PRODUCTION MANAGEMENT FOR HYDRAULIC FRACTURING IN NATURALLY FRACTURED SHALE GAS RESERVOIR

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Abstract

Recently, shale gas reservoirs have become more attractive for the petroleum industry because of the huge amount of reserves. However, without stimulation methods, production from a shale gas reservoir is almost impossible. Nanodarcy permeability can be characteristic of shale reservoirs. For this condition, natural gas does not flow easily or economically from the reservoir to the wellbore. Nowadays, in order to produce the gas from this type of reservoir, hydraulic fracturing is a common stimulation approach to achieve an economical gas production rate. Hydraulic fracturing provides conductive paths through the reservoir so that the gas is allowed to flow more easily.

Therefore, the objectives of this study were to manage and improve the gas production from this type of reservoir and to design the hydraulic fracturing strategies in order to maximize gas production while minimizing the production time in naturally fractured shale gas reservoirs. A horizontal-wellbore production was utilized and the effects of several parameters on the production performance were investigated. These parameters were fracture width, fracture spacing, and number of fractures. The results of this study showed improvement of gas recovery. Both the number of fractures and fracture width apparently are important factors used to design hydraulic fracturing strategy. With an optimum strategy, gas recovery in shale gas reservoirs can be improved.

Keywords: Shale Gas, Hydraulic Fracturing, Natural Fracture, Fracture Width

1. INTRODUCTION

Shale gas reservoirs have become more attractive for the petroleum industry in the past few years due to the increasing price of gas and the advancement in oilfield technologies. The nanodarcy permeability characteristic of shale reservoirs means there may not be sufficient permeability to allow natural gas to flow from the reservoir to the wellbore at an economic rate. Therefore, there has been an emphasis on improving gas extraction from this kind of reservoir using hydraulic fracturing. Hydraulic fracturing is a common stimulation method to achieve economical gas production rates by providing a conductive path through the reservoir which would otherwise have permeabilities measured in a nanodarcy range.

Without hydraulic fracturing in shale reservoirs, gas flow would be almost impossible.

The hydraulic fracturing treatment aims to increase the stimulation reservoir volume (SRV) and improve matrix communication so the gas will flow in the matrix and eventually flow through the main created conductive paths towards the wellbore. Therefore, the objectives of this study were to manage and improve the gas production in naturally fractured shale gas reservoirs and to design the hydraulic fracturing strategies in order to maximize gas production while minimizing the production time utilizing horizontal-wellbore production.

2. THEORY AND CONCEPT

Shale Rock Mechanics

An improved understanding of hydraulic fracture geometry and shale rock mechanics enables reservoir engineering teams to improve stimulation performance, well productivity, and hydrocarbon recovery. Many researchers have been studying hydraulic fracture propagation in the presence of natural fractures. As stated in Economides and Martin (2010), *"Fractures will always propagate along the path of least resistance. In a three-dimensional stress regime, a fracture will propagate so as to avoid the greatest stress and will create width in a direction that requires the least force. This means that a fracture will propagate parallel to the greatest principal stress and perpendicular to the plane of the least principle stress. This is a fundamental principle; therefore, the key to understanding fracture orientation is to understand the stress regime"*. As a hydraulic fracture will propagate perpendicular to the least principle stress; in some shallow formations, the least principal stress is the overburden stress; thus, the hydraulic fracture will be horizontal. In reservoirs deeper than approximately 1,000 ft, the least principal stress will likely be horizontal as the vertical stress is the overburden stress; thus, the hydraulic fracture will be vertical. The azimuth orientation of the vertical fracture will depend on the stress contrast of the minimum and maximum horizontal stresses.

Parameters Effect on Gas Production

Fracture Conductivity

Fracture conductivity is a key parameter in hydraulic fracturing and represents the ability to transmit the fluid from the fracture to production well. The dimensionless conductivity C_{fD} is a function of fracture permeability, fracture width, matrix permeability, and fracture half length.

Dimensionless fracture conductivity can be defined as

$$C_{fD} = \frac{k_f w}{k x_f} \tag{1}$$

The fracture conductivity may be increased by enlarging the propped fracture width by using high proppant concentration. In this model, the fracture half-length is constant and is equal to reservoir half-length; therefore fracture conductivity corresponds to variable fracture width.

Fracture Width

Fracture width is the perpendicular width of an open fracture. The fracture width corresponds to fracture permeability and fracture conductivity. Fracture permeability is determined by computing the permeability of the fracture as a cubic function of the fracture half-width (C.M. Freeman et al. 2009) which is given by

$$k_f = \frac{1}{12} b^3 \tag{2}$$

Fracture Spacing

Fracture spacing is one of the key factors in hydraulic fracturing optimization design. When hydraulic fractures are close to each other, a small reservoir area is in contact with the hydraulic fractures. If the spacing is increased, this results in more contact surface within the reservoir and gas will be drained more effectively. Increasing spacing brings more reservoir matrix into contact with fractures, leading to earlier production and much improved gas recovery. Figure 1 shows the effect of fracture spacing on gas drainage area. Design 1 apparently depicts smaller gas drainage area compare to Design 2. It is evident that the more evenly distributed fractures in the reservoirs; the gas in the matrix can be more effectively drained.

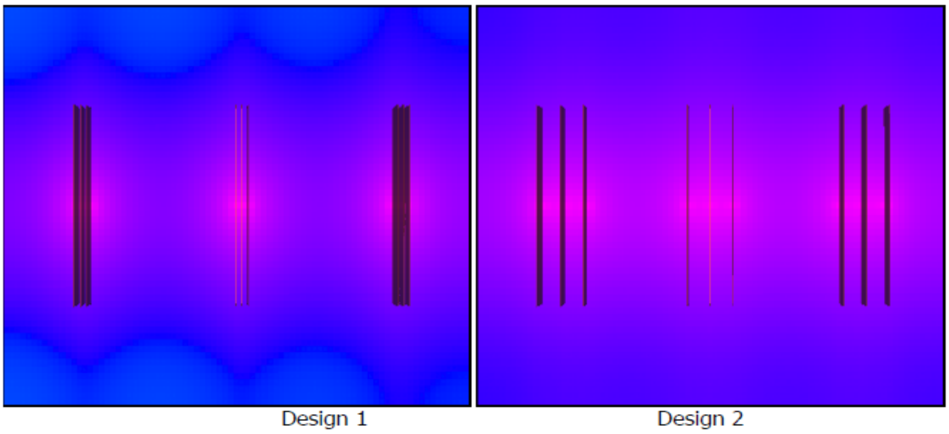

Figure 1: Gas drainage corresponding to fracture spacing (M. Mirzaei and C.L. Cipolla. 2012)

Number of Fractures

It is important to note that a higher complexity of fractures increases the productivity in ultra-tight gas shale as more flow channels are created, penetrating through the rock and increasing surface contact in the shale reservoir. In other words, this increases the stimulated rock volume (SRV). It appears in the work of C.L. Cipolla (2009) that the SRV is generated as a result of the complexity and conductivity of the fracture network which are the key components that control well productivity in shale gas reservoirs. With respect to the limitation of constructing the complexity, the investigation of multi-stage bi-wing hydraulic fracture is examined.

In this model, only three parameters; fracture width, fracture spacing, and number of fractures were investigated to understand their effects on the gas production performance.

3. RESERVOIR SIMULATION MODEL

The reservoir model was constructed using ECLIPSE100 simulation software to analyze gas production performance. The software uses finite difference numerical method to resolve material balance equations in order to observe the change of fluid flow, pressure, and saturation with time. There are basically four main components used to construct the reservoir model consisting of reservoir grid, fluid properties, SCAL (special core analysis), and well model. The reservoir grid section develops grid geometry as well as specifies porosity and permeability. The fluid properties section defines gas properties and initial reservoir condition. The SCAL section provides a data table showing relative permeability generated by the simulation software. The last section, well model; assembles the horizontal well bore production. In this model, the reservoir grid was 65 x 65 x 11 with the total dimensions of 50ft x 20ft x 10ft in the x-, y-, and z- direction, respectively. The reservoir model was built using Cartesian grid block with two phase fluids consisting of water and gas. The top of reservoir was at 8,000ft depth with the total thickness of 110ft. The horizontal well was placed in the middle of z-layer as well as in the middle of both x- and y- direction. Table 1 lists the reservoir properties which was input in the base case of the simulation model. The reservoir model and well placement can be seen in Figure 2 and 3.

Table 1: Reservoir Properties

Parameter	**Value**
Reference reservoir pressure, psi	3,500
Reservoir temperature, ^{0}F	260
Porosity, %	8
Matrix permeability, mD	0.0002
Water saturation, %	30
Horizontal Length, ft	3,050
Well bore diameter, inch	6.5
Tubing Size, inch	3.5
Tubing Head Pressure, psi	450
Original Gas In Place, MMSCF	4,779

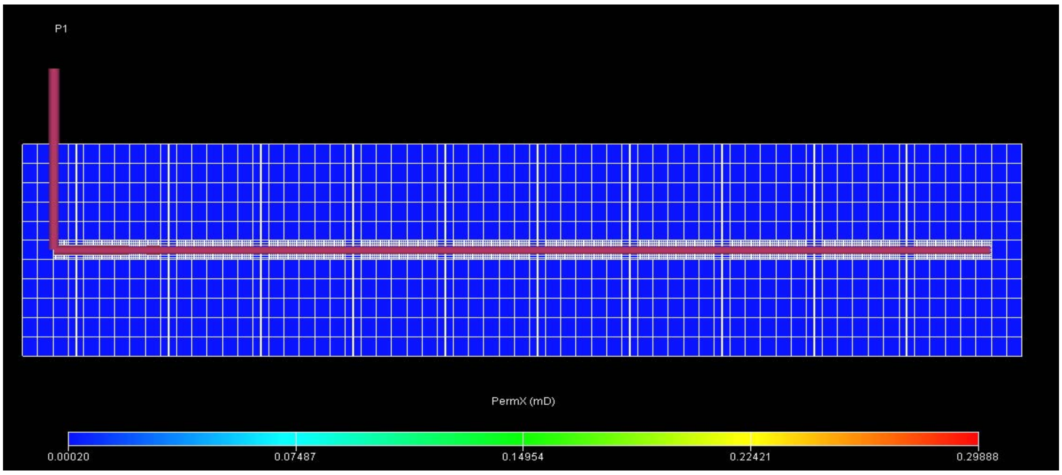

Figure 2: Side view of the reservoir model

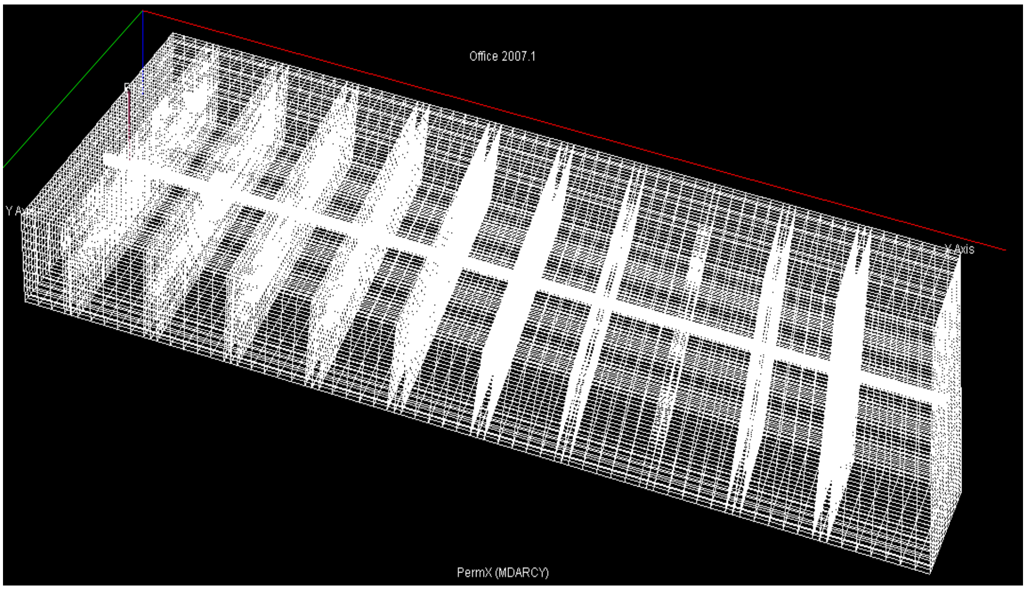

Figure 3: 3D view with transparent grid of the reservoir model

Fracture Model Assumptions

In this work, the assumptions applied on the reservoir simulation model were as follows;

1) Shale reservoir in-situ stress was homogeneous which means the stress regime was evenly distributed within the shale reservoir.

2) Fractures occured in the vertical direction assuming the maximum stress was in the vertical direction. Providing the top of reservoir was at 8,000ft, the maximum stress mostly relied on overburden pressure.

3) Induced hydraulic fracturing reactivated the natural fracture in the direction of an existing maximum stress or no in-situ stress changed after hydraulic fracturing was conducted.

4) Existing natural fractures height and half-length were extended for entire reservoir

thickness and length so the hydraulic fracturing was propagating throughout the reservoir thickness and length.

5) A horizontal well was drilled along the minimum stress regime so the hydraulic fracturing initiated is transverse fracture.

6) Fracture width was assumed to be constant from the top throughout the bottom of the reservoir.

7) Ductile shale was assumed in this study so the bi-wing hydraulic fracturing was initiated.

4. RESERVOIR SIMULATION RESULT AND DISCUSSION

The study of gas production performance was investigated by accounting for the following parameters

- Number of fracture and spacing
- Fracture width

Each case study exhibited the production performance to understand the effects of the parameters and obtain the appropriate strategy in designing hydraulic fracturing in a shale gas reservoir. The production period was set at 20 years.

Effect of Number of Fractures and Spacing

The number of fractures for this study were 10 (base case), 20, 30, and 60 fractures with a symmetrical spacing of 300ft, 150ft, 100ft, and 50ft, respectively. Other properties of the base case which were maintained constant were 0.030mm fracture width, 8% porosity, and 0.0002mD matrix permeability. Production rate was not controlled in order to observe maximum gas flow through the production well at the given reservoir condition.

Figure 4 shows the effect of the number of fractures on gas production rate with time. From Table 2 it is evident that the 60 fractures case provided the highest gas production. Increasing the number of fractures offered more gas flow channels. As a result, productivity could be improved. At the end of production, the recovery factor for the 60 fractures case was 1.99%. Gas recovery was linearly dependent on the number of fractures as shown in Figure 5.

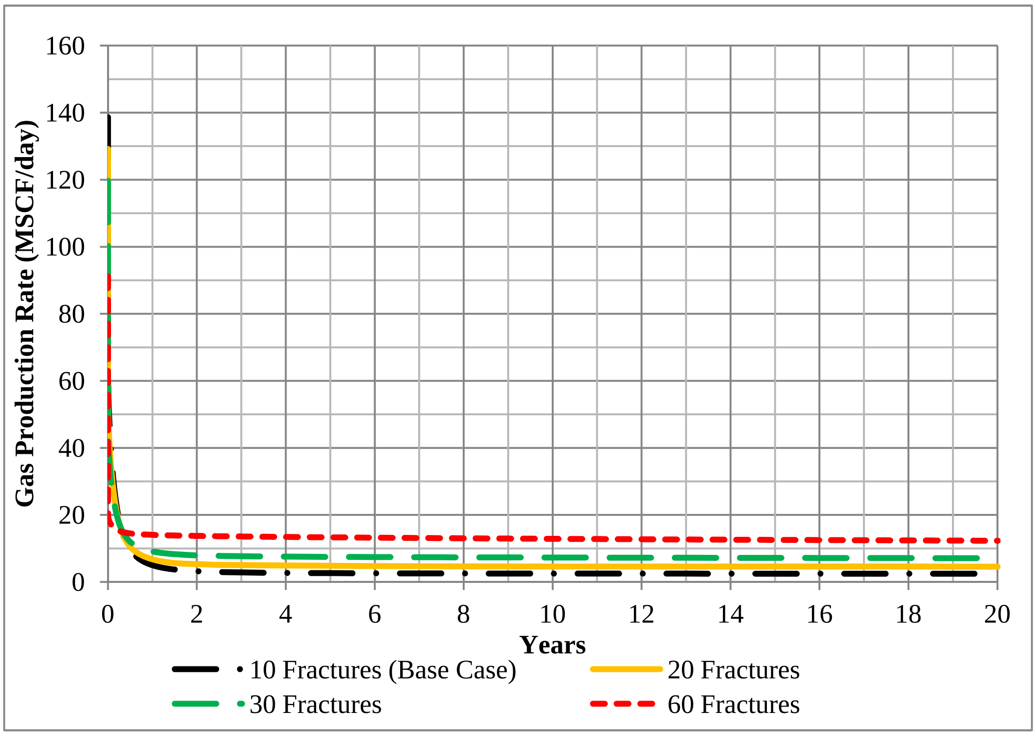

Figure 4: Gas production rate for different number of fractures

Table 2: Cumulative gas production for different number of fractures at the end of production

Number of Fractures	Cumulative Gas Production (MMSCF)	Recovery (%)
10	23.46	0.49%
20	38.24	0.80%
30	56.43	1.18%
60	95.12	1.99%

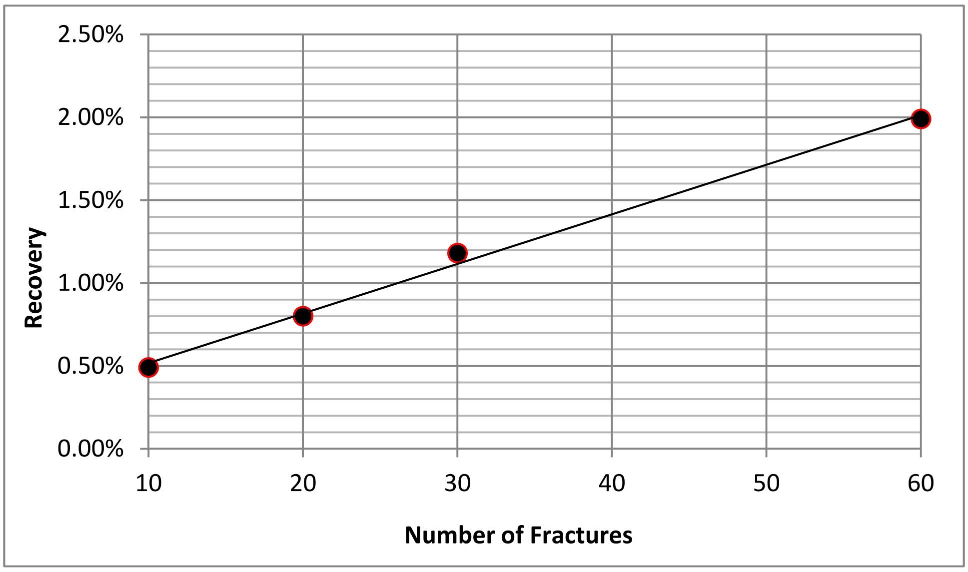

Figure 5: Recovery versus number of fractures

Effect of Fracture Width

Fracture width is another important factor which indicates fracture conductivity because the fracture permeability depends on fracture width. The investigated fracture widths were 0.030mm, 0.06mm, 0.09mm, and 0.18mm. Fracture permeabilities were calculated by Equation (2) and are shown in Table 4. The effect of fracture width on the production performance was investigated and is shown in Figure 6. A significant effect from fracture width was observed on the gas production performance. The widest fracture case shows the most effective performance. When fracture width increased, fracture conductivity could be increased as well; hence gas productivity would be improved. A recovery factor of 1.40% was achieved for the 0.18mm fracture width case. Figure 7 shows the gas saturation profile for the 0.18mm fracture width case. Apparently, the largest drainage area is shown along the fracture in green color. The red color area represents gas saturation that is still almost the same as initial condition even though the well has been operated for 20 years. It can be defined that with some distances far away from the fractures, gas is not effectively drained because the permeability in the matrix is still low. Therefore, gas saturation profile in the matrix almost remains unchanged at the end of production.

Since reservoir fluid was modeled as dry gas, it was technically not affecting much in terms of gas saturation change as gas expansion always occurs.

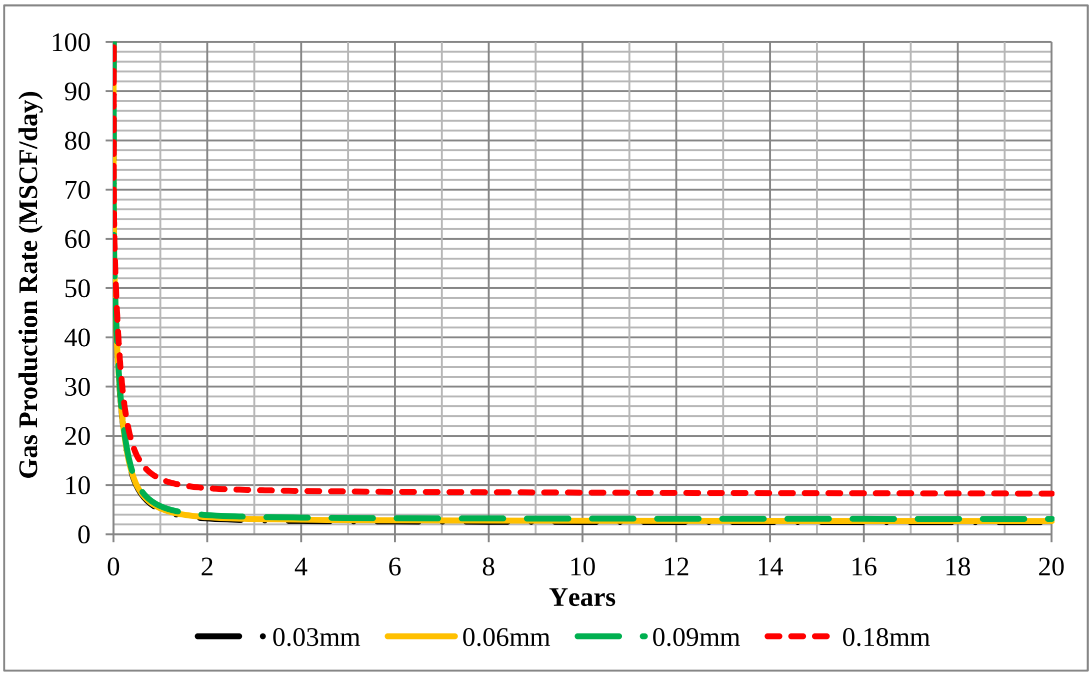

Figure 6: Gas production rate for different fracture widths

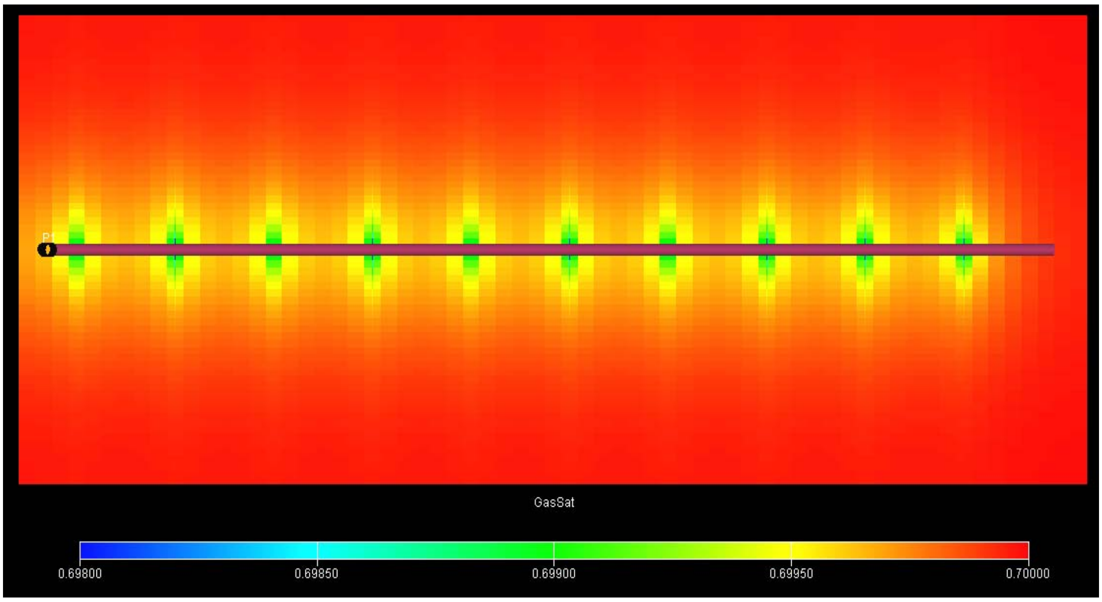

Figure 7: Gas saturation profile for 0.18mm fracture width at the end of production

Table 4: Cumulative gas production for different fracture widths at the end of production

Fracture Width (mm)	**Permeability (mD)**	**Cumulative Gas Production (MMSCF)**	**Recovery (%)**
0.03	0.30	23.46	0.49%
0.06	2.39	25.15	0.53%
0.09	8.07	28.39	0.59%
0.18	64.56	67.10	1.40%

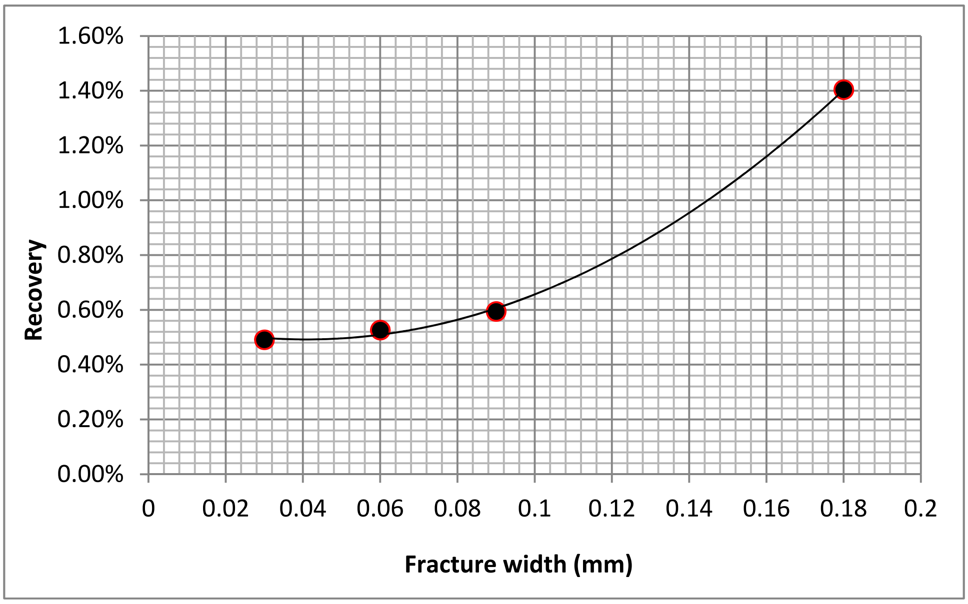

Figure 8: Recovery versus fracture width

Figure 8 shows the gas recovery plot versus fracture width. It can be observed that increasing width can improve gas recovery parabolically. Fracture width increased by 6 times (0.18mm) would yield 1.4 times increase in gas recovery while when width was varied from 0.03mm to 0.09mm this increase showed an insignificant improvement in gas recovery.

5. HYDRAULIC FRACTURING STRATEGIES

After investigating parameters affecting gas production performance, combination of number of fractures and fracture width were used to design hydraulic fracturing strategies. The objective of this section was to study the production efficiency by observing output given the comparable changes of input. The maximum number of fractures available for this reservoir simulation model was 60 fractures. Therefore the change of input was 6 times of the base case (10 fractures were increased to 60 fractures). Hence, the maximum width was 0.18mm. The varied strategies are shown in Table 5.

Table 5: Hydraulic fracturing strategies

Strategy	No. of Fractures / Width (mm)	10	20	30	60	Description
1	0.180	6x1				Width ratio:6, Fracture ratio:1
2	0.090		3x2			Width ratio:3, Fracture ratio:2
3	0.060			2x3		Width ratio:2, Fracture ratio:3
4	0.030				1x6	Width ratio:1, Fracture ratio:6

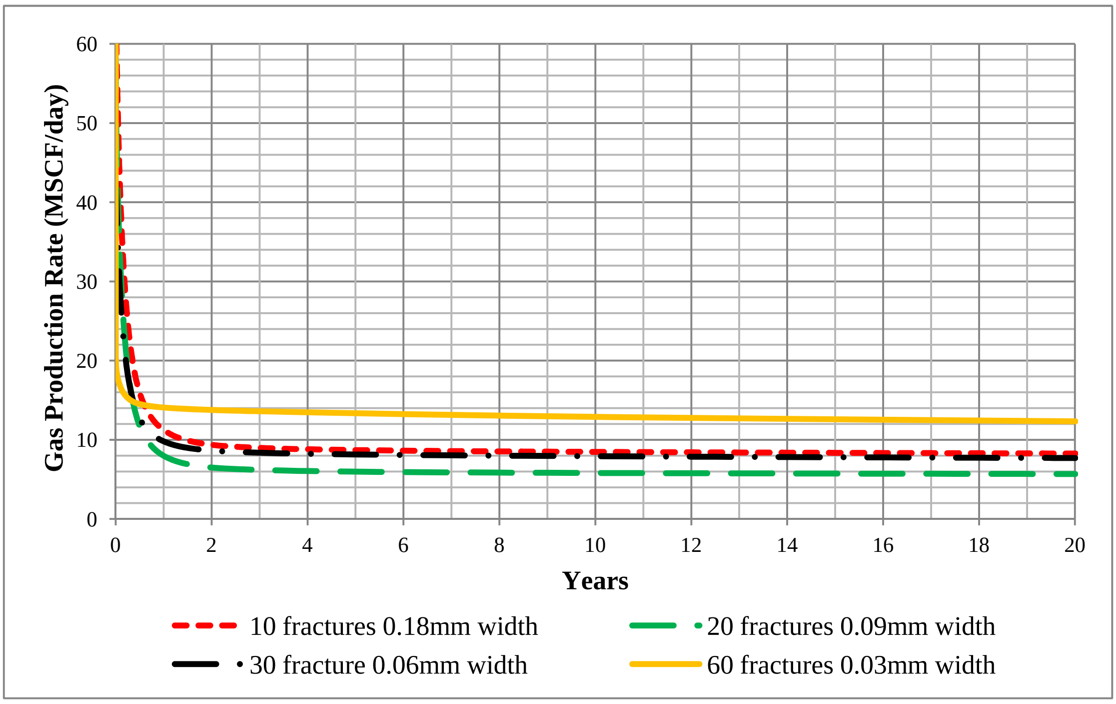

Figure 9: Gas production rate for different strategies

Table 6: Production efficiency

Strategy	Cumulative gas production (MMSCF)	Recovery Factor (%)	Production improvement ratio
1	67.10	1.40	1.86
2	46.62	0.98	0.98
3	61.25	1.28	1.61
4	95.12	1.99	3.05

Table 6 shows production efficiency in terms of input ratio of 6 times for all strategies. For Strategy 1 through Strategy 4, the production improvement ratios were 1.86, 0.98, 1.61, and 3.05, respectively. Figure 9 shows gas production rate plot versus time. Strategy 4 which was designed for 60 fractures and 0.03mm fracture width achieved the highest production rate and the greatest cumulative gas production. Recovery factors for Strategies 2 and 3 were less than Strategies 1 and 4 because the available fracture widths were 0.09mm and 0.06mm, respectively. From Figure 8, the recovery factor for these fracture width ranges were not significantly increasing; therefore, it did not show much gas production improvment compared to Strategies 1 and 4.

The studied width ranges for this study was only up to 0.18mm because the comparable changes of input was 6 times of the base case. From Figure 5 and 8, recovery factor tended to increase parabolically with increasing width compared to that increased linearly with the number of fractures. This indicated that the tendency of increasing gas recovery factor is mostly corrensponded by increasing fracture width greater than 0.18mm.

6. CONCLUSIONS

This study demonstrated a better understanding of the hydraulic fracturing effect for a shale gas reservoir. Increasing the number of fractures and fracture width can improve gas recovery. The study shows a linear relationship between gas recovery and the number of fractures, whereas fracture width can improve gas recovery parabollically. Given the same effort to change the fracture width and number of fractures; the number of fractures yields a more pronounced effect on production performance based on this study.

These results can be used as guide to optimize the hydraulic fracturing design in a more effective way. However this study was only focused on technical aspects of these two parameters and the cost to increase the number of fractures may not be in the same magnitude as the cost of increasing fracture width.

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