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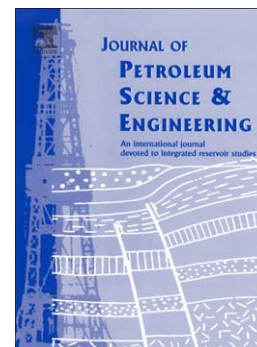
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Production performance of hydraulic fractures in tight gas sands, a numerical simulation approach

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Abstract

Hydraulically fractured tight gas reservoirs are one of the most common unconventional gas sources being produced today, and will be a regular source of gas in the future. The extremely low permeability of tight gas sands leads to inaccuracy of conventional build-up and draw-down well test results. This is primarily due to the increased time required for transient flow in tight gas sands to reach pseudo-steady state condition. To increase accuracy, well tests for tight gas reservoirs must be run for longer periods of time which is in most cases not economically viable. The large amount of downtime required to conduct well tests in tight sands makes them far less economical than conventional reservoirs, which leads to the need for accurate simulation of tight gas reservoir well tests.

This paper presents simulation results of a 3-D hydraulically fractured tight gas model created using Eclipse software. The key aims are to analyze the effect of differing fracture orientation, number and length. The focus of the simulation runs will be on the effect of hydraulic fracture orientation and length. The results will be compared to simulation runs without the abovementioned factors to determine their effects on production rates and well performance analysis. All results are plotted alongside an unfractured tight gas scenario in order to put the hydraulic fracture performance in perspective.

Key findings from this work include an approximately linear relationship between initial gas rate and the number of hydraulic fractures intersecting the wellbore. In addition, fracture length is found to have less of an impact on initial gas rate compared to number of fractures intersecting the wellbore, for comparable total fracture volumes.

Keywords: Production performance, hydraulic fractures, tight gas sands, numerical simulation approach

1.0 Introduction

The increasing global demand for energy along with the reduction in conventional gas reserves has led to the increasing demand and exploration of unconventional gas sources. Tight gas sands are one of the most commonly produced unconventional gas resources around the world, but the low productivity and permeability provide further challenges in meeting economic production (Pankaj and Kumar, 2010). Tight gas sands are most commonly defined as a reservoir system with low permeability, generally less than 0.1mD, and low porosity, generally less than 10%, (Pankaj and Kumar, 2010). More recent definitions outline the importance of reservoir stimulation by hydraulic fracturing in modern tight gas production. Tight gas sands have been defined by Holditch, 2006 “a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fractures.” Addis and Yassir (2010) also defined tight gas sands as requiring “man-made” permeability systems for economic production.

Due to the extremely low permeability, and subsequently low reservoir flow of tight gas sands, many conventional well tests and analysis methods are not economically viable (Manrique and Poe, 2007). This is partly due to the fact that tight gas sands require much longer time periods to reach stable reservoir pressure for conventional build-up tests. Similar issues arise with determining hydraulic fracture performance, the inherently low reservoir permeability increases time required to determine fracture performance (Garcia et al., 2006).

There are many documented studies regarding optimization of various fracture properties, such as fracture length and aperture, to improve performance. For example, Pankaj and Kumar (2010), analyzed various studies conducted on the impact of initial reservoir pressure (2100-2500psi), reservoir permeability (0.01-0.1mD) and fracture half length (100-500ft). However, fracture orientation with respect to the wellbore is not covered by the simulation analysis. Initial reservoir pressure was found to have a minimal impact on initial production rate compared to reservoir permeability. Shah et al. (2010), discusses the theoretical difference between hydraulic fracture performance based on orientation, comparing fractures perpendicular and along the wellbore. Hydraulic fractures formed

along the wellbore can be expected to have a greater impact on production performance due to the increased contact area of the hydraulic fracture and wellbore. In addition, the reduced contact area provides a smaller flow path into the wellbore, increasing fluid velocity therefore resulting in more turbulent flow.

Jamiolahmady et al. (2009), modified the Unified Fracture Design method (UFD), originally proposed by Valko et al. (1998), to account for coupling and internal effects.

Addis and Yassir (2010), take the approach of optimizing hydraulic fracture design via intersecting already existing natural fractures. The idea of intersecting natural fractures is economically advantageous as overall reservoir permeability and sweep is increased by both the new hydraulic fractures, and by increased connectivity with high permeability natural fractures.

Rushing and Blasingame (2003), used a combination of decline curve analysis and simulation of long production periods to determine the stimulation effectiveness of hydraulically fractured gas wells. A combination of Material Balance Decline Type Curve (MBDTC) methodology and different type curve plotting functions were used to match results against real tight gas reservoir data. Rietman (1998) also used decline curves to analyze the sensitivity of optimum fracture length under different reservoir parameters. The findings showed that reservoir porosity and pay thickness are more influential on performance than permeability and drainage area.

The aim of this paper is to generate common trends between fracture size, fracture spacing and fracture orientation on initial tight gas reservoir response. Using post hydraulic fracture production data, already calculated on most fields, to analyze early time reservoir response. As previously discussed, reducing time required for analysis is a major challenge for tight gas reservoirs; therefore the use of early time data is the key focus of this paper.

The approach is to use a 3-D reservoir model to analyze impacts of the abovementioned fracture parameters on a single vertical well completed in tight gas sands. Overall fracture volume between comparable hydraulic fracture scenarios will be similar, with a overall difference less than 10% (not equal due to the size of cells within the model). The variables varied for this investigation are, fracture number, fracture length and fracture

orientation. The results will aid in determining the most efficient hydraulic fracture layout with comparable proppant volume used (as per fracture volume). Comparisons will be made between 1150ft fractures and 550ft fractures; more 550ft fractures are simulated to obtain similar overall fracture volume. Gas production rates and cumulative gas production data will be used to analyze the impact of additional 1150ft and 550ft fractures on production performance.

Fracture orientation with respect to the wellbore is also simulated and analyzed. Similar to the previous comparison, the comparable hydraulic fracture models have equal overall fracture volume. One model has the hydraulic fracture created along the wellbore, while the other model has the hydraulic fracture perpendicularly intersecting the wellbore. This comparison aims to determine the production performance of hydraulic fractures orientation with respect to the wellbore; hence the results should be comparable for horizontally completed wells.

The findings from this analysis can be used in conjunction with other optimization techniques to improve overall hydraulic fracture design.

2.0 Model Description

Commercial simulation software is used to create a 3-D homogeneous model with tight gas properties, the properties of the model are outlined in Table 1. Commercial reservoir simulation software, Eclipse, is used for all simulations. Eclipse 100 is a numerical 3-D simulator capable of simulating various types of oil and gas reservoir production including tight gas reservoirs (Schlumberger GeoQuest, 2008). A single vertical well is created in the centre of the reservoir to ensure symmetrical depletion throughout the production periods. Numerous simulations are completed examining fracture orientation, size and fracture number effects on welltest response in terms of early time production rate and cumulative production.

To analyze the effect of fracture orientation, two simulations with fractures perpendicular to one another are created, both having equal fracture volume. One model contains a single fracture perpendicular to the wellbore, and the other model with a single fracture

along the wellbore, Figure 1 shows a schematic of the two cases for a vertical well. The hydraulic fracture along the wellbore model is created to with the expectation to achieve greater production. The “perpendicular fracture” is simulated in the centre of the perforated section of the box model intersecting the wellbore perpendicularly.

The impact of fracture size vs. fracture number is conducted with each comparative model containing almost equal total fracture volume but with a different number of fractures. The fracture volumes are not exactly equal between the models due the size of the grid-blocks used for simulation, however the difference is negligible (less than 10%) compared to the overall fracture volume. Having very similar fracture volume ensures that the overall increased permeability of the model is equal, leaving only the fracture size and spacing as the variables. One scenario compares one 1150ft horizontal fracture to four 550ft horizontal fractures; with the single fracture and four fracture models having equal fracture volume. This analysis aims to determine which hydraulic fracture method is more beneficial in terms of production performance, numerous smaller fractures or fewer larger fractures.

3.0 Results and Discussion

For all scenarios two sets of plots are discussed, gas production rate vs. time and cumulative gas production vs. time. Both the fracture size vs. number of fractures, and perpendicular vs. along the wellbore fracture cases are compared to a no fracture scenario, in order to put the increased production performance in perspective. This is achieved by making the production rate vs time plots dimensionless with respect to the un-fractured model. In other words, the production rates of all fractured models are divided by the no fracture production rate to emphasize the benefit with respect to an un-fractured tight gas reservoir. The production period is 12,000hours (~500days), however

only the early time gas production rate results (first 72 hours) along with cumulative production after 500days are analyzed.

The gas production rate results are plotted on a semi-log plot, with time displayed on a logarithmic scale; this creates clarity for early time production rate behavior analysis.

3.1 Fracture size vs. number of fractures

As discussed, this analysis is conducted to compare the production performance of generating large fractures (1150ft) or smaller fractures (550ft), all with comparable overall fracture volume.

The fractures simulated are symmetrical and have equal length and width, with all fractures also having equal aperture of 1mm (Figure 2). The equal length and width of the fractures means that 1 single fracture with a length, and width, of 1150ft has approximately four times the fracture volume of a single 550ft fracture (Table 2). Hence, the results of a 1x1150ft, 2x1150ft and 3x1150ft fracture models are compared to 4x550ft, 8x550ft and 12x550ft fracture models, respectively. As stated previously, the production rates in Figure 3 are dimensionless with respect to the un-fractured model.

From Figure 4 it is evident that increasing the number of fractures intersecting the wellbore drastically impacts the initial flow rate of a tight gas reservoir. In addition, initial production rate increases similarly with fracture number regardless of fracture volume. Simulation results show that the 4x550ft fracture model produces initially at a higher rate than the 3x1150ft fracture model although it has only 30% of the total fracture volume (Table 3). In terms of immediate drainage of tight gas formations, numerous smaller fractures will increase productivity more per volume of fracture, compared to fewer longer fractures.

This is due the initial gas being produced only from sands near the wellbore and hence within the drainage radius of both the simulated fracture sizes. The key difference between the different fracture length models is that the 1150ft fractures maintain the initial production for a longer period of time, whereas the 550ft fractures experience a drastic reduction in production rate within the first few days (Figure 4).

These simulation results show that the initial production rate of a single hydraulic fracture can be used to determine efficiency of subsequent fractures created. The results show that each additional fracture created should increase initial gas production by a similar value compared to the previous fracture over the first 24hours (Figure 5). This relatively linear increase in initial production rate is created as a result of the increased permeability near wellbore by hydraulic fractures. Therefore, the effectiveness of a fracture job can theoretically be estimated within 24 hours of first production, based on post shut-in initial gas rate.

In terms of assessing the performance of a hydraulic fracture jobs on real tight gas reservoirs, this form of analysis could serve as immediate feedback of additional fracture performance after shut-in. A lower increase in initial production rate (compared to the previous fracture) could be a result of near wellbore damage caused by poor clean-up post hydraulic fracture.

There is minimal difference in cumulative gas production between the 550ft fracture cases, particularly between the 8 and 12 fracture cases after 500days, overall difference of less than 2% (Figure 6). This is due to the fact that with increased fracture number, fracture spacing is reduced as a result of the reservoir size remaining constant (Table 2). Reduced fracture spacing can results in several fractures potentially producing from the same drainage area. With this in mind, it can be assumed that the 12_x550ft fracture model is not directly comparable to the 3_x1150 ft model in terms of cumulative production performance. Similarly the 8_x550ft model is likely to produce less cumulative gas than the 2_x1150ft fracture model due to multiple fractures producing from a common drainage

area. Therefore the 1_x1150ft and 4_x550ft is the only comparable pair in terms of cumulative production based on similar fracture volume.

As both scenarios have almost equal fracture volume, and fracture spacing is sufficient to ensure individual drainage area for each fracture, it can be expected that individual fracture drainage area is equal between the two cases. The single 1150ft fracture produces ~10% less cumulative gas and therefore can be said to be less effective compared to 4 smaller fractures. Another of the mitigating factors can be explained by the theoretical findings of Shah et al. (2010) regarding perpendicular fractures having more turbulent flow than fractures along the wellbore. With only one fracture providing flow for the 1150ft model (compared to four 550ft fractures), the majority of production comes from the single flow path via the hydraulic fracture, thus causing highly turbulent and flow and reducing production performance.

However, the cost of additional hydraulic fractures would have to be determined individually for all tight gas reservoirs prior to reaching any conclusions regarding fracture job planning and design. For instance, a highly faulted or discontinuous tight gas reservoir formation can have substantially less benefit from additional fractures than large homogenous tight gas reservoir.

3.2 Perpendicular versus along the wellbore fracture

Two models with equal fracture volume (identical fracture length and width) are simulated, one fracture model intersecting the vertical wellbore perpendicularly, and the other intersecting parallel along the wellbore. Dimensionless production rate and cumulative gas rate vs. time plots are created and analyzed (Figure 7 and 8).

The fracture along the wellbore produces ~60% more cumulative gas after 500 days of production, and doesn't drop below the perpendicular fracture production rate at any stage of production. This increase in production is due to the higher surface area of wellbore that the fracture along the wellbore intersects if compared to the perpendicular

fracture (Shah et al. 2010). The increase in contact area between the wellbore and hydraulic fracture increases average permeability near the wellbore and hence inflow performance. Similar to the multiple 550ft fracture model results, the parallel fracture model experiences a large decrease in production rate for the first day of production.

As further investigation, 2, 3 and 4 perpendicular fracture models are plotted against the single fracture along the wellbore to determine the number of perpendicular fractures required to achieve similar cumulative production.

The simulation results show that only the 4 perpendicular fractures achieve a higher cumulative production over the simulated time interval (Figure 10). Based on these results, and assuming symmetrical drainage, fractures along the wellbore have a significantly increased ultimate recovery compared to perpendicular fractures. Therefore it is suggested that whenever possible, hydraulic fractures should be created along the wellbore, rather than intersecting it perpendicularly. As discussed by (Shah et al., 2010), the fractures created along the wellbore have a higher contact area between the hydraulic fracture and wellbore. This increase in contact area increases the permeability, and therefore production performance, of the near wellbore section. For tight gas formations, this increase in near wellbore permeability has a significant impact on production performance, which makes the reservoir more economically viable. However, it must be noted that fracture propagation is dependent on the in-situ stresses within the reservoir, and the most productive fracture orientation may not be achievable in all tight gas sands.

4.0 Conclusions

Based on the analysis of all simulation results the following conclusions can be reached regarding the impact of fracture length, spacing and orientation on tight gas production performance:

- Fracture number has more significant impact on well productivity (initial production rate/capacity) than fracture length, in the cases with equal total fracture volume. This is

due to the smaller fractures having a larger contact area with the wellbore and subsequently increased production performance.

- However, fracture length has a larger impact on cumulative gas recovery than fracture number. This is primarily a result of the larger fracture spacing of longer fractures in this model, hence the longer fractures are not producing from the same zone as other fractures and accessing new portions of the reservoir.
- When possible, fractures should be completed along the wellbore to increase contact area between the wellbore and hydraulic fracture.
- Fractures along the wellbore are far more effective than perpendicular fractures, based on simulation results, 4 perpendicular fractures are required to better the along the wellbore fracture performance.
- After the initial hydraulic fracture, each subsequent fracture increases the initial gas production rate (within first 24hours) by a similar amount, and is independent of fracture length.

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ACCEPTED MANUSCRIPT

Table 1: Model description and properties

Table 2: Fracture spacing, initial gas rate and volume for different fracture number models

Table 3: Increase in Initial Gas Production Rate per subsequent fracture

Figure 1: Contact area with wellbore for perpendicular (bottom) and along the wellbore (top) fractures, Shah et al. (2010)

Figure 2: Schematic of 550ft and 1150ft fracture sizes (not to scale)

Figure 3: Gas production rate vs. Time for all simulated 1150ft and 550ft fracture cases

Figure 4: Average gas production rates for first three 24hour periods for all simulated 1150ft and 550ft fracture models

Figure 5: Average gas rate after 1 day vs. Number of Hydraulic Fractures

Figure 6: Cumulative gas production vs. Time for all simulated 1150ft and 550ft fracture cases

Figure 7: Gas production rate for single Perpendicular and along the wellbore fracture models

Figure 8: Cumulative gas production for single Perpendicular and along the wellbore fracture models

Figure 9: Gas production rate vs. Time for perpendicular and along wellbore hydraulic fracture models

Figure 10: Cumulative gas production rate vs. Time for perpendicular and along wellbore hydraulic fracture models

	Unit	Value		Unit	Value
Number of Cells	x, y, z	50, 50, 71	Reservoir Constraint	Gas rate, MSCF	500
Cell Size	x, y, z (ft)	75, 75, 2.5	Productin and Buildup Tests	3 consecutive	varying time interval
Porosity	%	8	Fracture Half Length	ft	275 - 575
Permeability	mD	0.1	Number of Hydraulic Fractures	-	0 - 12
Reservoir Pressure	psia	4000	Fracture Porosity	%	80
Well Type	-	Vertical, Single Well	Fracture Permeability	mD	28,000
Reservoir Thickness	ft	177.5	Perforation Length	ft	177.5

Table 1: Model description and properties

Fracture number and size	1x1150ft	2x1150ft	3x1150ft	4x550ft	8x550ft	12x550ft
Fracture Volume (ft ³)	4,338	8,676	13,013	3,969	7,938	11,906
Delta Initial Gas Rate Per Additional Fracture (Mscf/d)	-	9,294	7,223	10,979	8,189	8,187
Fracture Spacing (ft)	90	60	45	36	20	14

Table 2. Fracture spacing, initial gas rate and volume for different fracture number models

	2xFrac - 1xFrac	3xFrac - 2xFrac	4xFrac - 3xFrac	8xFrac - 4xFrac	12xFrac - 8xFrac
Delta Initial Gas Rate (Mscf/d)	9,294	7,223	10,979	32,756	32,746
Delta Initial Gas Rate per Fracture (Mscf/d)	9,294	7,223	10,979	8,189	8,187

Table 3. Increase in Initial Gas Production Rate per subsequent fracture

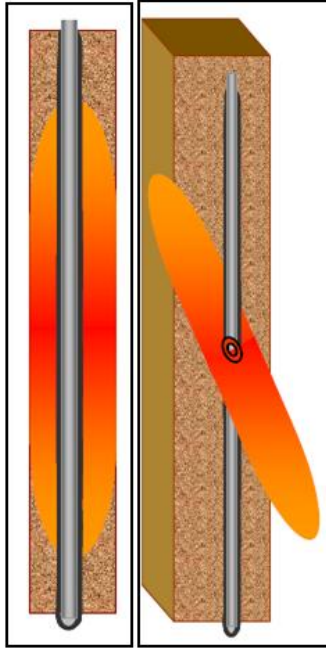


Figure 1: Contact area with wellbore for perpendicular (Right) and along the wellbore (Left) fractures, (Shah et al., 2010)

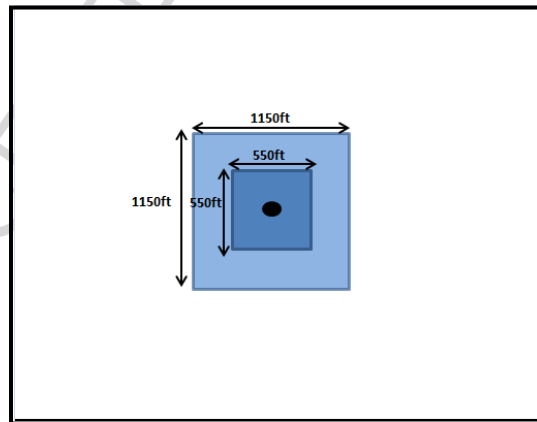


Figure 2: Schematic of 550ft and 1150ft fracture sizes (not to scale)

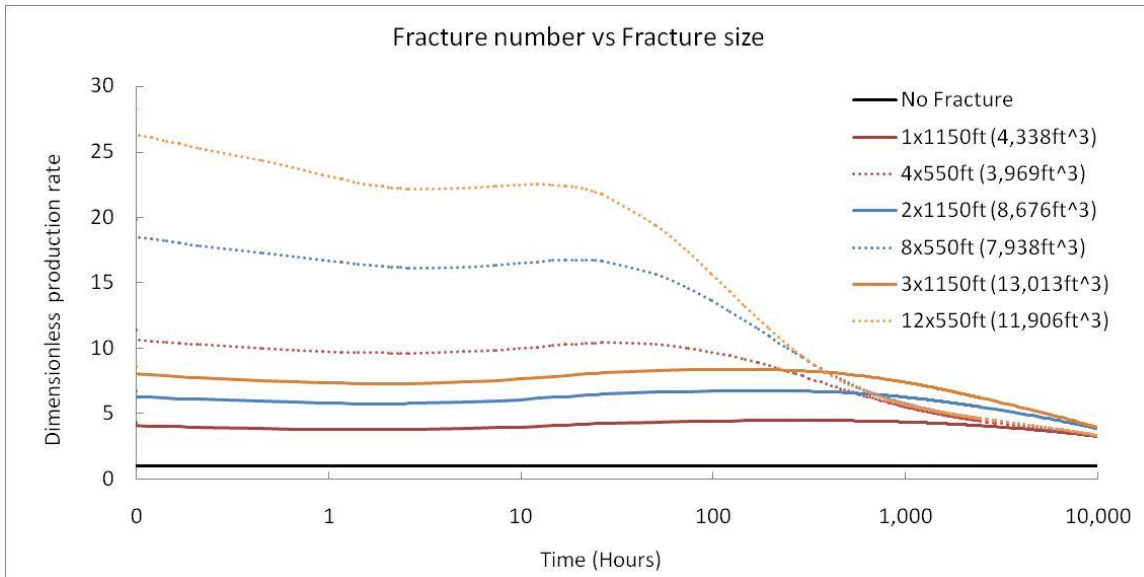


Figure 3: Gas production rate vs. Time for all simulated 1150ft and 550ft fracture cases

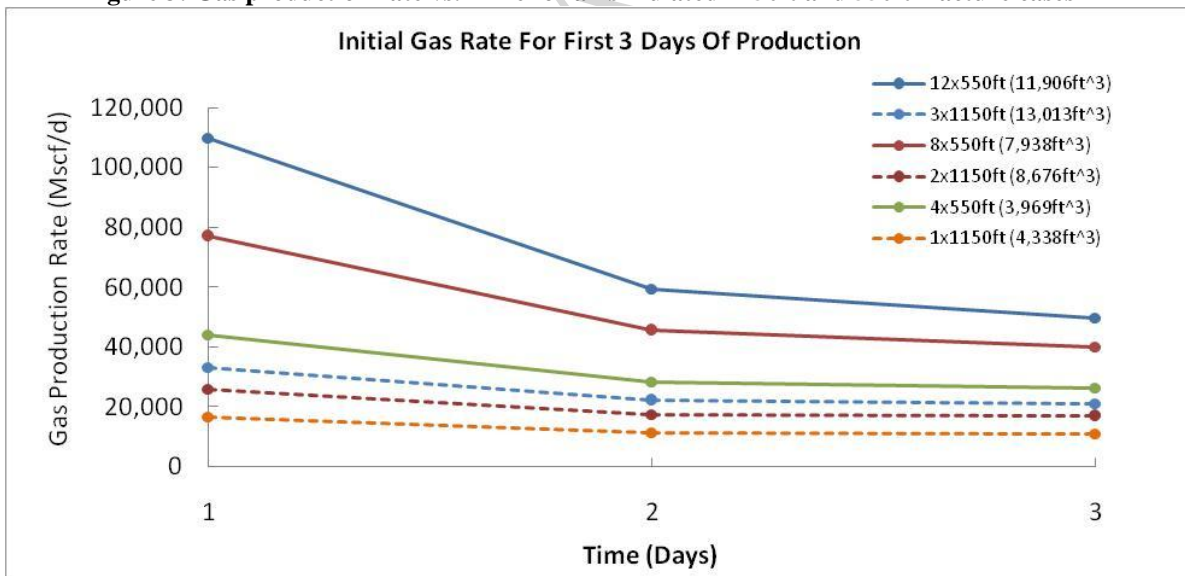


Figure 4: Average gas production rates for first three 24hour periods for all simulated 1150ft and 550ft fracture models

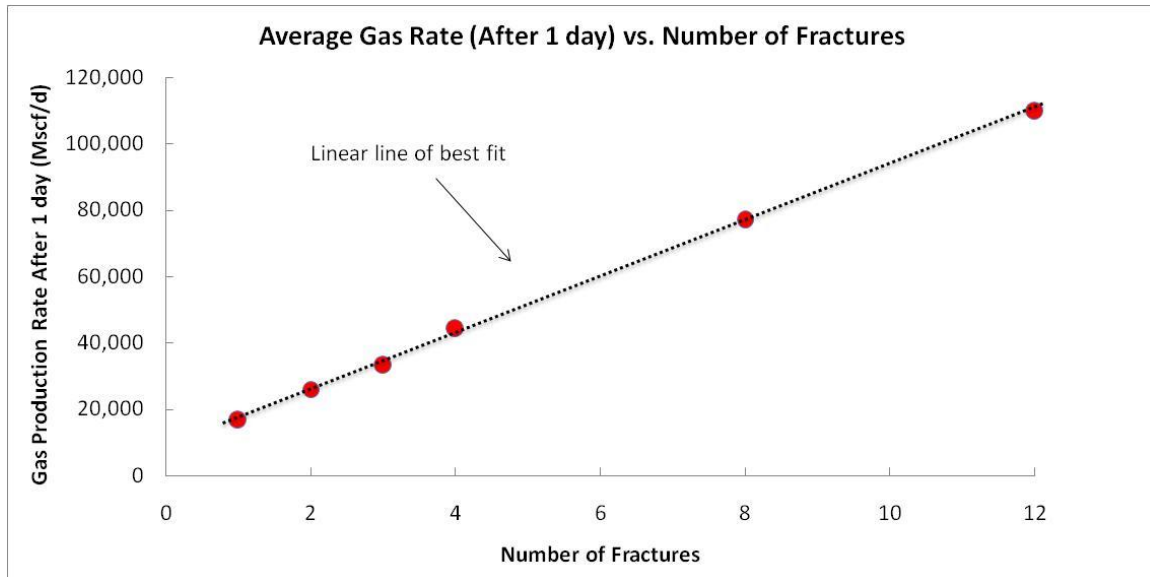


Figure 5: Average gas rate after 1 day vs. Number of Hydraulic Fractures

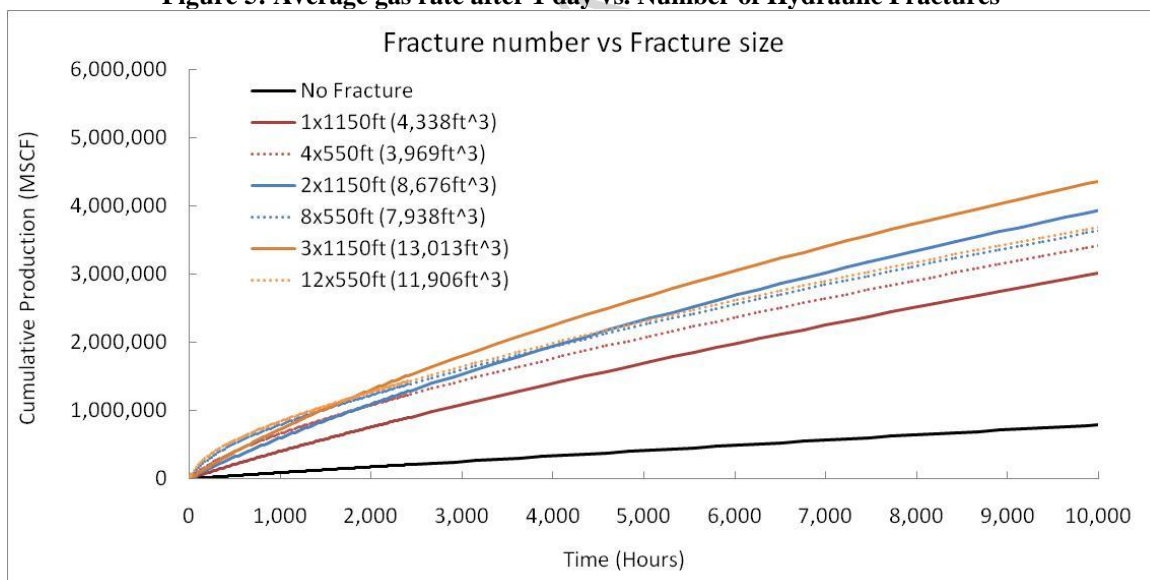


Figure 6: Cumulative gas production vs. Time for all simulated 1150ft and 550ft fracture cases

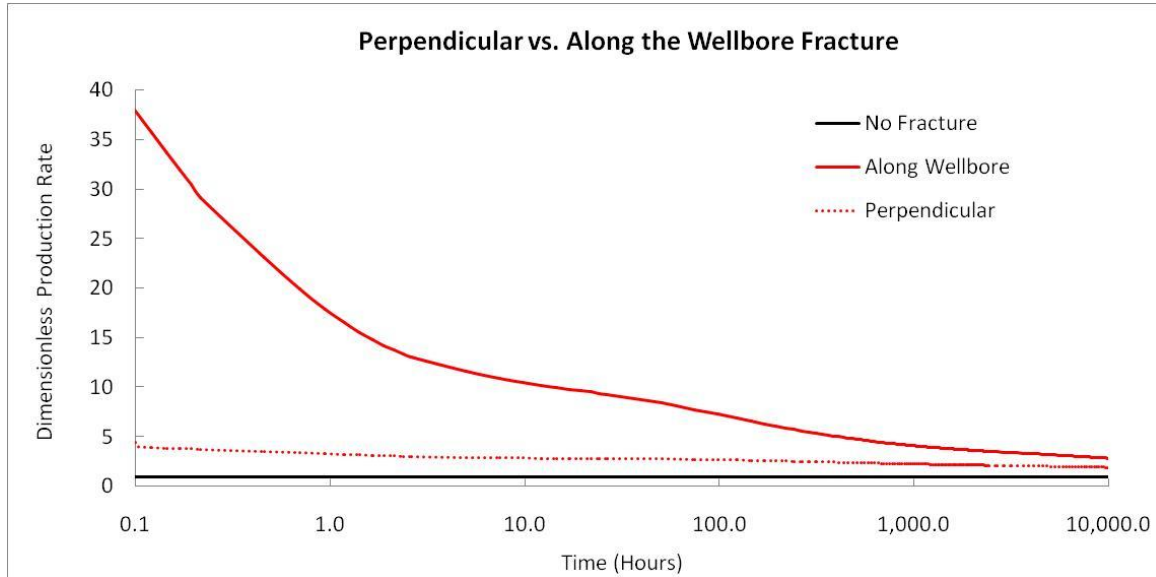


Figure 7: Gas production rate for single perpendicular and along the wellbore hydraulic fracture models

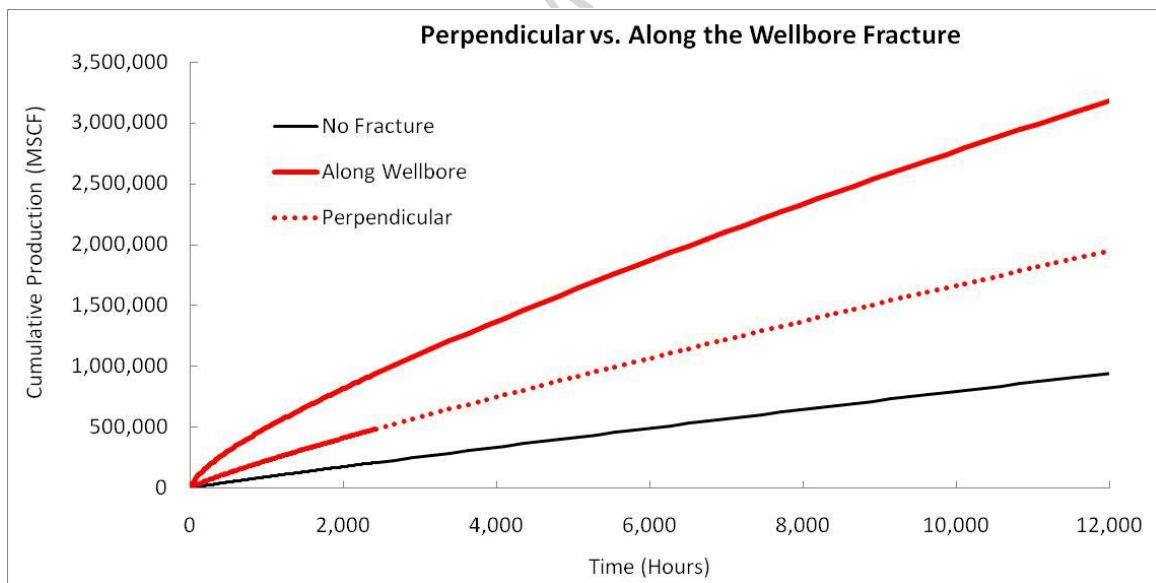


Figure 8: Cumulative gas production for single Perpendicular and along the wellbore fracture models

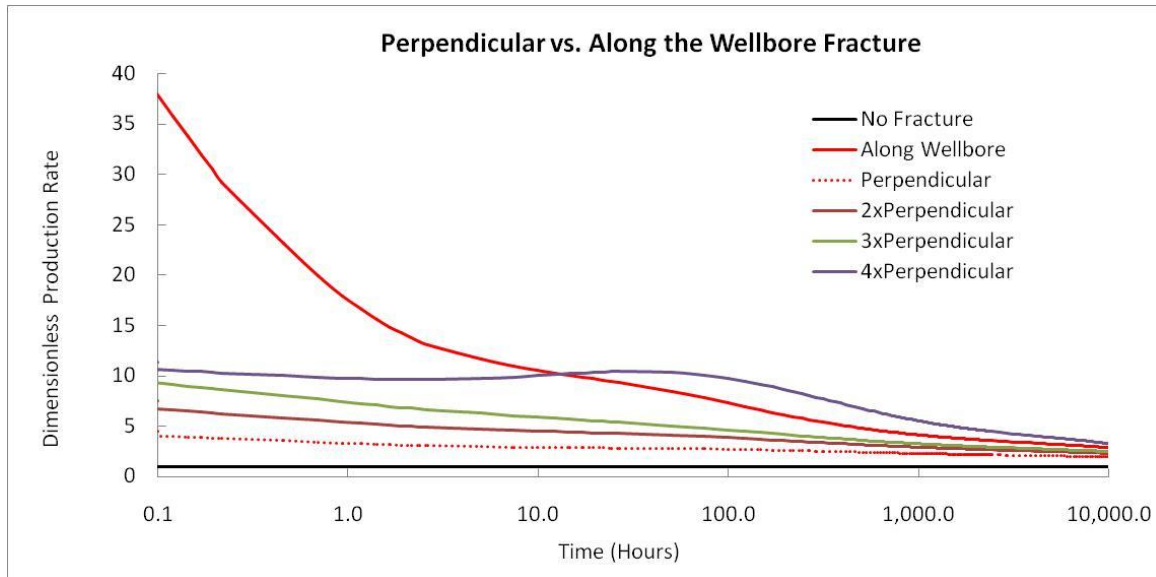


Figure 91: Gas production rate vs. Time for perpendicular and along wellbore hydraulic fracture models

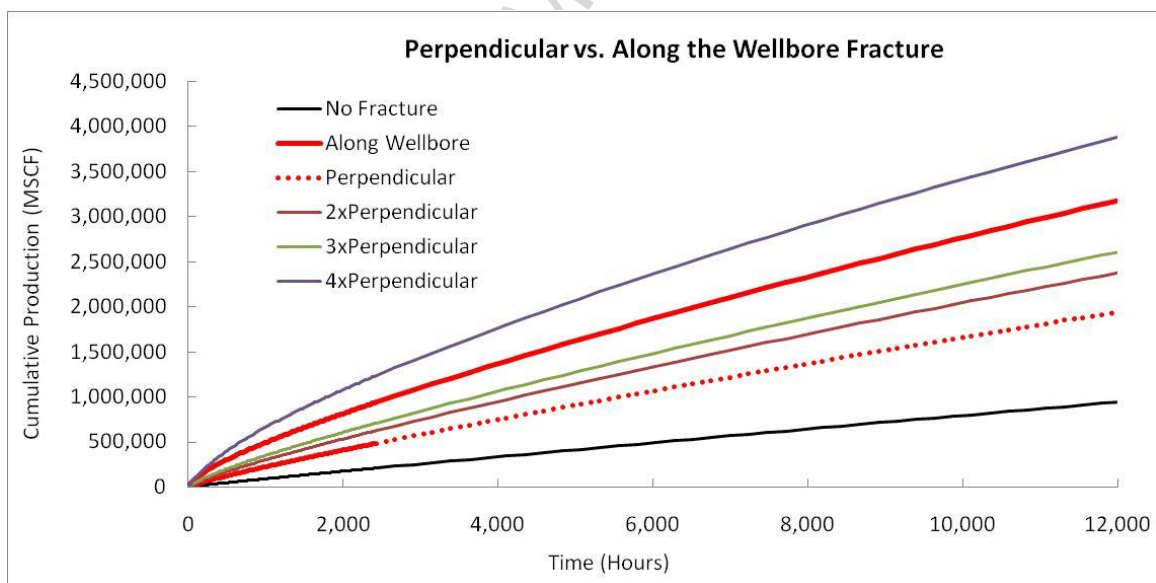


Figure 10: Cumulative gas production rate vs. Time for perpendicular and along wellbore hydraulic fracture models

Highlights

Based on the analysis of all simulation results the following conclusions can be reached:

- Fracture number has more significant impact on well productivity than fracture length.
- When possible, fractures should be completed along the wellbore.
- Fractures along the wellbore are more effective than perpendicular fractures, based on simulation results.
- After the initial hydraulic fracture, each subsequent fracture increases the initial gas production rate (within first 24hours) linearly, and is independent of fracture length.