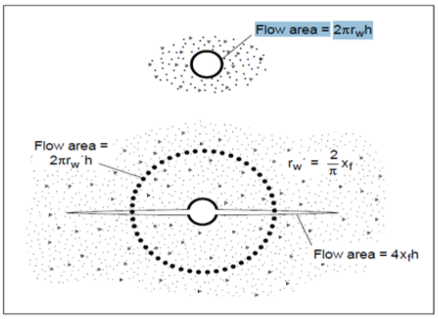

Figure 11. Equivalent wellbore radius.

- **Effects of Dimensionless Fracture Conductivity (C_{fd})**

The results of different fracture conductivity (C_{fd}) values were examined (e.g. 0.35, 2, 7, and 10). Figure 12 shows the results. The findings suggest a decline in bottomhole pressure by reducing the C_{fd} values.

This relationship can be explained based on Darcy's equation as described by equations 1,2, and 4.

Equation 4 confirms that a reduction in C_{fd} values will decreases the bottomhole pressure (BHP). As can be seen in Figure 12 below, a C_{fd} *value* of 0.35 resulted in a minimum and better match among the C_{fd} values of 2, 7, and 10.

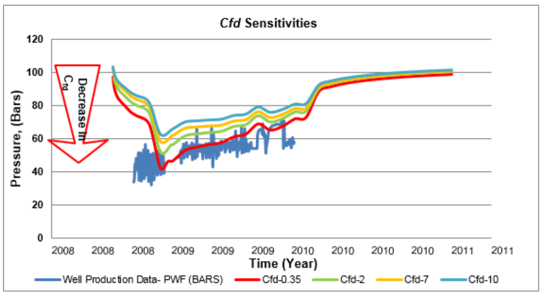

Figure 12. Dimensionless fracture conductivity sensitivities.

- **Effects of Fracture Half Height (h_f)**

Fracture half height (h_f) analysis was the next parameter to be tested. The findings (Figure 13) suggest a positive correlation between bottomhole pressure and fracture half height (h_f). Decreasing the fracture height would result in decreased bottomhole pressure. The results show that fracture half height (h_f) of 20 m is the best matched parameter (see Figure 13).

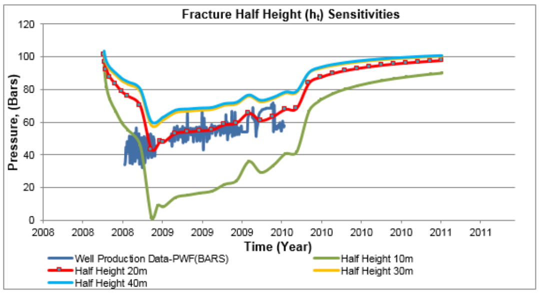

Figure 13. Fracture half height sensitivities.

▪ **Effect of Permeability Multipliers**

The influence of different permeability multipliers (e.g. 0.1, 0.2, 0.6 and 0.9) are shown in Figure 14. The results show a direct relationship (proportional) between the permeability multiplier (k) and bottomhole pressure. Therefore, a multiplier of 0.1 produces the minimum BHP. Figure 14 shows that a 0.2 permeability multiplier is a good BHP match among the other permeability multipliers of 0.1, 0.4, and 9.

Figure 15 shows the production profile for best matched parameters during the history matching phase. Accordingly, the highest cumulative oil, approximately 48000m3, was obtained by the permeability multiplier of 0.2 in X direction compared to other sensitivities tested in this study.

Other sensitivities examined (C_{fd}-0.35, H_f-20, H_t-20) have a fixed range with limitation and cannot be considered further analysis. For example, a fracture half-length and fracture half-height of 20m provide less reservoir contact area compared to the permeability multiplier of 0.2 (using fracture half-length of 37.5 and half-height of 30). In conclusion, the permeability multiplier of 0.2 was selected as the best- matched factor for further forecasting analysis. Figure 16 shows a forecasting simulation run for the vertical well, over 25 years, and a simulation run with the FBHP constraint at 40 Bara using a permeability multiplier of 0.2. Figure 17 exhibits the pressure profile for vertical well BHP and average reservoir pressure during a simulated 25-year run.

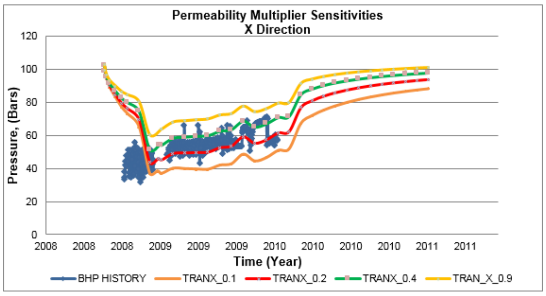

Figure 14. Permeability multiplier sensitivities.

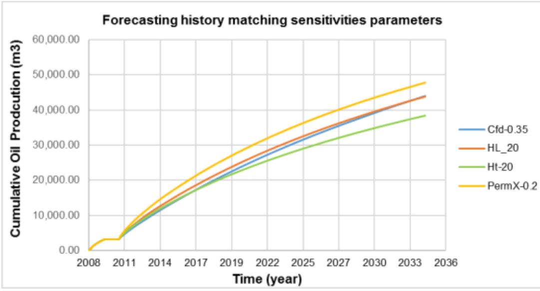

Figure15. Forecasting sensitivities.

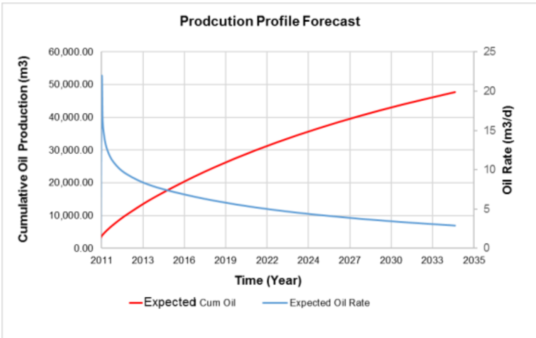

Figure 16. Production forecasting for the vertical well, FBHP at 40 Bara, permeability multiplier of 0.2.

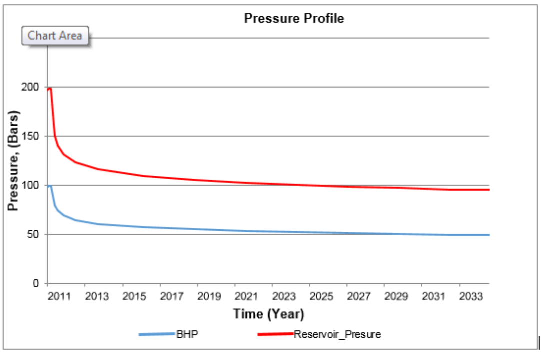

Figure 17. The vertical well BHP and average reservoir pressure.

Optimum Dimensionless Fracture Conductivity (C_{fd})

To obtain the optimum dimensionless fracture conductivity (Cf_d), a series of sensitivities were carried out based on different dimensionless fracture conductivities, fracture-half length (X_f) and production years. Dimensionless fracture conductivities and the fracture half lengths varied from 1 to 10,000 and 10m to 60m, respectively. The results shown in Figure 18 and Figure 19 indicate that a dimensionless fracture conductivity (C_{fd}) of 1.6 provides better cumulative oil production compared to other sensitivities after a 10-year simulation run. In addition, the results indicate that increasing the fracture half-length (X_f) increases the cumulative oil production.

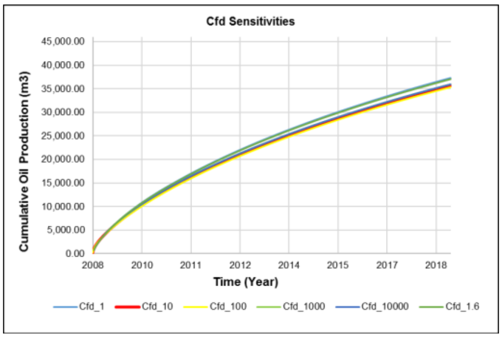

Figure 18. C_{fd} sensitivities.

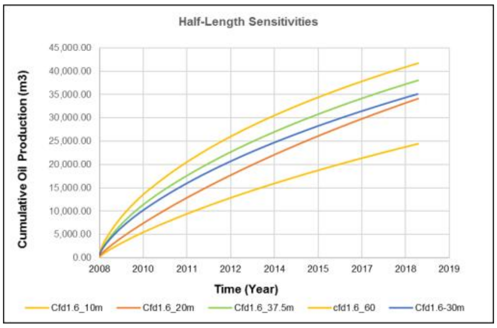

Figure 19. Half-length sensitivities.

Figure 20 and Figure 21 indicate the cumulative production after 1 and 10 years as a function of hydraulic-fracture conductivity for different propped lengths in tight sandstone. As expected, the cumulative production increases with fracture length and conductivity. More interestingly, by considering all these figures, it could be noticed that the cumulative production increases with conductivity at first, but reaches an asymptotic value. Therefore, for a given propped length, there is a conductivity threshold beyond which production is insensitive to further increases in conductivity. In this study the conductivity to obtain a near-maximum production is defined as critical conductivity.

To better understand the concept of critical conductivity, all cumulative oil productions are further normalized by the production of the same propped length with an infinite (very large) conductivity (see Figure 22 and Figure 23). The quantitative value of the critical conductivity is achieved as that which produces 97% of the maximum achievable production. The dotted lines in Figure 22 show that the critical conductivity for 32- and 197-ft fractures are 700 and 2500 mD/ft respectively for year 1 of production. It is 200 and 1000 mD/ft for 10 years of production. Critical conductivity results obtained from this study are converted to C_{fd} by the use of Eq. 1 (see **Error! Reference source not found.**). Figure 24 indicates the critical conductivity for 32,123, and 198ft fractures for 1 and 10 years of production.

Table 7: Critical dimensionless fracture conductivity (Cfd) for 1 year and 10 years.

Fracture length (ft)	C_{fd} for 1 year production	C_{fd} for 10 years production
32	14	6
123	18	4.2
197	13	3.2

The findings suggest a promotional correlation (positive relationship) between the critical conductivity and propped length as increasing the propped length increases critical conductivity. This is due to higher flow capacity, for the same production time, and decreases with increasing production time for the same propped length. Our findings showed similar results to previous research by Ming Gue et al. (2016). However, in our model we did not use uniform permeability in contrast to Ming Gue's model. Cipola et al. (2009) suggested that C_{fd} value of 30 can be considered optimum based on the pseudosteady state assumption and in general unconventional reservoirs a C_{fd} value of $30 \le C_{fd} \ge 1$ can be considered optimum.

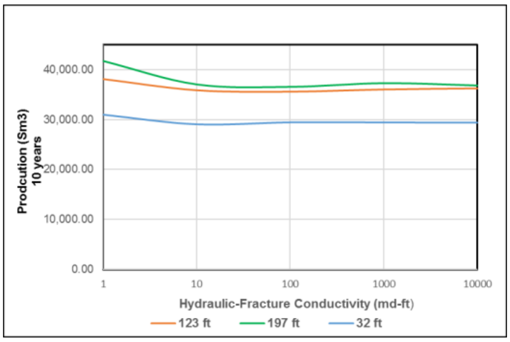

Figure 20. Hydraulic-fracture conductivity (mD/ft).

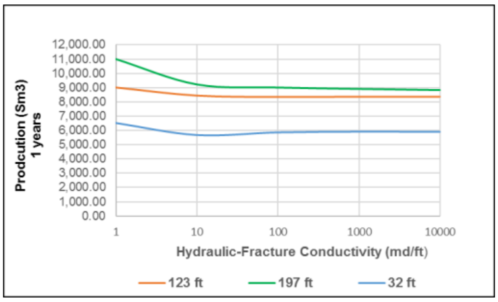

Figure 21. Hydraulic-fracture conductivity (mD/ft).

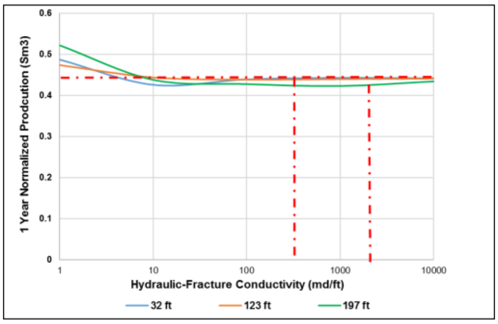

Figure 22. Hydraulic-fracture conductivity (mD/ft).

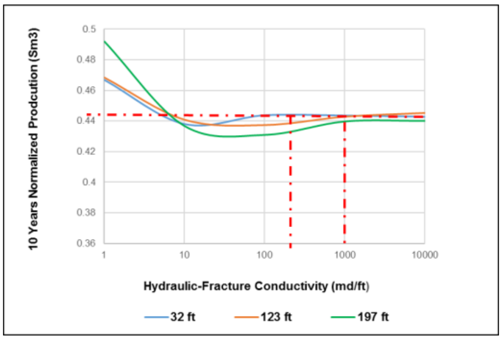

Figure 23. Hydraulic-fracture conductivity (mD/ft).

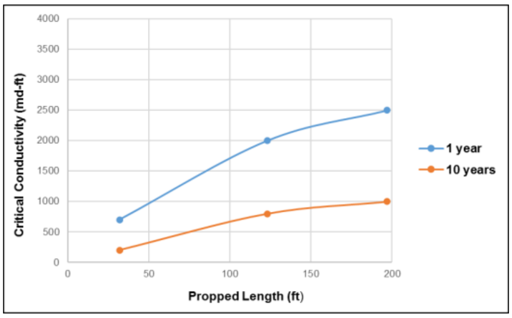

Figure 24. Critical conductivity vs. propped length for different production times.

Martin et al. (2007) also suggested that for a medium-to-high permeability reservoir, the optimal value of C_{fd} for most fracturing treatment is 1.6 in order for physical optimisation of production. However, it can be higher in lower permeability reservoirs. The actual value for each completion will be specific to the relative values of the formation and effective proppant permeabilities. The results in Figure 18 to Figure 24 suggest that dimensionless fracture conductivity (C_{fd}) of 1.6 provides optimum directionless fracture conductivity that was used in all forecasting scenarios.

Forecast Phase

The forecast phase involves two stages:

1. Choose the best matched case carried out during history match phase
2. Construct forecasting scenarios based on best history matched case

For the well performance study of the different side-track lengths and stimulations, the following cases were simulated in Reveal (Table8 and Table 9). All cases were run for a period of 25 years (2011 to 2036). The following fracture geometry and well control were used in all forecasting cases.

Table 8: Forecasting scenarios.

Horizontal Well Length (m)	Number of Fracs	Spacing (m)
300	0	----
300	4	----
300	6	----
300	8	----
600	0	----
600	4	----
600	6	----
600	8	----
900	0	----
900	4	----
900	6	----
900	8	----
900	8	110
900	10	90
900	12	75

Table 9: Fracture Dimensions.

Fracture Descriptions	Symbol	Unit	Value
Half height	h_t	m	30
Half length	h_x	m	37.5
Dimensionless Fracture Conductivity	(C_{fd})		1.6
Fracture width	w_f	cm	0.02

Well Control

- FBHP of 40 bara assumed for all cases
- Safety factor above the bubble point pressure of 22.1 bara
- Depletion drive mechanism

Hydraulic Fracturing Optimisation Results

Hydraulic fracturing optimisation scenarios were carried out based on the following scenarios for future forecasting:

- Horizontal well length
- Multi-stage hydraulic fracturing
- Fracture spacing

Horizontal Well Length Optimisations

To investigate the well performance of different horizontal well lengths, three different horizontal well lengths with no fractures were modelled in Reveal: 300m, 600m and 900m. The above cases were simulated based on a well azimuth of 15° and inclination of 88° and applying a permeability multiplier of 0.2 (as the best matched sensitivity) with no hydraulic fractures. Figure 25 shows the production profile of 300m, 600m, and 900m horizontal well lengths. The production performances of different horizontal well lengths with no hydraulic fractures were examined through considering the oil production rate and the cumulative oil production.

Figure 26 shows a significant increase in the total produced oil and oil rate by increasing the horizontal well lengths. Increasing the horizontal well length from 300m to 600m and then 300m to 900m increased the expected cumulative oil production by 38% and 62% respectively. The Recovery Factor (RF) further confirms the credibility of the 900m case compared to the other cases. The recovery factor achieved for this case was approximately 1% whilst for 600m and 300m was approximately 0.62 % and 0.4%, respectively. To this end, it could be concluded that the 900m horizontal length is the most beneficial case**.**

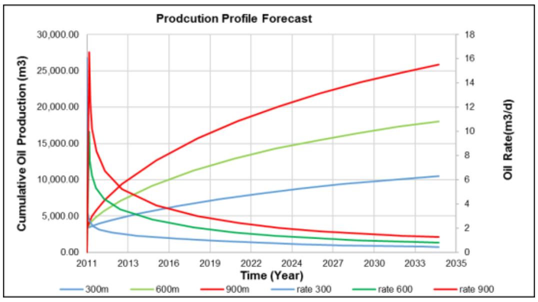

Figure 25. Production profile for horizontal lengths 300m, 600m and 900m.

- **Multistage Hydraulic Fracturing**

To assess the effect of the different number of fractures used in horizontal wells to maximize hydrocarbon recovery, several cases were studied (Table 10). The process consists of modelling different number of fractures (4, 6, and 8) along the 300m, 600m and 900m horizontal well lengths as well as fracking the existing vertical well. The existing vertical wells were refractured in all sensitivity cases examined. The effect of multistage fracturing on production is shown in Figure 26 through figure 28.

Figure 29 illustrate the performance of different numbers of fractures (4, 6, and 8) along the 300m, 600m and 900m horizontal well lengths.

Table 10: Forecasting with FBHP constraint at 40 bars only with no well rate constraint, all with 8 fractures.

Forecast	No Fracs	Recovery factors (%)	Cumulative oil production (Oil*1000m^3)	Peak initial oil rate (m^3/d)
300m	8	2.37	69	110
600m	8	2.42	70	110
900m	8	2.65	75	120

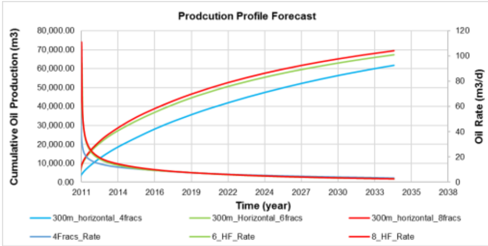

Figure 26. 300m lateral sensitivity with different fractures (4, 6, 8)-cumulative oil production.

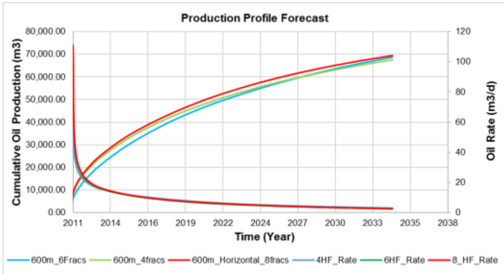

Figure 27. 600m lateral sensitivity with different fractures (4, 6, 8) - cumulative oil production.

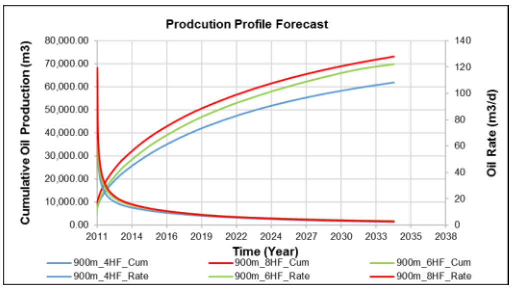

Figure 28. 900m lateral sensitivity with different fractures (4, 6, 8) - cumulative oil production.

Increasing the number of the fractures (in all cases) resulted in increased production performance (oil rate and cumulative oil), hence hydrocarbon recovery. To continue with the previous assessment to find out the optimum fracture numbers, all the sensitivities were analysed in terms of the expected daily oil rate and cumulative oil production as well as the recovery factor.

Figure 26 through

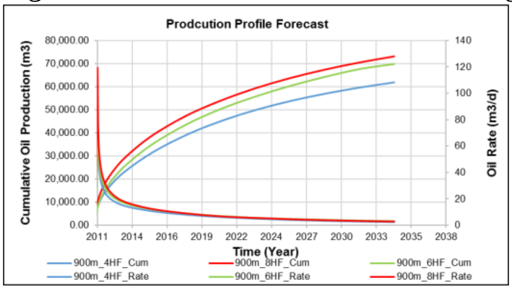

Figure28 illustrate that eight hydraulic fracture stages showed the higher oil rate and cumulative oil production among all cases examined. Comparing 8, 6 and 4 fractures for each case (900 m, 600 m, 300 m) showed increases in the expected cumulative oil production by 26%, 5% and 14 % respectively during the 25 years of production.

With regards to the expected daily oil rate, eight hydraulic fracture stages also showed a higher expected oil rate compared to the other cases tested. The 900m horizontal well, in conjunction with the eight hydraulic fracture stages, reached the highest oil pick rate and the higher production rate of approximately 120 m^3/d in February 2011 before experiencing a similar sudden decline in production and falling gradually to approximately 2 m^3/d by the year 2035.

The other cases showed the same pattern, only with lower productivity. At the end of this stage, the recovery factor was taken into consideration, comparing all cases to assess the effectiveness of the recent changes. The results reaffirmed the effectiveness of implementing the 900m horizontal well with eight fractures stage, through which a 2.65% recovery factor was obtained. The 600m and 300m horizontal well with eight hydraulic fracture stages showed lower recovery factors of 2.42% and 2.37% respectively.

- **Fracture Spacing**

Another sensitivity analysis carried out in this research paper was fracture spacing. To investigate the effect of different fracture spacing on well productivity and achieve the optimum fracture spacing, a number of cases were examined along the 900m horizontal well. This included 8, 10, and 12 hydraulic fractures with corresponding 110, 90 and 75 m spacing respectively (Figure 29).

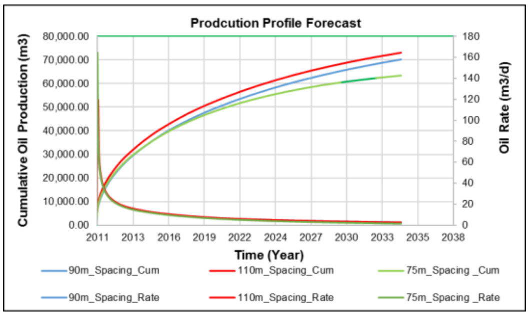

Figure 29. 900m lateral sensitivity with different spacing (110, 90, 75), eight fractures.

The finding indicated that increasing spacing between fractures gives a higher cumulative production (110m spacing, 8 fracture stages). The other two cases, 75 m (12 fracure stages) and 90m sapcing (10 fracture stages), produced less cumulative oil: 65,000 m^3 and 70,000 m^3 repectively. These observations suggest that reducing the spacing between fractures decreases the productivity of the hydraulic fracture (due to fracture interference). Similar to other cases, the recovery factor was assessed with the changes applied. The 110m spacing (8 fracture stages) case had a recovery factor of 2.65%, whilst the 90m and 75 m spacing cases had 2.42% and 2.22% respectively. These results indicated an increase of 60% in RF compared to the base case (vertical well with one fracture). The subsequent increase in RF (2.65%) could be interpreted as $5,000,000 million USD from an economic point of view of. Having said this, it is important to state that the above mentioned incremental value has not been subject to any relative taxation, capital or operational expenditures as the scope of this study is primarily based on subsurface development of a tight sandstone reservoir by hydraulic fracturing technique in conjunction with a horizontal well. Table 11 summarizes the results of horizontal well sensitivities based on different length, number of fractures and fractures spacing.

Table 11: Results of horizontal well sensitivities based on different length, number of fractures and fracture spacing.

Forecast	Horizontal Length (m)	NO. Fracs	Spacing (m)	Cumulative Oil x1000 (m3)	Average Initial Peak Oil rate, m3/d	Recovery Factor (%)
Sensitivity	**Vertical Well (Base Case)**	1	-	47	21	1.1
Horizontal well length	**300**	0	-	11	15	0.4
		4	-	62	60	2.1
		6	-	67	90	2.31
		8	-	69	110	2.37
	600	0	-	18	10	0.62
		4	-	68	61	2.31
		6	-	69	100	2.35
		8	-	70	110	2.42
	900	0	-	25	17	1
		4	-	62	82	2.1
		6	-	70	86	2.42
		8	-	72	120	2.55
		8	110	72	120	2.65
		10	90	70	142	2.42
		12	75	65	162	2.22

5. Conclusions

Hydraulic fracturing is an effective method for productivity enhancement. However, the production from a hydraulically fractured vertical in A3/A4 reservoirs was below the expectation. In this study, the parameters that affect the achieved production rate from the fracking operation were investigated and an optimised fracking scenario is proposed. Observations from the examined scenarios are summarized here:

- Hydraulic fracturing is a recognised, proven and extremely operative method for redeveloping mature oil and gas assets.
- All scenarios increase the estimated ultimate recovery(EUR) from the existing vertical well prediction.
- The greatest increase in EUR comes from extending the lateral rather than increasing the number of fractures; more fracture stimulations do not have a pronounced effect on ultimate recovery.
- The critical conductivity shows a positive relationship with propped length and an inverse relationship with production time.

- Fracture stimulations primarily provide acceleration rather than increasing recovery (i.e. higher initial oil rate).
- The performance of the existing well was used to history match the reservoir models. This required a permeability multiplier of 0.2.
- From the EUR/rate outputs, a 900m horizontal well without fracture stimulations shows the largest step-change from the vertical well.
- All hydraulic fractured horizontal wells showed increases in oil recovery compared to un-fractured existing wells. A 900m horizontal well with eight fractures and 110m spacing shows a much better oil recovery compared to the others, indicating that good programming in hydraulic fracturing can increase the oil recovery as all hydraulic fracture strategies raise oil recovery.
- From an overall combination of EUR and initial rate, a 900 m horizontal well with eight fractures and 110m spacing may provide the highest return. This would need to be checked by conducting a full techno-economic evaluation (i.e. cost-benefit analysis).

Nomenclature

FBHP =Flowing Bottomhole Pressure

Cfd = Fracture Conductivity

THP = Tubing Head Pressure

TVD = True Vertical Depth

σ' = minimum insitu effective stress

kv = Vertical Permeability, mD

kh = Horizontal Permeability, mD

P = pressure, psia

Pr= Reservoir Pressure, psia

Pwf = Well sand-face mid-perf pressure, psi

Q= production rate, L3/t, STB/day

Xf= Fracture Half Length, L, ft

wf = Width, L, ft

ht=Half height

Φ = Porosity

μ = viscosity, m/Lt, cp

Acknowledgment

We would like to thank Noel Atzmiller for helping to proofread the paper. This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

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