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EFFECT OF MULTI-PHASE FLOW ON RECOVERY OF FRACTURE FLUID AND GAS IN MARCELLUS SHALE RESERVOIRS

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ABSTRACT

Hydraulic fracture treatment of shale gas wells does not always yield the expected folds of increase in gas production. Low production rates could be attributed to a number of factors like proppant crushing, proppant diagenesis, clay swelling and rock-fluid interactions based on previous work (Osholake, Wang, Ertekin, 2011; Yue, 2012). In this research work, we evaluated the effect of multi-phase flow, capillary pressure, length of shut-in time and proppant crushing on performances of hydraulically fractured Marcellus Shale wells. To accomplish this, a 2-dimensional, 2-phase water-gas model was developed using a commercial software. Three hydraulic fracture (HF1, HF2, HF3) with different network sizes were used to simulate the effect of the above factors on long-term gas production and fracture fluid recovery from hydraulically fractured Marcellus wells. Two types of proppants were used to evaluate the effect of conductivity on the impact of the factors being studied.

With high conductivity 20/40 ceramics proppant in the hydraulic fractures, long term gas production was not affected by any of the factors studied. With 20/40 ceramics fracture fluid recovery on the other hand was affected by all the factors studied. Shut-in time had the greatest effect on fracture fluid recovery. Less than 1% of the fracture fluid used for treating the well was recovered after 1-year shut-in.

With the less conductive 100 mesh sand, long term gas production and fracture fluid recovery were affected by some of the factors studied. Multi-phase flow and proppant crushing were found to decrease cumulative gas production. Effect of proppant crushing on gas production was greater compared to multi-phase flow. In twenty years of production, multi-phase flow decreased gas production by 1.8%, 2.2% and 3.9% in HF1, HF2 and HF3 respectively while proppant crushing decreased gas production by 3.5%, 3.9% and 5.8% in HF1, HF2 and HF3 respectively. Capillary pressure had little or no effect on long-term gas production, but was observed to delay gas peak during initial production. Long term gas production was unaffected by shut-in time. Fracture fluid recovery was decreased by high capillary pressure, increased shut-in time and proppant crushing. After one year of shut-in, less than 1 % of fracture fluid was recovered.

The new understanding helps engineers design better treatment and flowback operation in Marcellus.

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Chapter 1

Introduction

Marcellus shale play is in the Appalachian basin of Northeastern United States. It spans approximately 95,000 square miles covering most of Pennsylvania and West Virginia, extending into parts of Virginia, Maryland, New York and Ohio. The Marcellus lies at depths ranging from 4,000 to 8,500 feet with thickness of 50 to 200 feet and is estimated by U.S. Energy Information Administration to contain 141 TCF of gas classified as unproved technically recoverable reserves (EIA, 2012). Marcellus became an unconventional gas field in America in early 2013. The reservoir has permeability ranging from 10 to 100 nano-Darcy and porosity of about 10 % which makes production rates uneconomical without stimulation. Marcellus shale is the source and reservoir rock in which gas is stored in the pores of the matrix and natural fractures as well as in adsorbed state.

Gas production from Marcellus shale reservoirs has become economically viable with advancement in horizontal drilling and multi-stage hydraulic fracturing techniques since 2005. Even though hydraulic fracture treatment has been successful, field data indicate that wells have been producing at rates less than expected. Research has been done to explain the low production rates from wells after fracture treatment.

Large quantities of water-based fracture fluid are injected at high pressures into the formation to create hydraulic fractures through which gas can easily flow to the wellbore. Propping agents are placed in the hydraulic fractures to keep it open. Fracture fluid leaks off into the formation during hydraulic fracture treatment which gives rise to multi-phase flow during subsequent gas production.

Capillary pressure is high in the Marcellus formation due mainly to the characteristic small pore of the formation rock. High pressure drawdown is required to produce hydrocarbon from the formation.

It has been recognized that proppant fines created due to high closure stresses during fracture closure could have an impact on proppant pack conductivity and consequently on post-fracture gas productivity. Also, the practice of producing the formation at very high rates immediately after hydraulic fracture treatment can increase stress on proppants leading to proppant crushing.

The following chapter (chapter 2) is a review of literature that was the basis for this work and chapter 3 discussed the problem statement. In chapter 4, mechanisms of the effects of the factors studied were discussed while model description is discussed in chapter 5. Results are presented and analyzed in chapter 6 and conclusions and recommendations are made in chapter 7.

This research work is based on previous work done by Osholake (2010) and Yue (2012).

Chapter 2

Literature Review

The increasing demand for fossil fuels to meet the growing global demand for energy has made it necessary to explore for oil and gas in unconventional reservoirs. Prior to the 19^{th} century, shale formations were classified only as source rocks. In 1821, shale gas was first extracted as a resource in Fredonia, New York; however, commercial production did not start until the 1970's. Recently, shale formations are gaining attraction as potential reservoirs. Gas production from the Marcellus formation is an added resource to meet the world's growing energy demand. Currently, United States is one of the world's largest producers of natural gas because of added gas production from unconventional shale plays like Marcellus Shale. In January 2012, US Energy Information Administration (EIA) reported that Marcellus formation contains 141 trillion cubic feet of natural gas that it classified as unproved technically recoverable reserve (EIA, 2012).

Gas production from unconventional reservoirs has become economically viable with advancements in horizontal drilling and multi-stage hydraulic fracture technology. Even though hydraulic fracture technology has been successful, production rates from hydraulically fractured wells could be lower than expected.

During hydraulic fracture treatment, large volumes of water based fracture fluid are injected into the wells at high rates and pressures to fracture the formation and create pathways through which gas can flow to the well bore. After the fractures are created, propping agents are pumped into the fractures to keep them open even after the treatment is completed. The fracture fluid is then flowed back for gas to flow.

Gas reserves can be decreased by thirty percent and initial gas rate reduced by eighty percent if the fracture fluid (gel) does not break at the end of the treatment (Voneiff, 1996). Gel damage could be the cause of inefficient cleanup and short ineffective fracture length (Wang, 2008). As a result of unbroken gel left in the fracture, fracture conductivity will reduce and consequently gas production rates will decrease. The effect of gel damage is worse in less conductive fractures.

Fracture fluid leaks off into the formation during hydraulic fracture treatment. This decreases gas saturation at the regions around the fracture face. Relative permeability to gas also decreases as gas saturation decreases around the invaded zone. As absolute permeability damage increases at the invaded zone, the time to clean up the well increases (Ning, 1995). Fracture fluid recovery can be promoted by high fracture conductivity and high water mobility in the formation (Sherman, 1991). On the other hand, Montgomery (1990) added that relative permeability hysteresis can decrease the relative permeability of the formation to gas in the invaded zone and as a consequence, the well productivity will suffer.

Fracture conductivity required to clean up the well is much greater than that needed to produce the well. For this reason, hydraulic fracture treatment designs should be done such that fracture conductivity is sufficiently high for proper clean up (Soliman 1985). A high conductive fracture makes the impact of damage (multiphase flow, proppant crushing, proppant diagenesis and capillary pressure) less significant compared with a low conductive fracture (Osholake 2010 and Ning 1995). Ning (1995) used a combination of numerical and analytical models to conclude that effect of fracture conductivity is more significant than fracture face damage.

Marcellus shale and other tight formations have characteristic small pores compared to higher permeability formations; as a result they have higher capillary pressures. The capillary pressures in these tight formations could be several hundred pounds per square inch which requires a high pressure drawdown for clean up to take place (Soliman 1985). High capillary pressures in the vicinity of the fracture can cause water blockage if pressure drawdown does not exceed the capillary pressures which could result in low gas production rates (Holditch 1979, Ning 1995, Cheng 2011 and Tianping 2012). Fracture fluid clean up in low permeability formations are slower than in high permeability formations because of higher capillary pressures (Mahadevan, 2005). The difficulty in cleaning up a formation with high capillary pressure could be worse if the formation pressures are low (Soliman, 1985; Tianping, 2012).

Initial reservoir pressure before a hydraulic fracture treatment is critical to the success of the stimulation treatment. The amount of energy needed to effectively clean up the fracture depends on yield stress of gel in the fracture and filter cake, depth of invasion of fracture fluid and magnitude of the capillary pressure. Low reservoir pressure does not provide enough flow for gas to displace fracture fluid from formation (Tianping 2012) while higher initial reservoir pressures provide more energy to flow back the fracture fluid filtrate and overcome gel damage inside the fracture (Wang 2009).

The practice of producing a well at high rates after hydraulic fracture treatment could lead to a decrease in fracture conductivity resulting from excessive closure stresses applied to the proppants (Sherman 1991). When excessive fracture closure stresses are applied to proppants it crushes the proppants, generating fines which can migrate within the fracture and reduce proppant pack porosity and permeability (Weaver, 2008). Proppant fines could also travel towards the well bore and accumulate to reduce the proppant pack flow capacity even more. Coulter (1972) reported that just 5% proppant fines reduce proppant pack conductivity by as much as 62% while Lacy (1997) concluded that 5% proppant fines could cause conductivity reduction of up to 54%.

High capillary pressures in low permeability reservoirs like Marcellus shale make the effect of water retention resulting from imbibition an important factor (Holditch 1979). Imbibition helps to reduce water saturation at areas closest to the fracture face by allowing the fracture fluid penetrate deeper into the formation leading to faster fracture fluid clean up (Li, 2007). As water saturation reduces along the fracture face, gas saturation and relative permeability to gas increases resulting in higher gas flow rates. Gdanski (2007) concluded that if water is able to imbibe deep into the formation and production drawdown is able to overcome capillary pressures, well productivity should not be affected by fracture fluid leakoff.

Chapter 3

Problem Statement

Hydraulic fracture treatment has been successfully used to improve gas production rate in Marcellus shale reservoirs but production data shows that gas rates are less than expected. The objective of this research is to evaluate the extent of reduction in gas productivity caused by multi-phase flow, capillary pressure, shut-in time and proppant crushing in fractured Marcellus wells.

The objective is achieved by simulating hydraulic fracture treatment using a 2-phase 2-dimensional gas water reservoir model developed using a commercial software. Initially, gas was produced from a single phase reservoir as the base case upon which the factors been evaluated will be added. Long term gas production was simulated by producing the well for twenty years. Multi-phase flow was then introduced by injecting fracture fluid into the well and the twenty year gas production was compared to the base case (single phase). In the multi-phase flow case we assumed an ideal situation with low capillary pressure in the formation. Effect of capillary pressure was simulated by adding capillary pressure curve to the multi-phase case. We then simulated the effect of shut-in time by shutting in the well for varied durations of time starting with the base case (no shut-in).

Chapter 4

Mechanism

In this section, we discussed the base model and mechanisms of four factors that affect gas production in fractured Marcellus wells. The factors discussed are multi-phase flow, capillary pressure, shut in time and proppant crushing.

4.1 Ideal Single Phase Flow (Base Case)

The effect of possible damage factors on fractured Marcellus Shale wells was evaluated by starting with an ideal single phase gas well. This single phase gas well was assumed to have propped hydraulic fractures in place. Two different proppant types were used in this work; they are 20/40 ceramics proppants and 100 mesh sand. This ideal single phase model is used as the basis for evaluating the effects of the different damage factors. The volume of gas produced from the single phase gas well represents the volume of gas that can be produced without the effects of the factors being studied.

4.2 Multi-Phase Flow

Multi-phase flow is the flow of more than one phase in the porous media. When a single phase (oil) is found in a reservoir, the permeability of the formation to the oil is the absolute permeability of the formation. The introduction of a second phase (fracture fluid) in the formation leads to a decrease in permeability of the formation to the oil. Relative permeability is the ratio of effective permeability of a particular fluid to the base permeability of the rock. Relative permeability of a phase increases with its saturation in porous media. The sum of relative permeability in a multi-phase system is usually less than one. Multi-phase flow lowers the flow capacity of the formation.

For a hydraulically fractured dry gas well, the introduction of fracture fluid could reduce the permeability of the rock formation to gas. As fracture fluid leaks off into the formation, it displaces gas further into the formation. This increases fracture fluid saturation in the near wellbore region while gas saturation decreases. This implies that relative permeability of fracture fluid in the near wellbore region increases while that of gas decreases. When the well is put on production, multi-phase flow may have an adverse effect on gas production. According to Ning (1995), the time to clean the well increases as absolute permeability damage increases at the invaded zone.

Multi-phase flow effect was evaluated in this study by fracture treating the well using fracture fluidf at high pressures. For ease of injection into the formation, we used a hydraulic fracture permeability of one million millidarcy in the model during injection while during the production stage we used the actual hydraulic fracture permeability based on the proppant type in the fracture.

Two relative permeability curves obtained from work done by Cluff (2010) on tight gas sandstone reservoirs was used for matrix. These relative permeability curves were chosen because they are for core samples with about the same matrix permeability (0.0001mD) as we used in our model. The relative permeability curves were generated using some equations. Gas relative permeability curve was generated using modified Corey equation (1954) as shown below.

$$krg = [1 - \frac{sw - swc}{1 - sgc - swc}]^p [1 - (\frac{sw - swc}{1 - swc})^q]$$

Where k_{rg} is gas relative permeability,

s_w is water saturation, fraction

s_{wc} is critical water saturation, fraction

s_{gc} is critical gas saturation, fraction

p and q are exponents

Water relative permeability was generated using the Corey wetting-phase equation given below

$$krw = \left[\frac{sw - swc}{1 - swc}\right]^r \left(\frac{kw}{kik}\right)$$

Where $k_w = k_{ik}^{1.32}$

k_{rw} is water relative permeability, mD

s_w is water saturation, fraction

s_{wc} is critical water saturation, fraction

k_w is water permeability, mD

k_{ik} is Klinkenberg gas permeability, mD

We used an x-shaped relative permeability curve for the fractures. The relative permeability curves are given in the figures below:

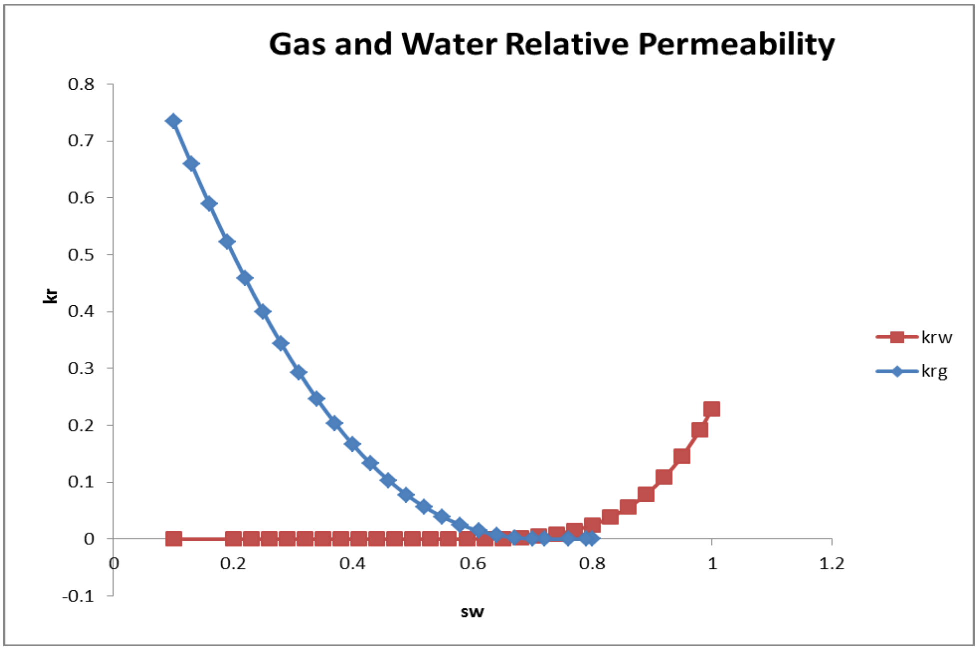

Figure 4-1: Matrix Relative Permeability, kr1 (Cluff, 2010)

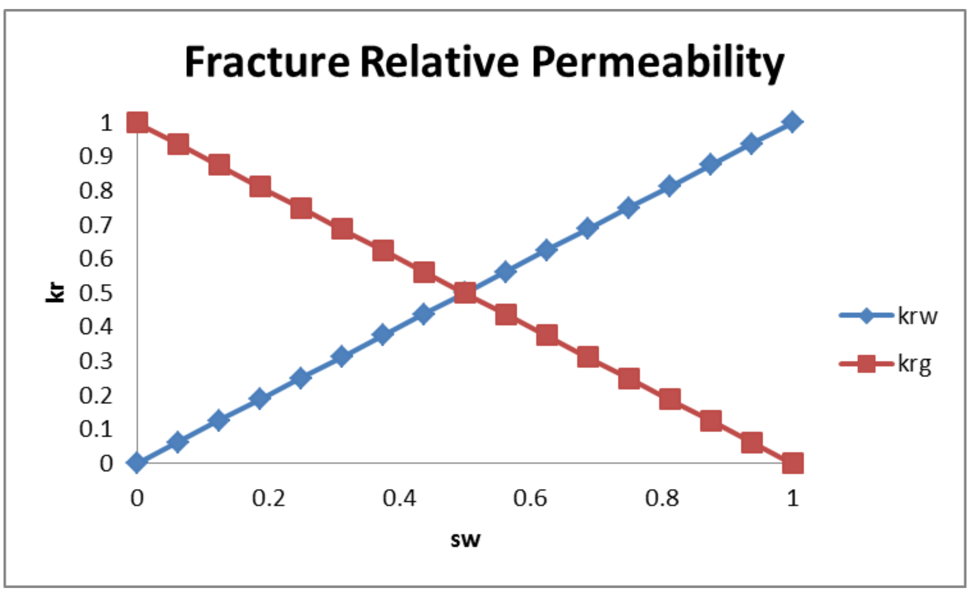

Figure 4-2: Fracture Relative Permeability, kr2

4.3 Capillary Pressure

Capillary pressure can be defined as the pressure difference between a non-wetting phase and a wetting phase as a function of saturation of the wetting phase. Naturally occurring rocks are usually water wet. A formation could also be considered as oil wet when oil displaces water during oil migration. Marcellus shale formation is slightly water wet (Engelder, 2013)

Under static conditions, capillary pressure, pc, is said to be proportional to the interfacial tension, σ, existing between two immiscible fluids, inversely proportional to the radius, r, of the capillary and also dependent on the wetting angle. Mathematically,

$$pc = \frac{2\sigma cos\theta}{r}$$

Marcellus shale formation has characteristic small pore radii which results in high capillary pressures. During hydraulic fracture treatment, fracture fluid leaks off into the formation by displacing gas in the formation resulting in high saturation of the fracture fluid around the fracture face. The high capillary pressure in the formation requires a high pressure drawdown to overcome the capillary pressure before the fluid can be produced. If the gas pressure does not exceed high capillary pressure in the vicinity of the fracture it will lead to water blockage (Holditch 1979, Ning 1995, Cheng 2011 and Tianping 2012). High capillary pressures make fracture fluid clean up difficult especially in low pressure formations (Soliman 1985, Tianping 2012).

To evaluate the effect of capillary pressure on fracture fluid recovery and long-term gas production, we included matrix capillary pressure to the multi-phase case. We generated capillary pressure curve for our matrix by using an equation for capillary pressure derived by combining capillary pressure function and J-function (Gdanski et al, 2006). The equation is given below:

$$pc = \frac{\sigma}{a2(sw)^{a1}}(\frac{\emptyset}{k})^{a3}$$

Where pc is capillary pressure, psi; σ is interfacial tension, dynes/cm; ø is porosity, fraction; k is matrix permeability, mD; sw is water saturation, fraction and a1, a2, a3 are adjustable constants.

We used a surface tension of 70 dynes/cm, a1 = 1.86, a2 = 6.42 and a3 = 0.50, porosity of 0.08 and matrix permeability of 0.0001mD for Marcellus shale. The figure below gives the capillary pressure plot used in our model:

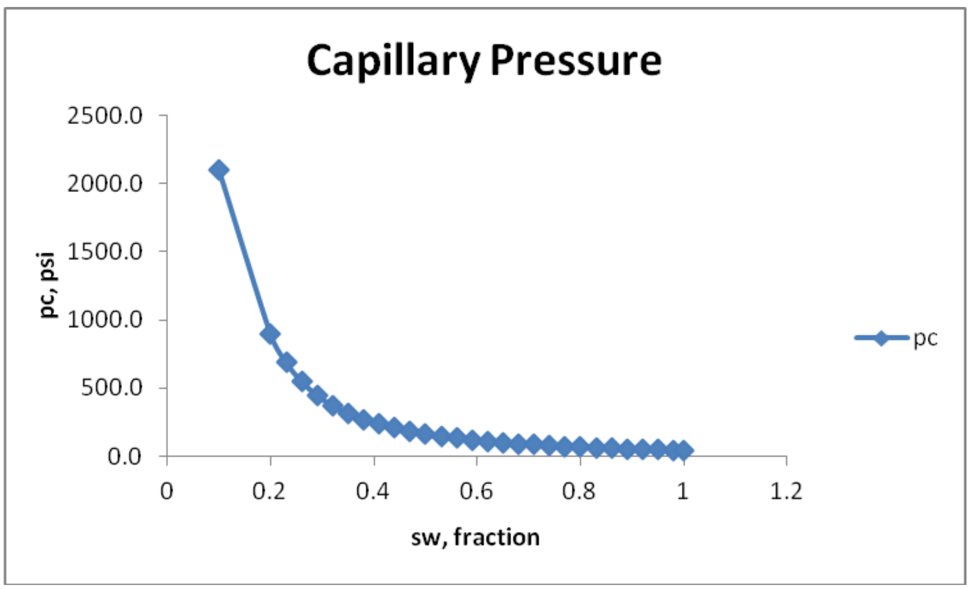

Figure 4-3: Matrix capillary pressure curve (Gdanski et al, 2006).

4.4 Shut in Time

The duration of shut in time after a hydraulic fracture treatment could have a significant effect on fracture fluid retention around the fracture after the treatment. This could have an effect on gas production after treatment. When pumping has stopped at the end of hydraulic fracture treatment, fracture fluid imbibes further into the Marcellus formation. The longer the duration of shut in, the deeper fracture fluid penetrates into the formation leading to further spreading of the fracture fluid in the formation.

In the industry, it is cheaper to complete all the fracture stages before the well is flowed back since rig time is expensive. Some people in the industry believe that waiting for all the fracture stages to be complete before flowing back could lead to the fracture fluid penetrating deeper into the formation in the early stages which will lead to longer time required to clean up the well. They believe it will have an adverse effect on long term gas production.

On the other hand, research has shown that imbibition helps to reduce water saturation at areas closest to the fracture face by allowing the fracture fluid penetrate deeper into the formation leading to faster fracture fluid clean up (Li, 2007). Reduction of fracture fluid saturation around the fracture face leads to increase in gas saturation.

Effect of shut in time was evaluated in this study by shutting in the well for durations of one week, two weeks and one year before being put on production.

4.5 Proppant Crushing

Proppants are used in hydraulic fracturing treatment to keep the fracture open. Proppants retain a conductive pathway to the wellbore after the fluid injection is stopped and fluid pressure has dropped below that required to keep the fracture open. Proppants help to retain the fracture permeability and porosity created at the end of treatment. During fracture closure, the stress transmitted from the earth to the proppants causes crushing of the proppants, reducing particle size and increasing surface area of the proppants both of which reduce the permeability of the propped fracture (Gidley 1989). Proppant fines cause a major degradation of conductivity of the proppant pack. The conductivity of the proppant pack can be further reduced by compacting effect of overburden stress on the particle bed which reduces proppant pack porosity. Coulter et al (1972) conclude that 5% proppant fines decrease conductivity by 62% while Lacy et al (1997) conclude that 5% fines decrease conductivity by 54%. Proppant fines can migrate towards the wellbore, accumulate and decrease proppant pack flow capacity.

The practice of producing a well at a high rate after hydraulic fracture treatment could lead to a decrease in fracture conductivity resulting from excessive closure stresses applied to the proppants (Sherman 1991). Excessive fracture closure stress could also lead to spalling of the formation rock which will produce fines large enough to plug the pores of the proppant pack. Osholake (2010) conclude that proppant crushing has the most impact on gas production compared to multiphase flow, proppant diagenesis and reservoir compaction.

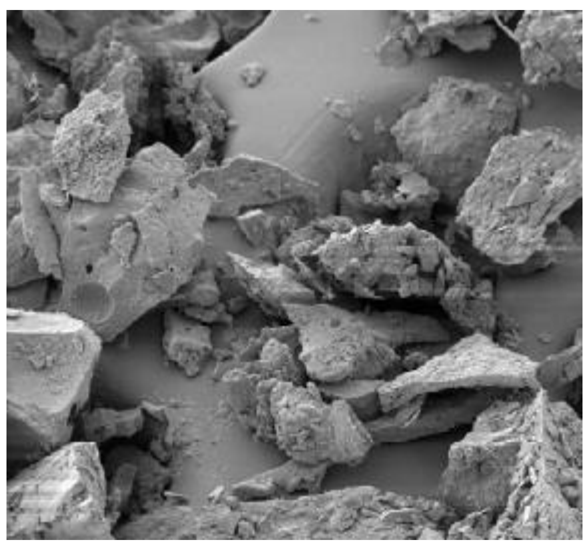

Figure 4-4: Scanning electron microscope photo of 40/80 light weight ceramics proppant after a wet, hot crush test

In order to select proppants of the right strength for a fracture treatment job, proppants are subject to API crush resistance test to determine the level of stress they can withstand. Figure

4-5 shows proppant fines generated during a proppant crush test while figure 4-6 shows proppant type selection based on closure stress.

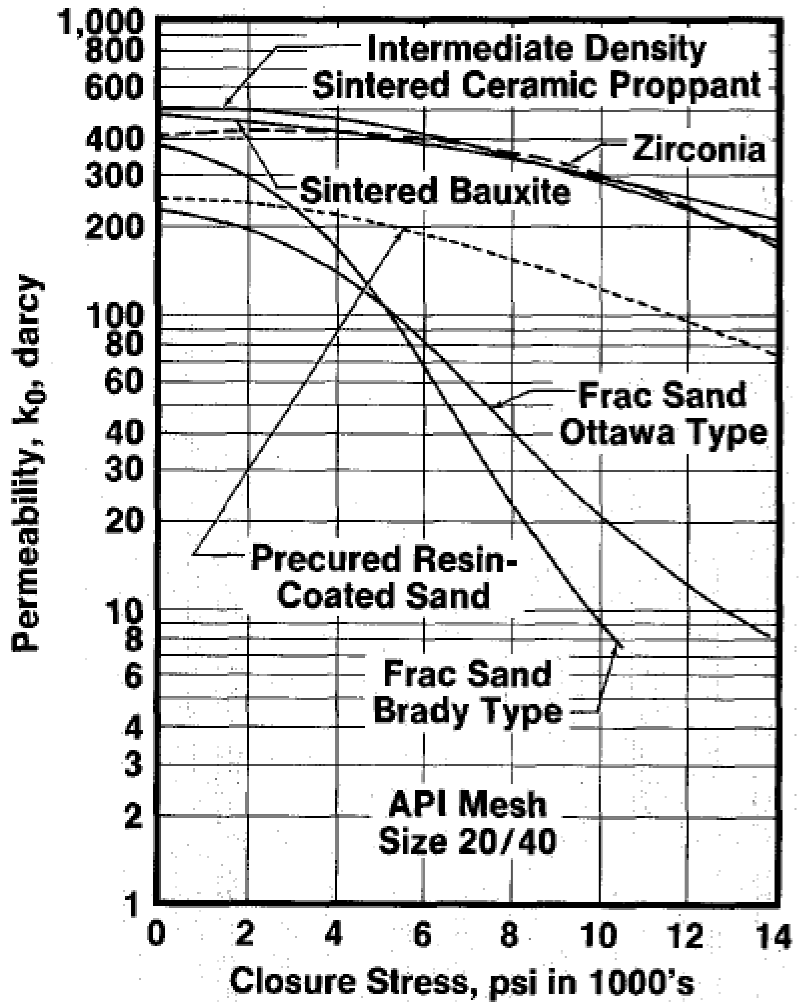

Figure 4-5: Effect of closure stress on permeability of various propping agents.

To evaluate the effect of proppant crushing on performance of fractured Marcellus wells, we used compaction model generated from API crush test data. The tables below show the compaction model for 20/40 ceramics proppant and 100 mesh sand.

Table 4-1: Compaction model for 20/40 Ceramics proppant

Pressure, psi	Porosity multiplier	Conductivity multiplier
14.7	1.0	0.87
1000	1.0	0.47
2000	1.0	0.40
3000	1.0	0.38
4000	1.0	0.31
6000	1.0	0.19

Table 4-2: Compaction model for 100 mesh sand

Pressure, psi	Porosity Multiplier	Conductivity multiplier
14.7	1.0	0.85
1000	1.0	0.24
2000	1.0	0.19
4000	1.0	0.11
6000	1.0	0.06

Chapter 5

Model Description

Reservoir properties and hydraulic fracture network configurations used for the study were explained in this chapter.

Hydraulic fracture treatment process was simulated using a 2-d, 2-phase water-gas reservoir model with local grid refinement. The model was developed using commercial software. To effectively evaluate the effects of the factors affecting gas production from fractured Marcellus wells, we started with a single phase gas reservoir as base model and subsequently added the effects of multi-phase flow, capillary pressure, shut in time and proppant crushing as we went on. This work is a continuation of Yue's (2012) thesis so her base models were used as starting point.

Reservoir Properties

The reservoir employed in this research work has a drainage area of 80 acre but due to symmetry only a quarter of the reservoir was represented in the model. This means fracture fluid and gas production obtained are only a quarter of their actual values. The reservoir was assumed to be homogeneous and isotropic. It was also assumed to contain mainly gas while oil and water saturations were assumed to be zero.

The reservoir properties used for these models are shown in Table 5-1.

Table 5-1: Reservoir Properties.

Properties	Values
Drainage Area (acres)	80
Formation Thickness (ft)	300
Formation Depth (ft)	5000
Reservoir Pressure (psia)	3500
Reservoir Temperature (F)	130
FBHP (psia)	1000
Wellbore Radius (ft)	0.125
Matrix Permeability (md)	0.0001
Natural Fracture permeability (md)	0.4793
Initial Water Saturation	0.1
Oil Saturation	0
Matrix Porosity	0.08
Natural Fracture Porosity	0.1
Hydraulic Fracture Porosity	0.03

Proppants

20/40 Ceramics proppant and 100 mesh sand were used in this study. Properties for 20/40 Ceramics proppant were obtained from the Carbo-ceramics website while properties for 100 mesh sand were obtained from StimLab website. Proppants were assumed to be evenly distributed throughout the hydraulic fracture network and all hydraulic fractures were assumed to be propped. Proppant conductivity used was at minimal closure stress.

Table below shows proppant type and proppant conductivity

Table 3-2: Proppant Conductivity.

Proppant Type	Proppant Pack Conductivity (mD-ft)
20/40 ceramics proppant	12500
100 mesh sand	852

Grid Blocks and Local Refinement

Figure 5-1 shows a diagram of one quarter of the reservoir used for this research. The reservoir has 16 grid blocks in the x-direction, 9 grid blocks in the y-direction and one grid block in the z-direction. The well is located in block 1, 1, 1, which is the block on the top left hand corner as shown in the diagram. The well block has dimensions of 0.2 ft in the x and y-directions and 300 ft in the z direction. The remaining 15 blocks in the x direction have dimensions of 88 ft and the remaining 8 blocks in the y direction have dimensions of 88 ft. All blocks have dimension of 300 ft in the z-direction. In total there are 144 grid blocks at a depth of 5000 ft from the surface.

The grid blocks were locally refined to effectively capture pressure and saturation changes around the fractures and well bore. Moving from left to right in the x direction, the first grid blocks were non-uniformly refined into 50 blocks in the y direction. Moving from top to bottom in y direction, the topmost grid blocks were refined into 50 grid blocks in the x direction. The remaining grid blocks were non-uniformly refined into 50 locally refined blocks in x direction and 50 locally refined blocks in y direction giving a total of 2500 locally refined block in a parent grid block. No local grid refinement was done in the z direction. The pattern of local refinement in feet is given below:

0.8, 3.5, 3.5, 0.8, 0.2, 0.8, 3.5, 3.5, 0.8, 0.2 ……

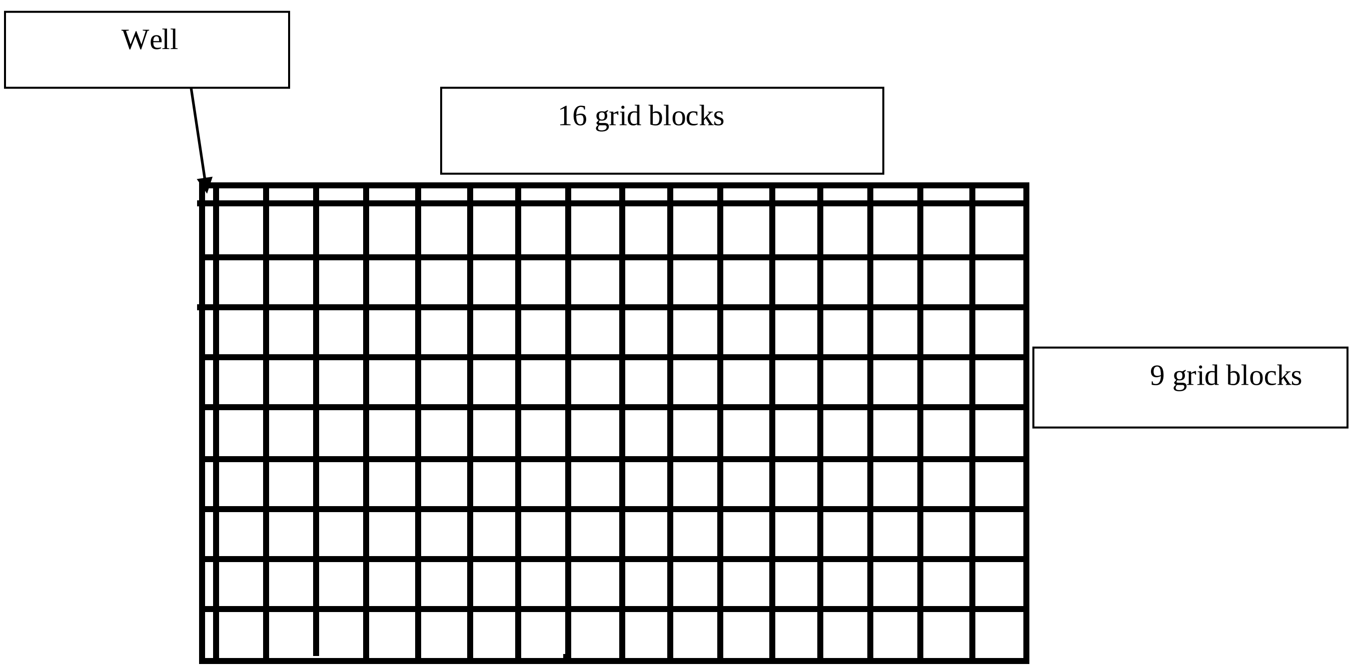

Figure 5-1: Diagram of reservoir grids.

Well and Fracture Blocks

A vertical well of radius 0.125ft is located in block 1:1:1 which is the first block on the top left hand corner. The well block has dimensions of 0.2 ft in x, 0.2 ft in y directions and 300 ft in z direction.

In our model, blocks of 0.2 ft represent natural fractures and blocks of 0.8ft and 3.5ft represent matrix. Hydraulic fractures have the same dimensions as natural fractures but have different permeability and porosity. Natural fractures were 8.8ft apart.

Descriptions of our different hydraulic fracture networks are given in the next section.

Hydraulic Fracture 1 (HF1)

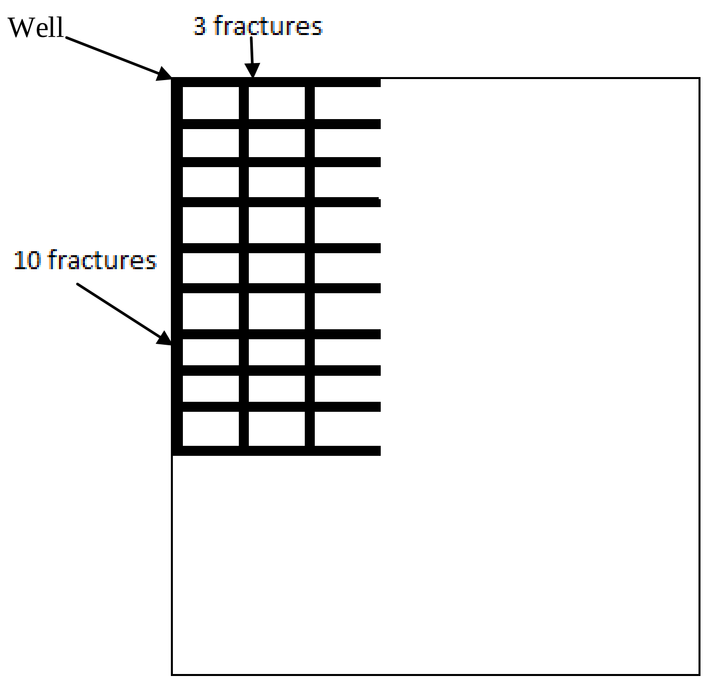

Figure 5-2: Diagram of HF1.

Figure 5-2 represents the hydraulic fracture network 1 (HF1). The diagram is not drawn to scale. HF1 is a 3x10 hydraulic fracture network with propped fracture length (L1) of 528 ft. It has 3 hydraulic fractures in the x-direction and 10 hydraulic fractures in the y-direction as shown in Figure 4-3. Width (W1) and height of the fracture are 0.2 ft and 300 ft respectively. This fracture network represents the smallest fracture network used in this study.

Volume of propped fracture (V) = 528ft x 0.2ft x 300ft = 31680 ft3

Hydraulic fracture permeability of 65500 mD was obtained using the conductivity of 20/40 Ceramics proppant.

Hydraulic Fracture 2 (HF2)

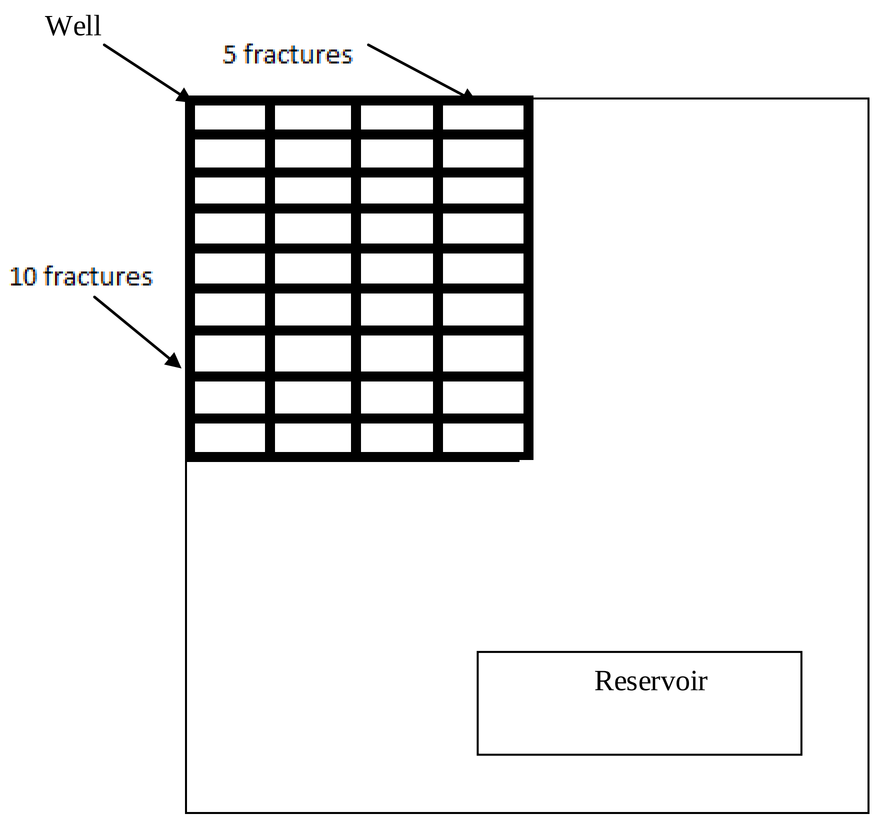

Figure 5-3: Diagram of HF2.

Figure 5-3 represents the hydraulic fracture network 2 (HF2). HF2 is a 5x10 hydraulic fracture network with a propped fracture length (L2) of 738 ft. HF2 has 5 hydraulic fractures in x direction and 10 hydraulic fractures in y direction. It is a larger network than HF1.

Volume of propped fracture (31680 ft^3) was the same in HF1, HF2 and HF3.

With a fracture height (H2) of 300 ft, propped width of hydraulic fracture (W2) is given as:

$$W2 = \frac{V}{H2 * L2} = \frac{31680\ ft3}{738.0ft * 300ft} = 0.1430ft$$

Hydraulic fracture permeability (kf2) for HF2 is given as 65500 mD based on 20/40 ceramics proppants. With hydraulic fracture permeability of 65500 mD and width of 0.142 ft, hydraulic fracture conductivity is obtained as 9301 mD-ft. In order to minimize the time required to run this model, we maintained fracture width of 0.2 ft instead of 0.142 ft. Fracture conductivity of HF2 was maintained by calculating corresponding fracture permeability.

$$kf2 = \frac{65500md * 0.142ft}{0.2ft} = 46505md$$

Hydraulic fracture permeability of 46505 mD and width of 0.2 ft were used which gives a fracture conductivity of 9301 mD-ft.

Hydraulic Fracture 3 (HF3)

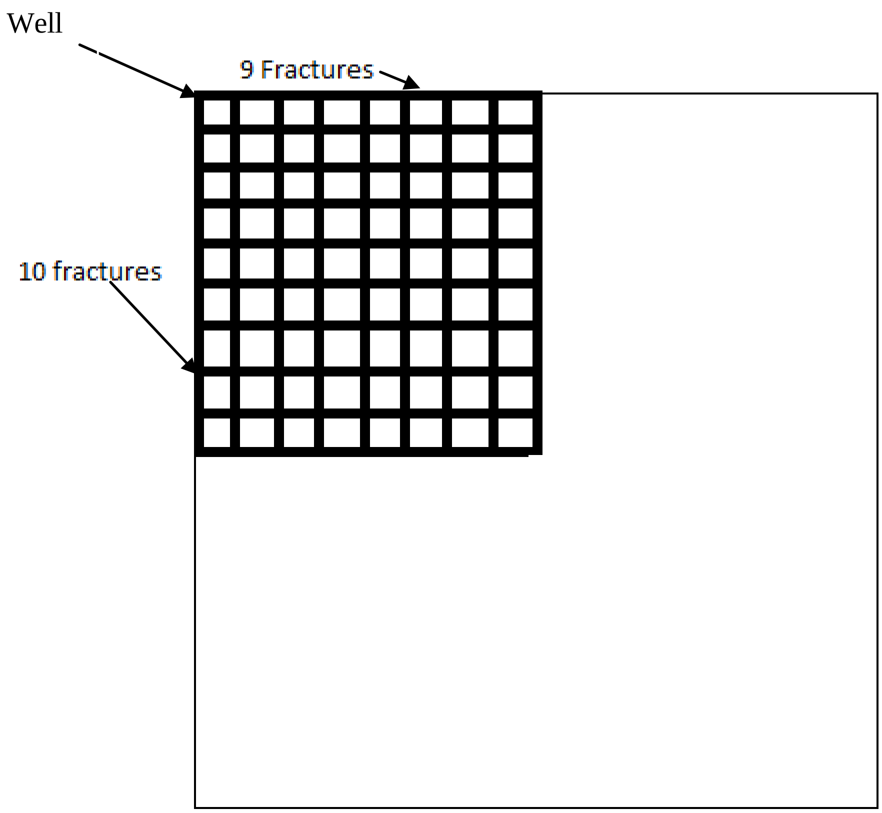

Figure 5-4: Diagram of HF3.

HF3 is a 9x10 hydraulic fracture network with a propped fracture length (L3) of 1398.8 ft and a height (H3) of 300ft. HF3 has 9 hydraulic fractures in x direction and 10 hydraulic fractures in y direction as shown in figure 5-4. By using a propped fracture volume of 31680 ft3, fracture width (W3) is calculated as:

$$W3 = \frac{V}{H3 * L3} = \frac{31680\ ft3}{1398.8ft * 300ft} = 0.0754ft$$

In order to minimize simulation run time, we used a hydraulic fracture width of 0.2 ft for the model instead of 0.0754 ft. Fracture permeability based on 20/40 ceramics proppant was

65500 mD. Since we are changing hydraulic fracture width from 0.0754 ft to 0.2 ft, corresponding hydraulic fracture permeability is calculated to maintain fracture conductivity.

Corresponding hydraulic fracture permeability (kf3) will be calculated as follows:

$$kf3 = \frac{65500md * 0.0754ft}{0.2ft} = 24724md$$

In summary, properties of the hydraulic fracture network described above are given in the table below:

Table 5-3: Properties of hydraulic fracture network

Properties	HF1	HF2	HF3
Fracture Length (ft)	528	738	1398
Fracture Width (ft)	0.20	0.143	0.075
SRV (ft^3) $*10^3$	697	836.4	1672.7
Propped Fracture Volume (ft^3)	31680	31680	31680

Table 5-3 shows hydraulic fracture network increasing in size from HF1 to HF3. Fracture length increased from 528ft in HF1 to 738ft in HF2 and 1398ft in HF3. It can be observed from the table that hydraulic fracture width decreases as the network size increases from HF1 to HF3. Propped fracture volume was maintained in all the networks at 31680ft^3 while fracture conductivity decreases as network size increases.

Table 5-4: Conductivity of fracture network using 20/40 Ceramics proppant

	Absolute conductivity (mD-ft)	Dimensionless conductivity, Cr
HF1	13,100	78,974
HF2	9,301	40,116
HF3	4,945	11,252

Table 5-4 shows the conductivity of fracture networks for 20/40 ceramics proppant. This shows fracture conductivity decreasing as we move from HF1 to HF3.

Table 5-5: Conductivity of fracture network using 100 mesh sand

	Absolute conductivity (mD-ft)	Dimensionless conductivity
HF1	470	2,833
HF2	334	1,022
HF3	176	150

Table 5-5 shows conductivity of fracture networks for 100 mesh sand. This also shows fracture conductivity decreasing as we move from HF1 to HF3.

Chapter 6

Result and Analysis

In this research, the effects of multi-phase flow, capillary pressure, shut-in time and proppant crushing on performance of fractured Marcellus shale wells were simulated using a 2-dimensional, 2-phase gas water reservoir model. This was accomplished by developing hydraulic fractures with different network sizes, HF1, HF2, and HF3 as described in chapter 4. The hydraulic fracture treatment process was simulated by injecting fracture fluid into the well for six days at a maximum flow rate of 450 barrels/day and at a maximum injection pressure of 8,000 psi. Total volume of fracture fluid injected into the well was 2250 barrels. A given volume of fracture fluid was injected into the well so as to maintain the same propped fracture volume in all the hydraulic fracture networks, HF1, HF2 and HF3. The well was then shut-in on the sixth day and put on production. Fracture fluid recovery and long-term gas production were simulated by producing the well for twenty years.

The effect of the various factors were evaluated by starting with a single phase gas well and then the effects of the factors were added one after the other. We first injected water to simulate the effect of multi-phase flow, we then added capillary pressures to the multi-phase case. Effect of shut-in was then evaluated by shutting the well using the case with capillary pressure. Finally we added the effect of proppant crushing to the shut-in case. It was done sequentially to have the combined effect of all the factors on gas production and fracture fluid recovery. The following sections give the results of the simulation.

6.1 Ideal Single Phase Flow

To evaluate the effect of damage factors on gas production in fractured Marcellus shale wells, we started by producing from a single phase gas well that has not been damaged. To effectively capture the ideal amount of gas that can be produced without damage, we assumed propped hydraulic fractures have been created in the well and that no fracture fluid was present in the fracture or matrix. 20/40 ceramics proppant and 100 mesh sand were used as propping agents for this research. We produced gas from the well for a period of twenty years. The results obtained are given below:

6.1.1 Ideal Single Phase Flow using 20/40 Ceramics Proppant

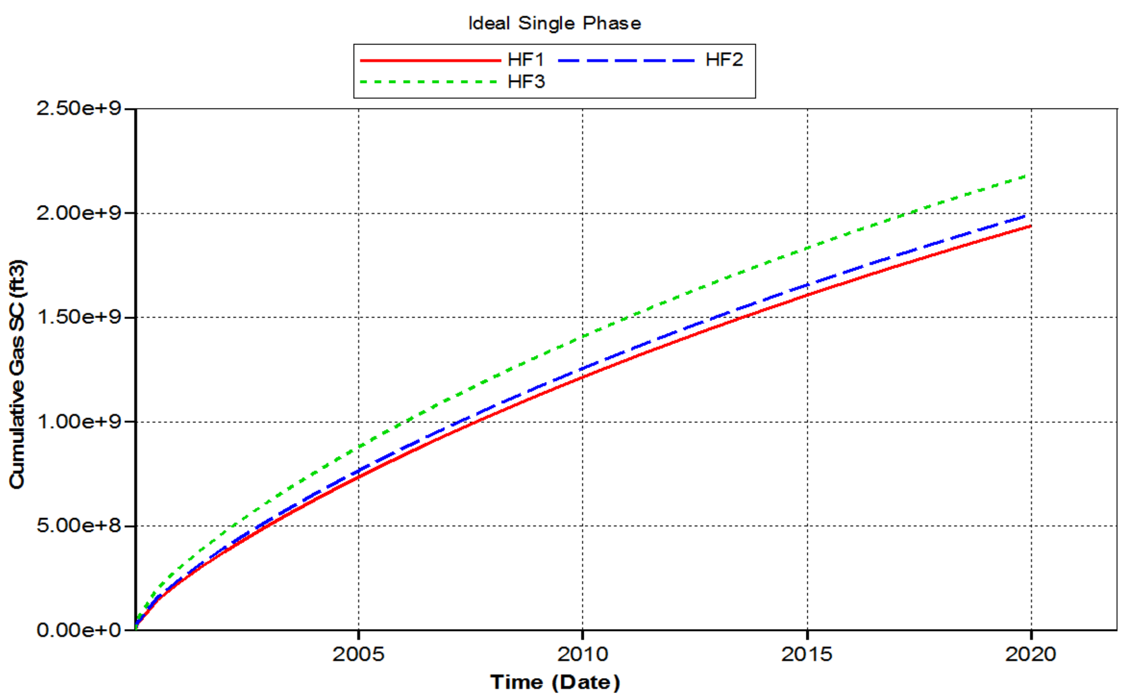

Figure 6-1: Cumulative gas production for ideal single phase reservoir using 20/40 ceramics proppant.

Table 6-1: Single phase 20-year cumulative gas production using 20/40 ceramics proppant

	Cumulative gas (BCF)
HF1	1.94
HF2	1.99
HF3	2.19

Twenty years cumulative gas production for ideal single phase is given in figure 6-1 and table 6-1. HF1 produced 1.94 BCF, HF2 produced 1.99 BCF and HF3 produced 2.19 BCF. HF1 produced the least amount of gas while HF3 produced the largest amount of gas. Cumulative gas production increased with increase in network size. It is worthy of note that HF1 has a higher fracture conductivity but produced the least amount of gas which could be due its small hydraulic fracture network compared to HF2 and HF3.

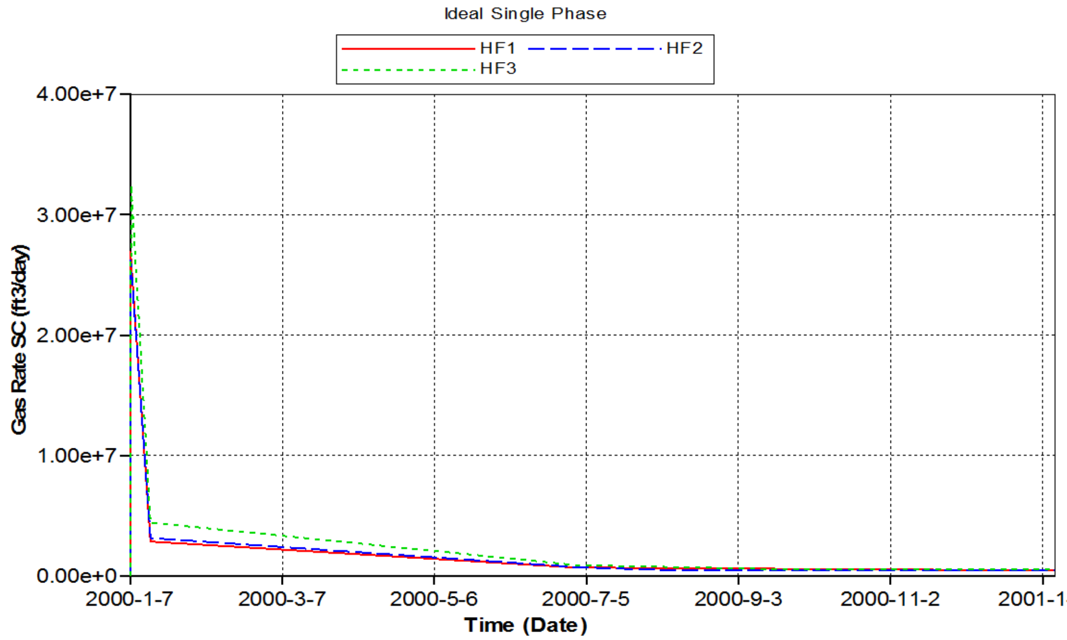

Figure 6-2: Gas production rate for ideal single phase reservoir (20/40 ceramics proppant)

Gas production rate for ideal single phase reservoir using 20/40 ceramics proppant is shown in figure 6-2. Initial gas production rate is higher for the larger fracture networks HF3 and HF2 compared to HF1. The difference in gas production rate is observed for the first year of production. This could be due to the volume of reservoir stimulated in each case which is higher for HF3 than HF2 while HF1 has the least reservoir stimulated volume. The higher cumulative production observed is due to the difference in gas production rate.

6.1.2 Ideal Single Phase Flow using 100 Mesh Sand

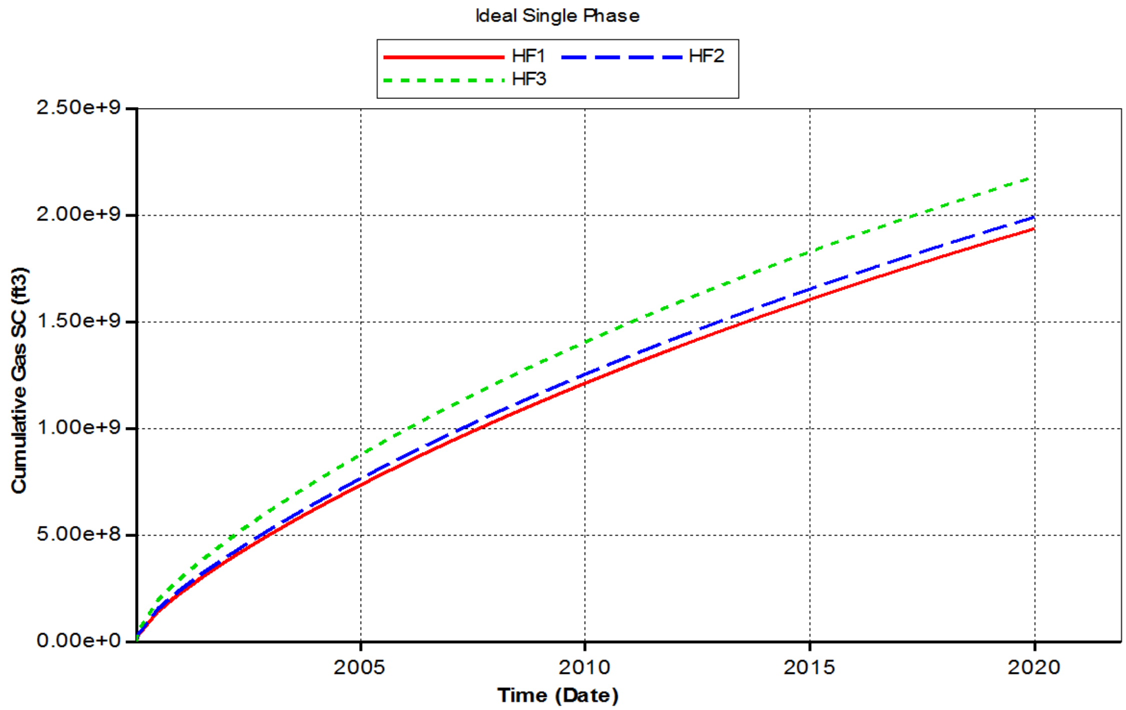

Figure 6-3: Cumulative gas production for ideal single phase reservoir using 100 mesh sand

Table 6-2: 20 years cumulative gas production using 100 mesh sand (Ideal single phase)

	Cumulative gas (BSF)
HF1	1.94
HF2	1.99
HF3	2.18

Figure 6.3 and table 6-2 represent cumulative gas production from an ideal single phase reservoir with 100 mesh sand as proppant. HF1 produced 1.94 BCF, HF2 produced 1.99 BCF and HF3 produced 2.18 BCF of gas. The higher production from HF3 and HF2 could be due to larger network size which resulted in greater stimulated reservoir volume.

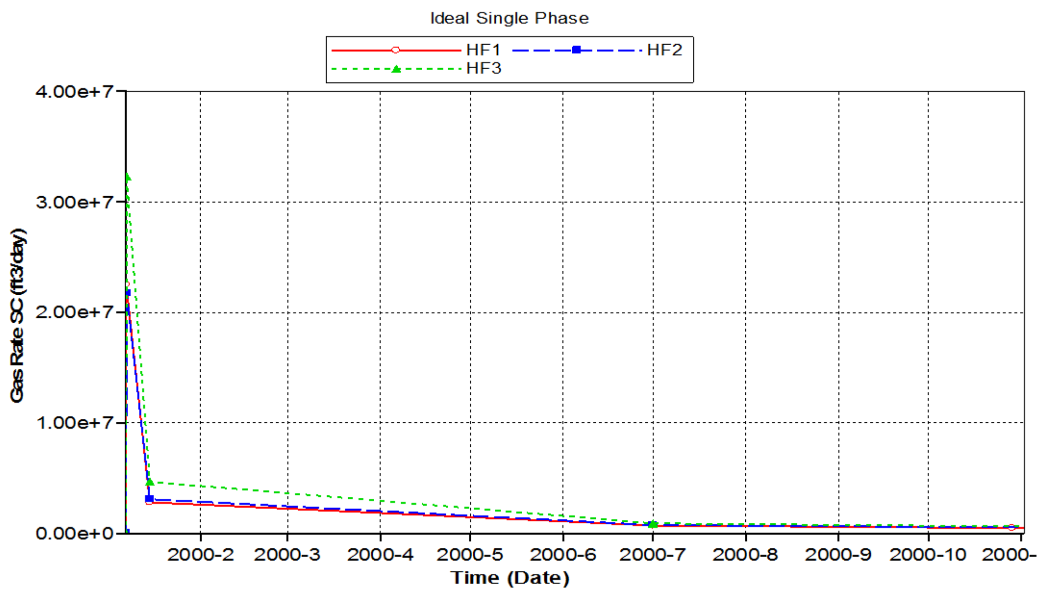

Figure 6-4: Gas production rate for ideal single phase reservoir (100 mesh sand)

Figure 6-4 represents the gas production rate from Ideal single phase flow using 100 mesh sand. The figure shows curves for gas rate for HF1, HF2 and HF3. Gas rate for HF3 was higher than HF2 and while HF2 was higher than HF1 for the first seven months of production. At the beginning of the seventh month of production, gas rate for HF1, HF2 and HF3 were about the same.

6.2 Effect of Multi-Phase Flow

To evaluate the effect of multi-phase flow, fracture fluid was injected into the single phase gas well in order to have two phase flow in the reservoir. The injection of fracture fluid represents the hydraulic fracture treatment process. The well is put on production right after treatment. Matrix relative permeability curve, kr1, and fracture relative permeability curve, kr2 were used; the curves can be found in figures 4-1 and figure 4-2 respectively. Two types of proppants (20/40 ceramics proppant and 100 mesh sand) were used.

6.2.1 Effect of Multi-phase flow using 20/40 Ceramics Proppant

In this section, 20/40 ceramics proppant was used to prop the hydraulic fractures. The following result were obtained

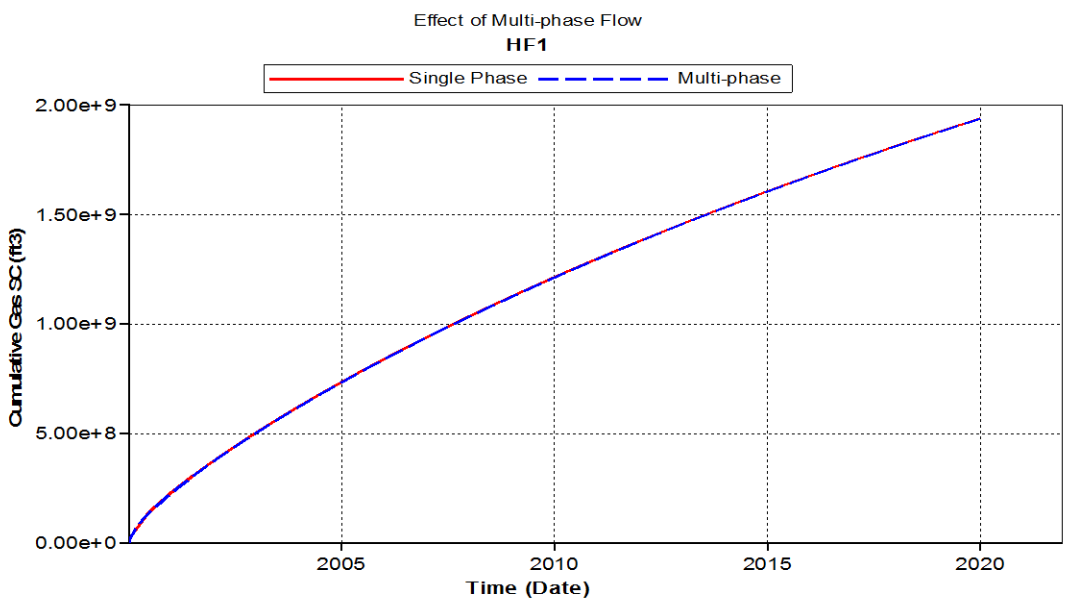

Figure 6-5: Effect of multi-phase flow on cumulative gas production in HF1 (20/40 ceramics proppant).

Figure 6-5 represents the effect of multi-phase flow on 20 years cumulative gas production in HF1. Cumulative gas production was 1.94 BCF for single phase and multi-phase flow. Cumulative gas production is observed to be unaffected by multi-phase flow using 20/40 ceramics proppant.

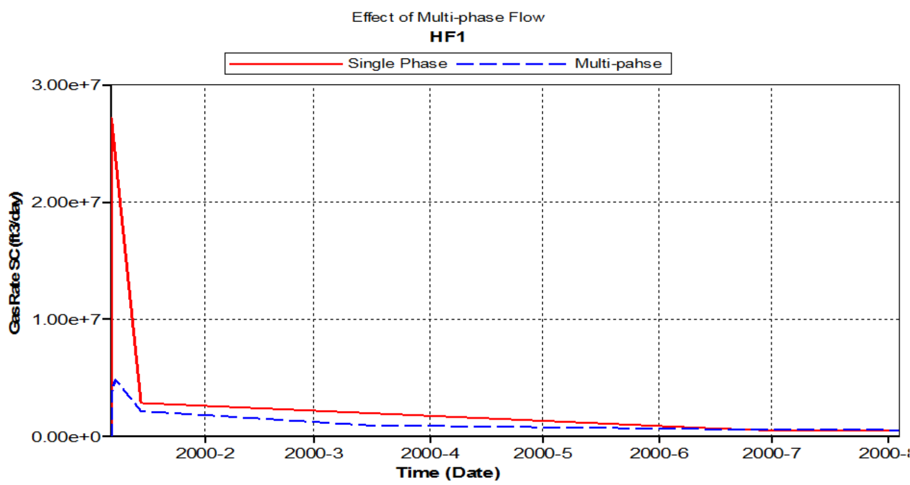

Figure 6-6: Effect of multi-phase flow on cumulative gas production in HF1 (20/40 ceramics proppant).

Figure 6-6 above shows the effect of multi-phase flow on gas production rate in HF1. From the figure above, ideal single phase has a higher gas production rate for the first seven months of gas production. Gas production rate is observed to be about the same throughout the remaining period of production.

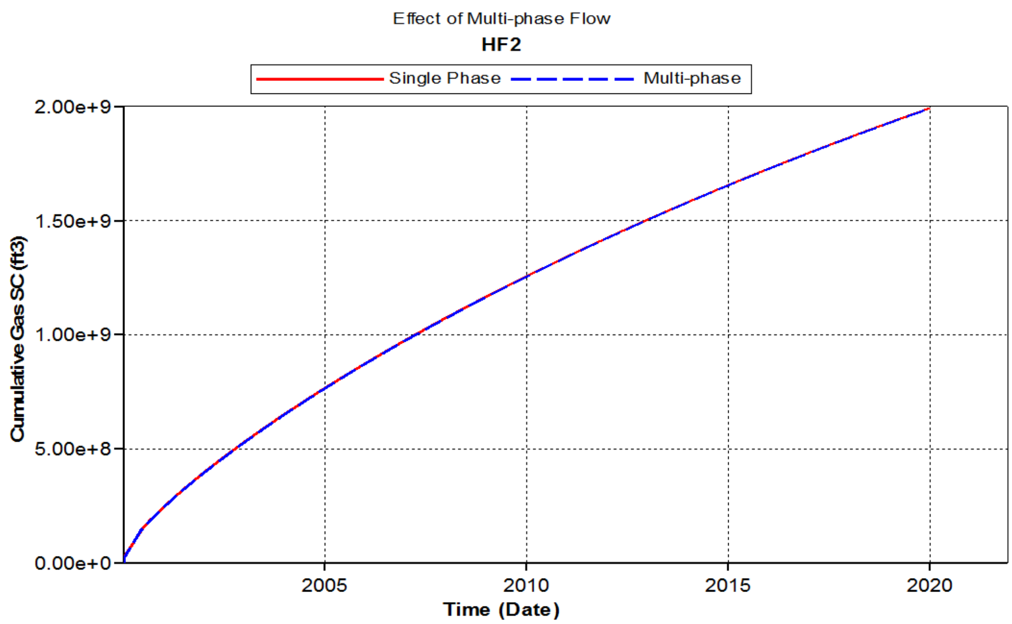

Figure 6-7: Effect of multi-phase flow on gas production in HF2 (20/40 ceramics proppant).

Figure 6-7 shows the effect of multi-phase flow on cumulative gas production in HF2. Cumulative gas production was 1.99 BCF for both ideal single phase and multi-phase flow. In HF2, cumulative gas production was observed to be unaffected by multi-phase flow using 20/40 ceramics proppant.

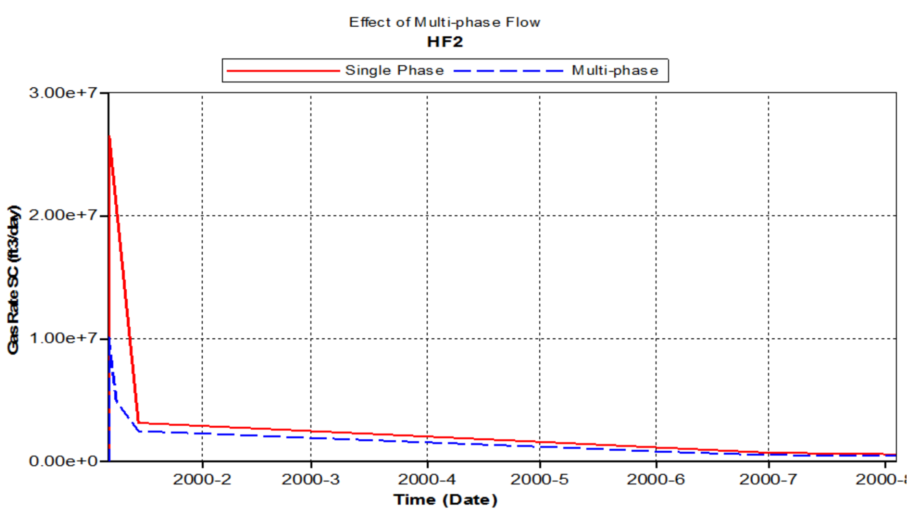

Figure 6-8: Effect of multi-phase flow on cumulative gas production in HF2 (20/40 ceramics proppant).

Figure 6-8 above represents the effect of multi-phase flow on gas production rate in HF2. During the first seven months of production, gas rate was observed to be higher for ideal single phase than multi-phase flow. Beyond the seventh month of production, gas rate was observed to be the same in single phase and multi-phase flow. The effect of multi-phase flow on gas production rate in HF2 was not significant.

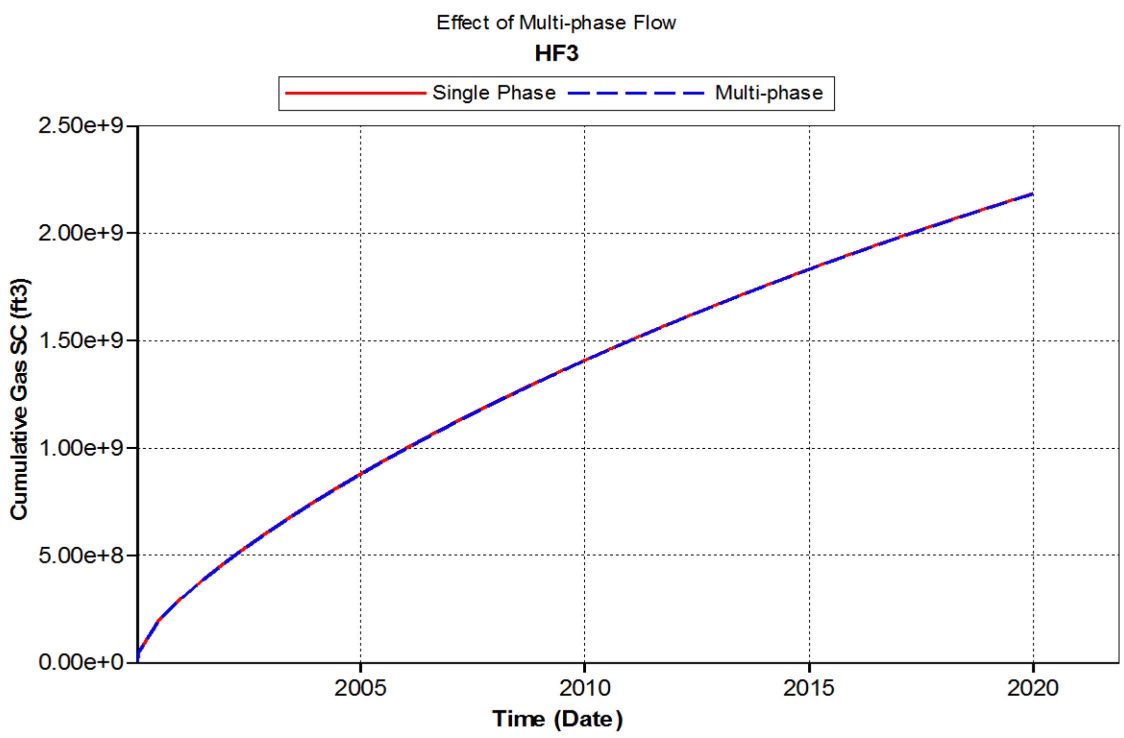

Figure 6-9: Effect of multi-phase flow on cumulative gas production in HF3 (20/40 ceramics proppant).

In figure 6-9 cumulative gas production was 2.19 BCF for ideal single phase and 2.18 BCF for multi-phase flow. After twenty years, gas production decreased by 7.13 MMSCF due to multi-phase flow. Cumulative gas production is largely unaffected by multi-phase flow using 20/40 ceramics proppant in HF3.

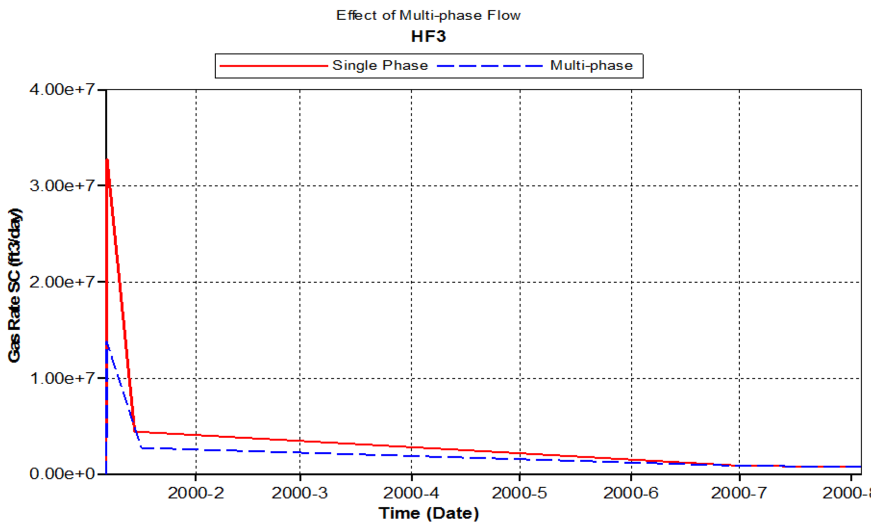

Figure 6-10: Effect of multi-phase flow on cumulative gas production in HF3 (20/40 ceramics proppant).

Figure 6-10 above shows the effect of multi-phase flow on gas production rate in HF3. Like we saw in figures 6-6 and 6-8, gas production rate was higher for single phase than for the multi-phase flow during the first seven months. But beyond the seventh month, gas rate was observed to be the same.

Table 6-3: Effect of Multi-phase flow on 20 years cumulative gas production using 20/40 ceramics proppant

	Single phase	Multi-phase
HF1	1.94	1.94
HF2	1.99	1.99
HF3	2.19	2.18

In summary, cumulative gas production was unaffected by multi-phase flow while using 20/40 ceramics proppant. In 20 years, single phase and multi-phase cumulative production was about the same for HF1 and HF2 and HF3. We also saw that multi-phase flow in the reservoir decreased gas production rate in the early stage of production beyond which gas rate was about the same in single phase and multi-phase flow in HF1, HF2 and HF3. The lack of effect of multi-phase flow could be due to high proppant pack conductivity of 20/40 ceramics proppant.

6.2.2 Effect of Multi-phase flow using 100 Mesh Sand

In this section, we used matrix relative permeability curve, kr1, and fracture relative permeability curve, kr2. We propped the hydraulic fractures with 100 mesh sand and production commenced without shutting in the well. When the well was produced for twenty years the following result were obtained.

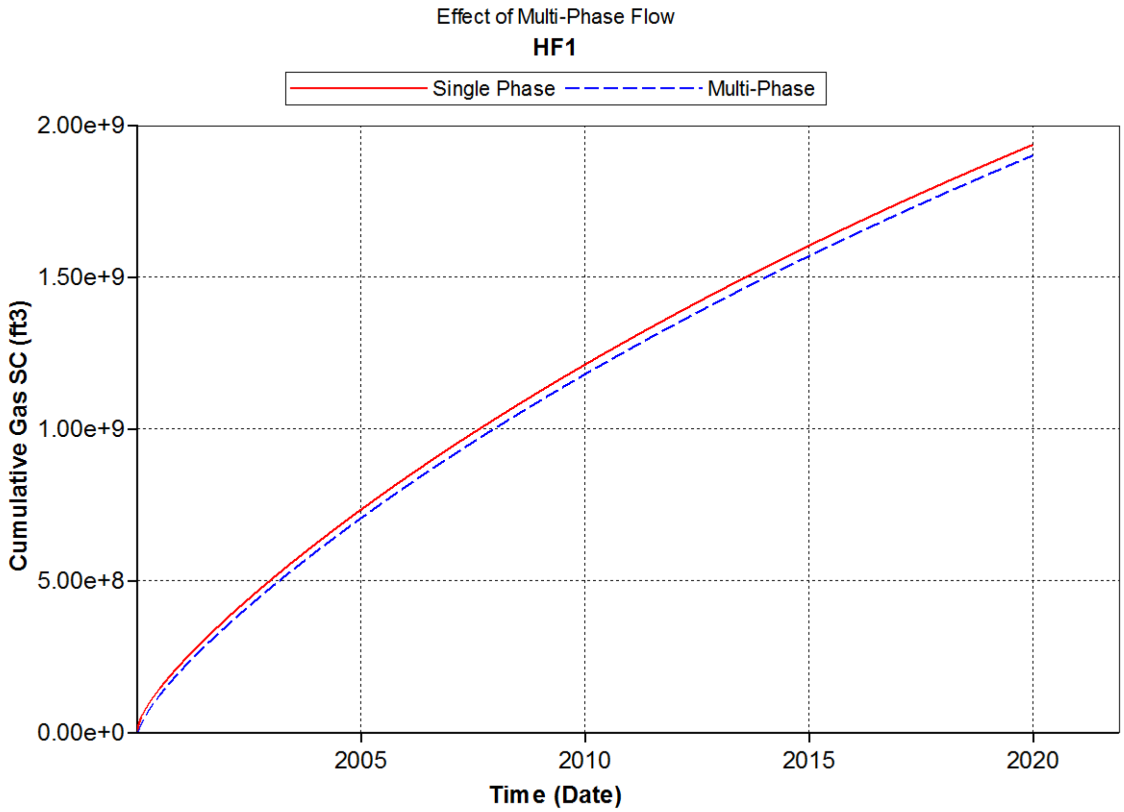

Figure 6-14: Effect of multi-phase flow on cumulative gas production in HF1 (100 mesh sand).

Figure 6-14 shows the effect of multi-phase flow on cumulative gas production from HF1 when 100 mesh sand was used to prop the hydraulic fractures. With ideal single phase, cumulative gas production for twenty years was 1.94 BCF while with multi-phase flow, gas production dropped to 1.90 BCF. Multi-phase flow in the reservoir caused a loss of 35.50 MMSCF (1.8%) of gas.

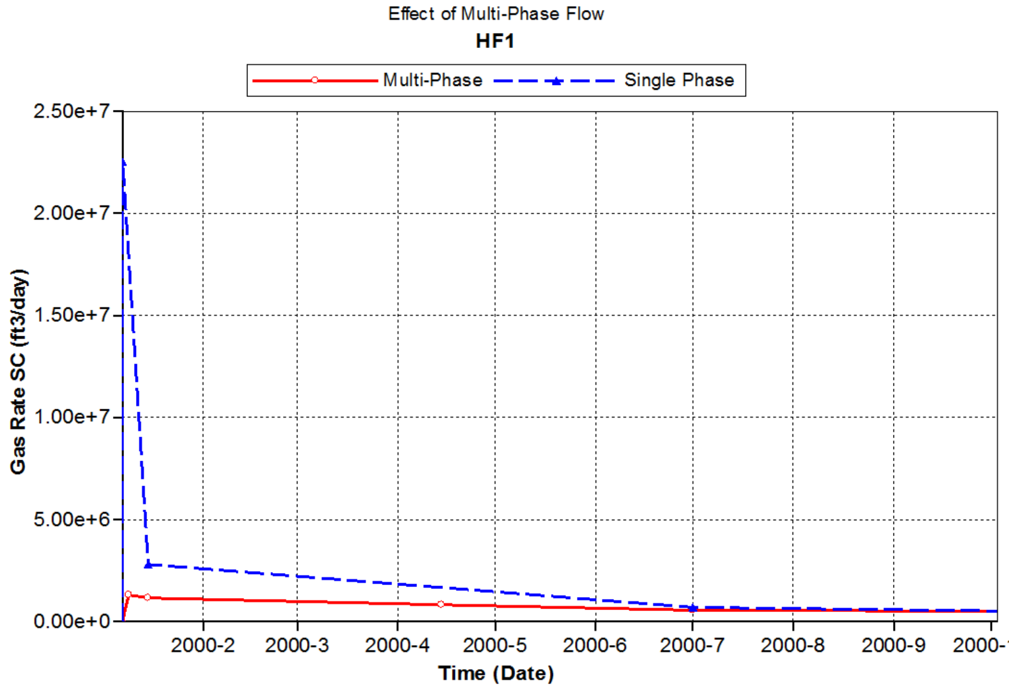

Figure 6-15: Effect of multi-phase flow on gas production rate in HF1 (100 mesh sand).

Figure 6-15 represents the effect of multi-phase flow on gas production rate in HF1. The figure captures gas production rate for the first ten months of a twenty year production period. Initial gas rate for single phase gas production was 22.52 MMSCFD while multi-phase flow had an initial gas rate of 1.31 MMSCFD. Gas rate was higher for single phase gas production for the first seven months of production than multi-phase flow. Gas rates were about the same for single and multi-phase flow after producing the well for ten months. The presence of multiple phases in the reservoir caused a decrease in gas production rate due to decrease in permeability to gas.

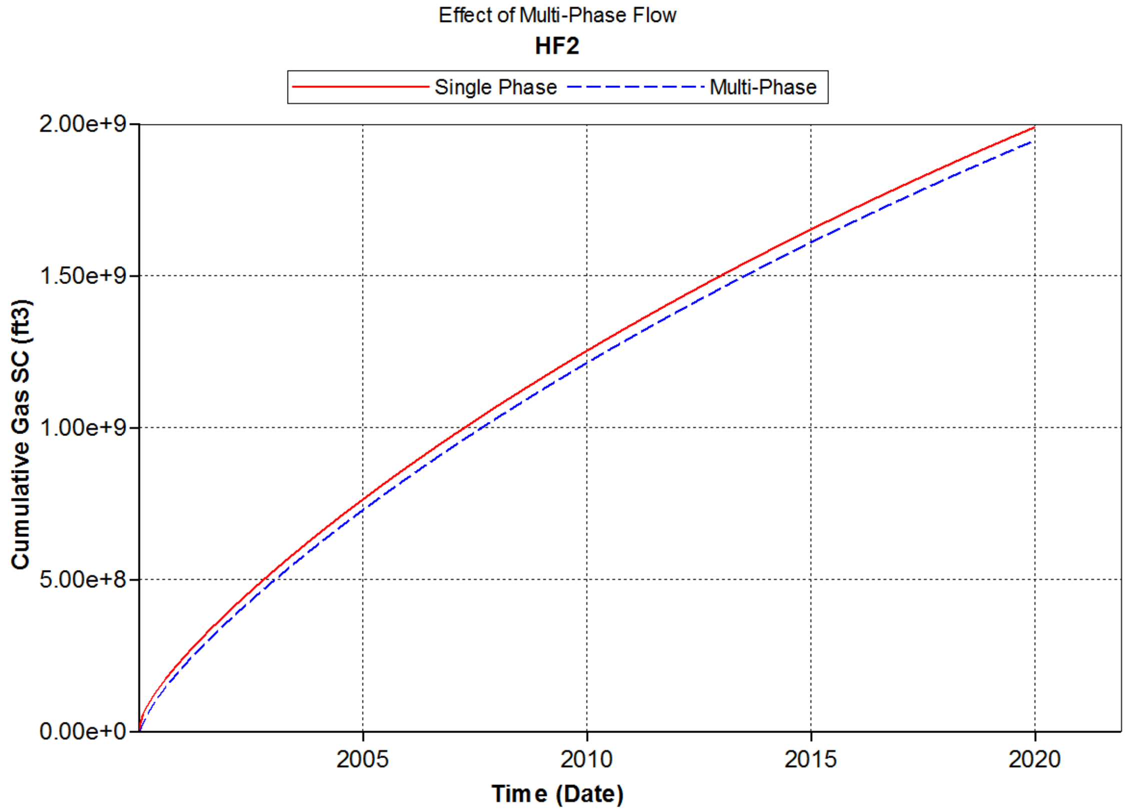

Figure 6-16: Effect of multi-phase flow on cumulative gas production in HF2 (100 mesh sand)

Effect of multi-phase flow on cumulative gas production for HF2 is represented in figure 6-16. HF2 is a larger hydraulic fracture network than HF1. 1.99 BCF of gas was produced from the single phase gas reservoir and with multi-phase flow in the reservoir, gas production was 1.95 BCF. The presence of a second phase in the reservoir decreased cumulative gas production by 43.90 MMSCF which is equal to a loss of 2.20 % in twenty years.

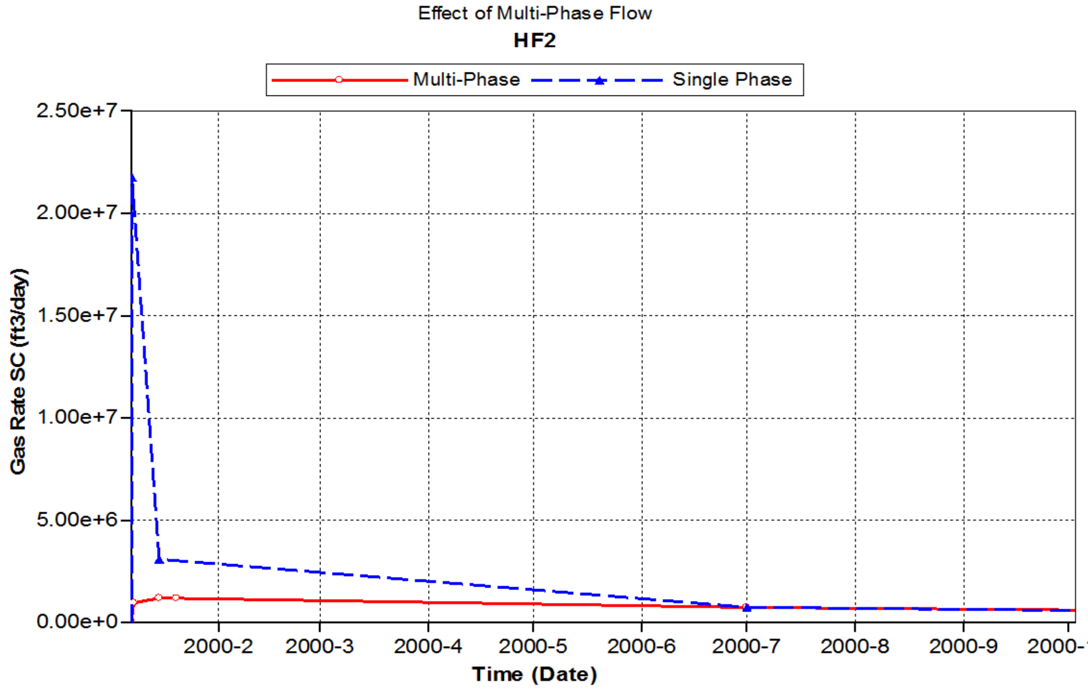

Figure 6-17: Effect of multi-phase flow on gas production rate in HF2 (100 mesh sand).

Effect of multi-phase flow on gas production rate in HF2 is shown in figure 6-17. In HF2, gas production rate was higher for single phase than multi-phase. At the start of production, gas rate was 22.61MMSCFD for single phase flow and 1.19 MMSCFD for multi-phase flow. A higher gas rate was maintained for single phase flow for the first seven months of production before both single and multi-phase flow rate became the same for the remaining duration of production.

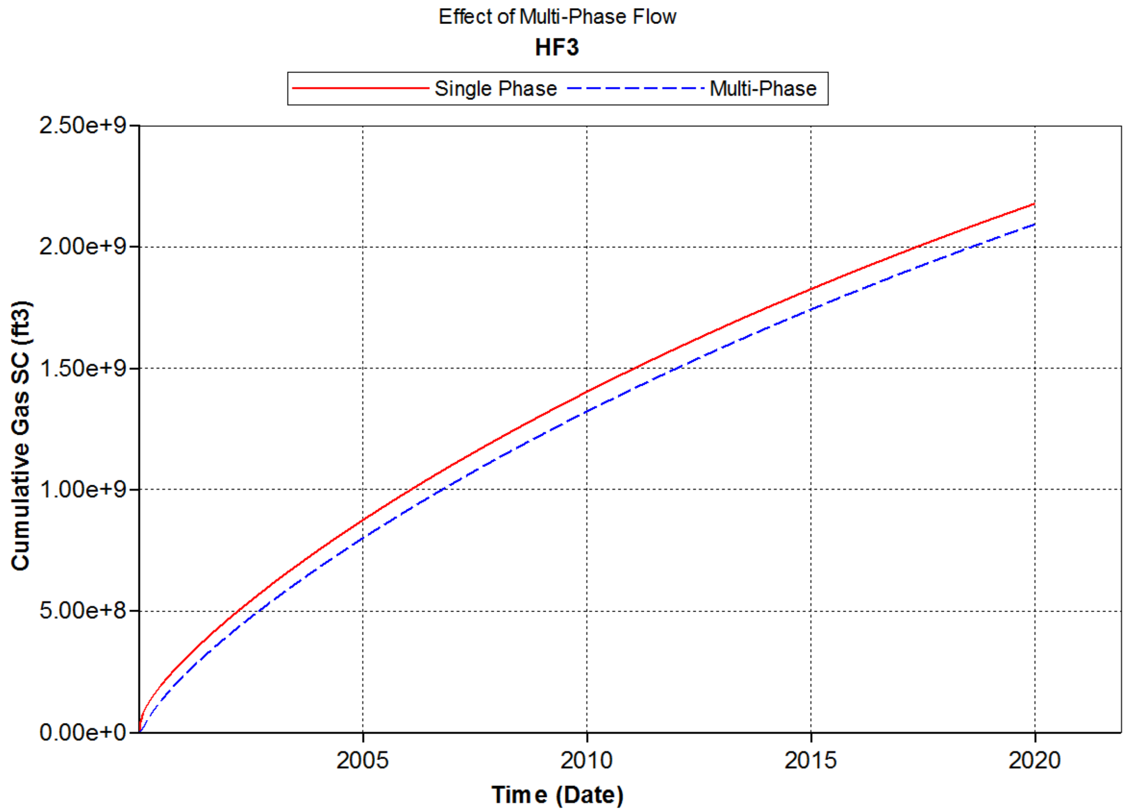

Figure 6-18: Effect of multi-phase flow on cumulative gas production in HF3 (100 mesh sand)

As shown in figure 6-18, twenty years cumulative gas production for single phase flow was 2.18 BCF and 2.09 BCF for multi-phase flow. In HF3, multi-phase flow in the reservoir decreased gas production by 84.80 MMSCF. This is a loss of 3.90 % of gas production due to multi-phase flow in the reservoir.

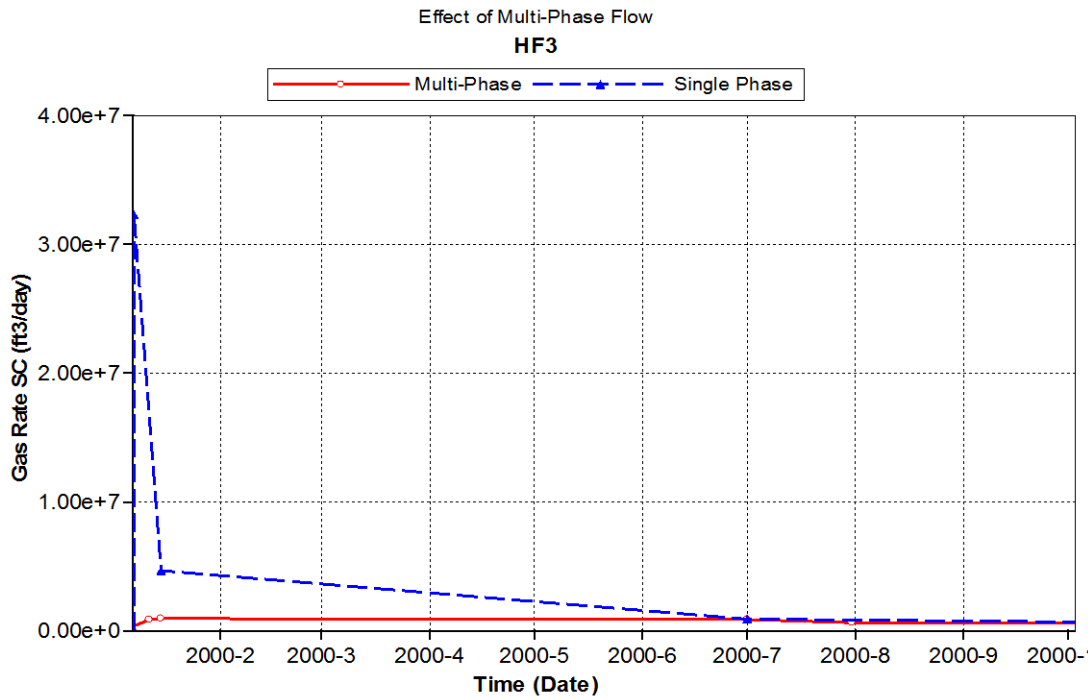

Figure 6-19: Effect of multi-phase flow on gas production rate in HF3 (100 mesh).

Figure 6-19 represents the effect of multi-phase flow on gas production rate in HF3. Same as in HF1 and HF2, gas rate is higher for single phase than multi-phase flow in HF3. Initial gas rate was 32.29 MMSCFD for single phase gas and 0.85MMSCFD for multi-phase. Gas rate was higher for the first seven months of gas production for single phase than multi-phase.

Table 6-5: 20 year multi-phase cumulative gas production (100 mesh sand)

	Single phase (BCF)	Multi-phase (BCF)
HF1	1.94	1.90
HF2	1.99	1.95
HF3	2.18	2.09

In summary, multi-phase flow is shown to have an effect on production rate and cumulative gas production using 100 mesh sand. It is also observed that the effect of multi-phase flow on cumulative gas production is more pronounced as hydraulic fracture network size increases. This could be due to the decrease in fracture conductivity as fracture network size increases.

We were limited by the relatively small amount of fracture fluid we could inject into the formation to evaluate the effect of multi-phase flow. We were only able to inject 2250 bbl of fracture fluid into the formation which is relative small compared to what obtains in the field. More fracture fluid in the formation could have had a more significant effect on the performance of the fractured well.

6.3 Effect of Capillary Pressure

The effect of high capillary pressure on gas production was simulated by using capillary pressure curves generated by Gdanski, 2006 (figure 4-3). Capillary pressure curve was added to the multi-phase flow case to evaluate effect of capillary pressure on the performance of the well after hydraulic fracture treatment. Effect of capillary pressure was evaluated for 20/40 ceramics proppant and 100 mesh sand.

6.3.1 Effect of Capillary Pressure for 20/40 Ceramics Proppant

In this section we analyzed results of effect of capillary pressure in the case with 20/40 ceramics proppant.

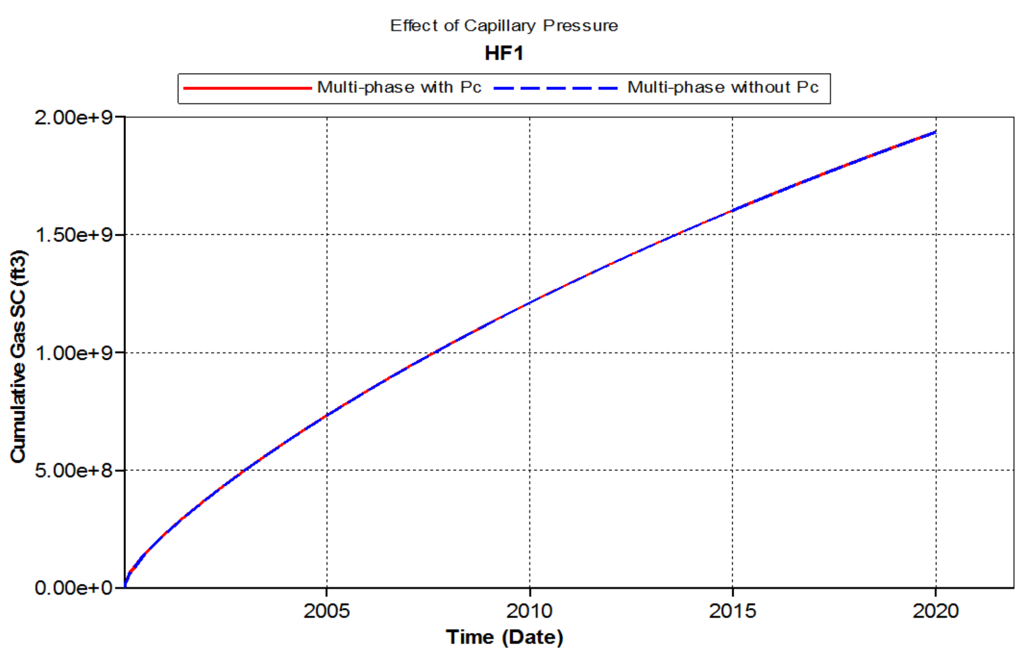

Figure 6-20: Effect of capillary pressure on cumulative gas production in HF1 (20/40 ceramics).

In figure 6-20, 1.94 BCF of gas was produced without capillary pressure while 1.94 BCF of gas was also produced with capillary pressure. Cumulative gas production was the same with or without capillary pressure. Figure 6-21 shows initial gas rate higher without capillary pressure than with high capillary pressure. Gas rate was about the same with or without capillary pressure after the initial production.

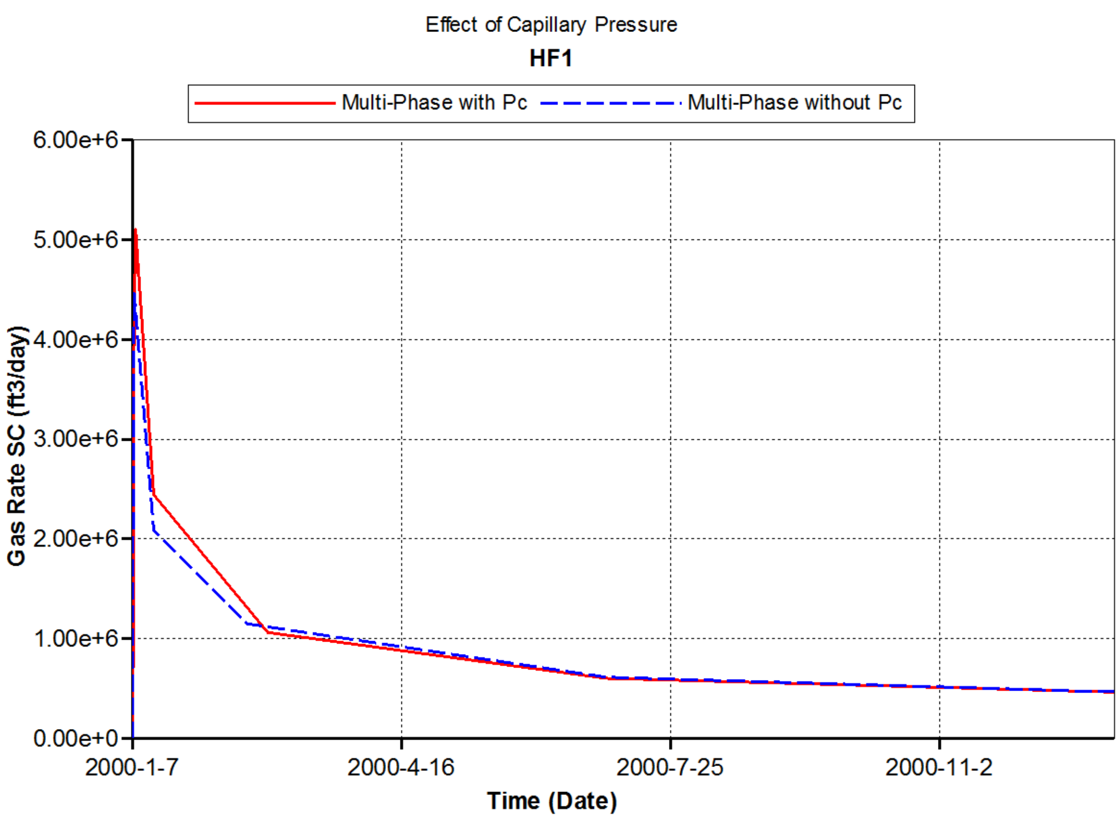

Figure 6-21: Effect of capillary pressure on gas production rate in HF1 (20/40 mesh).

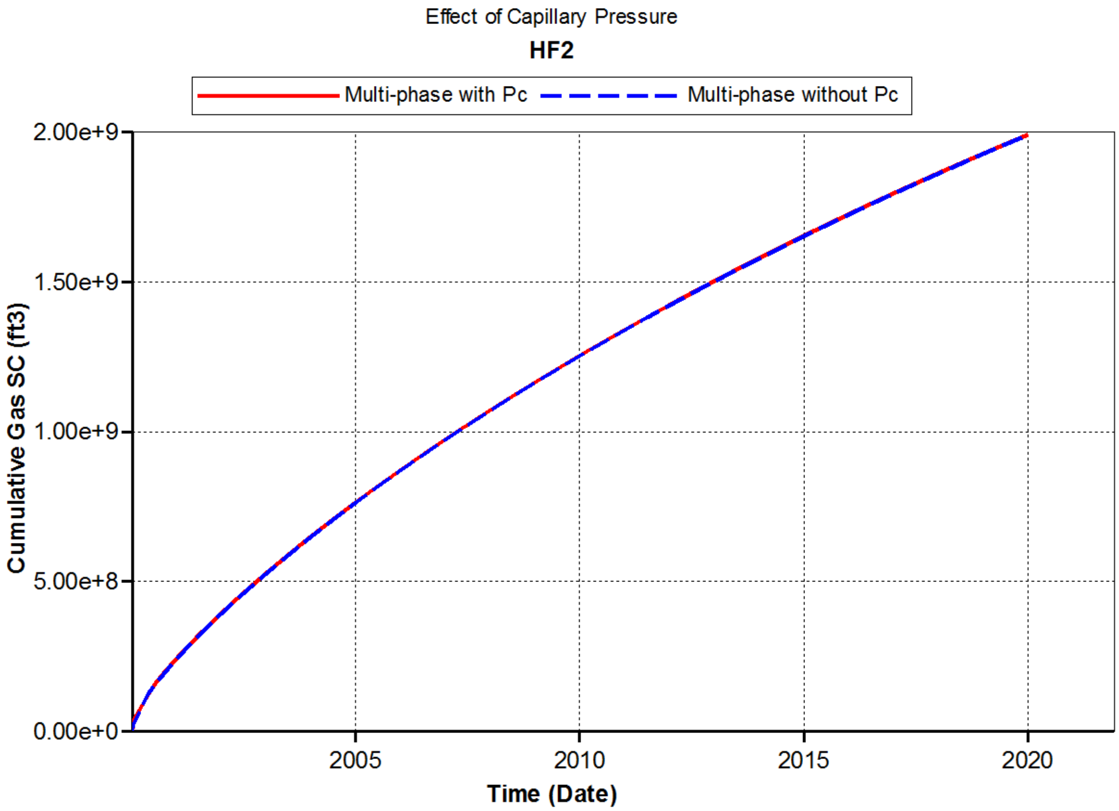

Figure 6-22: Effect of capillary pressure on cumulative gas production in HF2 (20/40 ceramics proppant).

Figure 6-22 represents the effect of capillary pressure on cumulative gas production in HF2. Cumulative gas production was 1.99 BCF without capillary pressure and 1.99 BCF with capillary pressure. Cumulative gas production was unaffected by higher capillary pressure in HF2.

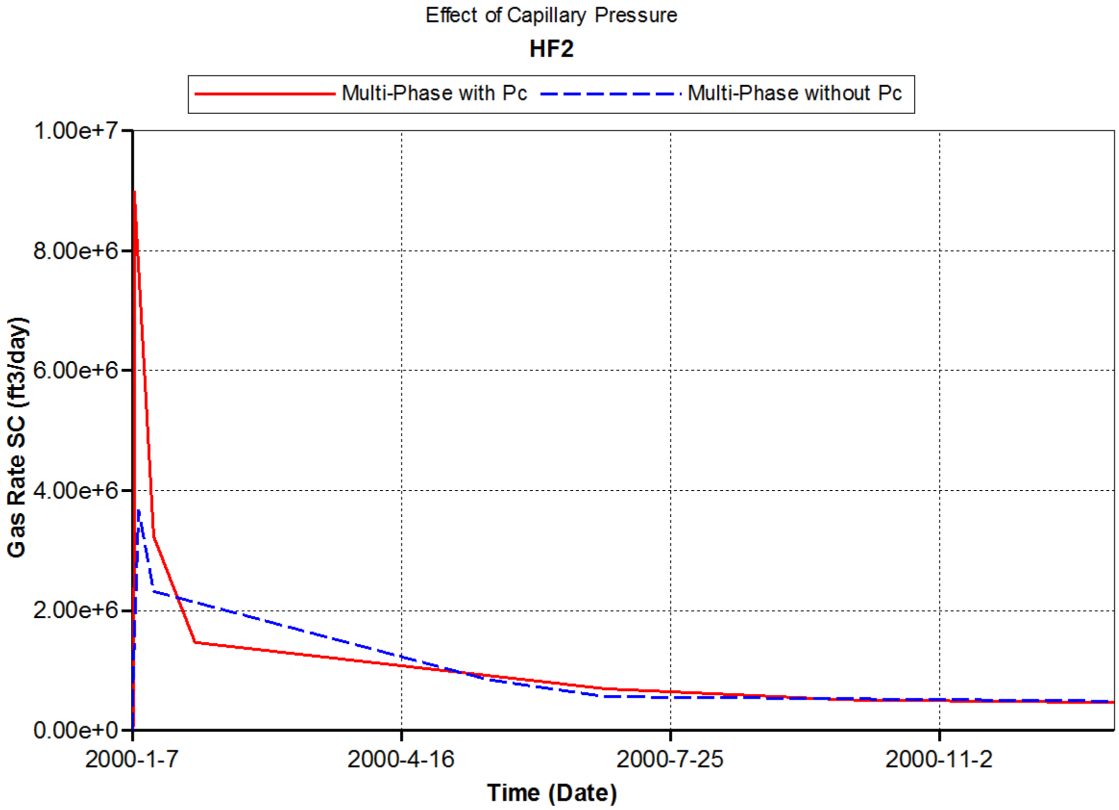

Figure 6-23: Effect of capillary pressure on gas production rate in HF2 (20/40 ceramics proppant).

Figure 6-23 shows the effect of capillary pressure on gas production rate in HF2. Gas rate peak is delayed due to capillary pressure compared to the case without capillary pressure. Asides from the delayed peak, gas production rate was about the same with and without capillary pressure.

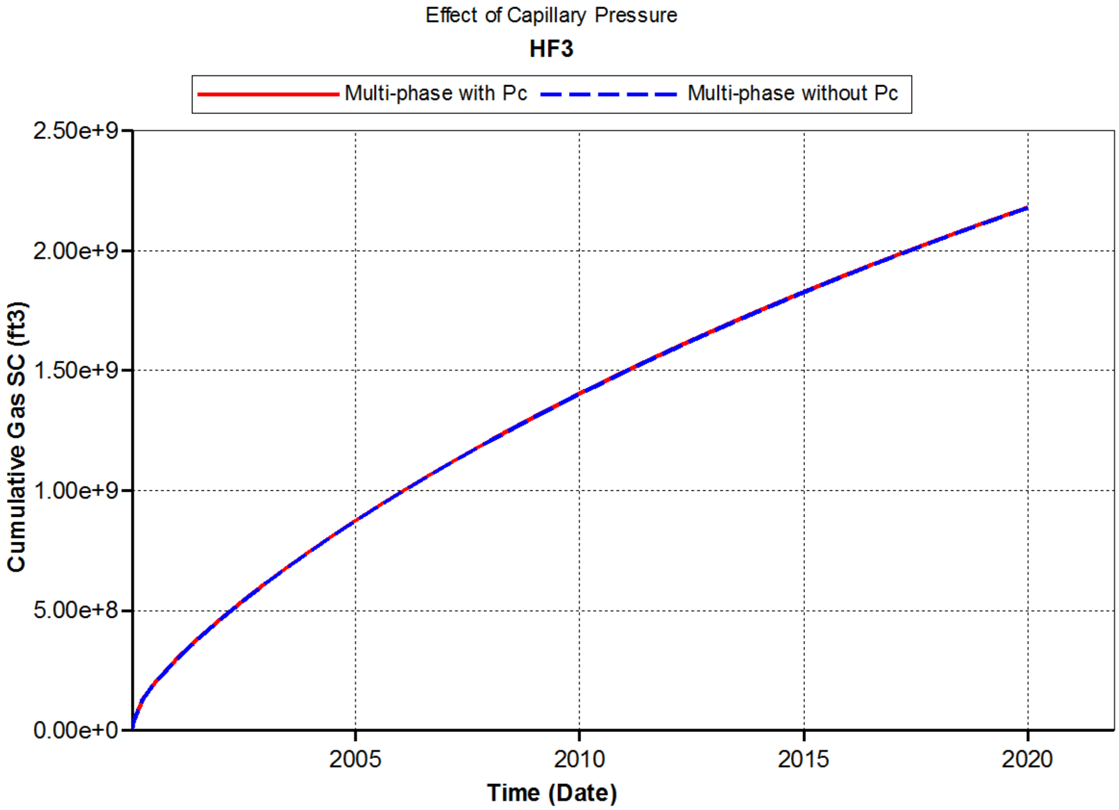

Figure 6-24: Effect of capillary pressure on cumulative gas production in HF3 (20/40 mesh).

Figure 6-24 represents the effect of capillary pressure on cumulative gas production in HF3. This shows about the same amount of gas production with capillary pressure and without capillary pressure. 2.18 BCF of gas was produced with low capillary pressure while 2.18 BCF of gas was produced with higher capillary pressure.

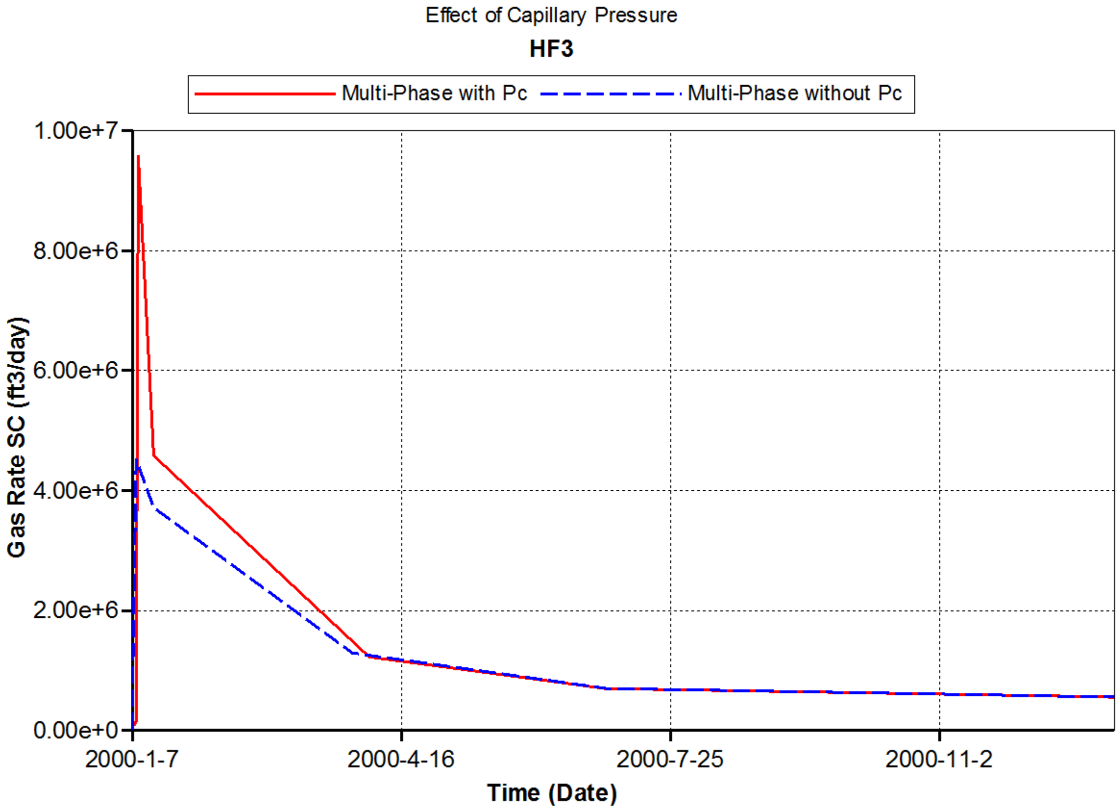

Figure 6-25: Effect of capillary pressure on gas production rate in HF3 (20/40 mesh).

Figure 6-25 shows the effect of capillary pressure on gas production rate in HF3. Gas production rates were close for the case with high capillary pressure and the case with low capillary pressure. With higher capillary pressure, gas rate started very low for the first few days of production then peaked. This shows that higher capillary pressure delays peak in gas rate. However, the delay in gas peak did not affect cumulative gas production with higher capillary pressure using 20/40 ceramics proppant.

Table 6-6: 20 years cumulative gas production with low and high capillary pressure (20/40 ceramics proppant)

	Low Pc, Volume (BCF)	High Pc, Volume (BCF)
HF1	1.94	1.94
HF2	1.99	1.99
HF3	2.18	2.18

Table 6-6 shows a summary of cumulative gas production with low and high capillary pressure. The table shows gas production about the same for both cases for HF1, HF2 and HF3. This shows that high capillary pressure does not have a significant effect on cumulative gas production in the long term.

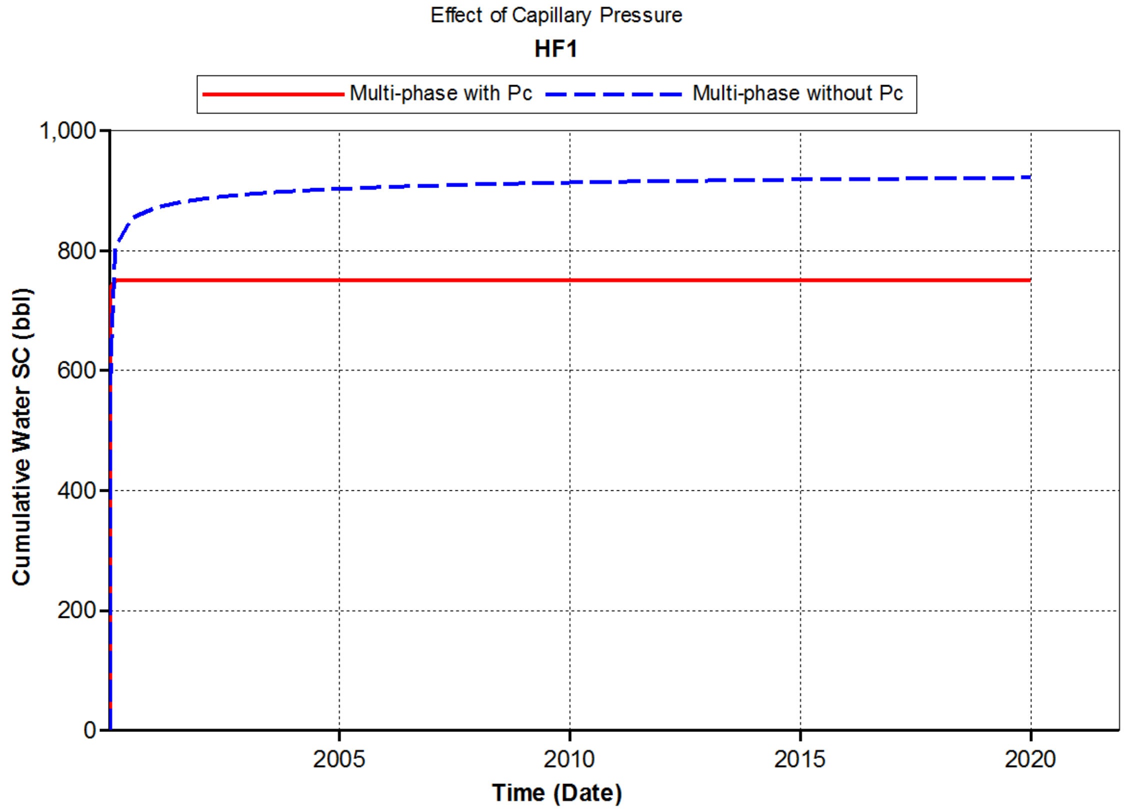

Figure 6-26: Effect of capillary pressure on cumulative fracture fluid production in HF1 (20/40 ceramics proppant).

Figure 6-26 represents the effect of high capillary pressure on cumulative fracture fluid production in HF1. With low capillary pressure, 921.60 bbl of fracture fluid was produced while 750.95 bbl was produced with high capillary pressure. This shows that capillary pressure decreases the volume of fracture fluid produced. This could be so because capillary pressure tends to make the fracture fluid penetrate deeper into formation making it more difficult to produce.

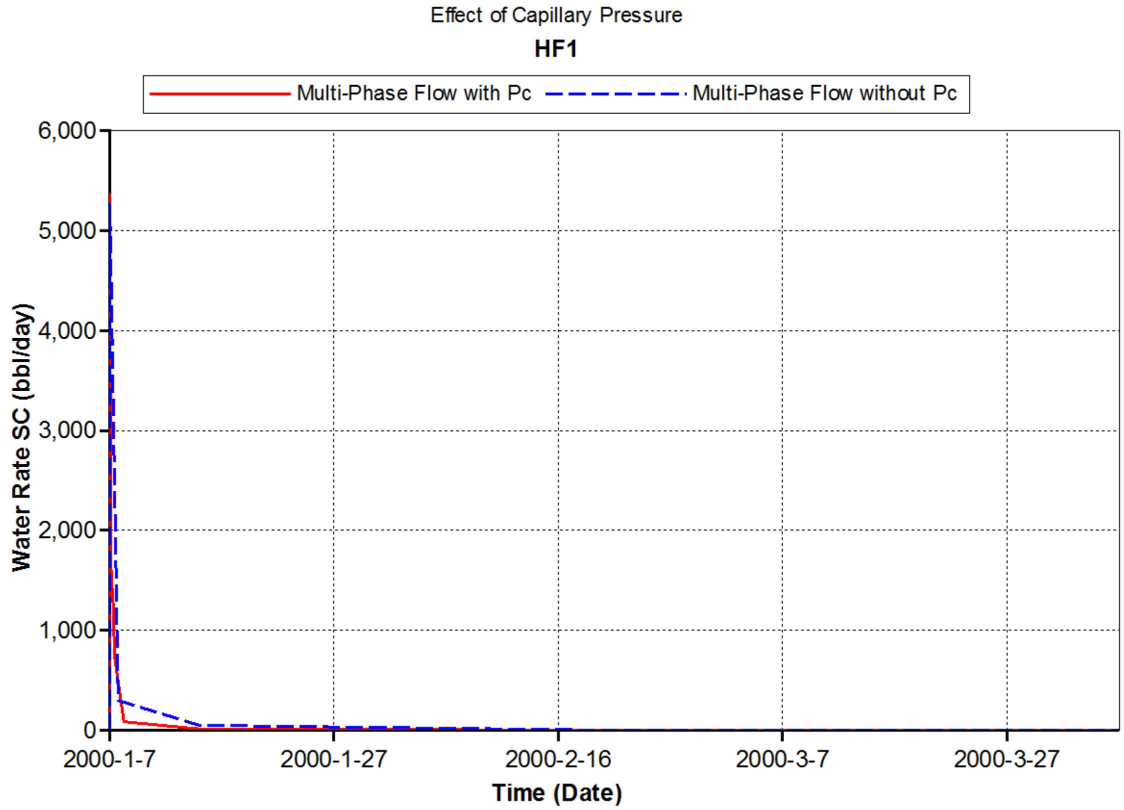

Figure 6-27: Effect of capillary pressure on fracture fluid production rate in HF1 (20/40 ceramics proppant).

Figure 6-27 represents the effect of capillary pressure on fracture fluid production rate in HF1. Fracture fluid rates are close with high capillary pressure and low capillary pressure even though rates are a bit higher with low capillary pressure within the first two months of production. The difference in fracture fluid production during the early stage of production resulted in higher cumulative fracture fluid production.

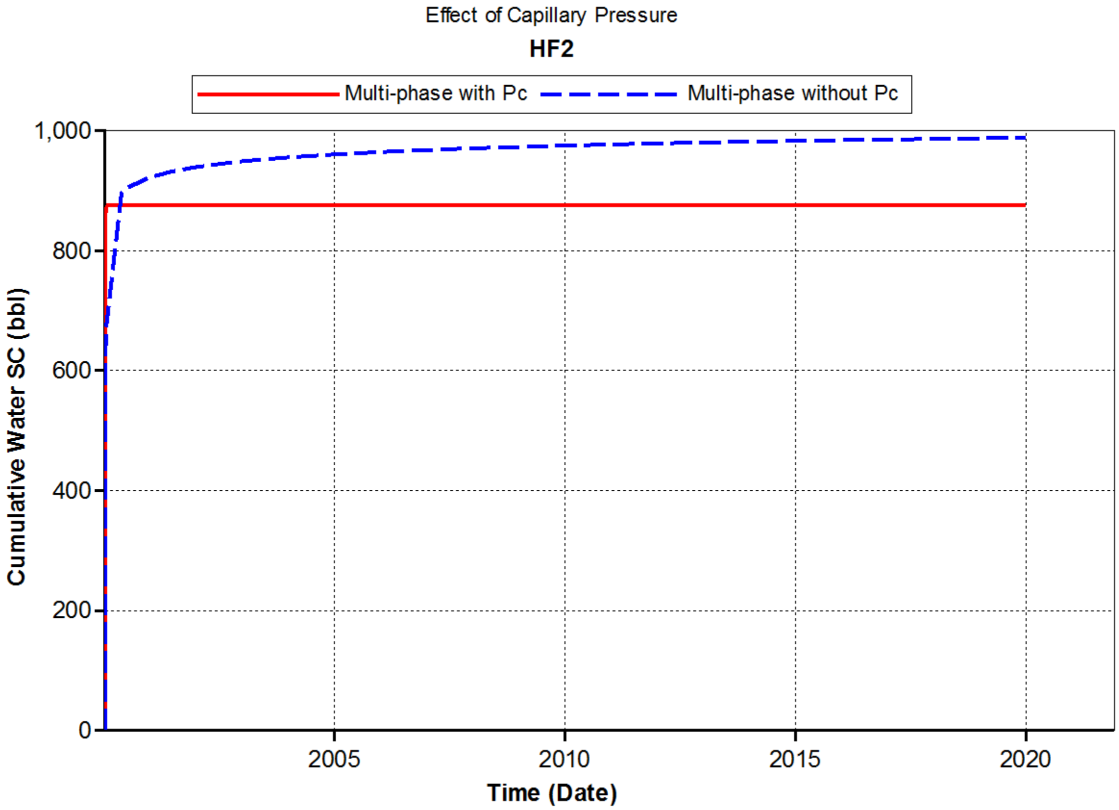

Figure 6-28: Effect of capillary pressure on cumulative fracture fluid production in HF2 (20/40 ceramics proppant).

Figure 6-28 above represents the effect of capillary pressure on cumulative fracture fluid production in HF2. The trend in HF2 is similar to HF1; cumulative fracture fluid production is higher with low capillary pressure than with high capillary pressure. This is due to the effect of capillary pressure which requires a higher pressure drawdown to produce from the formation. 987.99 bbl of fracture fluid was produced with low capillary pressure while 875.68 bbl was produced with high capillary pressure.

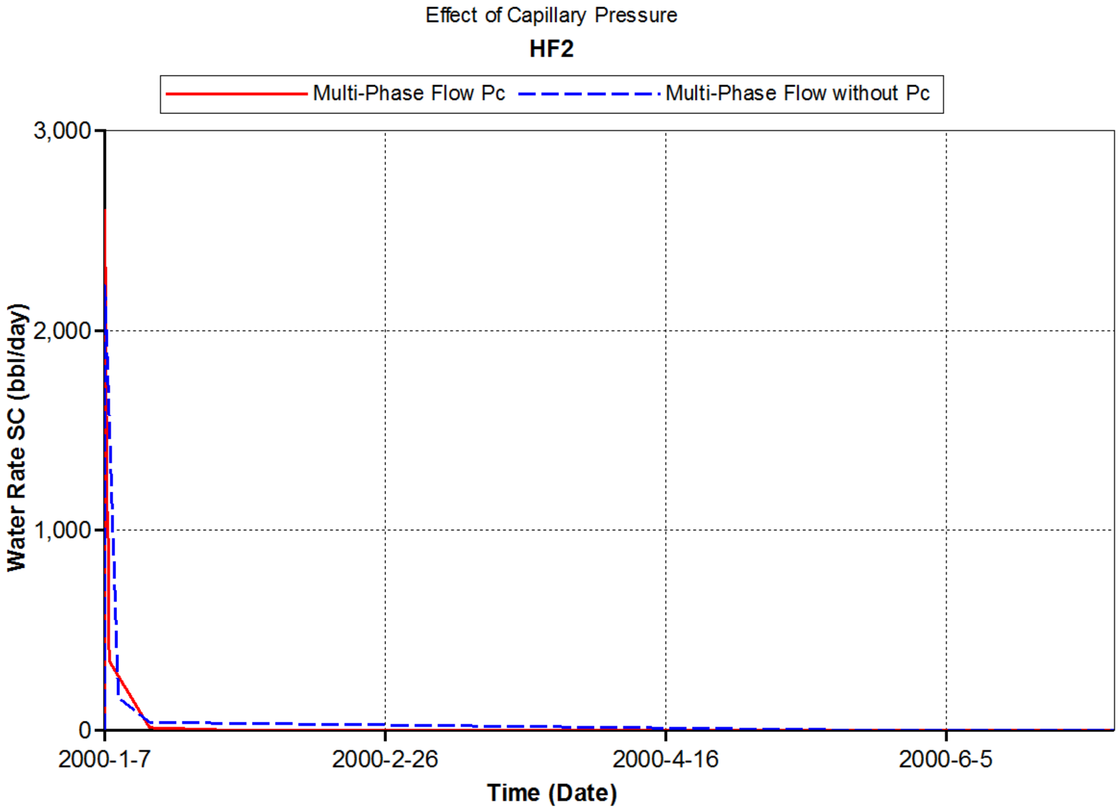

Figure 6-29: Effect of capillary pressure on fracture fluid production rate in HF2 (20/40 ceramics).

Figure 6-29 represents the effect of capillary pressure on fracture fluid production rate in HF2. Fracture fluid production rates were higher with low capillary pressure for the first four months of production. This difference in fracture fluid production rates led to a higher cumulative fracture fluid production with low capillary pressure compared to the case with high capillary pressure.

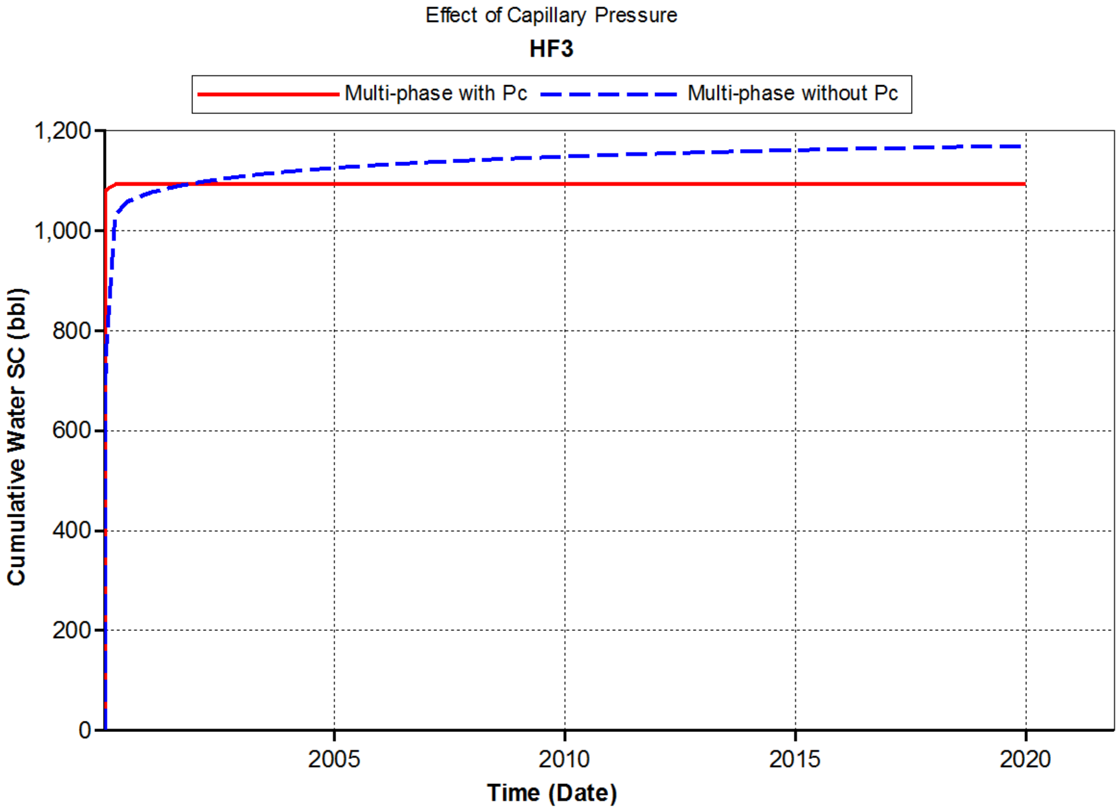

Figure 6-30: Effect of capillary pressure on cumulative fracture fluid production in HF3 (20/40 ceramics).

Figure 6-30 above shows the effect of capillary pressure on cumulative fracture fluid production in HF3. Same trend in fracture fluid production was observed in HF1 and HF2. More fracture fluid was produced with low capillary pressure compared to the case with high capillary pressure. 1169.57 bbl of fracture fluid was produced with low capillary pressure while 1092.94 bbl of fracture fluid was produced with high capillary pressure.

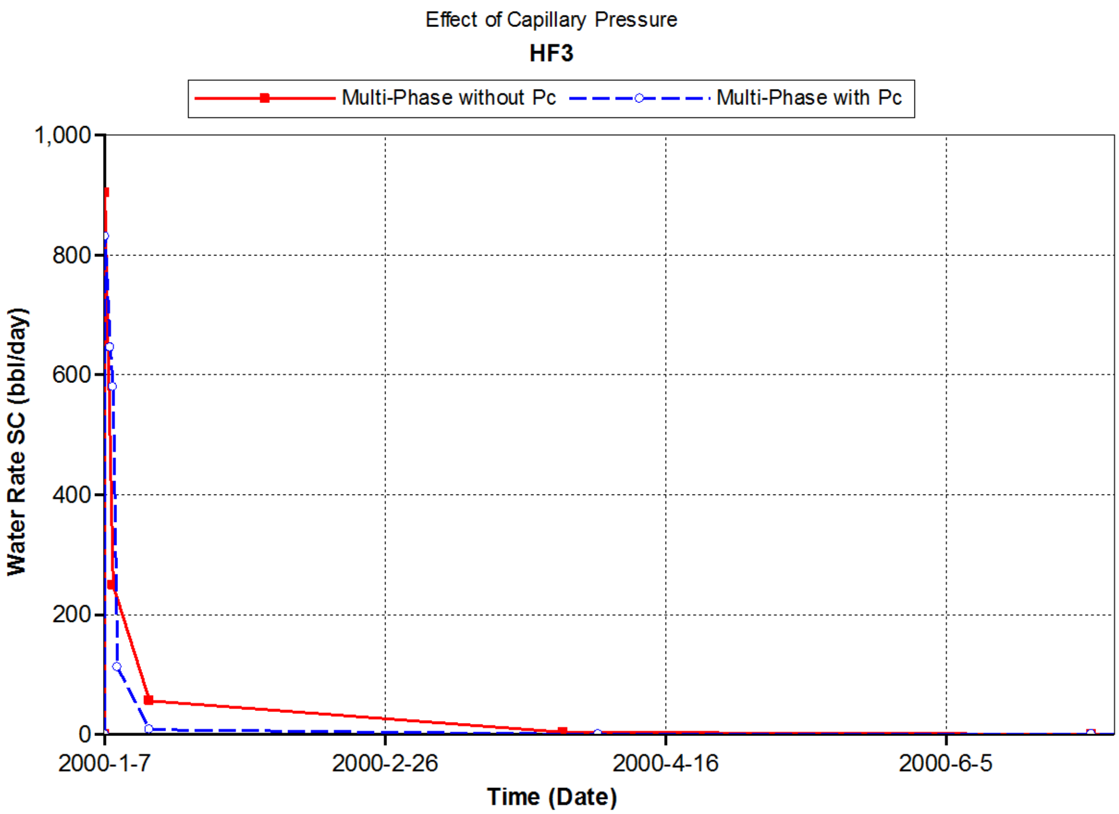

Figure 6-31: Effect of capillary pressure on fracture fluid production rate in HF3 (20/40 ceramics).

Figure 6-31 above shows the effect of capillary pressure on fracture fluid production rate in HF3. Fracture fluid production rate was observed to be higher for the first four months of production with low capillary pressure than with high capillary pressure. High capillary pressure decreases fracture fluid production rates which results in lower cumulative fracture fluid production.

Table 6-7: 1-year cumulative fracture fluid production with low and high capillary pressure

	Low Pc		High Pc	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
HF1	901.00	40.00	750.95	33.35
HF2	956.00	45.00	875.68	38.90
HF3	1118.25	49.70	1092.94	48.57

Table 6-7 above summarizes the cumulative fracture fluid production with low and high capillary pressure, fracture fluid production is observed to be higher in HF1, HF2 and HF3 with low capillary pressure.

6.3.2 Effect of Capillary Pressure for 100 Mesh Sand

In this section, 100 mesh sand was used as proppant in the hydraulic fractures. The following results were obtained for HF1, HF2 and HF3.

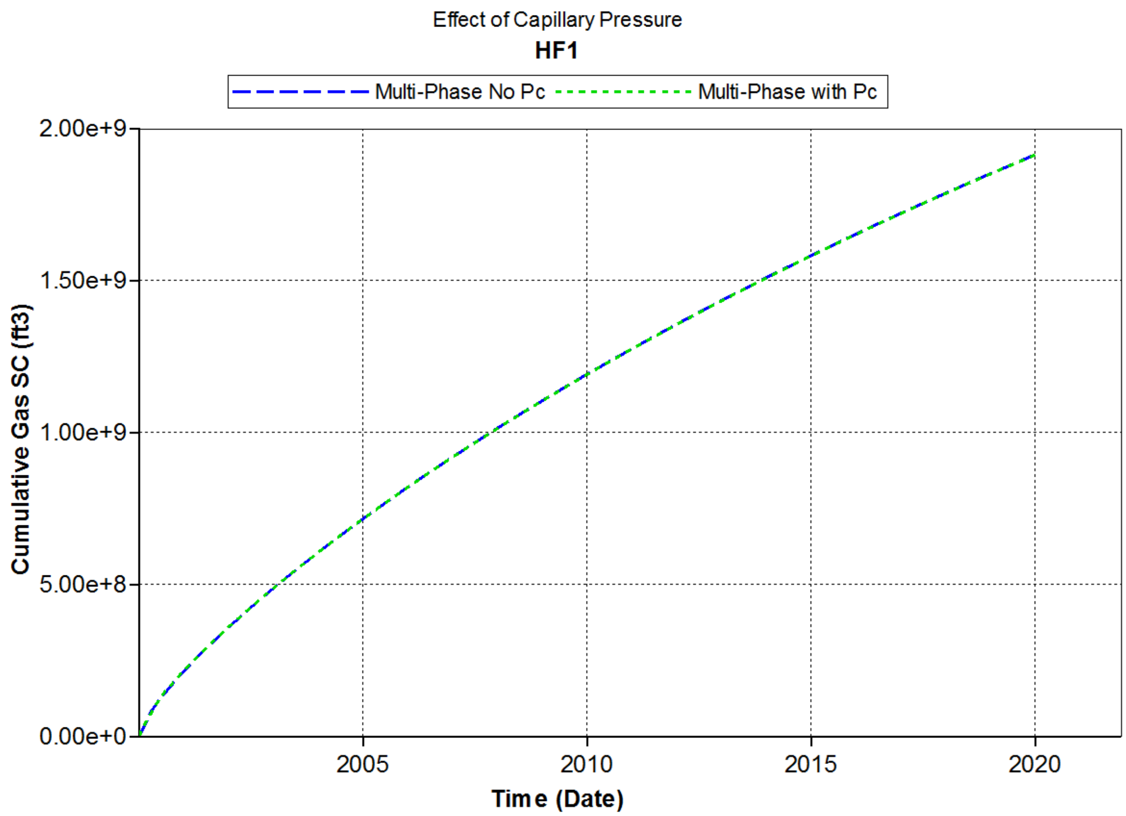

Figure 6-32: Effect of capillary pressure on cumulative gas production in HF1 (100 mesh sand).

Figure 6-32 above shows the effect of capillary pressure on cumulative gas production in HF1. With low capillary pressure, 1.90 BCF of gas was produced while 1.90 BCF of gas was produced with high capillary pressure. Cumulative gas production seems to be about the same with low and high capillary pressure.

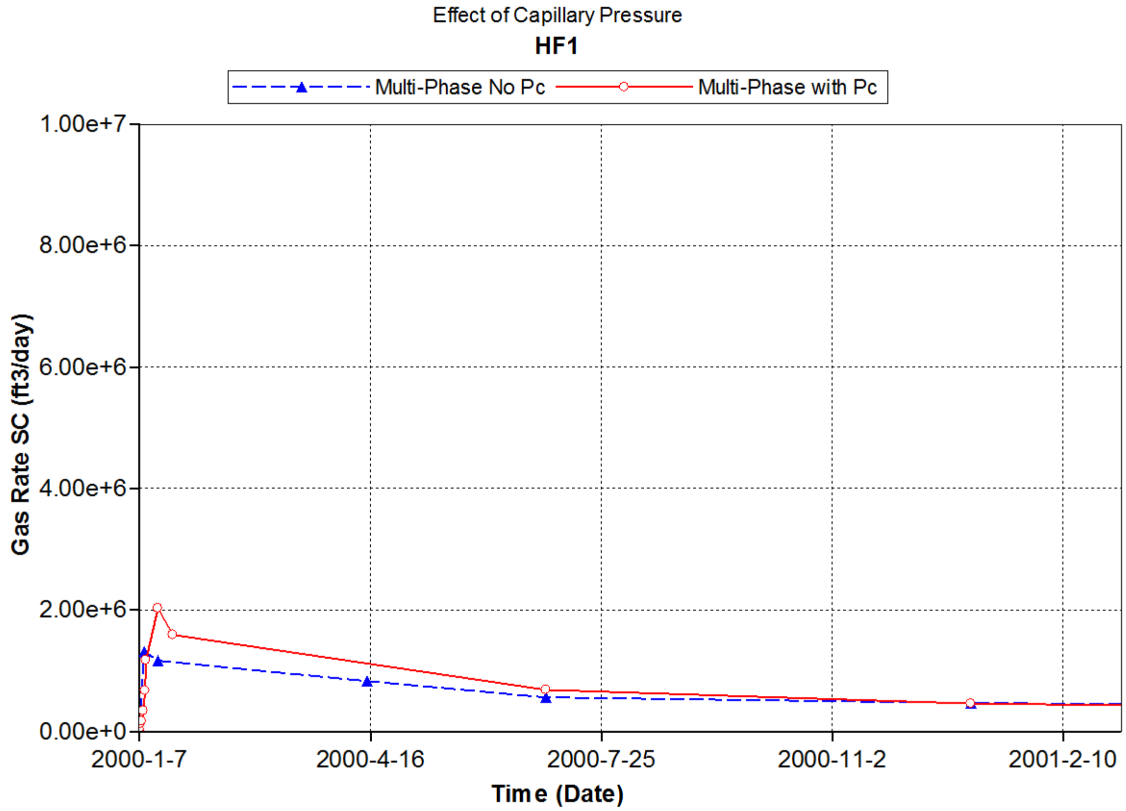

Figure 6-33: Effect of capillary pressure on gas production rate in HF1 (100 mesh sand).

Figure 6-33 represents the effect of capillary pressure on gas production rate in HF1. Production peaked earlier with low capillary pressure than with high capillary pressure. It took a few days of production before gas production peaked with high capillary pressure. This shows that capillary pressure delays peak in gas production rate. At the end cumulative gas production is about the same with low or high capillary pressure.

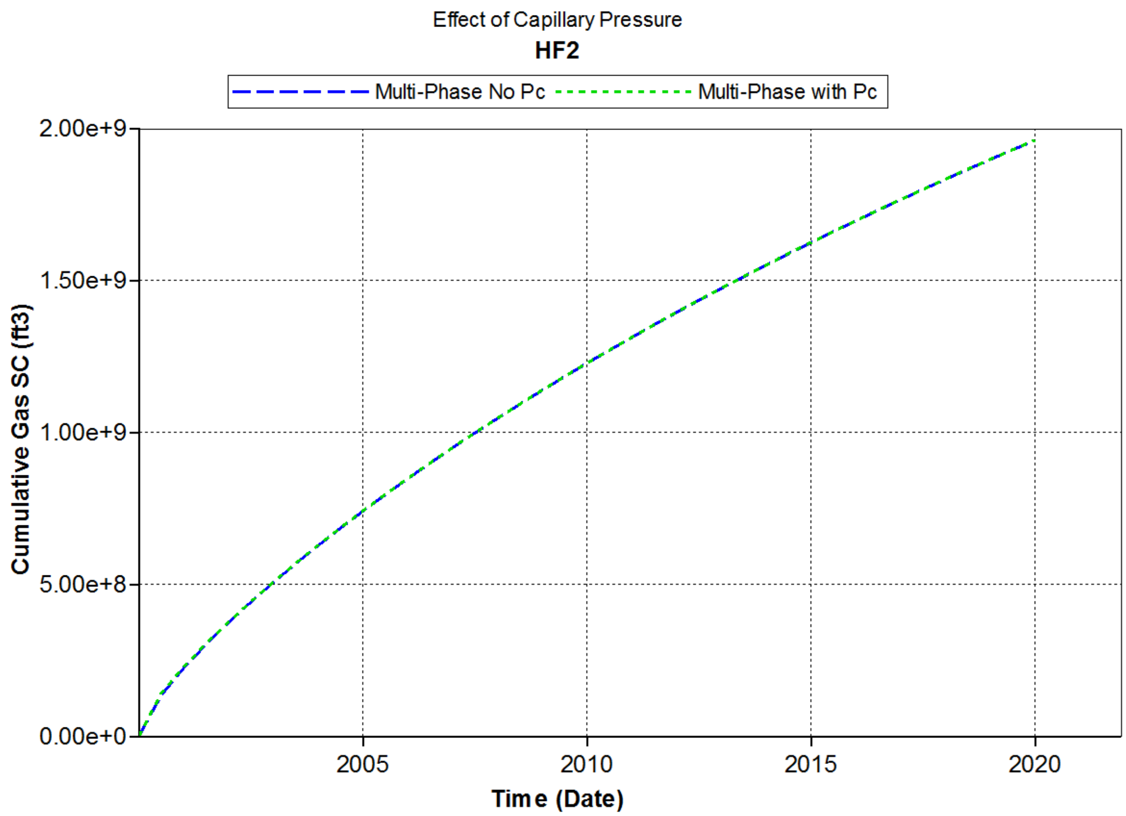

Figure 6-34: Effect of capillary pressure on cumulative gas production in HF2 (100 mesh sand).

Figure 6-34 represents the effect of capillary pressure on cumulative gas production in HF2. Cumulative gas production was 1.95 BCF with low capillary pressure and1.94 BCF with high capillary pressure. Cumulative gas production seems to be unchanged with high capillary pressure. Higher capillary pressure in the formation is observed to delay peak in gas production but does not affect long-term cumulative production.

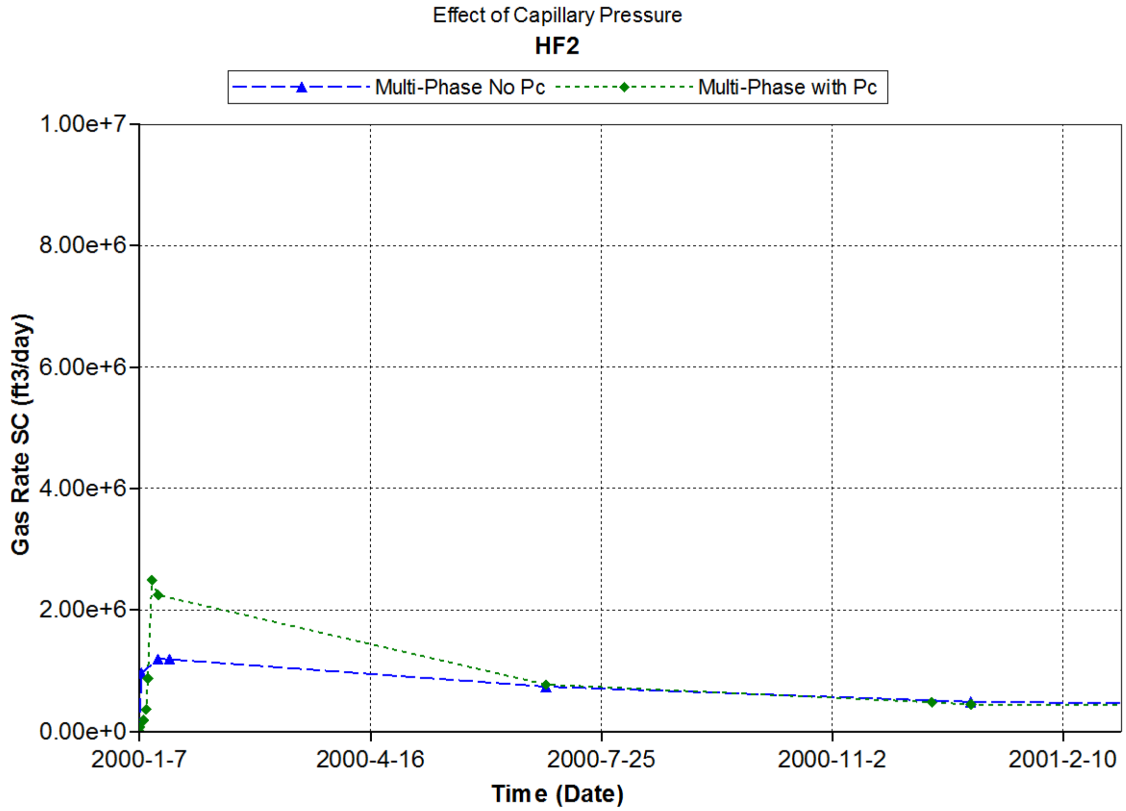

Figure 6-35: Effect of capillary pressure on gas production rate in HF2 (100 mesh sand).

Figure 6-35 represents effect of capillary pressure on gas production rate in HF2. Gas production rate peaked earlier with low capillary pressure than with high capillary pressure. Peak in gas production rate was delayed for a few days due to high capillary pressure compared to low capillary pressure. Cumulative gas production was unaffected by delayed peak in gas rate due to high capillary pressure.

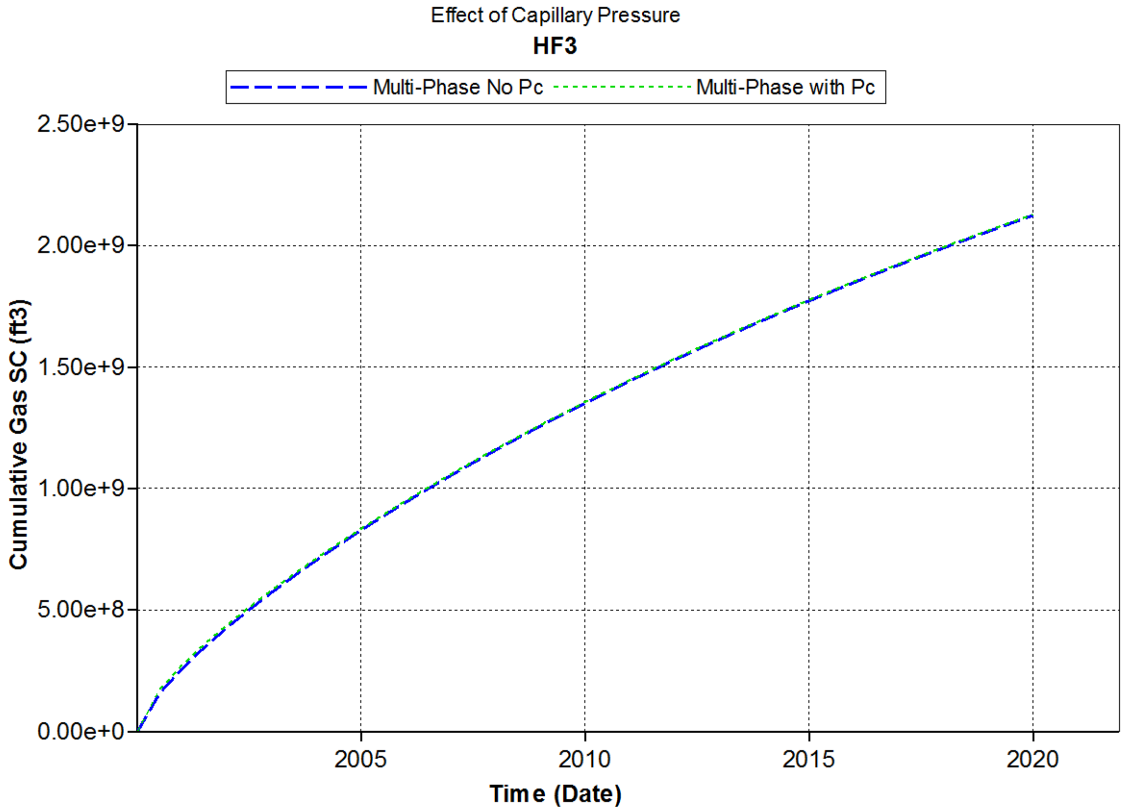

Figure 6-36: Effect of capillary pressure on cumulative gas production in HF3 (100 mesh sand).

Figure 6-36 shows the effect of capillary pressure on cumulative gas production in HF3. Cumulative gas production was 2.09 BCF with low and high capillary pressure. Gas production was the same with low and high capillary pressure.

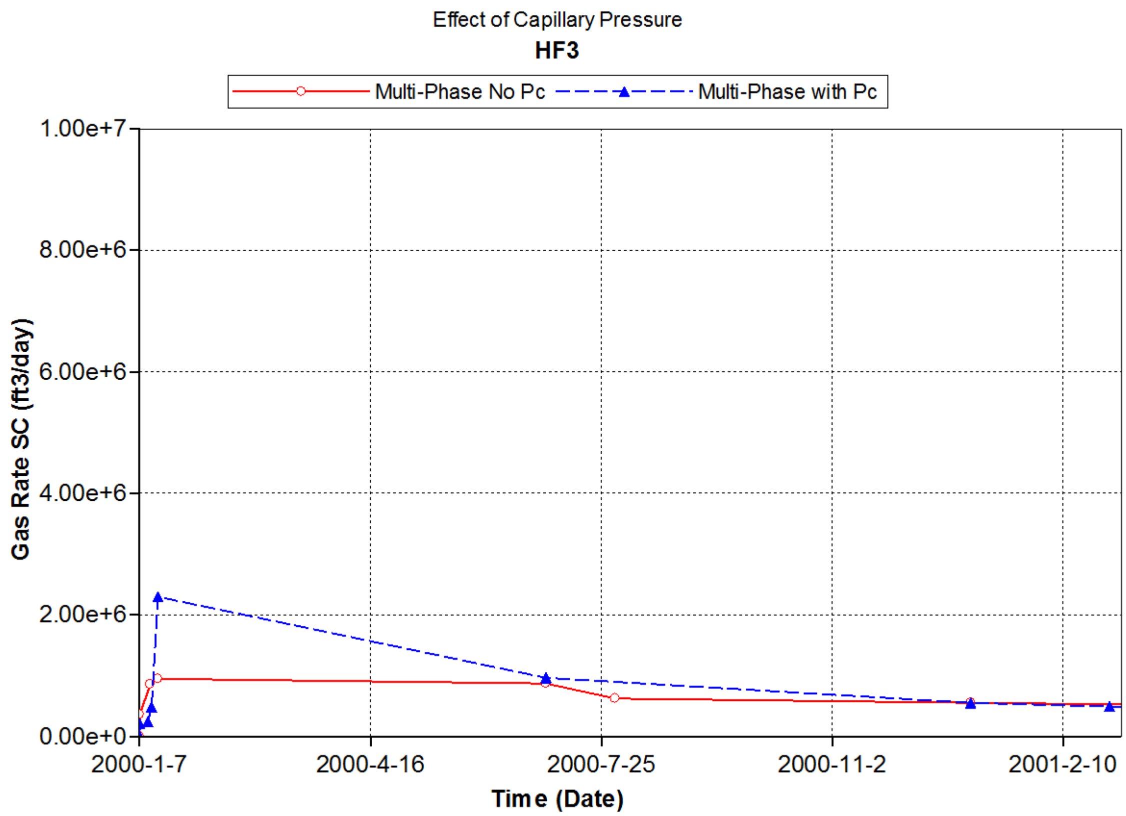

Figure 6-37: Effect of capillary pressure on gas production rate in HF3 (100 mesh sand).

Figure 6-37 represents the effect of capillary pressure on gas production rate in HF3. Gas production rate starts low with high capillary pressure compared to the case with low capillary pressure. With high capillary pressure, peak in gas production rate was delayed for a few days compared to the case with low capillary pressure where gas peak occurs earlier. Larger reservoir energy is required to overcome high capillary pressure at the start of gas production, which could lead to low initial gas production. This would be the reason for the delayed gas peak when capillary pressure is high in a formation.

Table 6-8: 20 years Cumulative gas production with low and high capillary pressure (100 mesh sand)

	Cumulative gas without Pc (BCF)	Cumulative gas with Pc (BCF)
HF1	1.90	1.90
HF2	1.95	1.94
HF3	2.09	2.09

Table 6-8 summarizes the cumulative gas production with low and high capillary pressure using 100 mesh sand. Cumulative gas production seems to be about the same in HF1, HF2 and HF3. Peak in gas production rate was delayed with high capillary pressure but long-term cumulative gas production was unaffected for the most part.

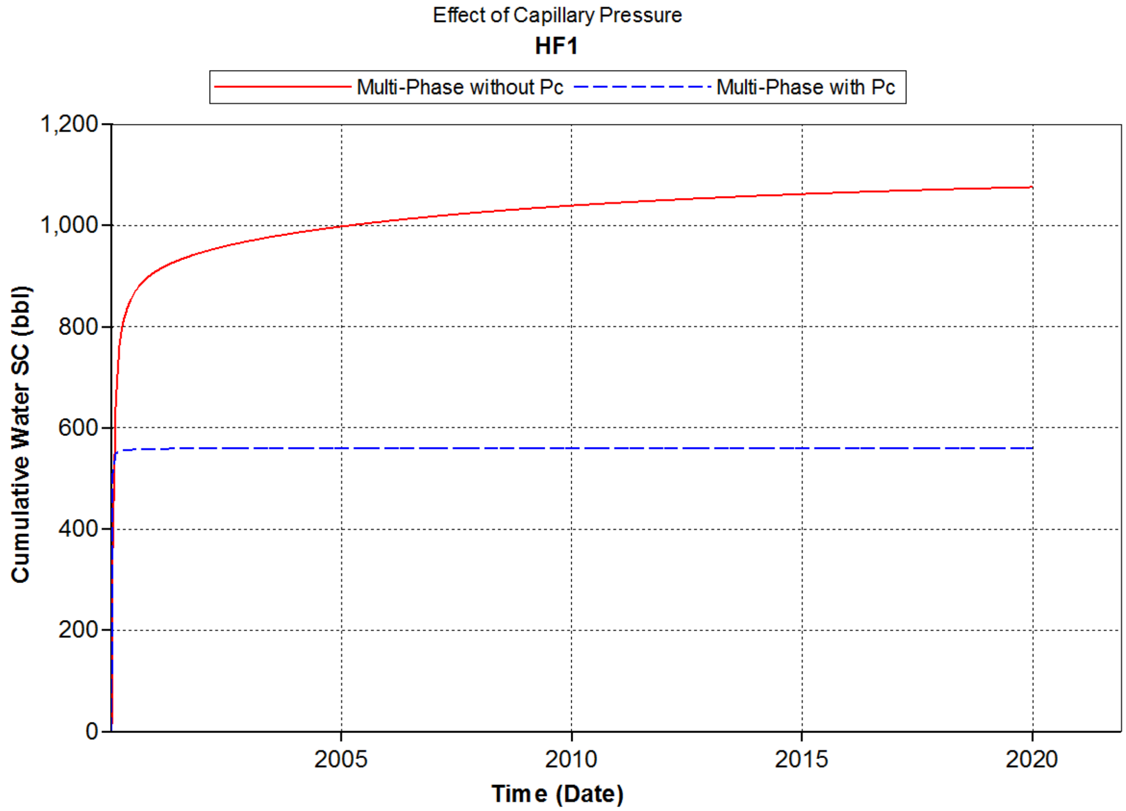

Figure 6-38: Effect of capillary pressure on cumulative fracture fluid production in HF1 (100 mesh sand).

Figure 6-38 represents the effect of capillary pressure on cumulative fracture fluid production in HF1. More fracture fluid is produced with low capillary pressure compared to high capillary pressure. 1075.94 bbl of fracture fluid was produced with low capillary pressure while 558.87 bbl of fracture fluid was produced with high capillary pressure. High capillary pressure decreased fracture fluid production by about one half in HF1.

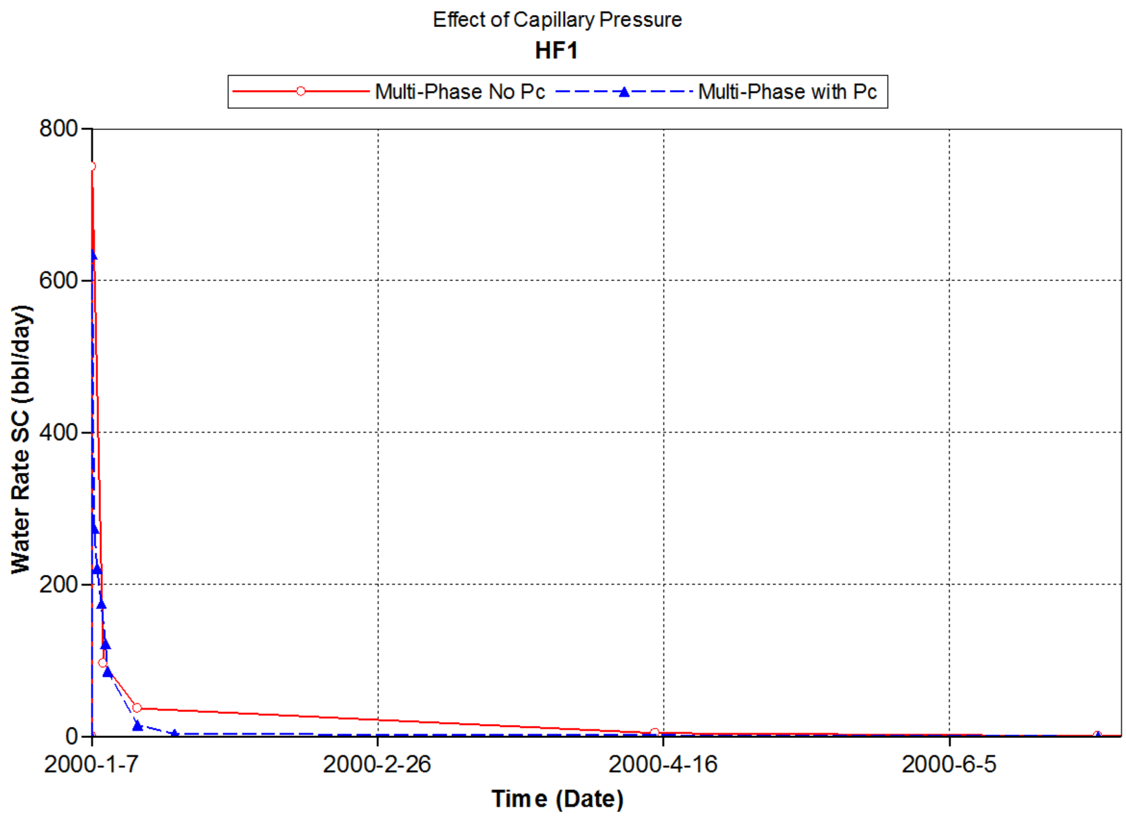

Figure 6-39: Effect of capillary pressure on gas production rate in HF1 (100 mesh sand).

Figure 6-39 represents the effect of capillary pressure on fracture fluid production rate in HF1. This figure shows fracture fluid production rate higher with low capillary pressure for the first few months of production. In HF1, fracture fluid production rate was lower with high capillary pressure which results in lower cumulative fracture fluid production. The presence of higher capillary pressure causes fracture fluid to penetrate deeper into the formation as well as increasing the energy requirement to clean up the well. This could lead to less fracture fluid production.

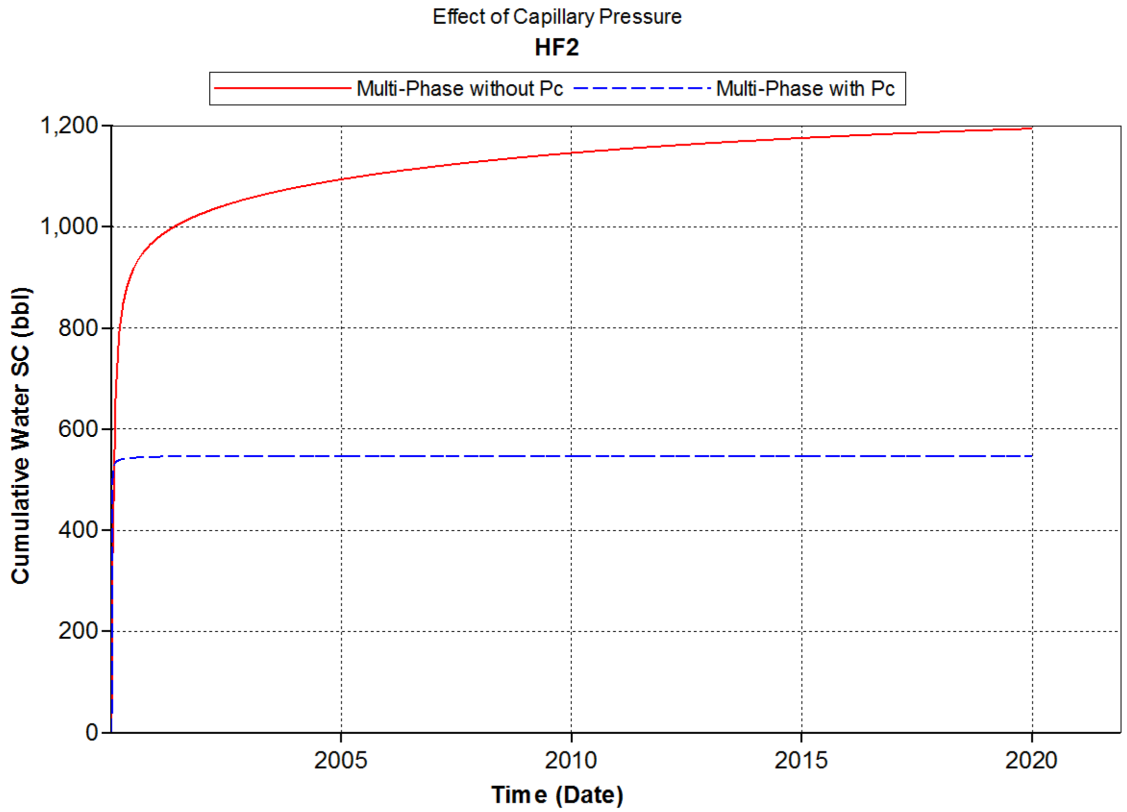

Figure 6-40: Effect of capillary pressure on cumulative fracture fluid production in HF2 (100 mesh sand).

Figure 6-40 shows the effect of capillary pressure on cumulative fracture fluid production in HF2. Fracture fluid production was observed to decrease as a result of high capillary pressure. 1194.28 bbl of fracture fluid was produced with low capillary pressure compared to 546.58 bbl produced with high capillary pressure. Similar to HF1, higher capillary pressure decreased fracture fluid production by half.

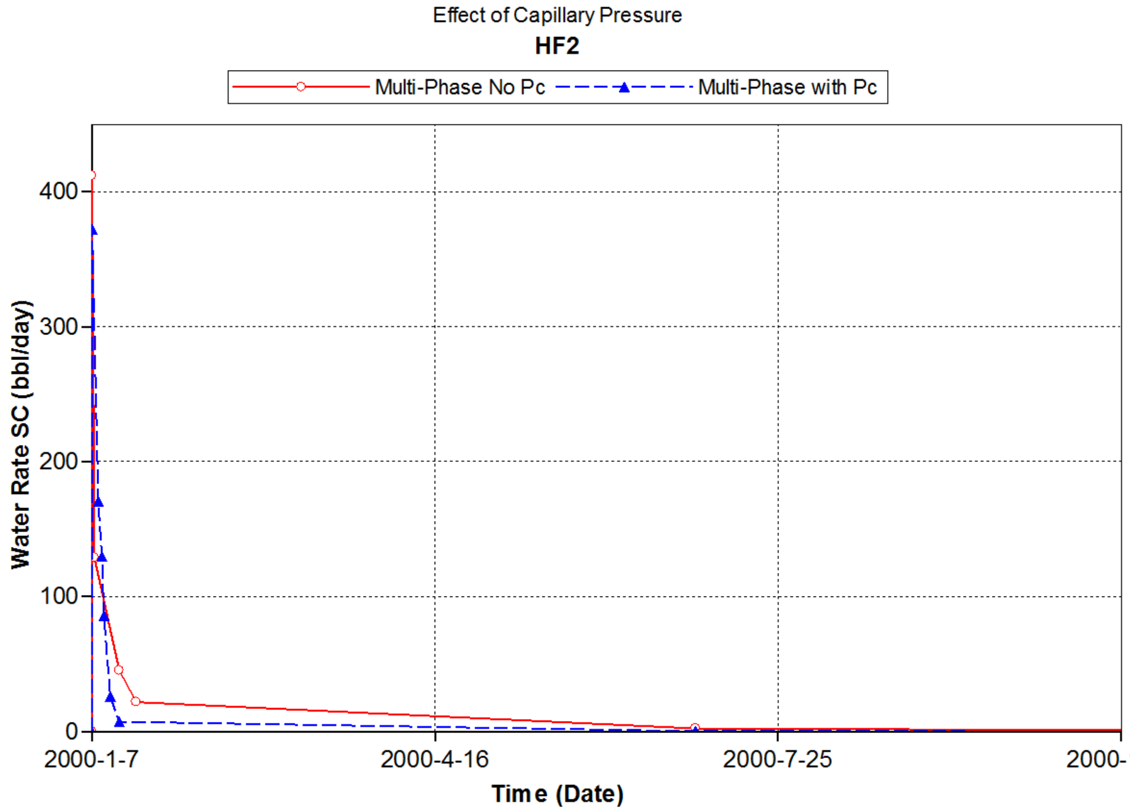

Figure 6-41: Effect of capillary pressure on fracture fluid production rate in HF2 (100 mesh sand).

Figure 6-41 represents effect of capillary pressure on fracture fluid production rate in HF2. Fracture fluid production rate is higher for the first few months of production with low capillary pressure compared to the case with capillary pressure. Lower fracture fluid production rate can be due to the higher capillary pressure which holds fluid in place requiring a higher pressure drawdown to overcome the high capillary pressure.

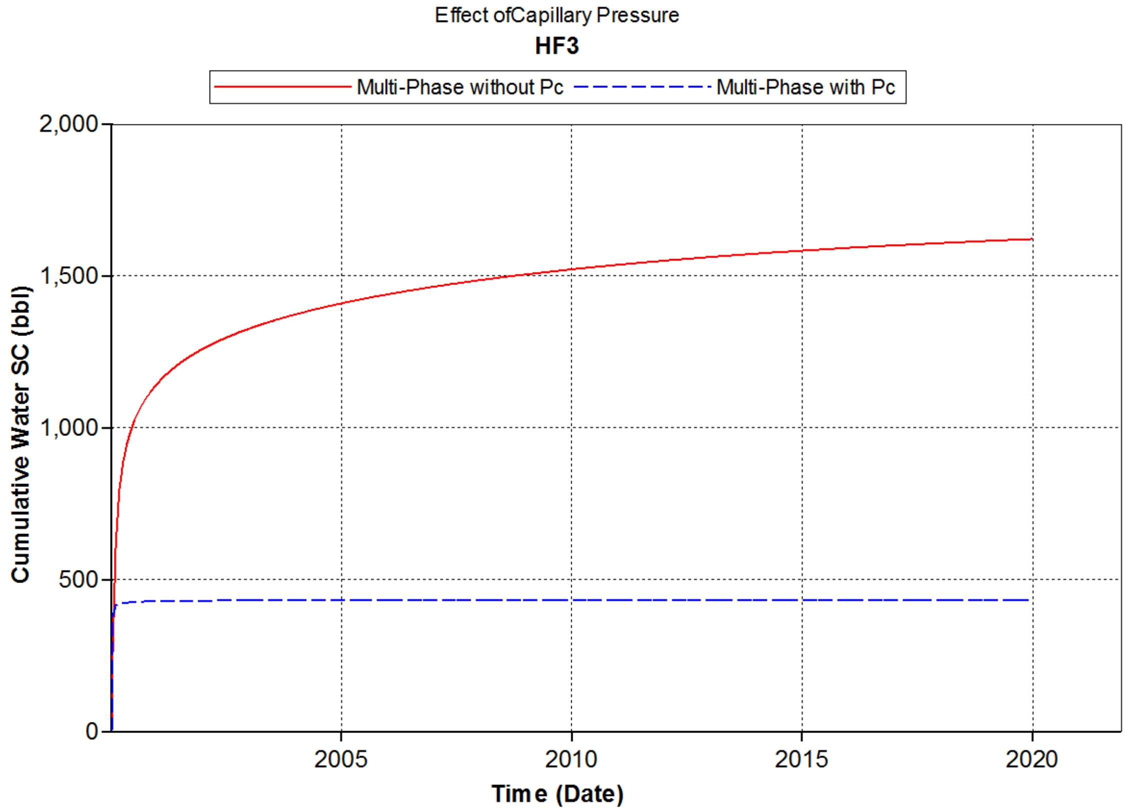

Figure 6-42: Effect of capillary pressure on cumulative fracture fluid production in HF3 (100 mesh sand).

Figure 6-42 represents the effect of capillary pressure on cumulative fracture fluid production in HF3. Similar to HF1 and HF2 above, fracture fluid production is higher with low capillary pressure than with high capillary pressure. High capillary pressure seems to decrease cumulative fracture fluid production. 1621.96 bbl of fracture fluid was produced with low capillary pressure compared to 431.99 bbl of fracture fluid with high capillary pressure. Cumulative fracture fluid produced with low capillary pressure was three times that with high capillary pressure.

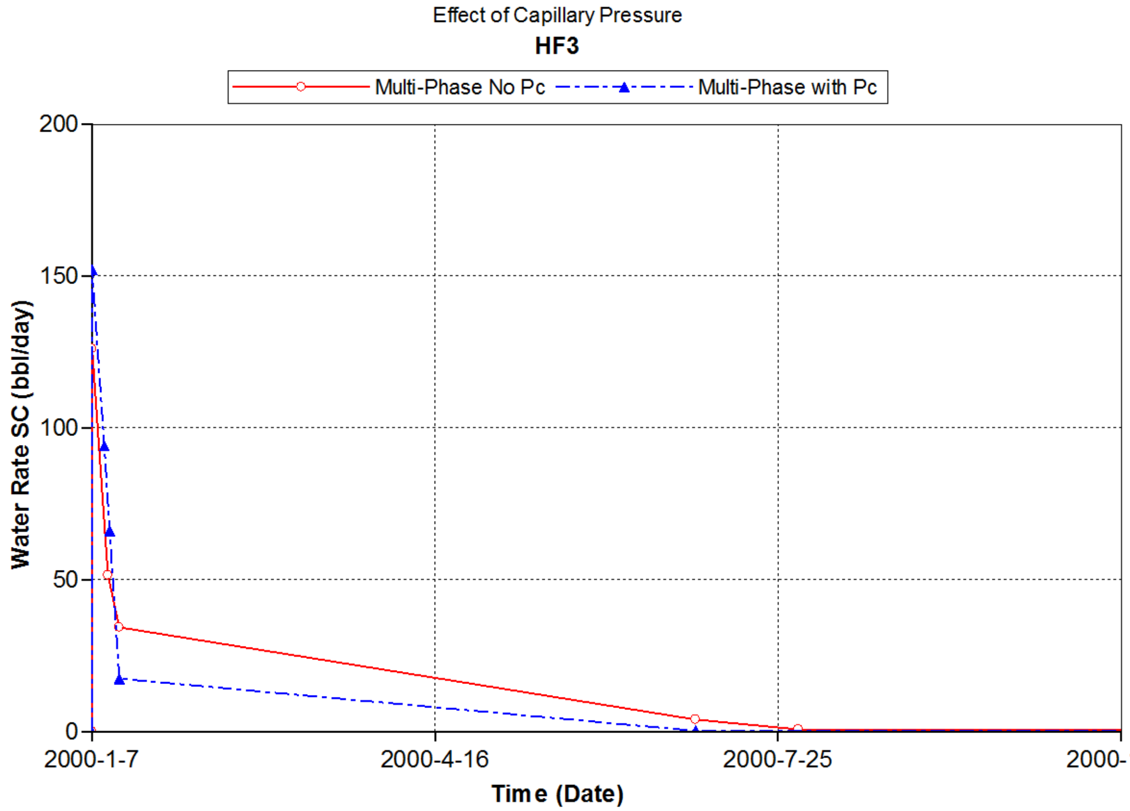

Figure 6-43: Effect of capillary pressure on fracture fluid production rate in HF3 (100 mesh sand).

In figure 6-43, capillary pressure in observed to decrease fracture fluid production rate in HF3. Fracture fluid production rate is observed to be higher during the first seven months of production with low capillary pressure. This difference in fracture fluid production rate within the first year is reflected in the cumulative amount of fracture fluid produced in the long term.

Table 6-9: One year cumulative fracture fluid production with low and high capillary pressure (100 mesh sand)

	Low Pc,		High Pc,	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
HF1	933.94	41.50	558.87	24.8
HF2	970.00	43.10	546.58	24.3
HF3	1100.00	48.80	431.99	19.2

Table 6-9 summarizes cumulative fracture fluid production with low and high capillary pressure. In HF1, HF2 and HF3, cumulative fracture fluid production was higher without capillary pressure than with capillary pressure.

6.4 Effect of Shut-in Time

Effect of shut-in was evaluated by shutting in the well for durations of one week, two weeks and one year as compared to base case of no shut-in. Capillary pressure was assumed to be high in this case. The results of gas and fracture fluid production for HF1, HF2 and HF3 using 20/40 ceramics proppant and 100 mesh sand proppant are also presented in this section.

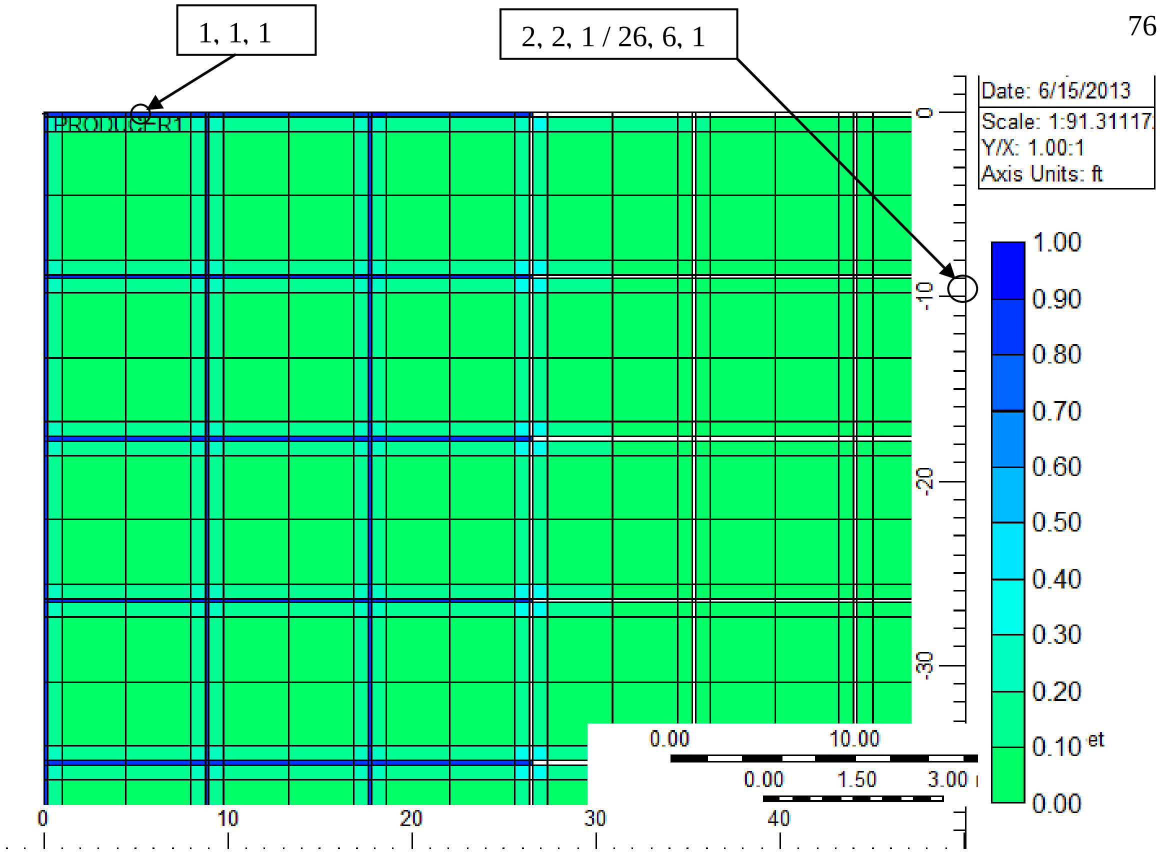

Figure 6-44: Map of water saturation after hydraulic fracture treatment in HF1 (with high Pc)

Figure 6-44 above shows water saturation in the hydraulic fractures and matrix near the well bore immediately after fracture fluid injection. To illustrate the change in water saturation in the reservoir grids due to shut-in we used two blocks; the well block (1 1 1) and matrix block (2 2 1/26 6 1) circled in the figure above. We would refer to the well block, 1 1 1, as well block and matrix block, 2 2 1/26 6 1, as matrix block for descriptive purposes. At the end of treatment, water saturation was 0.87 and 0.01 in the well and matrix blocks respectively. Water saturation after a week of shut-in is shown in the figure 6-45 below.

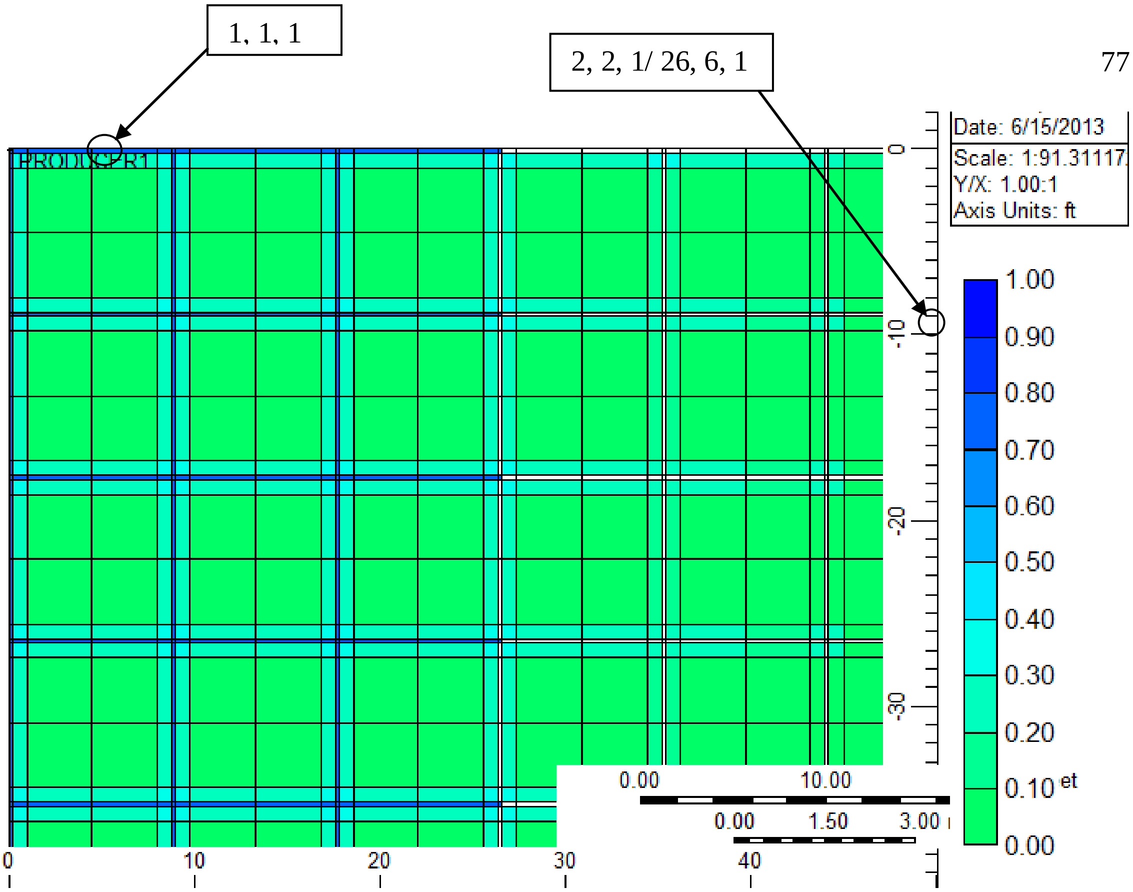

Figure 6-45: Map of water saturation after one week of shut-in HF1 (20/40 ceramics)

In figure 6-45, water saturation increased in areas away from the well block and the fractures. Fracture fluid penetrated deeper into the formation with time. Water saturation after one week of shut-in was 0.72 at the well and 0.16 at matrix block. Water saturation decreased in the fracture blocks and increased in matrix blocks nearby.

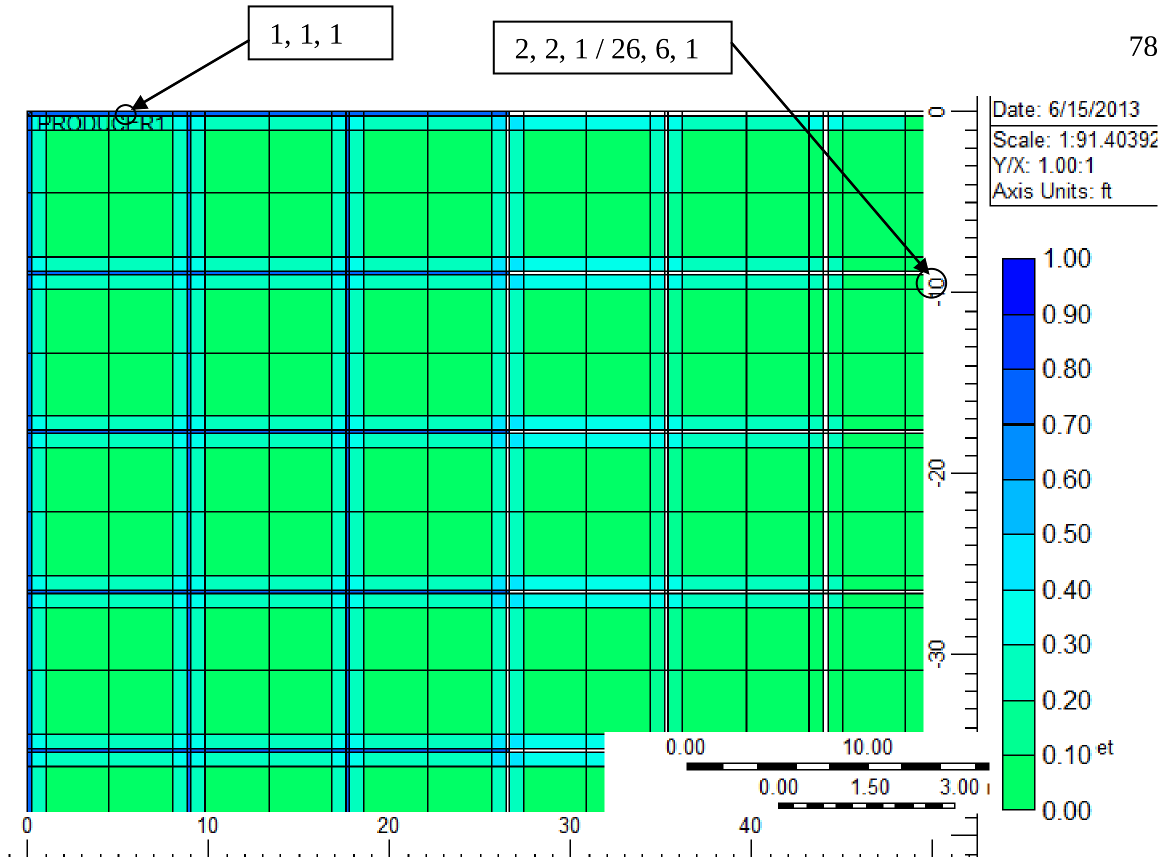

Figure 6-46: Map of water saturation after two weeks of shut-in in HF1 (20/40 ceramics)

In figure 6-46, water saturation increased away from the well block and hydraulic fractures. After two weeks of shut-in, water saturation dropped to 0.71 in the well block and increased to 0.21 in the matrix block. The Fracture fluid penetrated deeper as shut in time increased.

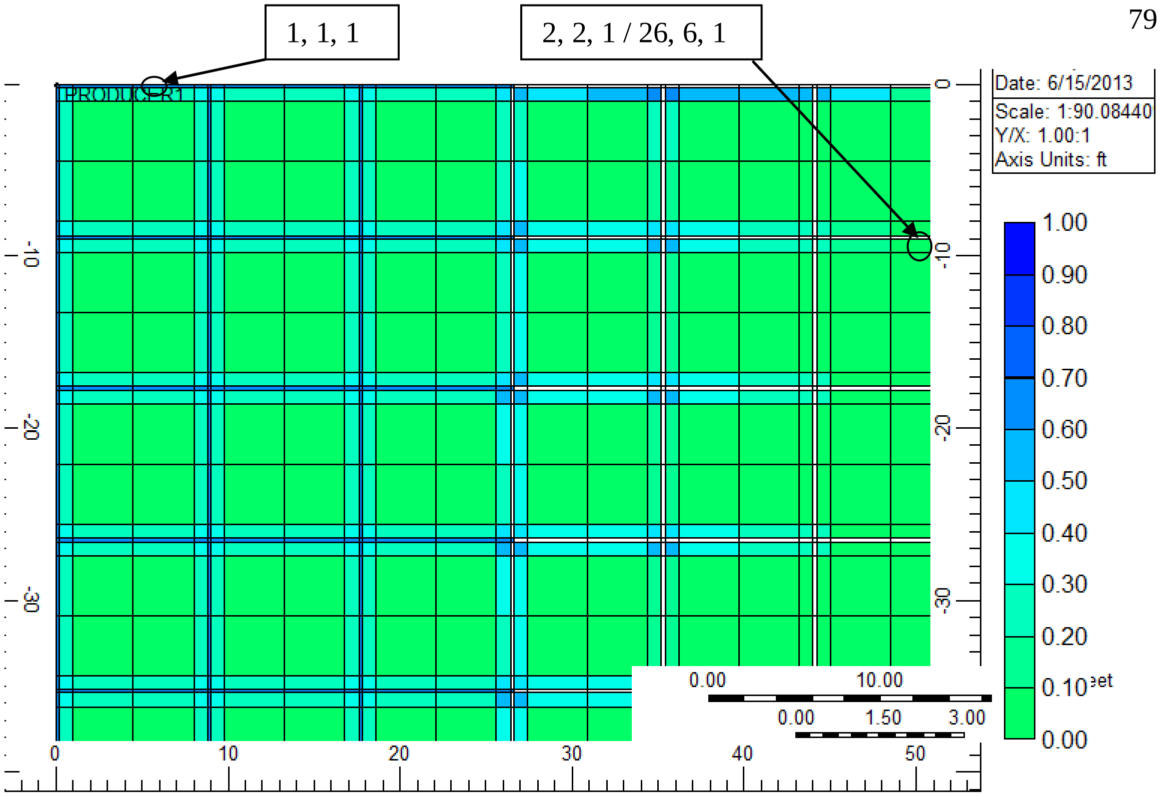

Figure 6-47: Water saturation after one year of shut-in in HF1 (20/40 ceramics)

Figure 6-47 water saturation around the well and hydraulic fractures after one year of shut-in. After one year of shut-in, water saturation in the well block reduced to 0.62 while in the matrix block water saturation increased to 0.27.

Table 6-10: Variation in water saturation as shut-in time increases, HF1

Duration of shut-in	Well block (1, 1, 1)	Matrix block (2, 2, 1/26, 6,1)
No shut in	0.87	0.01
1 week	0.72	0.16
2 weeks	0.71	0.21
1 year	0.62	0.27

In summary, table 6-10 above shows that length of shut-in time allows water to penetrate deeper into the formation. This could affect the rate of fracture fluid production as well as cumulative amount of fracture fluid that can be produced when the well is put on production as will be explained below.

6.4.1 Effect of Shut-in Time using 20/40 Ceramics Proppant

In this section, we discussed the results of the effect of shut-in time when the hydraulic fractures are propped with a highly conductive 20/40 ceramics proppant.

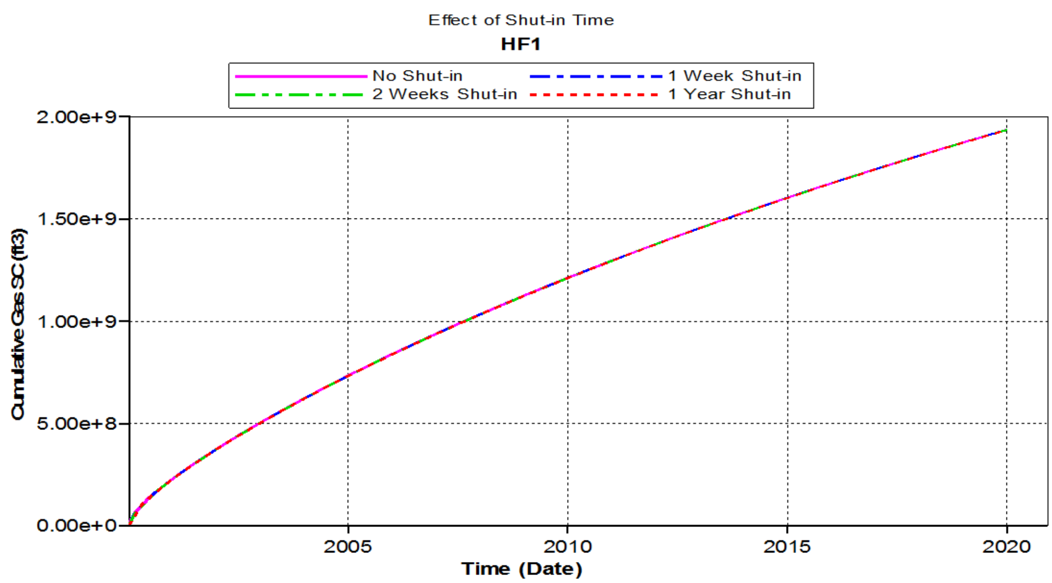

Figure 6-48: Effect of shut-in time on cumulative gas production in HF1 (20/40 ceramics)

Figure 6-48 above shows the effect of shut-in time in HF1. In the base case with no shut-in, 1.94 BCF of gas was produced in twenty years. After shutting in the well for one week, two weeks and 1 year, gas production was 1.94 BCF, 1.94 BCF and 1.94 BCF respectively. There was little or no change in cumulative gas production with shut-in over a twenty year period.

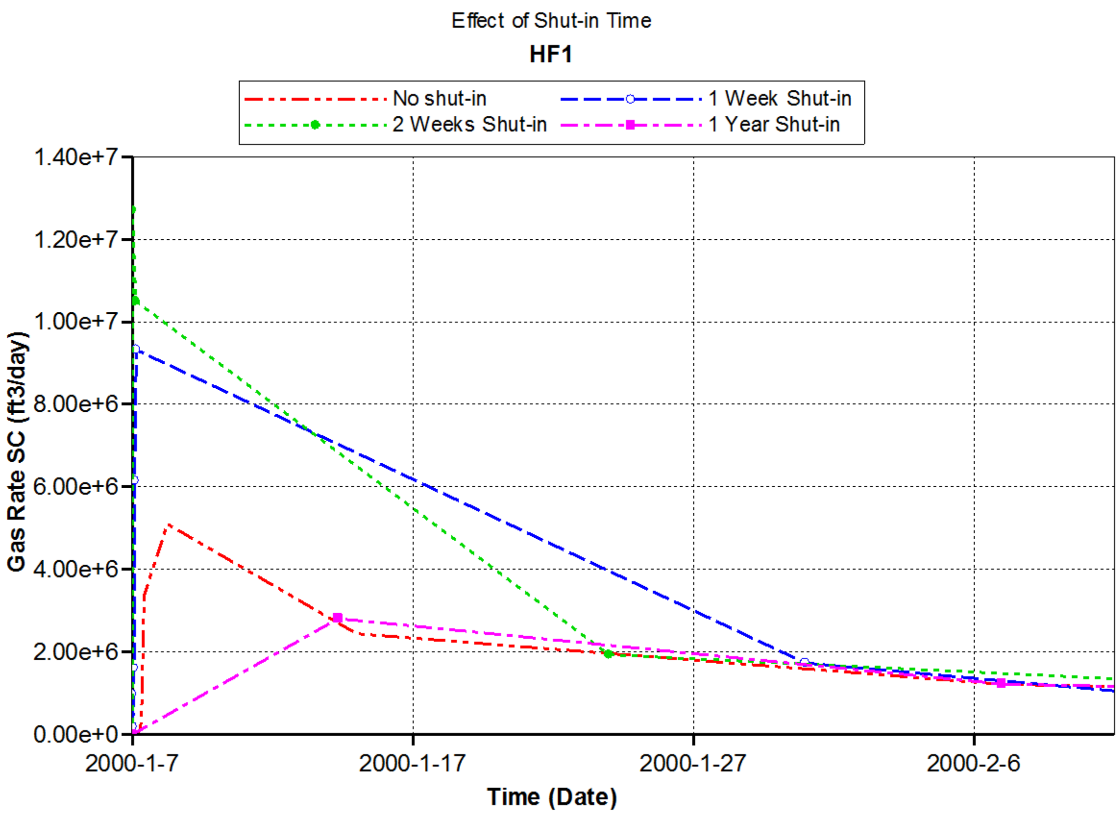

Figure 6-49: Effect of shut-in time on gas production rate in HF1 (20/40 ceramics)

In figure 6-49, initial production rate without shut-in was low for a few days before increasing to a peak, the low initial gas rate without shut-in represents the period of cleanup of the well. Initial gas rate was higher for cases with longer periods of shut in but gas rate became about the same after a month of production

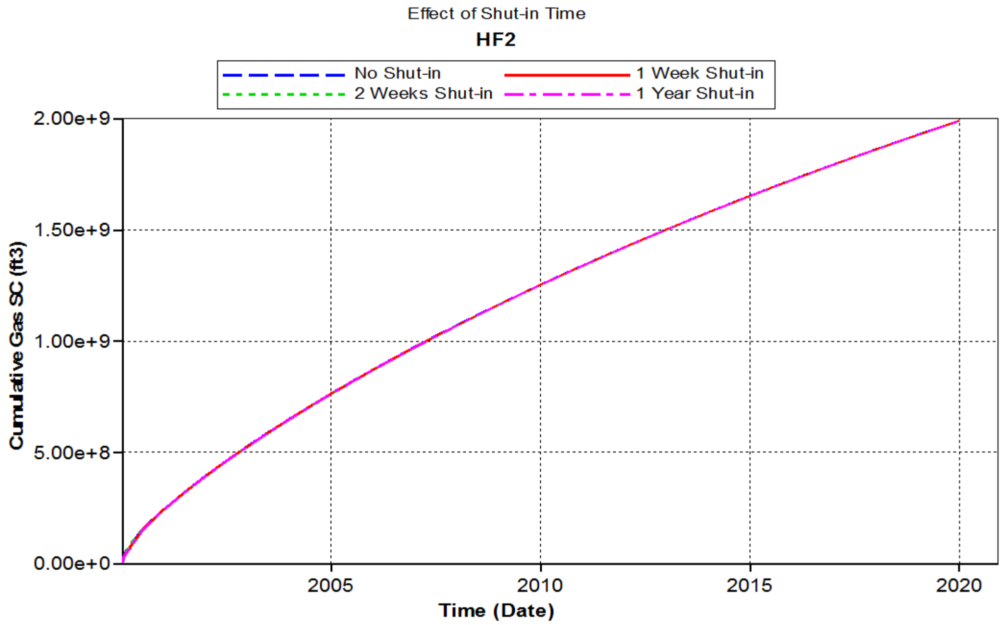

Figure 6-50: Effect of shut-in time on cumulative gas production in HF2 (20/40 ceramics)

Figure 6-50 shows the effect of shut-in on gas production in HF2. Gas production in twenty years was 1.99 BCF, 1.99 BCF, 1.99 BCF and 1.99 BCF for no shut-in, one week shut-in, two weeks shut-in and one year shut-in respectively. Twenty years cumulative production was the same for all durations of shut in.

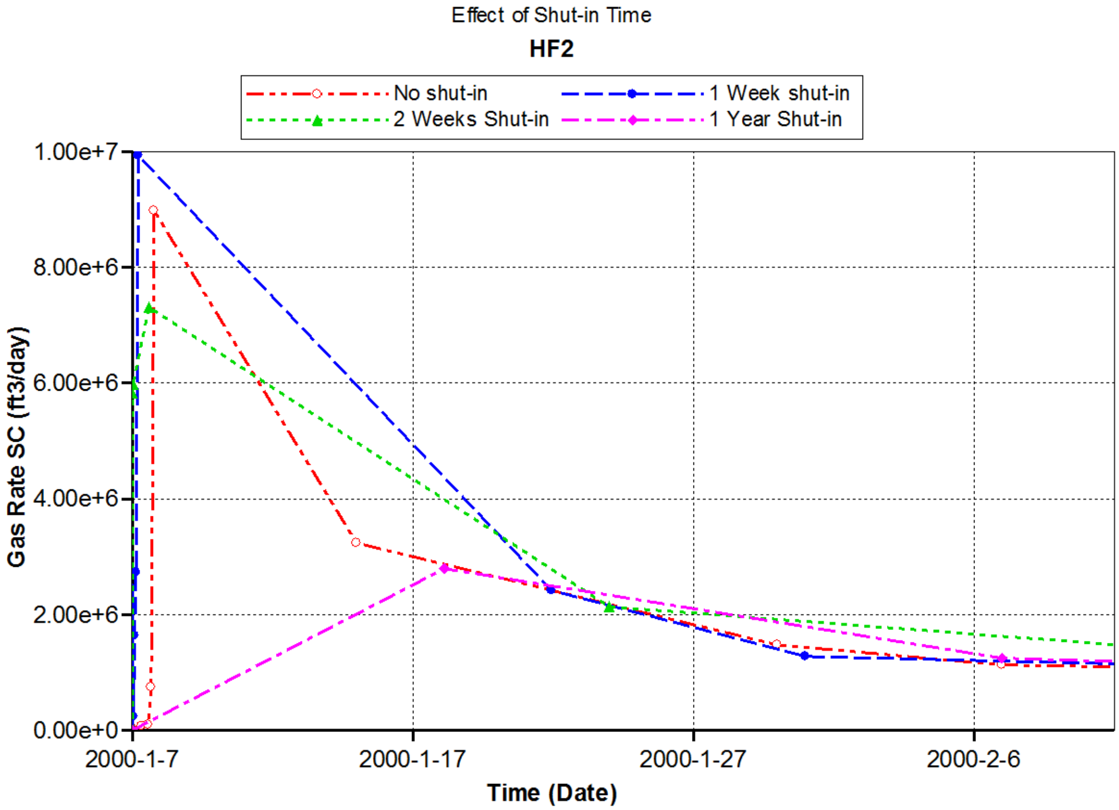

Figure 6-51: Effect of shut-in time on gas production rate in HF2 (20/40 ceramics)

In Figure 6-51, initial gas rate was low without shut-in but increased after a few days of production. This period of low gas rate would be the period of clean up of fracture fluid. Initial gas rate was higher with longer shut in time but gas rates became about the same after two months of gas production. This shows that the longer the duration of shut-in the less the time required to clean up the well.

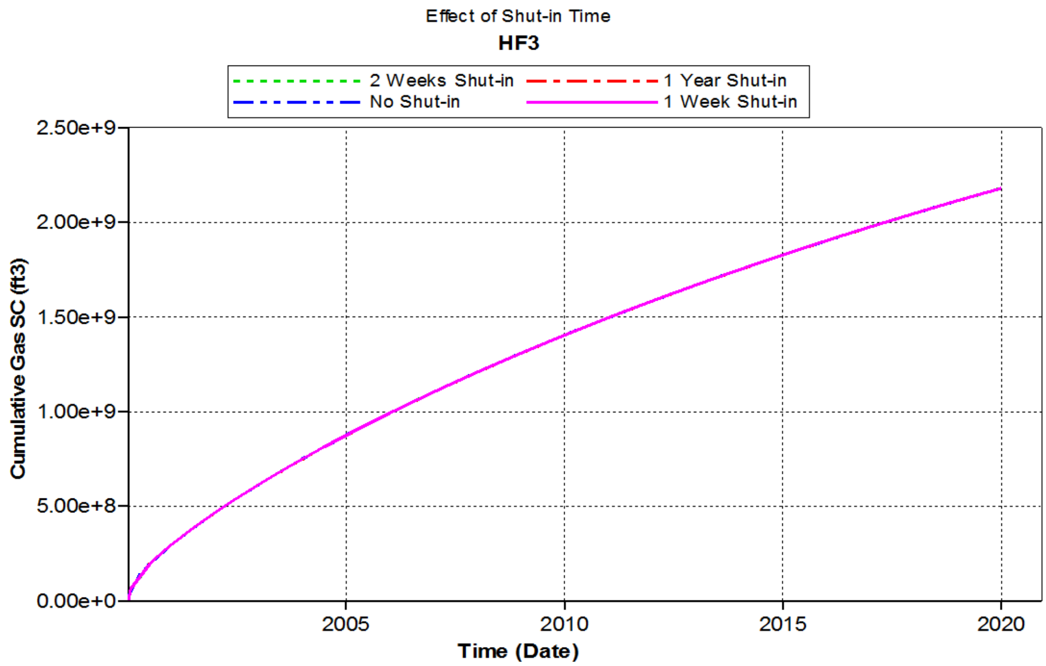

Figure 6-52: Effect of shut-in time on cumulative gas production in HF3 (20/40 ceramics)

Figure 6-52 shows about the same cumulative gas production in all four cases of shut-in time. Twenty years cumulative gas production was 2.18 BCF, 2.18 BCF, 2.18 BCF and 2.18 BCF with no shut-in, one week shut-in, two weeks shut-in and one year shut-in respectively. Cumulative gas production was the same for all durations of shut-in.

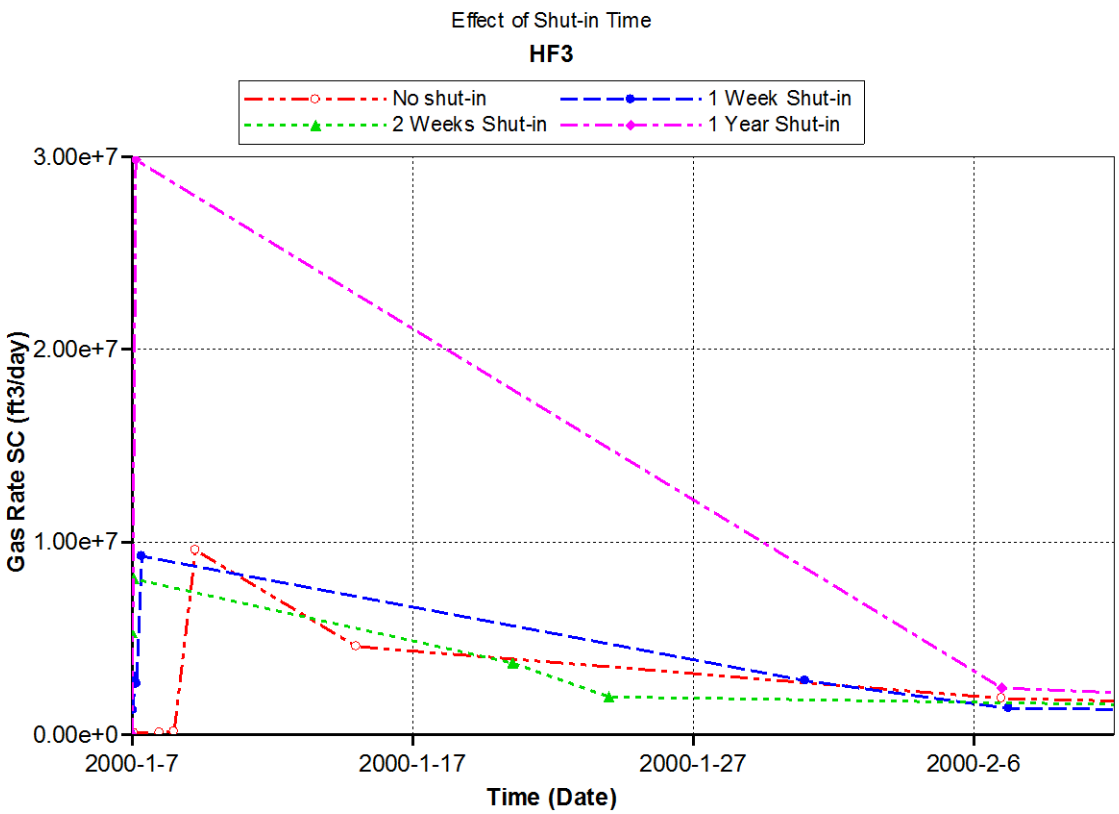

Figure 6-53: Effect of shut-in time on gas production rate in HF3 (20/40 ceramics)

In figure 6-53 above, initial gas production rate was low without shut-in and higher for longer durations of shut-in. Duration of shut-in affected the initial gas production rate but gas rates became about the same after producing the well for a period of two months. Longer duration of shut-in leads to shorter cleanup time which could mean higher initial gas rates.

Table 6-11: 20 years cumulative gas production for various durations of shut-in (20/40 ceramics)

Duration of shut-in	Cumulative gas, HF1 (BCF)	Cumulative gas, HF2 (BCF)	Cumulative gas, HF3 (BCF)
No shut-in	1.94	1.99	2.18
1 week	1.94	1.99	2.18
2 weeks	1.94	1.99	2.18
1 year	1.94	1.99	2.18

Table 6.11 shows cumulative gas production for HF1, HF2, and HF3 for various durations of shut-in. In HF1, HF2 and HF3, cumulative gas production remained about the same for all cases of shut-in.

From the figures of gas rate, it was observed that initial gas rate was higher with longer durations of shut-in than without shut-in. With this we can conclude that longer durations of shut-in makes a fractured gas well to start producing with a higher initial gas rate while gas rate peak in delayed without shut-in.

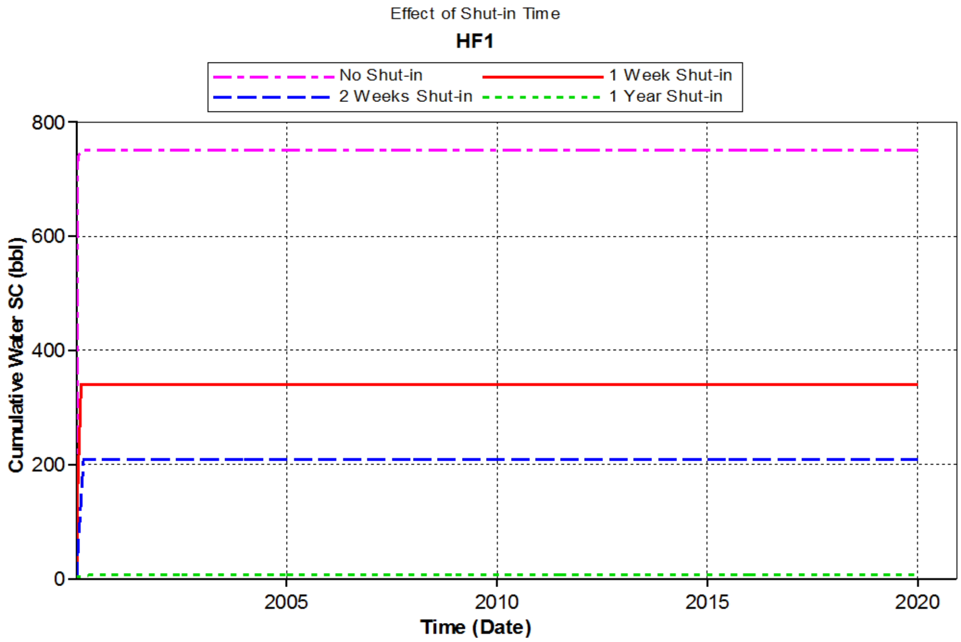

Figure 6-54: Effect of shut-in time on cumulative fracture fluid production in HF1 (20/40 ceramics)

In figure 6-54 above, cumulative fracture fluid production in HF1 was 750 bbl without shut-in, 340 bbl for 1 week shut-in, 208 bbl for 2 weeks shut-in and 6 bbl for one year shut in. In all four cases, most of the fracture fluid was recovered within the first three months of production. Cumulative fracture fluid production decreased with length of shut-in which could be due to deeper penetration of the fracture fluid into the formation as shut-in time is extended.

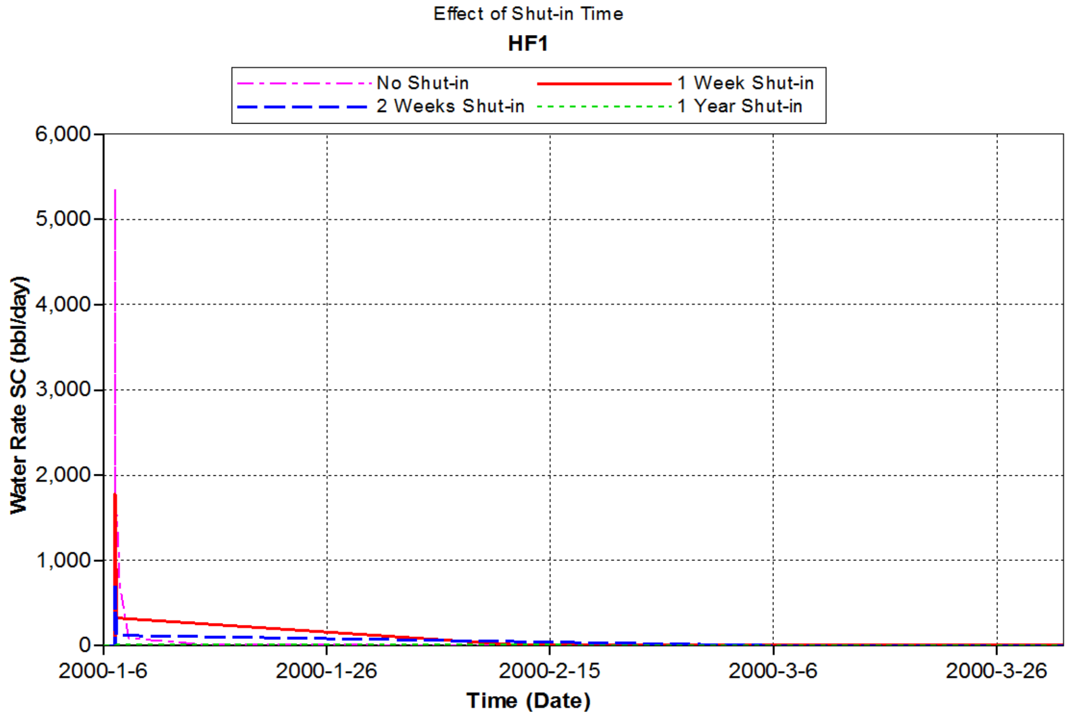

Figure 6-55: Effect of shut-in time on fracture fluid rate in HF1 (20/40 ceramics)

Figure 6-55 represents the effect of shut-in time on fracture fluid production rate in HF1. Initial fracture fluid rate was 5360 bbl/d without shut-in, 1775 bbl/d for one week shut-in, 708 bbl/d for two weeks shut-in and 13 bbl/d for one year shut-in. Initial fracture fluid rate decreased as length of shut-in increased. The longer the shut-in time, the less the initial fracture fluid rate and consequently the less the cumulative fracture fluid recovered.

The same trend is observed in HF2 and HF3 as shown in figure A-1 to A-4 in Appendix. Cumulative fracture fluid produced and initial fracture fluid rate decreased as length of shut-in increased.

Table 6-12: One year cumulative fracture fluid production at various shut-in times (20/40 mesh)

Duration of shut-in	HF1		HF2		HF3	
	Volume (bbls)	Recovery (%)	Volume (bbls)	Recovery (%)	Volume (bbls)	Recovery (%)
0 days	750.95	33.35	875.68	38.90	1092.94	48.57
1 week	340.34	15.11	326.04	14.50	256.73	11.40
2 weeks	214.59	9.53	202.83	9.04	150.88	6.72
1 year	6.32	0.28	5.56	0.25	5.12	0.22

Table 6-12 summary of cumulative fracture fluid production for HF1, HF2 and HF3.

From table 6-12, we observed that fracture fluid recovery decreased with length of shut-in. Fracture fluid penetrated deeper into the formation as length of shut-in increased which caused less fracture fluid to be produced. We can conclude that less fracture fluid is produced with longer periods of shut-in after hydraulic fracture treatment.

6.4.2 Effect of Shut-in Time using 100 Mesh Sand

The following results were obtained when 100 mesh sand was used as the proppant.

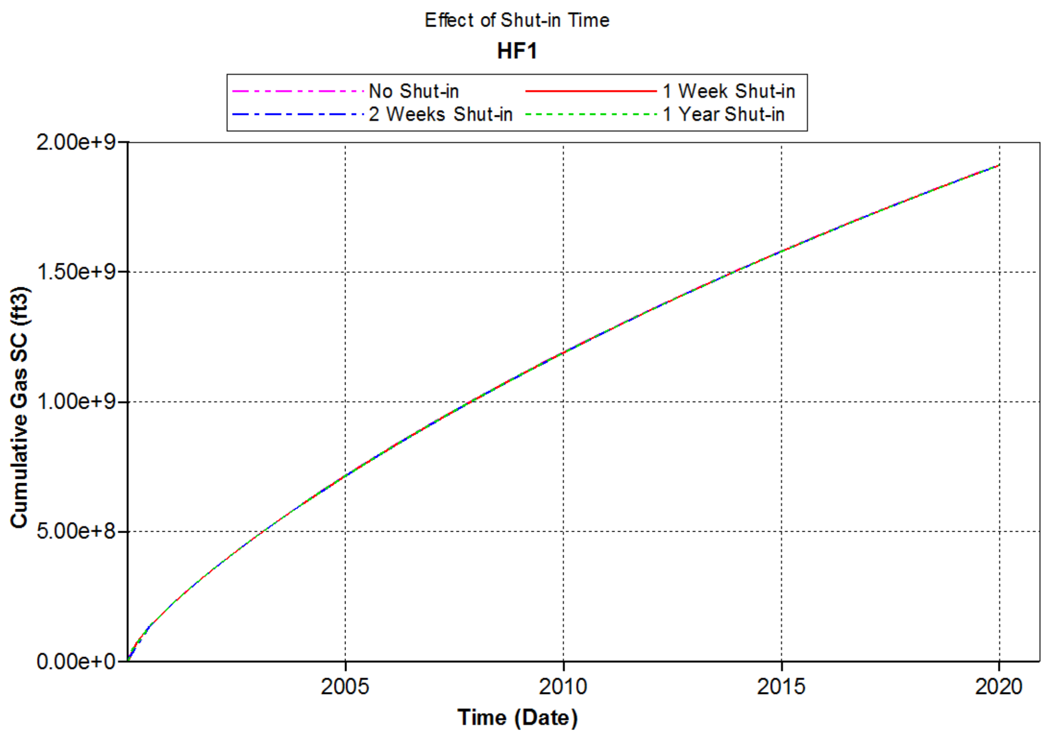

Figure 6-56: Effect of shut-in time on cumulative gas production in HF1 (100 mesh sand)

Figure 6-56 represents the effect of shut-in time on gas production in HF1 when the hydraulic fractures are propped using 100 mesh sand. Cumulative gas production for twenty years was about the same for all the durations of shut-in. 1.90 BCF of gas was produced in each of the cases of shut-in. Based on the above result we can say length of shut-in time did not affect cumulative gas production.

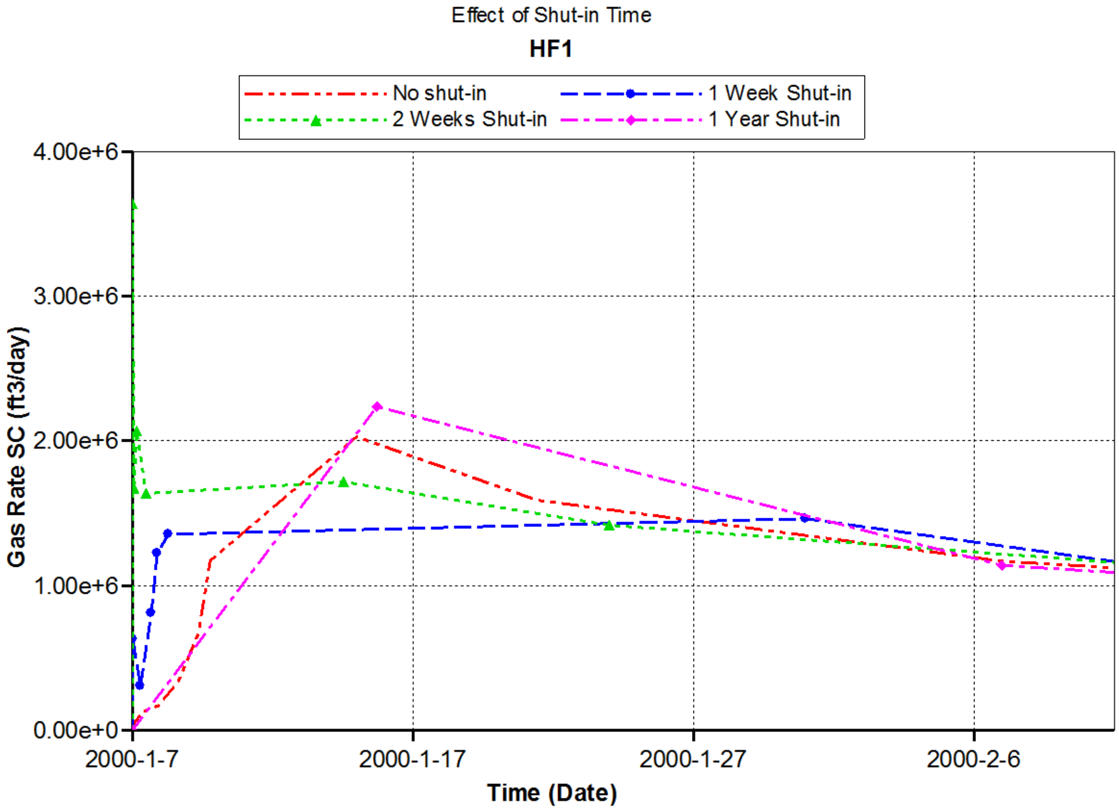

Figure 6-57: Effect of shut-in time on gas production rate in HF1 (100 mesh sand)

Figure 6-57 shows the effect of shut-in time on gas rate in HF1. Fracture fluid distribution and depth of fracture fluid penetration may affect the rate at which gas is produced. It can be seen that gas rate without shut-in started very low for a few days before increasing to a peak. Gas rate peak for one week shut-in was delayed for a day before it peaked while two weeks shut-in peaked on the first day of production. Gas rate for one year shut-in was observed to increase continuously for the first two weeks of production.

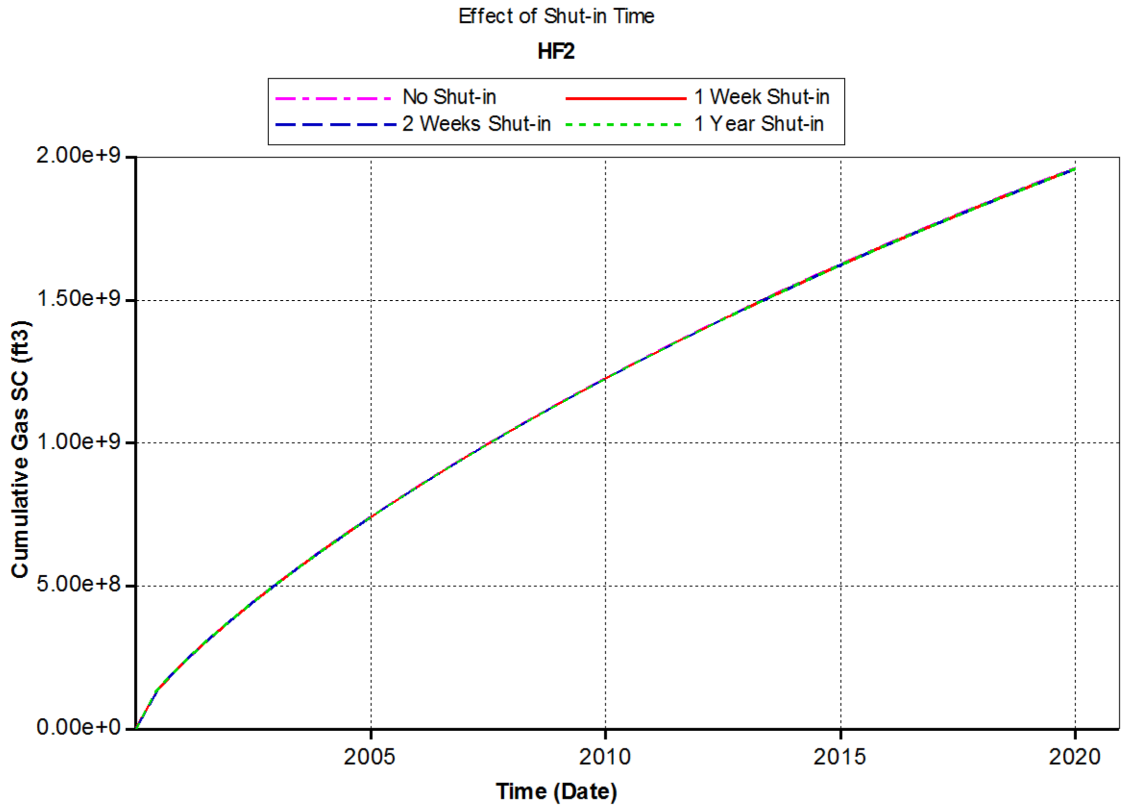

Figure 6-58: Effect of shut-in time on cumulative gas production in HF2 (100 mesh sand)

Figure 6-58 show the effect of shut-in time on cumulative gas production for HF2 in twenty years. The same amount (1.94 BCF) of gas was produced in all cases of shut-in. There was no change in the volume of gas produced in twenty years with the different lengths of shut-in. From this result we can say that shut-in time did not affect long-term cumulative gas production in HF2.

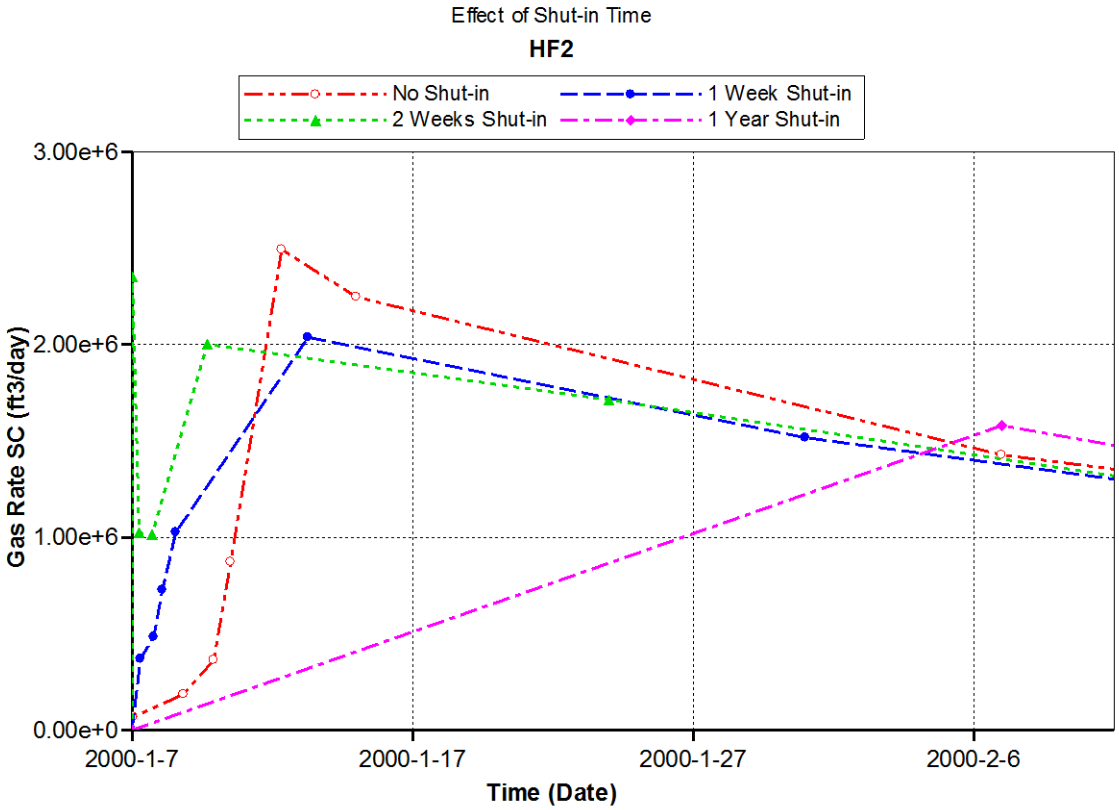

Figure 6-59: Effect of shut-in time on gas production rate in HF2 (100 mesh sand)

Figure 6-59 shows the effect of shut-in time on gas production rate in HF2. Initial gas rate was low without shut-in compared to cases with longer lengths of shut-in time. Initial gas rate was highest for two weeks shut-in followed by one week shut-in. Without shut-in, gas rate suffered a slow start mostly due to fracture fluid cleanup while gas rate for one year shut-in increased continuously for the first one month of production.

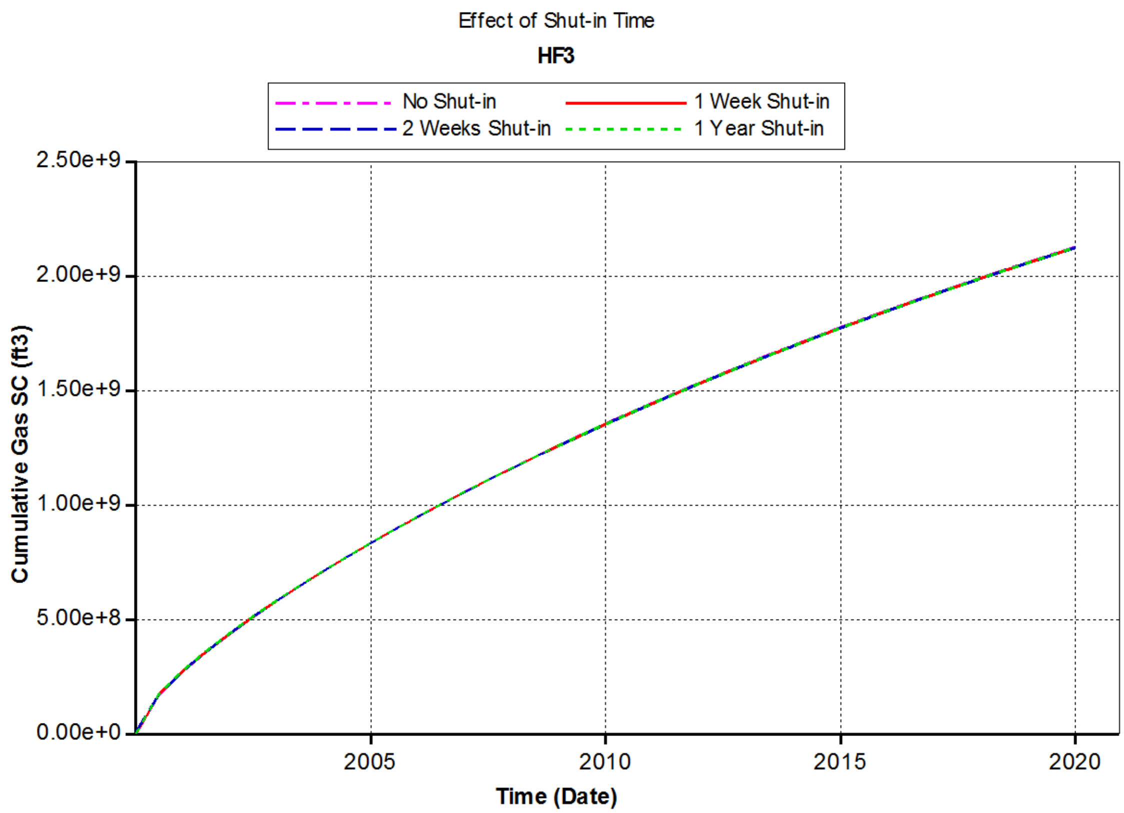

Figure 6-60: Effect of shut-in time on cumulative gas production in HF3 (100 mesh sand)

Effect of shut-in time on cumulative gas production in HF3 is shown in figure 6-60. Figure 6-60 shows about the same amount of gas production for all the cases of shut-in. 2.09 BCF of gas was produced in twenty years without shutting in the well but the cumulative volume of gas produced remained at 2.09 BCF after shutting in the well for one week, two weeks and one year. In general, length of shut-in time did not affect cumulative gas production in HF3 over a twenty year period.

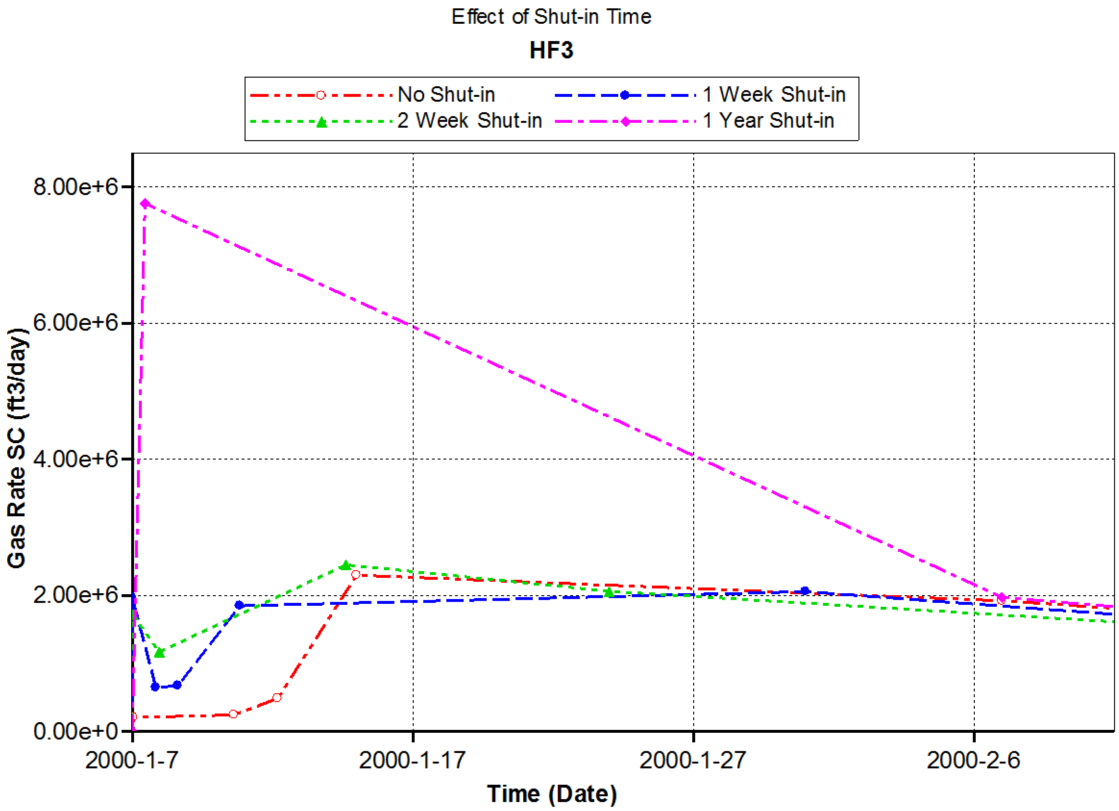

Figure 6-61: Effect of shut-in time on gas production rate in HF3 (100 mesh sand)

Figure 6-61 shows effect of shut-in time on gas production rate in HF3. Initial gas rate was highest for one year shut-in compared to all other cases. Two weeks shut-in was second after one year shut-in while initial gas rate was the lowest without shutting in well after hydraulic fracture treatment. In HF3, we can conclude that fracture fluid cleanup is faster with longer lengths of shut-in time.

Table 6-13: 20-year cumulative gas production at various shut-in times

Duration of shut-in	HF1, Volume (BCF)	HF2, Volume (BCF)	HF3, Volume (BCF)
0 day	1.90	1.94	2.09
1 Week	1.90	1.94	2.09
2 Weeks	1.90	1.94	2.09
1 Year	1.90	1.94	2.09

Table 6-13 above gives a summary of cumulative gas production from HF1, HF2 and HF3 for different durations of shut-in. From the table, we can see that cumulative gas production was unaffected by length of shut-in time.

Table 6-14: Two months cumulative gas production for various shut-in times

Shut-in duration	HF1 (MMSCF)	HF2 (MMSCF)	HF3 (MMSCF)
No shut-in	52.10	55.30	62.50
1 weeks	52.80	56.30	66.50
2 weeks	53.40	57.30	68.20
1 year	55.90	60.00	70.34

Table 6-14 above shows eight weeks cumulative gas production from HF1, HF2 and HF3. Cumulative gas production increased slightly with length of shut-in. In HF1, HF2 and HF3, cumulative gas production was highest for one year shut-in after eight weeks of production. This shows that length of shut-in time could increase cumulative gas production in the early stage of production. But the results obtained for twenty years showed equal volume of gas produced for all cases of shut-in, we can say that length of shut-in time increases cumulative gas production but only in the early stages (during cleanup).

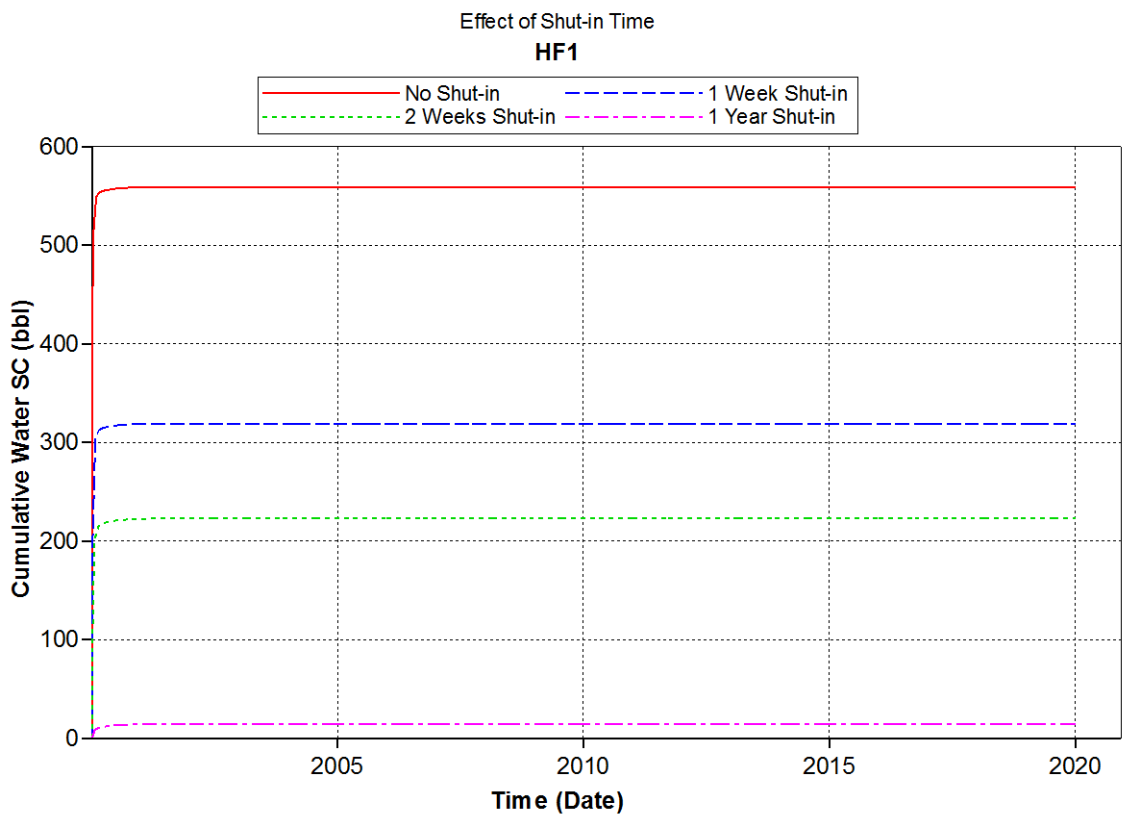

Figure 6-62: Effect of shut-in time on cumulative fracture fluid production in HF1 (100 mesh sand)

Figure 6-62 represents cumulative gas production for four cases of shut-in for HF1. During the hydraulic fracture treatment, 2250 bbl of fracture fluid was injected into the well to create the fractures. Of this total volume injected, 558.87 bbl (24.83%) was recovered without shut-in and recovery dropped to 316.19 bbl (14.05%) with one week of shut-in. Two weeks and one year shut-in had lower fracture fluid recovery of 222.86 bbl (9.86%) and 14.16 bbl (0.63%) respectively. These results show that length of shut-in time affects fracture fluid recovery after hydraulic fracture treatment. Cumulative fracture fluid production decreases with length of shut-in since the fracture fluid penetrates deeper into the formation with longer shut-in time.

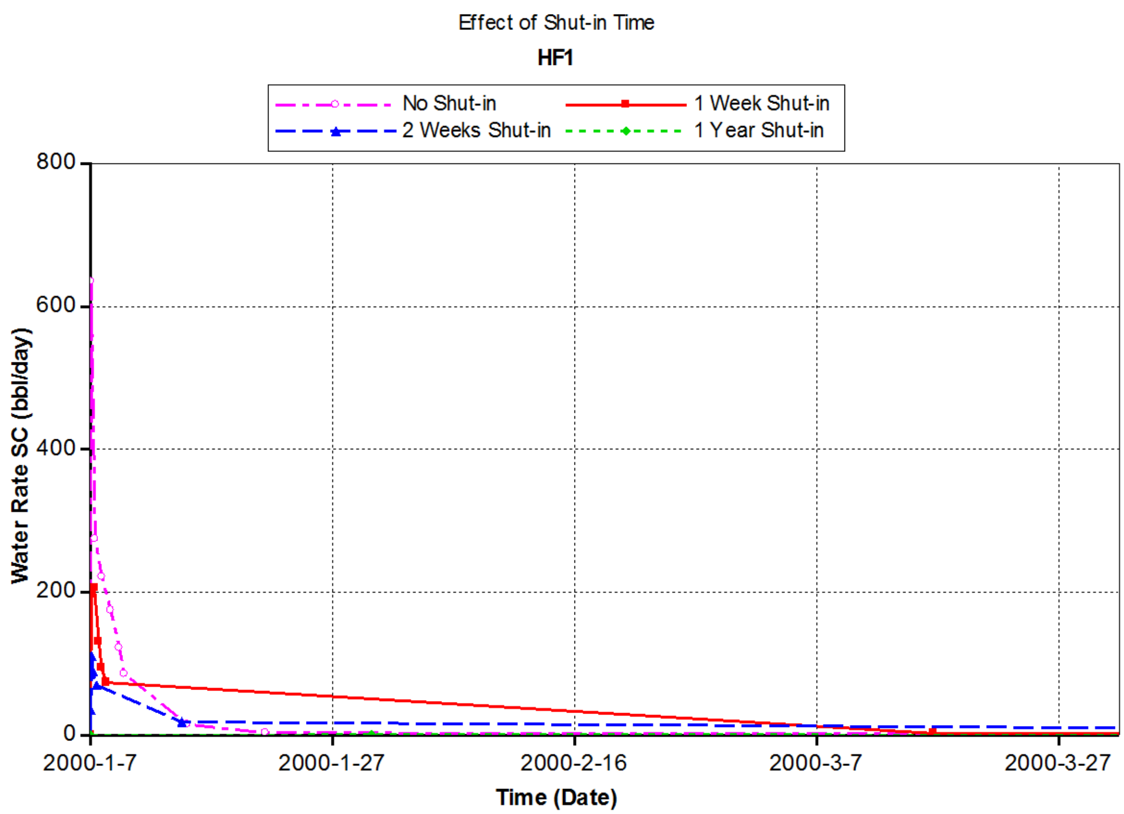

Figure 6-63: Effect of shut-in time on fracture fluid production rate in HF1 (100 mesh sand)

Effect of shut-in time on fracture fluid rate in HF1 is represented by Figure 6-63. Putting the well on production without shutting-in after hydraulic fracture treatment has the highest initial fracture fluid rate followed by one week shut-in, two weeks shut-in and lastly one year shut-in with fracture fluid rate close to zero. Initial fracture fluid rate decreases with length of shut-in.

Fracture fluid recovery has the same trend in HF2 and HF3 as shown in figure A-5 to A-8. Cumulative fracture fluid production decreases as length of shut-in increases.

Table 6-15 1-year cumulative fracture fluid production at various shut-in times (100 mesh sand)

Duration of shut-in	HF1		HF2		HF3	
	Volume (bbl)		Volume (bbl)		Volume (bbl)	
0 day	558.87	24.80	546.58	24.30	431.99	19.2
1 Week	316.19	14.12	308.78	13.70	189.77	8.40
2 Weeks	222.86	9.90	214.99	9.55	125.62	5.55
1 Year	14.16	0.62	17.99	0.79	14.47	0.60

In summary, cumulative fracture fluid production as shown in Table 6.15 above decreases as shut-in time increases in HF1, HF2 and HF3. Comparing to the high conductivity cases in Table 6-12, we observed a decrease in fracture fluid recovery.

6.5 Effect of Proppant Crushing

The effect of proppant crushing was evaluated using 20/40 ceramics proppant and 100 mesh sand. The well was shut-in for two weeks after hydraulic fracture treatment before production commenced. We compared the case of two weeks of shut-in without proppant crushing to the case of two weeks of shut-in with proppant crushing. The results using each proppant type are analyzed in this section.

6.5.1 Effect of Proppant Crushing using 20/40 Ceramics Proppant

In this section, we used the high conductive 20/40 Ceramics proppant to prop the hydraulic fractures. Twenty year production results are presented below.

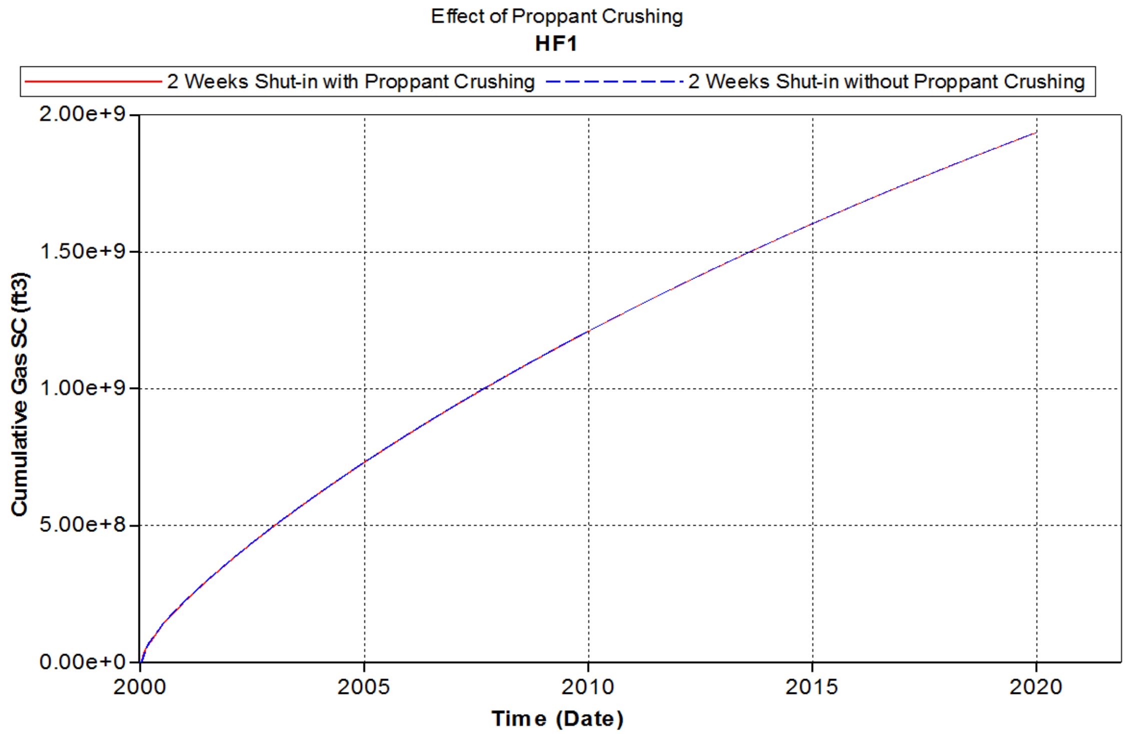

Figure 6-64: Effect of proppant crushing on cumulative gas production in HF1 (20/40 ceramics)

Effect of proppant crushing on cumulative gas production in HF1 is reported in figure 6-64. Cumulative gas production was 1.94 BCF without proppant crushing and 1.94 BCF with proppant crushing. Twenty years cumulative gas production was unaffected by proppant crushing using 20/40 ceramics which could be due to high conductivity of proppant in the hydraulic fractures.

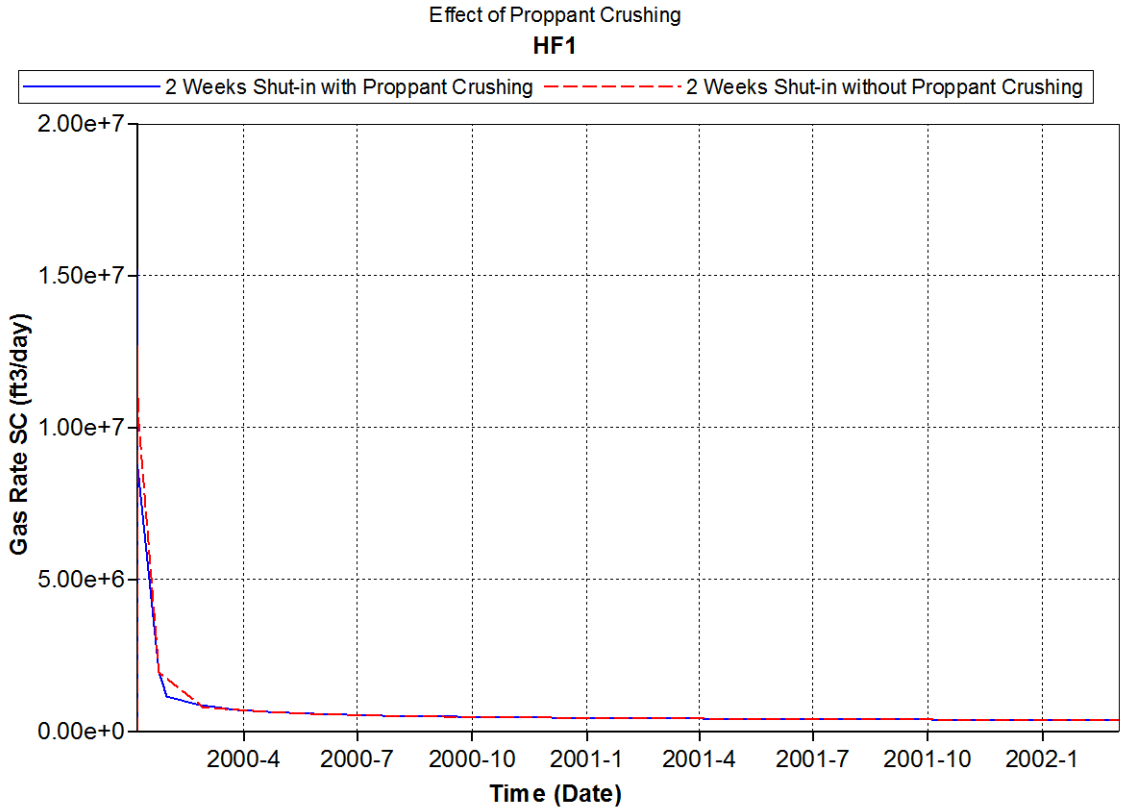

Figure 6-65: Effect of proppant crushing on gas production rate in HF1 (20/40 ceramics)

Figure 6-65 represents the effect of proppant crushing on gas rate in HF1. Gas rates were about the same with and without proppant crushing in HF1. This could be as a result of the high conductivity of the proppant pack before the proppants were crushed. The high conductivity of the proppant makes the effect of proppant crushing less significant.

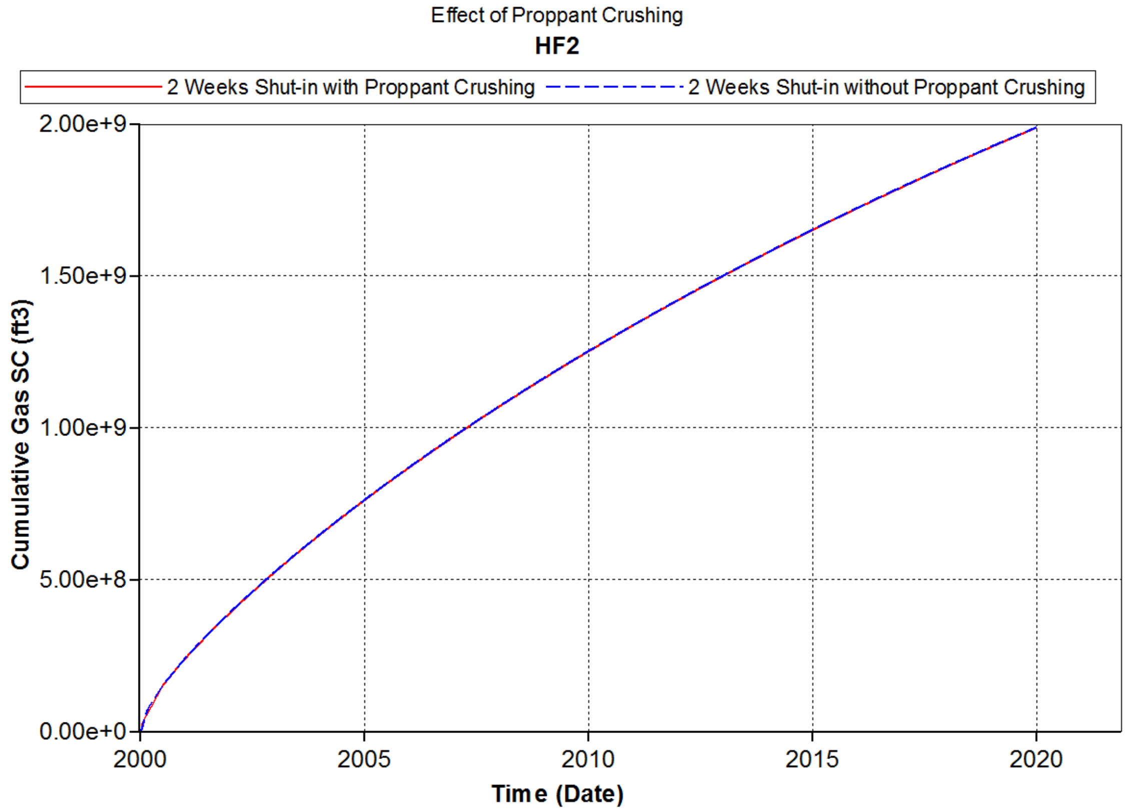

Figure 6-66: Effect of proppant crushing on cumulative gas production in HF2 (20/40 ceramics)

Figure 6-66 shows effect of proppant crushing on cumulative gas production in HF2. Similar to HF1, cumulative gas production is about the same for the case of proppant crushing and the case without proppant crushing after twenty years. 1.99 BCF and 1.99 BCF of gas were produced without and with proppant crushing respectively. Cumulative gas production was unaffected by proppant crushing when 20/40 ceramics proppant was used to prop hydraulic fractures in HF2.

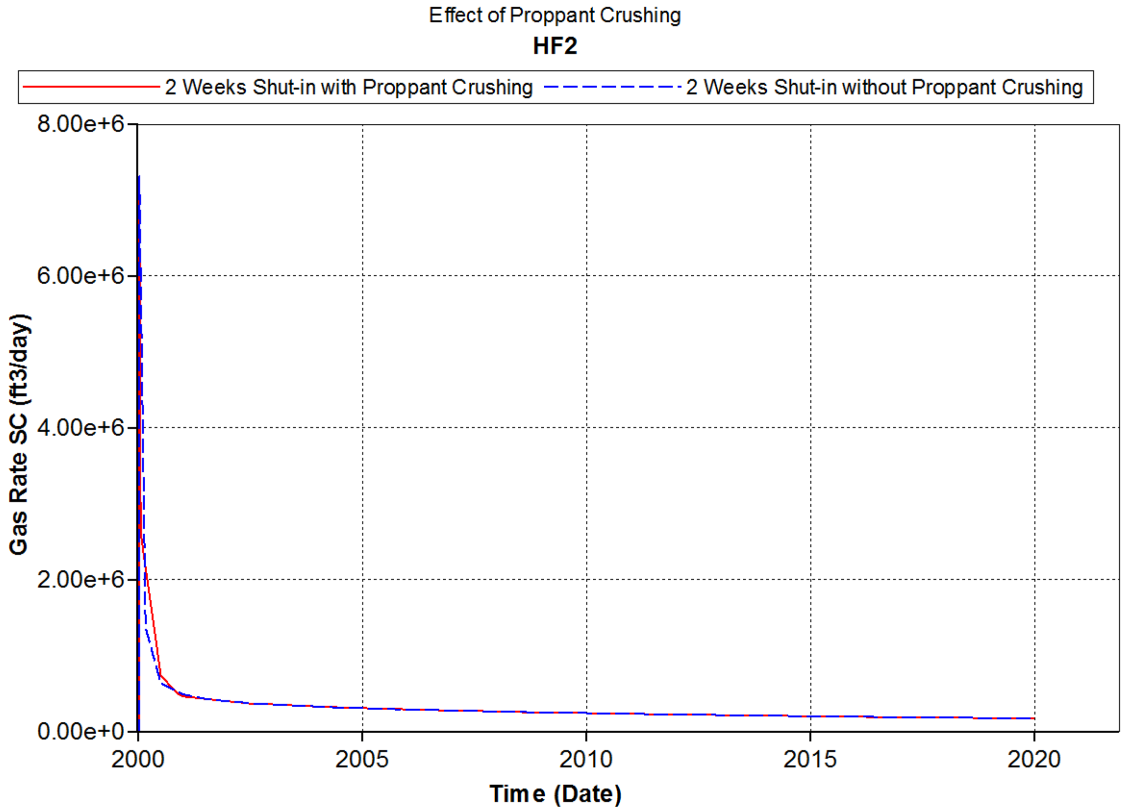

Figure 6-67: Effect of proppant crushing on gas production rate in HF2 (20/40 ceramics)

In Figure 6-67, shows the effect of proppant crushing on gas production rate. The rate of gas production was about the same throughout the twenty year period of production without proppant crushing and with proppant crushing.

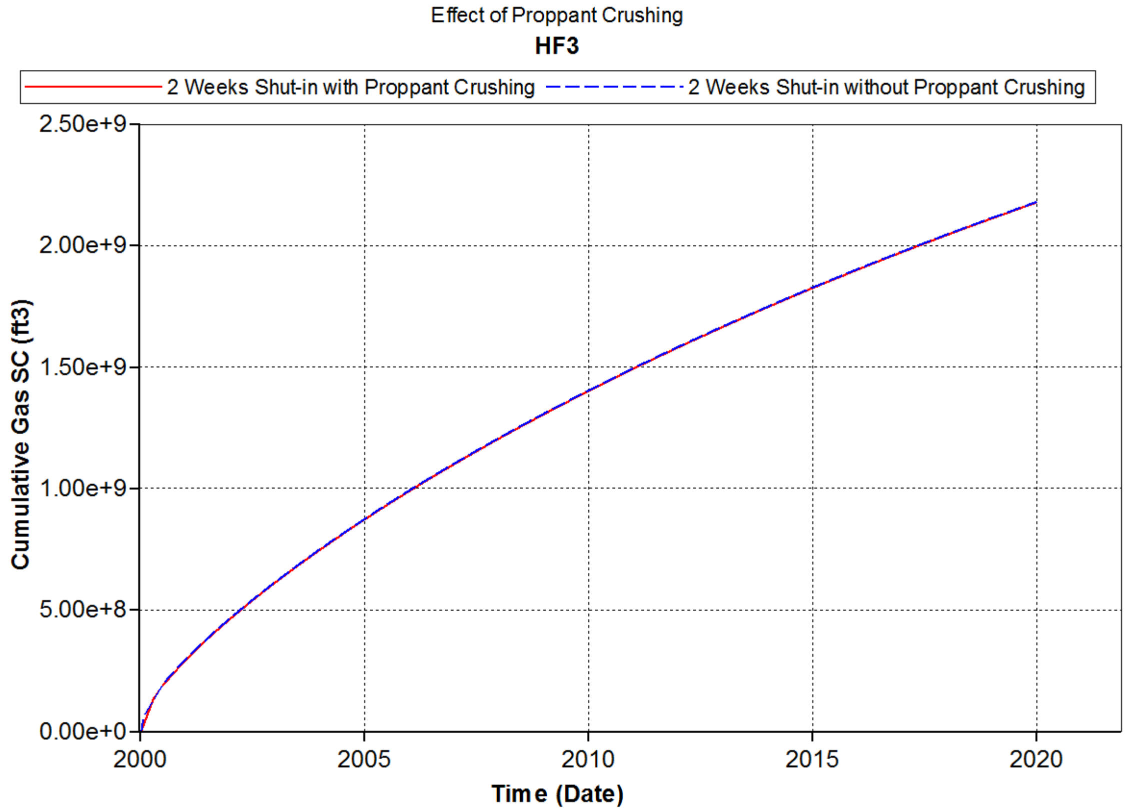

Figure 6-68: Effect of proppant crushing on cumulative gas production in HF3 (20/40 ceramics)

Figure 6-68 represents the effect of proppant crushing on cumulative gas production in HF3. The same amount (2.18 BCF) of gas was produced with or without proppant crushing. In HF3, proppant crushing did not affect cumulative gas production with 20/40 ceramics as proppant.

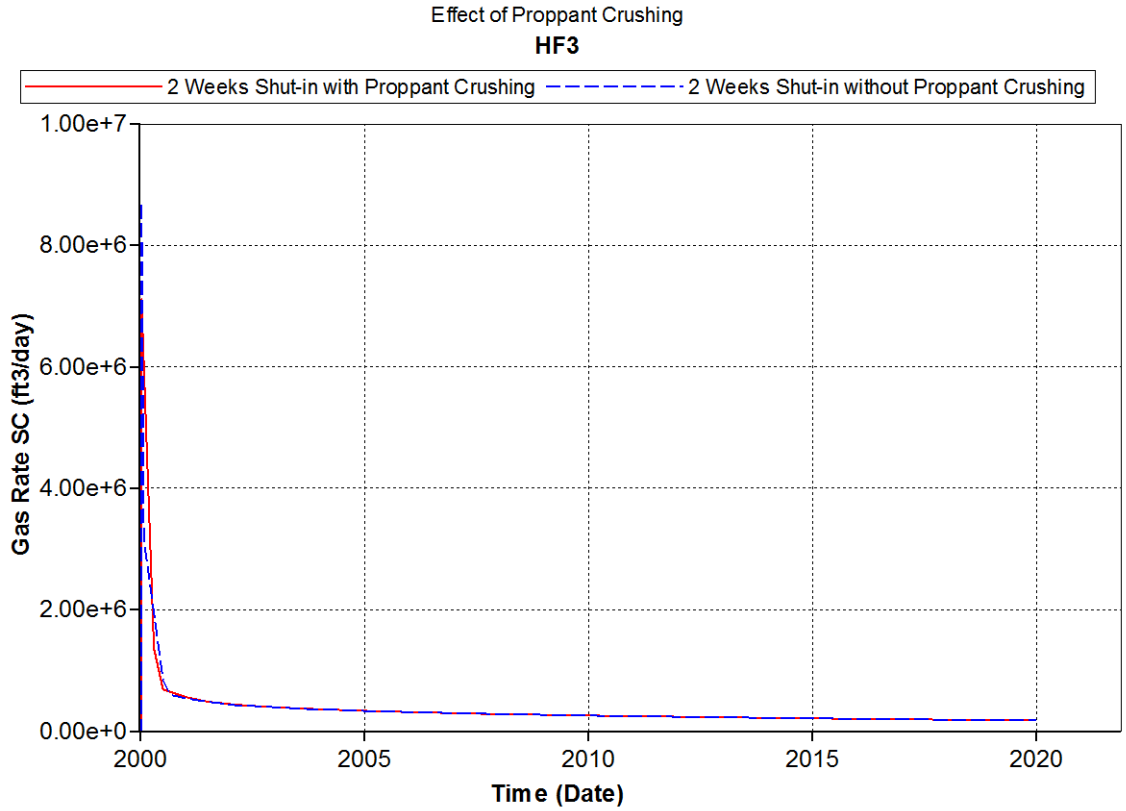

Figure 6-69: Effect of proppant crushing on gas production rate in HF3 (20/40 ceramics)

Figure 6-69 shows the effect of proppant crushing on gas rate. Gas rate without proppant crushing was higher than the case with proppant crushing at the start of gas production. Over time, the gas rates became about the same with and without proppant crushing throughout most of the production period.

Table 6-16: 20 year Cumulative gas production with and without proppant crushing (20/40 ceramics)

	Cumulative gas without crushing (BCF)	Cumulative gas with proppant crushing (BCF)
HF1	1.94	1.94
HF2	1.99	1.99
HF3	2.18	2.18

In summary, the effect of proppant crushing on cumulative gas production using 20/40 ceramics proppant in the hydraulic fractures was not significant as seen in table 6-16. Cumulative gas production was about the same with or without proppant crushing.

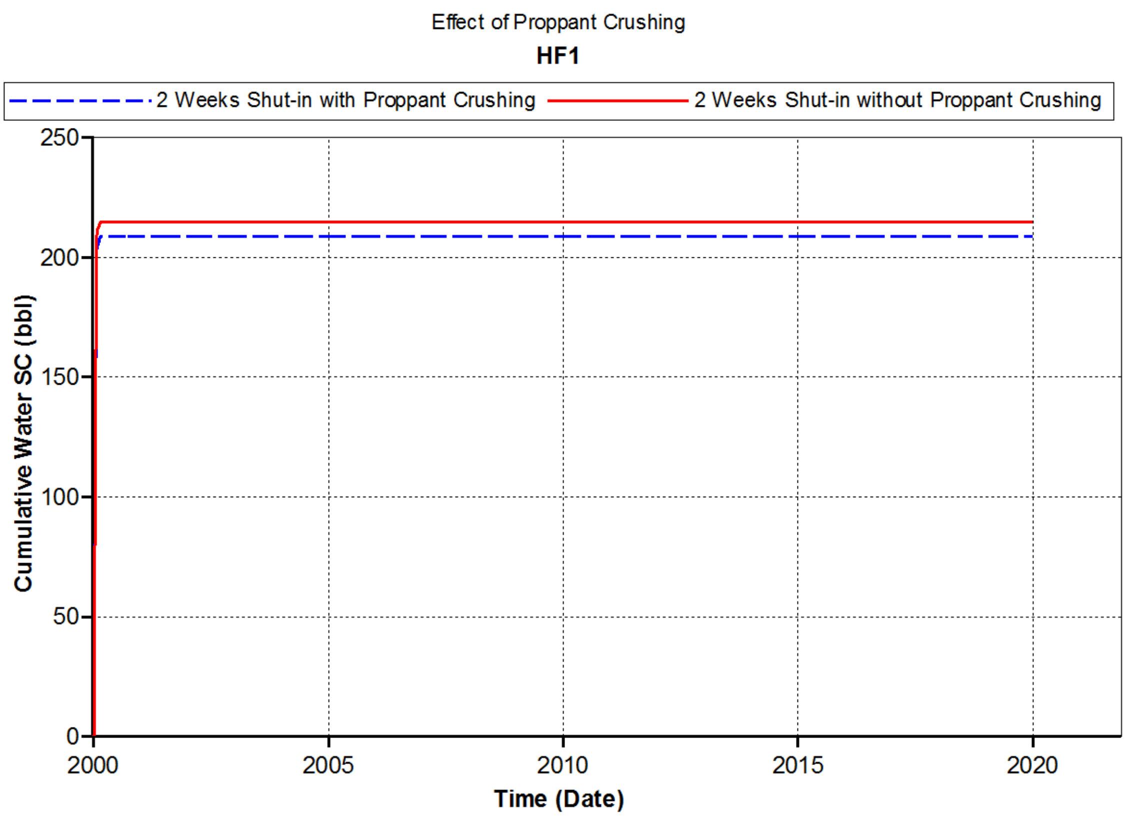

Figure 6-70: Effect of proppant crushing on cumulative fracture fluid production in HF1 (20/40 ceramics)

Figure 6-70 shows the effect of proppant crushing on cumulative fracture fluid production in HF1. Of the 2250 bbl of fracture fluid used for treating the well, 208.46 bbl (9.30%) and 214.59 (9.53%) bbl of fracture fluid were produced with proppant crushing and without proppant crushing respectively. HF1 showed a slight decrease in cumulative fracture fluid production with proppant crushing compared to the case without proppant crushing.

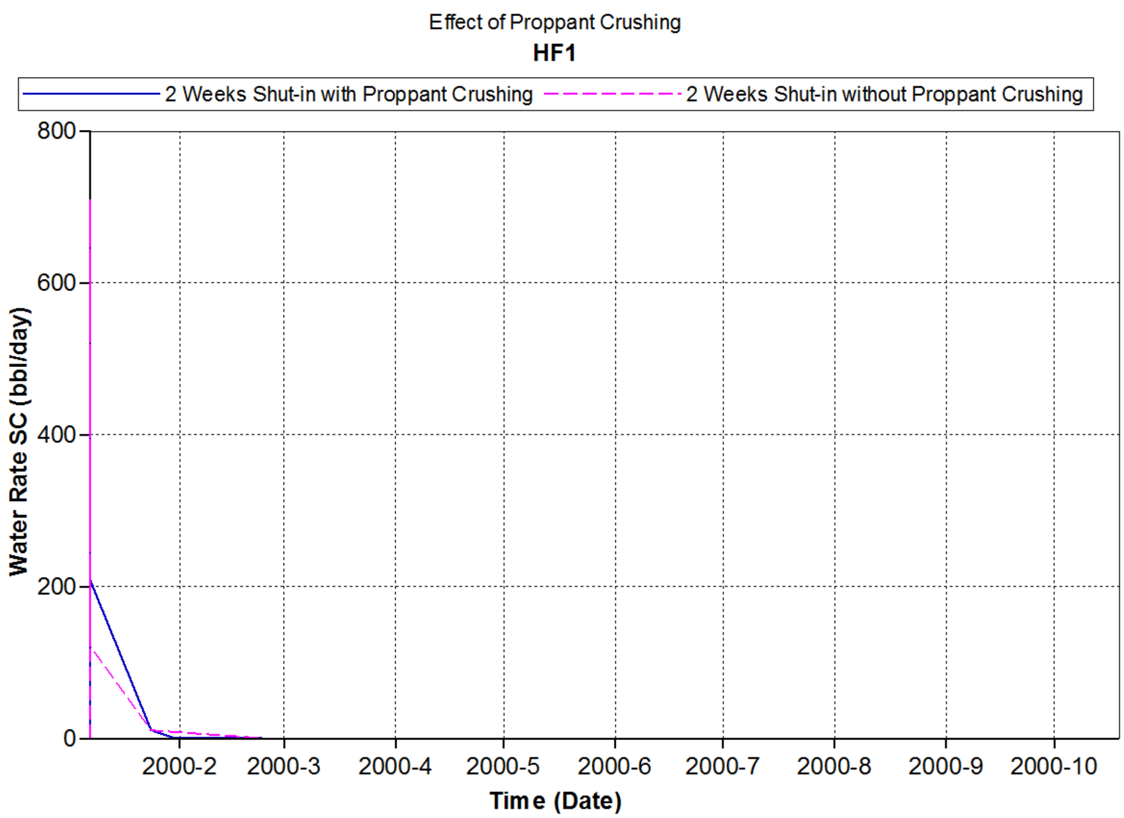

Figure 6-71: Effect of proppant crushing on fracture fluid production rate in HF1 (20/40 ceramics)

Figure 6-71represents the effect of proppant crushing on fracture fluid production rate in HF1. Most of the fracture fluid recovered was produced within the first month of production. Fracture fluid rates were about the same for most of the production period.

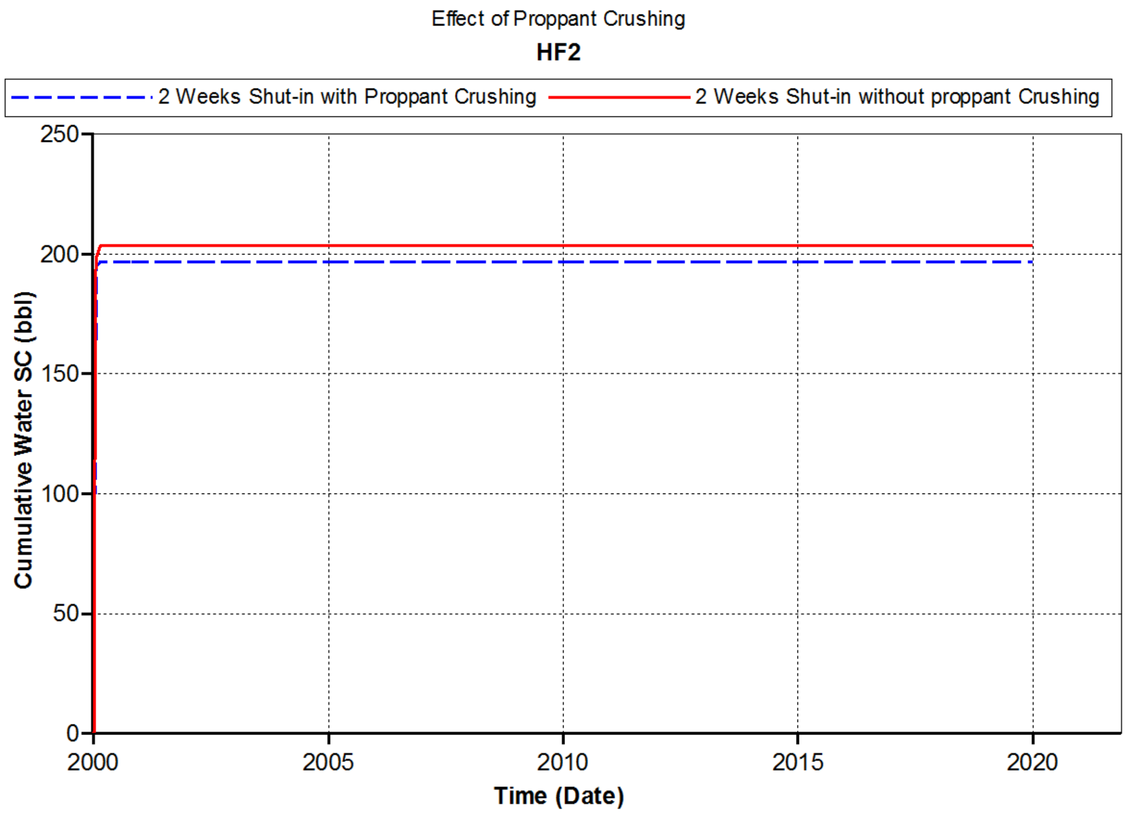

Figure 6-72: Effect of proppant crushing on cumulative water production in HF2 (20/40 ceramics)

Figure 6-72 represents proppant crushing effect on cumulative fracture fluid production in HF2. Cumulative fracture fluid production is slightly higher without proppant crushing than with proppant crushing. 202.83 bbl of fracture fluid was produced without proppant crushing while 196.86 bbl was produced with proppant crushing. This means 9.01 % and 8.76% of fracture fluid injected were produced without and with proppant crushing respectively. Proppant crushing only decreased fracture fluid production slightly.

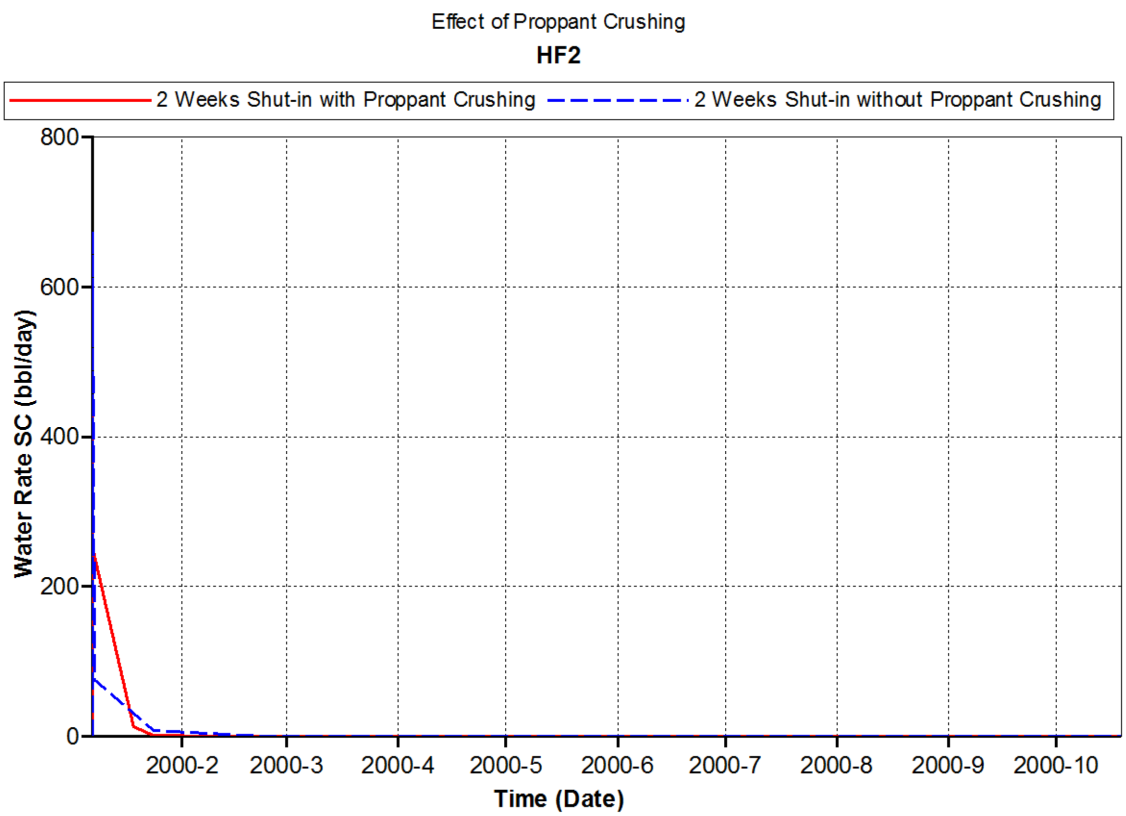

Figure 6-73: Effect of proppant crushing on fracture fluid production rate in HF2 (20/40 ceramics)

Figure 6-73 above represents proppant crushing effect on fracture fluid production rate in HF2. Most of the fracture fluid injected was produced within six months of production. Initial fracture fluid rate was higher without proppant crushing than with proppant crushing. Fracture fluid rate was about same throughout most of the production period.

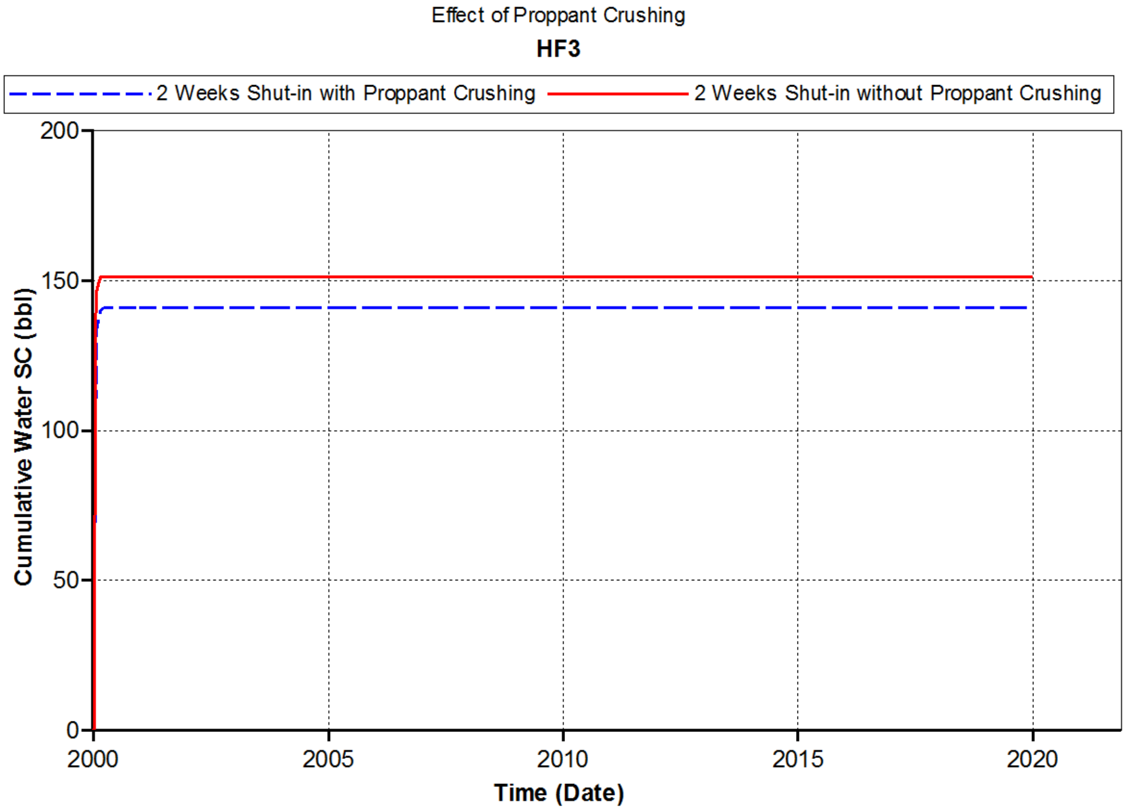

Figure 6-74: Effect of proppant crushing on cumulative fracture fluid production in HF3 (20/40 ceramics)

Figure 6-74 above represents effect of proppant crushing on cumulative fracture fluid production in HF3. 150.88 bbl of fracture fluid was produced without proppant crushing compared to 140.87 bbl of fracture fluid produced with proppant crushing. In HF3, fracture fluid production decreased by 10 bbl of fracture fluid due to proppant crushing. With 20/40 mesh ceramics, cumulative fracture fluid production was decreased only slightly.

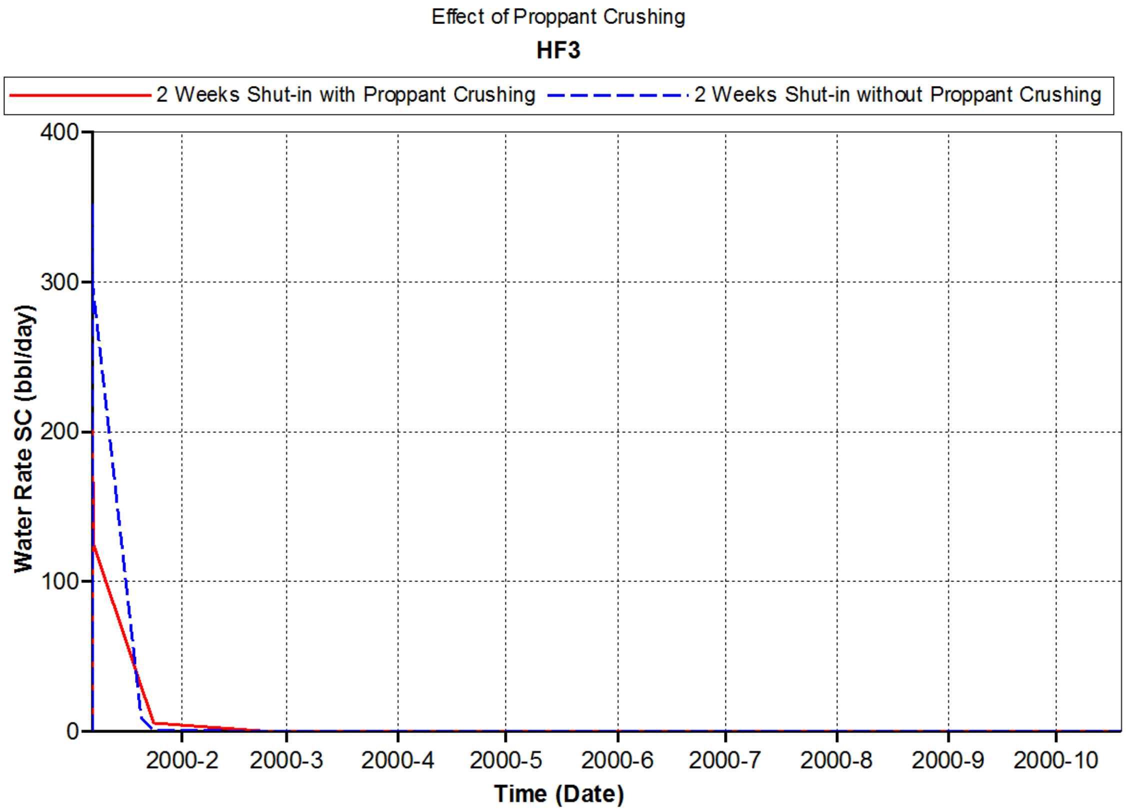

Figure 6-75: Effect of proppant crushing on fracture fluid production rate in HF3 (20/40 ceramics)

Figure 6-75 represents the effect of proppant crushing on fracture fluid production rate in HF3. Fracture fluid production rate was higher initially for the case without proppant crushing than the case with proppant crushing. Similar to HF1 and HF2, initial fracture fluid rate is higher without proppant crushing than with proppant crushing but fracture fluid rate became the same after a few weeks of production.

Table 6-16: 1-year cumulative fracture fluid production with and without proppant crushing (20/40 ceramics)

	Without proppant Crushing		With proppant crushing	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
HF1	214.29	9.53	208.46	9.27
HF2	202.83	9.04	196.86	8.75
HF3	150.87	6.72	140.88	6.26

Figure 6-16 shows a summary of fracture fluid production with and without proppant crushing. The result shows that proppant crushing reduced fracture fluid production slightly in HF1, HF2, and HF3. This could be due to reduction in proppant pack conductivity resulting from proppant crushing.

6.5.2 Effect of Proppant Crushing using 100 Mesh Sand

The following results were obtained using the less conductive 100 mesh sand proppant.

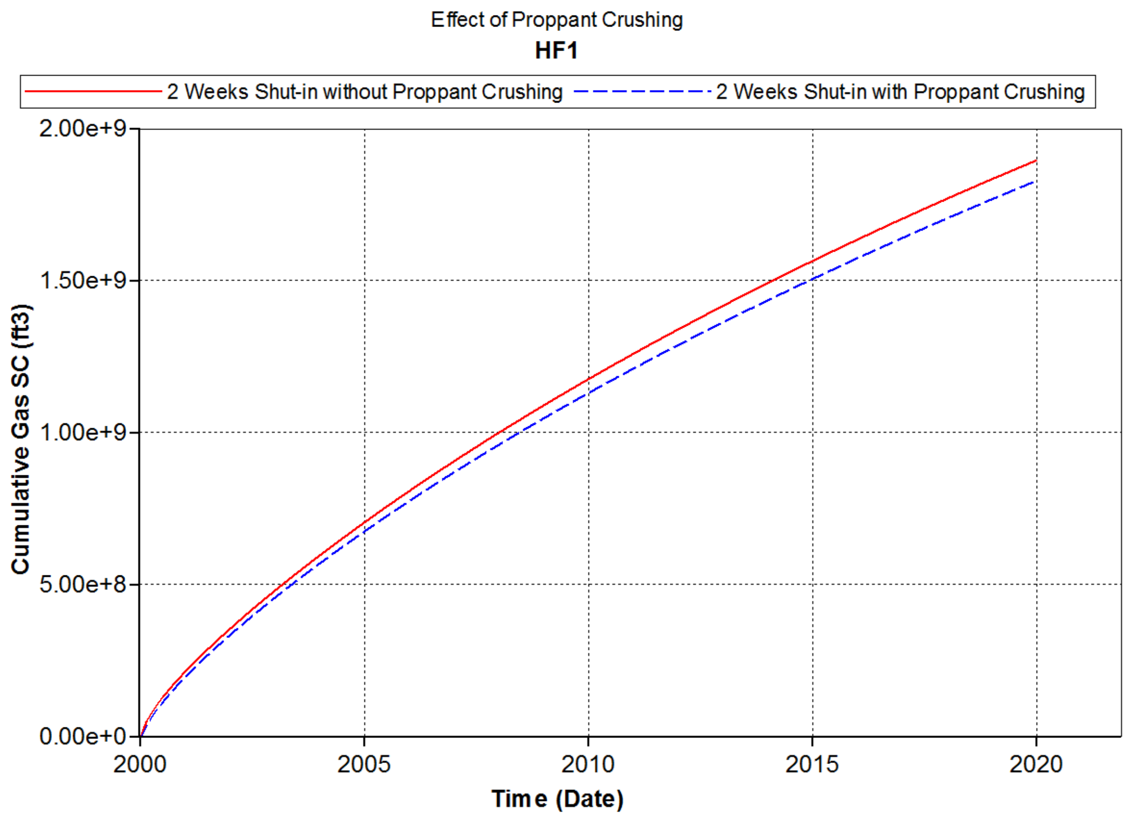

Figure 6-76: Effect of proppant crushing on cumulative gas production in HF1 (100 mesh sand)

Figure 6-76 above shows effect of proppant crushing on cumulative gas production in HF1. Twenty year cumulative gas production without proppant crushing was 1.90 BCF but dropped to 1.83 BCF due to proppant crushing. This represents a loss of 3.54% of gas in twenty years. The decrease in cumulative gas production due to proppant crushing could have been caused by decrease in hydraulic fracture conductivity.

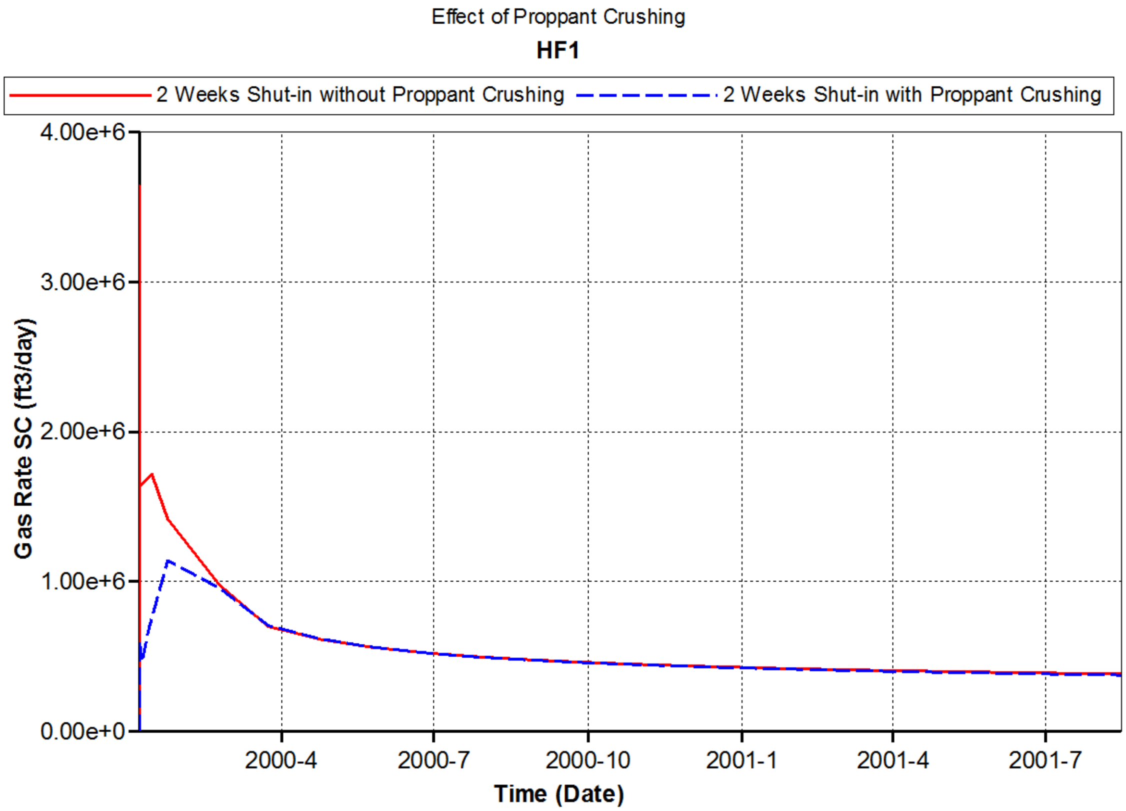

Figure 6-77: Effect of proppant crushing on gas production rate in HF1 (100 mesh sand)

Figure 6-77 shows the effect of proppant crushing on gas rate in HF1. Initial gas rate was higher without proppant crushing than with proppant crushing. Reduction in proppant conductivity due to proppant crushing could be the cause of the decrease in gas production rate.

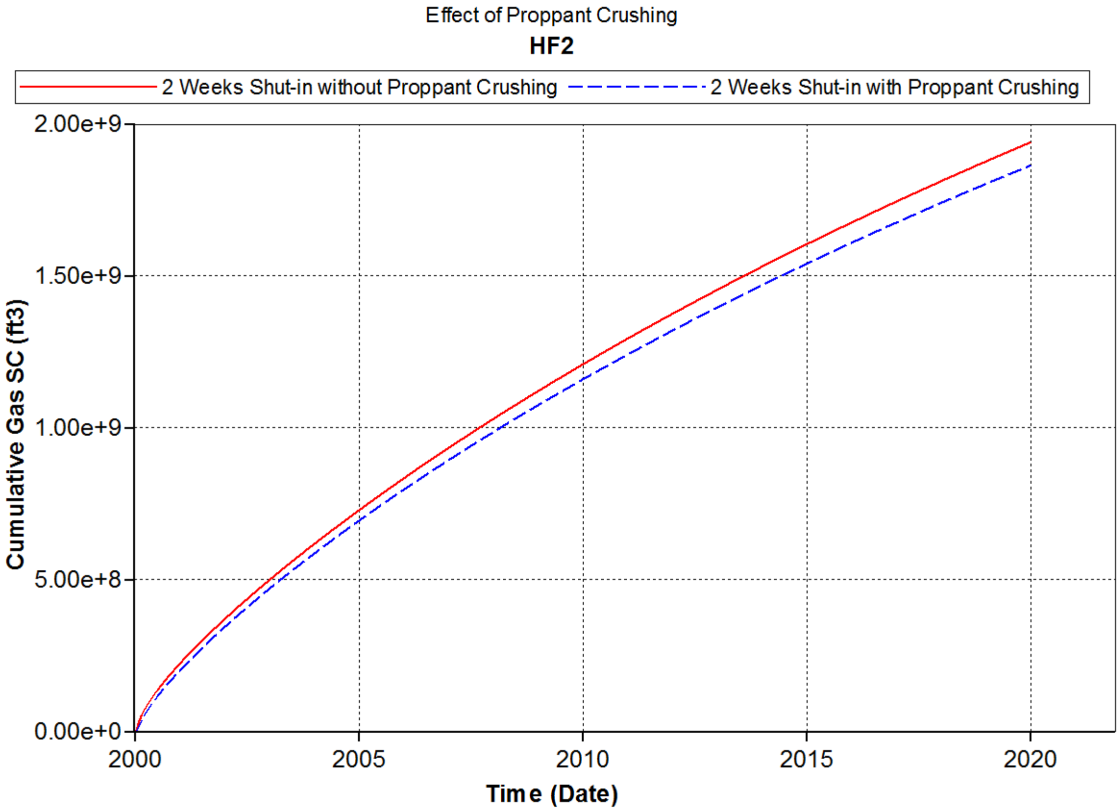

Figure 6-78: Effect of proppant crushing on cumulative gas production in HF2 (100 mesh sand)

Figure 6-78 reports the effect of proppant crushing on cumulative gas production in HF2. Twenty year cumulative gas production without proppant crushing was 1.94 BCF but due to proppant crushing gas production decreased to 1.86 BCF. This decrease represents a 3.92% loss in gas production as a result of proppant crushing in the hydraulic fractures.

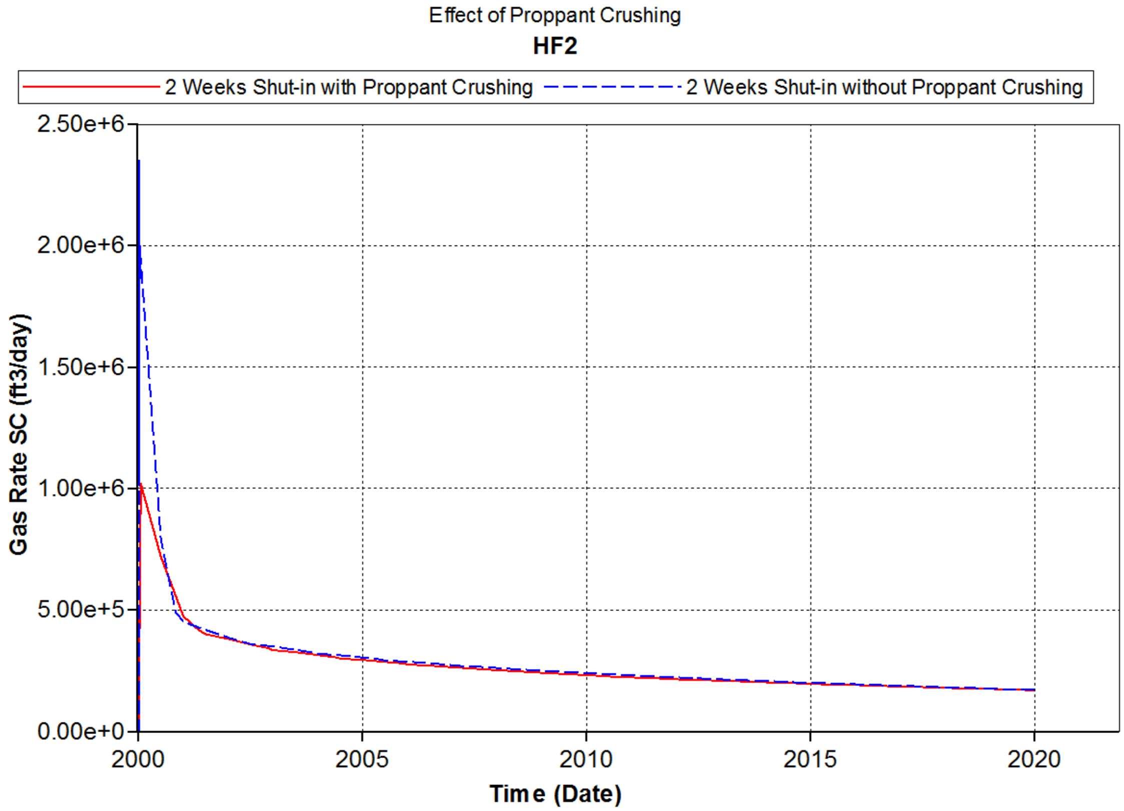

Figure 6-79: Effect of proppant crushing on gas production rate in HF2 (100 mesh sand)

Initial gas production rate as shown in Figure 6-79 above was higher for the first year without proppant crushing. The difference in cumulative gas production would be due to the difference in gas production rate in the first year of production. Lower gas production rate with proppant crushing may be due to reduction in proppant pack conductivity.

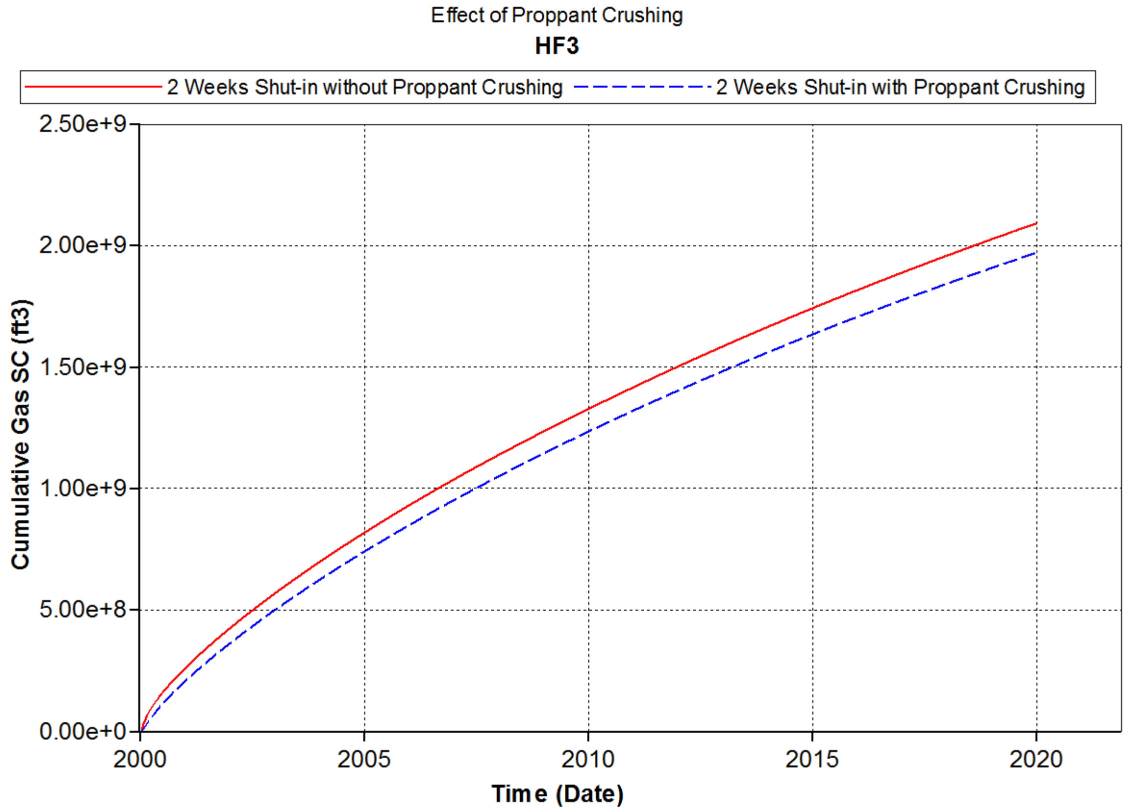

Figure 6-80: Effect of proppant crushing on cumulative gas production in HF3 (100 mesh sand)

Figure 6-80 shows effect of proppant crushing on cumulative gas production in HF3. This shows a similar trend as in HF1 and HF2 above. Cumulative gas production was higher without proppant crushing than with proppant crushing. 2.09 BCF of gas was produced in twenty years without proppant crushing compared to 1.97 BCF with proppant crushing. 5.77% of gas was lost in twenty years due to proppant crushing in HF3.

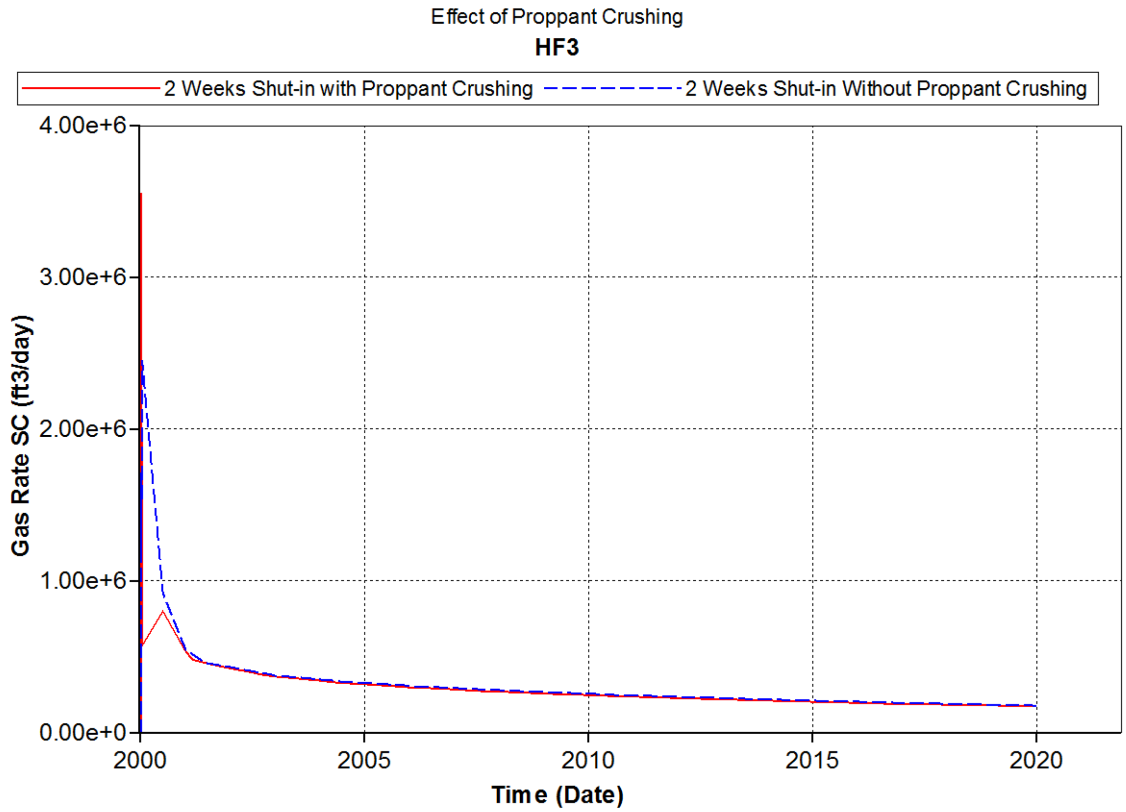

Figure 6-81: Effect of proppant crushing on gas production rate in HF3 (100 mesh sand)

Figure 6-81 represents the effect of proppant crushing on gas production rates in HF3. Gas rate was higher for the first year without proppant crushing compared to the case with proppant crushing. This difference is reflected as higher cumulative gas production in the case without proppant crushing.

Overall, proppant crushing caused a decrease in gas production rates and cumulative gas production in HF1, HF2 and HF3.

Table 6-17: 20 year cumulative gas production with and without proppant crushing (100 mesh sand)

	Cumulative gas without crushing (BCF)	Cumulative gas with proppant crushing (BCF)
HF1	1.90	1.83
HF2	1.94	1.86
HF3	2.09	1.97

Table 6-17 summarizes the effect of proppant crushing on cumulative gas production with 100 mesh sand. This shows that in all three fracture networks, HF1, HF2 and HF3, proppant crushing decreased cumulative gas production.

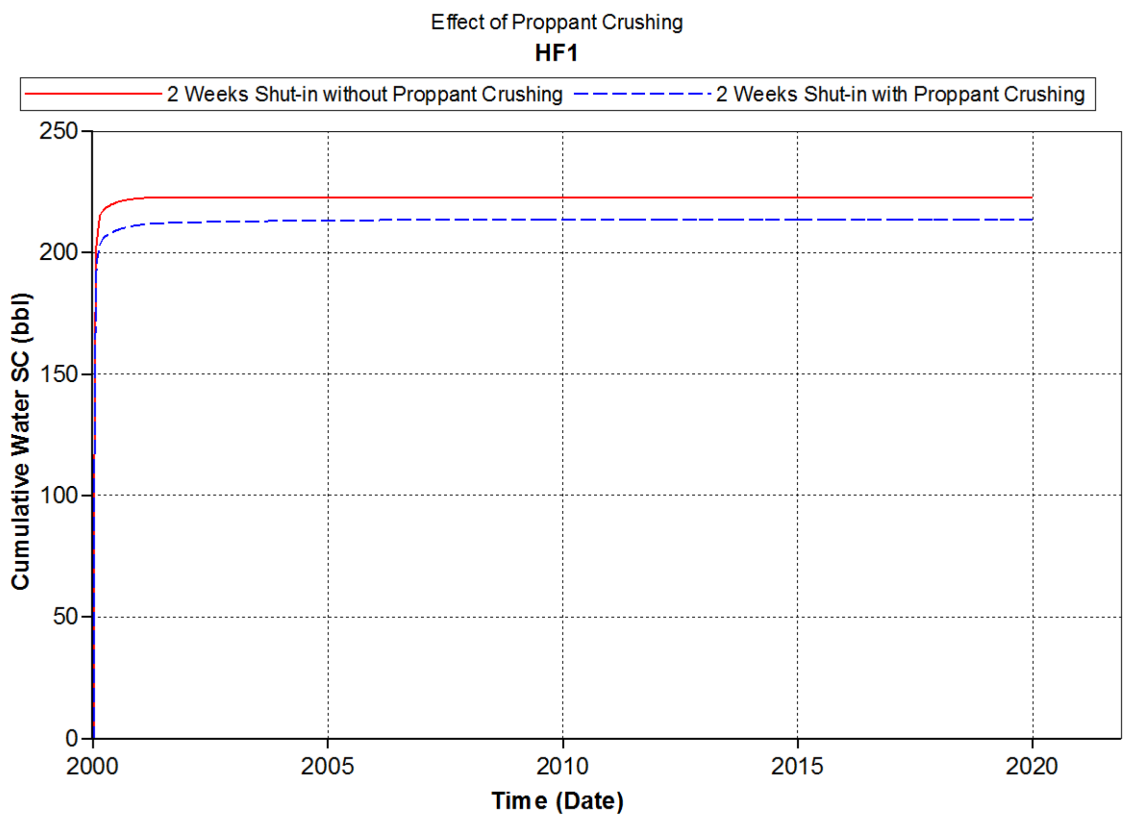

Figure 6-82: Effect of proppant crushing on cumulative fracture fluid production in HF1 (100 mesh sand)

Figure 6-82 shows cumulative fracture fluid production with and without proppant crushing. Fracture fluid production was 222.86 bbl without proppant crushing and 213.80 bbl with proppant crushing. Of the 2250 bbl of fracture fluid used for treatment, 9.90 % and 9.50% were recovered without proppant crushing and with proppant crushing respectively. There was a slight decrease in cumulative fracture fluid production due to proppant crushing.

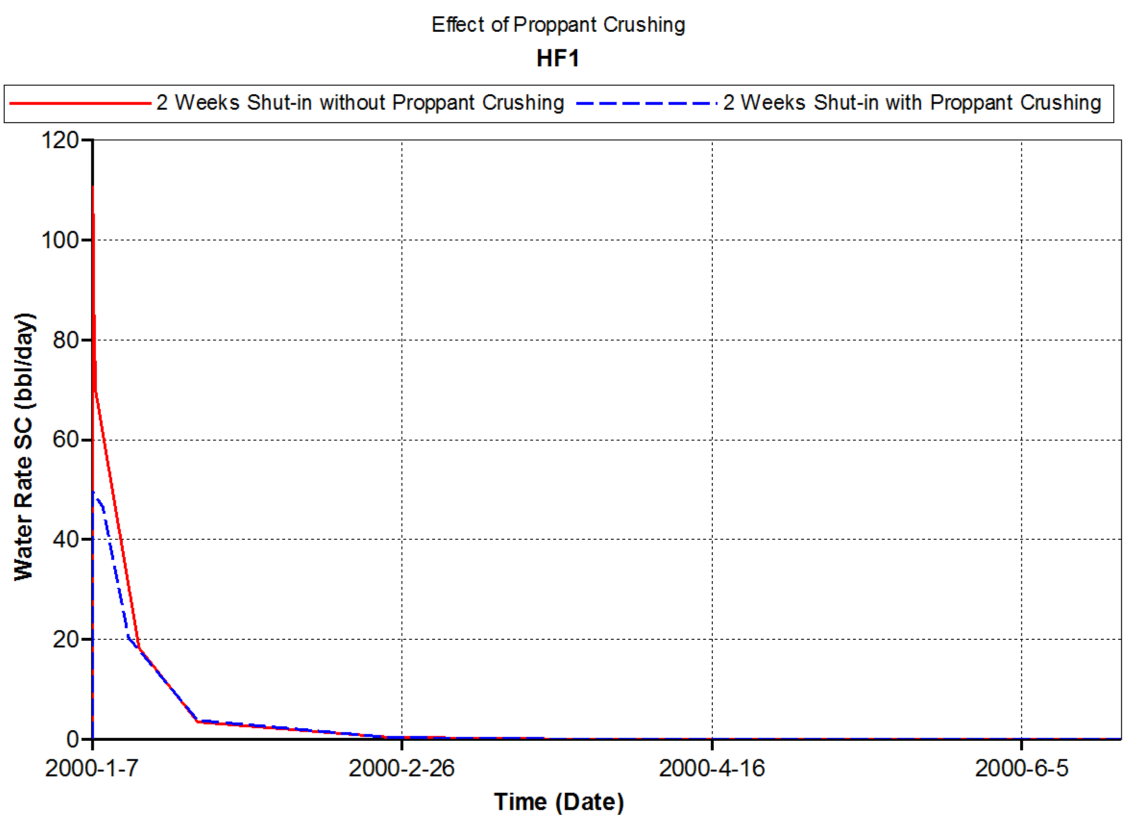

Figure 6-83: Effect of proppant crushing on fracture fluid production rate in HF1 (100 mesh sand)

Figure 6-83 shows the effect of proppant crushing on fracture fluid production rate in HF1. Fracture fluid rate was initially higher without proppant crushing compared to the case with proppant crushing. Fracture fluid rate became the same with and without proppant crushing after two weeks of production.

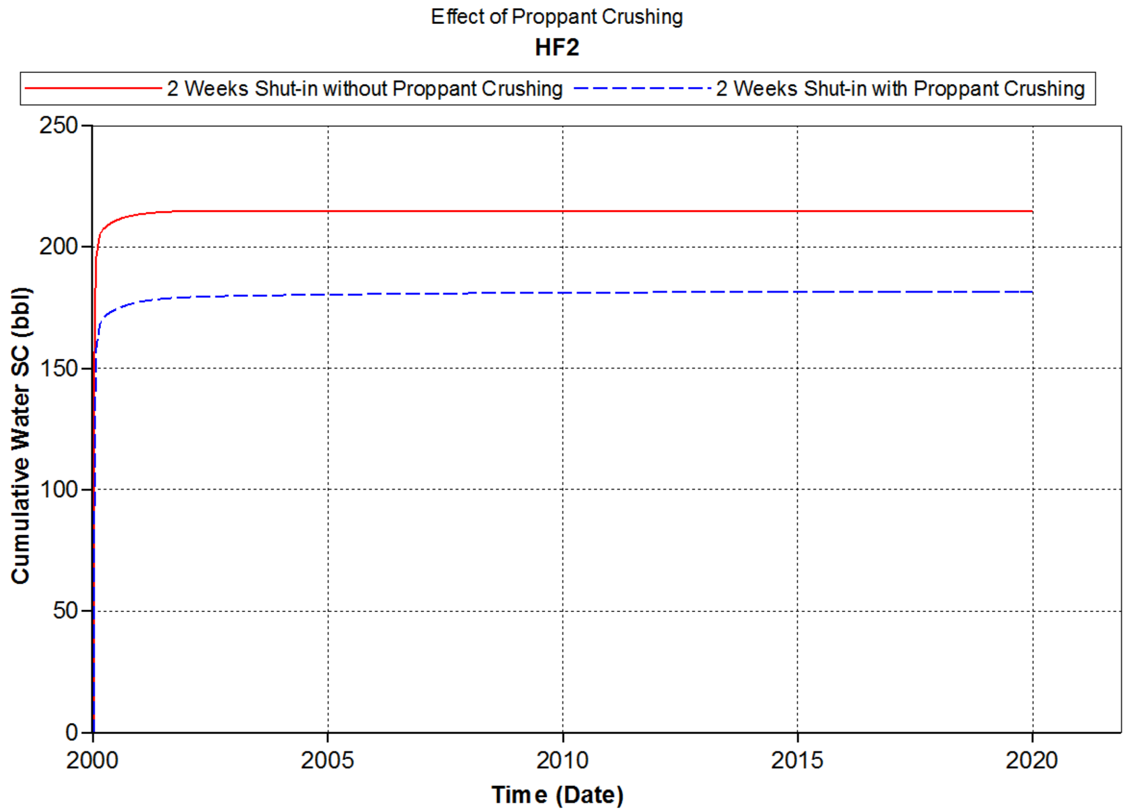

Figure 6-84: Effect of proppant crushing on cumulative fracture fluid production in HF2 (100 mesh sand)

Cumulative fracture fluid production was 214.99 bbl and 181.58 bbl without and with proppant crushing respectively. Reduction in hydraulic fracture conductivity due to proppant crushing could be responsible for the decrease in cumulative fracture fluid recovery in HF2. 9.51 % and 8.08 % of the fracture fluid injected was recovered without proppant crushing and with proppant crushing respectively.

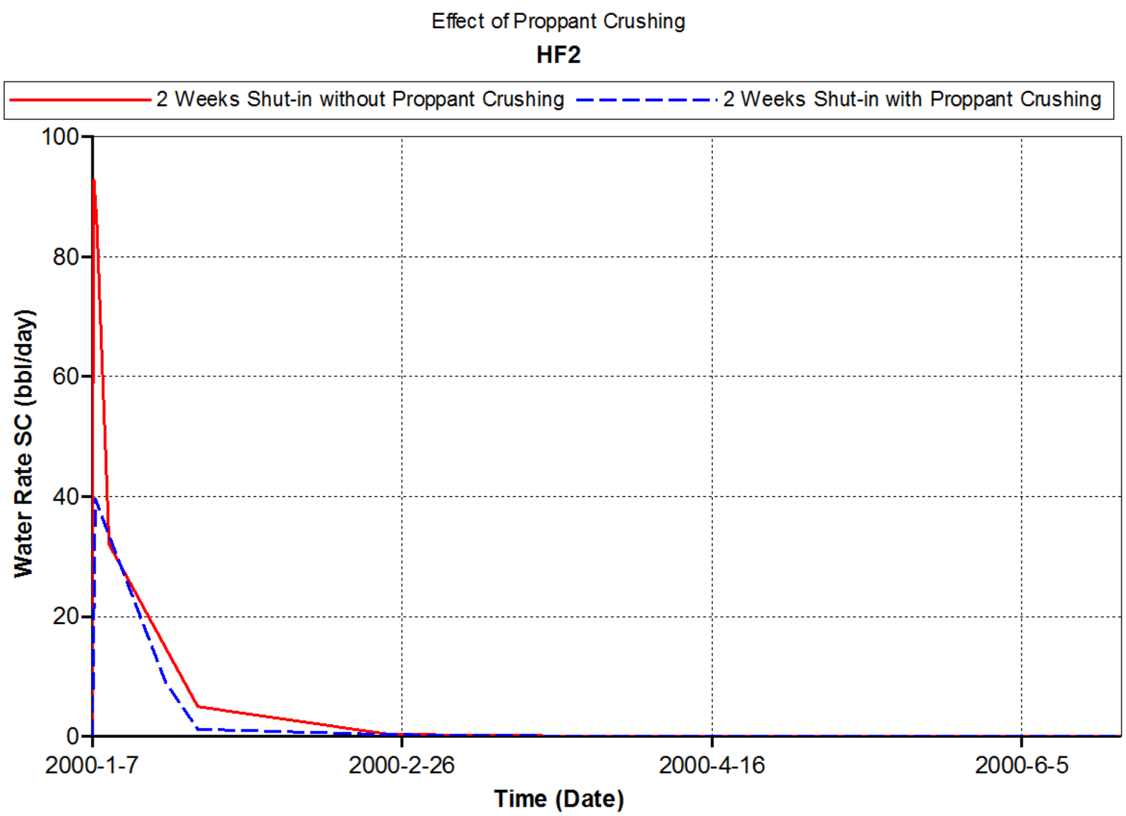

Figure 6-85: Effect of proppant crushing on fracture fluid production rate in HF2 (100 mesh sand)

Figure 6-85 shows the effect of proppant crushing on fracture fluid rate in HF2. Fracture fluid production rate was higher for the first month of production without proppant crushing than with proppant crushing. Fracture fluid rate became the same after 2 months of production.

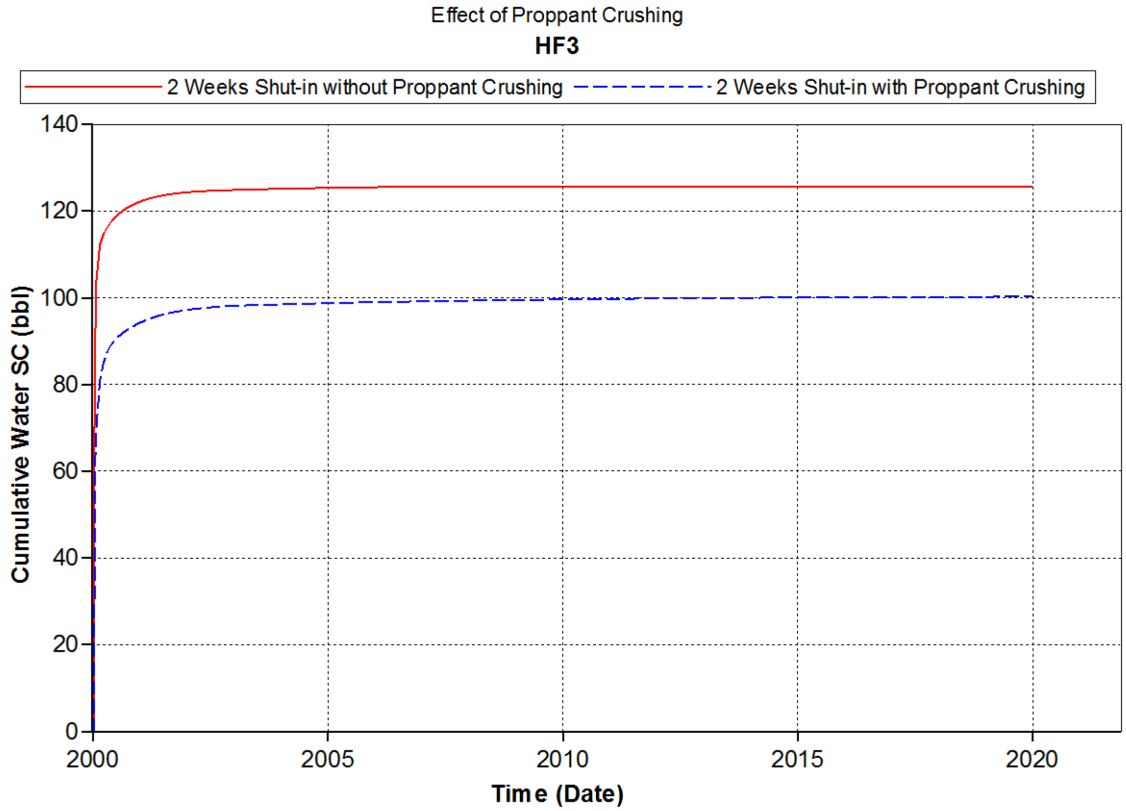

Figure 6-86: Effect of proppant crushing on cumulative fracture fluid production in HF3 (100 mesh sand)

Figure 6-86 represents the effect of proppant crushing on cumulative fracture fluid production in HF3. Fracture fluid production in HF3 follows the same trend as in HF1 and HF2, cumulative fracture fluid recovered was higher without proppant crushing than with proppant crushing. 125.62 bbl of fracture fluid was recovered without proppant crushing and 100.24 bbl was recovered with proppant crushing. 5.58% and 4.44% of the injected fluid were recovered without and with proppant crushing respectively.

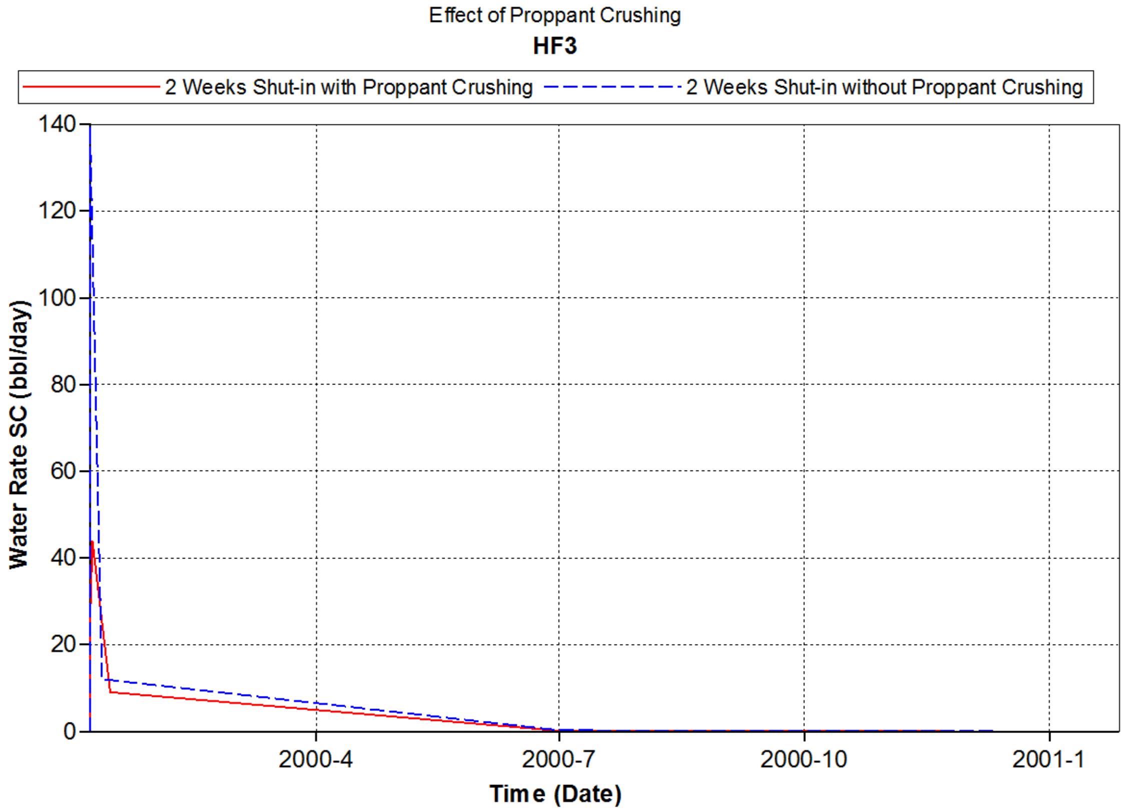

Figure 6-87: Effect of proppant crushing on fracture fluid production rate in HF3 (100 mesh sand)

Figure 6-87 shows the effect of proppant crushing on fracture fluid production rate in HF3. The figure shows a slight reduction in fracture fluid rate due to proppant crushing during the first few months of production.

Table 6-18: 1-year cumulative fracture fluid production with and without proppant crushing (100 mesh sand)

	Without proppant crushing		With proppant crushing	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
HF1	222.86	9.90	213.80	9.46
HF2	214.99	9.56	181.58	7.95
HF3	125.62	5.55	100.24	4.40

Table 6-18 above shows a summary of effect of proppant crushing on cumulative fracture fluid production. In HF1, HF2, and HF3 we can observe that fracture fluid production was a slightly less with proppant crushing compared to no crushing.

Summary

In this section, we analyzed the effects of all the factors studied on long-term gas production and fracture fluid recovery.

Table 6-19: Effect of all factors on 20 years cumulative gas production (20/40 mesh ceramics)

Factors	HF1, Volume (BCF)	HF2, Volume (BCF)	HF3, Volume (BCF)
Single Phase	1.94	1.99	2.18
Multi-Phase	1.94	1.99	2.18
Multi-Phase + Pc	1.94	1.99	2.18
1 Week Shut-in	1.94	1.99	2.18
2 Weeks Shut-in	1.94	1.99	2.18
1 Year Shut-in	1.94	1.99	2.18
2 Weeks Shut-in + Proppant Crushing	1.94	1.99	2.18

Table 6-19 above shows cumulative effect of the multi-phase flow, capillary pressure, shut-in time and proppant crushing on long-term gas production using 20/40 ceramics proppant. Loss in cumulative gas production after adding all the factors was 4.02 MMSCF (0.21%), 4.37 MMSCF (0.22%) and 7.43 MMSCF (0.34%) for HF1, HF2 and HF3 respectively. With 20/40 ceramics proppant, cumulative gas production after adding multi-phase flow, capillary pressure, shut-in time and proppant crushing was about the same as ideal single phase flow.

Table 6-20: Effect of all factors on one year cumulative fracture fluid recovery (20/40 mesh ceramics)

Factors	HF1		HF2		HF3	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
Single Phase	-		-		-	
Multi-Phase	901.58	40.00	956.00	42.50	1118.27	49.70
Multi-Phase + Pc	750.95	33.35	875.68	38.90	1092.94	48.57
1 Week Shut-in	340.34	15.11	326.04	14.50	256.73	11.40
2 Weeks Shut-in	214.59	9.53	202.83	9.04	150.88	6.72
1 Year Shut-in	6.32	0.28	5.56	0.25	5.12	0.22
2 Weeks Shut-in + Proppant Crushing	208.59	9.27	196.86	8.75	140.87	6.26

Table 6-20 above shows the cumulative effect of the factors studied on fracture fluid recovery with 20/40 ceramics proppant. The table shows a decrease in fracture fluid recovery with every additional factor. Less than 1% of the 2,250 bbl of the fracture fluid used for the treatment was recovered after 1 year of shut-in in HF1, HF2 and HF3.

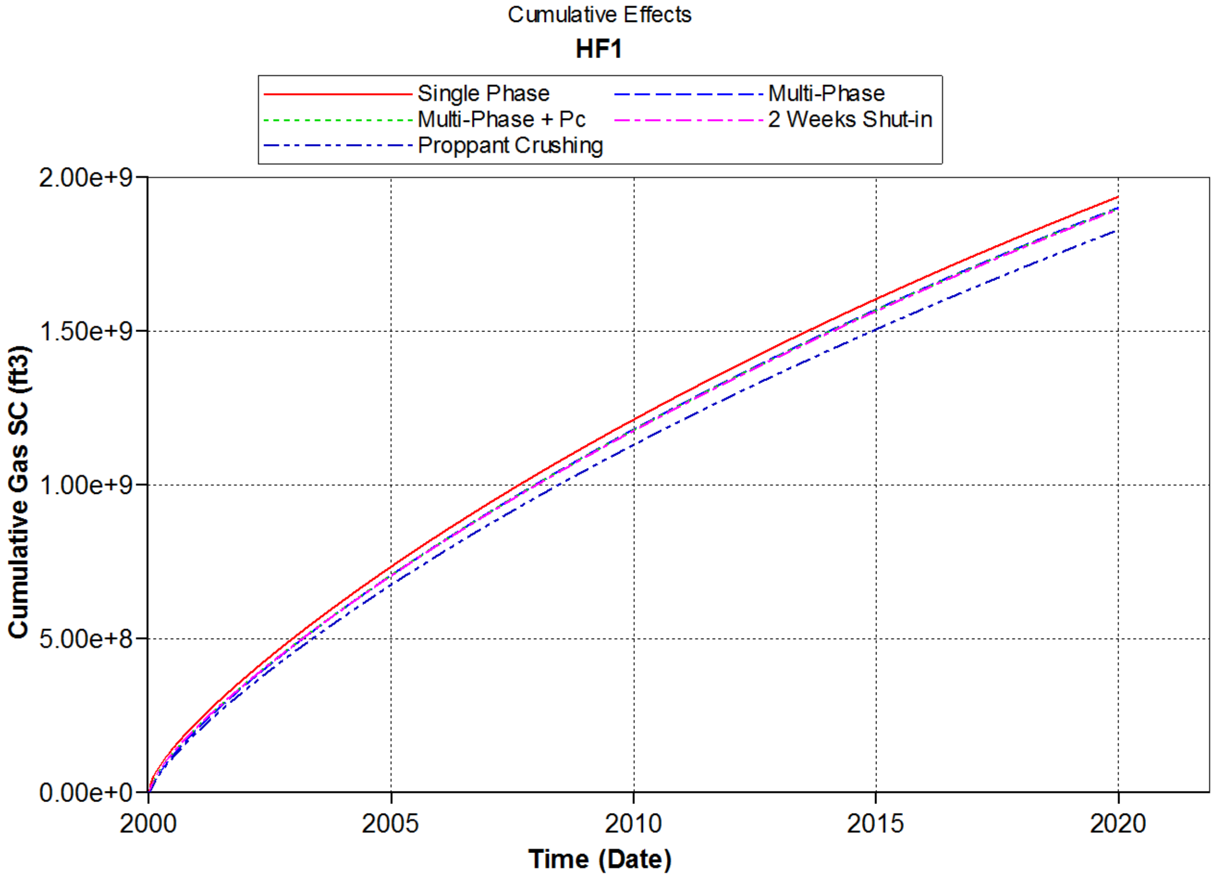

Figure 6-88: Effect of the different factors on cumulative gas production in HF1 (100 mesh sand)

Table 6-21: Effect of all factors on cumulative gas production (100 mesh sand)

Factors	HF1 , Volume (BCF)	HF2, Volume (BCF)	HF3, Volume (BCF)
Single Phase	1.94	1.99	2.18
Multi-Phase	1.90	1.95	2.09
Multi-Phase + Pc	1.90	1.94	2.09
1 Week Shut-in	1.90	1.94	2.09
2 Weeks Shut-in	1.90	1.94	2.09
1 Year Shut-in	1.90	1.94	2.09
2 Weeks Shut-in + Proppant Crushing	1.83	1.86	1.97

Figure 6-88 and Table 6-21 above show cumulative effect of the factors on long-term gas production using 100 mesh sand. The table shows a decrease in cumulative gas production due to multi-phase flow and proppant crushing. Multi-phase flow decreased gas production by 35.50 MMSCF (1.80%), 43.92 MMSCF (2.20%) and 84.80 MMSCF (3.89%) in HF1, HF2 and HF3 respectively. On the other hand, proppant crushing decreased cumulative gas production by 67.20 MMSCF (3.53%), 76.20 MMSCF (3.92%) and 120.80 MMSCF (5.77%) in HF1, HF2 and HF3 respectively. Gas production did not change with capillary pressure and shut-in time.

Overall, combined effects of all factors analyzed decreased gas production by 107.40 MMSCF (5.54%), 126.10 MMSCF (6.33%) and 207.60 MMSCF (9.53%) when 100 mesh sand was used as proppant.

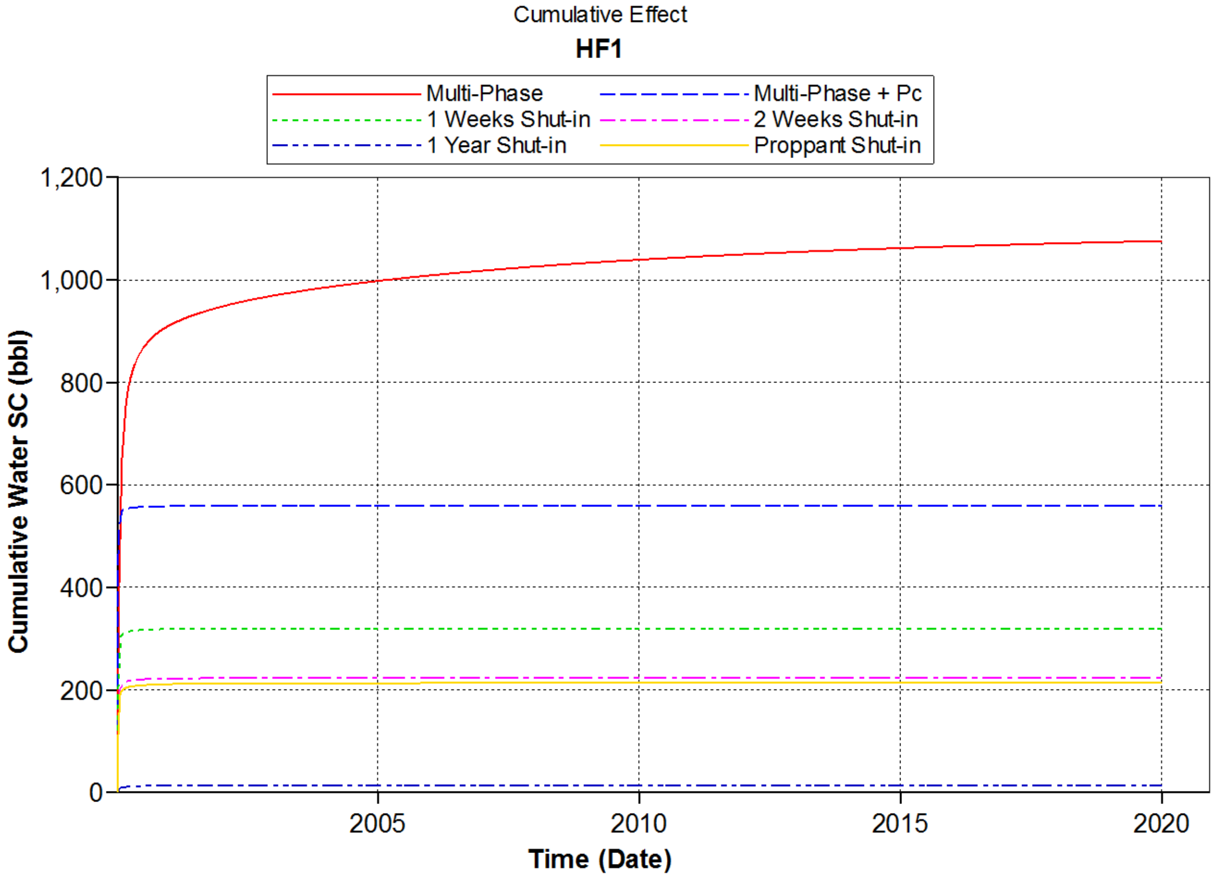

Figure 6-89: Effect of the different factors on cumulative fracture fluid recovery in HF1 (100 mesh sand)

Figure 6-89 above shows the effect of various factors on cumulative fracture fluid recovery in HF1. Cumulative fracture fluid recovery decreased with each added factor. After the first year of production, 40 % of the fracture fluid was recovered with multi-phase flow and low capillary pressure. One year cumulative fracture fluid recovery decreased to 24.8 % with high capillary pressure. One year cumulative fracture fluid recovery was 14.2 %, 9.9% and 0.62 % for one week, two weeks and one year shut-in durations respectively.

Table 6-22: Effect of all factors on one year cumulative fracture fluid recovery (100 mesh sand)

Factors	HF1		HF2		HF3	
	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)	Volume (bbl)	Recovery (%)
Single Phase	-		-		-	
Multi-Phase	933.94	41.5	970.00	43.10	1100.00	48.80
Multi-Phase + Pc	558.87	24.80	546.58	24.30	431.99	19.20
1 Week Shut-in	316.19	14.20	308.78	13.70	189.77	8.40
2 Weeks Shut-in	222.86	9.90	214.99	9.56	125.62	5.55
1 Year Shut-in	14.16	0.63	17.99	0.79	14.47	0.58
2 Weeks Shut-in + Proppant Crushing	213.80	9.46	181.58	8.00	100.24	4.33

Table 6-22 above shows the cumulative effect of factors on fracture fluid recovery with 100 mesh sand as proppant in HF1, HF2 and HF3. Fracture fluid recovery decreased with every additional factor. Less than 1% of fracture fluid injected was recovered after one year of shut-in for HF1, HF2 and HF3.

Chapter 7

Conclusion and Recommendation

The effects of various factors on the performance of hydraulically fractured wells in Marcellus shale reservoir were evaluated in this research work. Effect of factors such as multi-phase flow, capillary pressures, shut-in time and proppant crushing were evaluated. Based on the work done and our assumptions, we came up with the following conclusions and recommendations:

When 20/40 ceramics was used, 20-year cumulative gas production was unaffected by multi-phase flow, high capillary pressure, shut-in time and proppant crushing. 1.94 BCF of gas was produced for base case (ideal single phase) while after adding all factors gas production was 1.94 BCF. This could be due to the high conductivity of the proppant pack which nullified the effects of the factors.

Length of shut-in time had an effect on fracture fluid recovery in fractured Marcellus shale wells based on this research. This was observed for both high and low conductive proppant. Less than 1 % of the water injected was recovered after 1-year shut-in.

Length of shut in time did not affect cumulative gas production in the long term. Gas production remained about the same with 1-week, 2-weeks and 1-year shut-in time with both high and low conductive proppants. On the other hand, cumulative gas production increases slightly with shut-in time in the early stages of production.

With the less conductive 100 mesh sand as proppant, long term gas production was affected mainly by multi-phase flow and proppant crushing. Effect of proppant crushing was greater compared to multi-phase flow. Multi-phase flow decreased production by 1.8%, 2.2% and 3.9% in HF1, HF2 and HF3 respectively while proppant crushing decreased gas production by 3.5%, 3.9% and 5.8% in HF1, HF2 and HF3 respectively.

When all factors were considered, 20-year gas recovery decreased from 28.63 % to 25.43 % if fracture network size goes from HF3 to HF1 for 20/40 ceramics. For 100 mesh sand, the percentages go from 27.92 % to 25.11%. This could be a result of the decrease in stimulated reservoir volume as network size decrease from HF3 (1,672,700 ft3) to HF1 (697,000 ft3).

Future work should include increase in the amount of fluid injected into the formation during hydraulic fracture treatment.

Appendix

Table A-1: Summary of gas production and fracture fluid recovery

Run	Case	Shut-in Time	Network Size	Gas, Recovery (%)		Fracture Fluid, Recovery (%)		
	Proppant type: 20/40 ceramics			**5 Years**	**20 Years**	**2 Weeks**	**6 Months**	**3 Years**
1	Single phase		HF1	9.68	25.47	0	0	0
2			HF2	10.10	26.18	0	0	0
3			HF3	11.50	28.70	0	0	0
4	Multi-phase (kr1)		HF1	9.67	25.43	30.50	38.60	40.10
5			HF2	10.10	26.14	33.20	41.30	43.10
6			HF3	11.50	28.61	41.10	49.10	50.90
7	Multi-phase + Pc		HF1	9.66	25.44	30.00	33.40	33.40
8			HF2	10.10	26.15	38.70	38.90	38.90
9			HF3	11.50	28.63	48.20	48.60	48.60
10	Shut-in	0 days	HF1	9.66	25.44	30.00	33.21	33.40
11		1 wk	HF1	9.65	25.43	11.00	15.10	15.10
12		2 wks	HF1	9.65	25.43	7.58	9.54	9.54
13		1 yr	HF1	9.64	25.43	0.23	0.23	0.28
14	Shut-in	0 days	HF2	10.10	26.15	38.70	38.90	38.90
15		1 wk	HF2	10.10	26.14	13.90	14.50	14.50
16		2 wks	HF2	10.10	26.14	7.58	9.04	9.04

17		1 yr	HF2	10.10	26.14	0.25	0.25	0.25
18	Shut-in	0 day	HF3	11.50	28.63	48.20	48.60	48.60
19		1 wk	HF3	11.50	28.63	8.70	11.40	11.40
20		2 wks	HF3	11.50	28.63	6.39	6.72	6.75
21		1 yr	HF3	11.50	28.63	0.20	0.20	0.22
22	2 wks shut-in +		HF1	9.64	25.42	7.73	9.28	9.28
23	proppant		HF2	10.00	26.13	8.67	8.75	8.75
24	crushing		HF3	11.50	28.60	5.17	6.27	6.27
	Proppant type: 100 Mesh							
25			HF1	9.67	25.45	0	0	0
26	Single phase		HF2	10.10	26.16	0	0	0
27			HF3	11.50	28.65	0	0	0
28	Multi-phase (kr1)		HF1	9.30	25.14	19.40	38.60	43.10
29			HF2	9.60	26.78	19.40	41.00	47.00
30			HF3	10.60	27.93	15.70	45.60	59.00
31	Multi-phase + Pc		HF1	9.30	25.13	23.10	24.80	24.80
32			HF2	9.62	25.78	23.00	24.20	24.30
33			HF3	10.60	27.95	17.30	19.00	19.20
34	Shut-in	0 days	HF1	9.30	25.13	23.10	24.80	24.80
35	Shut-in	1 wk	HF1	9.29	25.11	11.20	14.11	14.20
36		2 wks	HF1	9.29	25.11	7.95	9.81	9.91
37		1 yr	HF1	9.29	25.11	0.24	0.58	0.63
38	Shut-in	0 days	HF2	9.62	25.78	23.00	24.20	24.30

39		1 wk	HF2	9.60	25.74	11.80	13.60	13.70
40		2 wks	HF2	9.60	25.74	8.21	9.38	9.56
41		1 yr	HF2	9.61	25.74	0.25	0.68	0.79
42	Shut-in	0 days	HF3	10.80	27.92	17.30	19.10	19.20
43		1 wk	HF3	10.80	27.92	6.56	8.13	8.40
44		2 wks	HF3	10.80	27.92	4.19	5.27	5.55
45		1 yr	HF3	10.80	27.92	0.09	0.40	0.58
46	2 wks shut-in +		HF1	8.89	24.52	7.53	9.30	9.46
47	Proppant		HF2	9.15	24.98	6.23	7.76	7.99
48	crushing		HF3	9.76	26.71	2.88	4.03	4.36

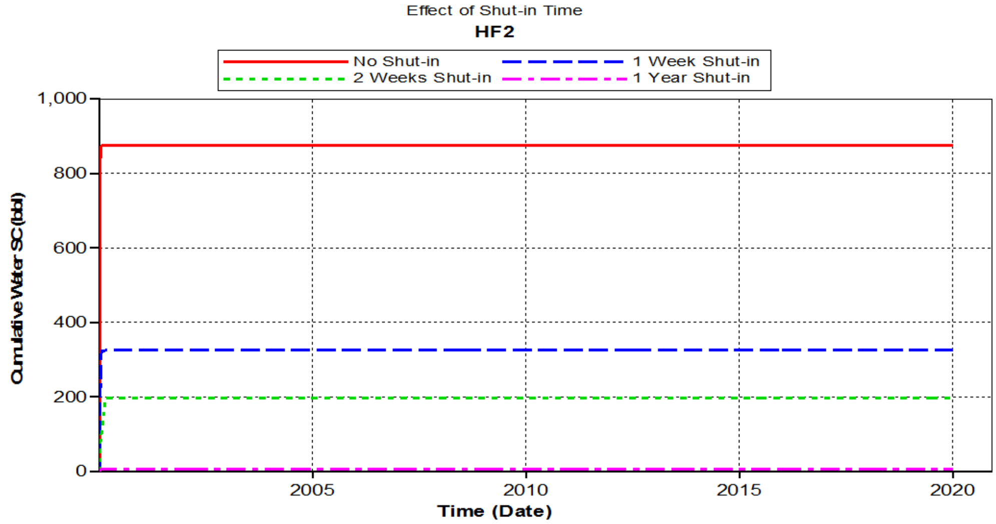

Figure A-1: Effect of shut-in time on cumulative fracture fluid production in HF2 (20/40 ceramic)

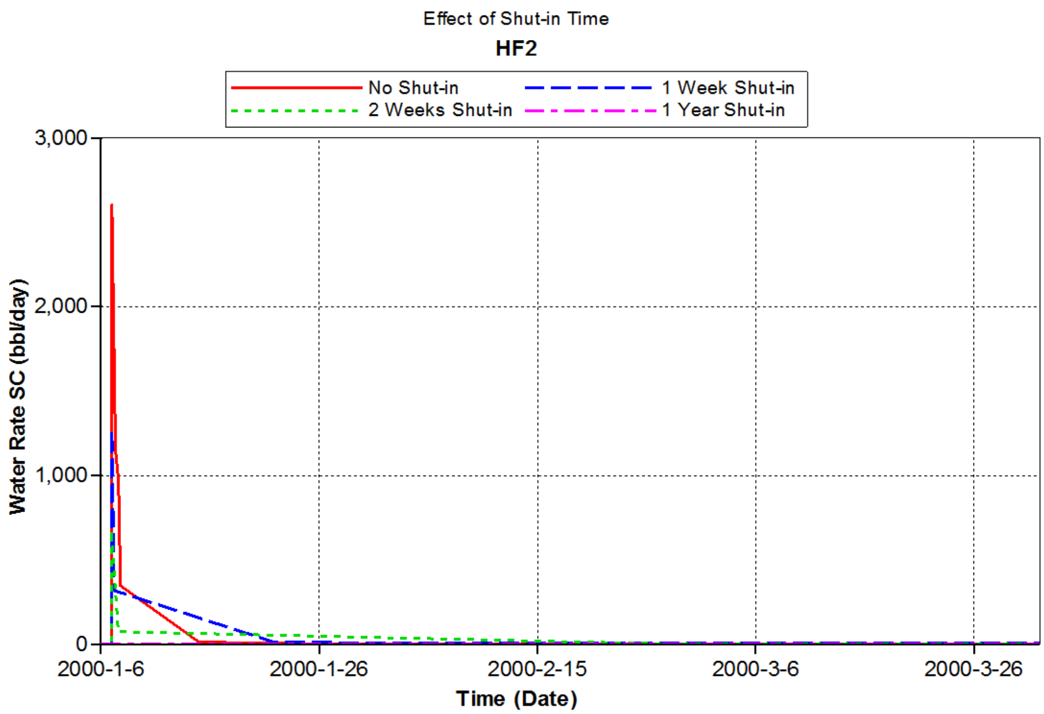

Figure A-2: Effect of shut-in time on fracture fluid rate in HF2 (20/40 ceramic)

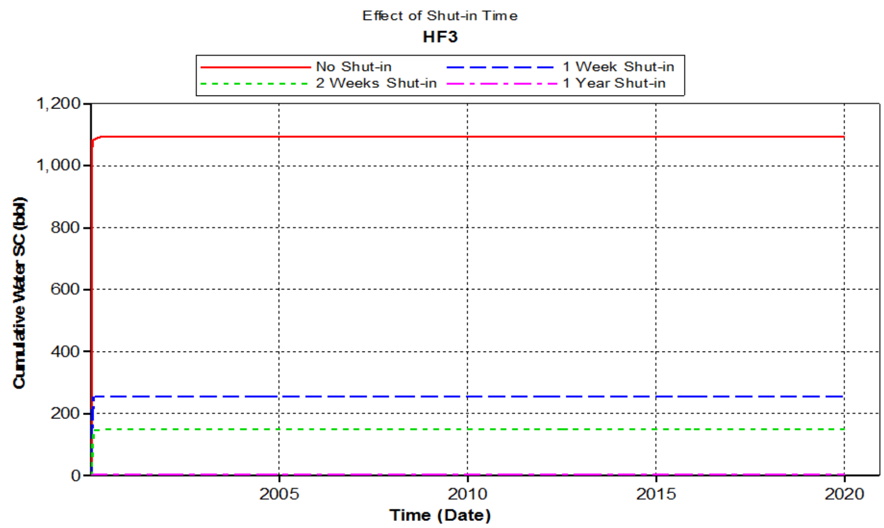

Figure A-3: Effect of shut-in time on cumulative fracture fluid production in HF3 (20/40 ceramic)

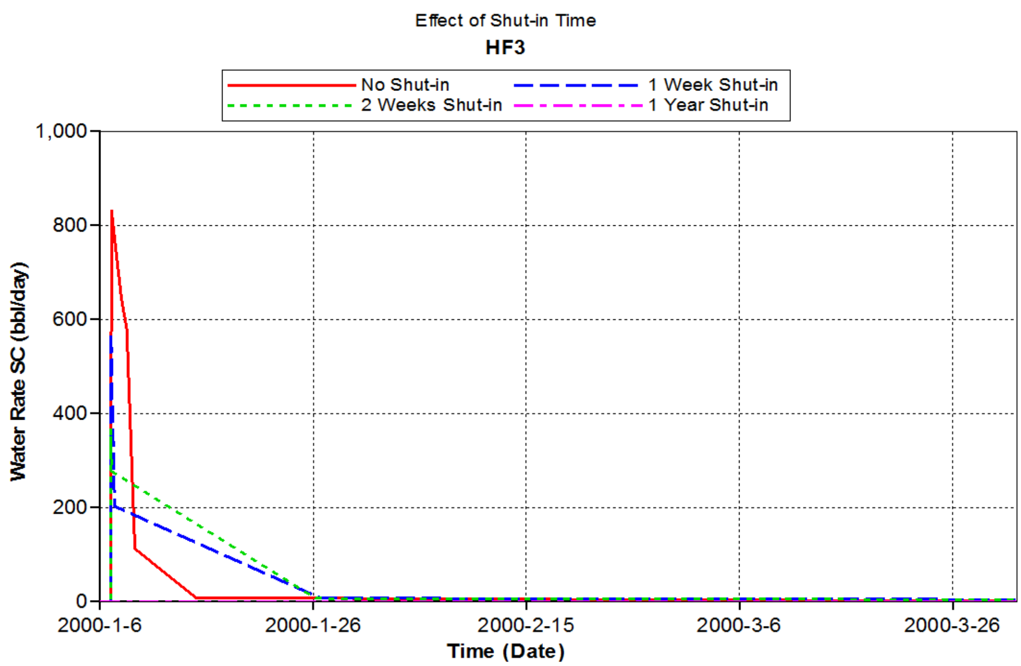

Figure A-4: Effect of shut-in time on fracture fluid rate in HF3 (20/40 ceramic)

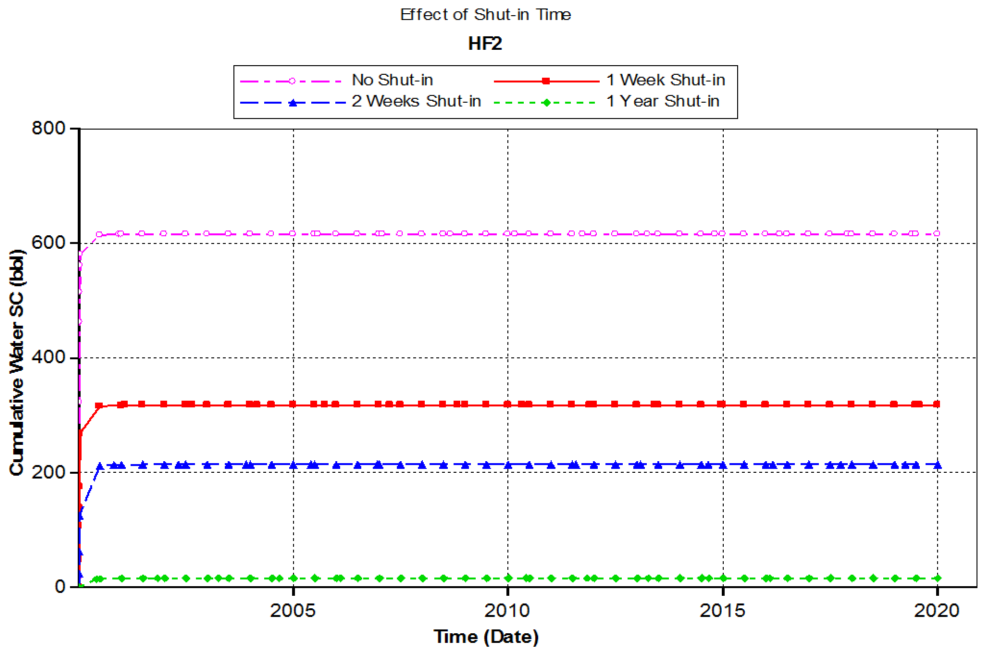

Figure A-5: Effect of shut-in time on cumulative fracture fluid production in HF2 (100 mesh)

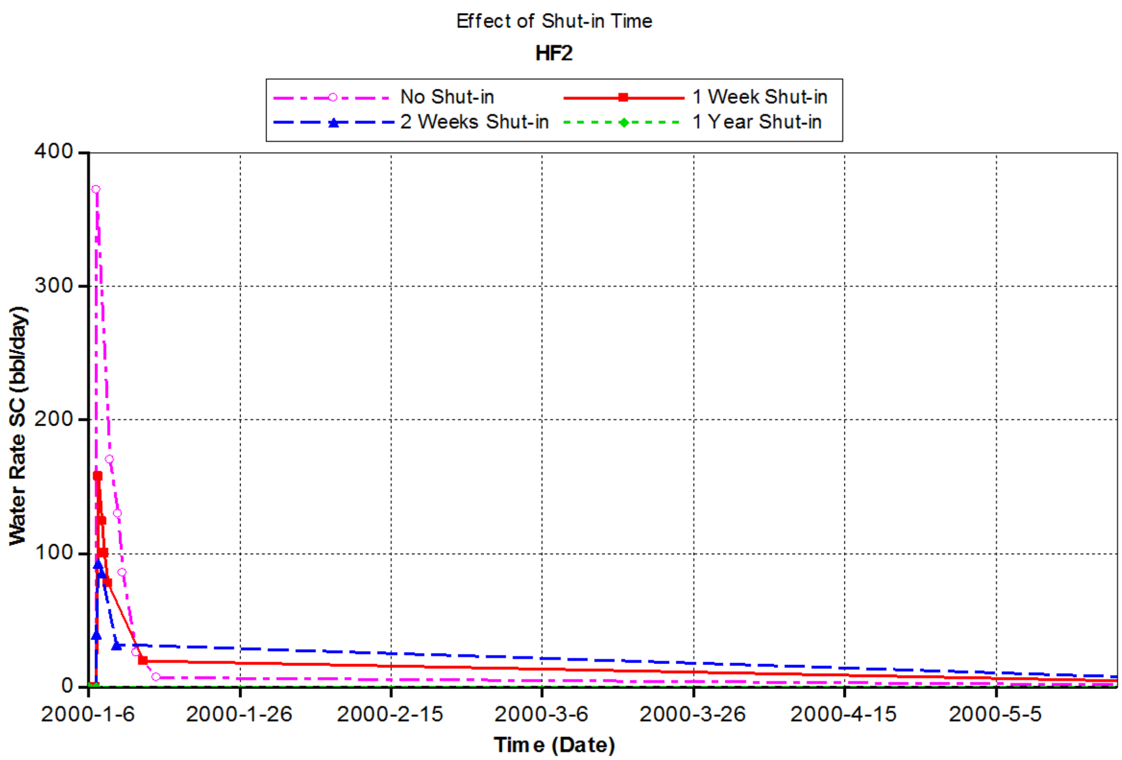

Figure A-6: Effect of shut-in time on fracture fluid production rate in HF3 (100 mesh)

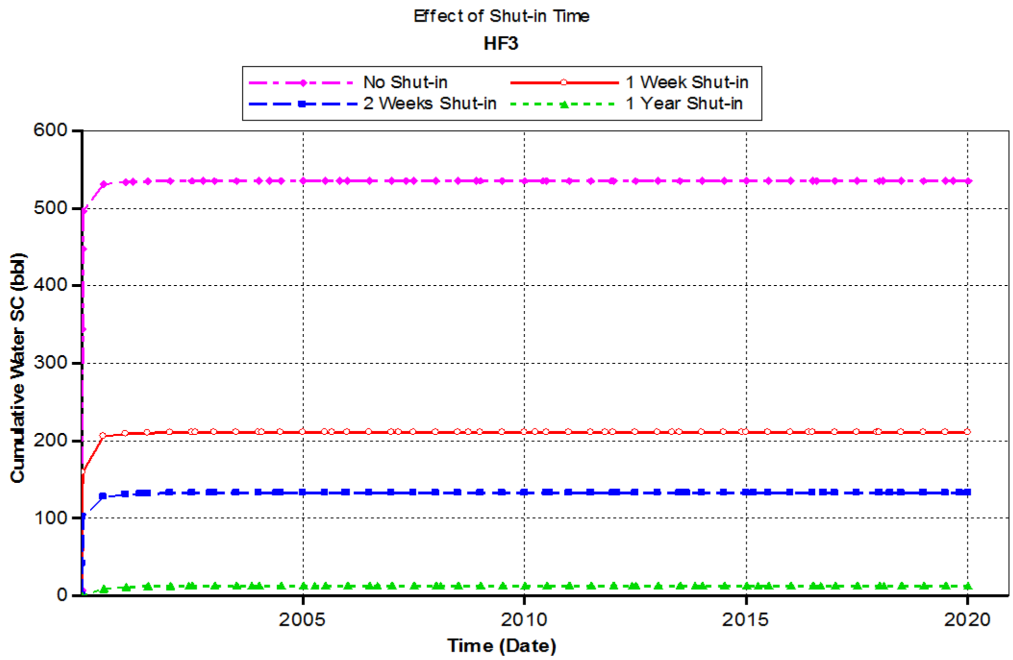

Figure A-7: Effect of shut-in time on cumulative fracture fluid production in HF3 (100 mesh)

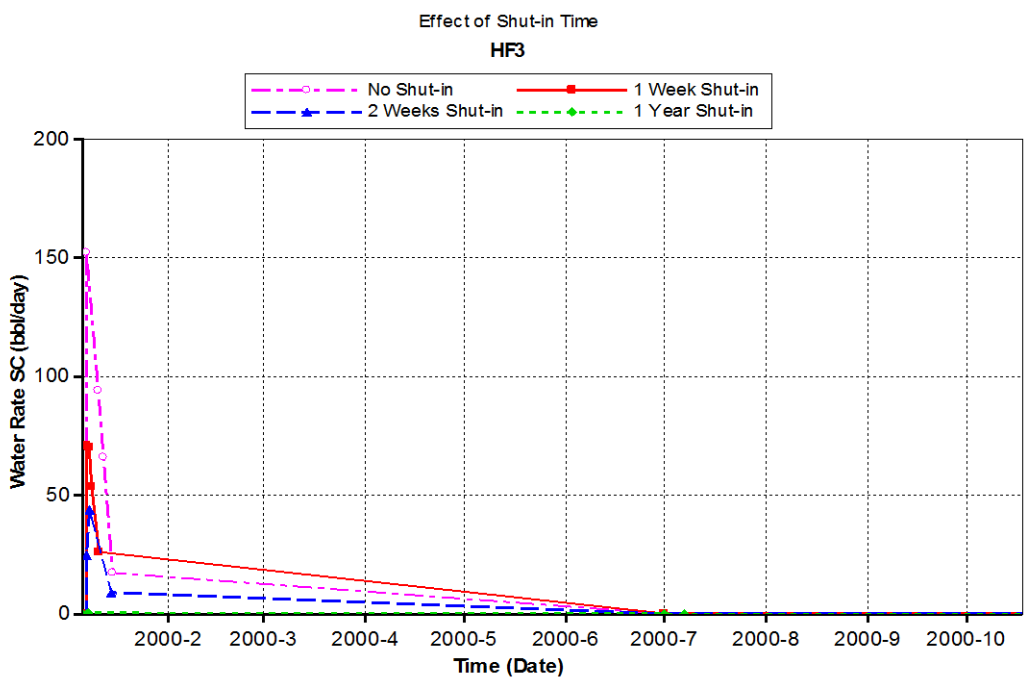

Figure A-8: Effect of shut-in time on fracture fluid production rate in HF3 (100 mesh)

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