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The Impact of Stress on Propped Fracture Conductivity and Gas Recovery in Marcellus Shale

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Abstract

It is commonly observed that the production rates from unconventional reservoirs decline rapidly as compared to conventional reservoirs. The net stress increases with the production because the pore (fluid) pressure decreases while the overburden pressure remains constant. This leads to the fracture compaction and conductivity impairment due to proppant embedment. Even though advances in technology have unlocked considerable reserves of hydrocarbon, the impact of the net stress changes on proppant conductivity, i.e. stress-dependent propped fracture conductivity, is not well understood.

The objective of this study is to investigate the impact of the net stress propped fracture conductivity from the horizontal wells with multiple hydraulic fractures completed in Marcellus Shale. A commercial reservoir simulator was used to develop the base model for a Marcellus Shale horizontal well. The model incorporated various storage and production mechanisms inherent in Shales i.e. matrix, natural fracture, and gas adsorption as well as the hydraulic fracture properties (half-length and conductivity). The core, log, completion, stimulation, and production data from wells located at the Marcellus Shale Energy and Environment Laboratory (MSEEL) were utilized to generate the formation and completion properties for the simulation model. MSEEL is a Marcellus Shale dedicated field laboratory and a research collaboration between West Virginia University, Ohio State University, The National Energy Technology Laboratory, and Northeast Natural Energy. Precision laboratory equipment was utilized to determine rock petrophysical properties such as permeability and porosity. Additionally, the natural fracture closure stress values were determined by an innovative experimental technique using core plug samples. The relation between fracture conductivity and the net stress were obtained from published studies (SPE 181867) on core plugs collected from Marcellus shale at two different locations. This relation was incorporated in the model to investigate the geomechanical impact of hydraulic fracture on the gas production. The model was used to perform a number of parametric studies to investigate geomechanical effects for fracture conductivity on gas recovery from Marcellus shale.

The production data from two horizontal wells at the MSEEL site, were utilized for production history matching both with and without geomechanical effects. The inclusion of the geomechanical effect in the model improved the predictions particularly at the early stages of the production. Simulation results show geomechanical effects of fracture conductivity on gas production performance for Elimsport and Allenwood

samples, which were cut parallel and perpendicular to the bedding planes. Moreover, the results indicate that the geomechanical effects have a significant impact on gas production when the pressure in the vicinity of the well has declined.

Introduction

The development of shale gas has become a crucial part of oil and gas industries globally during recent years, especially in North America. The application of horizontal drilling and hydraulic fracturing techniques have successfully unlocked considerable reserves of natural gas in shale-gas reservoirs. shale-gas reservoirs are characterized by complex petrophysical systems. Shale is a fine-grained sedimentary rock that is comprised of consolidated clay-sized particles leading to ultra-low permeability and low porosity. Shales contain a significant amount of organic matter (kerogen) and serve as both source rock and reservoir rock. The limited pore space of the shale can store gas in the free state, while the organic material stores gas in the adsorbed state.

Marcellus Shale is a black shale that is a brittle, soft, and carbonaceous with beds of limestone and carbonate solidifications and high Pyrite content. Marcellus Shale spans the majority of the Appalachian Basin from the southern tier of New York through northeastern and western Pennsylvania, West Virginia, into Ohio and Maryland (Bartuska, et al. 2012). The Marcellus Shale covers an area of approximately 95,000 square miles across six states in the northeastern U.S at an average thickness of 50 ft to 200 feet. The depth of the Marcellus production zone is between 4,000 ft to 8,500 feet. Marcellus Shale is a Middle Devonian-aged shale bounded above by shales of the Hamilton Group and below by limestones of the Tristates. The Marcellus Shale is the largest shale gas producer, accounting for almost 40% of the entire U.S. shale gas production. It has been estimated that as much as 500 trillion cubic feet of gas in place may be present in the entire Marcellus play area (Englander and Lash, 2009). Reservoir temperature in the Marcellus Shale is measured to be around 150 °F. The kerogen in Marcellus Shale is mainly Type II with a mixture of Type III (Weary 2000). Total organic carbon (TOC) in Marcellus Shale ranges from 2 to 20 wt%, and clay content is 10 to 45 wt% (Boyce et al. 2010). Fracture treatment in the Marcellus are performed using 2,500-20,000 barrels of water and 250,000–750,000 lbs sand proppant at a pumping rate of 30 to 100 barrels per minute (Bruner and Smosna, 2011).

Horizontal wells with multiple hydraulic fractures are the key technology to achieve economic production from shale gas reservoirs. The application of the hydraulic fracturing to create a high conductivity pathway in shale gas reservoirs has led to a dramatic increase in economically recoverable hydrocarbons from ultra-low permeability shale reservoirs. A hydraulic fracture treatment is performed by pumping fluid into the wellbore to increase the downhole pressure to a value greater than the fracture pressure (closure pressure) of the formation rock. This applied pressure causes the formation to crack, allowing the injected fluid to enter and extend the crack farther into the formation. Then a solid proppant, such as sand, is pumped into the fractures to prevent the cracks from closing after the injection is ceased. The propped hydraulic fracture becomes a high permeability conduit through which the gas can flow to the well. The transmissibility measure of fluid through a fracture is known as fracture conductivity. Fracture conductivity is defined as the product of fracture permeability and fracture width. As the gas is produced from the reservoir, the net stress increases because the pore (gas) pressure decreases while the overburden pressure remains constant. This leads to the fracture conductivity impairment and affects the ultimate gas recovery. The impact of the net stress changes on propped hydraulic fracture conductivity, i.e. stress-dependent propped fracture conductivity, is not well understood and often is neglected in production modeling studies. It is imperative to study and evaluate the impact of the stress-dependent propped fracture conductivity on well performance.

Background

Since unconventional reservoirs are the major supplier of the world's energy demand, it is essential to predict well performance and to understand the mechanisms which impact production performance. Fracture closure is one of the mechanisms that cause significant reductions in production performance. The increase in the net stress with production leads to hydraulic fracture conductivity impairment due to proppant crushing in hard rock and proppant embedment in softer rock (Fan et al., 2010).

Huitt and Mcglothlin (1958) stated that proppant would embed rather than crush under the weight of overburden. Pope et al. (2009) observed that shale with lower Young's modulus increases the degree of proppant embedment into the formation. Volk et al. (1981) studied several variables related to proppant embedment, including proppant size, proppant distribution, closure pressure, proppant concentration, surface roughness, and formation hardness. They found that the propped fracture will close because of proppant embedment if the proppant drops below 50% of a monolayer in shale formations. Lacy et al. (1997) conducted experimental research on embedment and fracture conductivity in soft formations. They found that embedment was affected mainly by rock type, proppant size, closure stress, strength, and concentration. Guo et al. (2008) developed a measurement and analysis system of proppant embedment. They concluded that softer rock sample would have greater proppant embedment than stiffer rock samples. Fracture conductivity is not a constant but decreases with the increasing closure pressure because of proppant embedment (Terracina et al. 2010). Alramahi and Sundberg (2012) performed laboratory experiments to study the proppant embedment and its impact on hydraulic fracture conductivity. Mechanical properties and the rock mineralogy were taken into consideration during these laboratory experiments. They observed that high proppant embedment and conductivity loss for samples with high clay content and low static Young's modulus. Based on their experiments, they developed a correlation between Young modulus and proppant embedment at a specific stress, which can be used to predict the fracture conductivity loss. Zhang et al. (2013) measured the fracture conductivity in Barnett Shale outcrop samples. They studied both natural and induced fractures for propped and unpropped fracture conductivity. Moreover, they studied the effects of proppant size and concentration on the conductivity. They found that higher proppant concentration, the rock properties' impact in fracture conductivity decreases. Guzek (2014) and Briggs (2014) did the same experiments on the Eagle Ford and Fayetteville shale outcrop samples, respectively. They agreed with Zhang et al. that as proppant concentrations increase, the importance of the rock properties decreases. McGinley et al. (2015) examined the impact of fracture orientation with respect to bedding planes. They found that fractures parallel to the bedding planes had lower conductivity than those perpendicular to the bedding planes. However, they correlated this behavior to the mechanical property anisotropy rather the surface topography or roughness. Cipolla et al. (2010) stated that shale formations with lower Young's modulus, such as the Marcellus and Haynesville shales, could be impacted significantly by stress-dependent unpropped fracture conductivity, resulting in substantially lower gas recovery. It is clear that the proppant embedment has a significant impact on hydraulic fracture conductivity; therefore, it is important to study the impact of the stress-dependent hydraulic fracture conductivity on the gas recovery.

Shale Gas Reservoir Modeling

It is difficult to accurately to model hydraulic fracture in shale gas reservoirs because of the complex nature of hydraulic fracture growth, lack of good quality reservoir information, and the very low permeability of the shale matrix. Reservoir simulation is the best method to predict and evaluate well performance. In this study, a reservoir simulation model (CMG-GEM, 2015) was used to simulate the gas flow in a shale reservoir with multiple hydraulic fractures. A dual permeability grid is used to allow matrix-to-matrix and fracture-to-fracture flows. This method can efficiently and accurately model transient gas production from hydraulic fractures associated with a horizontal well in shale gas reservoirs (Rubin, 2010; Cipolla et al., 2010). The hydraulic fracture is explicitly modeled in the block. Furthermore, the size of the matrix cells is increased logarithmically away from the hydraulic fracture to properly simulate the large pressure drop between fracture and matrix. Moreover, it is assumed that fractures are in a transverse direction and perpendicular to horizontal well (lateral). The hydraulic fractures are considered to be evenly spaced between the created clusters and equal in length. Local grid refinement (LGR) with higher spatial discretization of cell spacing is used to model bi-wing hydraulic fractures, and it can accurately simulate the pressure, rates dynamically during gas production.

Adsorption

In shale gas reservoirs, gas can be stored in three forms: free gas in matrix pores which has high storage capacity but very low permeability, free gas in fractures with a higher permeability but low storage capacity, and adsorbed gas on the surface of the shale. Langmuir isotherm is often utilized to express the quantity of the gas which adsorbed to the surface of a solid. Langmuir isotherm provides the gas surface occupancy as a function of pressure. Once the entire surface the solid is coated with a single layer of gas molecules, no further adsorption can occur. The Langmuir isotherm can be expressed as:

$$G_s = \frac{V_L P}{P + P_L} \tag{1}$$

Where G_s is the adsorbed gas volume in scf/ton and P is pressure in psia. V_L is the Langmuir volume in scf/ton, P_L is the Langmuir pressure in psia. Langmuir Volume (V_L) is the maximum volume of gas that can be adsorbed by the rock and Langmuir Pressure (P_L) is the pressure at which the volume of adsorbed gas is one-half of the maximum volume (V_L). As the reservoir pressure decreases, gas is desorbed from the rock. Zamirian et al.(2015) performed gas adsorption measurements on a Marcellus shale core plug using Precision Petrophysical Analysis Laboratory (PPAL) set-up. The values of the Langmuir pressure and volume from these measurements were incorporated in the models developed in this study.

Reservoir Geomechanics

The conductivity of the propped hydraulic fracture plays an important role in gas production from the unconventional gas reservoirs. Generally, the net stress in the reservoir increases with the production because the pore (fluid) pressure decreases while the overburden pressure remains constant. The increase in net stress can lead to hydraulic fracture compaction and results in conductivity impairment due to proppant embedment. This phenomenon is predominant in the Marcellus shale, which is considered a ductile shale due to its low Young's modulus. Furthermore, as seen in Figure 1, the Marcellus Shale is a relatively soft formation (Stegent et al., 2010).

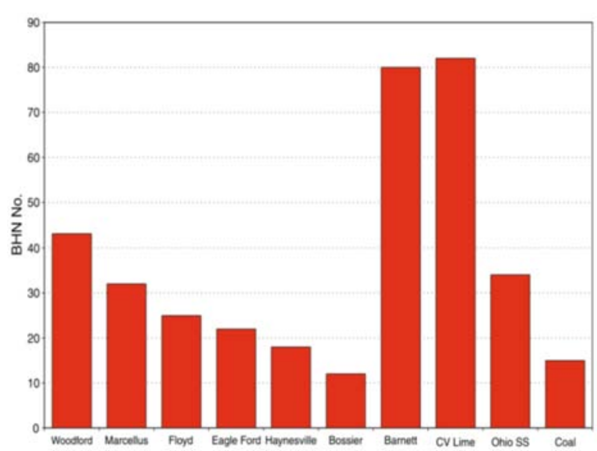

Figure 1—Brunell Hardness Numbers for various shale reservoirs in North America (Stegent et al., 2010).

Proppant can easily embed in the Marcellus shale surface as result of the reservoir pressure depletion. Therefore, it is vital to consider the geomechanical impact on the gas production. McGinley et al. (2015) performed a number of experiments to measure the conductivity of the propped hydraulic fractures in the Marcellus shale as a function of the net stress. The core plugs were used in their study were collected at two different locations. In addition, the core plugs were cut perpendicular and parallel to the bedding planes in order to investigate the effect of anisotropy on fracture conductivity. Table 1 summarizes the mechanical properties of the core plugs used in their study.

Table 1—Mechanical Properties For Both Sample

Property	Elimsport	Allenwood
E_h	1.1×10^6 *Psi*	3.99×10^6 *Psi*
E_V	2.32×10^6 *Psi*	4.41×10^6 *Psi*
v_h	*0.256*	*0.202*
v_v	*0.283*	*0.161*

The measured propped fracture conductivity for Allenwood and Elimsport samples as a function of closure Stress (net stress) are shown in Figures 2 and 3, respectively. For the vertical (bed-parallel) samples, Allenwood has a decline constant of 3.77×10^{-4} psi^{-1}, which is smaller than the Elimsport decline constant of 4.60×10^{-4} psi^{-1}. Similarly, for the horizontal (bed-perpendicular) samples, the decline rate for Allenwood is 4.456×10^{-4} psi^{-1} while Elimsport is 1.03×10^{-3} psi^{-1}. McGinley et al. (2015) concluded that the decline rate for the conductivity is inversely related to Young's modulus.

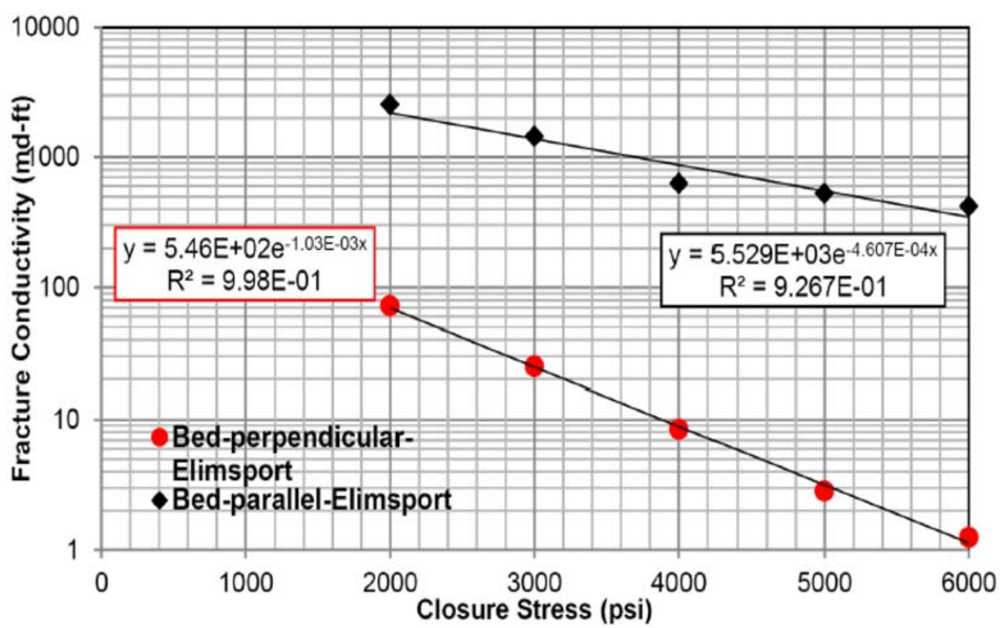

Figure 2—Measured Propped Fracture Conductivity versus Closure Stress for Elimsport Samples (McGinley et al., 2015)

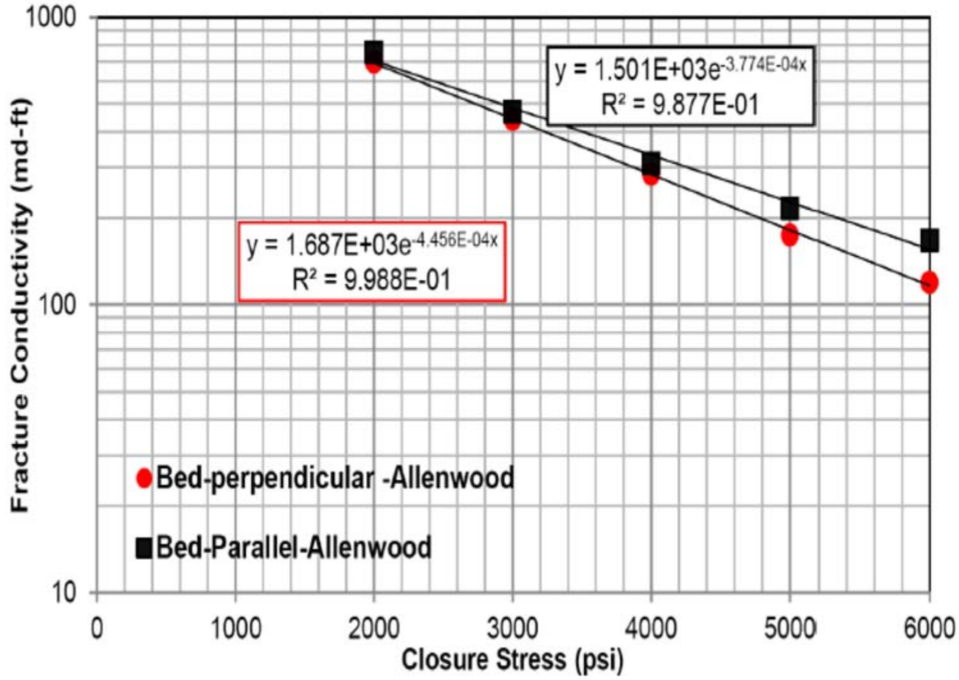

Figure 3—Measured Propped Fracture Conductivity versus Closure Stress for Allenwood Samples (McGinley et al., 2015)

Objective and Methodology

The objective of this study is to investigate the impact of the net stress on the production performance of horizontal wells with multiple hydraulic fractures. In this study, numerical reservoir simulation techniques were used to predict production performance of the horizontal wells with multiple hydraulic fractures completed in Marcellus shale. The stress-dependent propped fracture conductivity was incorporated into the numerical reservoir simulator.

To incorporate stress-dependent fracture conductivity into the model, the Marcellus shale stress-dependent propped fracture conductivity measurements (McGinley et al., 2015) were utilized. The fracture conductivity at a certain closure stress was normalized against the measured conductivity at initial closure stress. This is the same procedure that was employed by Wilson (2015) and Yu and Sepehrnoori (2014). The net stress is determined by subtracting minimum horizontal stress (7100 psi obtained from the well log) from the initial reservoir pressure (4700 psi), which results in 2400 psi. The conductivity values at 2400 psi in Figures 2 and 3 are then considered as the initial conductivity. The maximum net stress is determined by subtracting the wellbore pressure (500 psia) from the minimum horizontal stress, which results in 6600 psi. Therefore, the data between 2400 psi and 6600 psi are then normalized for both samples. After the fracture conductivity data were normalized, they were converted to conductivity multiplier as a function of the reservoir pressure (pore pressure) for use in the reservoir simulator. The conductivity multipliers used in the reservoir simulator are given in Figures 4 and 5 for both samples.

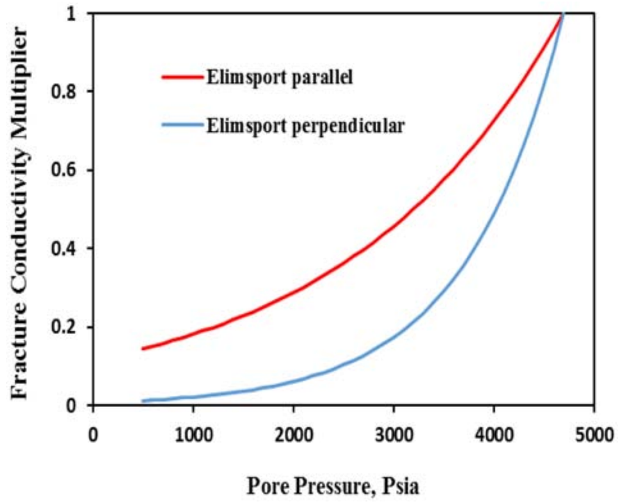

Figure 4—Fracture Conductivity Multiplier for Elimsport Sample

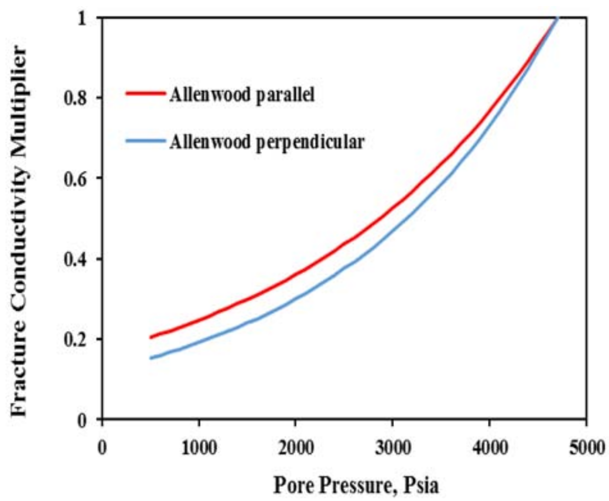

Figure 5—Fracture Conductivity Multiplier for Allenwood Sample

The data collected and used in this study were acquired from the Marcellus Shale Energy and Environment Laboratory (MSEEL), which are located in Morgantown Industrial Park (MIP) site in the state of West Virginia (USA). MSEEL is a field laboratory operated by Northeast Natural Energy (NNE). Stimulation and the production data from two horizontal wells (MIP-4H and MIP-6H) that were drilled in 2011 at the site were available through the MSEEL project. Moreover, two new horizontal wells (MIP-3H and MIP-5H) were drilled from the existing pad and placed on production in December 2015. MIP site also includes a vertical scientific observation well (MIP-SW) drilled approximately one-half mile to the northwest between the two new horizontal wells for additional subsurface data collection and microseismic monitoring. The location of the existing and newly drilled wells is illustrated in Figure 6.The collected data are discussed below:

Figure 6—Marcellus Shale Energy and Environment Laboratory (MSEEL) just outside Morgantown, West Virginia, USA. The MSEEL site consists of four horizontal production wells operated by Northeast Natural Energy LLC (Amini et al., 2017)

Petrophysical Properties

The results of core analysis were collected and used in the study. The petrophysical analysis performed through the Precision Petrophysical Analysis Laboratory (PPAL) (Elsaig et al., 2016) showed an average permeability of 124 nano-Darcy (nD) and an average porosity is about 2%.

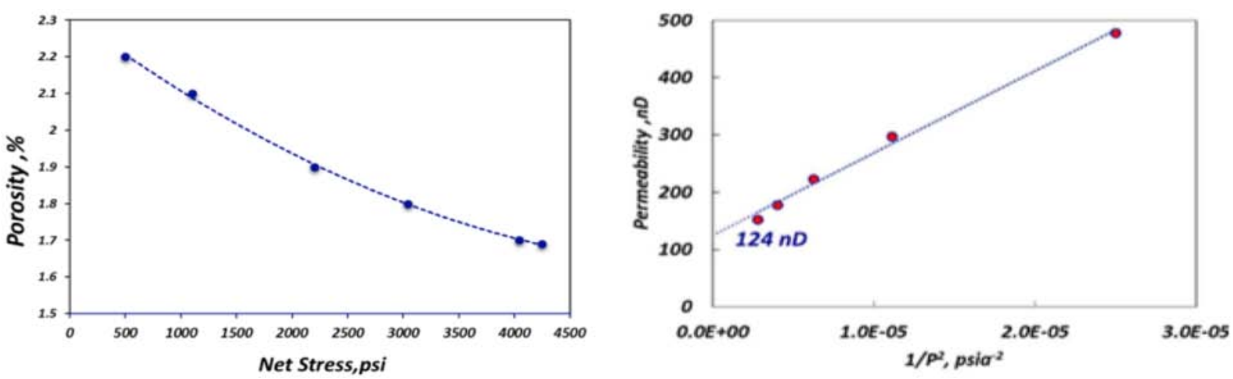

Figure 7—Porosity and Permeability from core plug (Elsaig et al., 2016)

Completion Records

Completion data for two horizontal wells MIP-4H and MIP-6H were collected. MIP-6H was stimulated with eight fracture stages at over a lateral length of 2,380 ft. MIP-4H was stimulated with eleven stages over a lateral length of 3800 ft.

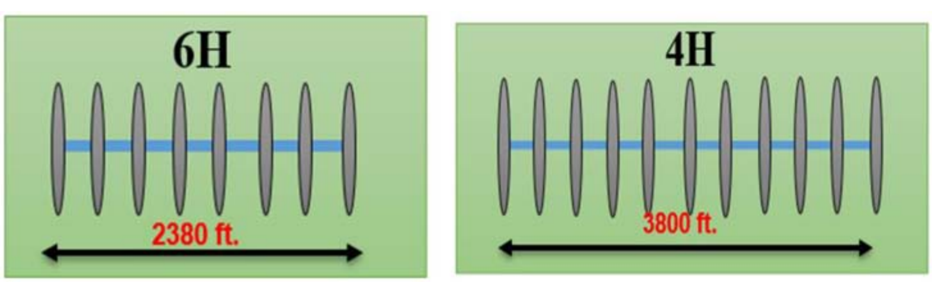

Figure 8—Wells MIP-6H and MIP-4H

Production History

Field production data (1473 days) from two horizontal Marcellus Shale gas wells at MSEEL site (MIP-6H and MIP-4H) were collected. Production started from the MIP-4H and MIP-6H on December 11, 2011, and continued to the end of December 2015. The production and cumulative production of the two laterals are shown in Figures 9 and 10.

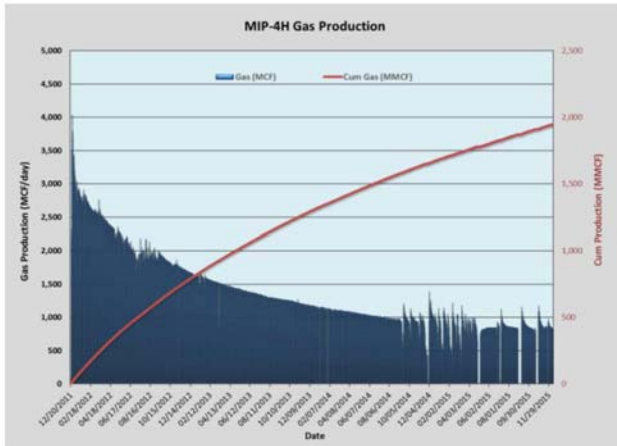

Figure 9—The production and cumulative production for MIP-4H

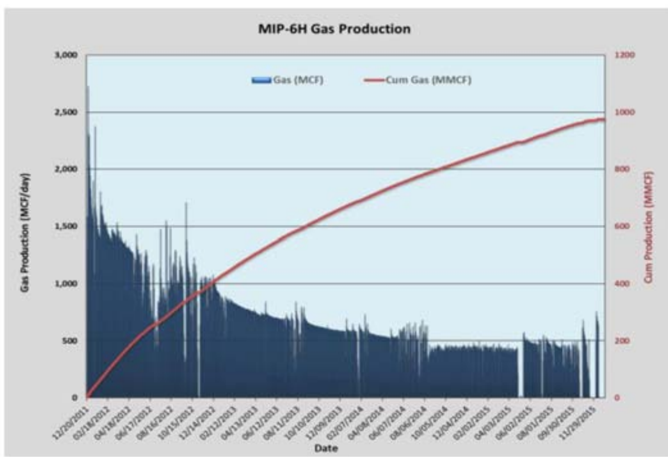

Figure 10—The production and cumulative production for MIP-6H

Model Development

The results of the data analysis were used as input to develop the simulation models for wells MIP-4H and MIP-6H. Table 2 summarizes the basic model parameters. Two models, one for each well, were developed. The results of the experimental study by McGinley et al. (2015), as discussed earlier, were utilized to estimate the initial fracture conductivity and to account for the impact of stress on hydraulic fracture conductivity (geomechanical effects). It should be noted that geomechanical effects were implemented using only the results from the Elimsport sample was for the history matching. This is because the geomechanical and anisotropy impacts are more pronounced in the case of the the Elimsport sample. As discussed earlier, the decline rate for fracture conductivity is related to the lower values of the Young's modulus. Therefore, the lower values for the Young's modulus result in more significant fracture conductivity reduction as the stress increases leading to lower gas recovery from the shale-gas reservoirs.

Table 2—Basic Model Parameters for MIP-6H and MIP-4H

Parameters	Value	Unit
Model dimensions (MIP-6H)	4000 (Length) × 1000 (Width) ×90 (Height)	ft.
Model dimensions (MIP-4H)	4500 (Length) × 1500 (Width) ×90 (Height)	ft.
Initial Pressure	4700	psia.
Fissure Porosity	0.0001	Fraction
Matrix Porosity	0.02	Fraction
Fissure Permeability i, j, k	0.0013,0.0013,0.00013	md
Matrix Permeability i, j, k	0.000124,0.000124,0.0000124	md
Gas Saturation	0.85	Fraction
Water Saturation	0.15	Fraction
Denisty	120	lb/ft^3
Langmuir Pressure	0.002	psi^{-1}
Langmuir Volume	0.12	gmol/lb
Fraction Spacing for (MIP-6H)	340	ft.
Fraction Spacing for (MIP-4H)	380	ft.

History Matching

The results of history matching for MIP-6H using production data for the first 730 days are provided in Table 3. The history matching was performed by varying hydraulic fracture half-length, whereas the reservoir properties were held constant. Figure 11 illustrates the match between the simulation results and the actual field production data for the first 730 days. Consequently, the matched model was used to predict the production for the next 730 days to verify the accuracy and reliability of the matched model. The predicted production rates are nearly identical to the actual data as seen in Figure 12. This confirmed the reliability of the matched model.

Table 3—History matching parameters for MIP-6H & MIP-4H with geomechanical impact

Parampters	Elimsport Sample	
	MIP-6H	MIP-4H
Number of hydraulic fractures	8	11
Fracture Half-Length, xf ft.	260	400
Initial Fracture Condutivity Horizantal, kf wf, mD-ft.	46	46
Initial Fracture Condutivity Vertical, kf wf, mD-ft.	1800	1800

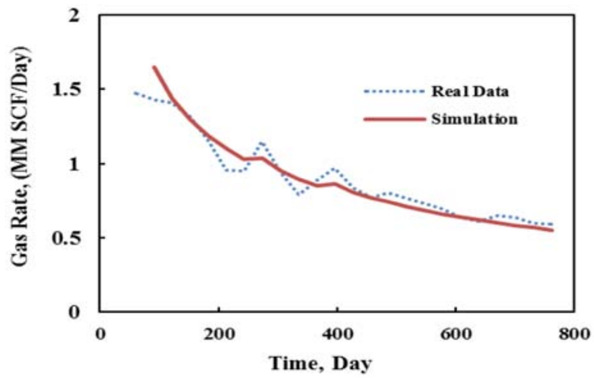

Figure 11—History matching for MIP-6H with geomechanical impact for first two years

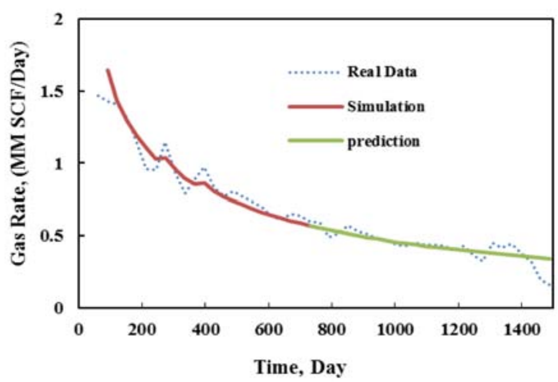

Figure 12—History matching for MIP-6H with geomechanical impact for four years

Impact of Geomechanical Effects

To investigate the impact of stress-dependent propped fracture conductivity on the production, the geomechanical effects were excluded from the matched model for MIP-6H and the entire production history was simulated for the comparison purposes. The results are illustrated in Figure 13. It is obvious from Figure 13, that the stress-dependent propped fracture conductivity has a significant impact on gas production initially and to a much lesser extent at the late times. It should be noted that even though the decrease in fracture conductivity at early times is small, the production is impacted significantly because of higher gas flow rates. While later, the impact of fracture conductivity on production is less significant because of the low gas flow rate. Furthermore, at lower Young's modulus, the stress-dependent propped hydraulic fracture conductivity could substantially reduce the initial production rate and ultimate gas recovery. Subsequently, the impact of stress-dependent propped hydraulic fracture conductivity must be taken into consideration for predicting shale gas production, particularly at the early stages of production.

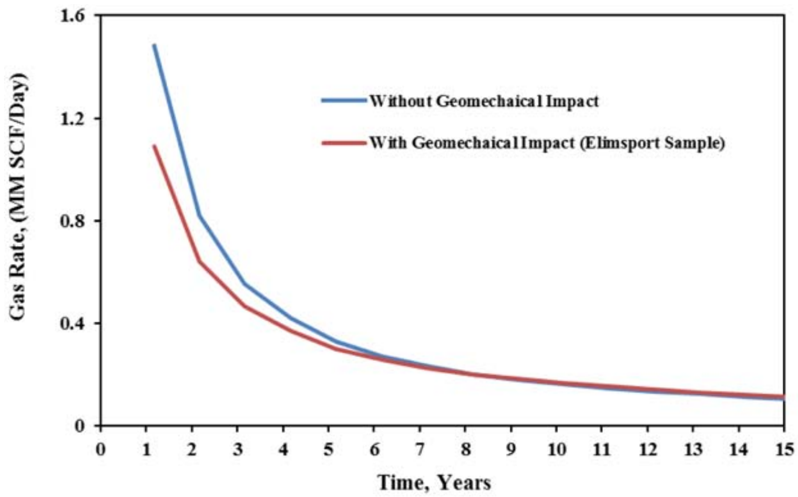

Figure 13—Gas flow rate for 15 years with and without considering geomechanical effect for MIP-6H Well (Elimsport Sample)

Figure 14 illustrates history matching for MIP-4H well for 1473 days of production. The results of history matching for MIP-4H are also provided in Table 3.

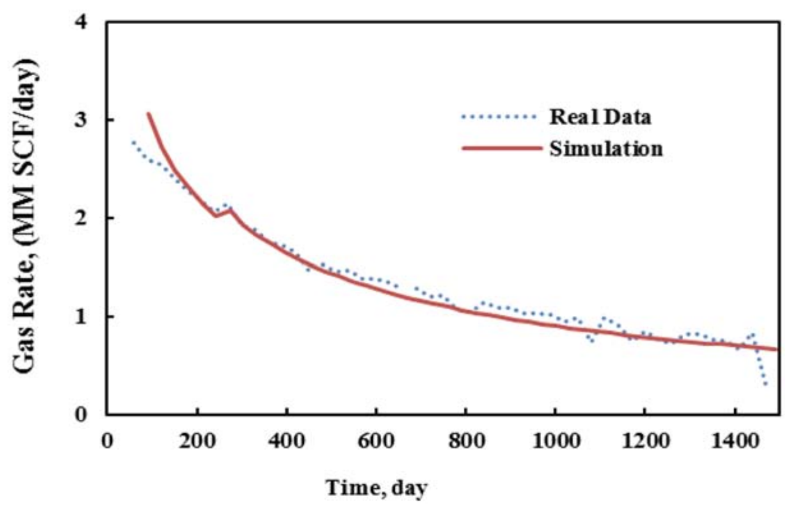

Figure 14—History matching for MIP-4H well with geomechanical impact for 1473 days

Parametric study

The parametric studies, using the matched models for MIP-6H, were conducted to investigate the impact of the wellbore pressure, fissure permeability, matrix porosity, fracture half-length and hydraulic fracture spacing on stress-dependent propped hydraulic fracture conductivity on production performance. The geomechanical effects (stress-dependent propped hydraulic fracture conductivity) were excluded from the model for MIP-6H and the entire production history (15-year simulated production) was predicted for the comparison purposes.

Effect of Wellbore Pressure. Three values (500, 1000, and 1500 psia) were considered for the constant wellbore pressure to investigate the impact of the stress-dependent propped hydraulic fracture conductivity on production. The comparison of constant hydraulic fracture permeability and stress-dependent hydraulic fracture permeability on cumulative gas production at 15 years is 16.34% for 500, 11.71% for 1000, and 7% for 1500 psia as illustrated in Figure 15. Therefore, the impact of stress-dependent propped hydraulic fracture conductivity becomes more pronounced when wellbore pressure is lower.

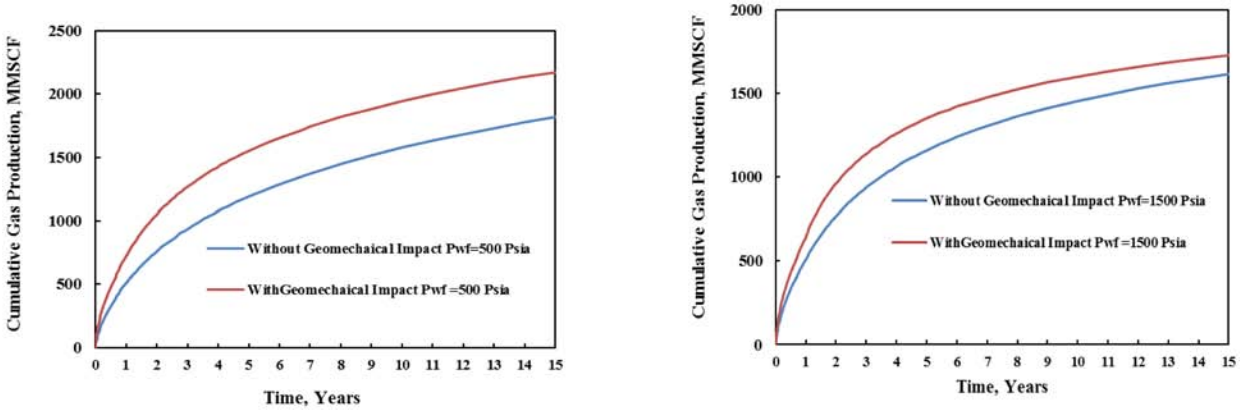

Figure 15—Impact Pwf on stress-dependent propped hydraulic fracture conductivity for cumulative gas production

Effect of Fissure Permeability. Three values (0.002, 0.004, and 0.008 md) were considered for the fissure permeabilities to investigate the impact of the stress-dependent propped hydraulic fracture conductivity on production. The comparison of constant hydraulic fracture permeability and stress-dependent hydraulic fracture permeability on cumulative gas production at 15 years is 16.4% for 0.002 md, 15.68% for 0.004 md, and 13.0% for 0.008 md as can be seen in Figure 16. Therefore, the impact of stress-dependent propped fracture conductivity is more pronounced a the lower values of the fissure permeability.

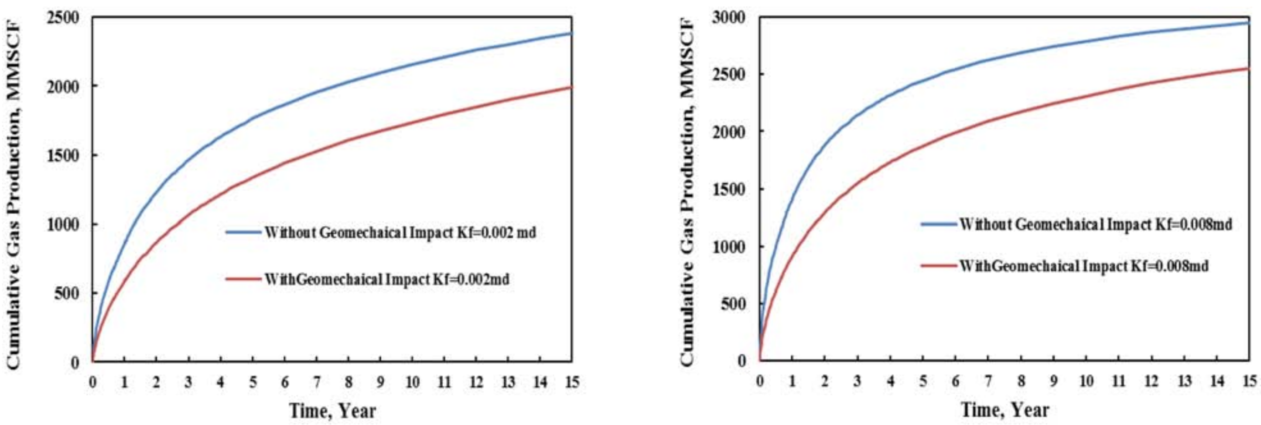

Figure 16—Impact fissure permeability on stress-dependent propped hydraulic fracture conductivity for cumulative gas production

Effect of Matrix Porosity. Three values (2.5%, 4.5%, and 6.5%) were considered for the matrix porosity to investigate the impact of the stress-dependent propped hydraulic fracture conductivity on production. The comparison of constant hydraulic fracture permeability and stress-dependent hydraulic fracture permeability on cumulative gas production at 15 years is 16.3% for porosity of 2.5%, 18% for porosity of 4.5%, and 19.6% for porosity of 6.5% as illustrated in Figure 17. Increasing matrix porosity leads to production increase. Consequently, the impact of the stress-dependent propped hydraulic fracture conductivity increases with increasing matrix porosity.

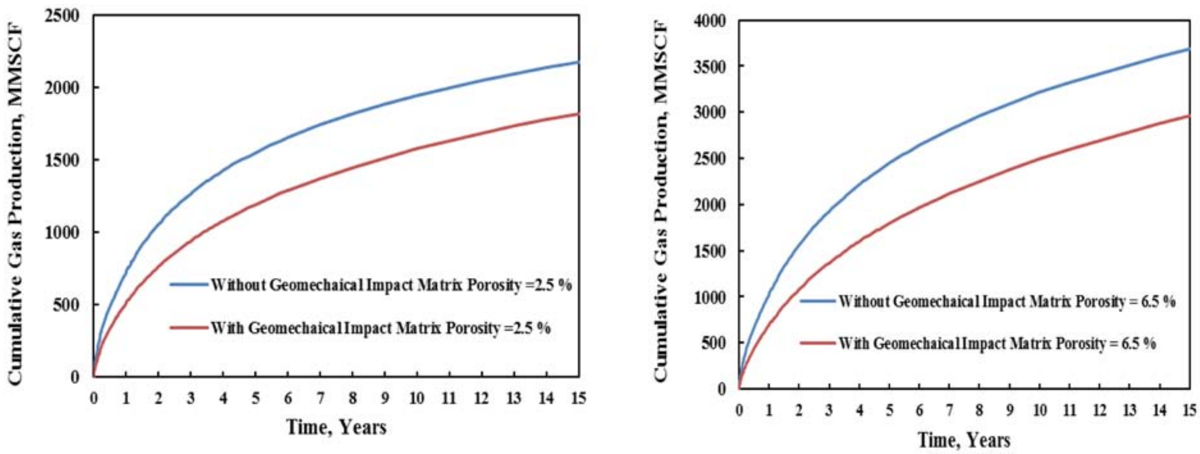

Figure 17—Impact matrix porosity on stress-dependent propped hydraulic fracture conductivity for cumulative gas production

Effect of Hydraulic Fracture Half-Length. Four values (160, 200, 250, 300, and 350 ft.) were considered for the fracture half-lengths to investigate the impact of the stress-dependent propped hydraulic fracture conductivity on production performance. The comparison of constant hydraulic fracture permeability and stress-dependent hydraulic fracture permeability on cumulative gas production at 15 years is 11.5% for 160 ft., 13.68% for 200 ft., 15.73% for 250 ft., 17.76% for 300 ft., and 19% for 350 ft. as seen in Figure 18. The fracture half-length has a significant impact because the higher fracture half-length leads to the higher the pressure depletion causing more increase in stress. This makes the impact of the stress-dependent propped hydraulic fracture conductivity on production more pronounced.

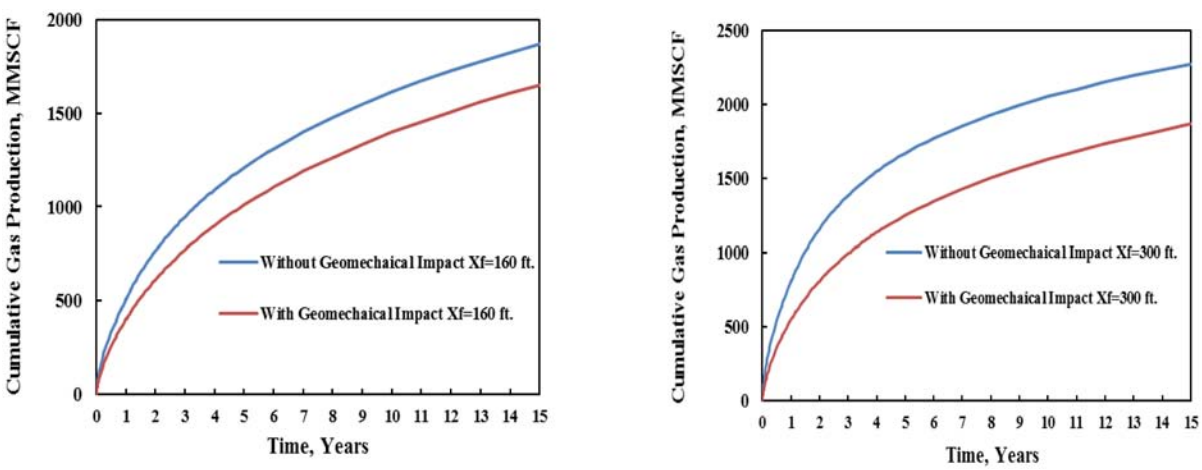

Figure 18—Impact fracture half-length on stress-dependent propped hydraulic fracture conductivity for cumulative gas production

Effect of Hydraulic Fracture Spacing. During this study, the fracture spacing of the wells was held constant in order to maintain verifiable results. Hydraulic fracture spacing was decreased from 340ft., 300ft., 260ft., and 220ft. to understand the impact of the stress-dependent propped hydraulic fracture conductivity on production. The comparison of constant hydraulic fracture permeability and stress-dependent hydraulic fracture permeability on cumulative gas production at 15 years is 16.3% for 340 ft., 16% for 300 ft., 15.4 % for 260 ft., and 14.5% for 220 ft. as can be seen in Figure 19. The impact of the stress-dependent propped hydraulic fracture conductivity decreases slightly with the closer hydraulic fracture spacing.

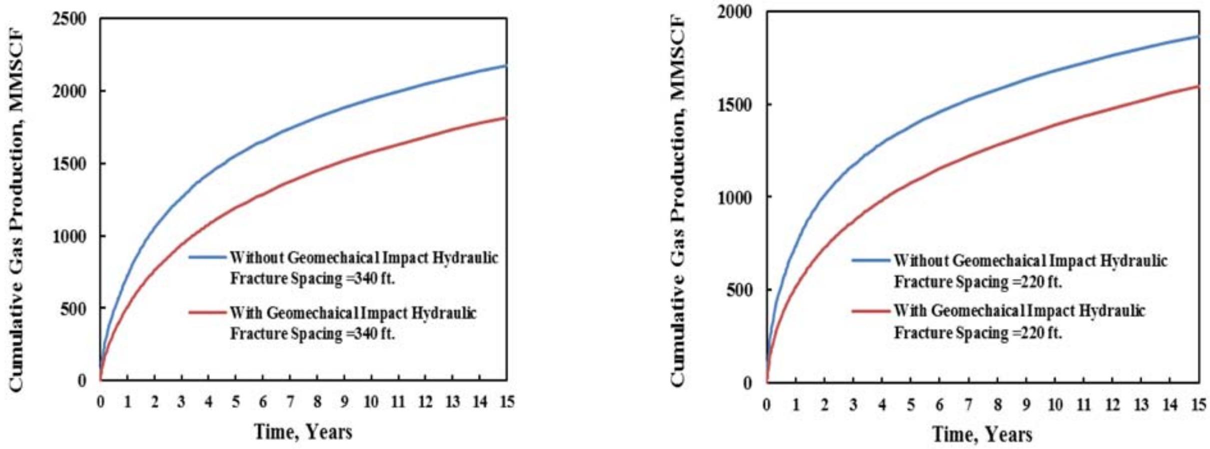

Figure 19—Impact hydraulic fracture spacing on stress-dependent propped hydraulic fracture conductivity for cumulative gas production

Figure 20 summarizes and compares the relative impact of critical parameters that influence the stress-dependent propped hydraulic fracture conductivity.

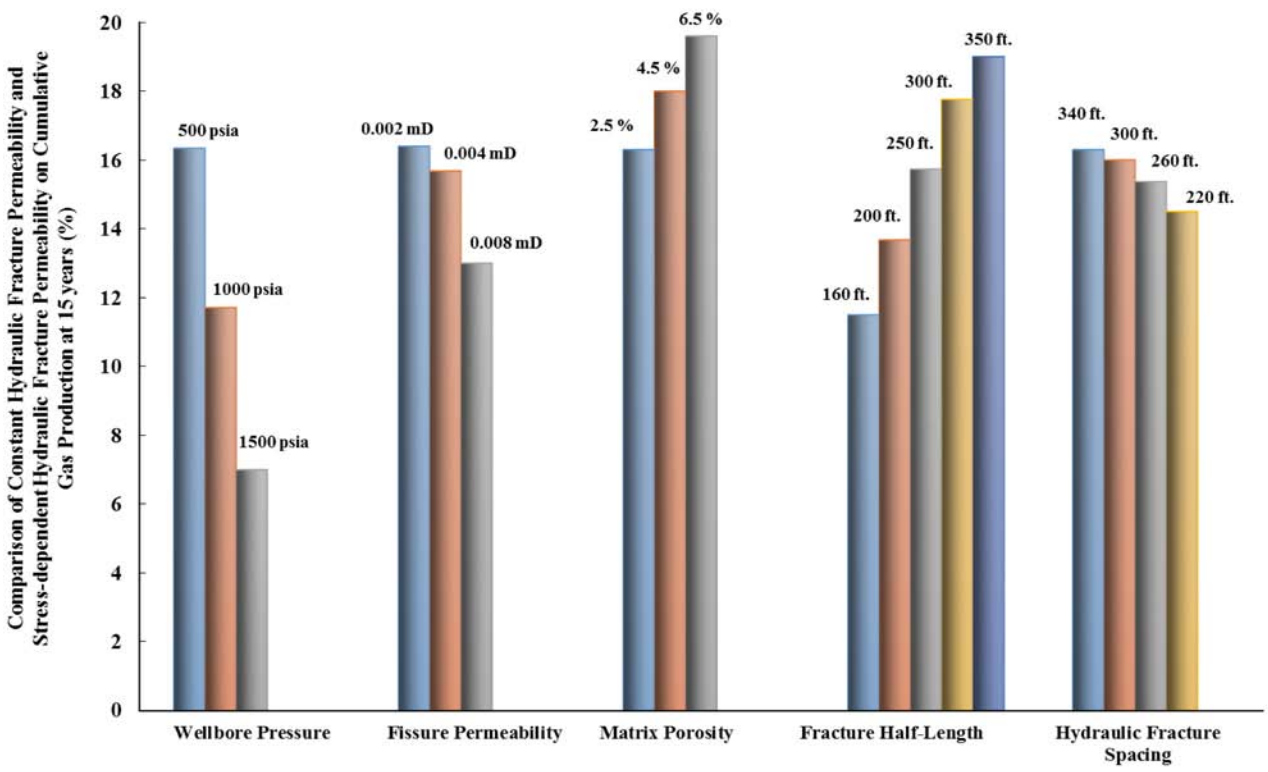

Figure 20—Illustrates critical parameters that influence the stress-dependent propped hydraulic fracture conductivity

Conclusions

1. The results of the history matching wells MIP-4H and MIP-6H indicated that the inclusion of the geomechanical effects results in higher fracture half-lengths.
2. The impact of stress-dependent propped hydraulic fracture conductivity in the formations with lower Young's modulus is more prominent.

3. Wellbore pressure profoundly impacts the stress-dependent propped hydraulic fracture conductivity and as a consequence the production performance. The impact of stress becomes more prominent at the lower wellbore pressures.
4. Fissure permeability has an impact on the stress-dependent propped hydraulic fracture conductivity. The impact of stress increases as the fissure permeability decreases.
5. Matrix porosity has a significant effect on the stress-dependent propped hydraulic fracture conductivity. The impact of stress becomes more pronounced at the higher matrix porosity.
6. Fracture half-lengths have a substantial impact on the stress-dependent propped hydraulic fracture conductivity. The higher the fracture half-length, the more obvious is the impact of the stress.
7. Hydraulic fracture spacing has a slight impact on the stress-dependent propped hydraulic fracture conductivity. The impact of stress is greater when hydraulic fracture spacing is wider.

Nomenclature

E_h	Horizontal Young's Modules (Bed-Perpendicular), Psi
E_v	Horizontal Young's Modules (Bed-Parallel), Psi
ν_h	Horizontal Poisson's Ratio (Bed-Perpendicular), Psi
ν_v	Horizontal Poisson's Ratio (Bed-Parallel), Psi
k_m	Matrix Permeability, md
k_f	Fissure Permeability, md
ϕ_m	Matrix Porosity
ϕ_f	Fissure Porosity
P_{wf}	Wellbore Pressure, psia
CMG	Computer Modeling Group
MMSCF	10^6 Standard Cubic Feet, ft^3
LGR	Local Grid Refinement
$k_f w_f$	Fracture Conductivity, md-ft.
Xf	Fracture Half-Length, ft.
P_L	Langmuir Pressure, scf/ton
V_L	Langmuir Volume, psi
G_S	Gas Content, scf/ton

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