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Single phase gas flow response of fractured horizontal and vertical wells to repeated production

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SINGLE PHASE GAS FLOW RESPONSE OF FRACTURED HORIZONTAL AND VERTICAL WELLS TO REPEATED PRODUCTION/SHUT-IN CYCLES

by

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ABSTRACT

Historically, the conventional approach to well production has been to produce continuously, minimizing interruptions to flow insofar as possible. Yet some operators have observed improved well flow rates and ultimate recovery after a significant well shut-in periods. These production increases have not been documented. This study investigates the production impact of cyclic production/shut-in on fractured vertical and horizontal gas well performance.

A numerical reservoir model in Stimplan software was used to model production in fracture stimulated vertical and horizontal gas wells. Reservoir permeability is varied over a range of 0.0001 md to 1 md, and the shut-in period was varied from 0 percent to 100 percent. Results of the simulations are presented as normalized recovery versus shut-in time, where normalized recovery is defined as cumulative production from any simulation case divided by the cumulative production of 0 percent shut-in case.

Results of 120 simulation cases showed that there is an improvement in production in fractured horizontal gas well reservoirs. In vertical gas well reservoirs with permeability greater than 0.001 md, the normalized recovery did not decline significantly with increase in shut-in period. This result shows that cyclic production/shut-in strategy is beneficial in horizontal gas wells and it is not detrimental in vertical gas well reservoirs with permeability greater than 0.001 md.

This study helps to identify the optimum shut-in period required to maximize the production in horizontal gas well reservoirs. In a vertical gas well, cyclic production/shut-in strategy can be used in reservoirs above 0.001 md permeability without significant loss in production.

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Though only my name appears on the cover of this dissertation, many people have contributed to its production. I owe my gratitude to all those people who have made this dissertation possible and because of whom my graduate experience has been one that I will cherish forever.

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TABLE OF CONTENTS

LIST OF ILLUSTRATIONS

LIST OF TABLES

NOMENCLATURE

Symbol	Description
V	Grad
∇^2	Laplacian operator
a	Half axis of horizontal well damage ellipse, ft, m
B_g	Gas formation volume factor, res ft^3/SCF, m^3/Sm^3
B_{gi}	Initial gas formation volume factor, res ft^3/SCF, m^3/Sm^3
C_g	Gas compressibility, psi^{-1}, Pa^{-1}
C_t	Total system compressibility, psi^{-1}, Pa^{-1}
D	Non-Darcy coefficient, $(STB/d)^{-1}$
G_p	Cumulative gas production, STD
h	Thickness of reservoir, ft
I_{ani}	Index of permeability anisotropy, dimensionless
k	Reservoir permeability, md
k_H	Horizontal permeability, md
k(p)	Effective permeability
M	Molecular weight
m(p)	Real gas pseudo pressure, psi^2/cp
p	Pressure, psi
$\bar{p}$	Average reservoir pressure, psi
p_i	Initial reservoir pressure, psi
p_{wf}	Flowing bottom hole pressure, psi
q	Production rate, STB/d, m^3/sec

R	Gas constant, 10.73 psi ft^3/lb mole-^oR
r_w	Wellbore radius, ft
s	Skin effect, dimensionless
S_w	Water saturation, fraction
S_{wi}	Initial water saturation, fraction
t	Time, sec
T	Temperature, ^oR
T_R	Reservoir temperature, ^oK
Z	Gas compressibility, dimensionless
$\boldsymbol{\rho}$	Density, gm/cm^3
Ø	Porosity, fraction
μ	Viscosity, cp
Subscript	Description
e	External boundary
l	Liquid
r	Radius
sc	Standard condition
w	Internal boundary, the well

1. INTRODUCTION

Historically, the conventional approach to well production has been to produce continuously, minimizing interruptions to flow insofar as possible. Mechanical defects, or other wellbore problems which force well shut downs, are viewed negatively, as an interruption to production and cash flow. Even planned shut-ins for pressure build up tests have historically required rigorous justification. This preference for “continuous operation” has been a fundamental approach to managing oil and gas wells since oil and gas was first discovered.

There are a few, specific exceptions to the continuous production approach. One exception is in producing gas wells where flowing bottom hole pressures approach the critical gas velocity, below which water can build up in the tubing and tubing casing annulus. In gas wells with sufficient tubing pressure it is often possible to shut-in the well, allowing tubing pressure to build and push liquids back into the formation. Subsequent production after pressure build up allows gas to flow for a period of time above the critical velocity. This cyclic, pressure management approach to producing a loaded gas well is common and effective for a period of time.

Other applications of well cyclic shut-in have been for secondary or enhanced oil recovery. The literature contains studies citing advantages of shut-in periods coupled with chemical well treatments (Somaruga et al., 2001; Jiang et al., 2013; Jiang et al., 2013, Adhoobi et al., 2013)). While not directly relevant to this work, these studies demonstrate coupling well shut-in time with other well recovery processes.

Al-Zahrani (2012) describes a cyclic production scheme to control high water cuts for the first row of producers near peripheral water injectors. This simulation study evaluates varying shut-in and production times for the producers. The primary objective of the cyclic production scheme was to save the reservoir energy by maintaining pressure and to enhance sweep efficiency by forcing back the liquid column in the wellbore back into the reservoir. Figure 1.1 shows a general cyclic production concept with production/shut-in stage.

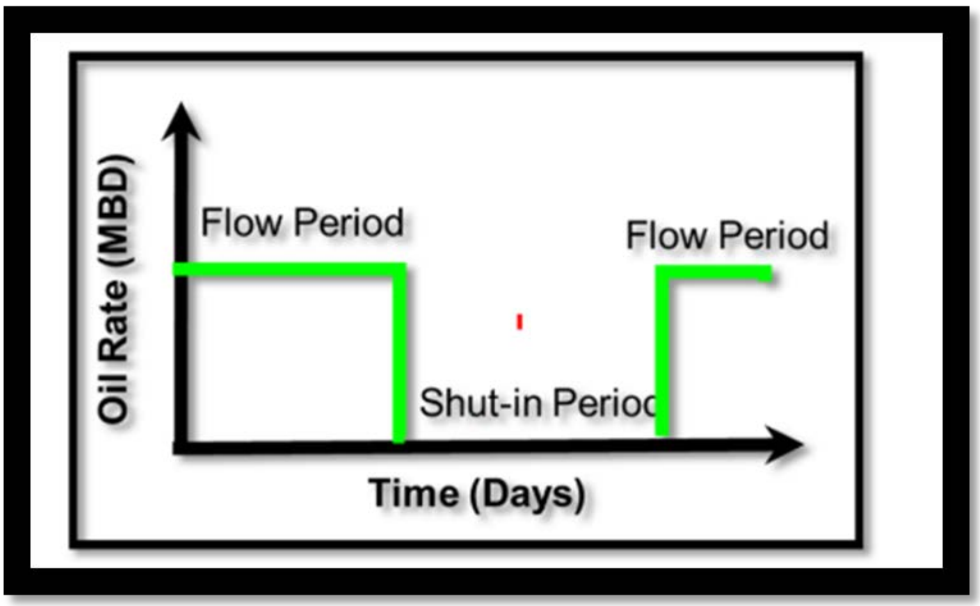

Figure 1.1. Cyclic production scheme (Al-Zahrani, 2012).

Apart from gas well loading or enhanced recovery situations, most operators attempt to produce their wells continuously. Some operators have observed improved well flow rates after a significant well shut-in period, which also improved the ultimate recovery of the well (Britt, 2015). This phenomenon is not well documented. Although it is known that shutting in a well allows the wellbore to come back to equilibrium with current reservoir pressure which increases flowing bottom hole pressure and rate, the effect of the shut-in on ultimate recovery has not been studied in detail.

Other operators have expressed concerns regarding even short term shut-ins of producing wells, on the basis that shut-ins many influence changes in well performance. Again, this phenomenon has not been well documented.

This thesis seeks to summarize available literature related to production shut-ins and related well performance, and to model cyclic production for a single phase gas reservoir using a single phase reservoir simulator.

1.1. PRESSURE RESPONSE IN WELL AND RESERVOIR

When a well is drilled and flow is established from a reservoir a pressure gradient is introduced into the reservoir. The pressure at the wellbore (p_{wf}) will be the lowest pressure and the pressure profile will increase to the boundary of the drainage unit. If the pressure disturbance from the producing well has not reached the reservoir boundary, the pressure is transient. Steady state production occurs when the pressure reaches all reservoir boundaries.

As the pressure is reduced at the wellbore, reservoir fluids will begin to flow near the vicinity of the well. The pressure drop of the expanding fluid will provoke flow from further, undisturbed regions in the reservoir for an unfractured well. The pressure disturbance and fluid movement will continue radially away from the wellbore. This gradually extending region affected by flow is seen in the Figure 1.2. In the time for which the transient condition is applicable it is assumed that the pressure response in the reservoir is not affected by the presence of the outer boundary, thus the reservoir appears infinite in extent.

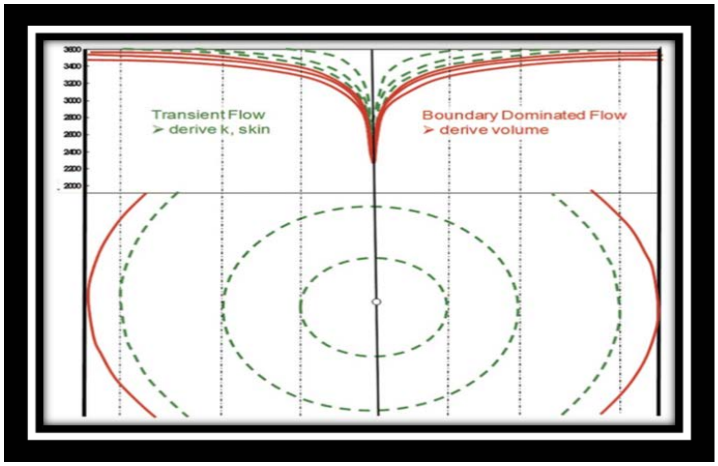

Figure 1.2. Pressure disturbance with production in unfractured well (csgerecorder, web).

There are two modes of transient production. They are constant production rate and constant flowing wellbore pressure as shown in Figure 1.3. For transient laminar flow of homogeneous fluids, constant pressure implies that there is decrease in wellbore production with time and constant rate implies there is decrease in wellbore pressure with time.

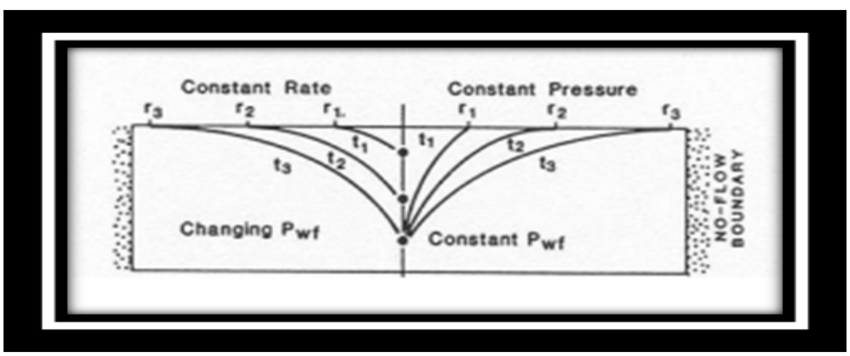

Figure 1.3. Modes of transient flow in unfractured well (Infohost,web).

Pseudo steady state flow occurs during the late time region when the boundaries of the reservoir are all no flow boundaries. It occurs when the pressure transient reaches physical boundaries, or no flow boundaries due to existence of other producing wells or constant pressure due to injection. When reaching boundaries on all sides, a pseudo steady state is reached and pressure drops at same rate in every part of the system. Figure 1.4 depicts pseudo steady state flow in an unfractured vertical well.

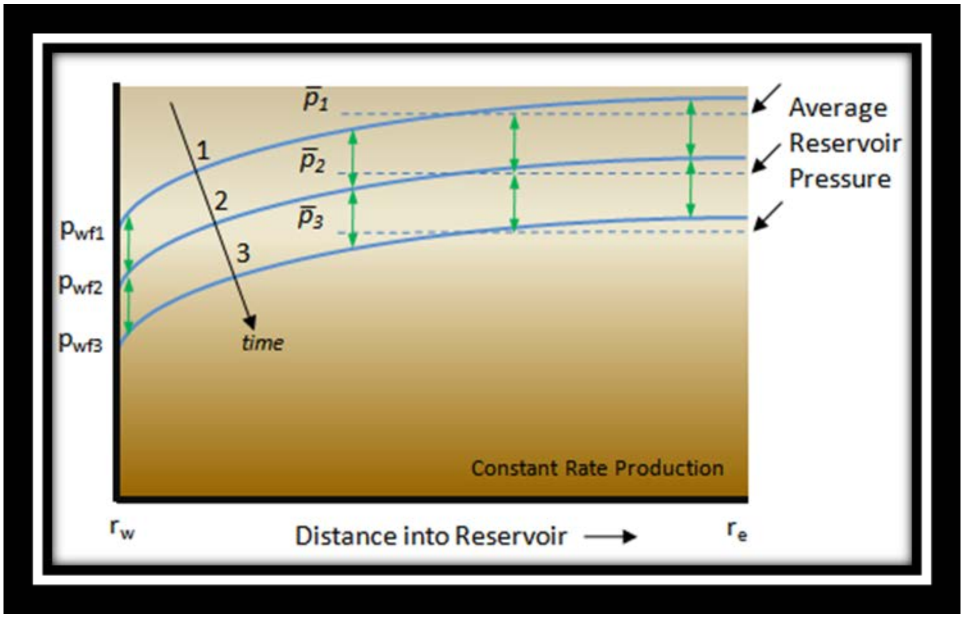

Figure 1.4. Reservoir pressure in an unfractured well in pseudo steady state (Fekete).

For a hydarulically fractured well there are multiple flow periods, which occur in the fracture and the formation, as shown in Figure 1.5. These successive flow patterns include fracture linear flow, formation linear flow, bilinear flow, elliptical and psuedo radial.

When a well is placed on continuous production, transient flow occurs first. When the pressure distribution reaches boundaries, transient flow changes to pseudo transient flow.

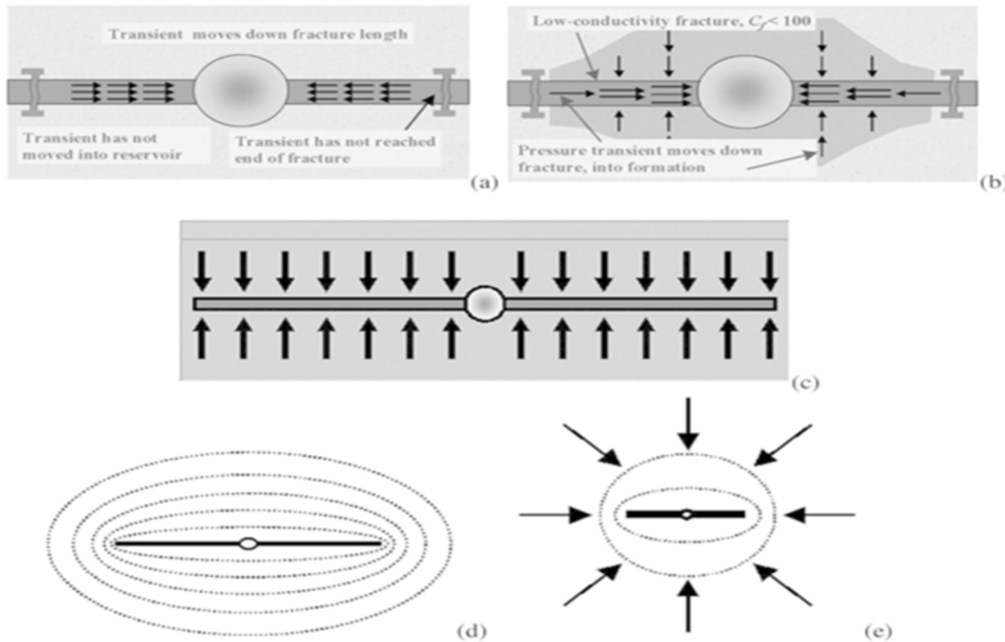

Figure 1.5. Flow periods in a vertically fractured well (Cinco-ley et al. 1981).

If the pressure disturbance hits all the boundaries and pressure at the boundary is constant then then the flow enters either steady state or pseudo steady state flow.

When a fractured well is placed on continuous production, transient flow occurs first. Fracture linear flow occurs first (Figure 1.5-a) although this flow may be for a short time. Following this, bilinear transient flow begins when the formation contribues flow directly to the fracture (Figure 1.5-c) . In late time, the fracture drains the reservoir in an elliptical pattern as shown in Figure 1.5 (d) unless the fracture is short and penetrating a high permeability formation. In this case, late time flow is pseudoradial as shown in Figure 1.5 (e). These late time fracture flow regimes are the flow patterns associated with pseudo steady state flow.

Fluid withdrawals from a reservoir are made by lowering the pressure in the reservoir. The flow of fluids toward low pressure creates zone of lower pressure extending into the reservoir. When a well is shut-in for considerable amount of time, pressure in near wellbore region stabilizes then increases in the area where pressure was previously reduced due to production. If shut-in is maintained for a sufficient duration, and the reservoir permeability is high, the near wellbore pressure can build back to current reservoir pressure (Figure 1.6.). The pressure behavior after shut-in can be analyzed for reservoir properties (Horner, 1951; Matthews and Russell, 1967). Once the well is placed on production again, the higher pressure increases well flowrate. It is expected that this flowrate will be higher than the pre-shut-in flowrate.

In low permeability formations, particularly nanodarcy permeabilities found in unconventional reservoirs, the transient flow period may last months, or even years. Hence the pressure increases incurred by shutting in tight gas wells will be less than that of high permeability wells for a given period of time.

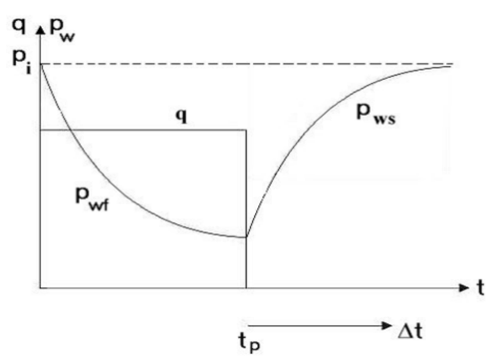

Figure 1.6. Well flow and pressure build up after shut-in (Testwells.com).

1.2. GAS FLOW IN POROUS MEDIA

Fluid flow through porous medium is governed by the properties of fluid, pressure distribution in the system and geometry of the matrix. The fundamental flow equations are derived by combining the continuity equation with Darcy's Law, and assuming the porous media is homogeneous, the composition of the gas is constant, and there is laminar and isothermal flow. This leads to

$$\emptyset \frac{\partial \rho}{\partial t} = \nabla(\rho \frac{k}{\mu} \nabla p) \qquad (1)$$

For real gases density is given by equation

$$\rho = \frac{M}{RT}[\frac{p}{z(p)}] \qquad (2)$$

Density is eliminated from Equation 1 by substitution to give a non-partial differential equation that describes isothermal flow of real gas through porous media

$$\nabla[\frac{k(p)}{\mu(p)z(p)} p\nabla p = \phi \frac{\partial}{\partial t}[\frac{p}{z(p)}] \qquad (3)$$

Pressure dependent permeability effects are neglected as the impact of pressure on gas properties is much more important. Therefore the equation can be written as

$$\nabla \left[\frac{p}{\mu(p)z(p)}\right] p\nabla p = \phi\ [\frac{\partial}{\partial t} \frac{p}{z(p)}] \qquad (4)$$

Real gas diffusivity is given by $\frac{k}{\phi\mu(p)C_g(p)}$ and $p\nabla p = \frac{1}{2}\nabla p^2$ By substituting these two relationships in Equation 4 and assuming that viscosity and gas compressibility change slowly with pressure and also assuming that pressure gradients are very small, results in the equation.

$$\nabla^2 p^2 = \frac{\phi\mu(p)C_g(P)}{k} \frac{\partial P^2}{\partial t} \qquad (5)$$

Equation 5 is in the form of the diffusivity equation and its solutions, under the assumption listed in this section, could have the shape of the solutions of the equation for oil, presuming that p^2 is used instead of p. This solution suggests that a gas well production rate is proportional to the pressure squared difference.

$$\bar{p}^2 - p_{wf}^2 \quad = \frac{1424\ q\bar{\mu}\,\bar{Z}T}{kh}(\ln\frac{0.472re}{rw} + s) \qquad (6)$$

Equation 6 presents the Pseudo steady state form of this approximation. It is important to remember that this is derived assuming Darcy flow it the reservoir, i.e. small gas flow rates and P<2000 psi. For larger gas flow rates the gas flow approximation equation is used, with the constant "C" and exponent "n" determined from a four point test on the well.

$$q = C\ (\bar{p}^2 - p_{wf}^2) \qquad (7)$$

The assumption that pressure gradients are very small is not valid in many cases particularly for high flowrate wells where p>2000 psi. Equation 5 can lead to large errors in these wells. A-Hussainy and Ramey (1966) introduced the real gas pseudo-pressure function, m(p), defined as

$$\mathrm{m(p)} \ = 2\int_{p}^{p_0} \frac{P}{\mu z} dp \qquad (8)$$

Where p_o is some arbitrary reference pressure. The real gas pseudo pressure function is applicable for all pressures. The differential psuedo pressure is Δ m(p), defined as m(p)-m(p_w), is the driving force of the reservoir. For low pressures this function is

$$2\int_{p_{wf}}^{p_i} \frac{P}{\mu z} dp \approx \frac{p_i^2 - p_{wf}^2}{\mu Z} \qquad (9)$$

Whereas for high pressure (both P_i, P_{wf} higher than 2000 psi) the real gas pseudo pressure becomes

$$2\int_{p_{wf}}^{p_i} \frac{P}{\mu z} dp = \frac{\bar{p}}{\overline{\mu \bar{Z}}}(p_i - p_{wf}) \qquad (10)$$

The real gas pseudo-pressure can be used instead of the pressure squared difference in any gas well deliverability relationship, properly adjusted for the viscosity and the gas deviation factor. All solutions for the diffusivity equation for oil are also applicable for gas well with pseudo pressure. For example, the transient flow equation for gas with the real gas pseudo-pressure function for pressure is

$$\mathrm{Q\ (MSCF/d)} = \frac{kh[m(P_i)-m(P_{wf})]}{1638\,T}\left[\log t + \log\frac{k}{\text{Ø}(\mu c_t)_i r_w^2} - 3.23\right]^{-1} \quad (11)$$

Gas production in a vertical well is described with the flow equations briefly presented thus far. For horizontal wells, the drainage area becomes an ellipse and the inflow performance relationship for a horizontal gas well in pseudo steady state with turbulence effects is given by

$$Q = \frac{k_H h(\bar{P}^2 - P_{wf}^2)}{1424\mu ZT\left(\ln\left\{\frac{a+\sqrt{a^2-\left(\frac{L}{2}\right)^2}}{\frac{L}{2}}\right\} + \frac{I_{ani}h}{L}\left\{ln\frac{I_{ani}h}{r_w(I_{ani}+1)} - 3/4 + Dq\right\}\right)} \quad (12)$$

This equation uses the pressure squared difference approximation but the real gas pseudo pressure could be used instead.

1.3. GAS MATERIAL BALANCE

Material balance methods are useful in estimating initial reserves or produced gas at any pressure as the reservoir depletes. The material balance equation for gas reservoir with no water influx is

$$G_p B_g = G(B_g - B_{gi}) \quad (13)$$

$$\text{Where } B_g = \frac{1}{5.61}\frac{14.7}{P}\frac{T_r Z}{P} = \frac{0.0005\,T_r Z}{P} \quad (14)$$

Substituting for Bg into Equation 13 and simplifying gives

$$G_p = \left(1 - \frac{\frac{\overline{Pr}}{Z}}{\frac{P_i}{Z_i}}\right) \quad (15)$$

This equation shows that a plot of Gp versus p/z on rectangular coordinate paper should result in a straight line. Figure 1.7. shows the plot of p/z vs G_p. The extrapolation of the straight line to any p/z value gives total recovery at that pressure value, and its extrapolation to p/z = 0 gives the initial gas in place.

The p/z plot is used in the petroleum industry for conventional gas reservoirs, to predict gas recovery versus pressure an initial gas in place. Some pressure and production data are required to establish the depletion characteristics. In addition, any water influx must be accounted for separately.

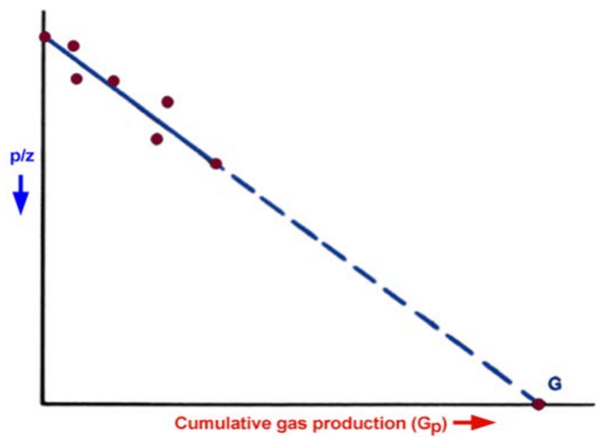

Figure 1.7. Gas material balance, p/z vs G_p ((Horner, 1951).

In applying the material balance equation to gas reservoirs with no water influx, it is normally assumed that the rock and its associated water expansion is insignificant compared to that of the gas expansion and is normally ignored. In the case of abnormally pressured reservoirs the compressibility of the rock cannot be ignored. It acts to maintain the pressure at a relatively high values. If a gas reservoir is abnormally pressured the following equation is used to calculate the recovery or gas in place:

$$G = \frac{G_p B_g}{B_g - B_{gi} + \frac{B_{gi}}{1 - S_{wi}}(S_w C_w + C_r)(P_i - \overline{P_r})} \tag{16}$$

A brief presentation of gas material balance is included in this section since the fundamental concept of material balance is included in all reservoir simulators. Reservoir simulators like the single phase model in stimplan consist of sets of equations for a large number of grid blocks. These equations represent conservation of mass of each component in the grid block over a time step. These calculations are far more complex, but the concept is embodied in the simple gas material balance equations.

1.4. DESCRIPTION OF THE TOPIC

The main objective of this study is to investigate the effect of repeated production/shut-in cycles on recovery from reservoirs over varied permeability. stimplan software is used to run the simulation cases with varied shut-in time to identify the optimum shut-in time for a reservoir. Optimum shut-in time is investigated for a range of permeability from 0.0001 md to 1 md in both horizontal and vertical fractured stimulated gas wells.

Input data such as reservoir data, fracture data, fluid data are taken from the Eagle Ford shale play as described in Section 4. The cyclic production/shut-in stages are described in detail in the simulation control section of Section 4. The duration of production and shut-in stages are calculated over each period of three months. For instance, in a three months period if the well is shut-in for 1 % of the time, then it is flowing for 99 % of the time. So, the well is on production for 90.3375 days and it is closed for 0.9125 days. Similarly, shut-in and flowing time are calculated for 5 %, 10 %, 20%, 30%, 40%, 50%, 75% are calculated on each period of three months. These production/shut-in cycles are continued for first 20 years and well is continuously, without interruption for an additional 30 years on production for the rest thirty years.

Section 5 presents the results of the simulations and Section 6 summarize those results and provides conclusions of the study.

2. LITERATURE REVIEW

A literature survey revealed few papers directly related to the effect of cyclic production/shut-in on production operations. Much of the prior work was related to post fracture clean-up and how to maximize polymer clean-up by managing the post-fracture flow-back. Unfortunately, the literature is mixed as to the best ways to flow-back wells. Ely, for example, suggested that “forced closure” of the fracture by immediately flowing-back the well at the end of the fracture treatment resulted in better well performance. The concept was that by immediately flowing-back the well the proppant would be maintained near the perforated interval and the final fracture dimensions and thus well performance would be improved as compared to a post fracture extended shut-in to closure and the associated proppant settling (Ely et al. 1990).

Similarly, Anderson et al. discussed benefits of aggressive flow-back in the Codell formation over the conventional shut-in flow back procedures. Generally, the well that is fractured is shut-in over-night and allowed to flow back in the morning, on a small choke in an attempt to manage the closure stress on the proppant and prevent crushing. Rapid flow-back results in a better proppant pack in the fracture as compared to shutting the well in and allowing proppant settling to occur unabated. One concern with rapid flow back procedures is that it can cause wear on production equipment due to proppant flow-back. Such wear can be limited by using physical or chemical methods such as using fiber proppant and resin coated proppant are proposed to reduce the production of proppant with rapid and high rates of flow back fluids (Dowell et al. 1936).

Pope et al. also reviewed the Codell Formation data and determined that fracture clean-up can be quantified by measuring the amount of polymer recovered. This work further showed that increased polymer recovery resulted in increased gas production rates and that increasing the initial flow-back rate increases the load water and polymer recovery. More importantly to this work they found that the impact of varying flow-back methods and fluid chemistries could be quantified and optimized (Pope et al. 1996).

Willberg et al. studied the East Texas Cotton Valley Formation and found that polymer recovery and fracture fluid clean-up in general is limited if formation water is being recovered during clean-up. As a result, fracture clean-up was hindered in the Cotton Valley Formation of East Texas (Willberg et al. 1997).

May et al. continued this work by investigating the polymer fluid clean-up to determine why Cotton Valley fracture treatments produced less than half of the injected polymer. In this study, the effect of cyclic shut-in is implemented to see if the fracture length increases by shutting in the well after the initial clean up. Wells are shut-in for one hour for 30 days, 90 days and 6 months. In all these cases, cumulative production is increased slightly though there is no significant increase in the clean-up length (May et al. 1997).

Anderson et al. rapid flow-back procedures implemented in North Central Texas showed that well productivity and clean-up improved with aggressive flow back procedures. This work documented an experiment in the Barnett shale. The experiment included immediately flowing-back a portion of the wells while the rest are closed for 4 to 6 hours after the treatment. The wells that are closed are put back on production with flow rates less than 0.6 BPM, while the wells immediately flowed-back are produced at 3 BPM. As a result, the high flow-back rate wells were cleaned-up for 46 hours while the slower flow-back wells were cleaned up for 186 hours. The economic evaluation of this field test showed that wells that are aggressively flowed back saved nearly $ 6,000 per well in flow back operations cost not including the gas deferred due to prolonged flow back (Willberg et al. 1998).

Conversely, Crafton showed that gas well performance was extremely sensitive to early time production management especially in more ductile shales when the fractures are liquid filled (Crafton & Noe, 2013).

Crafton also conducted a study of flow-back behavior using both physical and mathematical experiments, as well as actual production data to show that once the proppant pack is immobilized, low flow-back rates can be more beneficial to well performance than rapid flow-back especially when production delays due to proppant flow-back are factored into the economics (Crafton, 2008).

This mixed flow-back message was best explained in a study by Smith et al. Their work showed that the final proppant placement and fracture dimensions and ultimately well performance resulted from a complex interaction of geomechanical, fracturing, and physical parameters such as in-situ stress contrast, fluid loss variations, gravity (proppant settling), and fracture fluid rheology (Smith et al. 2001).

All agree that once the well starts cleaning up the process shouldn’t be interrupted lest well performance be detrimentally impacted. However, once the well is cleaned-up it was shown by Britt in his 1999 Distinguished Lecture presentation entitled Reservoir Management through Hydraulic Fracturing that shut-ins may be beneficial to long term well performance. This presentation documented a twenty well pilot in the East Texas Cotton Valley Formation where wells were shut-in for one to two weeks. In this field test, post shut-in well performance was improved in each and every well. The best post shut-in performers were wells with liquid loading issues, however (Britt, 1999).

Whitson et al. proposed the use of cyclic shut-in periods for low permeable wells that are stimulated. That is the well is put on alternative production and shut-in cycles. This is implemented to eliminate liquid loading in the wells. Liquid loading occurs when the gas rate falls below the critical flow velocity required for the liquids to be recovered and they fall back in the wellbore. Once the well is loaded it is shut-in. During the shut-in period the bottom hole pressure increases and when the well is put back on production the increased pressure drop results in an increased production of gas. Due to an increase in the gas rate the liquids are produced assuming the flow rate is in excess of the critical flow velocity. This increase in bottom hole pressure is seen in both vertical and horizontal stimulated wells (Whitson et al. 2012).

In 2012, Al-Zahrani compared the production performance of oil wells with cyclic production/shut-in stages to continuous production through reservoir simulation. The cyclic production scheme was initially implemented to see the effect on water production, coning effects, and sweep efficiency. The results showed that there are various advantages in applying a cyclic production strategy over a noncyclic production strategy. This strategy was applied on 93 wells and most of these proved that cyclic production strategy improves overall oil recovery, reduction in water production and sweep efficiency is increased. This study mainly focused on identifying the best cyclic production scheme to minimize water production, however (Al-Zahrani, 2013).

Crafton investigated various early production management strategies and concluded that delay of first production is detrimental to the production. Two hundred and seventy wells were analyzed in the Marcellus shale to determine the significant factors that mitigate the damage caused by shut-in. First, non-volatile surface tension management using IFT chemistry mitigates the damaged caused by shut-in, however, it will not prevent it. Another factor found was the rate of change of surface pressure caused by shut-in and flow-back. Crafton found that it the surface pressure changes by more than 250 psi, it impacts the well performance by damaging the wellbore connectivity. He proposed using high conductivity proppants to reduce the damage caused by shut-in. Finally, he proposed the use of a combination of IFT chemistry, high conductive proppants, and Interfacial tension management fluids to reduce the damage caused by shut-in (Crafton, 2013).

3. WELL AND RESERVOIR PARAMETERS

3.1. CONVENTIONAL AND UNCONVENTIONAL RESOURCES

Some in the oil and gas industry deem resources conventional and/or unconventional based on reservoir permeability. Others deem reservoirs with organics (source rock) as unconventional and the lack of organic material as evidence of a conventional reservoir. However, these definitions are too simplistic. After all aren't the heavy oil deposits of Canada unconventional and aren't the coalbed methane reservoirs in the San Juan Basin or Queensland, Australia unconventional resources? What makes a reservoir unconventional or conventional is whether conventional recovery methods are suitable to extract hydrocarbons from the reservoirs. Although unconventional resources contribute tremendous reserves stimulation techniques like hydraulic fracturing were applied to these resources that they became economically viable. Due to low permeability of unconventional resources, great attention must be given to the design of hydraulic fracturing to make these resources profitable (Zahid et al. 2007).

Along with hydraulic fracturing, extraction from unconventional resources also depends on well design. Commonly used vertical wells are not always viable for the economic development of unconventional resources. Horizontal drilling is preferred over the vertical drilling in many unconventional resources (Ishak et al. 1995).

Development of massive hydraulic fracturing has increased the productivity considerably from unconventional resources. Massive hydraulic fracturing is a process of pumping huge amounts of fluid and proppant for production from tight gas formations. Massive hydraulic fracturing applied on Raageshwari deep gas field in India proved to be very successful. While applying massive hydraulic fracturing attention must be paid to fracture design such as fluid selection, proppant, pump rate, volume of fluid required for treatment, etc., (Shaoul et al. 2007).

With the advancement in horizontal drilling techniques, hydraulic fracturing and massive hydraulic fracturing, unconventional resources that were once considered not economically viable have become profitable. Now, these unconventional resources are major sources of energy that helps in bridging the gap between supply and demand. Figure 3.1. depicts a resource triangle with classification of resources.

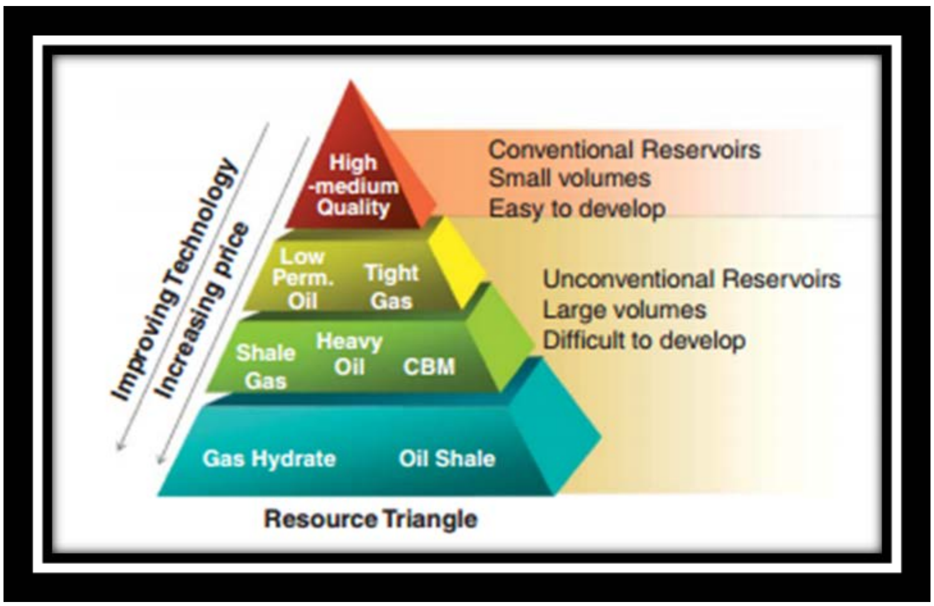

Figure 3.1 Classification of resources (Dong et al. 2011).

3.2. HYDRAULIC FRACTURING

Hydraulic fracturing is defined as the process in which fluids are pumped down the wellbore into the formation with sufficiently high pressure to exceed the minimum horizontal stress and induce a crack in the formation. Proppant (often sand) is then pumped with fluid to hold the fracture open so that a conductive pathway can carry reservoir fluids to the wellbore. In the unconventional reservoirs fluid flow from reservoir to wellbore is limited by poor connectivity. The main objective is to create long conductive fractures to access these resources and improve the recovery of hydrocarbons (Lindley, 2011).

Successful hydraulic fractures require the selection of right candidate. A candidate well is selected based on formation damage, formation flow capacity, existing reserves, and economics. Hydraulic fracturing removes skin and improves the productivity by increasing the effective wellbore radius. Orientation of hydraulic fracture depends on the in-situ stresses with the induced hydraulic fracture propagating perpendicular to the least principal stress (Coulter, 1976).

Table 3.1. Shows typical values of some parameters for candidate well selection in hydraulic fracturing (Zhang et al. 1994).

Table 3.1. Hydraulic fracturing candidate well selection.

Parameter	Oil Reservoir	Gas Reservoir
Hydrocarbon	> 40 %	> 50 %
Water Cut	<30 %	< 200 bbl/MMSCF
Reservoir Pressure	< 70 % depleted	twice abandonment pressure
Gross Reservoir Height	> 10 m	> 10 m

Successful of hydraulic fractures also depend on the treatment design. Treatment design includes selection of fluid (type and volume), proppant (type, size, and concentration), and pump-rate. Dimensionless fracture conductivity is used to determine the fracture dimensions required for a particular formation. Dimensionless fracture conductivity is defined as ratio of fracture conductivity to the product of fracture half-length and reservoir permeability. For reservoirs with low permeability, longer fracture lengths are required and for reservoirs with higher permeability high conductivity fractures are required (Al-Khatib et al. 1984).

Figure 3.2. shows the fractures created by hydraulic fracturing. Hydraulic fracturing of horizontal wells in low permeability reservoirs is considered a profitable means of recovering hydrocarbons. Optimum fracture orientation and length can be ascertained by careful consideration of a reservoir's geometry, permeability, and stress contrast and fluid saturations (Hudson & Matson, 1992).

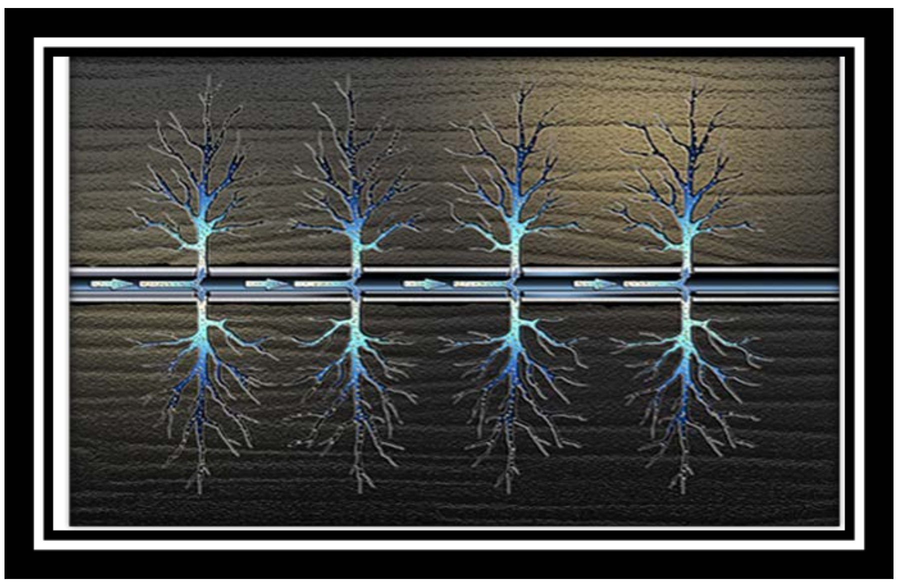

Figure 3.2. Hydraulic fractures (FracFocus).

3.3. VERTICAL VS HORIZONTAL WELL

Vertical wells were commonly drilled in any type of formation until horizontal drilling was introduced to the oil and gas industry. Horizontal drilling was first introduced to the industry in 1929, though the first commercial horizontal well was drilled in Pennsylvania in 1944. Horizontal drilling has proven to be productive especially in low permeability formations. As a result, there has been a tremendous increase in the use of horizontal drilling in the United States as nearly 60% of all wells drilled in the U.S. are now horizontal (Rachel et al. 2011).

Horizontal wells have several advantages over the vertical wells in conventional reservoirs with low productivity, reservoirs with vertical fractures, recovery is limited by water or gas coning, thick continuous heavy oil and bitumen containing sands. Horizontal wells improve productivity of these wells by accessing the areas that are not accessed by vertical wells. Vertical wells will only be able to access the hydrocarbons that immediately surrounds the end of the well. Horizontal wells are able to access hydrocarbons surrounding the entire portion of the horizontally drilled section (Qui et al. 1988).

Horizontal wells are better producers than vertical wells in isotropic reservoirs mainly because of two factors: the inclination and the longer contact length with the reservoir. But in reservoirs with very low vertical permeability than horizontal permeability horizontal wells may perform worse than the vertical wells. Horizontal wells are suitable to reservoirs with $k_v/k_h > 0.5$ (Zhang et al. 1994).

Horizontal wells have been very successful in naturally fractured reservoirs and in reservoirs with gas/water coning problems. Fracturing a horizontal well is more complex than vertical wells. Because of the dependence of fracture orientation on well direction with respect to the stress field, the possibility of fracturing a horizontal well must be considered before the well is drilled. Fracture orientation in horizontal wells is more complex, if wellbore is aligned with the maximum horizontal stress, the fracture will be perpendicular to wellbore, it is referred as transverse fracture. If wellbore is aligned perpendicular to the wellbore, it is referred as longitudinal fracture. Above critical permeability of reservoir, longitudinal fractured horizontal wells outperform transverse fractured horizontal wells. (Yang et al, 2015). Figure 3.3. depicts the difference between horizontal and vertical drilling in gas sources rock in shale/coalbed methane.

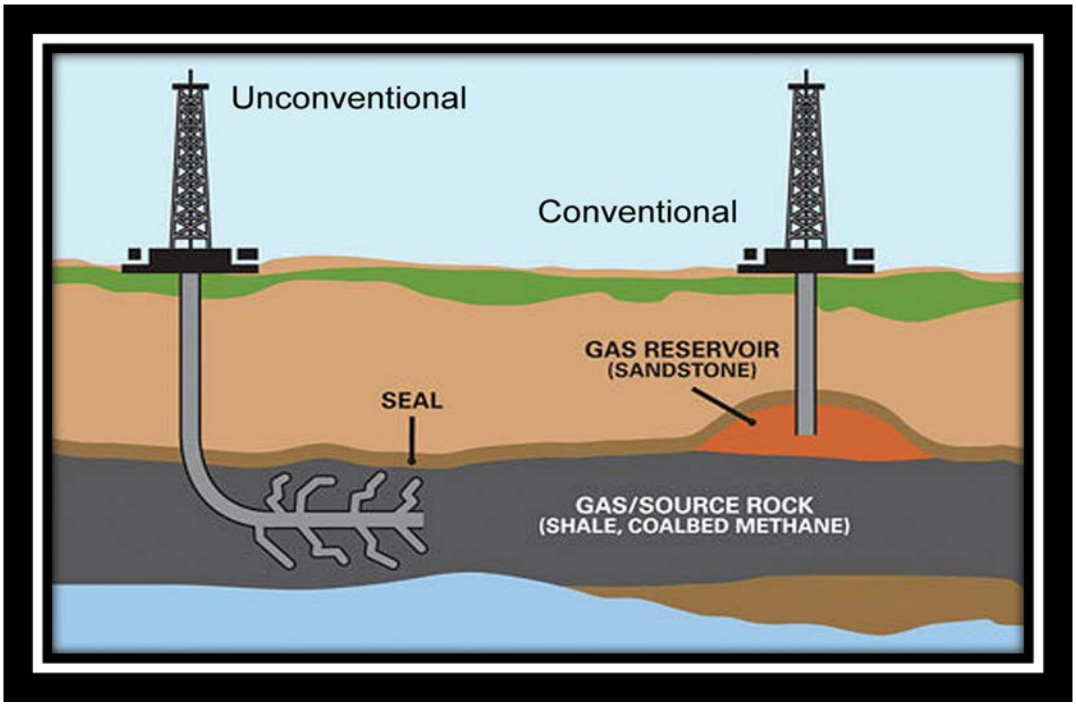

Figure 3.3. Horizontal drilling vs vertical drilling (Worldinfo.org).

4. METHODOLOGY

4.1. STIMPLAN SOFTWARE

The single phase numerical reservoir simulator in stimplan is used for modelling the reservoir in this study. This software is provided by NSI Technologies Inc. It is a robust software package that has been commercially available since 1985. stimplan is a highly sophisticated software system used for designing, executing, and post appraising hydraulic fracture stimulations even in complex reservoirs.

Key features of the stimplan software include data handling and analysis, rigorous fracture geometry modelling, acid fracturing in carbonate reservoirs, integrated reservoir simulation, accurate proppant placement, automated treatment scheduling, post-frac production analysis, economics, and fracture optimization. Updated software includes modules to analyze micro-seismic data and stimulation design with discrete fracture network model.

Fracture geometry modelling is done using a numerical simulator. In the fracture module there are several models available including a pseudo 3-D model and a much more rigorous fully three dimensional finite element model. In addition to the fracture geometry models two different reservoir simulators are available to analyze the pre and post fracture well performance. One is an analytical reservoir simulator and one is a numerical reservoir model.

For this study the reservoir model used is the numerical reservoir model. Reservoir data, flowing conditions, fluid data, and fracture data is given as input in the simulator data. Shut-in cycles and well head flowing conditions were input into the reservoir simulator. Either gas well or oil wells and vertical or horizontal wells can be simulated.

4.2. DESCRIPTION OF RESERVOIR MODEL

This study used a single well, single phase finite difference model to examine the effect of shut-ins on well performance. The reservoir fluid is a considered as a single phase, compressible liquid or non-ideal gas. The numerical solution also includes the compressibility of the rock and the saturated water.

The reservoir can contain multiple vertical layers, with varying properties for horizontal/vertical permeability, porosity, pressure, water saturation, non-Darcy "β". The non-Darcy β is a function of formation porosity and permeability. The model simulates a single well in a rectangular drainage area.

The model also has the capability of including fractured and un-fractured vertical or horizontal wells. In horizontal wells the fractures can be orthogonal to or parallel to the wellbore. The fracture conductivity ($k_f b_f$), fracture permeability (k_f), propped width (b_f), and non-Darcy β can be constant or vary when coupled to a fracture simulator.

For fractured cases the perforated height can differ from the pay height. The external boundary conditions can be either constant pressure or no flow. For the constant surface pressure cases, the well pressure solution is coupled to the reservoir pressure solution.

In the reservoir the temperature is assumed constant but the viscosity for gas calculations varies with changing pressure.

4.3. INPUT DATA

The purpose of this study is to investigate the effect of shut-in/production cycles on the cumulative production from hydraulically fractured horizontal and vertical gas wells. To model gas reservoirs following data is needed:

A hydraulically fractured gas well is selected for the study. It is assumed that there is non-Darcy flow in the fractures but not in the formation. The reservoir drainage area is 640 acres with an aspect ratio of 1.0 (5280 ft. × 5280 ft.) and a closed reservoir boundary.

Reservoir properties such as rock compressibility, water compressibility, wellhead temperature, and reservoir temperature are given. Completion data includes the top and bottom perforations are given in true measured depth as well as tubing ID, flow string length and pre fracture skin is zero.

Since it is a gas well, properties of gas from the reservoir are input. Gas composition such as volume fraction of CO_2, H_2S, N_2 are given. Reservoir pressure and bottom hole flowing pressure are input and these are used to calculate viscosity of gas, compressibility of gas and compressibility factor. Calculated values are used the numerical simulator. If these values are available from the field data, they can be directly input into the fluid properties instead of calculating based on the reservoir temperature and pressure. The reservoir model input includes net pay which for this project a value of 300 feet was used, an average porosity of 8%, an average water saturation of 25%, and a permeability varied from 0.0001 to 0.1 md. Table 4.1 to 4.4 captures the input data for the study including the reservoir data, well data, produced fluid data, and fracture data, respectively.

Table 4.1. Reservoir data.

Reservoir Data			
Drinage	A	640	Acre
Aspect Ratio	As	1	
Net Pay Top Depth		8000	ft
Net Pay Bottom Depth		8300	ft
Net Pay Height	h	300	ft
Reservoir Pressure	Pi	4000	psi
Reservoir Temperature	Tr	280	
Boundary Condition		Closed Boundary	
Reservoir Permeability	k	Varied	
Porosity	Ø	0.05	
Water Saturation	Sw	0.25	

Table 4.2. Well data.

Well Data			
Well Type		Horizontal	
Well Type		Gas well	
Lateral Length	L	4000	ft
Well head Temperature	68	68	F

Table 4.3. Production fluid data.

Production Fluid Data			
Gas Viscosity	µg	0.02	cp
Gas compressibility	Cg	362	E-6 1/psi
Gas Expansion Factor	Z	0.866	
Gas Gravity	SGg	0.65	

Table 4.4 Fracture data.

Fracture Data			
Fracture Orientation		Transverse	
Fracture Half Length	Xf	500	ft
Dimensionless	Fcd	10	
Number of fractures	Nf	10	

4.4. PARAMETRIC STUDY

In hydraulically fractured gas wells, the effect of periodic shut-in cycles on productivity is analyzed. Recognize that since the time taken for the pressure to build-up is higher for low permeability reservoirs than a high permeability reservoir the optimum shut-in time likely will vary as a function of permeability. As a result, two distinct studies were undertaken. The first case analyzed the effect by considering constant shut-in periods and varying reservoir permeability from 0.0001 md to 0.1 md. Table 4.5. shows the simulation cases used. The second case maintained constant reservoir permeability and varied the shut-in period to investigate and determine the optimum shut-in period.

Table 4.5 Simulation cases.

Percentage of shut in	Flow days	Shut-in days	1 md Cum gas mmcf	0.1 md Cum gas mmcf	0.01 md Cum gas mmcf	0.001 md Cum gas mmcf	0.0005 md Cum gas mmcf	0.0001 md Cum gas mmcf
0	91.25	0						
1	90.3375	0.9125						
5	86.6875	4.5625						
10	82.125	9.125						
20	73	18.25						
30	63.875	27.375						
40	54.75	36.5						
50	45.625	45.625						
75	22.8125	68.4375						
100	0	91.25						

4.5. SIMULATION CONTROL

Simulation control is the major part of any numerical reservoir model and within stimplan there are two sub-divisions called stages and cases. The production cycles and wellhead pressure control are given in stages while the fracture length, fracture conductivity, fracture width, and number of fractures are specified in cases.

The stage section of well control includes both the flowing stage and shut-in stage. The flowing stage is the time for which the well is open and flowing and the shut-in stage is when the well is shut-off and there is no production. Simulations are repeated for a constant permeability case by changing the percentage of shut-in from 0 to 100 %. Similarly simulations are repeated by changing reservoir permeability from 0.0001 to 0.1 md and keeping the period of shut-in constant.

The percentage of the shut-in and flow time is calculated for every three months. For example, a case with a 1% shut-in period, the well flows for 90.3375 days and is shut-in for 0.9125 days. Similarly, flowing and shut-in time are calculated for 2% , 5%, 10%, 20%, 30%, 40%, 50%, 75% shut-in as show in Table 4.5.

In simulation control, the flowing stages are controlled either well head pressure or bottom hole pressure. This study uses well head pressure as the control. The limit of wellhead pressure is fixed at 50 psi, during which the maximum allowable flow rate is 10 MMSCFD. Shut-in period is controlled with rate and the value being zero as there is no production during shut-in period.

Cumulative well life is 50 years that is 18250 days. Thus shut-in cycles are continued for first 20 years and then well is allowed to flow for next 30 years. This is same for all 60 simulation cases.

4.6. COMPARISON CRITERION

There are two ways data from the study are considered. They are:

- To find optimum shut-in period for a constant time permeability
- To analyze effect of a constant shut-in period on varied reservoir permeability

In all cases, normalized recovery is used to analyze the results. Normalized recovery is defined as the ratio of recovery for the case to the recovery for zero percent shut-in case. Graphs of normalized recovery show the percentage of increase or decrease in recovery as a function of shut in and permeability.

5. RESULTS AND ANALYSIS

5.1. HORIZONTAL GAS WELL RESERVOIR

Sixty simulation cases were run for the fracture stimulated horizontal well geometry. Shut-in period is varied from 0 percent to 100 percent over a range of permeability 0.0001 md, 0.0005 md, 0.001 md, 0.01 md, 0.1 md, 1 md. Normalized recovery is used to compare results from simulation runs. Table 5.1 summarizes the results from simulation cases.

Table 5.1.Simulation results for fractured horizontal gas well.

Permeability Percentage of Shut-in	0.0001 md	0.0005 md	0.001 md	0.01 md	0.1 md	1 md
0	1	1	1	1	1	1
1	1.0015	1.0154	1.0288	1.0147	1.0061	1.0051
5	0.9936	1.0132	1.029	1.0192	1.0036	1.0047
10	0.9894	1.0124	1.0295	1.0315	1.0035	1.0045
20	0.9726	1.0022	1.0273	1.0199	0.9996	1.0046
30	0.953	0.9745	1.0147	1.0134	0.994	1.0035
40	0.9286	0.9729	1.0179	0.9871	0.9876	1.0023
50	0.9069	0.8397	1.0136	0.9844	0.9814	1.002
75	0.8135	0.7802	0.9699	0.9394	0.961	0.9989
100	0	0	0	0	0	0

The results given in Table 5.1 are shown graphically in Figure 5.1. The normalized recovery value for each shut-incase is noted on the figure. A normalized recovery of 1 indicates that the result of the shut in simulation case is equal to a well that produces continuously.

For the 0.0001 md permeability case, normalized recovery decreases slowly to a maximum of 10% at 50% shut-in. At 75% shut-in the normalized recovery has decreased 17% and declines rapidly after this point.

These results indicate that for a very tight reservoir (0.0001 md) in a fractured horizontal well, there is no advantage to cyclic production. This is likely due to effect of extremely low permeability on the time required to build P_{wf} to the average reservoir pressure.

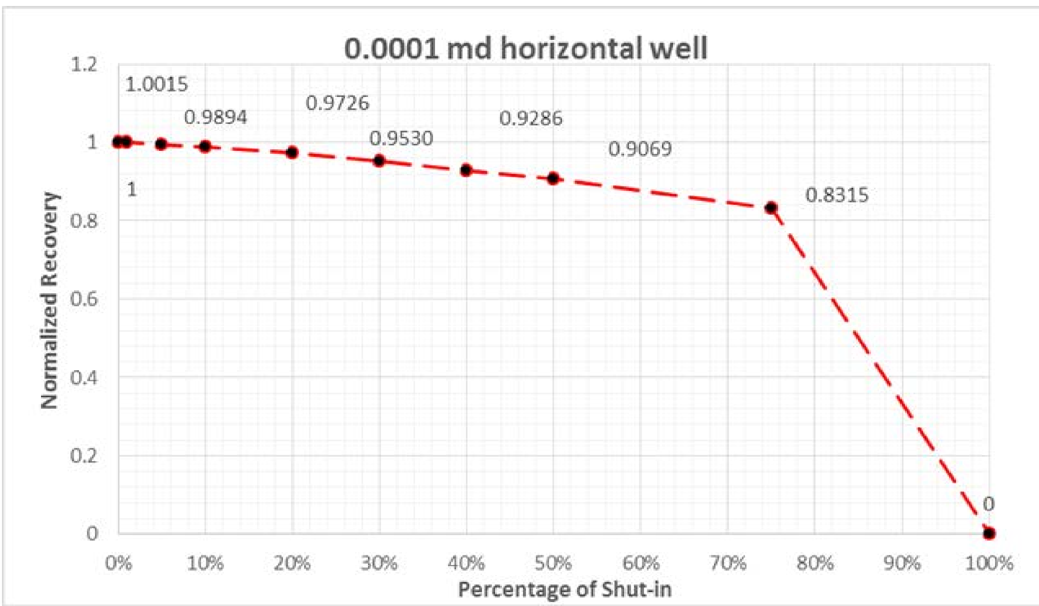

Figure 5.1. Effect of shut-in on fractured horizontal well with 0.0001 md permeability.

Figure 5.2 shows the effect of shut-in on fractured horizontal gas reservoir with 0.0005 md permeability. Results of these simulations are slightly different, indicating a very slight increase in productivity until 20% shut-in. The normalized recovery then decreases slightly to 40% shut in. After this shut-in the productivity of the fractured horizontal well decreases more rapidly.

This reservoir case has five times the permeability compared to the previous case, yet the rock is still very tight. The simulation result shows a very slight benefit of shut-ins up to 20 % shut-in time, for a horizontal well in this reservoir permeability.

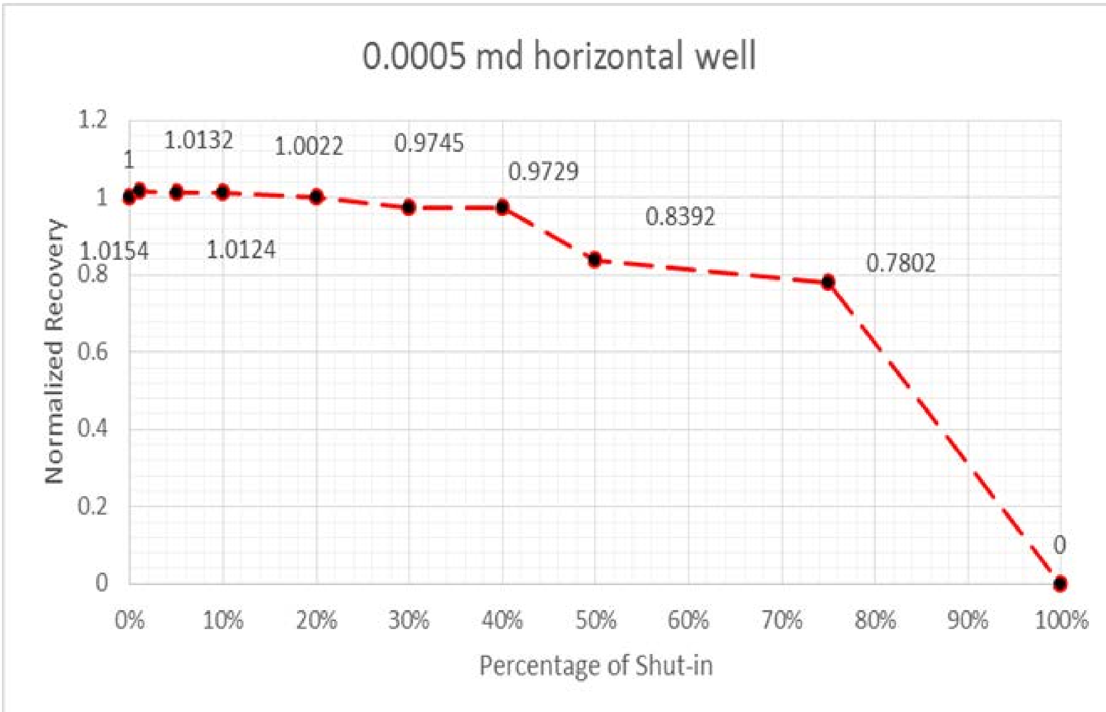

Figure 5.2. Effect of shut-in on fractured horizontal well with 0.0005 md permeability.

Figure 5.3 shows the effect of shut-in period for a gas reservoir with 0.001 md permeability. Y-axis represents normalized recovery while X-axis represents percentage of shut-in. Percentage of shut-in is varied from 0 % to 100 % for a reservoir with 0.0005 md permeability. For a 1 % shut-in the productivity improves by 2.88 % and the improvement remains essentially constant (2.9%) for 5 % and 10% shut-in periods. There is an overall increase in productivity seen until the 50 % shut-in period. Beyond the 50% shut-in time the wells productivity decreases.

From the simulation results, it is shown that productivity increases from the cyclic shut-in of the well, up to a maximum shut-in time of 10%. Stimulated horizontal wells completed in this permeability reservoir should benefit from shut-ins.

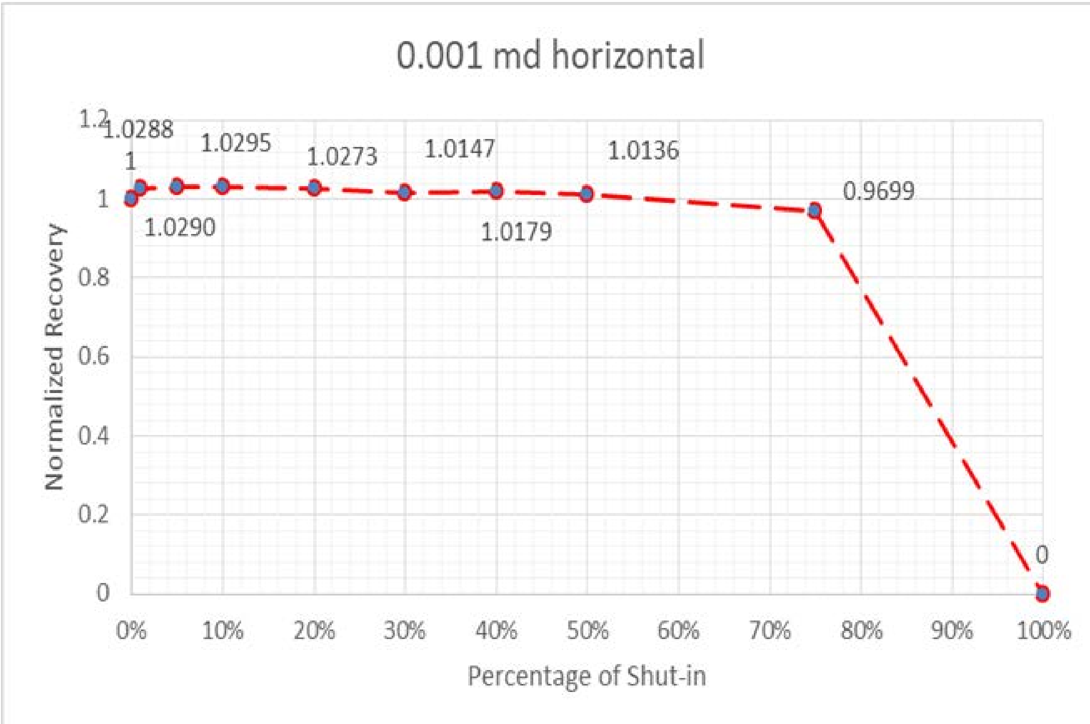

Figure 5.3. Effect of shut-in on fractured horizontal well with 0.001 md permeability.

Figure 5.4 shows the effect of shut-in period for a gas reservoir with 0.01 md permeability. For a 1 % shut-in the productivity improves by 1.47 % and the improvement reaches 3.14% at 10% shut-in. There is an overall increase in productivity seen until a point between 30% shut-in and 40 % shut-in. The productivity is not significantly reduced until shut-in is beyond 50%.

From the simulation results, it is shown that productivity increases from shut-in also occur an even higher permeability reservoir (0.01 md).

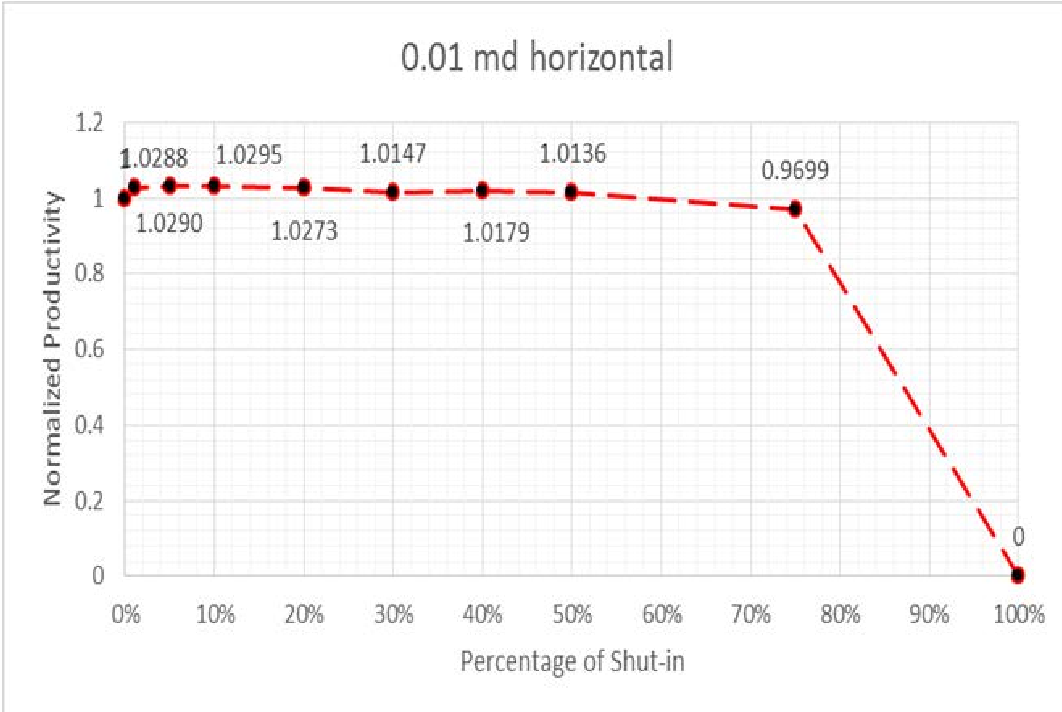

Figure 5.4. Effect of shut-in on fractured horizontal well with 0.01 md permeability.

Figure 5.5 shows the effect of shut-in on fractured horizontal well with 0.1 md reservoir permeability. Y-axis represents normalized recovery while X-axis represents percentage of shut-in. Percentage of shut-in is varied from 0 % to 100 % for a reservoir with 0.01 md permeability. For a 1 % shut-in the productivity improved by 0.6 % and this improvement remains constant for 5 % shut-in, then decreases to 0.3% at 10% shut-in. Between 10% and 20% shut-in productivity begins to decrease slightly until 50% shut-in, and then falls more rapidly.

The simulation results indicate that the benefit from shut-ins still exists at this permeability, but is not as significant a benefit compared to the response seen in lower permeability reservoirs (0.01 md, 0.001 md).

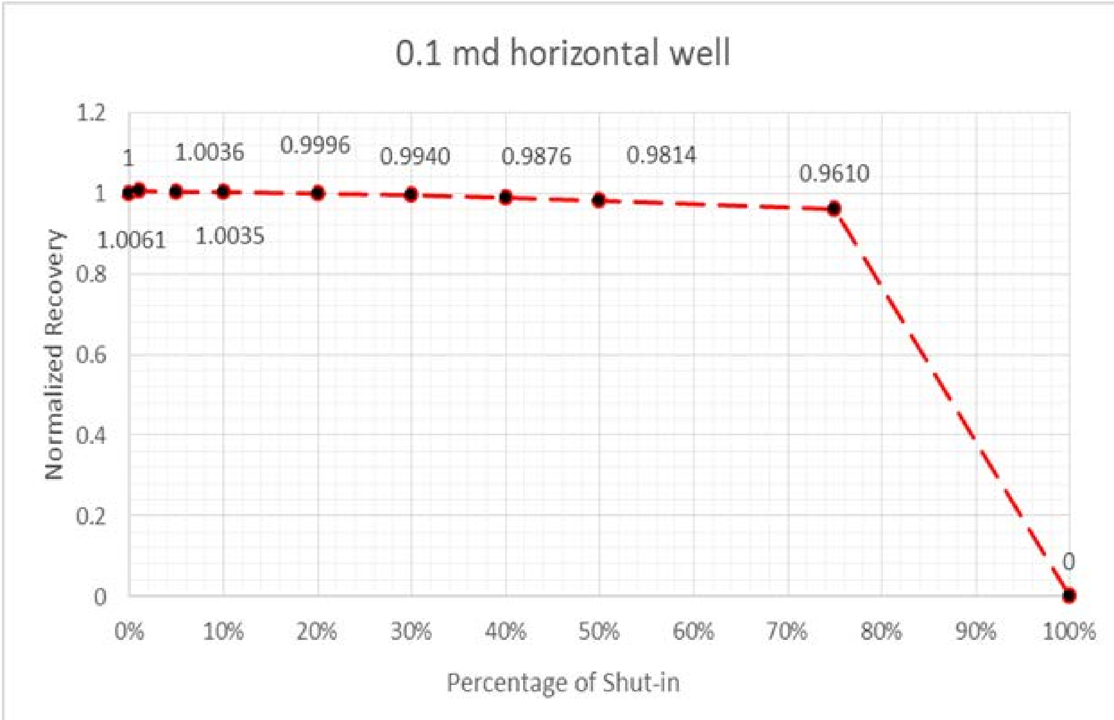

Figure 5.5. Effect of shut-in on fractured horizontal well with 0.1 md permeability.

Figure 5.6. Shows the effect of shut-in on fractured horizontal gas well in a 1 md reservoir permeability. Y-axis represents normalized recovery while X-axis represents percentage of shut-in. Percentage of shut-in is varied from 0 % to 100 % for a reservoir with 1 md permeability. For this higher reservoir permeability, the increase in production is less than the previous case, starting at around 0.5 % for 1 % shut-in period and decreasing to 0.2% by 50% shut-in.   Although there is still a very slight increase, the effect is diminishing as reservoir permeability increases.

Appendix A provides plots of fracture stimulated horizontal well normalized recovery versus permeability, for constant shut-in times. These graphs help illustrate maximum productivity benefit for each shut-in time.

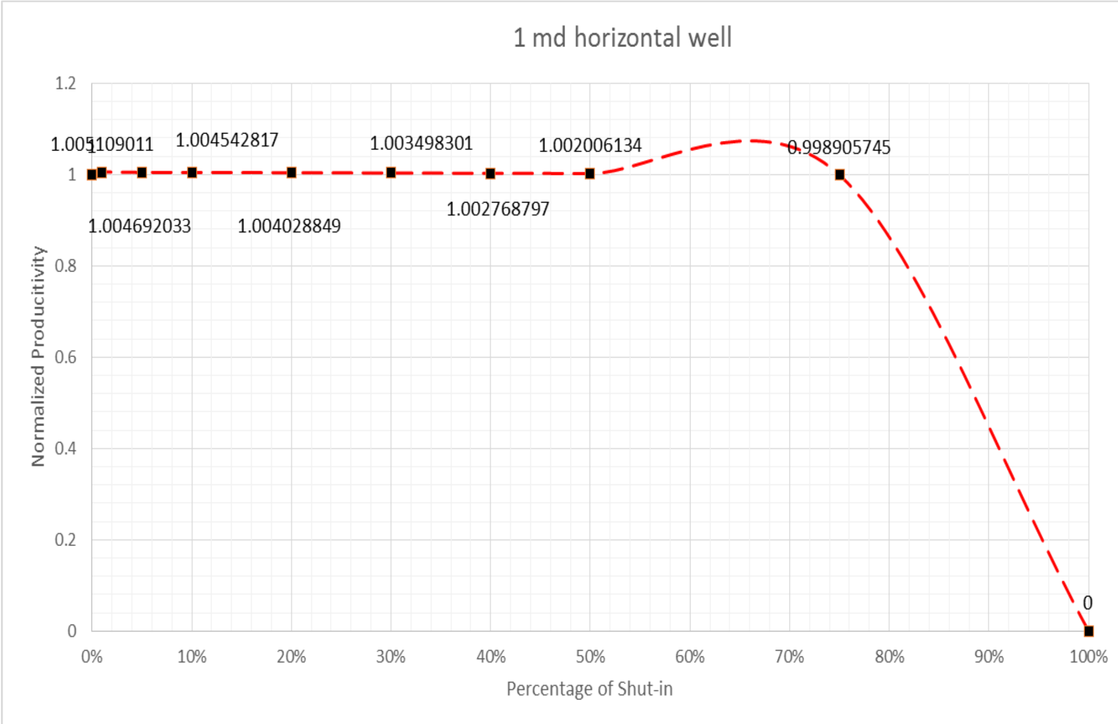

Figure 5.6. Effect of shut-in on fractured horizontal well with 1 md permeability.

5.2. VERTICAL GAS WELL RESERVOIR

Sixty simulation cases were run for the fracture stimulated vertical well geometry. Shut-in period is varied from 0 percent to 100 percent over a range of permeability 0.0001 md, 0.0005 md, 0.001 md, 0.01 md, 0.1 md, 1 md. Normalized recovery is used to compare results from simulation runs. Table 5.2 summarizes the results from simulation cases.

The results given in Table 5.2 are shown graphically in Figure 5.1. to Figure 5.7. The normalized recovery value for each shut-incase is noted on the figure. A normalized recovery of 1 indicates that the result of the shut in simulation case is equal to a well that produces continuously.

Table 5.2. Simulation results for fractured vertical gas well.

Permeability / Percentage of Shut-in	0.0001 md	0.0005 md	0.001 md	0.01 md	0.1 md	1 md
0	1	1	1	1	1	1
1	0.9099	0.9484	0.9969	0.9978	1.0062	1.0067
5	0.9043	0.9048	0.9934	0.9964	1.0019	1.0051
10	0.9057	0.9447	0.996	0.9977	1.0022	1.0044
20	0.8973	0.9389	0.9989	0.9898	0.9973	1.0008
30	0.8898	0.933	0.9911	0.9828	0.9898	0.9961
40	0.8771	0.92	0.9854	0.972	0.9741	0.9906
50	0.8655	0.91	0.9826	0.9652	0.9659	0.9852
75	0.8116	0.86	0.9605	0.9165	0.9274	0.9675
100	0	0	0	0	0	0

Figure 5.7 shows the effect of shut-in on fractured vertical gas well reservoir with 0.0001 md permeability. In all shut-in cases, production decreases compared to a well with no shut-in. Almost immediately (1%) shut-in, productivity decreases by 10%. This loss in productivity then declines slowly to 50% shut-in. After 50% shut-in productivity declines rapidly.

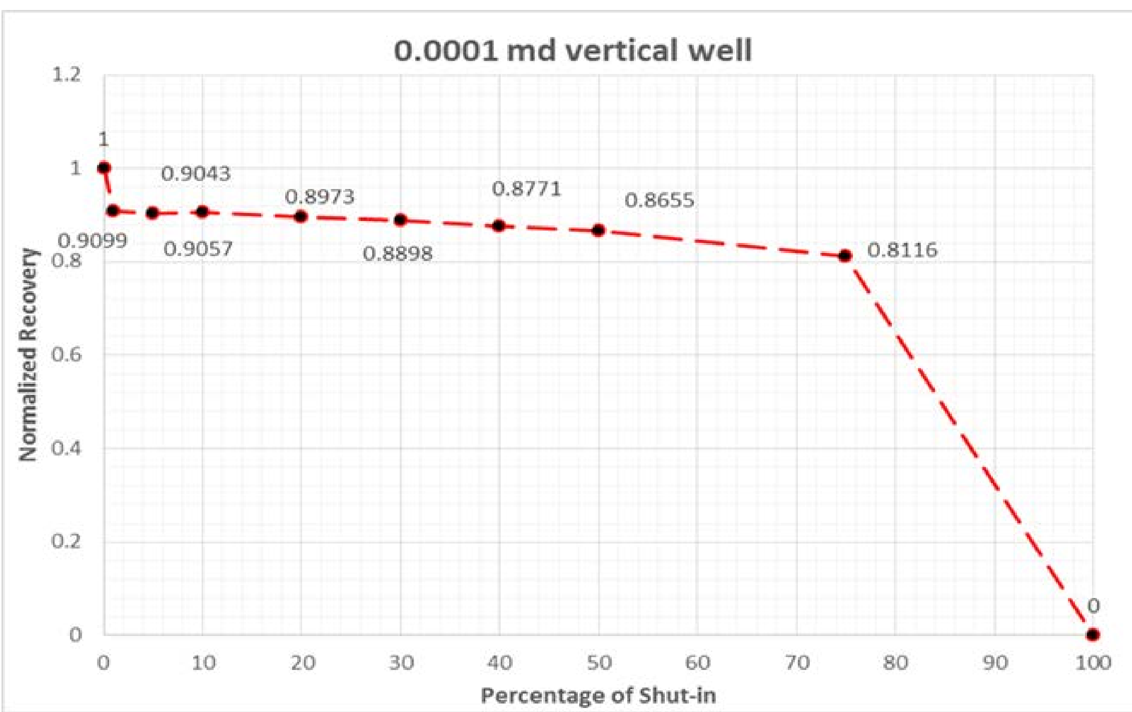

Figure 5.7. Effect of shut-in on fractured vertical well with 0.0001 md permeability.

Figure 5.8 shows the effect of shut-in on fractured vertical gas well reservoir with 0.0005 md permeability. Normalized recovery is shows on Y-axis and percentage of shut-in is taken on X-axis. Shut-in time is varied from 0 % to 100 %. The results are similar to those for the 0.0001 md reservoir, except that the loss in production is smaller (6% reduction in productivity at 1% shut in compared to 10% in the previous case). After the initial loss at 1% shut in, the normalized conductivity declines slowly to 50% shut-in, and then declines more rapidly.

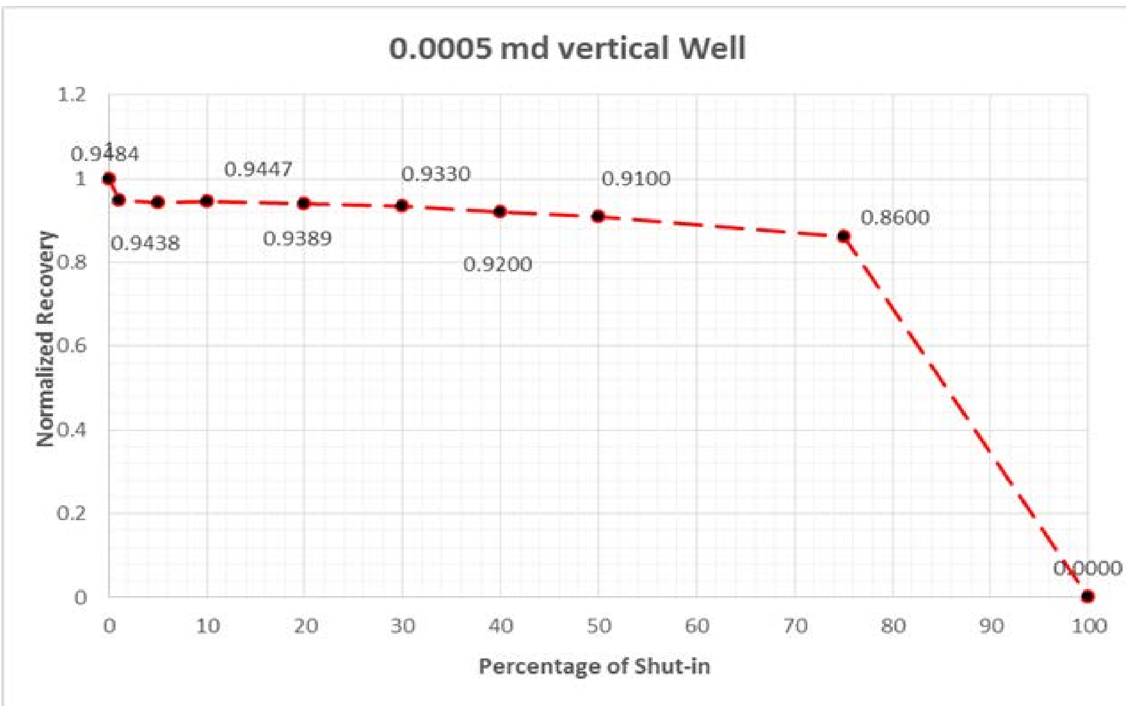

Figure 5.8. Effect of shut-in on fractured vertical well with 0.0005 md permeability.

Figure 5.9 shows the effect of shut-in on fractured vertical gas well reservoir with 0.001 md permeability. Normalized recovery is shows on Y-axis and percentage of shut-in is taken on X-axis. Shut-in time is varied from 0 % to 100 %. Unlike the previous cases, there is no large, immediate production loss from well shut-in. The normalized recovery is still less in all cases, but the decrease is 1% up to 30% shut-in time and 2% between 30% shut-in and 50% shut-in.

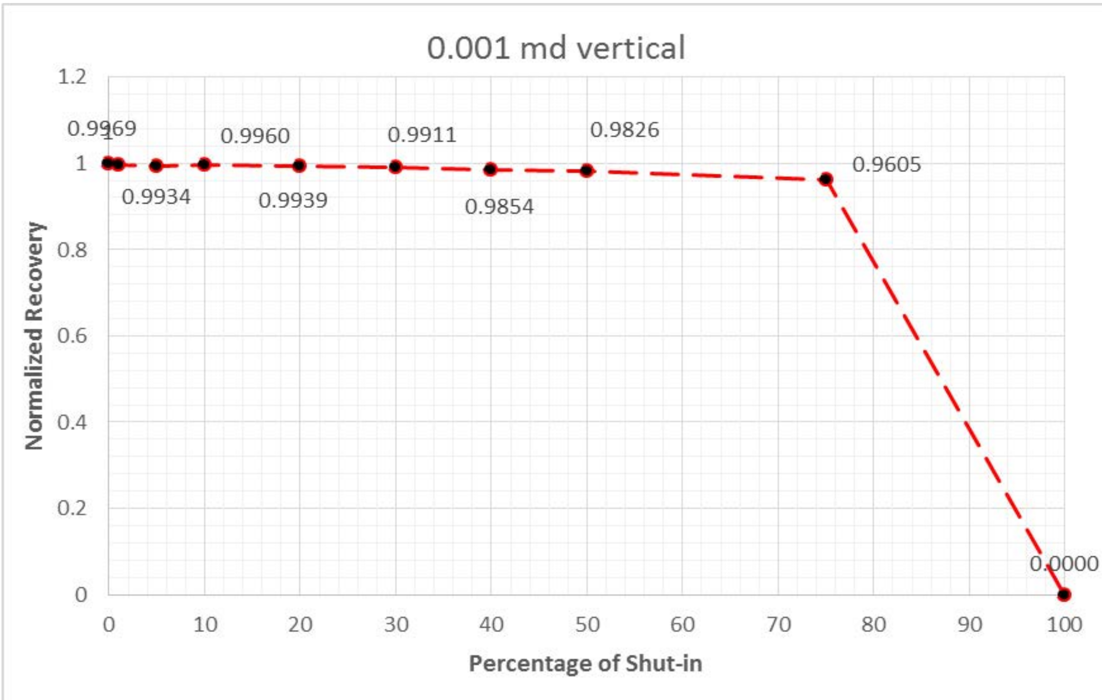

Figure 5.9 Effect of shut-in on fractured vertical well with 0.001 md permeability.

Figure 5.10 shows the effect of shut-in on fractured vertical gas well reservoir with 0.01 md permeability. Normalized recovery is shows on Y-axis and percentage of shut-in is taken on X-axis. Shut-in time is varied from 0 % to 100 %. Results for this reservoir permeability are similar to those in the previous case. There is reduced normalized permeability for all values of shut-in, however the decrease is 1% up to shut-in of 10% and 4% by 50% shut in.

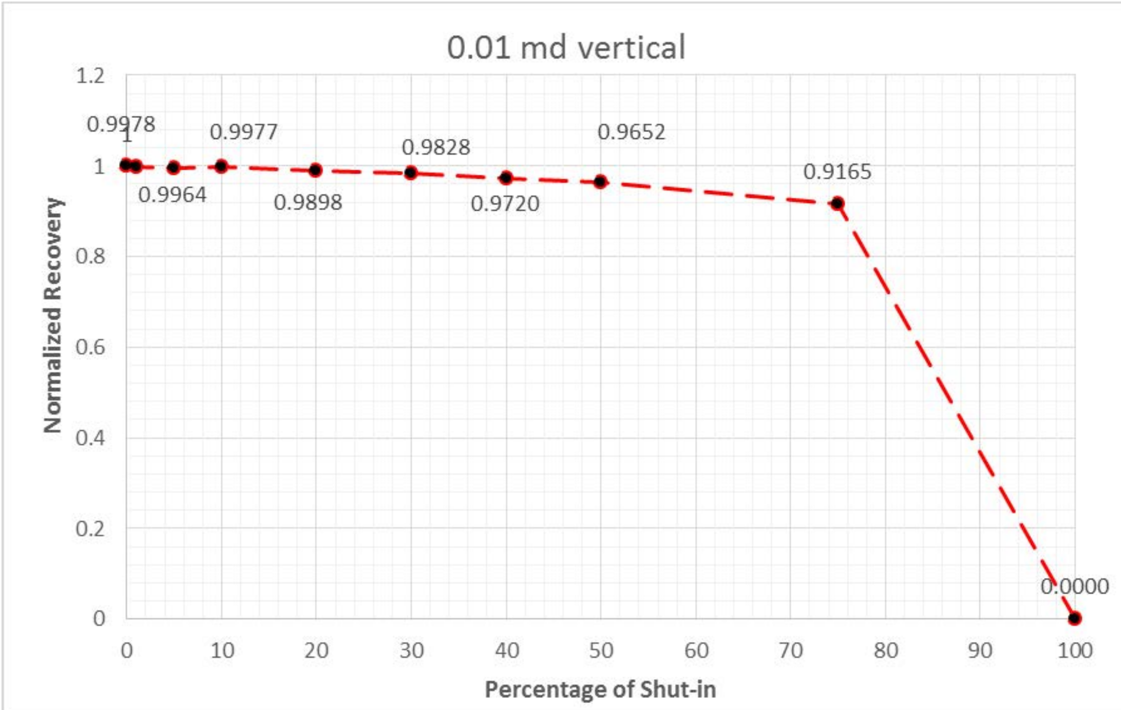

Figure 5.10. Effect of shut-in on fractured vertical well with 0.01 md permeability.

Figure 5.11 shows the effect of shut-in on fractured vertical gas well reservoir with 0.1 md permeability. Y-axis represents normalized recovery while X-axis represents percentage of shut-in. Percentage of shut-in is varied from 0 % to 100 % for a reservoir with 0.01 md permeability. For the first time, there is actually a slight increase in normalized recovery, although it is a small increase (0.6% at 1% shut-in). This benefit decreases until 10% shut-in.

After that point there is a continual decrease in the normalized recovery with longer shut-in time. However, this case indicates that it is possible to see a slight increase in production from cyclic production in a fractured stimulated vertical well in a 0.1 md gas reservoir.

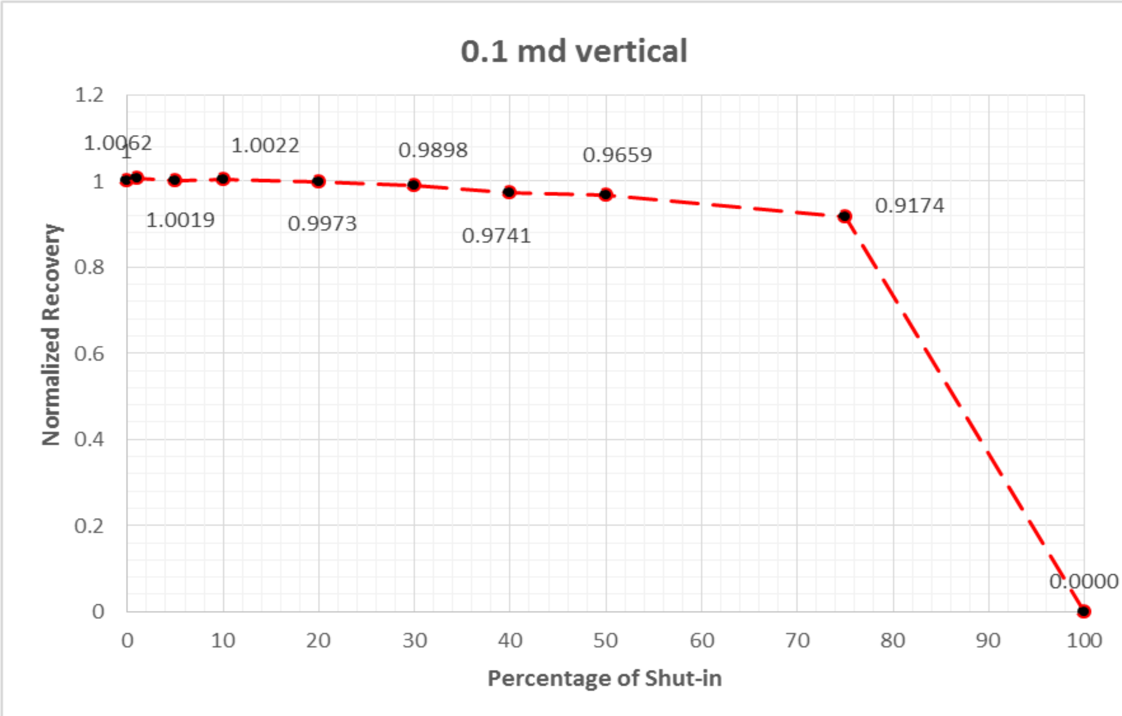

Figure 5.11. Effect of shut-in on fractured vertical well with 0.1 md permeability.

Figure 5.12 shows the effect of shut-in on fractured vertical gas well reservoir with 1 md permeability. Y-axis represents normalized recovery while X-axis represents percentage of shut-in. Percentage of shut-in is varied from 0 % to 100 % for a reservoir with 0.1 md permeability. It is seen that shut-in cycles will not affect the reservoirs of permeability 0.1 md as there is no increase or decrease in the normalized recovery seen with varying shut-in time.

As in the previous case, there is a small increase in the normalized recovery. The magnitude of the productivity increase hasn't become greater, but the effect lasts longer. In this case there is the same 0.6% increase at 1% shut-in, but the increase exists until a point between 20% and 20% shut-in.

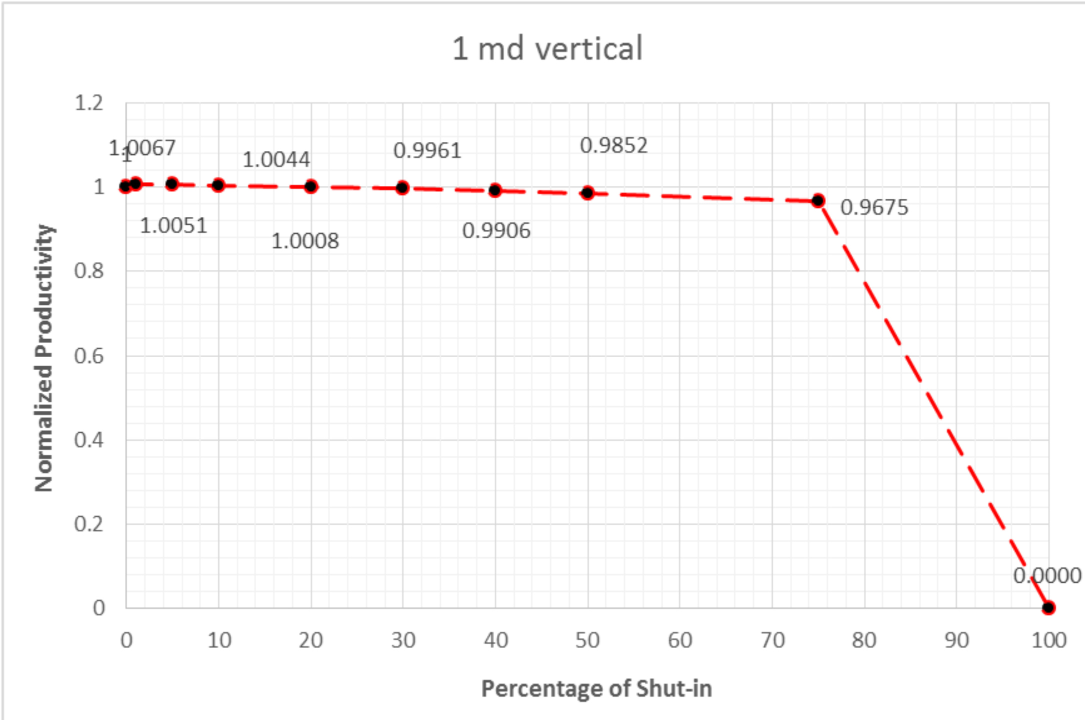

Figure 5.12. Effect of shut-in on fractured vertical well with 1 md permeability.

Appendix B provides plots of fracture stimulated vertical well normalized recovery versus permeability, for constant shut-in times. These graphs help illustrate maximum productivity benefit for each shut-in time.

6. CONCLUSIONS AND DISCUSSION

This study analyzed the effect of repeated production/shut-in cycles on flow response of fractured horizontal wells and vertical wells. Normalized recovery is evaluated over varied permeability through simulating cases with shut-in period ranging from 0 percent to 100 percent. Results obtained for horizontal and vertical wells were different and are discussed separately.

6.1. FRACTURED HORIZONTAL GAS WELL RESERVOIR

Results obtained from the horizontal well simulations indicate that horizontal wells can benefit from cyclic production, although the magnitude of the benefit depends on the reservoir permeability. For extremely tight gas reservoirs (=< 0.0001 md) there is no benefit to cyclic production. Table 6.1 summarizes the maximum productivity benefit obtain for the horizontal well cases.

This study indicates a particular reservoir permeability where cyclic production in fracture stimulated horizontal wells can produce the greatest benefit, and that the associated shut-in period for to achieve this benefit is ~10%.

Table 6.1. Summary of horizontal well productivity and impact of shut-in.

Permeability (md)	Maximum Productivity Increase	Shut-in period %
0.0001	0	Na
0.0005	1.54 %	1%

Table 6.1. Summary of horizontal well productivity and impact of shut-in (Cont.).

0.001	2.95%	5-10%
0.01	3.15%	10%
0.1	0.6%	1%
1	0.6%	1%

6.2. FRACTURED VERTICAL GAS WELL RESERVOIR

Results from the vertical well simulations were significantly different than results for the horizontal wells. For vertical wells, there appears to be no benefit to cyclic production. And for vertical wells in extremely low permeability reservoirs, shutting in the well for 1% continuously may have a detrimental impact on well productivity. Table 6.2. shows effect of shut-in time on productivity in vertical gas wells.

Table 6.2. Summary of vertical well productivity impact and shut-in.

Permeability (md)	Maximum Productivity Increase	Shut-in period %
0.0001	-9 %	1%
0.0005	-6 %	1%
0.001	-0.3%	1%
0.01	-0.2%	1%
0.1	0.6%	1%
1	0.6%	1%

The benefit from cyclic production depends heavily on the buildup of bottomhole pressure during the shut-in period. For a benefit to be fully realized, the bottomhole pressure should build to the current reservoir pressure. For extremely low permeability environments (0.0001-0.0005 md), that build up time could take months. Given a 1% shut-in period, it is simply not possible for the bottomhole pressure to build to a sufficient level. Very likely the difference in drainage area of the horizontal well masks this effect, that is, the vertical well experiences a 6-9% decrease in productivity while the horizontal well is not impacted.

In the high permeability environment (0.1 to 1 md) bottomhole pressure can build more quickly during shut-in. Despite the differences in drainage area, both the vertical and horizontal wells exhibit similar responses to cyclic production, i.e, it provides little benefit. Conversely, it is shown that shut-ins of even 10-20% will not hurt either vertical or horizontal wells completed in high permeability gas reservoirs.

Additional work is suggested to evaluate this phenomena. In particular multi-phase production, and the effects of the completion should be considered.

APPENDIX A

SIMULATION RESULTS OF FRACTURED HORIZONTAL WELL

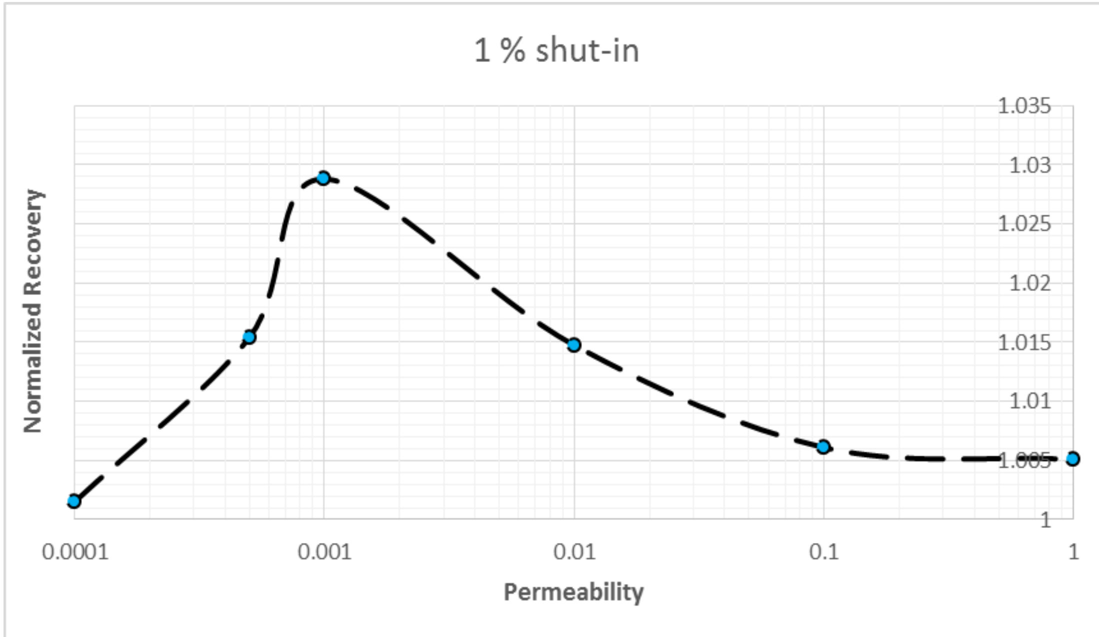

Figure A.1. Effect of 1 % shut-in on horizontal gas well from 0.0001md to 1 md.

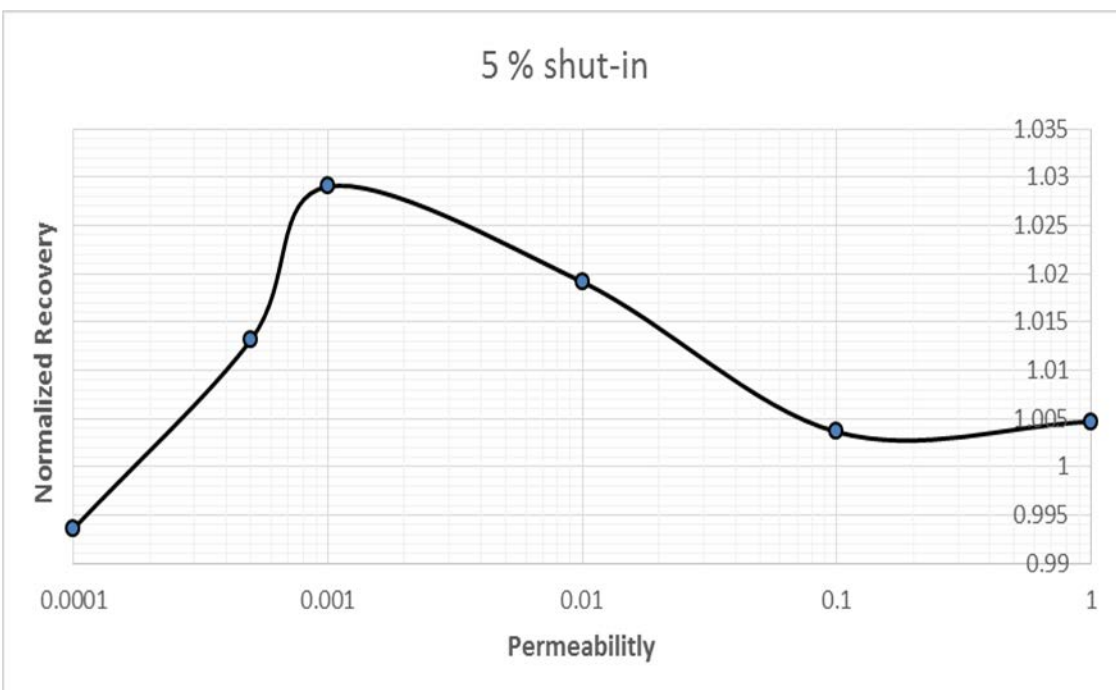

Figure A.2. Effect of 5 % shut-in on horizontal gas well from 0.0001 md to 1 md.

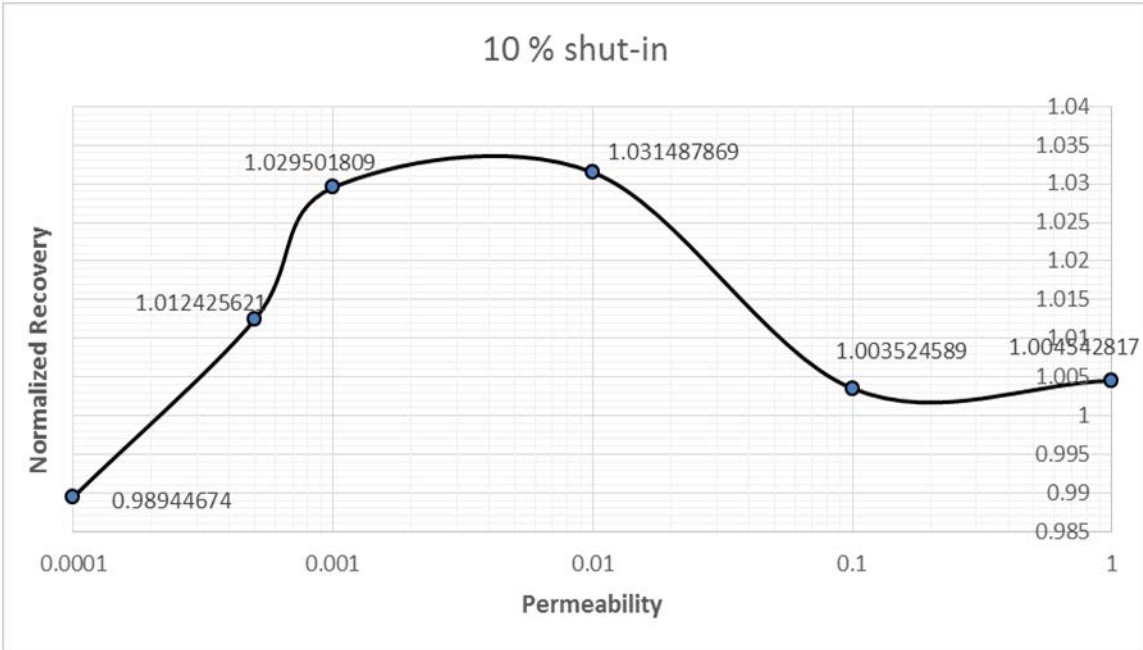

Figure A.3. Effect 10 % shut-in on horizontal gas well from 0.0001 md to 1 md.

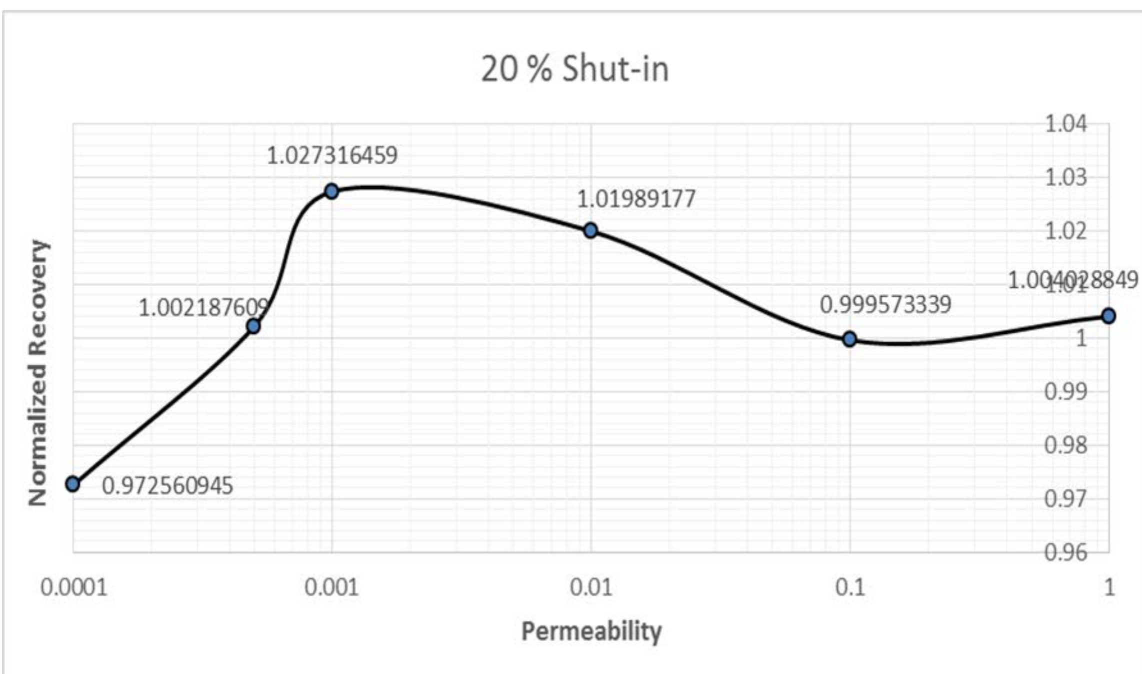

Figure A.4. Effect of 20% shut-in on horizontal gas well from 0.0001 md to 1 md.

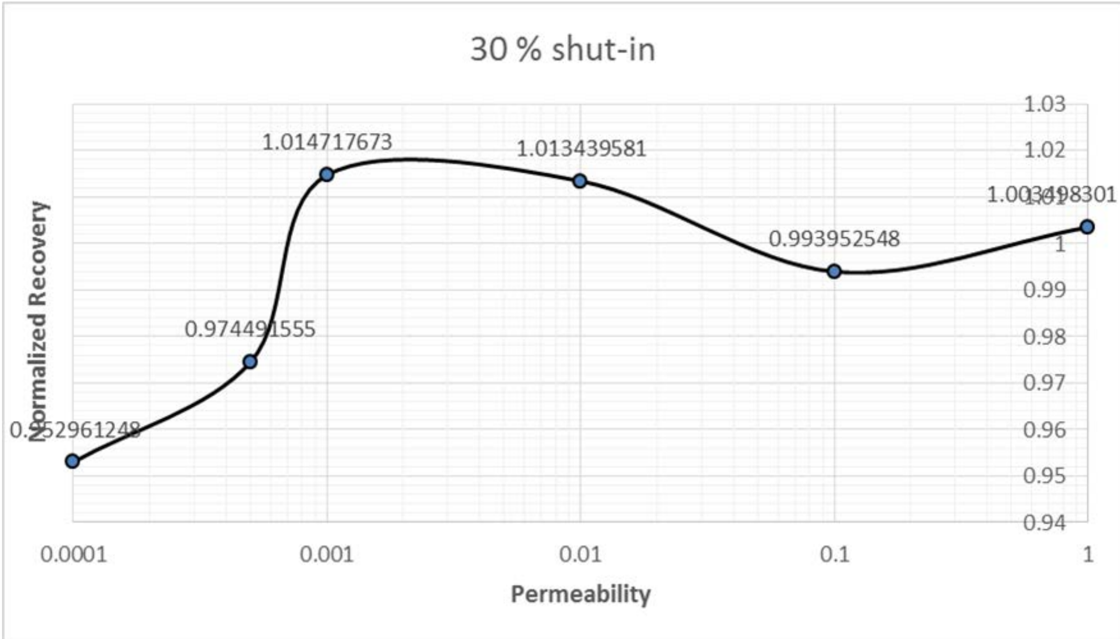

Figure A.5. Effect of 30% Shut-in on horizontal gas well from 0.0001 md to 1 md.

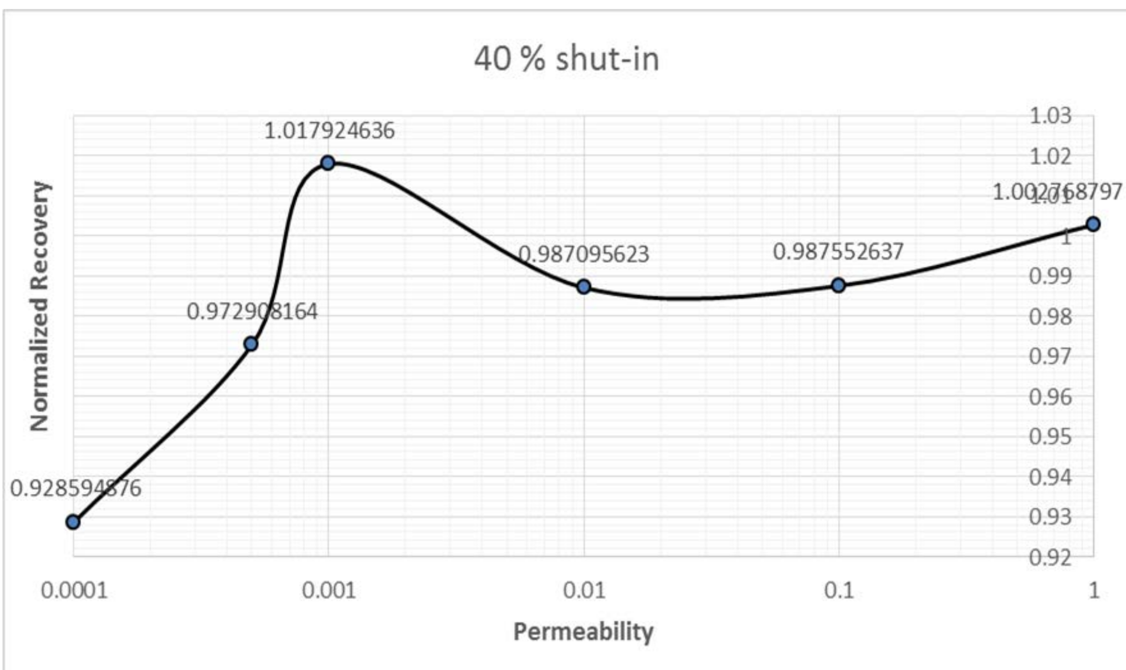

Figure A.6. Effect of 40% Shut-in on horizontal gas well 0.0001 md to 1 md.

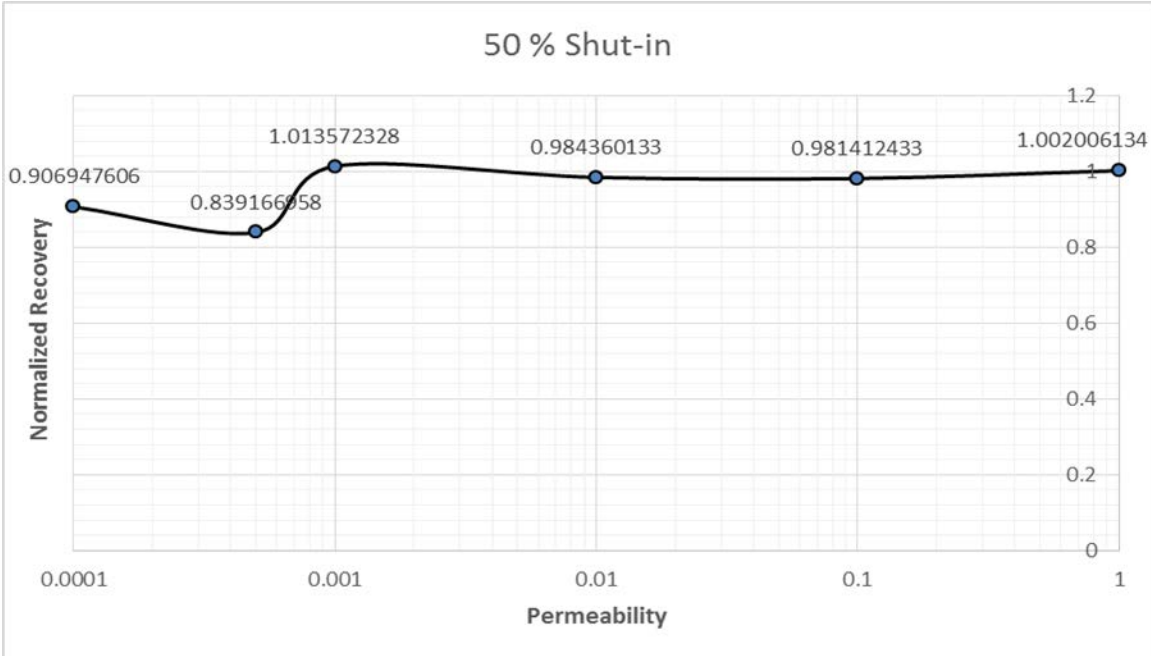

Figure A.7. Effect of 50% Shut-in on horizontal gas well from 0.0001 md to 1 md.

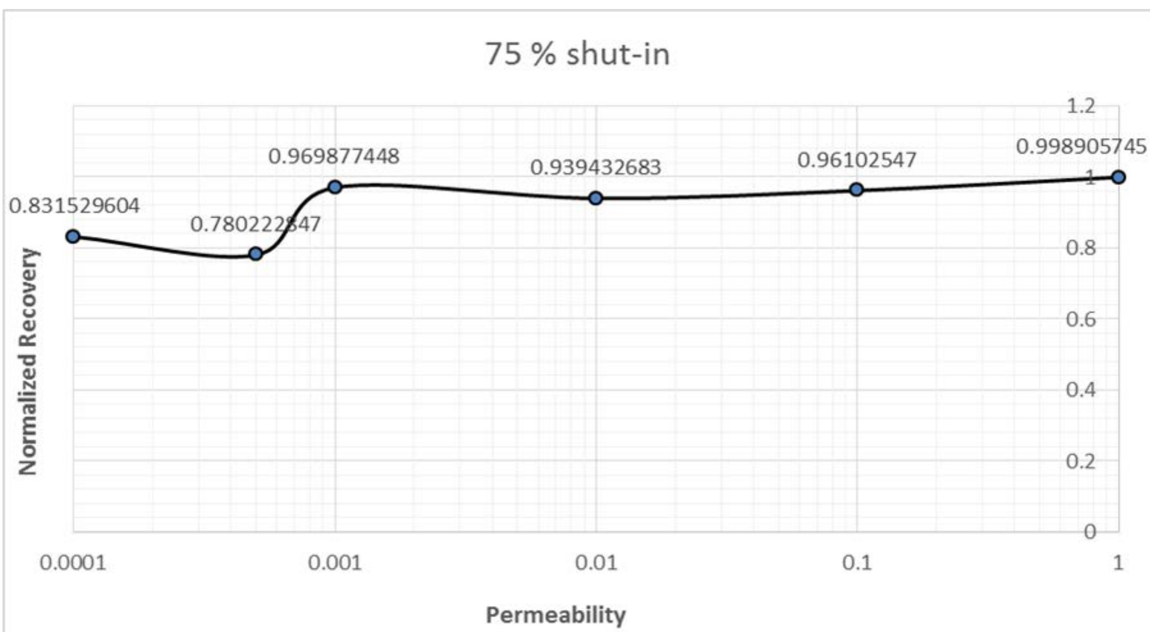

Figure A.8. Effect of 75% Shut-in on horizontal gas well from 0.0001 md to 1 md.

APPENDIX B

SIMULATION RESULTS OF FRACTURED VERTICAL WELL

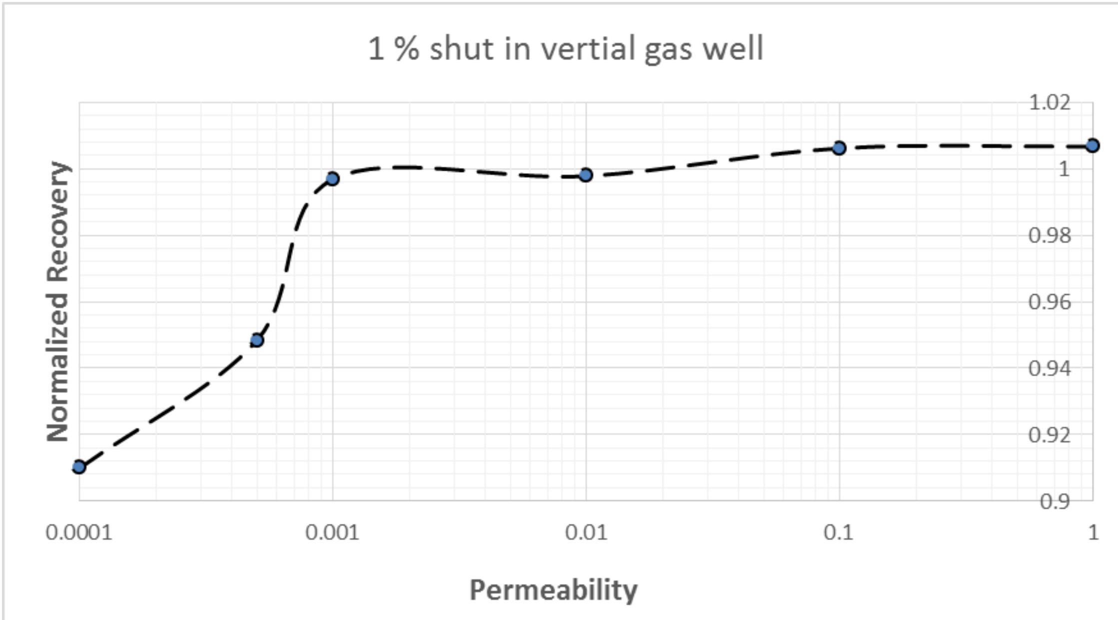

Figure B.1. Effect of 1 % Shut-in on vertical gas reservoir from 0.0001 md to 1 md.

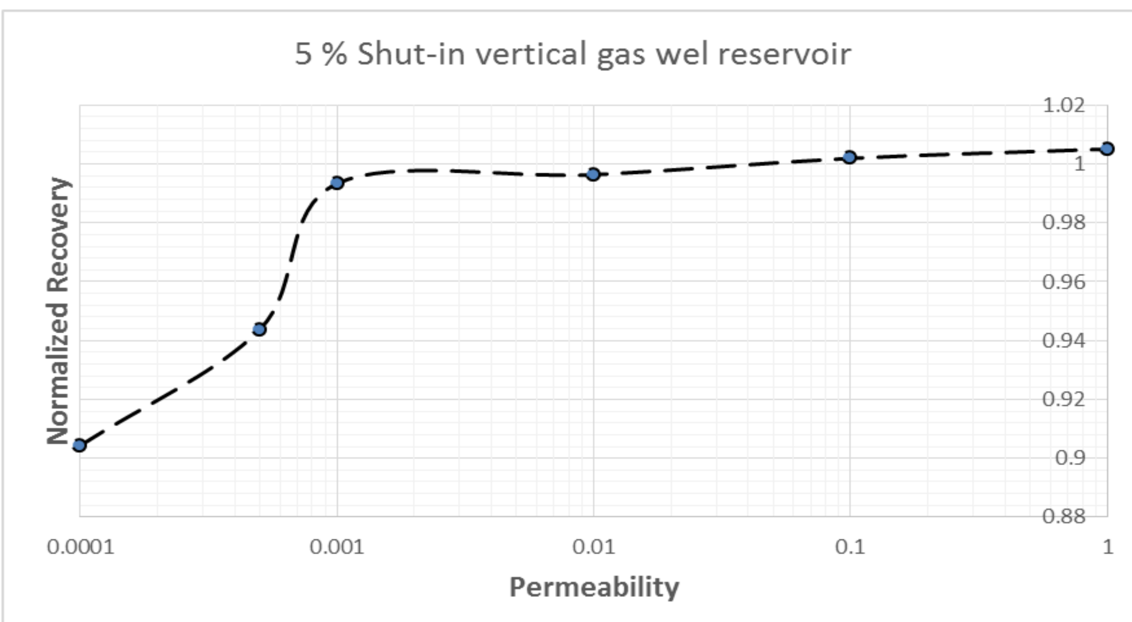

Figure B.2. Effect of 5 % Shut-in on vertical gas well reservoir from 0.0001 md to 1 md.

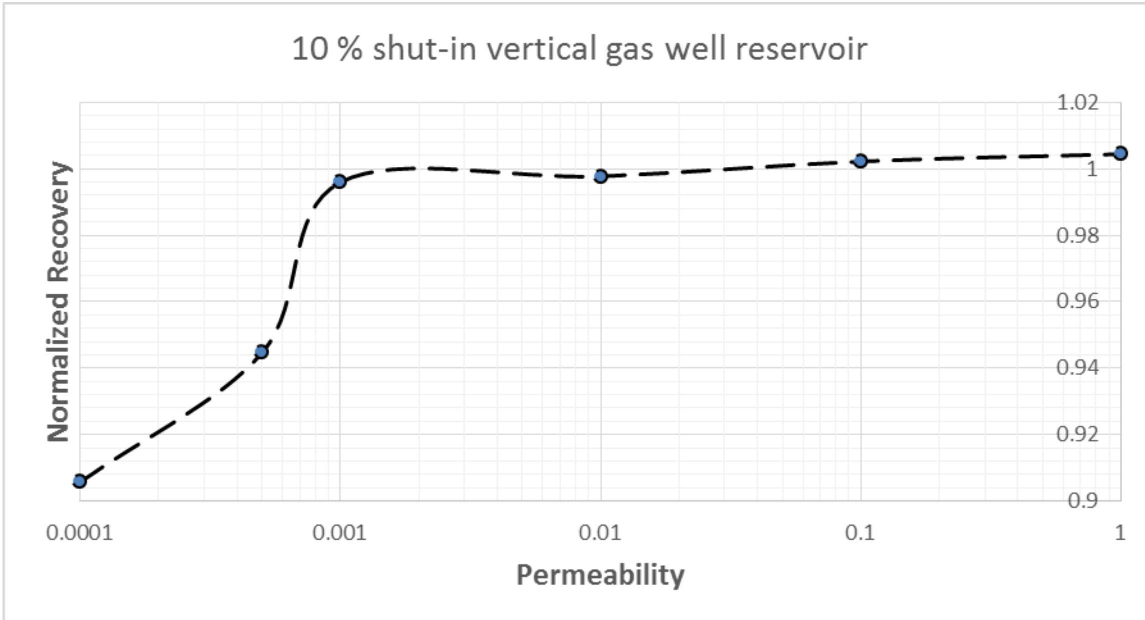

Figure B.3. Effect of 10% Shut-in on vertical gas well from 0.0001 md to 1 md.

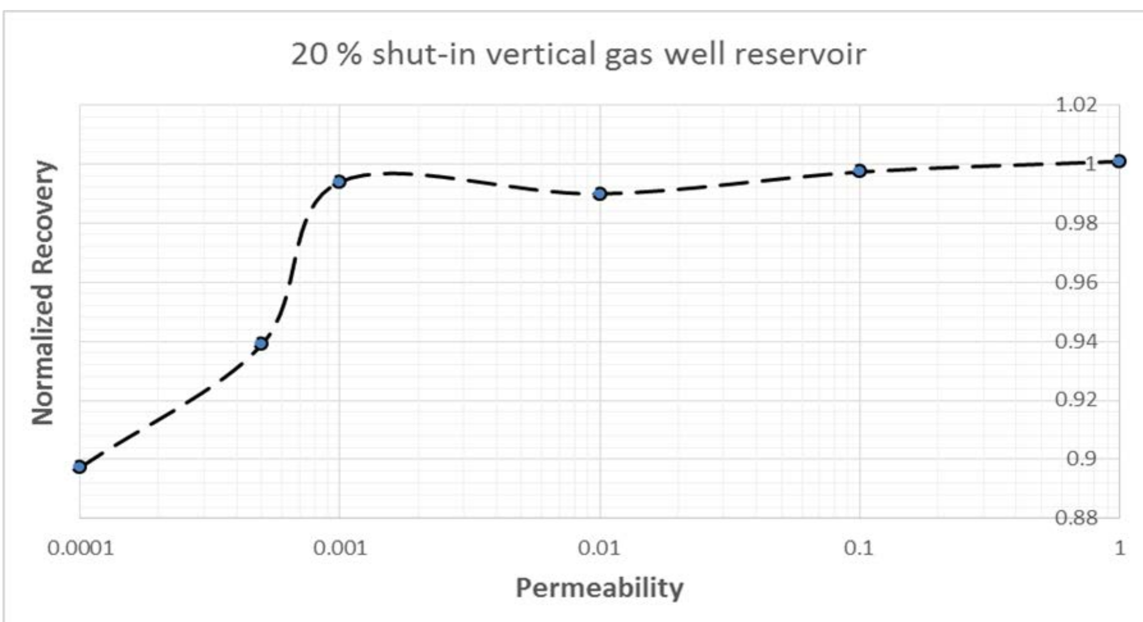

Figure B.4. Effect of 20% Shut-in on vertical gas well from 0.0001 md to 1 md.

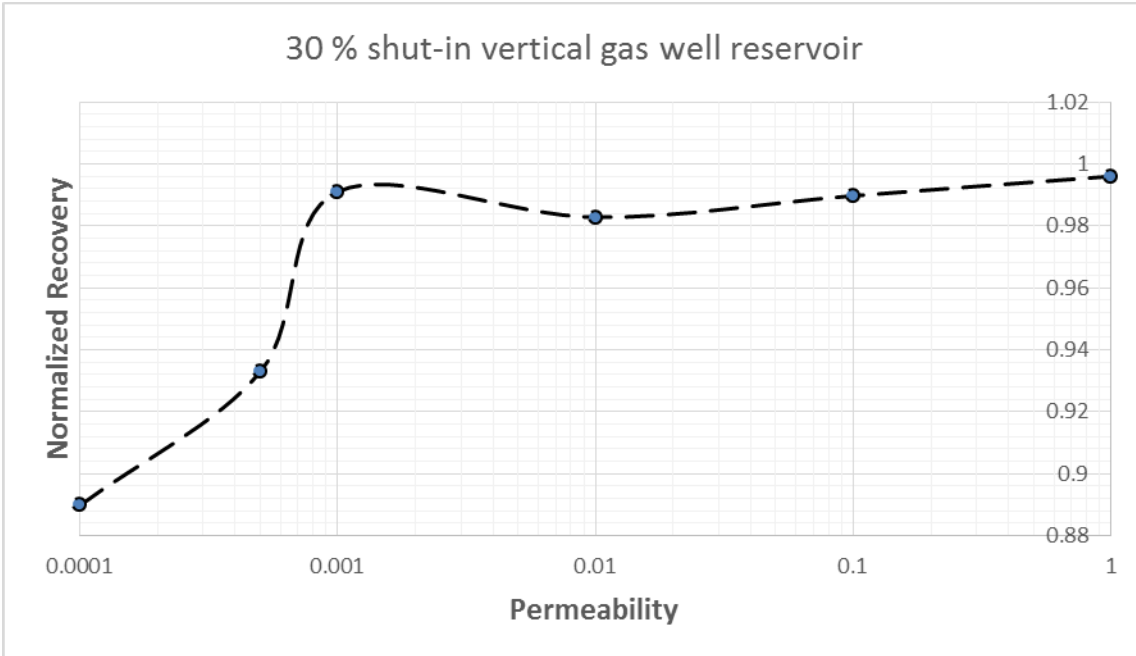

Figure B.5. Effect of 30% Shut-in on vertical gas well reservoir from 0.0001 md to 1 md.

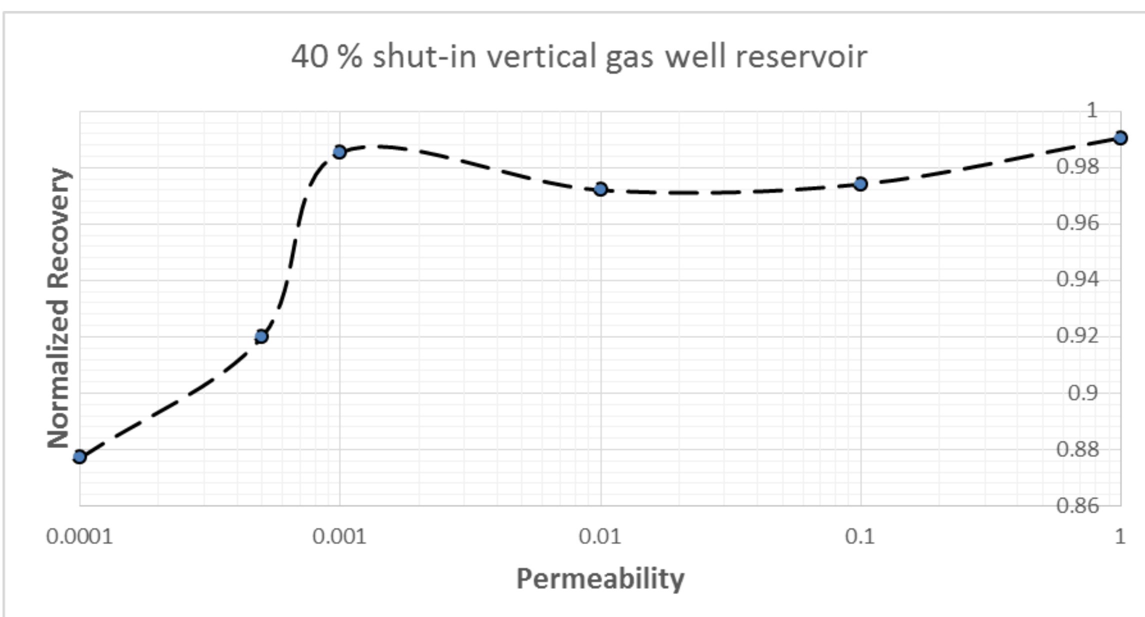

Figure B.6. Effect of 40% Shut-in time on vertical gas well from 0.0001 md to 1 md.

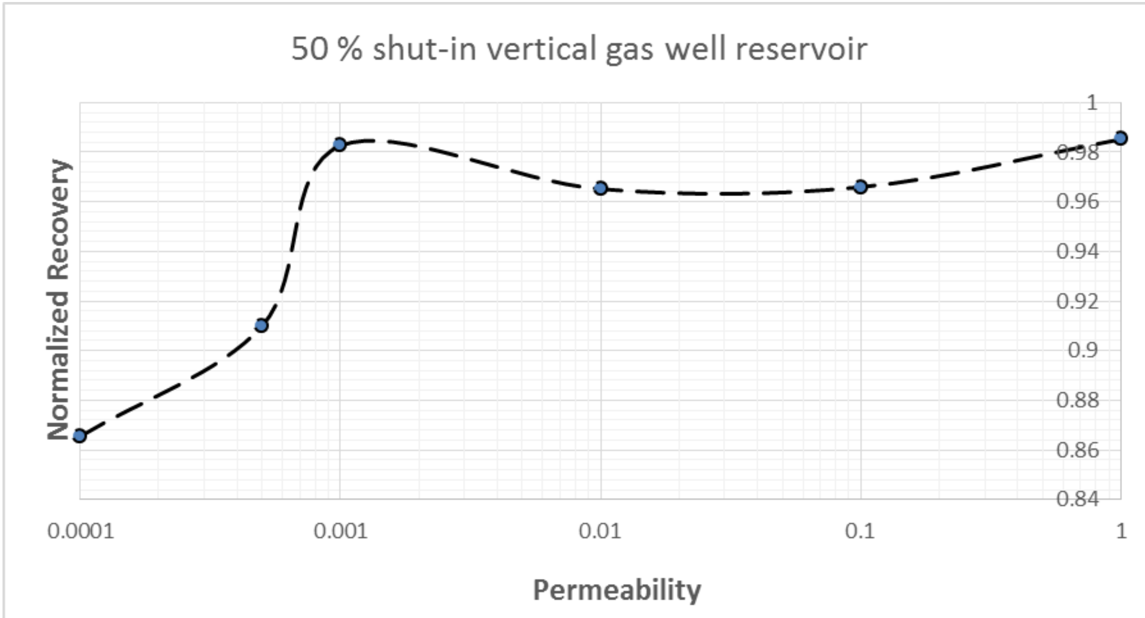

Figure B.7. Effect of 50% Shut-in time on vertical gas well from 0.0001 md to 1 md.

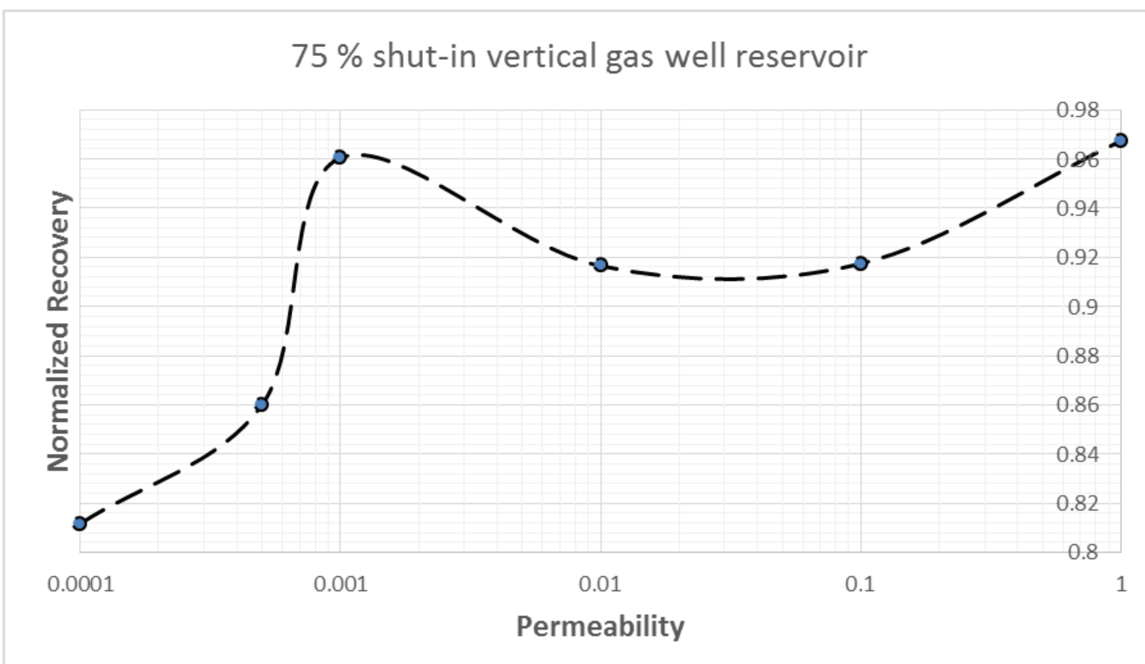

Figure B.8. Effect of 75% Shut-in on vertical gas well from 0.0001 md to 1 md.

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VITA

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