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PERFORMANCE COMPARISON OF TRANSVERSE AND LONGITUDINAL FRACTURED HORIZONTAL WELLS OVER VARIED RESERVOIR PERMEABILITY

by

FEN YANG

A THESIS

Presented to the Faculty of the Graduate School of the

MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

In Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE IN MECHANICAL ENGINEERING

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Approved by

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ABSTRACT

Since the first application in the mid-1980's, multiple fractured horizontal wells have proven to be an effective means of extracting hydrocarbons. These wells require careful consideration of wellbore orientation relative to the horizontal principle stress. Wellbore orientation can lead to transverse fractures which are perpendicular to the wellbore, or longitudinal fractures parallel the wellbore. Questions arise regarding whether one fracture orientation is consistently preferred over the other, or if certain conditions affect the choice.

Historical work has examined the impact of horizontal wellbore azimuth in the Barnett and Marcellus Shale where public data was reviewed and statistical well analysis was conducted respectively. Comparison between transverse and longitudinal fracturing in moderate gas reservoirs has been performed with experimental study. This work includes both simulations and actual field cases studies. It compares transverse multiple fractured horizontal wells with longitudinal ones in terms of both well performance and economics. The study covers both gas and oil reservoirs and extends prior work to unconventional resources by extending the reservoir permeability to 0.00005 md.

A range of reservoir permeability is identified for the preferable fracture configuration through simulations. Field production history of the Bakken, Barnett, Eagle Ford and Delaware formations are investigated and compared to the simulation results. In addition, this work analyzes the impact of fracture conductivity, lateral length, fracture half-length, completion method and hydrocarbon prices. The conclusions can be used as a reference in decision making on horizontal drilling and hydraulic fracturing for both unconventional and conventional resources.

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1. INTRODUCTION

1.1. DESCRIPTION OF THE TOPIC

Since 1980's, with the combination of four technologies: horizontal drilling (started in 1938), slick water fracturing (started in 1953), multi stage fracturing (started in 1987) and high rate fracturing (started in 1980s), hydraulic fracturing has become a highly effective stimulation mechanism, enabling economic development of unconventional resources (King 2012). At the same time, advances in steerable, directional drilling tools enabled engineers to purposefully plan and place the horizontal wellbores along specific azimuths, relative to in-situ formation stress.

There are three principle compressive stresses acting on the reservoir rock: minimum horizontal stress (σ_{Hmin}), maximum horizontal stress (σ_{Hmax}) and vertical stress (σ_v).

In a vertical well, at typical reservoir depths, the fracture will be vertical as shown in Figure 1.1.

Fracture orientation in horizontal wells is more complex, as the horizontal wellbore can be oriented throughout a 360 degree rotation.

If the wellbore is aligned with the maximum horizontal stress, the fracture will evolve coincident with the wellbore, which is referred to as a longitudinal fracture.

If the wellbore is aligned with the minimum horizontal stress, the fracture will be perpendicular to the wellbore, which is referred to as a transverse fracture.

If the wellbore deviates an angle (α, well azimuth) from the maximum horizontal stress other than above two directions, the fracture will be oblique to the wellbore, which is referred to as a oblique fracture (Fig 1.1).

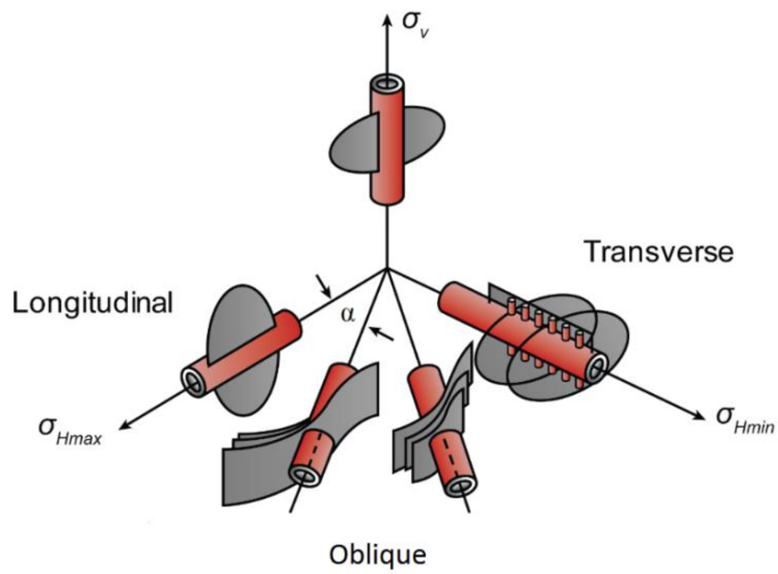

Figure 1.1. Wellbore and Fracture Orientation (EPT International)

Questions arise regarding whether one fracture orientation is consistently preferred over the other, or if certain conditions (e.g. reservoir permeability, fracture-to-wellbore connection) affect the choice.

Transverse fractures are believed to be more effective in draining low permeability reservoirs compared to longitudinal fractures because of the increased contact area with the reservoir (Economides and Martin 2007). However, transverse fractures may have a relatively poor connection to the wellbore, which chokes production. A near wellbore choking effect can seriously affect productivity in medium and high permeability gas wells (Martin 2012). This near wellbore choking, termed non-Darcy convergent flow, is a rate dependent skin effect.

Longitudinal fractures are preferred in high permeability reservoirs (Economides, 2007). They have a longer connection to the wellbore, and the post-fracture production is not typically choked at the contact between longitudinal fractures and wellbore (Martin 2012).

Oblique fractures in between transverse and longitudinal ones yield lower production due to smaller simulated reservoir volume, and have the effect of higher drilling risk due to smaller safe mud weight window, higher breakdown pressure

(Wutherich et al. 2013; Zinn, Blood, and Morath 2011). For this reason, industry is careful to orient horizontal wells to create transverse or longitudinal fractures. Hence, this study focuses specifically on these two horizontal well fracture configurations.

Historical work has examined transverse versus longitudinal fracturing in moderate gas reservoirs from 0.01 md to 5 md (Liu et al. 2012). A series of recommendations on the optimum application of well and fracture configuration were made through comparing vertical fractured wells to transversely and longitudinally fractured horizontal wells respectively, on tight and conventional oil and gas reservoirs from 0.001 md up to 500 md (Economides and Martin 2007; Economides et al. 2010).

This work compares transversely fractured horizontal wells to longitudinally fractured horizontal wells for both oil and gas reservoirs, and extends prior work to the unconventional range of reservoir permeability (0.00005 md).

The main historical findings related to this topic were obtained based on Unified Fracture Design (UFD) theory. This theory provides a method to calculate dimensionless well productivity for fractured well. The approach uses Proppant Number (Np) as the correlating parameter to determine the productivity for the fracture configurations, which are designed with same proppant mass. The Proppant Number is the ratio of propped volume to reservoir volume, which represents the amount of resources spent on the treatment. As a function of dimensionless fracture conductivity (F_{CD}) and penetration ratio, Np determines the maximum dimensionless productivity. This approach generates an answer to the question: for a given mass of proppant injected, which fracture configuration would maximize well productivity?

This study utilizes StimPlan software to simulate production from the horizontal fractured well. In StimPlan a numerical single-phase three dimensional reservoir simulator is used to predict production data. A bottom-hole flowing pressure or well-head pressure is set to control the simulations, the well is producing at this pressure. When the well starts producing, the corresponding change of reservoir pressure and hydrocarbon saturation are determined from the implicit finite solution to the single phase general flow equation, which is derived from mass conservation law. Cumulative production is obtained based on the change of hydrocarbon saturation.

Instead of proppant mass, this study assumes a constant dimensionless fracture conductivity and the same fracture half-length for both fracture configurations. It attempts to answer the question: Given the same dimensionless fracture conductivity, and under the same reservoir conditions, which fracture configuration yields higher cumulative production, productivity, and present value?

A parametric study was performed for permeability ranging from 0.00005 md to 5 md, in a 4000 ft horizontal well. For each permeability and well configuration, four longitudinal fractures were compared to 6 ~ 42 transverse fractures. By simulating well production it is possible to compare the two well architectures over a large range of factors. Actual well production from the Bakken, Barnett, Eagle Ford and Delaware Bone Springs formations were used to verify the simulation results.

This research also includes a comprehensive economic evaluation using current hydrocarbon prices, and cost data from industry. The two fracture configurations were compared by examining Initial Potential (IP), Estimated Ultimate Recovery (EUR), Discounted Recovery (DR), Present Value (PV), Net Present Value (NPV). The final fracturing choice is evaluated by PV.

1.2. OBJECTIVES & APPROACH

The objective of this research is to identify the better option between transverse and longitudinal fractured horizontal wells for both gas and oil reservoir over a wide range of reservoir permeability

This objective is accomplished in three steps through both experimental and field studies.

The first step is using reservoir simulations to compare production from the two fracture configurations. It includes: 1) simulating a series of transverse and longitudinal fractured horizontal wells over a range of permeability in both gas and oil formations; 2) collecting the production rate and cumulative production from each simulation; 3) comparing the productivity and recovery of longitudinal and transverse multiple fractured horizontal wells; 4) using a reasonable oil and gas price, drilling, completion and stimulation cost to calculate the PV and NPV of the two fracture configurations; and 5) identifying a range of reservoir permeability for the preferable fracture configuration for gas and oil wells based on the comparison criterion chosen.

The second step is a sensitivity study of major influencing parameters through simulation. The parameters include the number of fractures, the dimensionless fracture conductivity, lateral length, fracture half-length, completion method (cased hole or open hole), or hydrocarbon price.

The final step is validating the conclusions from simulations with field cases.

With field data collected from both oil and gas formations over a range of reservoir permeability, the historical production data of transverse fractured and longitudinal fractured horizontal wells in the same field were analyzed, and the performance of these two well architectures were compared to the simulation results within the same reservoir permeability range.

2. LITERATURE REVIEW

This section summarizes the previous studies and comparisons of productivity and economics for longitudinal and transverse fractured horizontal wells over different reservoir permeability ranges. It first addresses the main findings and methods on this topic in the chronological order and then outlines the studied permeability range and comparison criteria.

Starting from the first successful application of horizontal drilling and multi hydraulic fracturing in 1987, researches have been focusing on two horizontal well architectures: horizontal well with transvers fractures and horizontal well with longitudinal fractures.

Before 1996, it was recognized in both literature and practice that transverse fracture configuration was applicable for relatively low-permeability formations (Valkó and Economides 1996).

In 1996, P. Valkó and M.J. Economides compared the Discounted Revenue of longitudinal fractured well and vertical fractured well in high permeability reservoirs (1 md, 10 md and 10 md). They used the same propped volume and fracture permeability for both fracture configuration and calculated the discounted revenue, also referred as Present Value. The results show that longitudinally fractured horizontal wells were more productive and economical than vertical fractured horizontal wells at reservoir permeability of 1 md and 10 md.

In 2007, Economides and Martin compared the dimensionless productivity of vertical fractured well to transversely and longitudinally fractured horizontal well respectively in gas reservoirs with permeability ranging from 0.01 md to10 md (Economides and Martin 2007). They used the unified fractured design approach, which was developed to unify the fracture treatment size and determine the optimal fracture half-length and fracture width at which the maximum productivity can be obtained. This approach provided a method to calculate well productivity. It correlated proppant mass to the productivity of vertical and horizontal fractured well. By examining the ratio of horizontal fractured well productivity to the vertical fracture well productivity for a given proppant mass at varied reservoir permeability, this study identified the range of attractiveness of each option for gas well.

In 2010, Economides et al. continued the same comparison for oil and gas reservoirs with permeability ranging from 0.001 md to 500 md (Economides et al. 2010). Similarly, they compared horizontal well with transverse or longitudinal fracture to vertical fractured well using the unified fracture design approach. However, there was still no direct comparison between transverse and longitudinal fracture configuration.

Based on these studies, Economides et al. developed a series of recommendations for both gas and oil formations, summarized in table 2.1, which was widely referred in industry and studies later on. Generally, 10 md was suggested to be a threshold in oil formations. It was recommended that longitudinal fractured horizontal well would be a better choice comparing to transverse fractured horizontal well in oil reservoirs with permeability over 10 md. Likewise, 0.5 md was identified to be the critical value in gas formation. Above this value, longitudinal fracture configuration appeared to outperform transverse one. Additionally, when the gas reservoir permeability was lower than 0.1 md, vertical fractured well could be a better option depending on the economics.

Table 2.1. Suitable Options (Economides and Martin 2007; Economides et al. 2010)

Best option	Oil formation	Gas formation	Remark
Longitudinal fractured horizontal well		K > 5 md	Turbulent effect makes transverse less attractive.
Longitudinal fractured horizontal well or Vertical fractured well (Depend on economics)	K > 10 md	0.5 md < k <5 md	Above 0.5md, the "choked" connection between the fracture and the wellbore makes transverse fractures relatively inefficient.
Transverse fractured horizontal well	K < 10 md	0.1 md < K < 0.5 md	
Transverse fractured horizontal well or Vertical fractured well (Depend on economics)		K < 0.1 md	

As the technology advanced, more research were conducted on unconventional reservoirs and more comparison was made among the horizontal fracture configurations rather than vertical ones.

In 2011, the impact of horizontal wellbore azimuth was studied for the Barnett Shale and Marcellus Shale. In the Barnett study public data was reviewed. The optimal well azimuth was determined through the comparison of gas recovery (Lafollette and Holcomb 2011). In the Marcellus evaluation a statistical well analysis was conducted. Horizontal wells with well azimuth from 0 degree to 90 degree were first investigated using multiple regression analysis. Over 500 public domain wells were evaluated. The results demonstrated that transverse fracture outperformed all other well azimuth configurations in the Marcellus Shale, the more the horizontal wellbore deviated from σ_{Hmin}, the lower the EUR (Zinn et al. 2011).

Realizing the importance of well azimuth was recognized, operators shifted to drill the horizontal well at the direction of minimum horizontal stress to create multiple transverse fractures which would maximize the production in unconventional reservoirs. It was no longer a more normal distribution of well azimuth as previous.

In 2013, Wutherick et al. further studied the impact of well azimuth and explained the conclusions made in the Marcellus shale by Zinn et al. using a simple geometry to illustrate the simulated reservoir volume of (SRV) at varied well azimuth. The results showed that transverse fracture configuration had the highest SRV. Oblique fractures configuration were found not competitive with transverse ones due to their lower SRV in shale gas reservoirs. Furthermore, this study pointed out that not drilling the well in the direction of lowest horizontal stress would result in higher drilling risk, higher breakdown pressure and ultimately lower production (Wutherich et al. 2013).

Meanwhile, a comparison between transversely and longitudinally fractured horizontal wells was done in moderate permeability gas reservoirs (0.01 md ~ 5 md), based on a field example in Asia. It was the first study to employ the unified fracture design approach to directly compare transverse to longitudinal fracture configuration. This study adjusted the unified fracture design to account for non-Darcy flow for gas production. It investigated multi lateral and compared the net present value of nine transverse configurations to three longitudinal configurations with different well and fracture spacing. It concluded that the completion strategies with highest productivity may not provide the best value. The drainage optimization and flow mechanism were important considerations to maximize well performance (Liu et al. 2012).

In summary, previous work on the performance comparison of transversely and longitudinally fractured horizontal wells covered the permeability range of 0.001 md to 500 md in oil and gas formations. Continuous study on the comparison of different fracture configurations from 1996 to 2013 provided important guidance on optimal options under different reservoir permeability (Table 2.1). However, these conclusions were obtained through experimental study and they were not verified with field data. Few field studies that have been done were limited to tight and moderate gas reservoirs.

With regard to the comparison criteria, productivity, recovery, discounted revenue and net present value were compared in previous work. Dimensionless productivity (J_D) was compared in the early studies. Net present value was added as comparison criterion in later evaluation on moderate gas reservoir. In the Marcellus shale, the necessary lateral length needed to achieve the same net present value was compared. In shale gas well azimuth evaluation, the recommendations were developed according to the comparison of simulated reservoir volume which was relative to the gas recovery. Similarly, in Barnett Shale studies, gas recovery was used to identify the optimal azimuth.

3. DESCRIPTION OF MAIN CONCEPTS

3.1. UNCOVENTIONAL & CONVENTIONAL RESOURCES

What is unconventional resource? The definition varies over time. Meckel and Thomasson, 2008, used a permeability threshold of 0.1 md to define unconventional resources. Harris Cander, 2012, defined unconventional resources as those petroleum reservoirs whose permeability/viscosity ratio requires use of technology to alter either the rock permeability or the fluid viscosity in order to produce the petroleum at commercially competitive rates (Cander 2012). George King, 2012, illustrated that tight gas ranging from 0.001 md to 0.1 md connected unconventional and conventional reservoirs (figure 3.1). At present, the term of unconventional resource is used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics different from conventional sandstone and carbonate reservoirs.

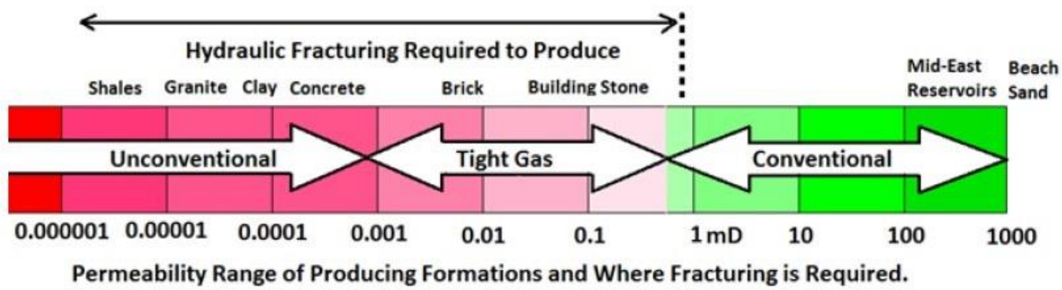

Figure 3.1. Permeability Range (George King, 2012)

Conventional oil or gas comes from geological formations that are relatively straightforward to develop. In practice, conventional resources are the resources, which can be extracted by the natural pressure of the wells and pumping, or compression operations. Because they are easier and less expensive to produce, they were the first targets of industry activity and they have been the most practical and easiest resource to produce.

In contrast, unconventional reservoirs are trapped in hydrocarbon reservoirs with low permeability and porosity, which has little or no ability for the oil or gas to flow through the rock into the wellbore and are more difficult or less economical to extract. They are essentially any resources that requires special recovery operations outside the conventional assessment methodology and operating practices. From an economic standpoint, they cannot be profitably produced with conventional production methods. General categories of unconventional resources include tight-gas sand, gas and oil shales, coalbed methane, heavy oil and tar sands and gas-hydrate deposit.

According to International Energy agency’s (IEA), as technologies and economies change, what was unconventional yesterday may become conventional tomorrow. Over time, what will qualify as unconventional will depend on the resource characteristics, the available exploration and production technologies, the economic environment and the scale, frequency and duration of production from the resource (Schlumberger 2014b). The differences in reservoir characteristics and producing mechanisms between conventional and unconventional resources have provided technical, developmental, and economic challenges to the industry.

3.2. HYDRAULIC FRACTURING

Hydraulic fracturing is a well stimulation treatment performed on oil and gas wells in low permeability reservoirs. It involves the use of the fluid and material to create or restore fractures in a formation. Specially engineered fluids including sand or proppant are pumped into the reservoir at high pressure and rate to crack the reservoir rock, as the formation pushes back, the sand keeps the rock apart that provides a flow path towards the wellbore, which has significant higher permeability than the formation itself (George King, 2012). The direct indicator of a successful treatment is the increase of production rate.

Hydraulic fracturing began as an experiment in 1947 and began to be used commercially in 1949. With the first multi fracture job done in horizontal well in 1987, it became effective in extracting hydrocarbons from low permeability reservoirs. Till now, after nearly 30 years of experience, hydraulic fracturing and horizontal drilling are proven technologies and are intensively used in industry to unlock reserves of oil and gas found in unconventional reservoirs such as shale and other tight rock formations. Fig 3.2 shows how hydraulic fracturing creates a flow conduct for the natural gas in the reservoir.

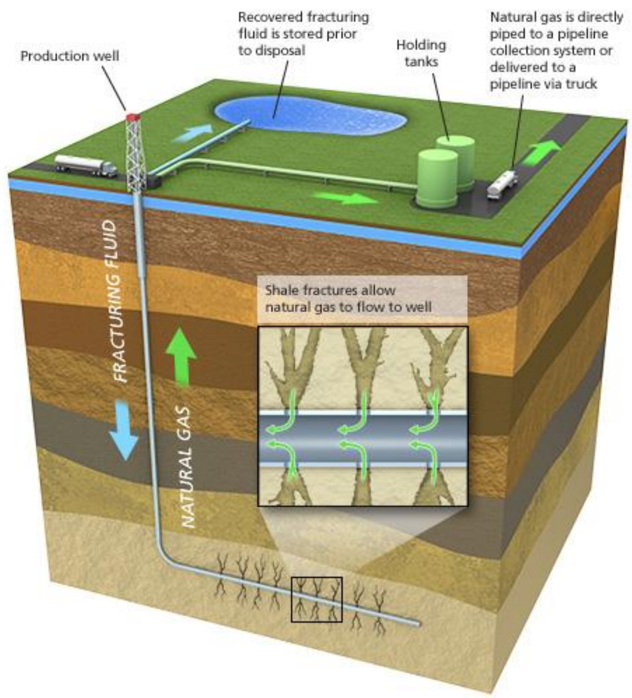

Figure 3.2. Fracking Info (Sandcan 2014)

A typical fracturing includes the following stages:

1. Clean up stage: Use a mix of water with diluted acid to clear debris in the wellbore to provide an open conduit for the frac fluid.
2. Break down stage: Pump incompressible fluid from surface down into the well to create fracture in the formation.
3. Pad stage: Pump pad fluid into formation to extend and propagate the fracture. The fracture width is developed and the fractures stop growing in length once pad is spent through leak off.
4. Proppant stage: Pump slurry of gel and proppant immediately after pad to hold the fracture open and create permeable flow path.
5. Flush stage: Pump fresh water to displace the slurry. Avoid overdisplacement which will push the proppant away from the wellbore.

3.3. CASED HOLE / OPEN HOLE COMPLETION

There are two common horizontal completion systems to execute the multiple fracturing operations: Open Hole Multi-stage System (OHMS) and cased hole Plug and Perf (P-n-P) system.

With the P-n-P completion, the casing or liner needs to be cemented first. The wellbore is then perforated, and hydraulic fracturing is completed in stages. The first set of perforations is created near the toe, acid is pumped down to clean up the debris from perforation, and then fracturing fluid is injected to create the first stage of fracturing. The plug is set in place after the first stage is complete. The process of plug setting, perforation and pumping is repeated till all fracturing stages are completed. At the end, all plugs will be milled out.

The most recent advance in P-n-P completion, posted on April 2014, is Baker Huges' OptiPort multistage fracturing system. It modified plug-and perf method with a coiled-tubing bottom-hole assembly which can stimulate an unlimited number of stages (Figure 3.3). This system has been used in some of the US unconventional plays to optimize placement of frac fluid and proppant.

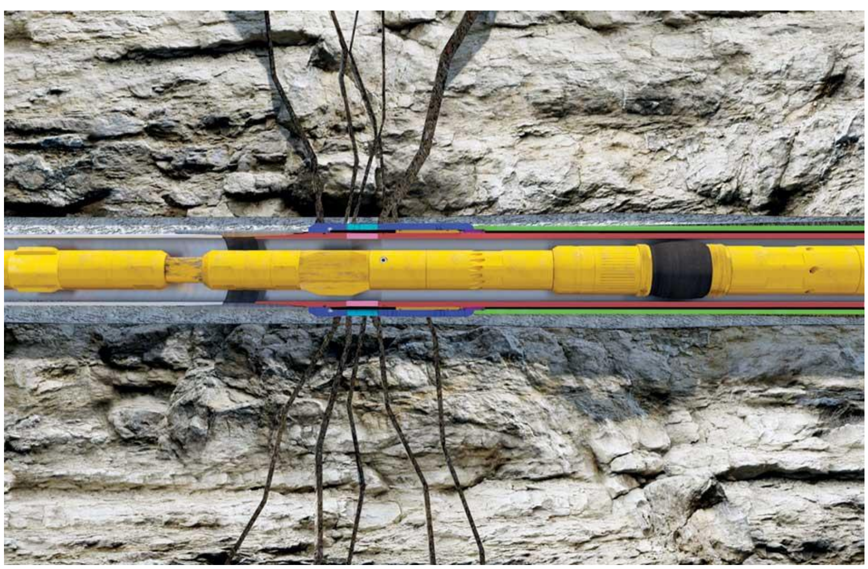

Figure 3.3. OptiPort Multistage Fracturing System (Baker Hughes 2014)

In the OHMS completion, the horizontal section of wellbore is not cemented. The first frac begins after the open hole packer is set in place. Once the first frac is complete, a ball is dropped from surface. When the ball lands on the sliding sleeve's seat, it isolates the previous zone and opens the sleeve , which allows the frac fluid to go to the next interval. In this system, the fracturing operation can be done continuously to createmultiple fractures from uncemented wells (Figure 3.4).

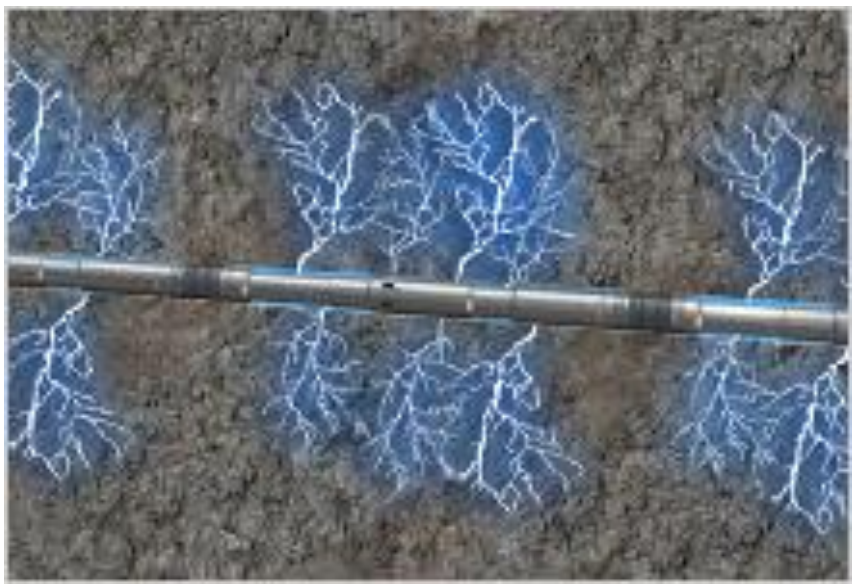

Figure 3.4. Isolate & Stimulate Continuously (Schlumberger 2014a)

Because the formation near well-bore is not cemented in the open hole system, the reservoir fluid can flow through it into the wellbore, which contributes to production. Open hole fractures have cleaner connection between fracture and wellbore than cased and perforated fractures. Higher production rate can be expected with open hole completion. However, open hole operation is hard to control and it can be only used for formations where wellbore stability is not a problem.

In this work, both open hole and cased hole completions are simulated, the well performance of two methods are compared and discussed in Chapter 4.

3.4. TRANSVERSE & LONGITUDINAL FRACTURE

Underground formation are confined and under stress. The stresses can be divided into three principle stresses: minimum horizontal stress (σ_{Hmin}), maximum horizontal stress (σ_{Hmax}) and vertical stress (σ_v) (Figure 3.5). These stresses determine the direction of fractures. Hydraulic fractures open in the direction of the least principal stress and propagate perpendicular to the least principal stress direction (in the plane of the greatest and intermediate stresses).

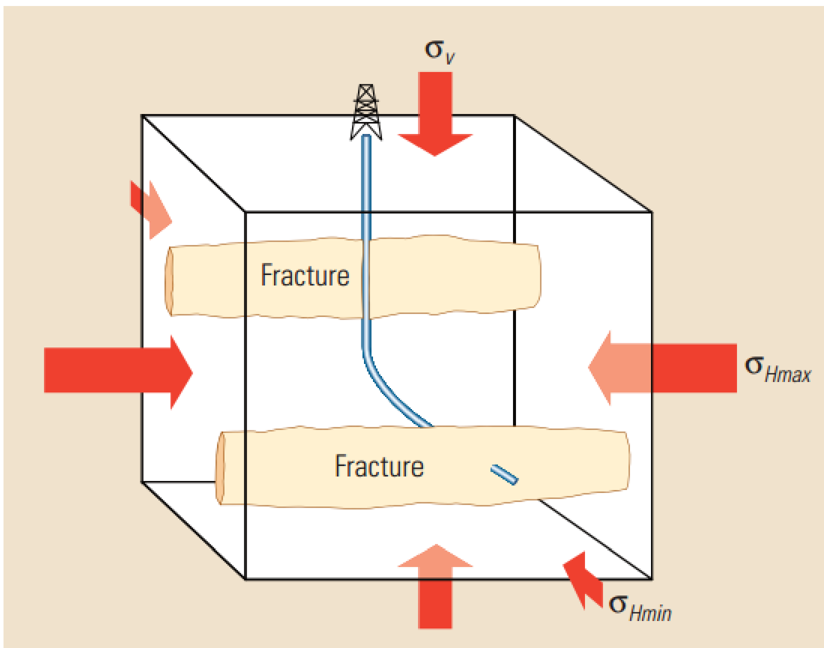

Figure 3.5. In-situ Stresses (Schlumberger 2014a)

If a horizontal well is drilled in the direction of σ_h which is the least principle stress, the fractures created by hydraulic fracturing will be perpendicular to the wellbore. These are transverse fractures. When the well is drilled along σ_H, the fractures created will be parallel to the wellbore, they are longitudinal fractures (Figure 3.6).

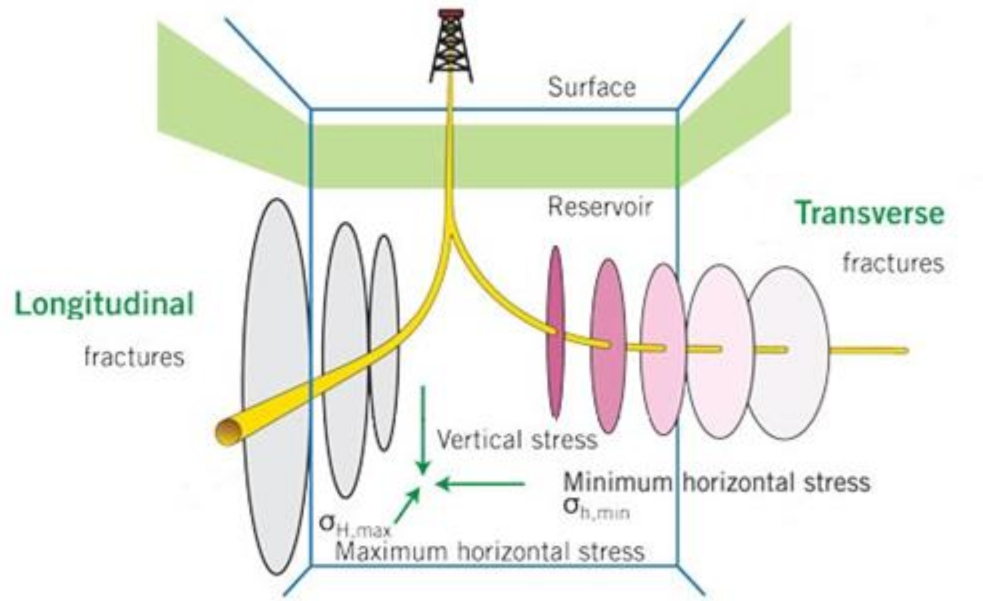

Figure 3.6. Transverse and Longitudinal Fractures

In very low permeability reservoirs, horizontal wells are preferably to be drilled at the direction of minimum horizontal stress to create multiple transverse fracture. Transverse fractures provide the highest simulated reservoir volume as more contact areas are created within the formation. However, in high permeability gas formations, the near wellbore choking effect and turbulence reduce the effectiveness of transverse fractures, in which case, longitudinal fractures is desired. It is important to identify a reservoir permeability range within which transverse or longitudinal fractures have advantages over each other in both gas and oil formations.

3.5. COMPARISON CRITERION

Production rate, recovery, and economics are used as critieria in this study to fully address the performance difference between transverse and longitudinal fractured horizontal wells under certain reservoir conditions. These three criteria are described in details below.

3.5.1. IP & Annualized First Year Rate. Initial production rate indicates a well's production ability. The initial potential of a well refers to the flow rate measured during the initial completion of a well in a specific reservoir, referred as the daily rate of production. In this study, IP is set to the production rate on the 30^{th} day.

The annualized first year rate is the cumulative production at the end of the first year divided by 365 days. It is also an indicator of the well's ability to produce hydrocarbons. The annualized first year rate takes the first year's production into account, which demonstrates the well's initial potential in a longer initial period.

3.5.2. EUR. Estimated ultimate recovery (EUR) is the amount of oil and gas expected to be economically recovered from a reservoir by the end of its producing life. It is an approximation of the quantity of the reserves that is potentially recoverable. EUR is essential in evaluating the profitability of a drilling project.

In this work, 50-year cumulative production is considered to be the ultimate recovery. However, in practice, not many wells can produce 50 years. Some wells may produce less than 10 years and not economically feasible afterwards due to low production rate and high daily production cost, especially in unconventional reservoirs. Therefore, this study also compares the 5-year and 10-year cumulative recovery for the two fracture configurations.

3.5.3. DR, PV & NPV. Higher recovery does not necessarily mean more profit. It is crucial to look at the cost needed to produce that amount of oil and gas. Economic benefit is the ultimate goal. The final choice between two configurations is made based on the comparison of PV in this study.

Discounted Recovery (DR) is the recovery discounted at the annual interest rate, This study uses an interest rate of 10%, which is commonly accepted in the energy industry.

$$\mathrm{DRn}(Mscf\ or\ bbl) = \sum_{i=1}^{n} \frac{cumulative\ production\ of\ No.\ i\ year}{(1+interest\ rate)^{i}} \tag{1}$$

Present value (PV) is the estimated future oil and gas revenues discounted at an annual interest rate. PV represents both the cumulative production differences and their distribution in time.

$$\text{PVn}(MM\$) = \frac{n\ years\ total\ DR(Mscf\ or\ bbl)*price\left(\frac{\$}{Mscf\ or\ bbl}\right)}{1000000} \qquad (2)$$

Net present value (NPV) is present value minus the total cost. It is a prediction of net profit.

$$\text{NPVn}(MM\$) = \text{PVn} - \text{Total}\ Cost \qquad (3)$$

In this study, the total cost is composed of drilling cost, completion cost and stimulation cost.

The vertical drilling cost is a fixed amount for a given well, while the lateral drilling cost varies with the lateral length designed for the horizontal well section. For either completion or stimulation cost, it consists of a fixed cost portion and a flexible cost portion which is determined by the number of stages. The cost also depend on the completion method.

The cost applied in this work, summarized in table 3.1, is from the cost database on Duvernay formation.

Table 3.1. Economic Parameters Used for Calculations

Economic Parameters	unit	Open Hole System	Cased Hole System
Gas price	$/Mscf	**4.17**	**4.17**
Oil price	$/bbl	**103.59**	**103.59**
IR	Interest rate	**0.1**	**0.1**
Drill Vertical	MM$	**2.65**	**2.65**
Drill Lateral	$/ft	**301**	**740**
Completion & Simulation cost per stage	MM$/stage	**0.29**	**0.495**
Fixed Completion & Stimulation cost	MM$	**2.5**	**3**

4. RESERVOIR SIMULATION

4.1. DESCRIPTION OF SIMULATION MODEL

4.1.1. Simulation Software. This study uses StimPlan™, a fracturing simulation software, to do reservoir simulation. StimPlan is developed and marketed by NSI Technologies, INC., which specializes in providing technology and well stimulation engineering service. It is a software solution for hydraulic fracture design, analysis, and optimization. StimPlan integrates data handling and analysis, multiple fracture geometry modeling, 3-D numeric reservoir simulation, economic analysis and Post-Frac production analysis. It helps operators maximize the well performance while lowering expenditure and reducing the environmental footprint.

StimPlan includes a numeric single-phase three dimensional (3-D) reservoir simulator for predicting or history matching production data from fractured and un-fractured wells. It is a numeric single phase reservoir simulator that has an automated gridding feature based on the work of Bennett (Bennett 1982) for fractured horizontal wells. The simulator can model the well performance of both longitudinal and transverse horizontal wells. Further, it has the ability to simulate both oil and gas reservoirs and the effects by varying lateral length, fracture length, conductivity, and reservoir parameters.

4.1.2. Parametric Range of Simulations. This study used the work of Prat's (Prats 1961) to establish a fracture conductivity for each case stimulated. For practical purposes, he introduced a dimensionless fracture conductivity, F_{CD}, defined as the ratio of fracture conductivity, $k_f w$, to the product of reservoir permeability, k, and fracture half-length, X_f. In his work it was shown that F_{CD} of 30 represented an infinite conductivity fracture. This value was used for all simulations in this study.

A fracture half-length of 500 feet was used for all simulations of fractures in longitudinal and transverse horizontal wells. The equation for F_{CD}, shown below, was then used to determine the fracture conductivity for any reservoir permeability simulated.

$$F_{CD} = \frac{(k_f)(w)}{(k)(x_f)} \tag{4}$$

Where F_{CD} is dimensionless fracture conductivity

k_f,is fracture permeability (md)

w is fracture width (ft)

X_f is fracture half-length (ft)

k is reservoir permeability (md)

In this study, the reservoir permeability ranges from 0.000050 md (50 nD) to 5.0 md (50,000,000 nD). For a given reservoir permeability, the fracture conductivity was varied to maintain an F_{CD} of 30 for each simulation with the fixed fracture half-length.

4.1.3. Input. This study focuses on hydraulically fractured horizontal wells with either transverse or longitudinal fractures. To model the performance of these two fractures for both gas and oil reservoirs, the following data are needed: reservoir data, production fluid data, well data, completion data and stimulation data.

First, a typical gas or oil reservoir is introduced. All cases of study are under this reservoir condition. The reservoir is designed with closed boundary. The drainage area is set at 640acres with an aspect ratio of 1, which is a 5280 ft × 5280 ft square. The pay zone is located at the depth from 8000 ft to 8300 ft.

The reservoir is assumed to contain only gas or oil in order to use single phase simulator in StimPlan. The fluid properties are given below (Table 4.1).

Then, a horizontal well is placed at the center of the pay zone with a lateral length of 4000 ft. The horizontal well can be fractured transversely or longitudinally by selecting the corresponding options in StimPlan.

Non-Darcy flow is assumed inside the fractures.

All the base cases are designed with open-hole completion. For the sensitivity study of completion method, several cases with cased-hole completion are simulated.

Table 4.1 lists the input data needed for each case. The fractured horizontal wells are designed in the same gas reservoir and the same oil reservoir.

Table 4.1. Input Data for StimPlan Simulation

STIMPLAN INPUT							
RESERVOIR DATA				**WELL DATA**			
Drainage	A	640	acre	Well Type		Horizontal	
Aspect Ratio	As	1		Well Type		Gas Well <u>or</u> Oil well	
Net Pay Top Depth		8000	ft				
Net Pay Bottom Depth		8300	ft	Later length	L	4000	ft
Net Pay Height	h	300	ft	Wellhead Temperature	Twh	68	°F
Reservoir Pressure	Pi	4000	psi				
Reservoir Temperature	Tr	280	°F				
Boundary Condition		Closed Boundary					
Reservoir Permeability	k	Varied					
Porosity	ϕ	0.05					
Water Saturation	Sw	0.25					
PRODUCTION FLUID DATA				**FRACTURE DATA**			
Gas Viscosity	μg	0.02	cp	Fracture Orientation		Transverse <u>or</u> Longitudinal	
Gas Compressbility	Cg	362	E-6 1/psi				
Gas Expansion Factor	Z	0.866		Fracture Half Length	Xf	500	ft
<u>or</u>				Demensionless Fracture Conductivity	Fcd	30	
Oil Viscosity	μo	0.5	cp	Number of fractures	Nf	Varied	
Oil Compressbility	Co	20	E-6 1/psi				
Oil Formation Factor	Bo	1.324					

4.1.4. Simulation Control. Simulation control refers to the conditions set in StimPlan to simulate the production of the wells. Bottom-hole flowing pressure and wellhead pressure are used to control the simulations.

This study assumes an initial reservoir pressure of 4000psi. Oil wells produce at a fixed bottom-hole pressure of 250 psi. Gas wells produce at a fixed wellhead pressure of 725 psi, which falls into the general range of 500 psi to 1000 psi. Wellhead pressure is used for gas wells because the hydrostatic head for dry gas wells is generally small.

4.1.5. Output. Production rate and cumulative production are used to evaluate production from the specified well in the designed reservoir. Cumulative production is obtained based on the change of oil or gas saturation in the reservoir blocks, which is determined from the implicit finite solution to the single phase general flow equation derived from mass conservation law. Production rate is calculated accordingly when time is taken into account. The average reservoir pressure at different time are listed along with the production in the result excel file. Daily and yearly reports are used in this study. They are interpolations from an output file named "Gasliq3dOut.01" in the StimPlan folder.

4.2. GAS WELL SIMULATION

The production from transversely and longitudinally fractured wells were compared for gas reservoir. Major influencing factors were discussed, including number of fractures, F_{CD}, lateral length, fracture half-length, completion method, and gas price.

The gas well simulation results and the calculated economic parameters are listed in Appendix A.

4.2.1. Comparison of Transverse & Longitudinal Configurations. To compare the performance of transverse and longitudinal fractured horizontal wells, 56 transverse cases and 8 longitudinal cases were simulated with reservoir a permeability range of 0.00005 md to 5 md (Table 4.2) .

Longitudinal cases were set up with four longitudinal fractures, which resulted in total fracture length of 4000 ft given the fracture half-length of 500 ft. For transverse cases, various numbers of fractures were simulated, including 6,12,18,24,30,36 and 42. The number 42 was the upper limit of transverse fractures on the 4000 ft lateral according to the practice in industry.

The transverse and longitudinal fractures were compared under the same permeability condition. The comparison was then used to identify the range of reservoir permeability at which transverse and longitudinal fractured horizontal wells have advantages over each other.

Three criteria were used in the comparison to evaluate performance of horizontal wells with transverse or longitudinal fractures:

1) Production Rate (IP and annualized 1st year rate);
2) Recovery (1st year, 5years, 10years cumulative recovery and EUR); and
3) Economics (DR, PV and NPV).

The final evaluation is determined by PV, which represents both the cumulative production differences and their distribution in time. Because cost varies from operator to operator, NPV was considered as a reference.

Table 4.2. Gas/Oil Well Simulation Cases (F_{CD} = 30)

Gas/Oil Well Transverse Simulation Cases (F_{CD} = 30)												
Case	K	K_f W	F_{CD}	Lateral	X_f	No. of Transverse fractures						
No.	(md)	(md.ft)		(ft)	(ft)	A	B	C	D	E	F	G
1A~G	0.00005	0.75	30	4000	500	42	36	30	24	18	12	6
2A~G	0.0001	1.5	30	4000	500	42	36	30	24	18	12	6
3A~G	0.001	15	30	4000	500	42	36	30	24	18	12	6
4A~G	0.01	150	30	4000	500	42	36	30	24	18	12	6
5A~G	0.1	1500	30	4000	500	42	36	30	24	18	12	6
6A~G	0.5	7500	30	4000	500	42	36	30	24	18	12	6
7A~G	1	15000	30	4000	500	42	36	30	24	18	12	6
8A~G	5	75000	30	4000	500	42	36	30	24	18	12	6
Gas/Oil Well Longitudinal Simulation Cases (F_{CD} = 30)												
Case	K	K_f W	F_{CD}	Lateral	X_f	No. of Longitudinal fractures						
No.	(md)	(md.ft)		(ft)	(ft)							
1	0.00005	0.75	30	4000	500	4						
2	0.0001	1.5	30	4000	500	4						
3	0.001	15	30	4000	500	4						
4	0.01	150	30	4000	500	4						
5	0.1	1500	30	4000	500	4						
6	0.5	7500	30	4000	500	4						
7	1	15000	30	4000	500	4						
8	5	75000	30	4000	500	4						

4.2.1.1 IP & annualized 1st year rate. The Initial Potential of a well was represented by the first month production rate. Figure 4.1 compares the Initial Potential of transverse fracture configuration and longitudinal fracture configuration in oil formation over varied permeability.

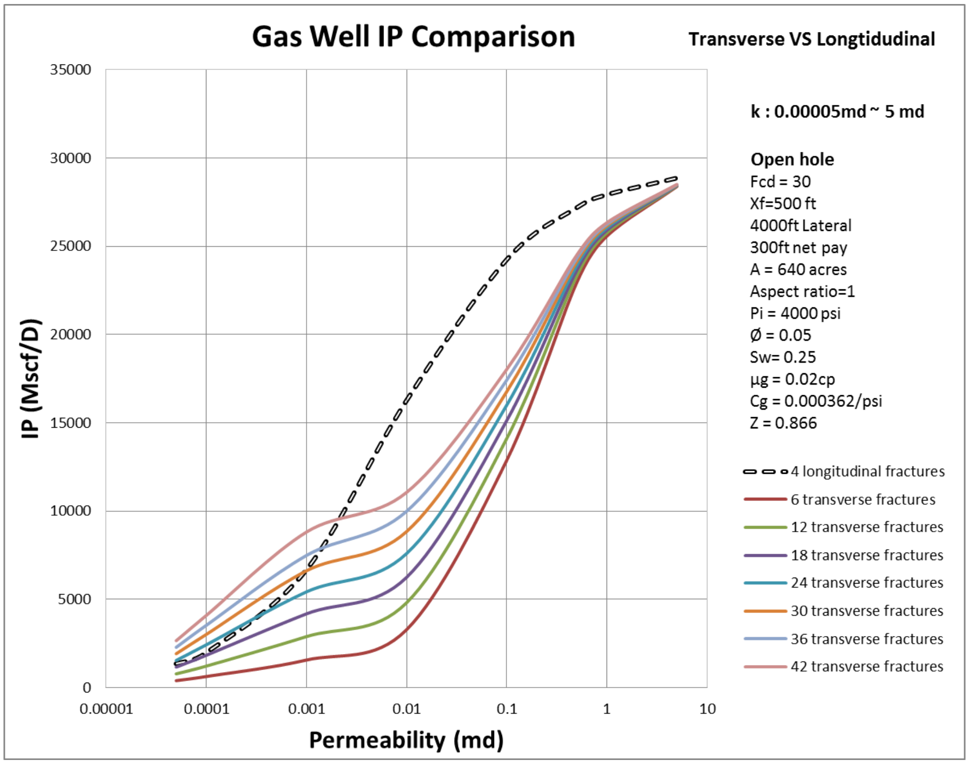

Figure 4.1. Gas Well IP Comparison

For transvers fractures, IP increases with the number of fractures, especially when permeability is within 0.0001-0.1 md; as permeability goes above 0.1 md or drops below 0.0001 md, the influence of fracture number on IP tends to diminish (Figure 4.1). When reservoir permeability is over 0.003 md, four longitudinal fractures creates higher IP than 42 transverse fractures. Longitudinal fractures have better connection to the wellbore and the advantage presents when reservoir permeability is high.

The annualized 1st year rates of two fracture configurations show similar features (Figure 4.2). More transverse fractures yields higher 1st year annualized rate. Four longitudinal fractures result in higher annualized 1st year rate than 42 transverse fractures when reservoir permeability is over 0.008 md.

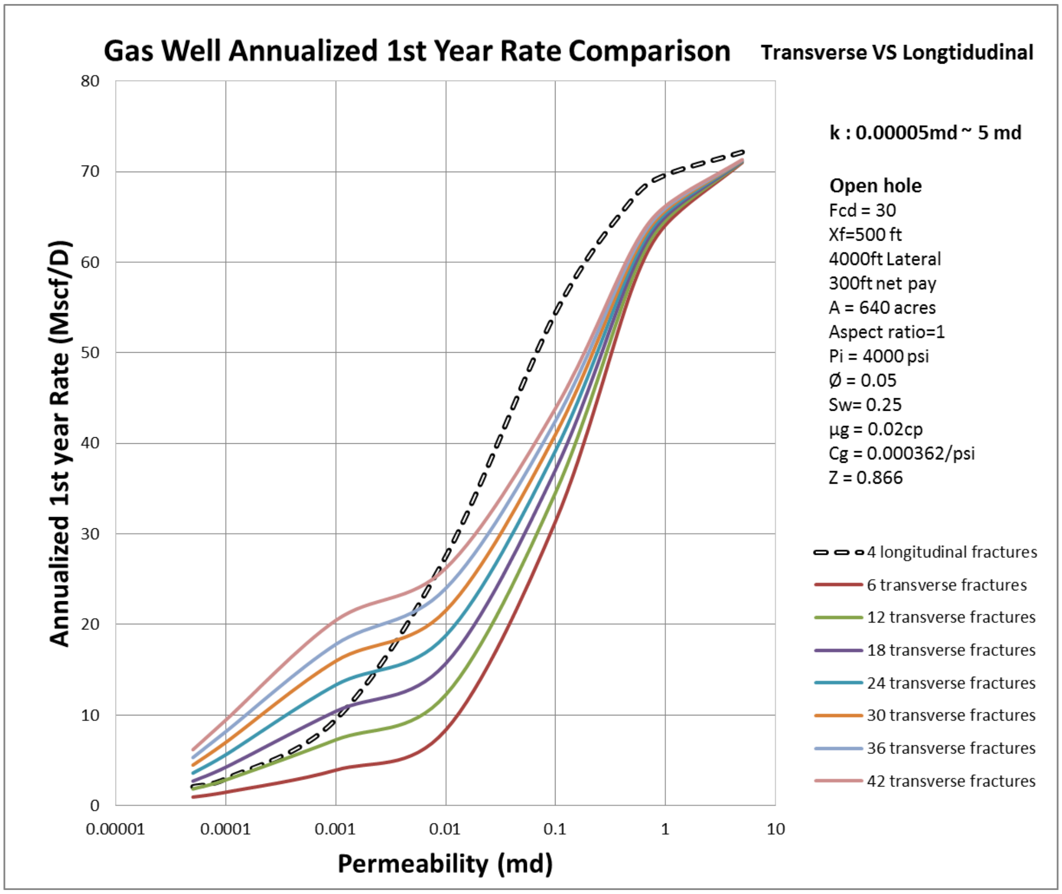

Figure 4.2. Gas Well Annualized 1st Year Rate Comparison

4.2.1.2 Cumulative production. To compare the cumulative production between the two configurations, two sets of plots were made: 1) Cumulative production vs. time and 2) cumulative production vs. permeability.

The change of cumulative production with time illustrates the well's life in the given drainage area.

Figure 4.3 shows the cumulative recovery of the horizontal well with 42 transverse fractures over 50 years. Figure 4.4 shows the cumulative recovery of the horizontal well with four longitudinal fractures over 50 years.

The cumulative production of fractured horizontal gas well with 42 transverse (solid line) and those with four longitudinal fractures (dash line) were compared at four different reservoir permeabilities (Figure 4.5).

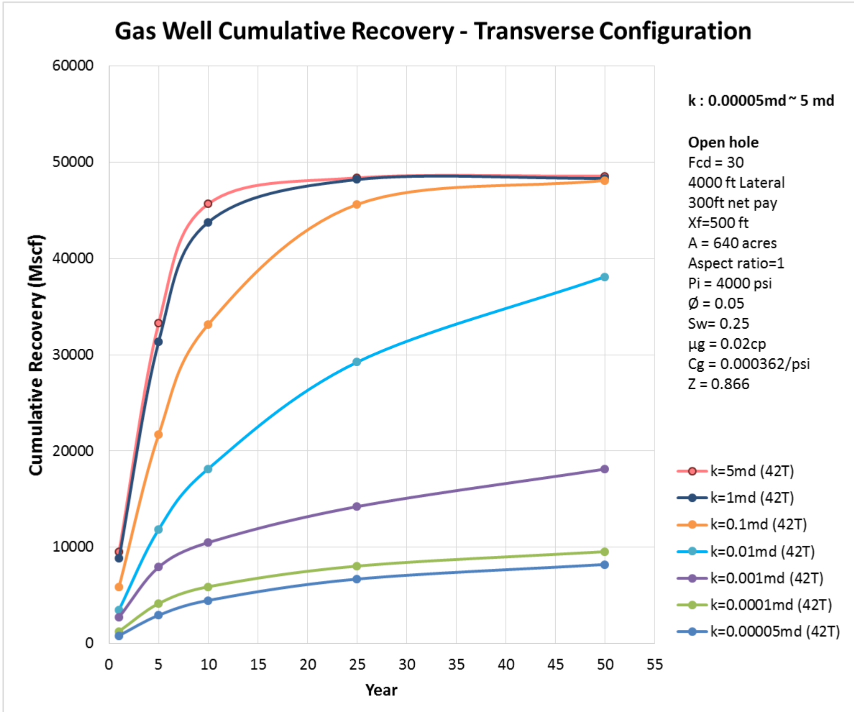

Figure 4.3. Gas Well Cumulative Recovery over 50 Years (42 T)

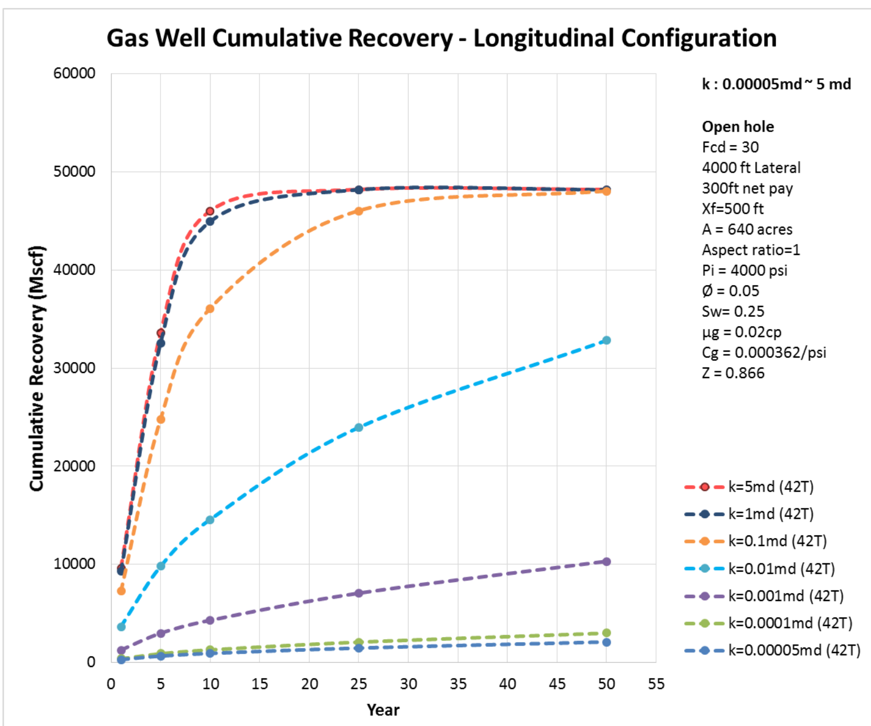

Figure 4.4. Gas Well Cumulative Recovery over 50 Years (4 L)

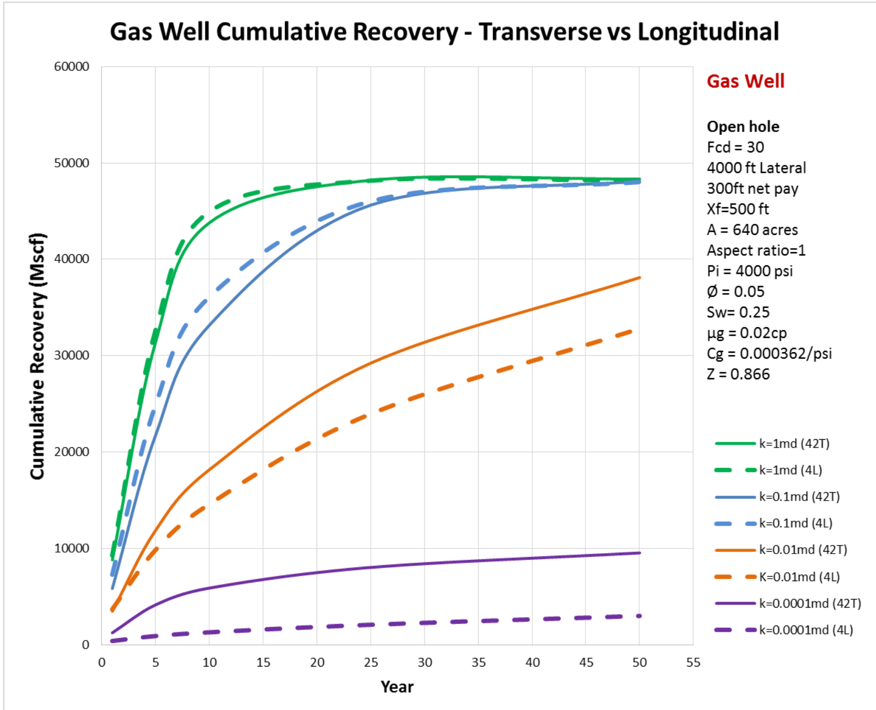

Figure 4.5. Gas Well Cumulative Recovery over 50 Years (42 T vs. 4 L)

The first 10 years are the most productive period for both configurations, a rapid increase in cumulative production was shown during that time. Afterwards, the production depends on reservoir permeability.

When the reservoir permeability is higher than 1 md, most of the gas in the 640 acres reservoir can be extracted within 10 years, and very few production occurs after 10 years.

When the reservoir permeability is 0.01 md, the production steadily increases after 10 years, which means the well may produce for a longer time.

When the reservoir permeability falls into unconventional reservoir range (e.g. k = 0.00005 md), the cumulative production is lower over 50 years for both fracture configurations.

Overall, transverse fracture configuration shows higher production at reservoir permeability lower than 0.01 md.

Longitudinal configuration yields higher recovery when the reservoir permeability increases from 0.01 md to 0.1 md.

The change of cumulative production with reservoir permeability demonstrates the permeability ranges where a transverse or longitudinal fracture configuration is favorable.

The cumulative production of one year, 5 years, 10 years, and 50 years from the two fracture configurations were compared at reservoir permeability ranging from 50 nD to 5 md (Figure 4.6 ~ 4.9).

The critical reservoir permeability was identified by the critical point where the dash line (four longitudinal fractures) meets the solid line (42 transverse fractures), beyond which longitudinal fracture configuration outperforms transverse configuration.

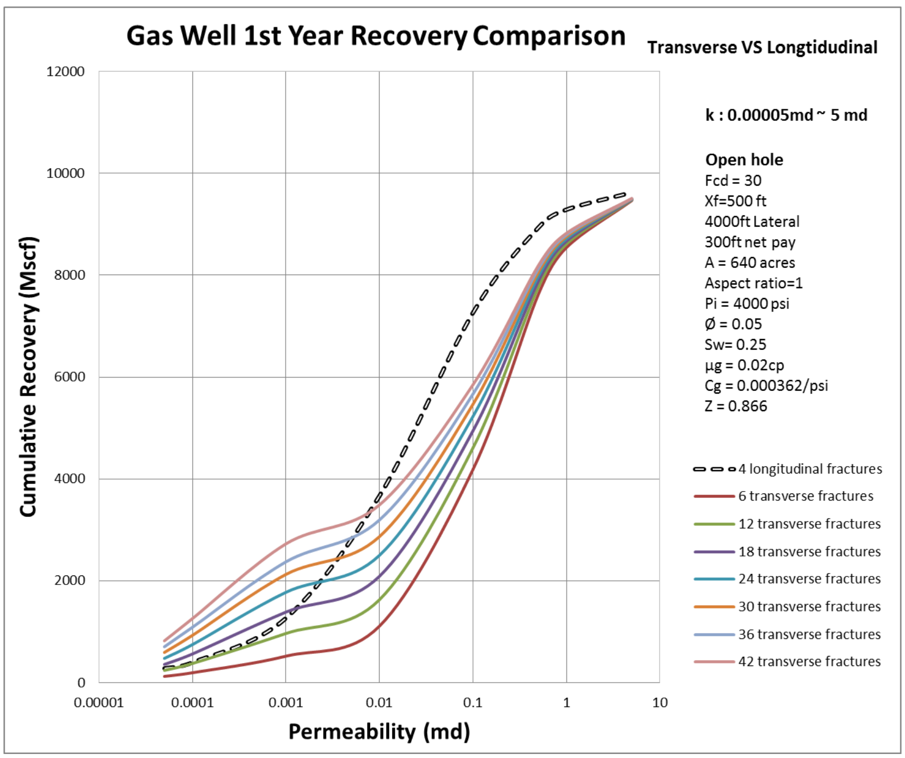

Figure 4.6. Gas Well 1st Year Recovery Comparison

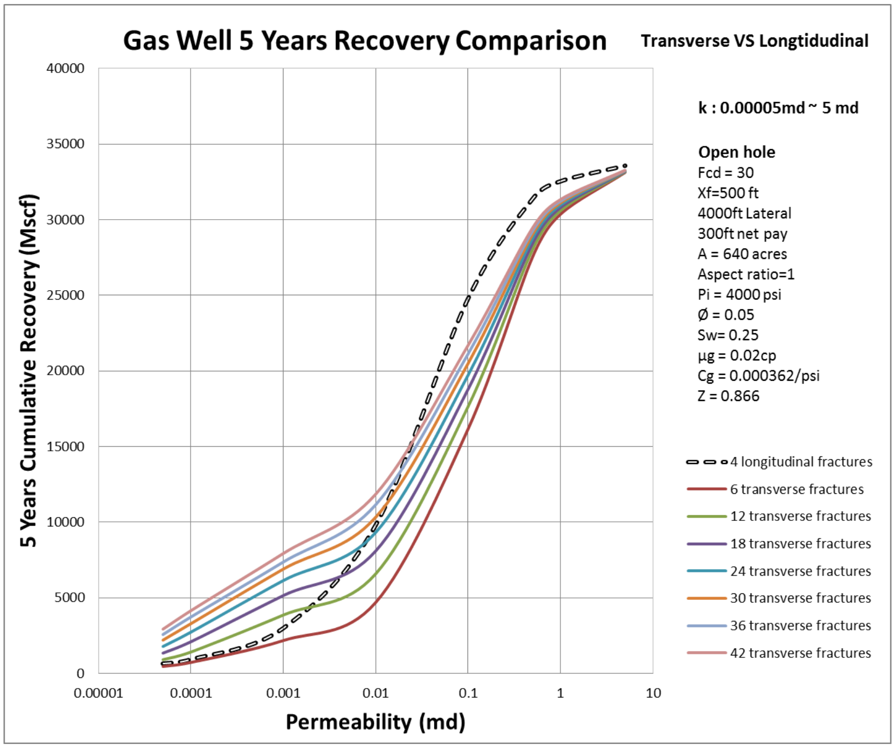

Figure 4.7. Gas Well 5-year Recovery Comparison

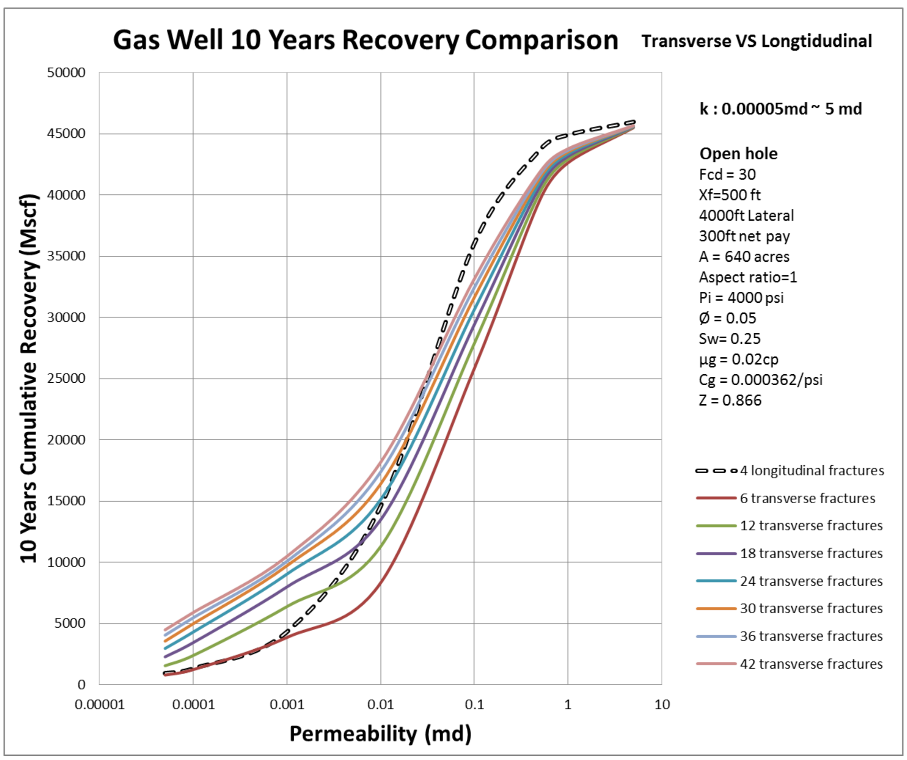

Figure 4.8. Gas Well 10-year Recovery Comparison

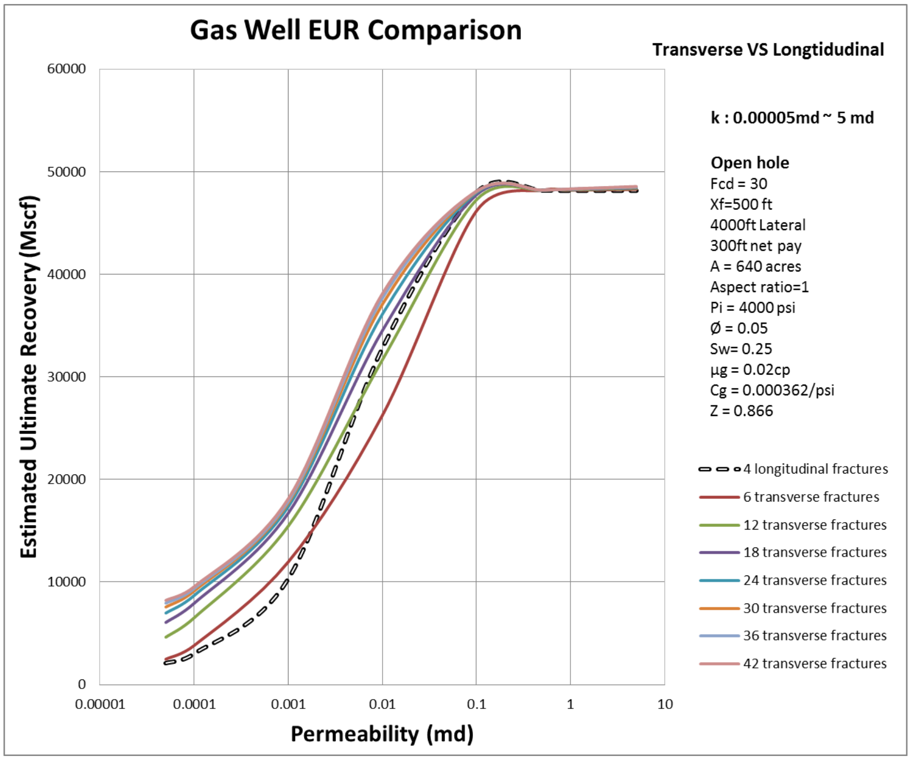

Figure 4.9. Gas Wells EUR Comparison (50-year Recovery)

The critical reservoir permeability identified from above plots is summarized in table 4.6. It is 0.03 md in terms of 5-year cumulative production, which means at reservoir permeability over 0.03 md, the 5-year cumulative production from longitudinal fractured well is higher than it from transverse fractured well.

Longitudinal fracture configuration has similar EUR as transverse fracture configuration in high permeability reservoir. However, at permeability lower than 0.01 md, the advantage of transverse configuration is obvious.

4.2.1.3 DR comparison. Discounted Recovery is calculated based on the cumulative production simulated from StimPlan. The formula of DR is included in chapter 3.

Figure 4.10 shows the discounted recovery change over time for horizontal well with 42 transverse fractures and horizontal well with four longitudinal fractures.

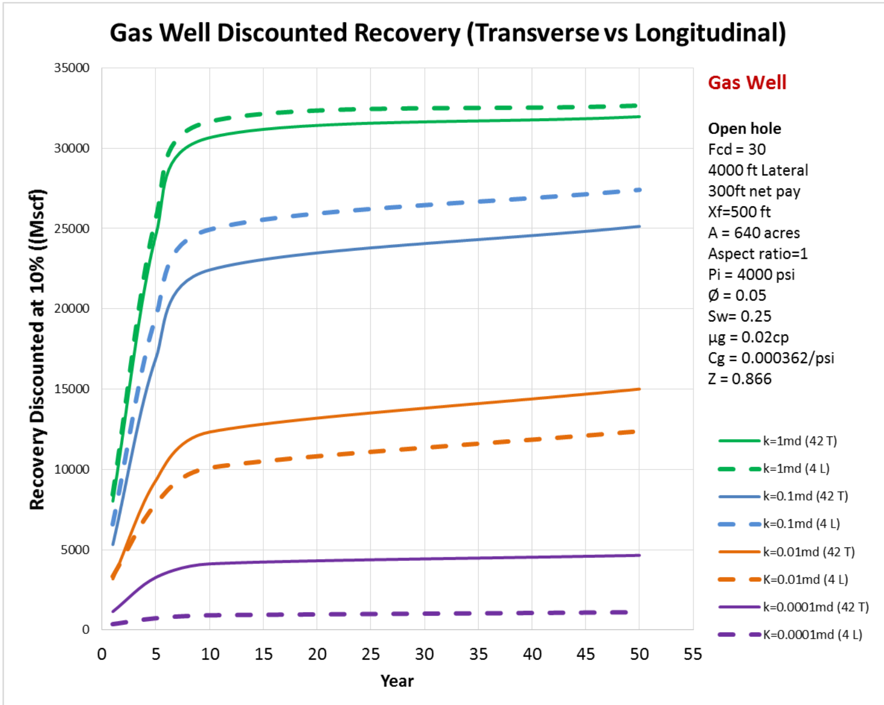

Figure 4.10. Gas Well DR over 50 Years (42 T vs. 4 L)

The DR increases sharply during the first seven years and turns to stabilize at a low increasing rate after seven to ten years.

The DR increases very slowly at the later period for both very high and very low permeability cases (k=0.0001 md and 1 md). For these formations, most of the recoverable reserve in the given drainage (640 acres) can be produced in less than 10 years because the DR hardly increases later on.

For formation with a permeability of 0.01 md or 0.1 md, DR slowly increases after 10 years. The wells are still productive, but may not be economically beneficial.

Figure 4.11 and Figure 4.12 compare DR of the two fracture configurations at 5 years and 50 years. The critical reservoir permeability is between 0.01 md to 0.1 md. Above this permeability, four longitudinal fractures results in higher DR than transverse fractures. Below this value, transverse fractures perform better in terms of DR.

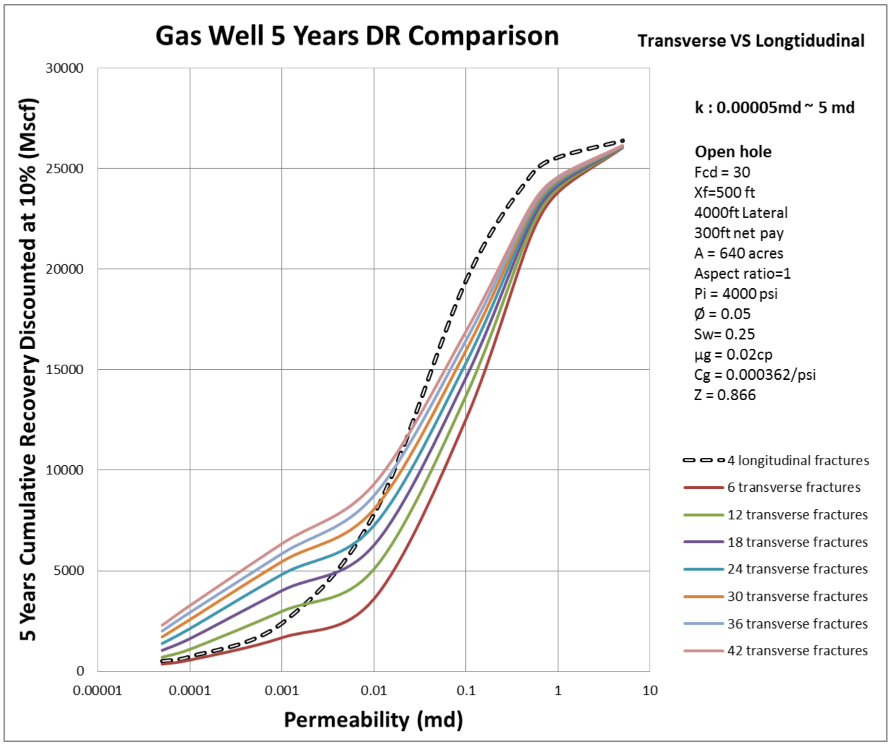

Figure 4.11. Gas Well 5-year DR Comparison

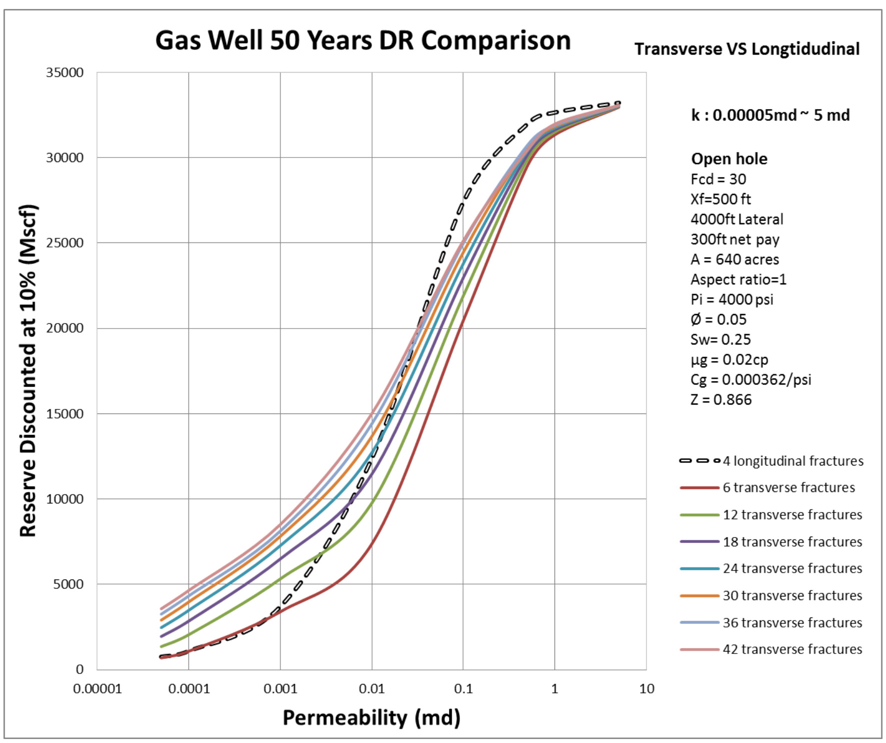

Figure 4.12. Gas Well 50-year DR Comparison

4.2.1.4 PV. PV is the product of cumulative DR and hydrocarbon price, the formula is included in chapter 3. The gas price is set at $4.17/Mscf according to the Henry Hub spot gas price in July 2014.

Figure 4.13 shows the change of PV over time for both fracture configurations. The PV increases sharply in the first seven to ten years and then reaches a plateau for reservoirs with permeability of 0.0001 md and 1 md. This suggests continuing production after ten years may not be beneficial. For reservoir with a permeability of 0.01 md or 0.1 md, PV slowly increases after ten years. The wells are still productive, but may not be economically beneficial when time is taken into account.

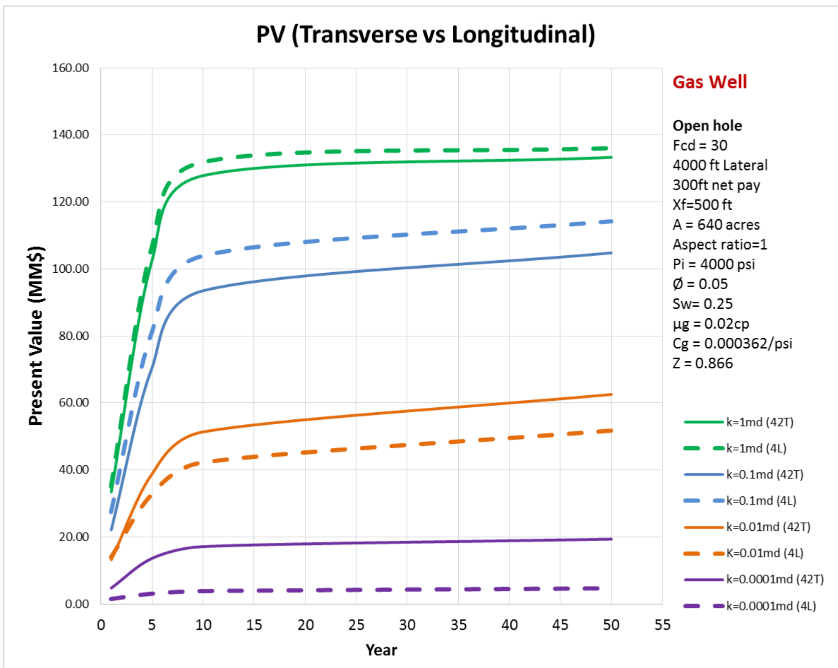

Figure 4.13. Gas Well PV over 50 Years (42 T vs. 4 L)

Fractured well with 42 transverse fractures (solid line) has higher PV in low permeability reservoir (0.01 md and 0.0001 md), while fractured well with four longitudinal fractures (dash line) shows higher PV in high permeability reservoir (k = 0.1 md and 1 md).

Figure 4.14 and Figure 4.15 show the 5-year and 50-year PV of the horizontal well with transverse fractures and the same horizontal well with longitudinal fractures.

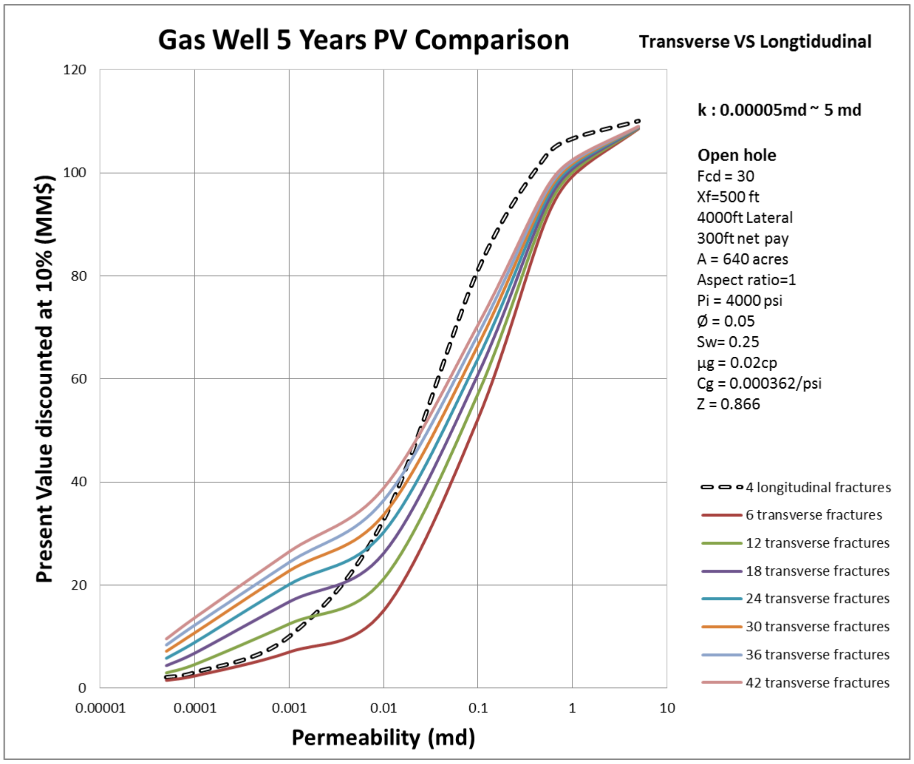

Figure 4.14. Gas Well 5-year PV Comparison

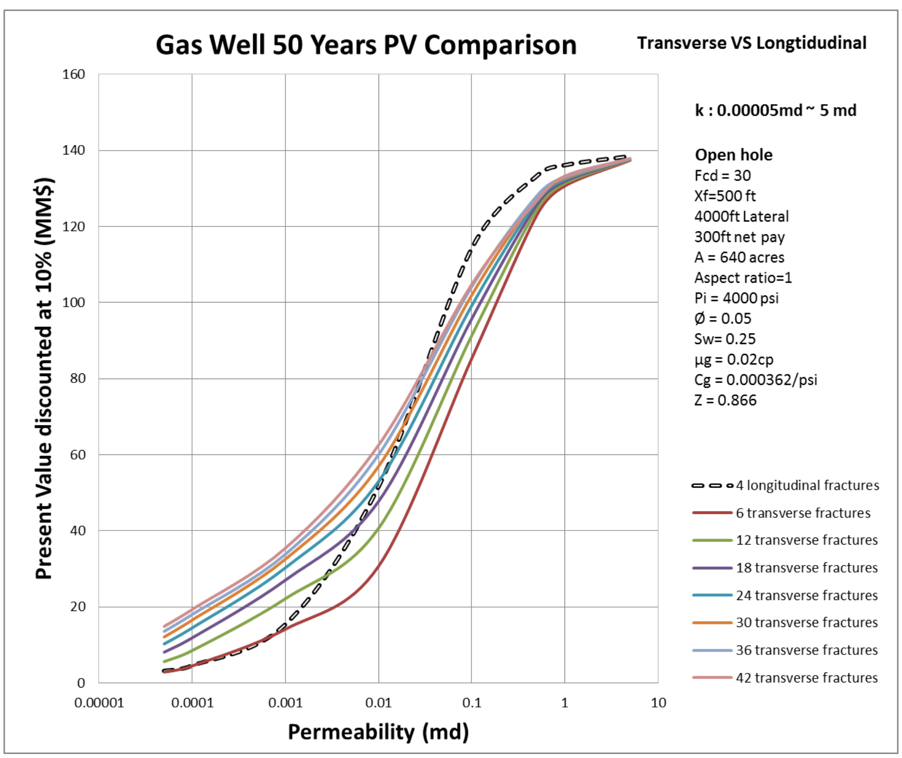

Figure 4.15. Gas Well 50-year PV Comparison

The critical reservoir permeability identified is 0.04 md according to 50-year PV comparison. In gas reservoir, when the permeability is over 0.04 md, a longitudinal fractured horizontal well is more beneficial than a transverse one.

4.2.1.5 NPV. Different from PV, NPV takes cost into account. Figure 4.16 shows the change of NPV over time for both transverse and longitudinal fracture configurations.

NPV increases rapidly in the first seven to ten years. At the reservoir permeability of 0.0001 md and 1 md, it reaches a plateau after about ten years. At reservoir permeability of 0.01 md and 0.1 md, NPV is slowly increasing after ten years. Although NPV increases, producing the well after ten years may not be economically beneficial.

This finding is in accordance with previous observations from EUR, DR and PV comparison.

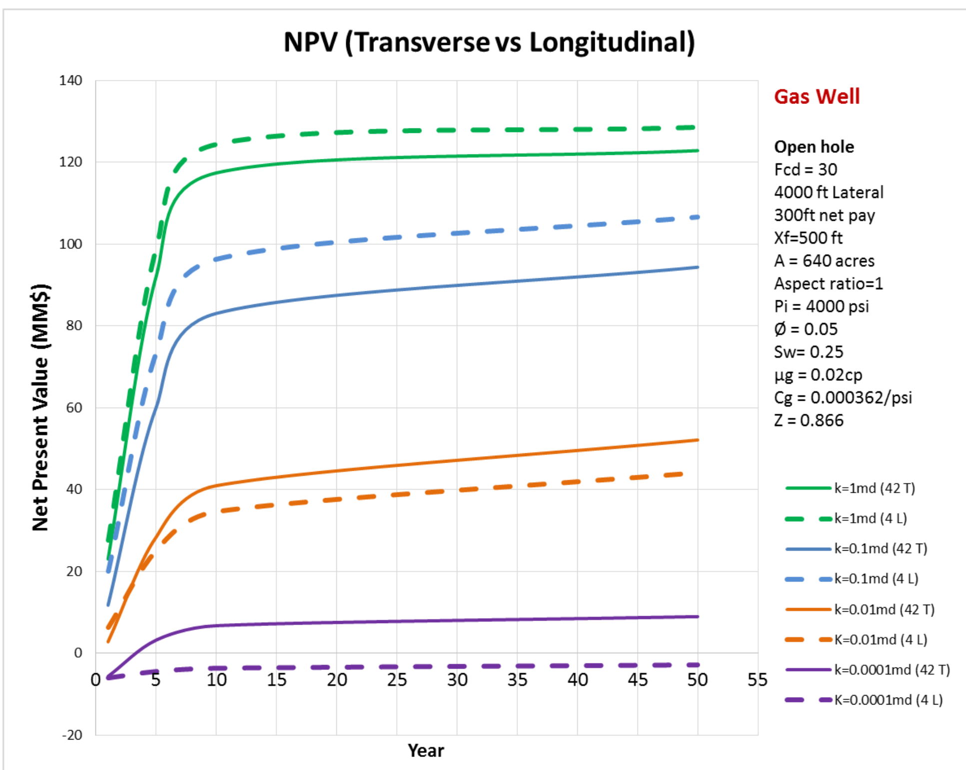

Figure 4.16. Gas Well NPV over 50 Years (42 T vs. 4 L)

It is also illustrated that fractured well with 42 transverse fractures (solid line) has higher NPV at reservoir permeability below 0.01 md, while fractured well with four longitudinal fractures (dash line) perform better at high permeability reservoir (k = 0.1 md and 1 md).

The permeability threshold are found similar to each other based on the 5-year (Figure 4.17) and 50-year NPV (Figure 4.18) comparison. At reservoir permeability lower than 0.01 md, fractured wells with transverse fractures (solid line) has higher NPV. At reservoir permeability higher than 0.1 md, fractured well with longitudinal fractures (dash line) has higher NPV.

In summary, for gas wells with open hole completion, longitudinal configurations outperform transverse at reservoir permeability over 0.04 md. The comparison of cumulative production, DR, PV and NPV identify the similar critical permeability (Table 4.6), which is within the same permeability range (0.1 md to 1 md).

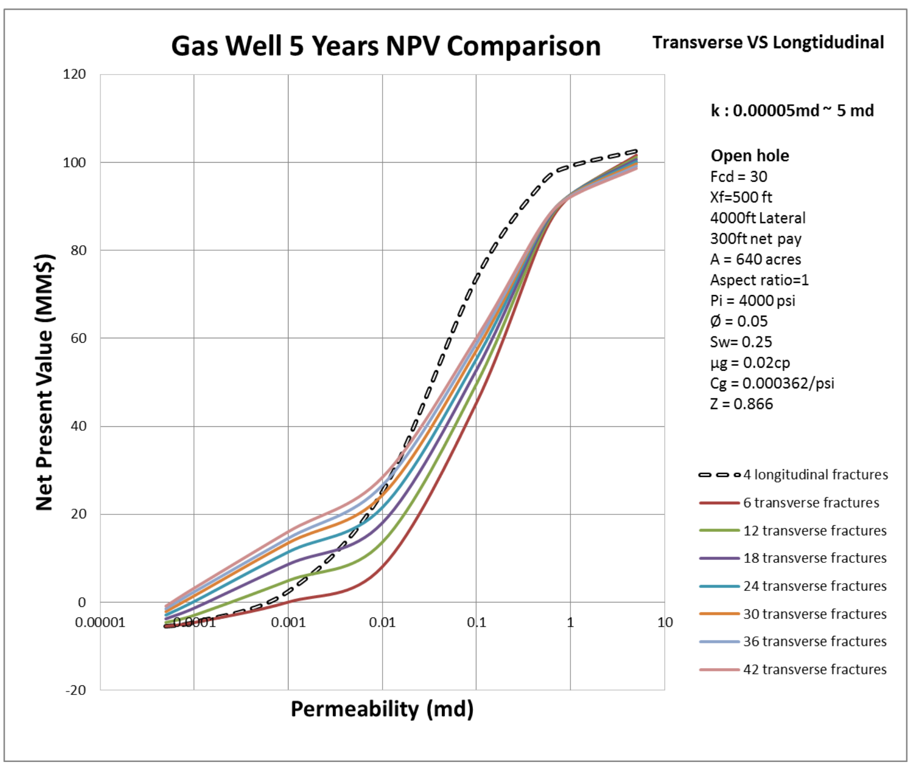

Figure 4.17. Gas Well 5-year NPV Comparison

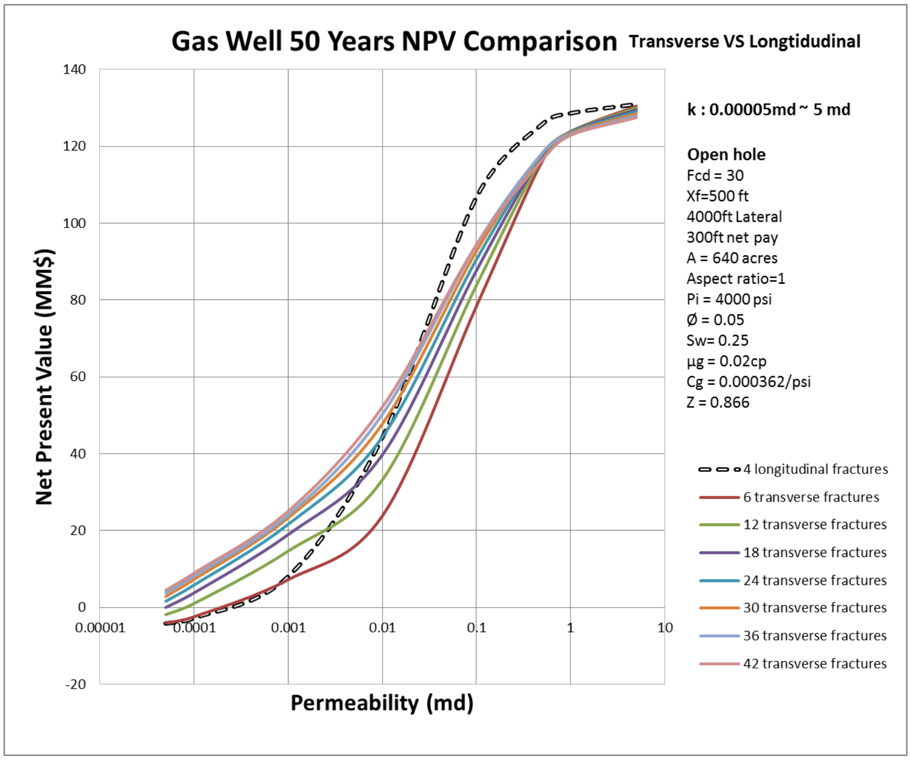

Figure 4.18. Gas Well 50-year NPV Comparison

4.2.2. Sensitivity Study. The effect of important parameters on the determination of fracture configuration was studied. The parameters include the number of fractures, F_{CD}, lateral length, fracture half-length, completion method, and gas price.

4.2.2.1 Number of fractures. The number of longitudinal fractures maintains at four because four 500 ft results in a total fracture length of 4000 ft, which is the same as the lateral length.

The number of transverse fractures increases to 100. All other parameters are unchanged. Figures 4.19~22 compare the IP, EUR, PV and NPV of 100 transverse fractures and four longitudinal fractures.

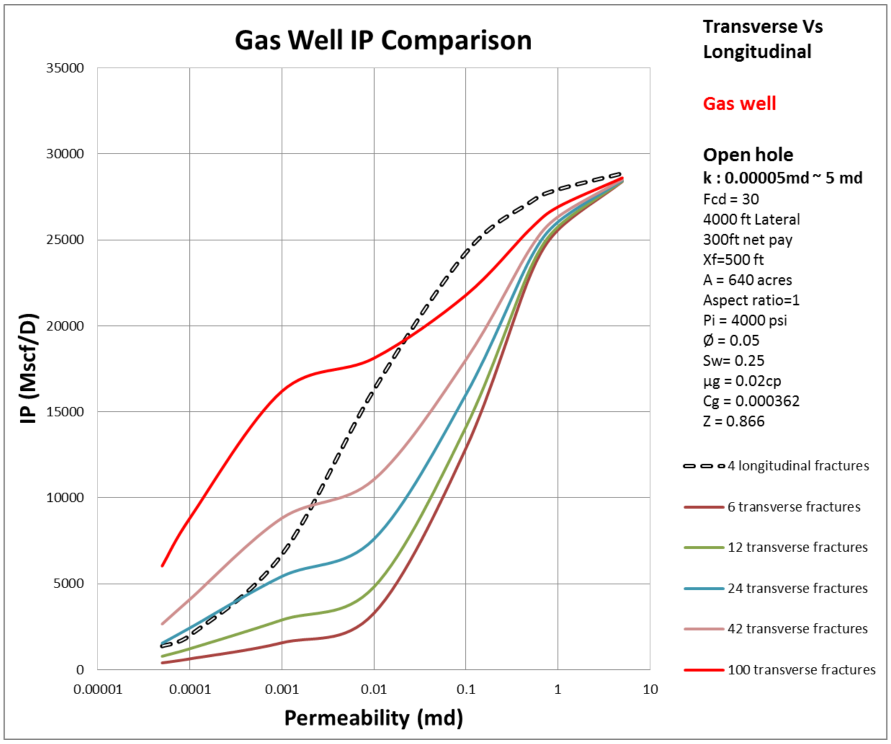

Figure 4.19. Gas Well IP Comparison (100 T vs. 4 L)

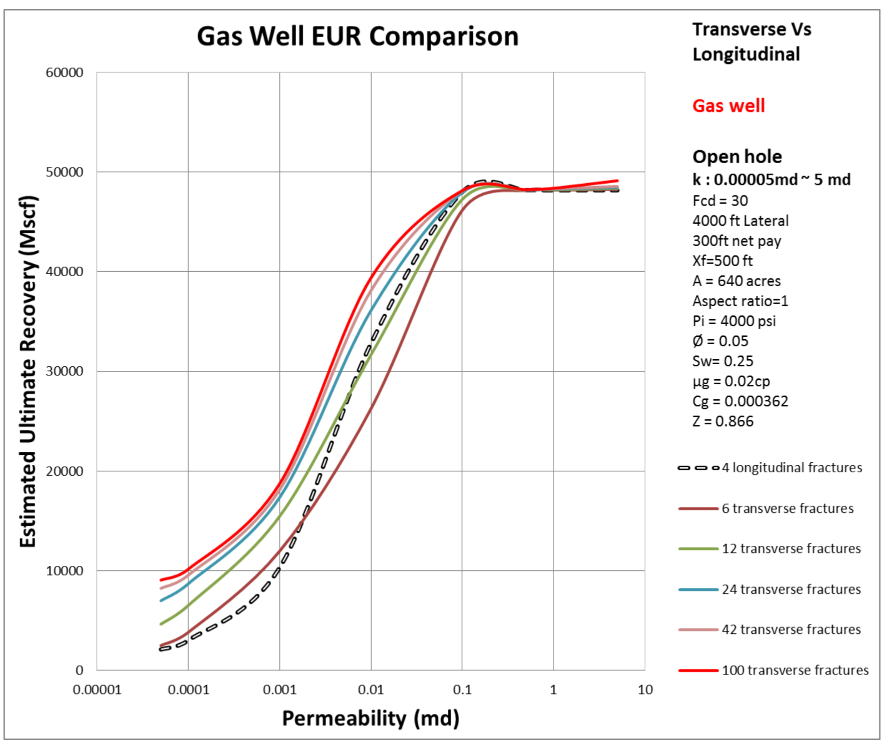

Figure 4.20. Gas Well EUR Comparison (100 T vs. 4 L)

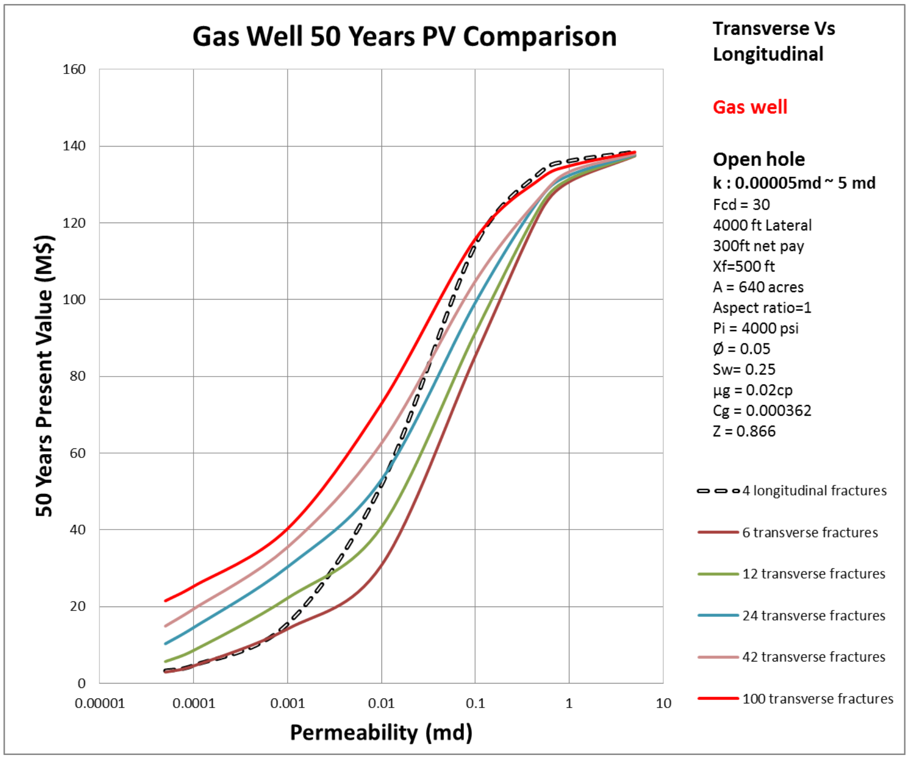

Figure 4.21. Gas Well PV Comparison (100 T vs. 4 L)

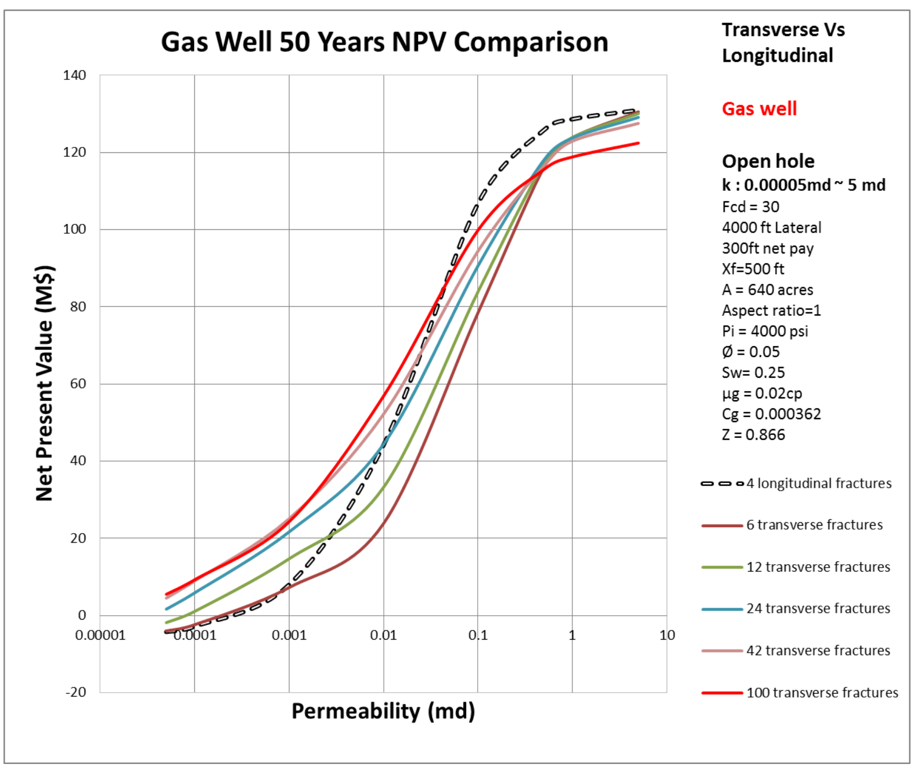

Figure 4.22. Gas Well NPV Comparison (100 T vs. 4 L)

According to the 50-year NPV, the critical permeability is 0.05 md when four longitudinal fractures is compared to 100 transverse fractures, while it is 0.03 md when four longitudinal fractures is compared to 42 transverse fractures.

Considering cost, the critical reservoir permeability remains at the same level.

Additionally, it is not practical to design 100 fractures on 4000 ft lateral. Comparing 42 transverse fractures to four longitudinal fractures would provide reliable results. In this study, the critical reservoir permeability is identified through the comparison of 42 transverse fractures to four longitudinal fractures.

4.2.2.2 F_{CD} (2 vs. 30). As mentioned in chapter 4.1.1, a **F_{CD}** of 30 represents infinite fracture conductivity. A F_{CD} of 2 is an optimum dimensionless fracture conductivity irrespective of clean-up. This session compares the fractured well performance at a F_{CD} of 2 and 30.

A set of cases with a F_{CD} of 2 were simulated in StimPlan (Table 4.3). Figures 4.23-4.27 compare the IP, 5-year recovery, EUR, PV, and NPV between 42 transverse fractures and four longitudinal fractures at a F_{CD} of 2 and 30.

Table 4.3. Gas/Oil Well Simulation Cases (F_{CD} = 2)

Gas/Oil Well Transverse Simulation Cases (F_{CD}=2)					
K (md)	K_f W (md.ft)	F_{CD}	Lateral (ft)	X_f (ft)	No. of Transverse fractures
0.001	1	2	4000	500	42
0.01	10	2	4000	500	42
0.1	100	2	4000	500	42
0.5	500	2	4000	500	42
1	1000	2	4000	500	42
5	5000	2	4000	500	42
Gas/Oil Well Longitudinal Simulation Cases (F_{CD}=2)					
K (md)	K_f W (md.ft)	F_{CD}	Lateral (ft)	X_f (ft)	No. of Longitudinal fractures
0.001	1	2	4000	500	4
0.01	10	2	4000	500	4
0.1	100	2	4000	500	4
0.5	500	2	4000	500	4
1	1000	2	4000	500	4
5	5000	2	4000	500	4

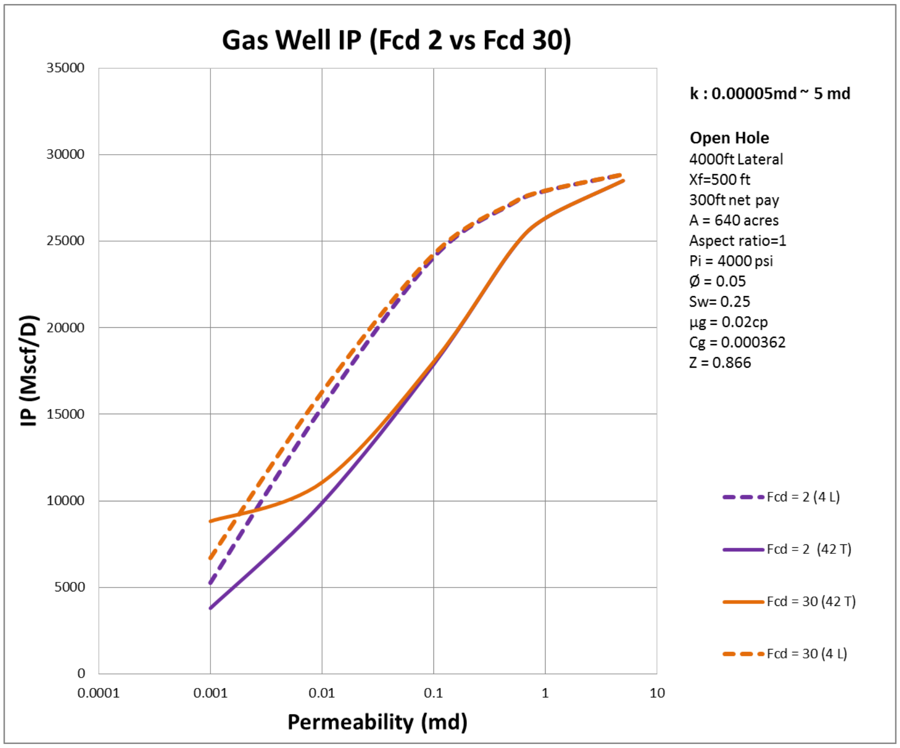

Figure 4.23. Gas Well IP Comparison (F_{CD} 2 vs. F_{CD} 30)

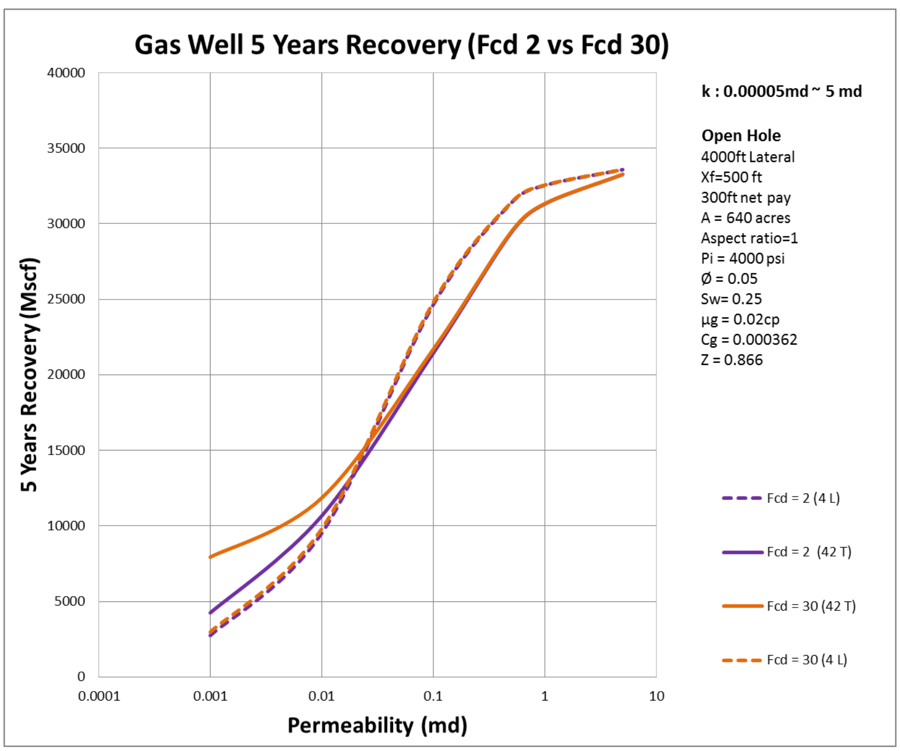

Figure 4.24. Gas Well 5-year Recovery Comparison (F_{CD} 2 vs. F_{CD} 30)

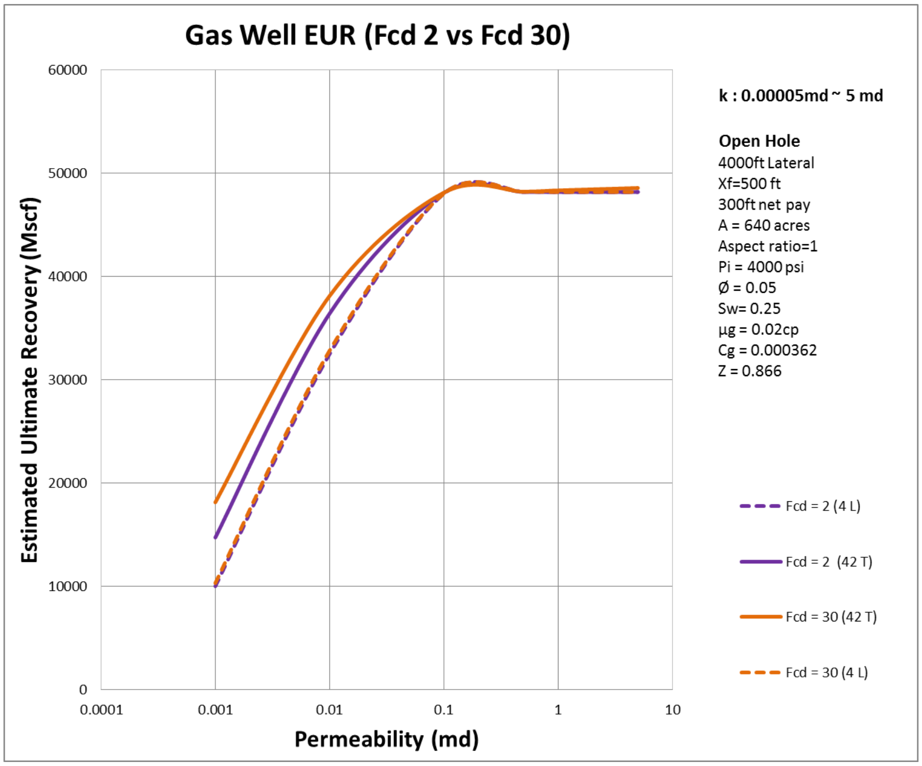

Figure 4.25. Gas Well EUR Comparison (F_{CD} 2 vs. F_{CD} 30)

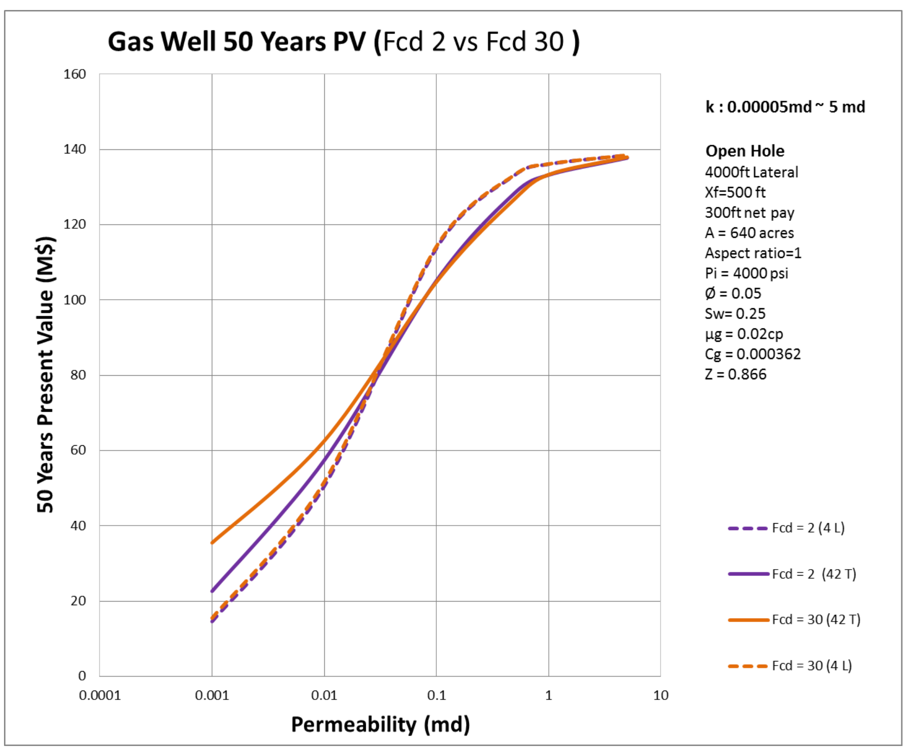

Figure 4.26. Gas Well 50-year PV Comparison (F_{CD} 2 vs. F_{CD} 30)

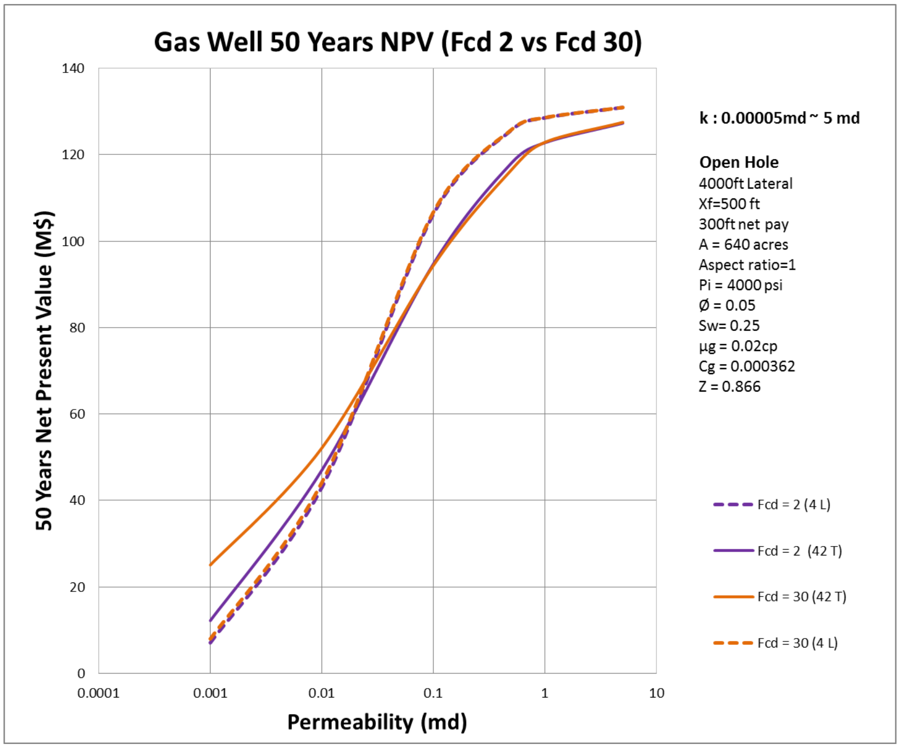

Figure 4.27. Gas Well 50-year NPV Comparison (F_{CD} 2 vs. F_{CD} 30)

The critical reservoir permeability is about the same for both F_{CD} values.

The F_{CD} has negligible effect on the longitudinally fractured horizontal gas wells. However, it affects transverse fracture configuration at gas reservoir permeability below 0.01 md, higher F_{CD} results in better performance.

4.2.2.3 Lateral length (2000 ft vs. 4000 ft). Two lateral length performance was studied: 2000 ft and 4000 ft.

Table 4.4 summaries the cases set up with 2000 ft lateral length.

Figures 4.28 ~ 32 compare the IP, 5-year recovery, EUR, PV and NPV between 42 transverse fractures and four longitudinal fractures at both lateral lengths.

Table 4.4. Gas/Oil Well Simulation Cases (2000 ft Lateral)

Gas/Oil Well Transverse Simulation Cases (2000 ft lateral)					
K	K_f W	F_{CD}	Lateral	X_f	No. of Transverse fractures
(md)	(md.ft)		(ft)	(ft)	
0.00005	0.75	30	2000	500	42
0.0001	1.5	30	2000	500	42
0.001	15	30	2000	500	42
0.01	150	30	2000	500	42
0.1	1500	30	2000	500	42
0.5	7500	30	2000	500	42
1	15000	30	2000	500	42
5	75000	30	2000	500	42
Gas/Oil Well Longitudinal Simulation Cases (2000 ft lateral)					
K	K_f W	F_{CD}	Lateral	X_f	No. of Longitudinal fractures
(md)	(md.ft)		(ft)	(ft)	
0.00005	0.75	30	2000	500	4
0.0001	1.5	30	2000	500	4
0.001	15	30	2000	500	4
0.01	150	30	2000	500	4
0.1	1500	30	2000	500	4
0.5	7500	30	2000	500	4
1	15000	30	2000	500	4
5	75000	30	2000	500	4

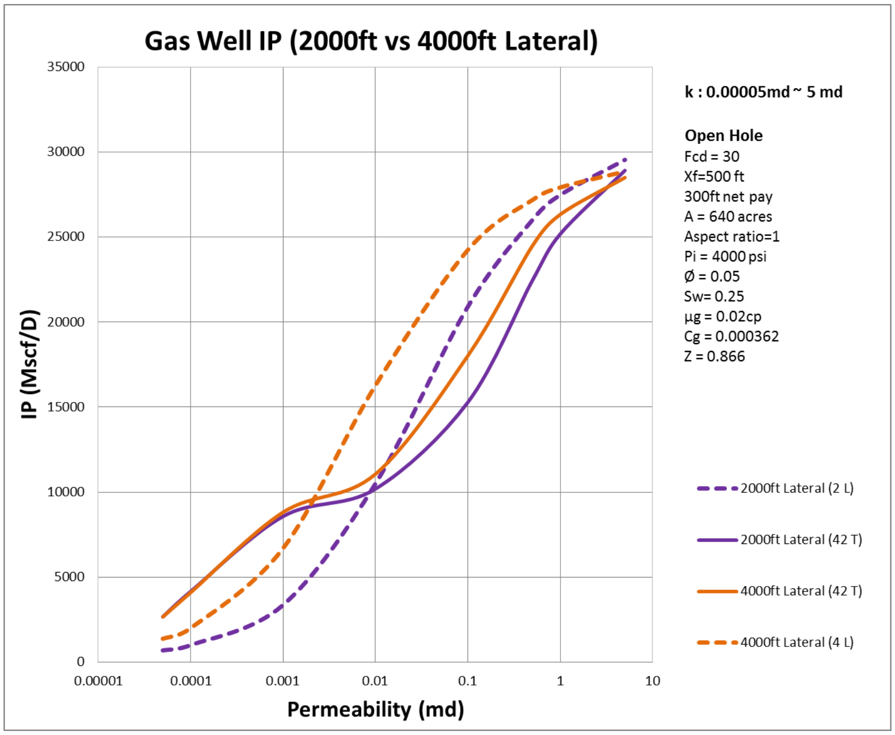

Figure 4.28. Gas Well IP Comparison (2000 ft vs. 4000 ft Lateral)

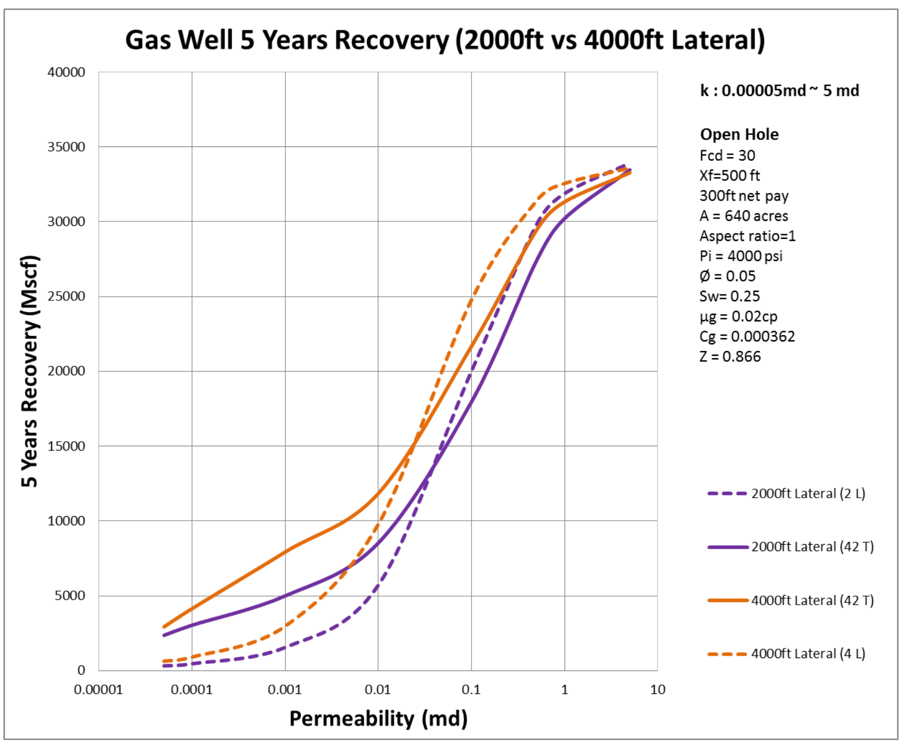

Figure 4.29. Gas Well 5-year Recovery (2000 ft vs. 4000 ft Lateral)

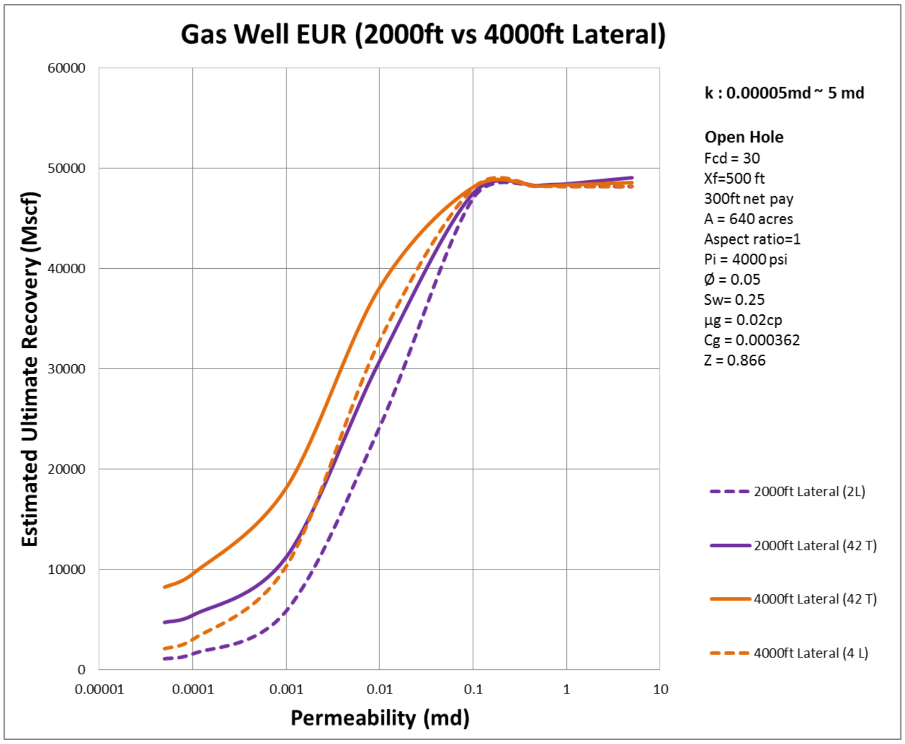

Figure 4.30. Gas Well EUR Comparison (2000 ft vs. 4000 ft Lateral)

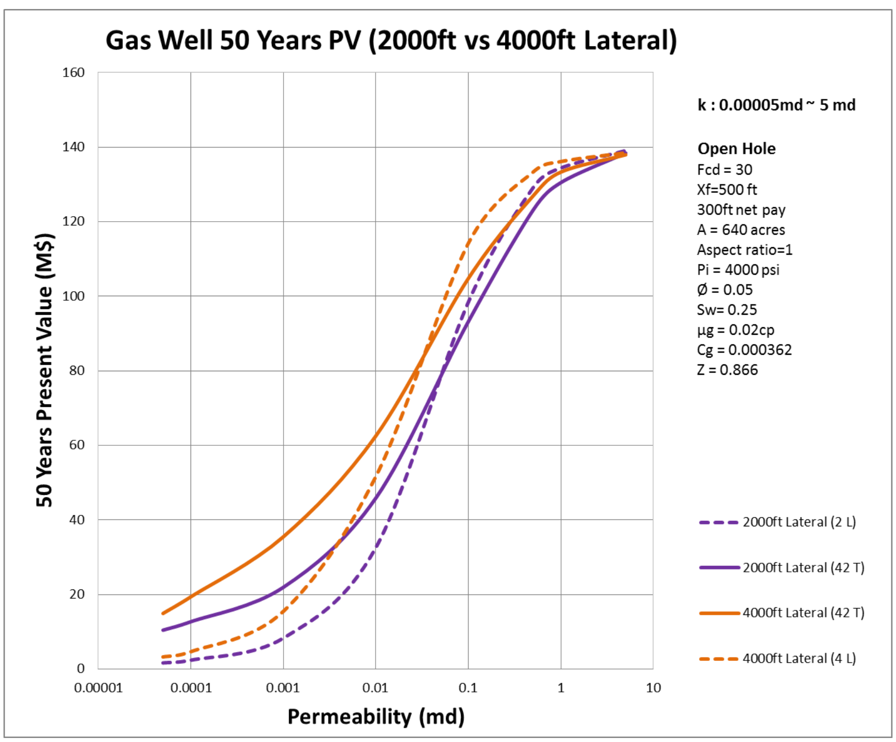

Figure 4.31. Gas Well 50-year PV Comparison (2000 ft vs. 4000 ft Lateral)

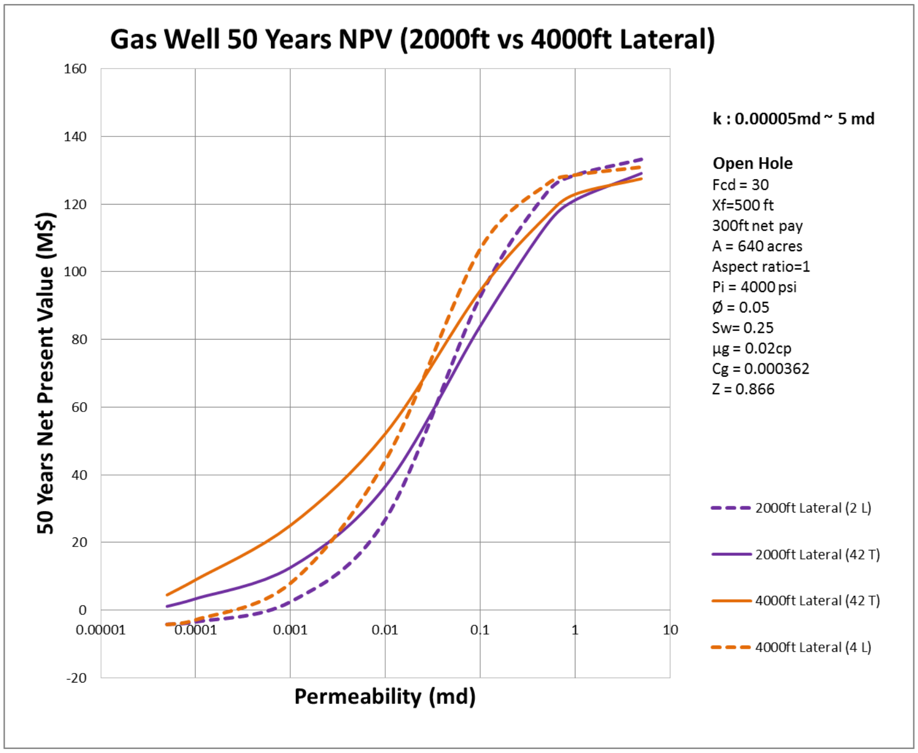

Figure 4.32. Gas Well 50-year NPV Comparison (2000 ft vs. 4000 ft Lateral)

The critical reservoir permeability identified from the 50-year PV comparison is 0.04 md for the 4000 ft lateral cases and 0.05 md for the 2000 ft lateral cases. Shortening the lateral length slightly increases the critical permeability.

For gas reservoir between 0.0001 md to 1 md, higher lateral leads to higher cumulative recovery, PV, and NPV.

When the reservoir permeability is very high (e.g. 1 md), increasing lateral length does not improve well performance significantly for a given drainage area.

For gas reservoir, at reservoir permeability below 0.01 md, a transverse fractured horizontal well performs better than a longitudinal one. At reservoir permeability above 0.1 md, a longitudinal fractured horizontal well performs better.

4.2.2.4 Fracture half-length (250 ft vs. 500 ft). Two fracture half-lengths were studied: 250 ft and 500 ft (Table 4.5).

Table 4.5. Gas/Oil Well Simulation Cases (X_f = 250 ft)

Gas/Oil Well Transverse Simulation Cases (X_f = 250 ft)					
K	K_f W	F_{CD}	Lateral	X_f	No. of Transverse fractures
(md)	(md.ft)		(ft)	(ft)	
0.0001	0.75	30	2000	250	42
0.001	7.5	30	2000	250	42
0.01	75	30	2000	250	42
0.1	750	30	2000	250	42
0.5	3750	30	2000	250	42
1	7500	30	2000	250	42
5	37500	30	2000	250	42
Gas/Oil Well Longitudinal Simulation Cases (X_f = 250 ft)					
K	K_f W	F_{CD}	Lateral	X_f	No. of Longitudinal fractures
(md)	(md.ft)		(ft)	(ft)	
0.0001	0.75	30	2000	250	4
0.001	7.5	30	2000	250	4
0.01	75	30	2000	250	4
0.1	750	30	2000	250	4
0.5	3750	30	2000	250	4
1	7500	30	2000	250	4
5	37500	30	2000	250	4

Figure 4.33 ~.37 compare IP, 5-year recovery, EUR, PV and NPV.

The critical reservoir permeability identified from the 50-year PV comparison is 0.02 md for the 250 ft lateral cases, and it is 0.04 md for the 500 ft lateral cases.

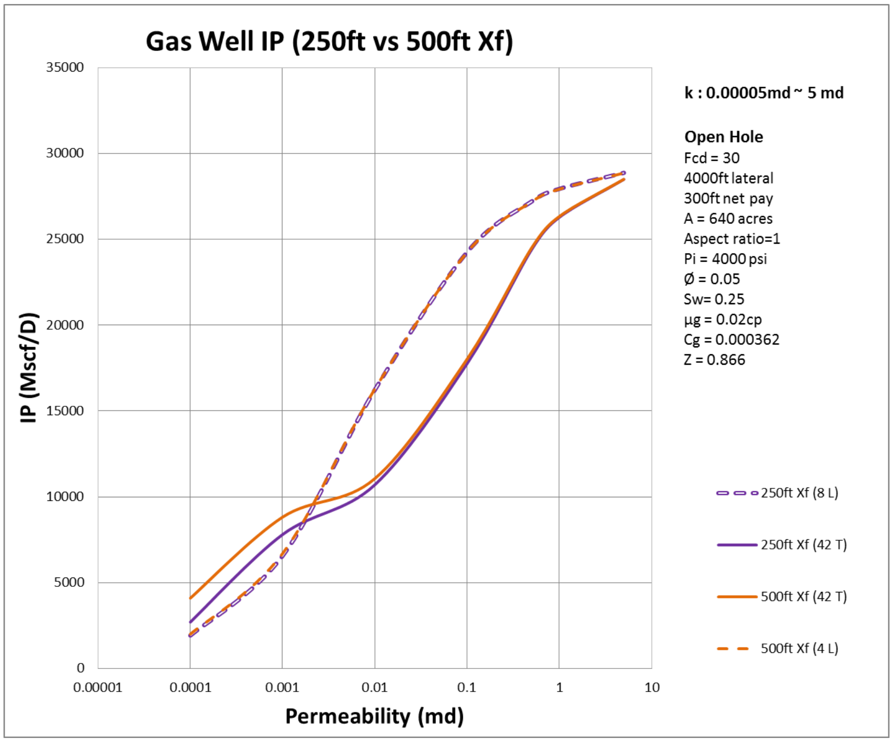

Figure 4.33. Gas Well IP Comparison (250 ft vs. 500 ft Xf)

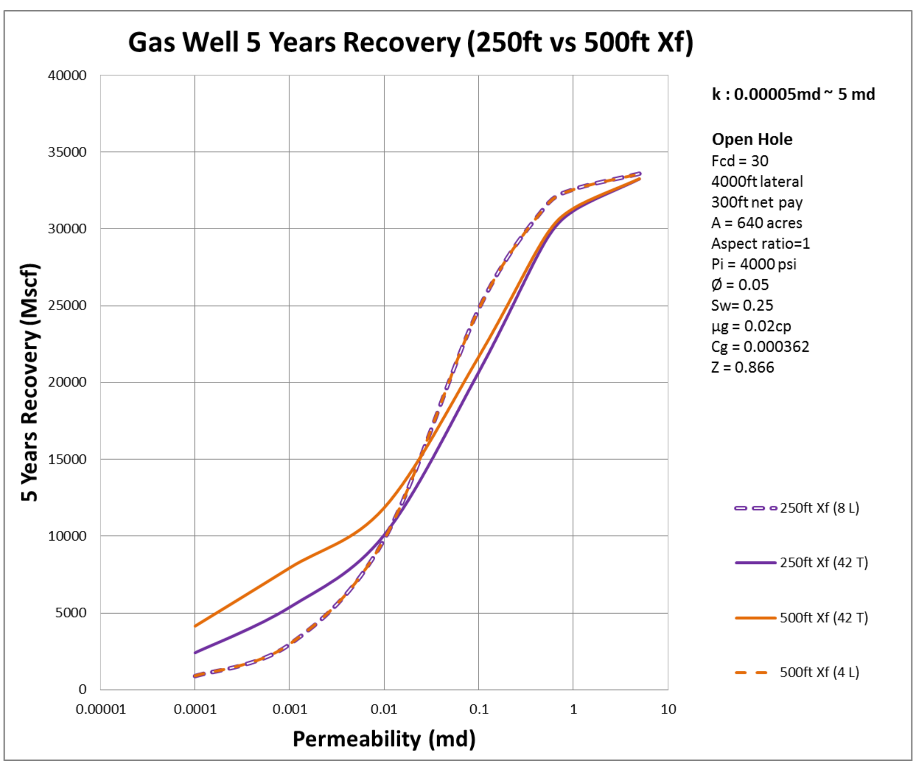

Figure 4.34. Gas Well 5-year Recovery Comparison (250 ft vs. 500 ft Xf)

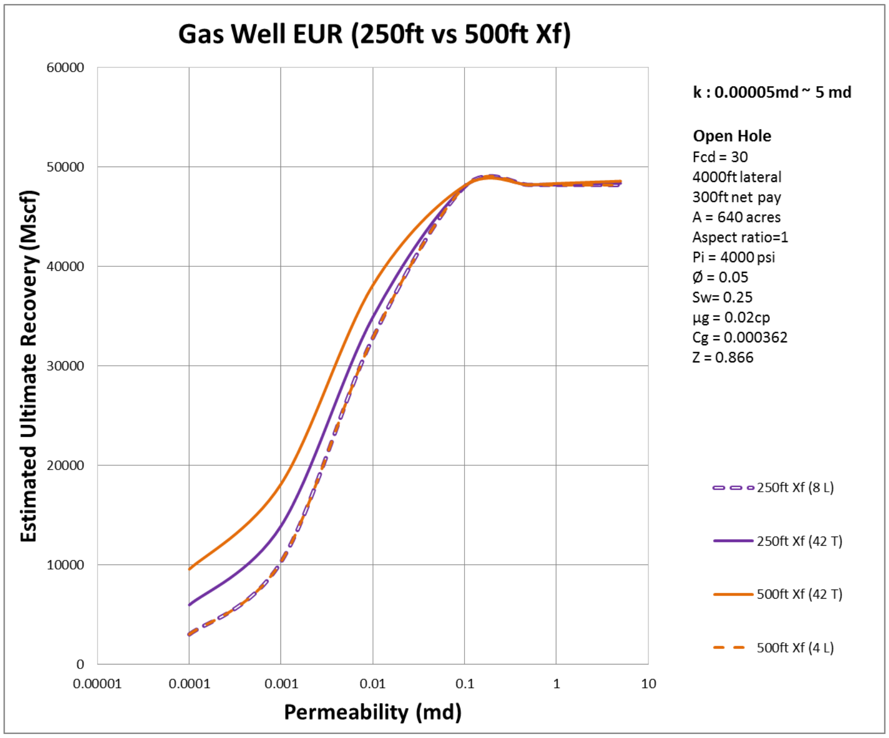

Figure 4.35. Gas Well EUR Comparison (250 ft vs. 500 ft Xf)

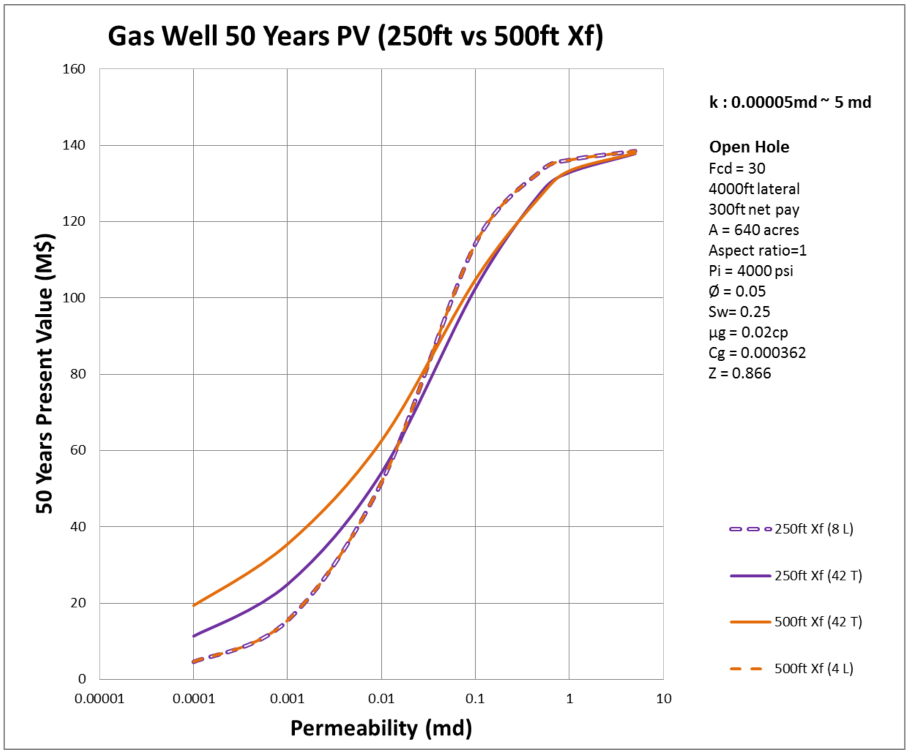

Figure 4.36. Gas Well 50-year PV Comparison (250 ft vs. 500 ft Xf)

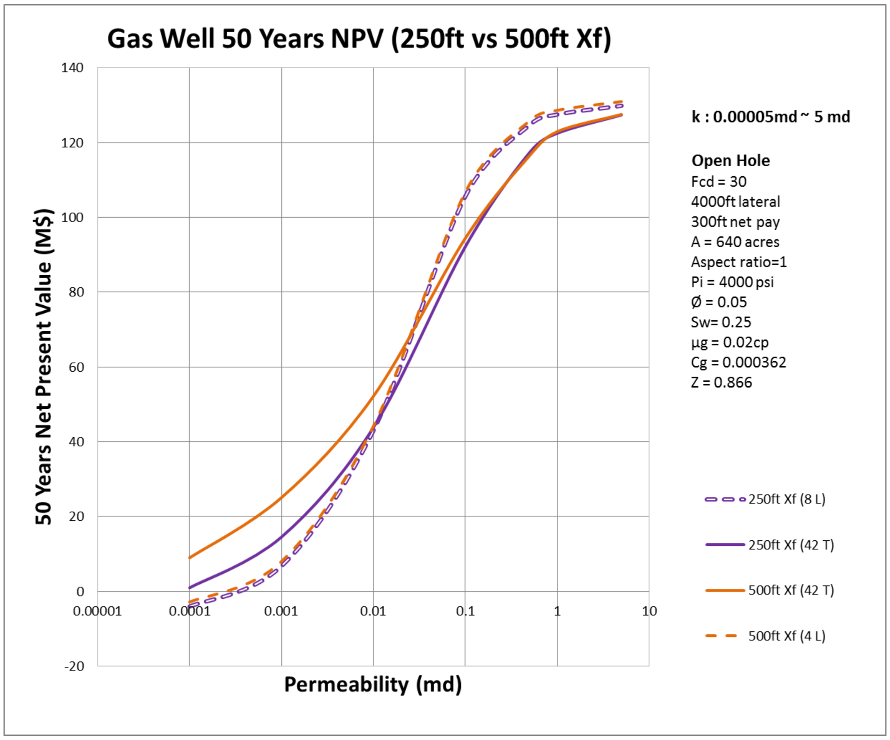

Figure 4.37. Gas Well 50-year NPV Comparison (250 ft vs. 500 ft Xf)

In a gas reservoir, the two fracture half-length cases have similar performance for longitudinally fractured horizontal wells. Changing the fracture half-length does not affect the performance of longitudinal fracture configuration because the dimensionless fracture conductivity is the same. However, it affects transverse fracture configuration at reservoir permeability below 0.01 md, the longer the fracture length, the better the performance of the transverse fractured horizontal well.

Generally, transverse fractured wells performs better than longitudinal ones when the reservoir permeability is below 0.01 md, and longitudinal fracture shows advantage over transverse ones when the reservoir permeability is over 0.1 md.

4.2.2.5 Completion method (Cased Hole vs. Open Hole). Open hole and cased hole completion are the two common completion method that are widely used in industry.

A series of cases with cased hole completion were simulated under varied reservoir permeability (Table 4.2).

Figure 4.38 ~ 42 compare the performance of cased hole completion and open hole completion in terms of IP, 5-year cumulative production, EUR, PV and NPV.

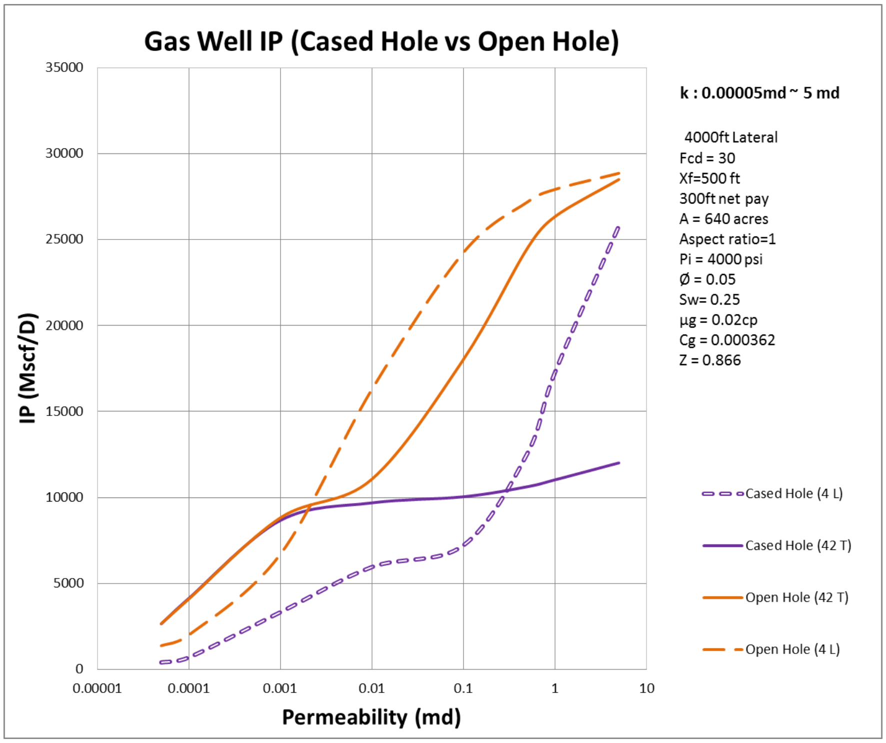

Figure 4.38. Gas Well IP Comparison (Cased Hole vs. Open Hole)

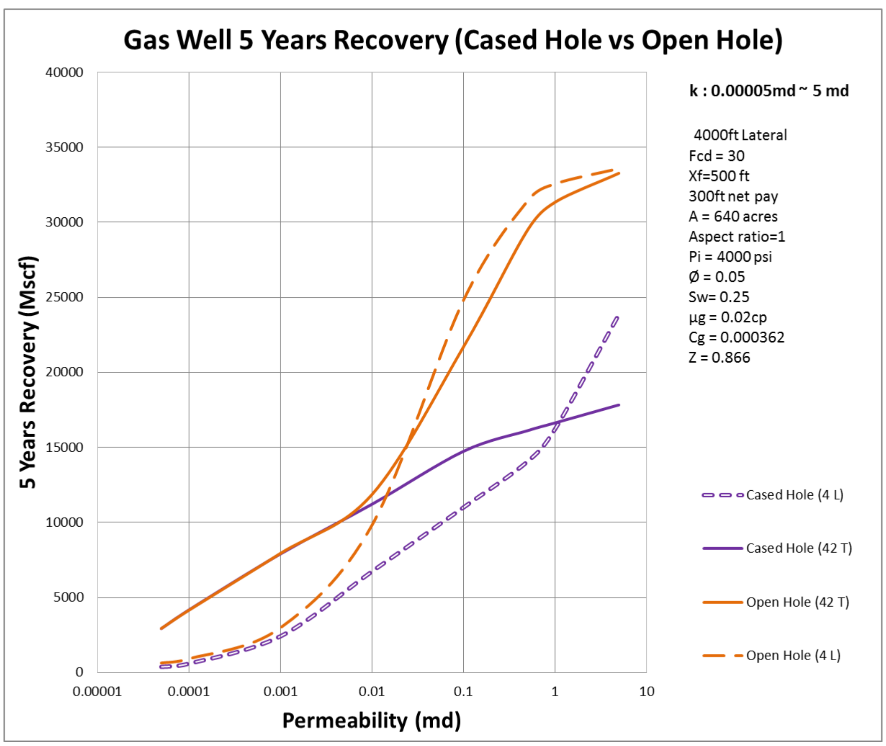

Figure 4.39. Gas Well 5-year Recovery (Cased Hole vs. Open Hole)

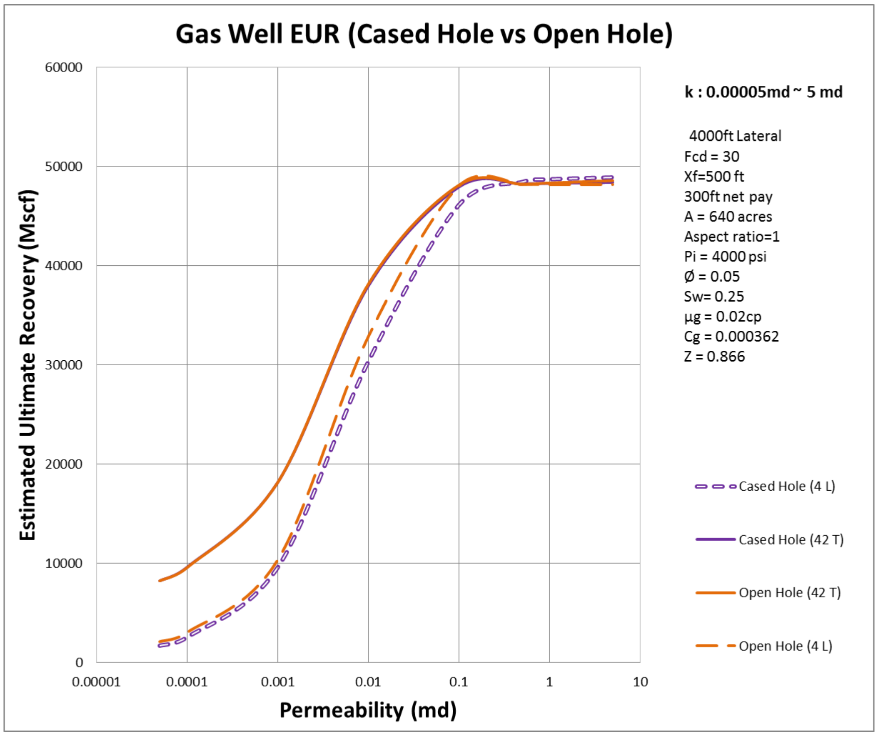

Figure 4.40. Gas Well EUR Comparison (Cased Hole vs. Open Hole)

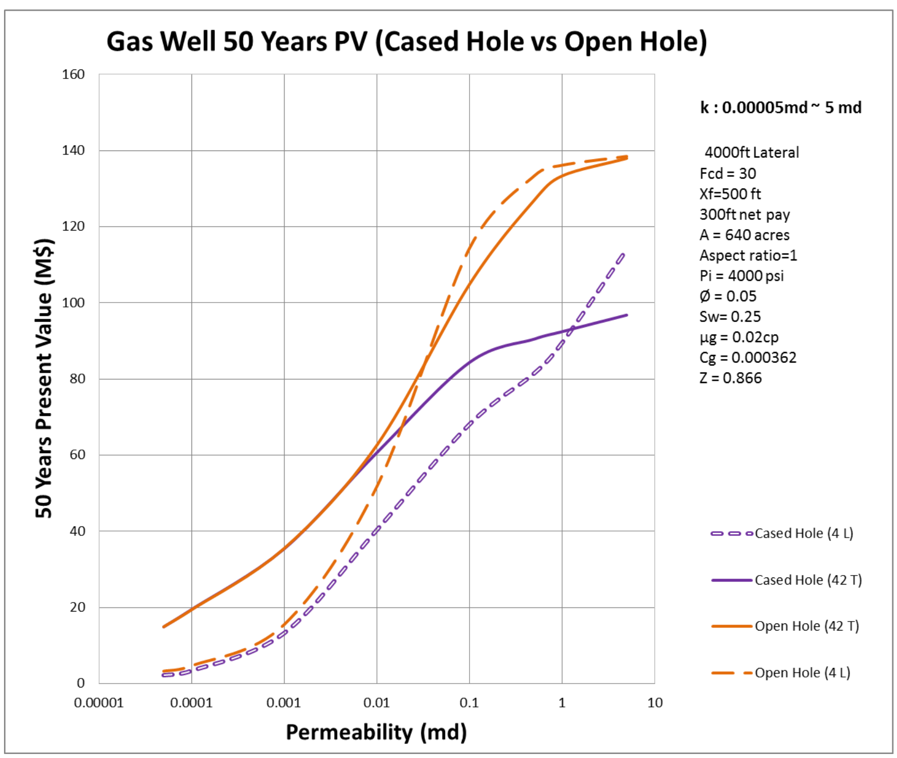

Figure 4.41. Gas Well 50-year PV Comparison (Cased Hole vs. Open Hole

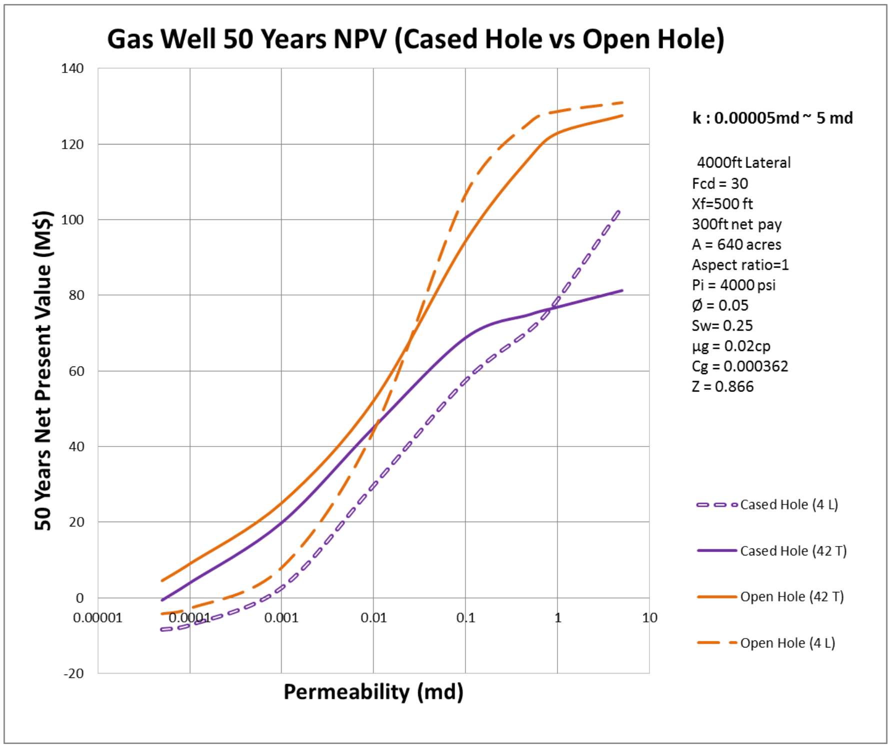

Figure 4.42. Gas Well 50-year NPV Comparison (Cased Hole vs. Open Hole)

For gas reservoir, open hole completion performs better than cased hole completion.

For transverse fracture configuration, open hole completion shows advantage at reservoir permeability higher than 0.01 md.

For longitudinal fracture configuration, open hole system performs better, and show more advantage as reservoir permeability increases.

4.2.2.6 Gas price. Hydrocarbon price is involved in the calculation of PV, which determines the optimal reservoir permeability range for longitudinal fracture configuration of this study.

Based on the Henry Hub Spot price published over the past 10 years, three different Henry Hub spot gas price were picked to evaluate the impact: the highest gas price from 2004 to 2014, the lowest gas price during this period and the current price in July 2014 (Figure 4.43). Both PV and NPV were calculated at each price and compared (Figure 4.44 ~ 47).

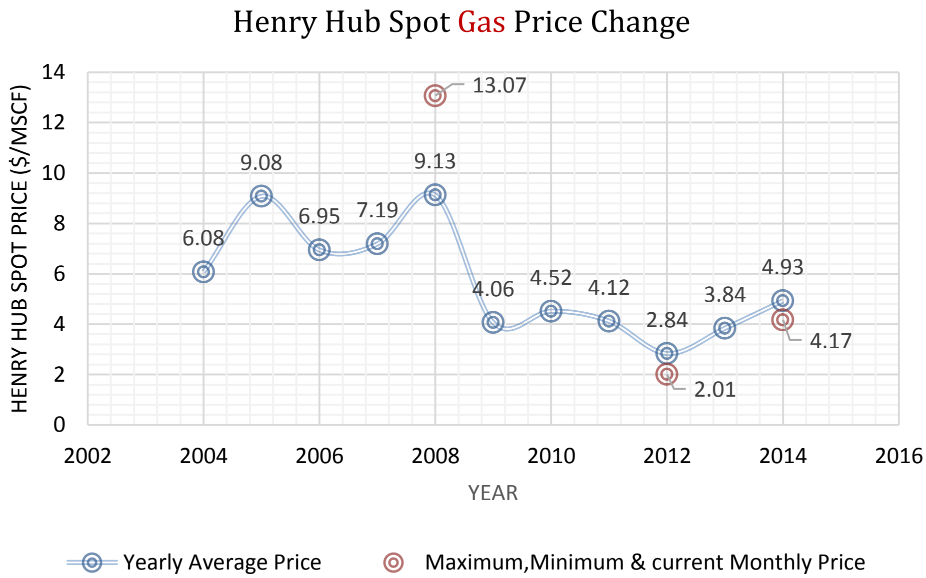

Figure 4.43. Henry Hub Spot Gas Price from 2004 to 2014

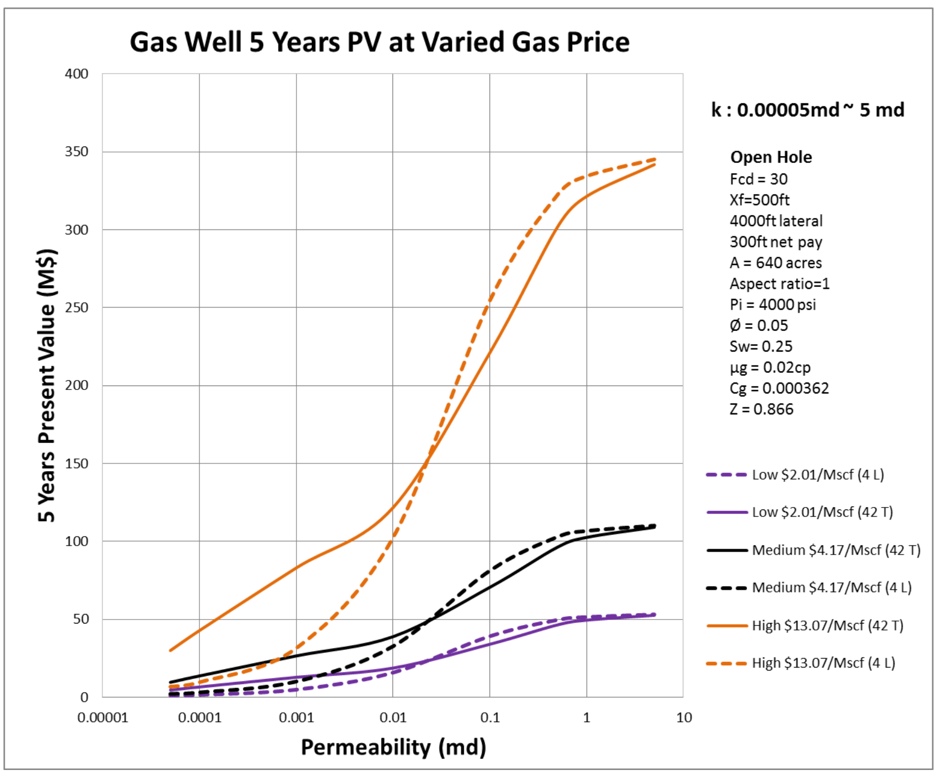

Figure 4.44. Gas Well 5-year PV at Varied Gas Price Comparison

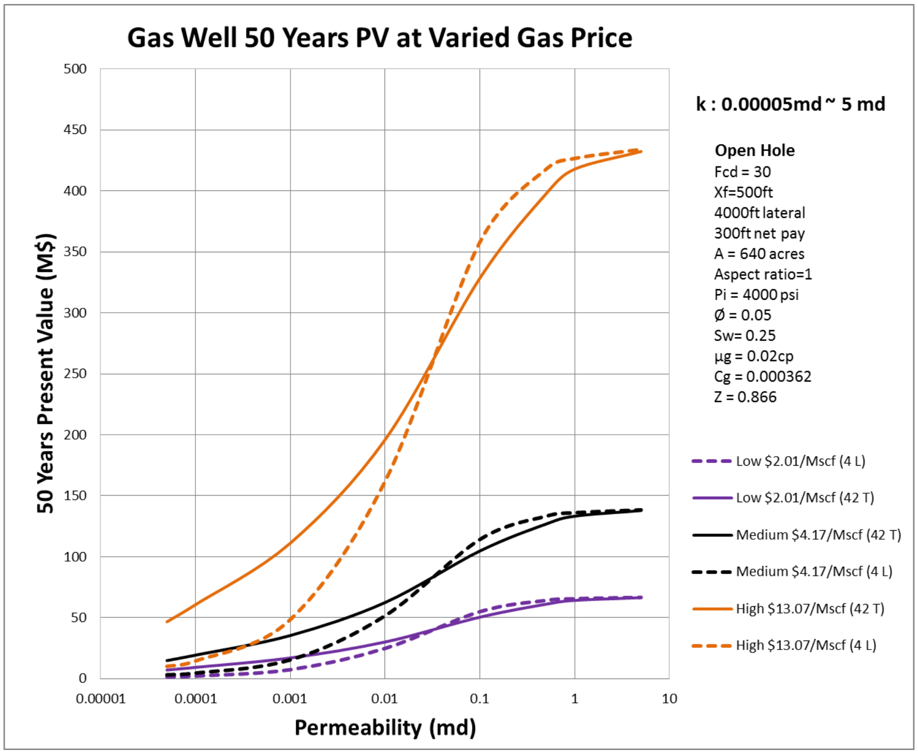

Figure 4.45. Gas Well 50-year PV at Varied Gas Price Comparison

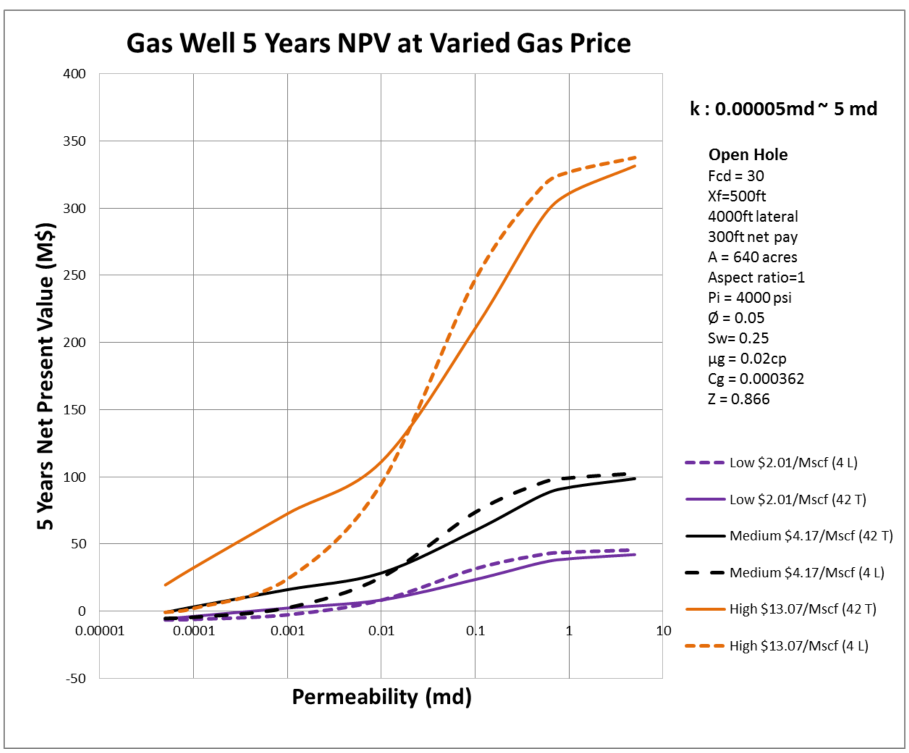

Figure 4.46. Gas Well 5-year NPV at Varied Gas Price Comparison

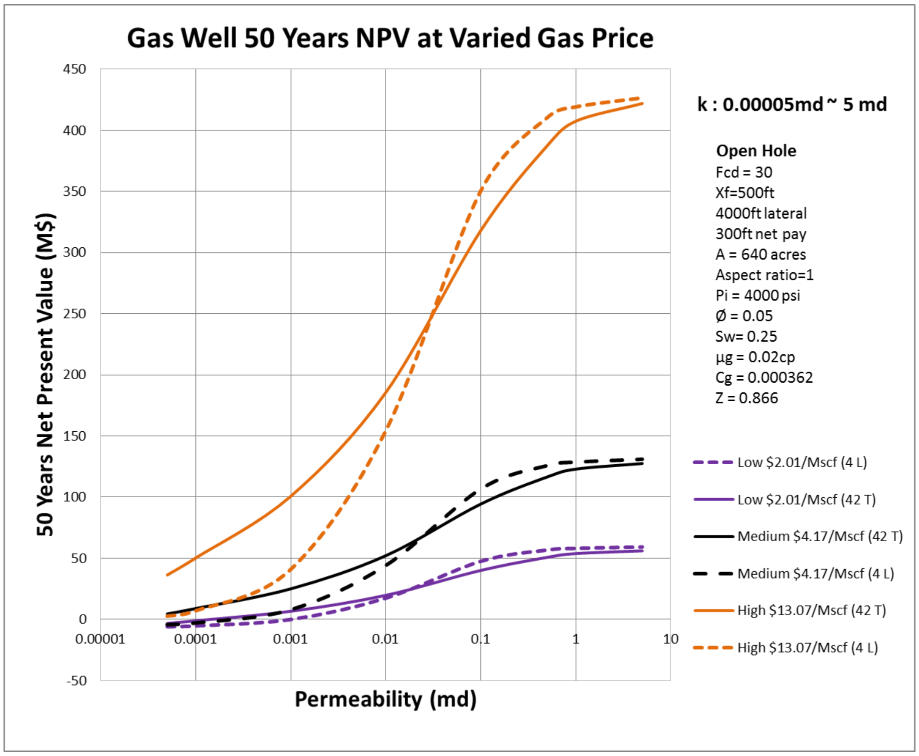

Figure 4.47. Gas Well 50-year NPV Comparison at Varied Gas Price

The critical permeability identified from the 50-year PV comparison is the same (0.05 md) at three different prices.

The critical permeabilities identified from the 5-year PV comparison at three different prices are close to each other.

Oil price has negligible effect on the determination of critical reservoir permeability.

4.2.3. Critical Reservoir Pemeability. This section summarizes the the critical permeability for gas wells in terms of each criterion compared (Table 4.6).

The critical reservoir permeability identifies the reservoir permeability range within which longitudinal fractured horizontal well is preferred. It is the permeability at the cross point of longitudinal and transverse fractured horizontal well performance curve.

Table 4.6. Critical Reservoir Permeability for Gas Wells Simulated

Critical Reservoir Permeability Identified for Gas Well in terms of Varied Comparison Criterion					
Comparison Criterion	Open Hole				Cased Hole
	42T vs. 4L (L=4000 ft X_f=500 ft F_{CD}=30)	42T vs. 2L (L=2000 ft)	42T vs. 8L (X_f =250 ft)	42T vs. 4L (F_{CD} =2)	42T vs. 4L (L=4000 ft X_f =500 ft F_{CD} =30)
IP	0.003 md	0.009 md	0.002 md	< 0.001 md	0.3 md
Annualized 1st Year Rate	0.008 md	0.03 md	0.005 md	0.002 md	0.7 md
EUR	N/A	N/A	N/A	N/A	**0.5 md**
5-year Recovery	0.03 md	0.04 md	0.01 md	0.02 md	1.2 md
50-year DR	0.04 md	0.05 md	0.02 md	0.03 md	1.5 md
5-year DR	0.03 md	0.04 md	0.01 md	0.02 md	1 md
50-year PV	**0.04 md**	**0.05 md**	**0.02 md**	**0.03 md**	**1.5 md**
5-year PV	0.03 md	0.04 md	0.01 md	0.02 md	1 md
50-year NPV	0.03 md	0.04 md	0.01 md	0.02 md	0.8 md
5-year NPV	0.02 md	0.03 md	0.007 md	0.01 md	0.6 md
Beyond critical permeability, longitudinal configuration outperforms transverse configuration. (0.00005 md ~ 5 md studied)					

The lateral length, fracture half-length, fracture conductivity, and gas price have negligible effect in identifying critical reservoir permeability. However, completion method has a significant impact.

According to 50-year PV in a gas reservoir, with open hole completion, longitudinal fractured horizontal well outperforms transverse fractured well when the reservoir permeability is over 0.04 md. However, with cased hole completion, longitudinal fractured horizontal well performs better at reservoir permeability over 1.5 md.

In a gas reservoir, with cased hole completion, longitudinal fractures yields higher EUR at reservoir permeability over 0.5 md.

4.3. OIL WELL SIMULATION

The production from transversely and longitudinally fractured wells were compared for an oil reservoir. Major influencing factors were discussed, including number of fractures, F_{CD}, lateral length, fracture half-length, completion method, and gas price.

The oil well simulation results and the calculated economic parameters are listed in Appendix B.

4.3.1. Comparison of Transverse & Longitudinal Configurations.

4.3.1.1 IP & annualized 1st year rate. Figure 4.48 compares the Initial Potential of transverse fracture configuration and longitudinal fracture configuration in oil formation over varied permeability.

For transvers fractures, IP increases with the number of fractures. As permeability drops below 0.001 md, the influence of fracture number on IP tends to diminish (Figure 4.48). When the oil reservoir permeability is over 0.08 md, four longitudinal fractures creates higher IP than 42 transverse fractures.

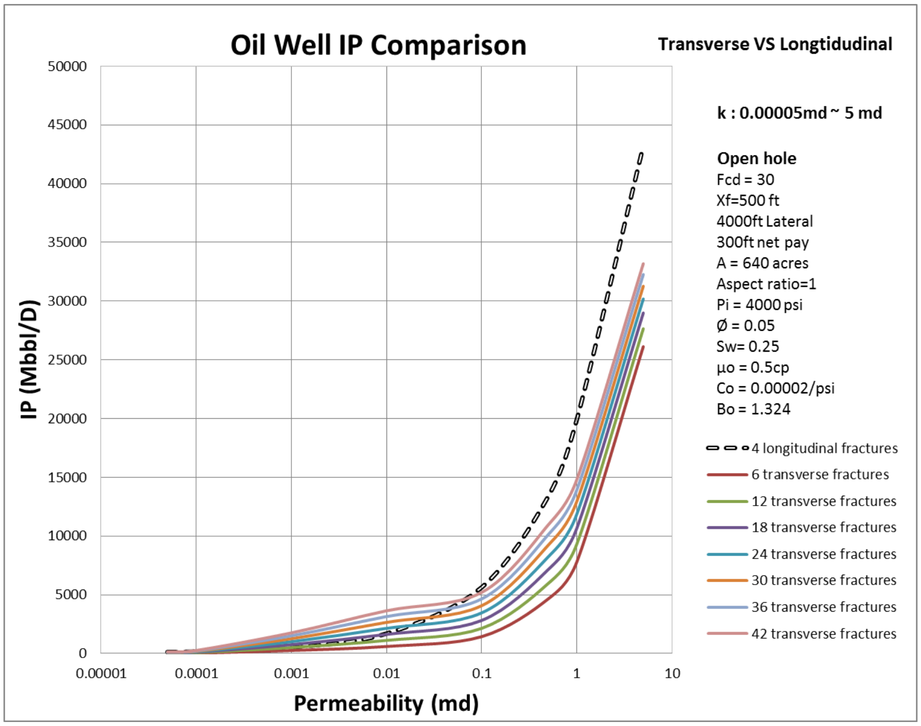

Figure 4.48. Oil Well IP Comparison

The annualized 1st year rates of two fracture configurations show similar features (Figure 4.49). More transverse fractures yields higher 1st year annualized rate. Four longitudinal fractures result in higher annualized 1st year rate than 42 transverse fractures when reservoir permeability is over 0.2 md.

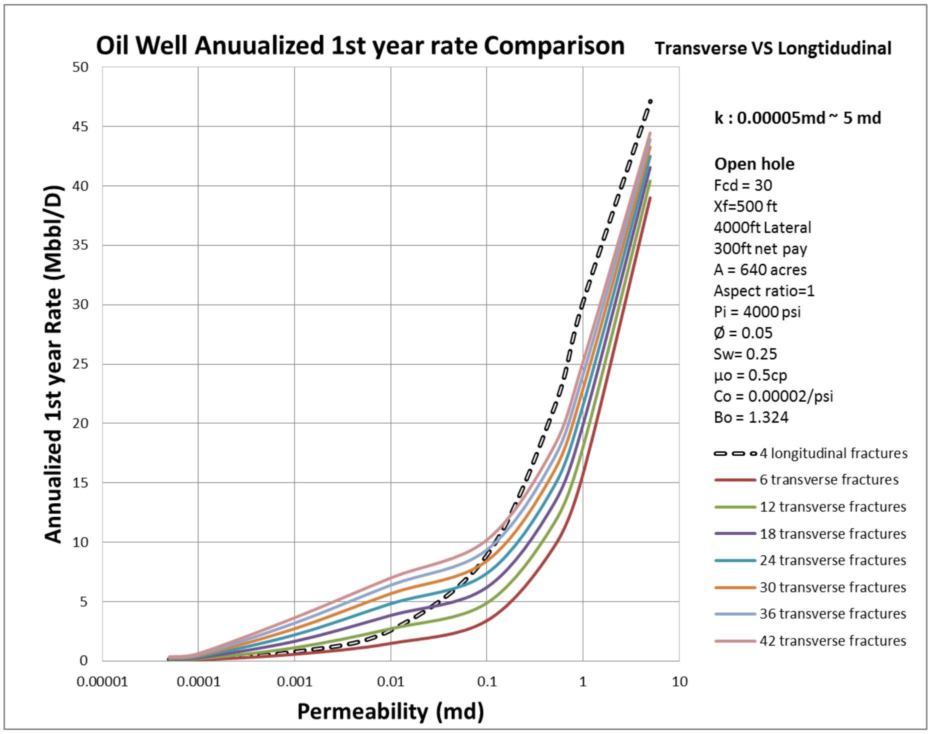

Figure 4.49. Oil Well Annualized 1st Year Rate Comparison

4.3.1.2 Cumulative production. To compare the cumulative production between the two configurations, two sets of plots were made: 1) Cumulative production vs. time and 2) cumulative production vs. permeability.

Figure 4.50 shows the cumulative recovery of the horizontal well with 42 transverse fractures over 50 years. Figure 4.51 shows the cumulative recovery of the horizontal well with four longitudinal fractures over 50 years.

The cumulative production of fractured horizontal oil well with 42 transverse (solid line) and those with four longitudinal fractures (dash line) were compared at four different reservoir permeabilities (Figure 4.52).

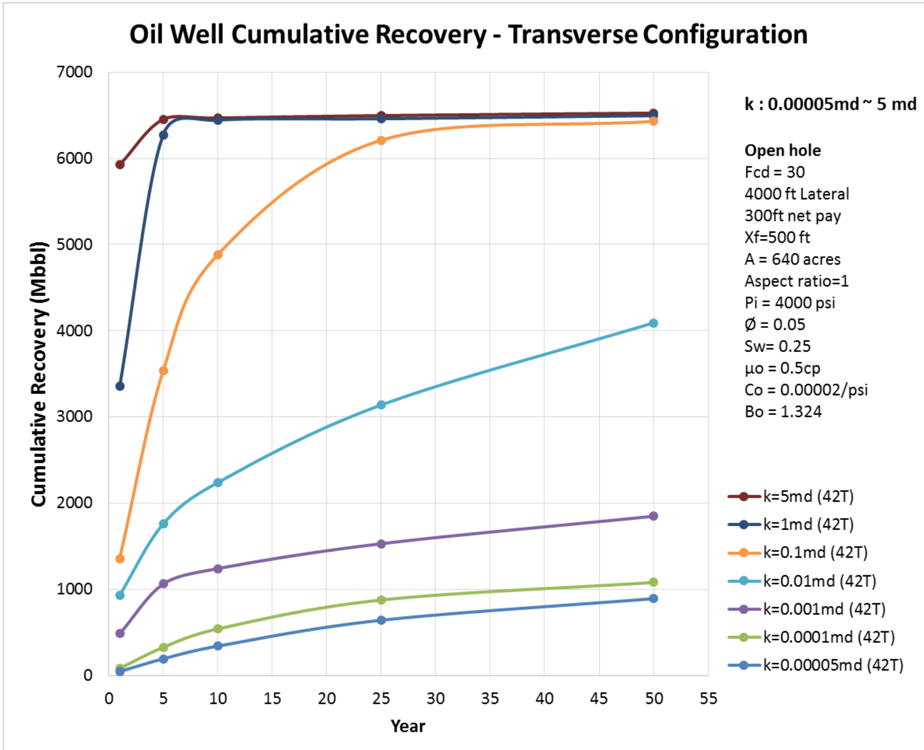

Figure 4.50. Oil Well Cumulative Recovery over 50 Years (42 T)

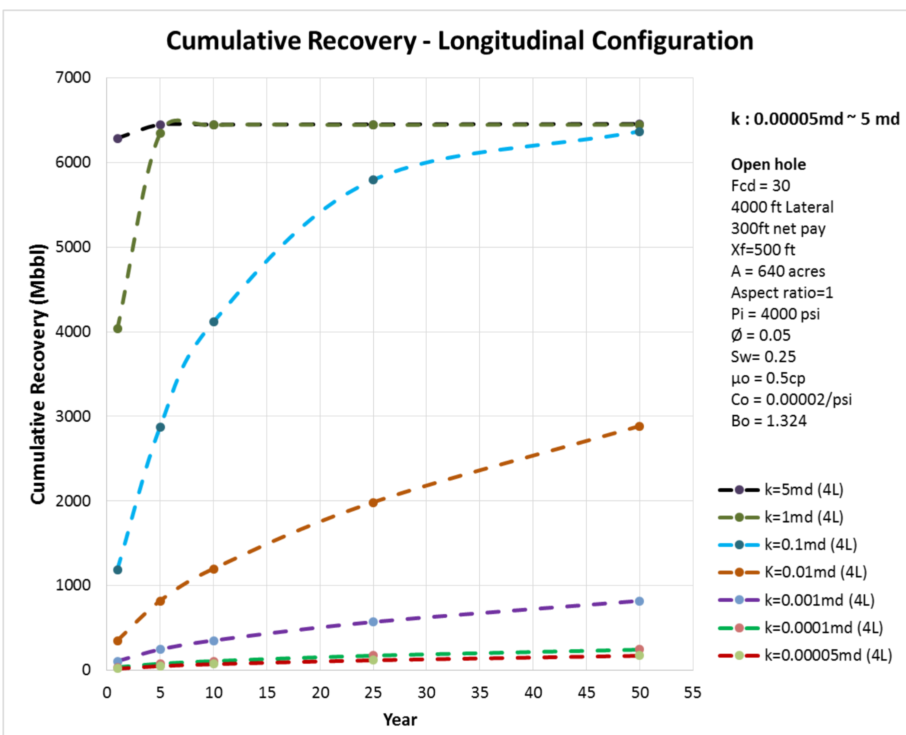

Figure 4.51. Oil Well Cumulative Recovery over 50 Years (4 L)

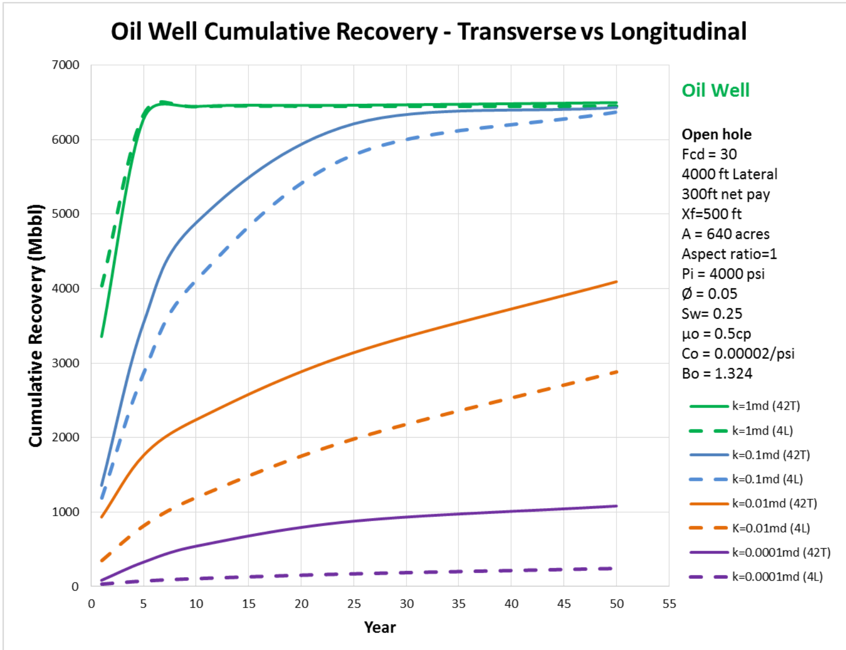

Figure 4.52. Oil Well Cumulative Recovery over 50 Years (42 T vs. 4 L)

The first 5-year are the most productive period for both configurations. Afterwards, the production depends on reservoir permeability.

When the reservoir permeability is higher than 1 md, most of the gas in the 640 acres reservoir can be extracted within 5 years, and very few production occurs after 5 years.

When the reservoir permeability is 0.01 md, the production steadily increases after 10 years, which means the well may produce for a longer time.

When the reservoir permeability falls into unconventional reservoir range (e.g. k = 0.00005 md), the cumulative production is lower over 50 years for both fracture configurations.

Overall, transverse fracture configuration shows higher production at reservoir permeability lower than 0.1 md. Longitudinal configuration yields higher recovery when the reservoir permeability increases from 0.1 md to 1 md.

The cumulative production of one year, 5 years, 10 years, and 50 years from the two fracture configurations were compared at reservoir permeability ranging from 50 nD to 5 md (Figure 4.53 ~ 4.56).

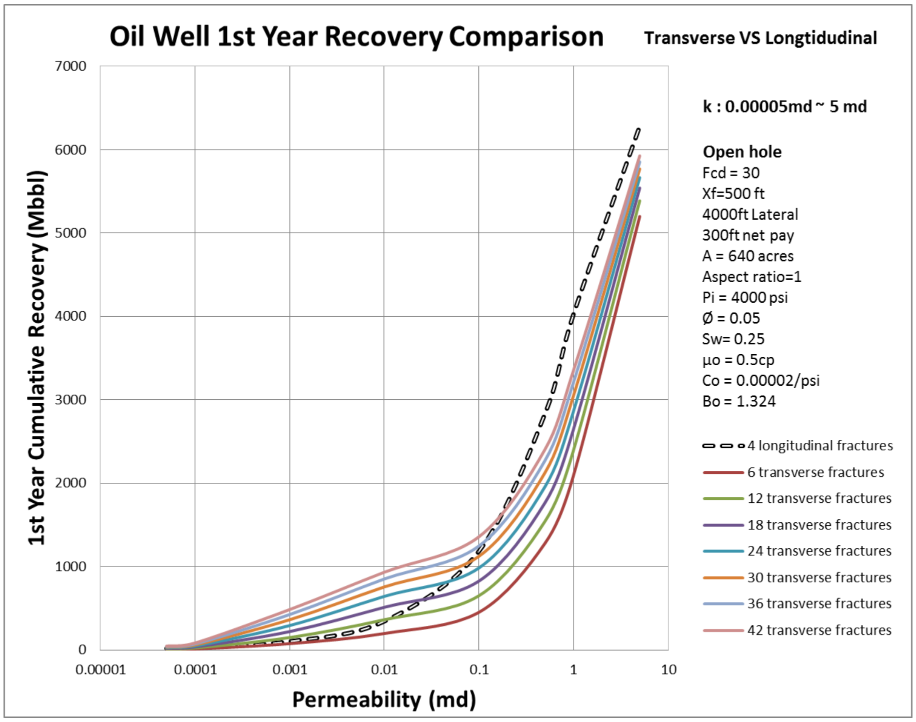

Figure 4.53. Gas Well 1st Year Recovery Comparison

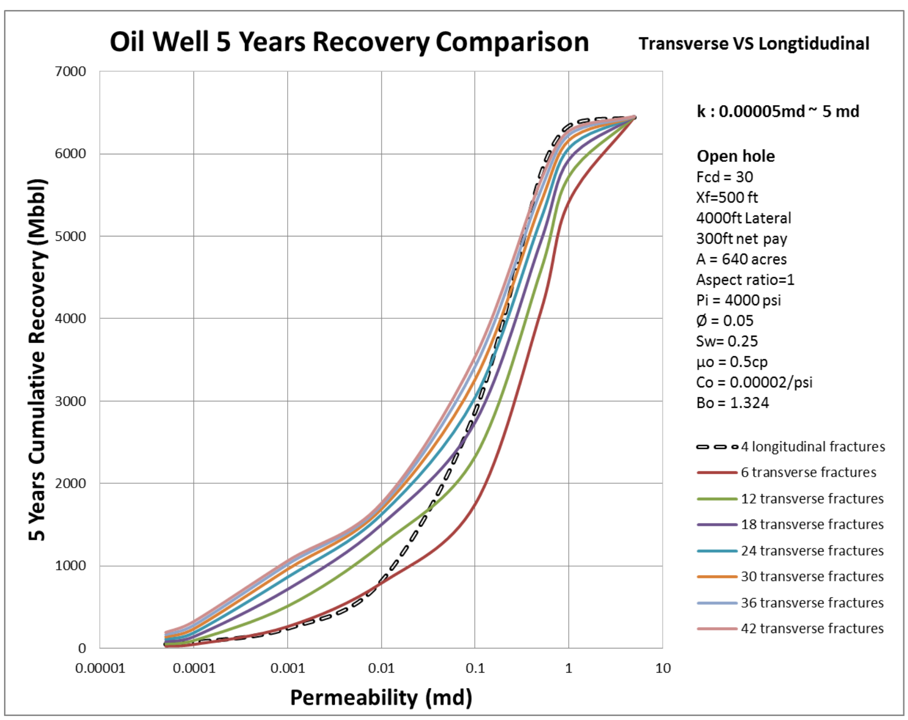

Figure 4.54. Oil Well 5-year Recovery Comparison

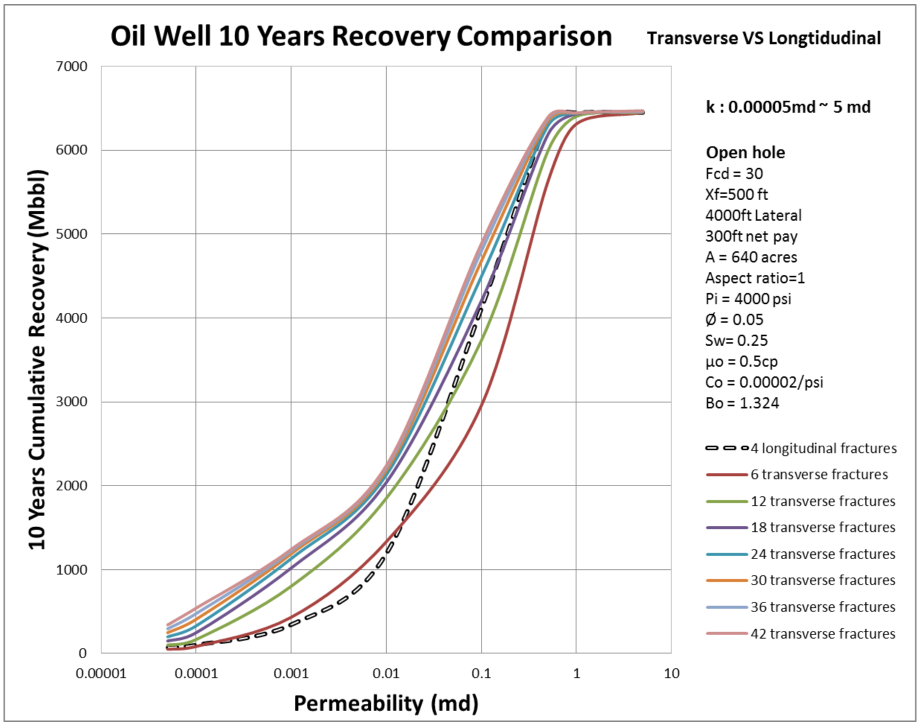

Figure 4.55. Oil Well 10-year Recovery Comparison

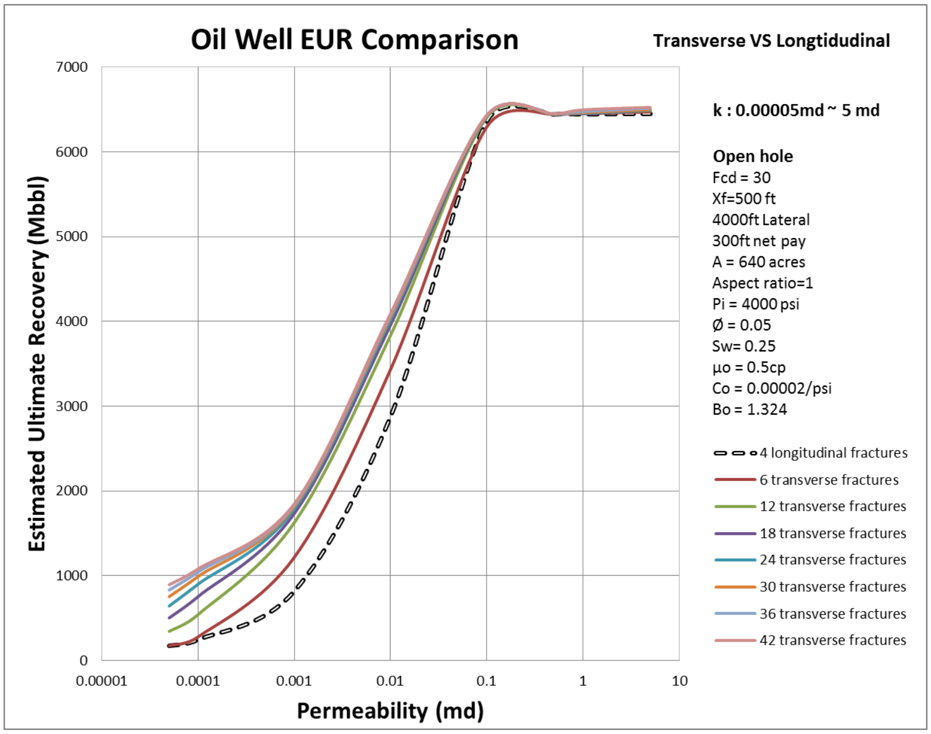

Figure 4.56. Gas Wells EUR Comparison (50-year Recovery)

The critical reservoir permeability identified from above plots is summarized in table 4.7. It is 0.4 md in terms of 5-year cumulative production, which means at reservoir permeability over 0.4 md, the 5-year total recovery from longitudinal fractured well is higher than it from transverse fractured well.

Longitudinal fracture configuration has similar EUR as transverse fracture configuration in high permeability reservoir. However, at permeability lower than 0.1 md, the advantage of transverse configuration is obvious.

4.3.1.3 DR. Figure 4.57 investigates the discounted recovery change over time for horizontal well with 42 transverse fractures and horizontal well with four longitudinal fractures.

The DR increases sharply during the first five years and turns to stabilize at a low increasing rate after five years.

The DR increases very slowly at the later period for both very low and very high permeability cases (k=0.0001 md and 1 md). For these formations, most of the recoverable reserve in the given drainage (640 acres) can be produced in less than 10 years because the DR hardly increases later on.

For formation with a permeability of 0.01 md or 0.1 md, the DR slowly increases after 10 years. The wells are still productive, but may not be economically beneficial.

As to the fracture configuration, Fractured transverse fracture has higher DR at low reservoir permeability ($k < 0.01$ md), while four longitudinal fracture performs better at 0.1 md; however, the advantage of transverse fracture on DR at 1 md is not as prominent as that of longitudinal fracture at 0.1 md.

Figure 4.58 and Figure 4.59 compare the DR of the two fracture configurations at 5 years and 50 years. The critical reservoir permeability is between 0.1 md to 1 md. Above this permeability, four longitudinal fractures perform better than transverse fractures. Below this value, transverse fractures perform better.

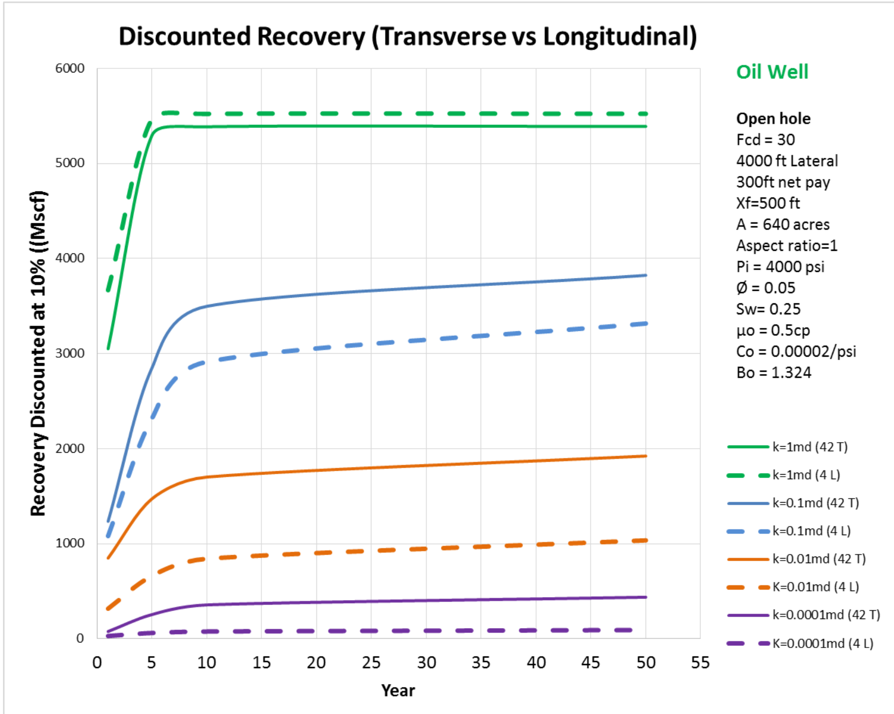

Figure 4.57. Oil Well DR over 50 Years (42 T vs. 4 L)

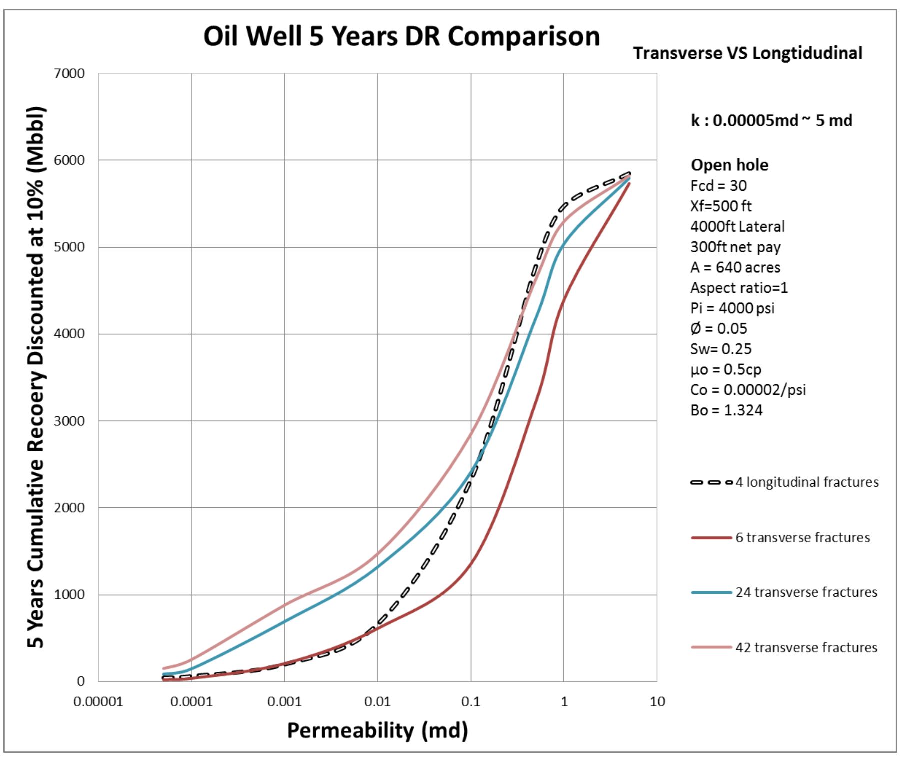

Figure 4.58. Oil Well 5-year DR Comparison

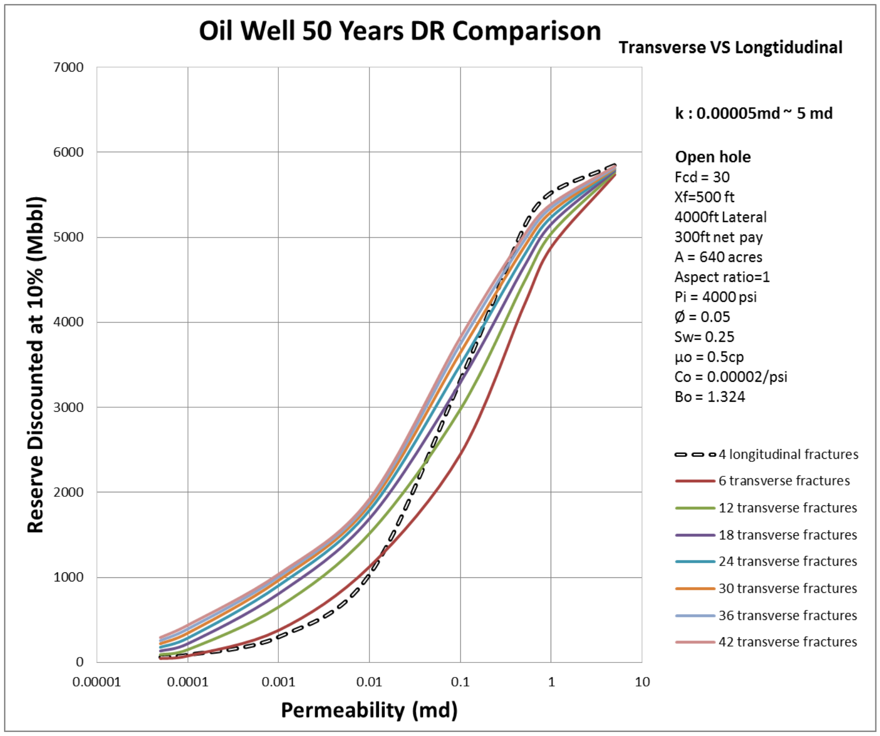

Figure 4.59. Oil Well 50-year DR Comparison

4.3.1.4 PV. The oil price is set at $103.59/bbl according to the West Texas Intermediate (WTI) spot crude oil price in July 2014.

Figure 4.60 shows the change of PV over time for both fracture configurations. The PV increases sharply in the five years and then reaches a plateau for reservoirs with permeability of 0.0001 md and 1 md. This suggests continuing production after five years may not be beneficial.

For reservoir with a permeability of 0.01 md or 0.1 md, PV slowly increases after 10 years. The wells are still productive, but may not be economically beneficial when time is taken into account.

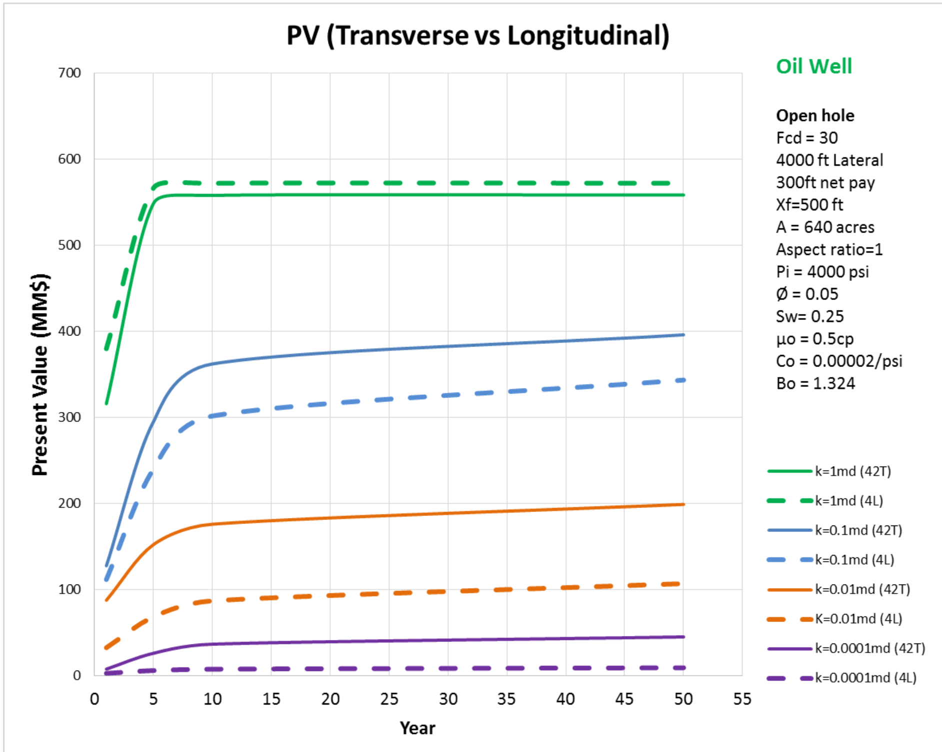

Figure 4.60. Oil Well PV over 50 Years (42 T vs. 4 L)

Fractured well with 42 transverse fractures (solid line) has higher PV in low permeability reservoir (0.1md, 0.01 md and 0.0001 md), while fractured well with four longitudinal fractures (dash line) shows higher PV in high permeability reservoir (k = 1 md).

Figure 4.61 and Figure 4.62show the 5-year and 50-year PV of the horizontal well with transverse fractures and the same horizontal well with longitudinal fractures.

The critical reservoir permeability identified is 0.4 md according to 50-year PV comparison. In oil reservoir, when the permeability is over 0.4 md, a longitudinal fractured horizontal well is more beneficial than a transverse one.

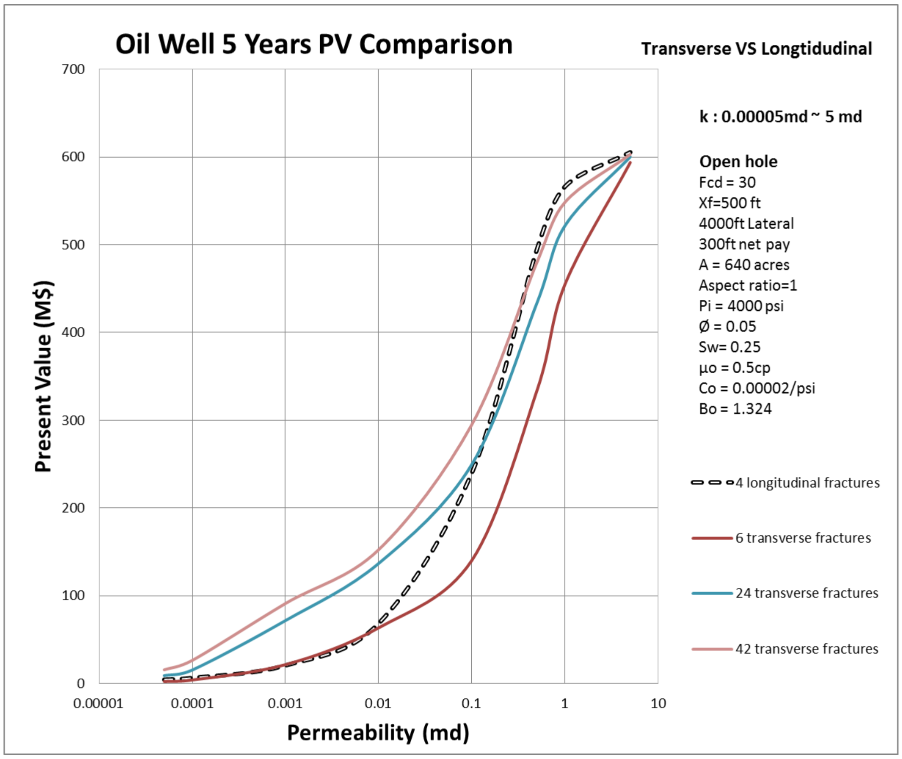

Figure 4.61. Oil Well 5-year PV Comparison

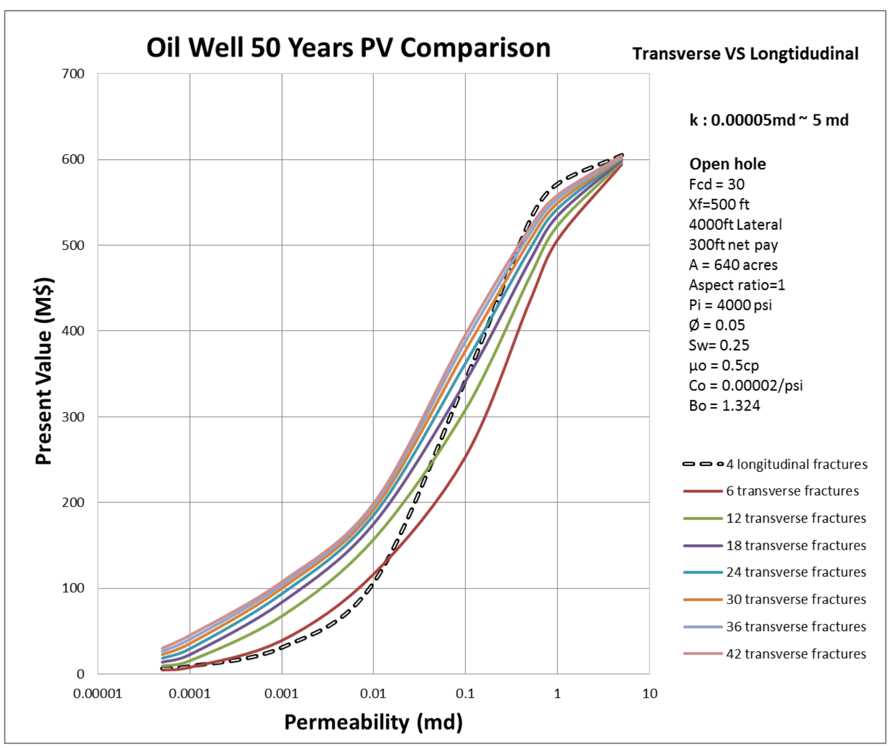

Figure 4.62. Oil Well 50-year PV Comparison

4.3.1.5 NPV. Figure 4.63 shows the change of NPV over time for both transverse and longitudinal configurations.

NPV increases rapidly in the first five to ten years. At the reservoir permeability of 0.0001 md and 1 md, it reaches a plateau after about ten years. At reservoir permeability of 0.01 md and 0.1 md, NPV is slowly increasing after ten years. Although NPV increases, producing the well after ten years may not be economically beneficial.

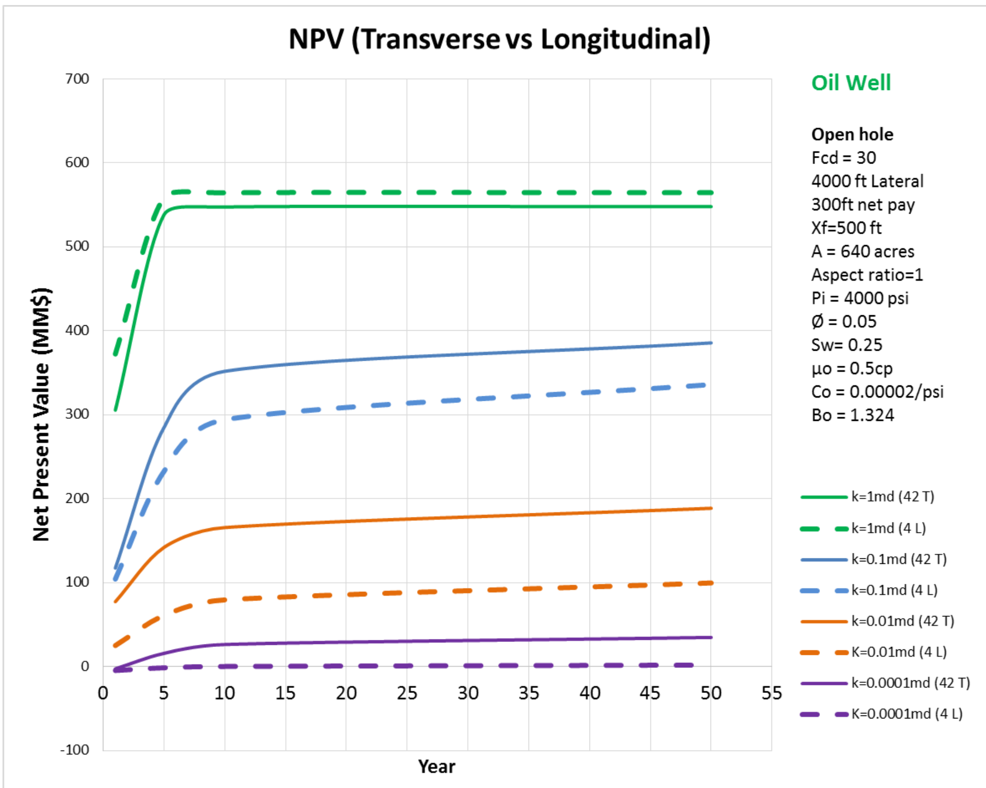

Figure 4.63. Oil Well NPV over 50 Years (42 T vs. 4 L)

It is also illustrated that fractured well with 42 transverse fractures (solid line) has higher NPV at low reservoir permeability (k < 0.1 md), while fractured well with four longitudinal fractures (dash line) perform better at high reservoir permeability (k = 1 md).

The permeability threshold are found similar to each other based on the 5-year (Figure 4.64) and 50-year NPV (Figure 4.65) comparison.

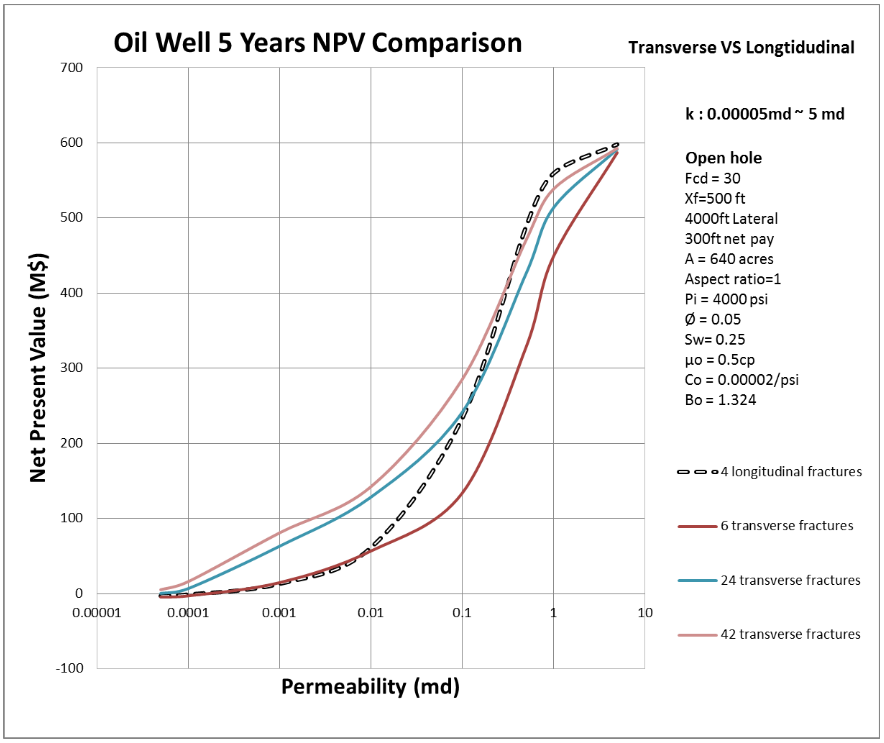

Figure 4.64. Oil Well 5-year NPV Comparison

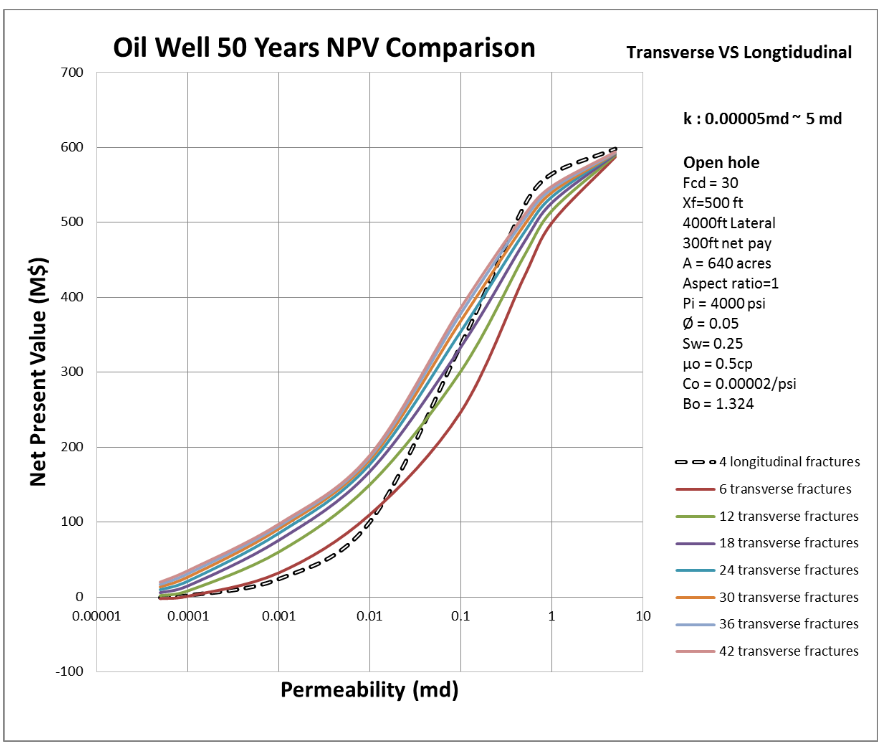

Figure 4.65. Oil Well 50-year NPV Comparison

In summary, for oil wells with open hole completion, longitudinal configurations outperform transverse at reservoir permeability over 0.4 md. The comparison of cumulative production, DR, PV and NPV identify the similar critical permeability (Table 4.7), which is within the same permeability range (0.1 md to 1 md).

4.3.2. Sensitivity Study. The effect of important parameters on the determination of fracture configuration was studied. The parameters include the number of fractures, F_{CD}, lateral length, fracture half-length, completion method, and oil price.

4.3.2.1 Number of fractures. The number of longitudinal fractures maintains at four because four 500 ft results in a total fracture length of 4000 ft, which is the same as the lateral length.

The number of transverse fractures increases to 100. All other parameters are unchanged. Figures 4.66~69 compare the IP, EUR, PV and NPV of 100 transverse fractures and four longitudinal fractures.

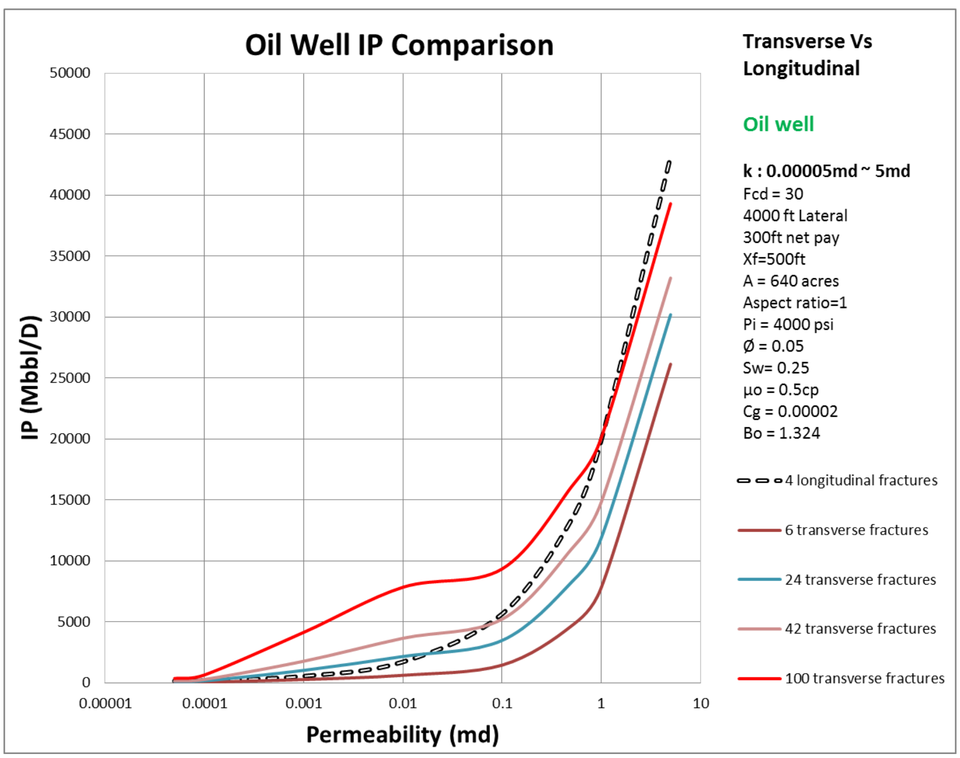

Figure 4.66. Oil Well IP Comparison (100 T vs. 4 L)

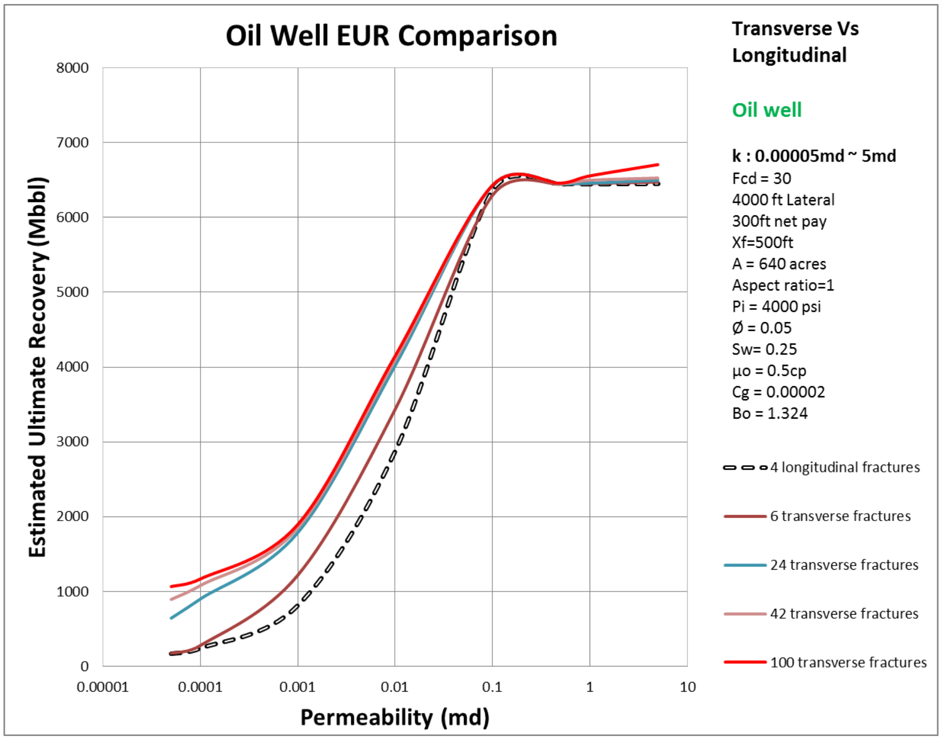

Figure 4.67. Oil Well EUR Comparison (100 T vs. 4 L)

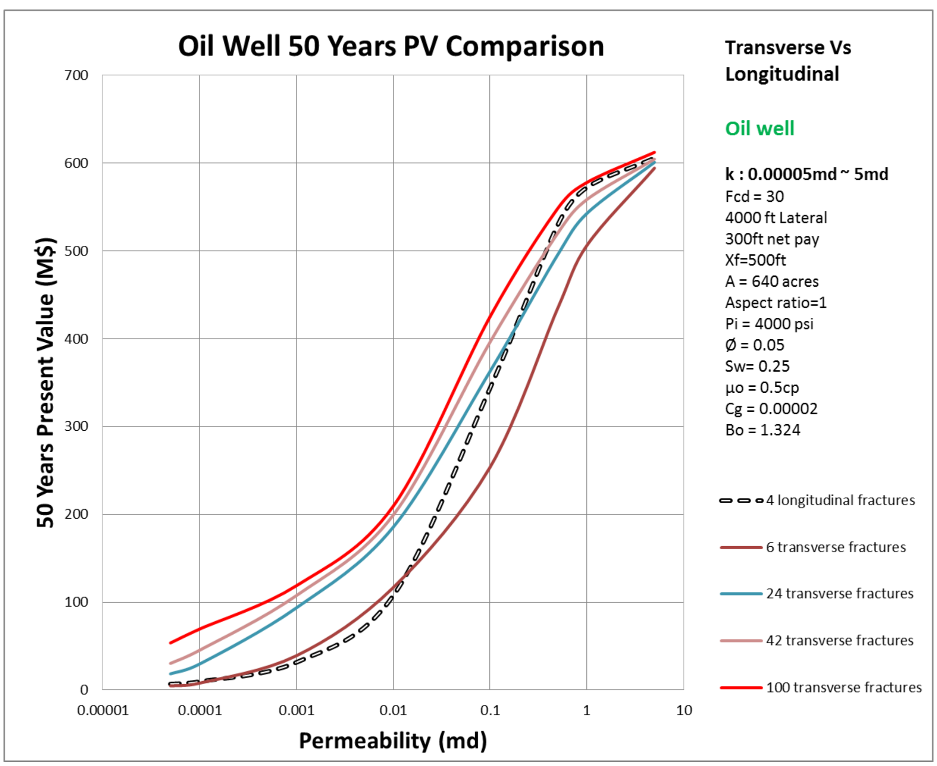

Figure 4.68. Oil Well PV Comparison (100 T vs. 4 L)

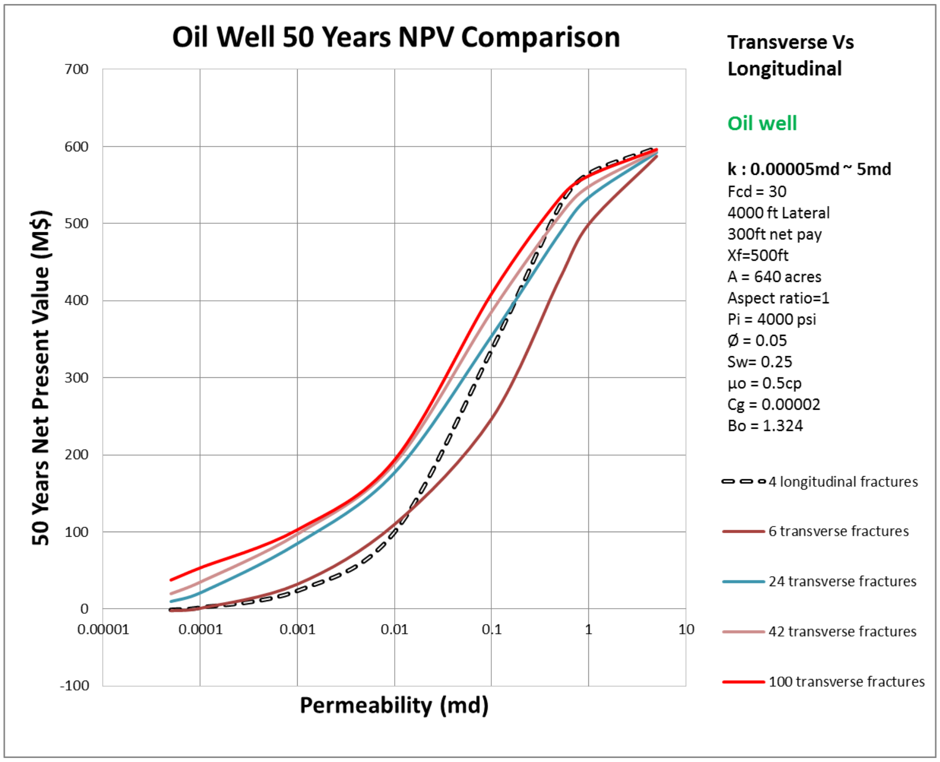

Figure 4.69. Oil Well NPV Comparison (100 T vs. 4 L)

According to the 50-year NPV, the critical permeability is 0.8 md when four longitudinal fractures is compared to 100 transverse fractures, while it is 0.4 md when four longitudinal fractures is compared to 42 transverse fractures.

Considering cost, the critical reservoir permeability remains at the same level.

Additionally, it is not practical to design 100 fractures on 4000 ft lateral. Comparing 42 transverse fractures to four longitudinal fractures would provide reliable results. In this study, the critical reservoir permeability is identified through the comparison of 42 transverse fractures to four longitudinal fractures.

4.3.2.2 F_{CD} (2 vs. 30). This session compares the fractured well performance at a F_{CD} of 2 and 30. A F_{CD} of 30 represents infinite fracture conductivity. A F_{CD} of 2 is an optimum dimensionless fracture conductivity irrespective of clean-up.

A set of cases with a F_{CD} of 2 were simulated in StimPlan (Table 4.3). Figures 4.65 ~ 69 compare the IP, 5-year recovery, EUR, PV and NPV between 42 transverse fractures and four longitudinal fractures at a F_{CD} of 2 and 30.

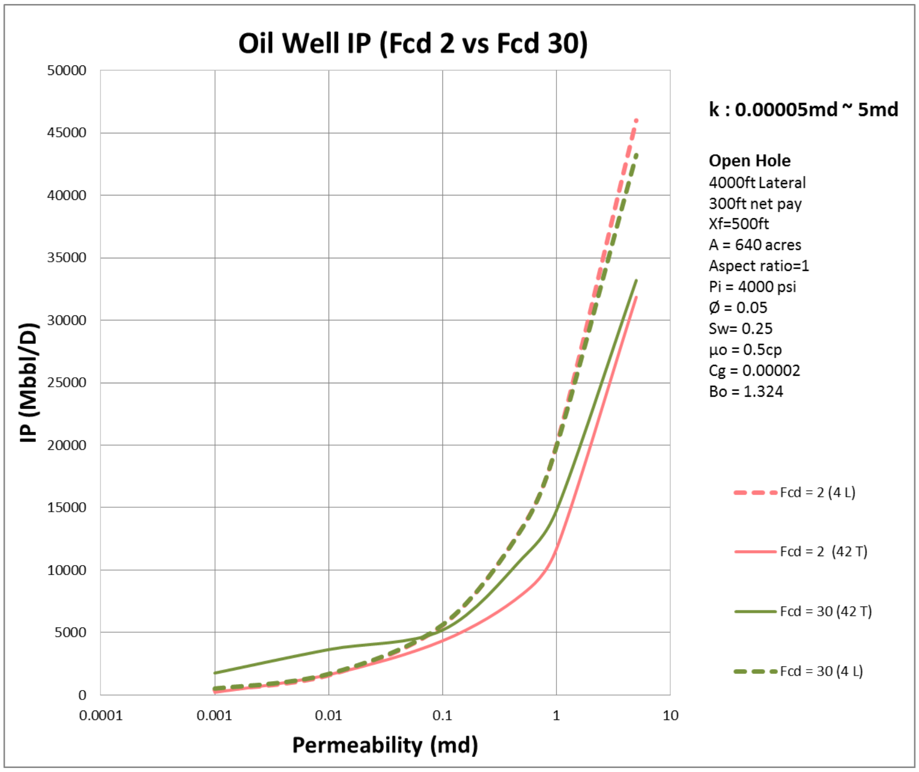

Figure 4.70. Oil Well IP Comparison (F_{CD} 2 vs. F_{CD} 30)

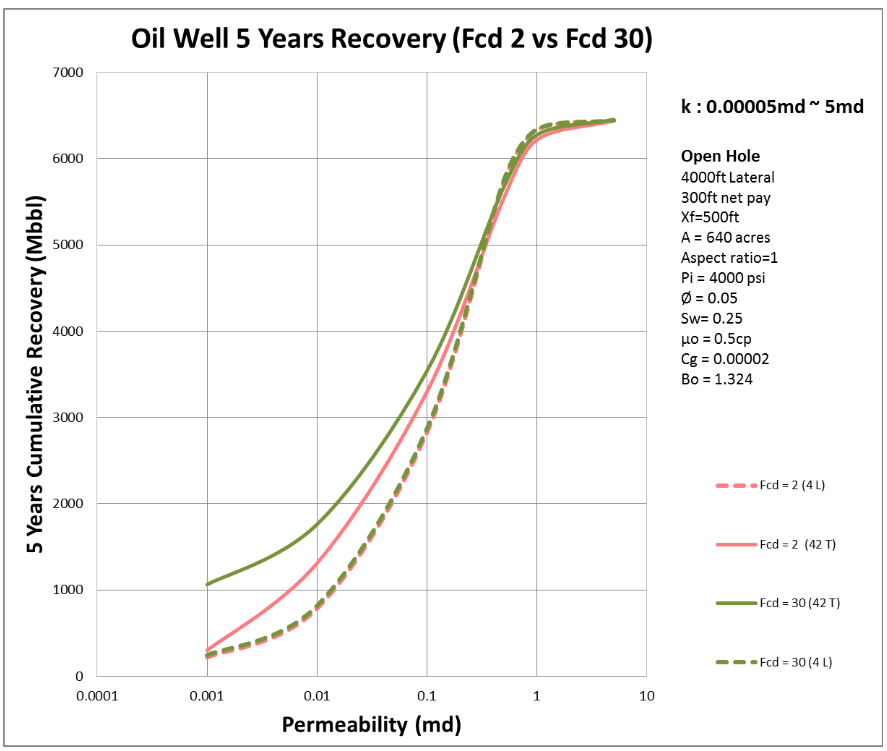

Figure 4.71. Oil Well 5-year Recovery Comparison (F_{CD} 2 vs. F_{CD} 30)

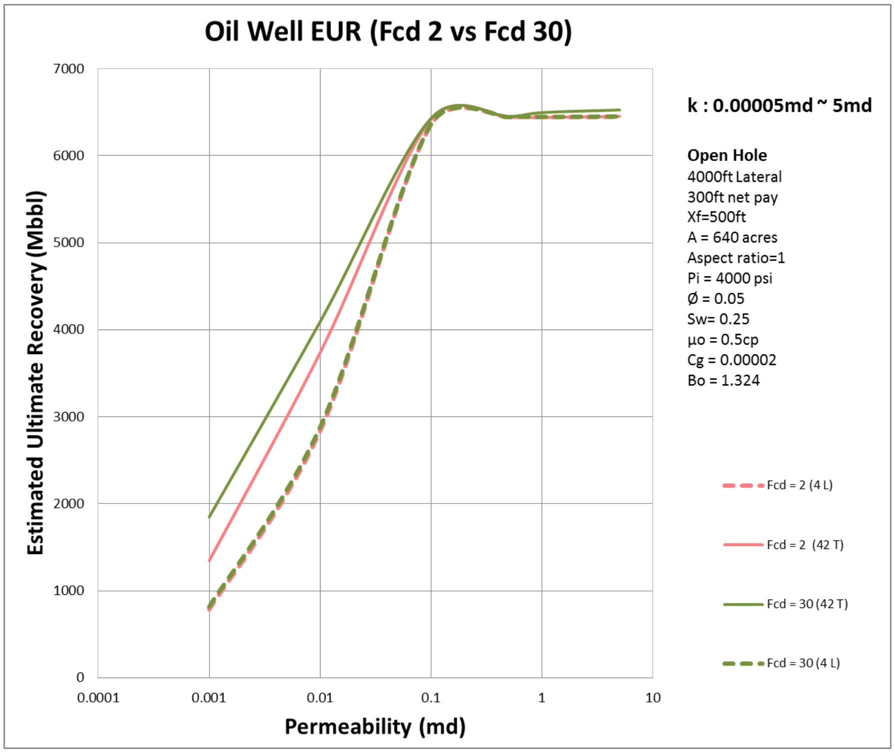

Figure 4.72. Oil Well EUR Comparison (F_{CD} 2 vs. F_{CD} 30)

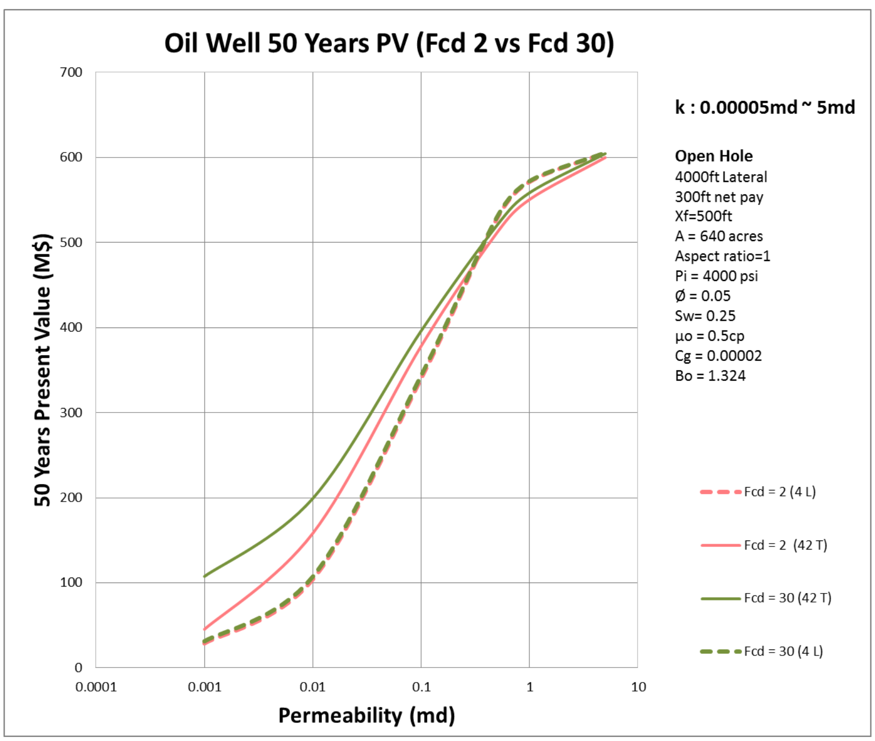

Figure 4.73. Oil Well 50-year PV Comparison (F_{CD} 2 vs. F_{CD} 30)

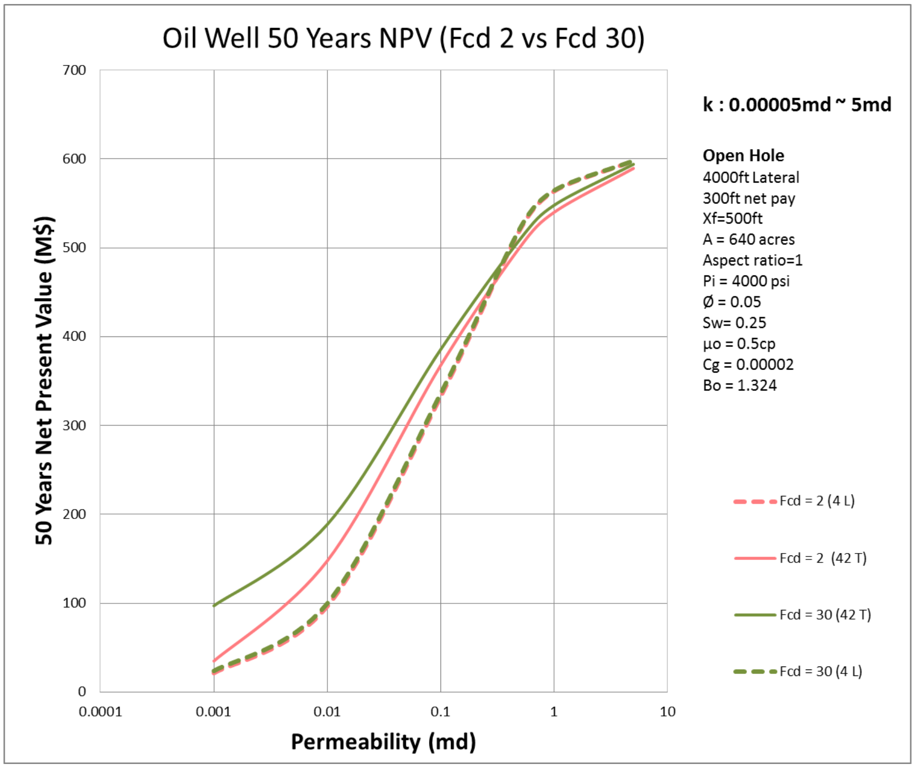

Figure 4.74. Oil Well 50-year NPV Comparison (F_{CD} 2 vs. F_{CD} 30)

The critical reservoir permeability is about the same for both F_{CD} values.

The F_{CD} has negligible effect on the longitudinally fractured horizontal oil wells. However, it affects transverse fracture configuration at oil reservoir permeability below 0.1 md, higher F_{CD} results in better performance.

4.3.2.3 Lateral length (2000 ft vs. 4000 ft). Two lateral length performance was studied: 2000 ft and 4000 ft.

A series of cases were set up with 2000 ft lateral length and simulated in StimPlan (Table 4.4).

Figures 4.75 ~ 78 compare the IP, 5-year recovery, EUR, PV and NPV between 42 transverse fractures and four longitudinal fractures at both lateral lengths.

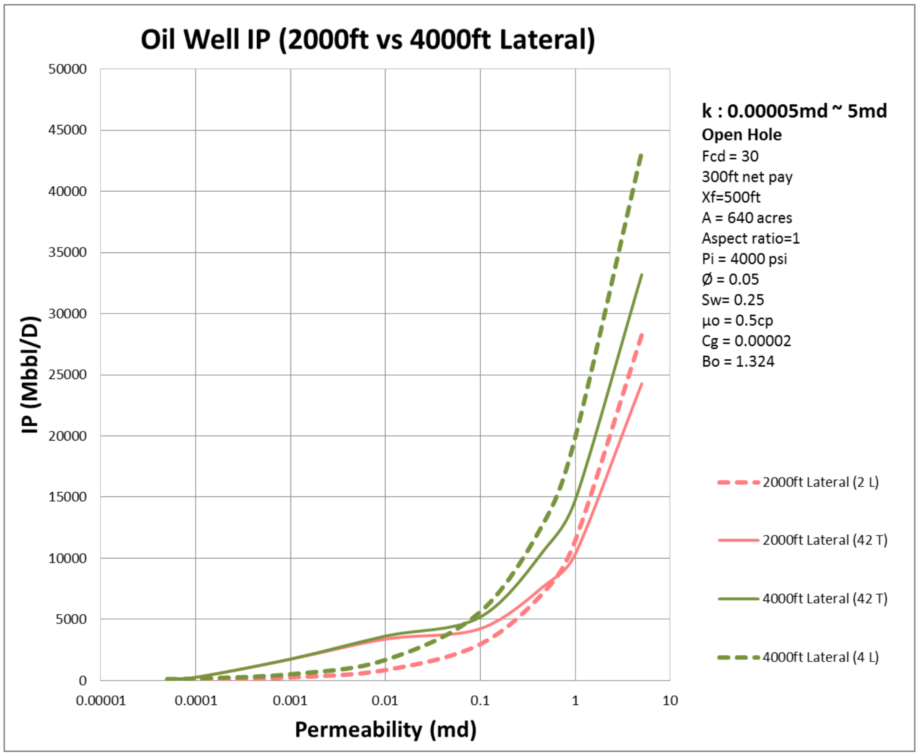

Figure 4.75. Oil Well IP Comparison (2000 ft vs. 4000 ft Lateral)

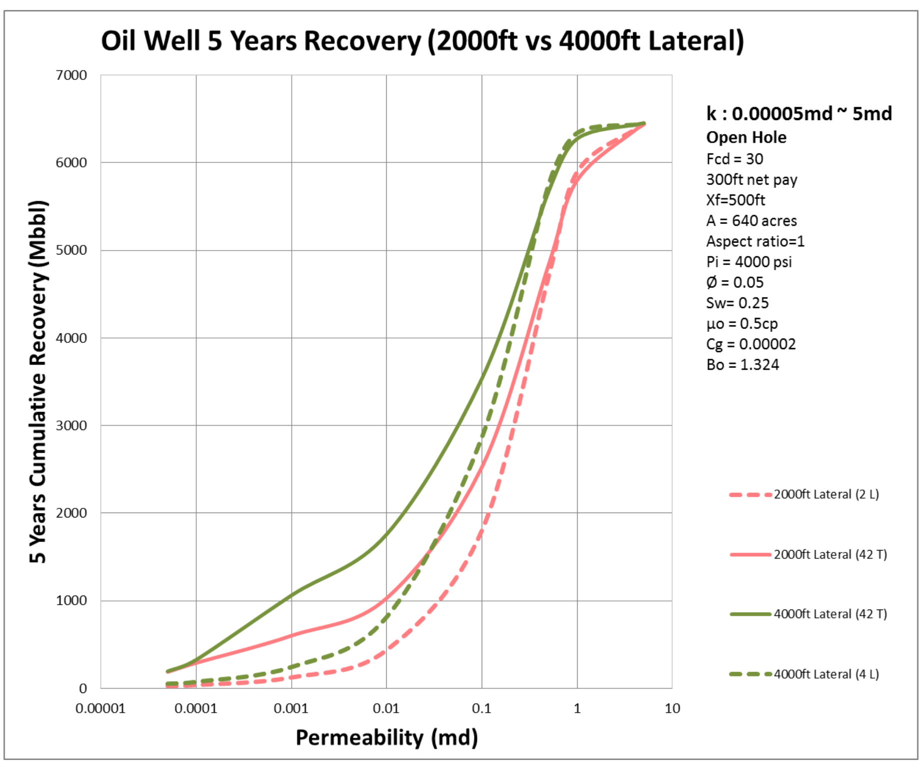

Figure 4.76. Oil Well 5-year Recovery (2000 ft vs. 4000 ft Lateral)

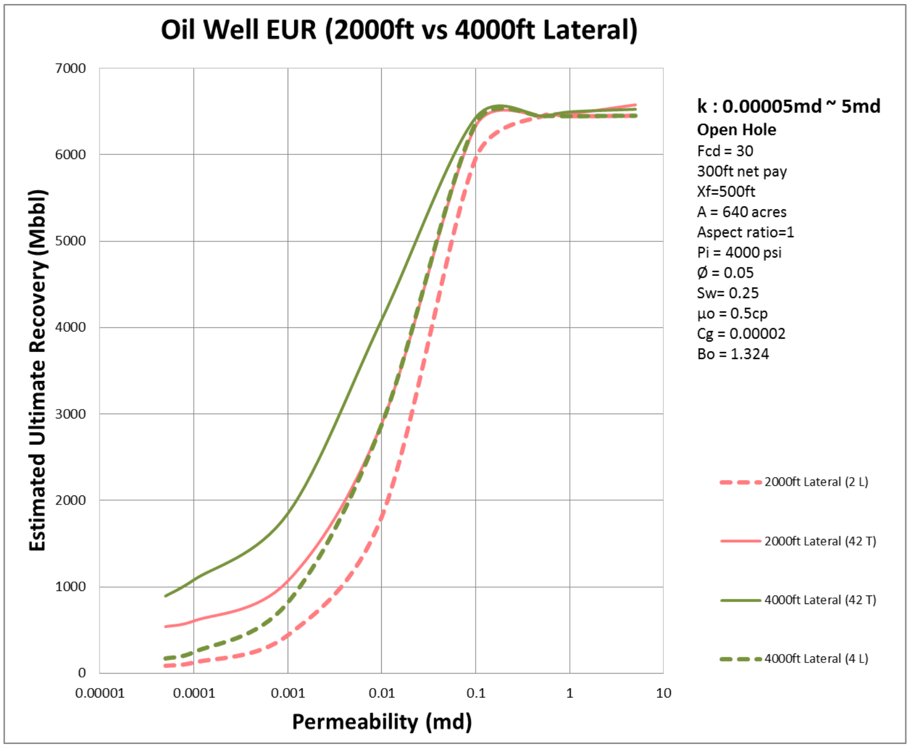

Figure 4.77. Oil Well EUR Comparison (2000 ft vs. 4000 ft Lateral)

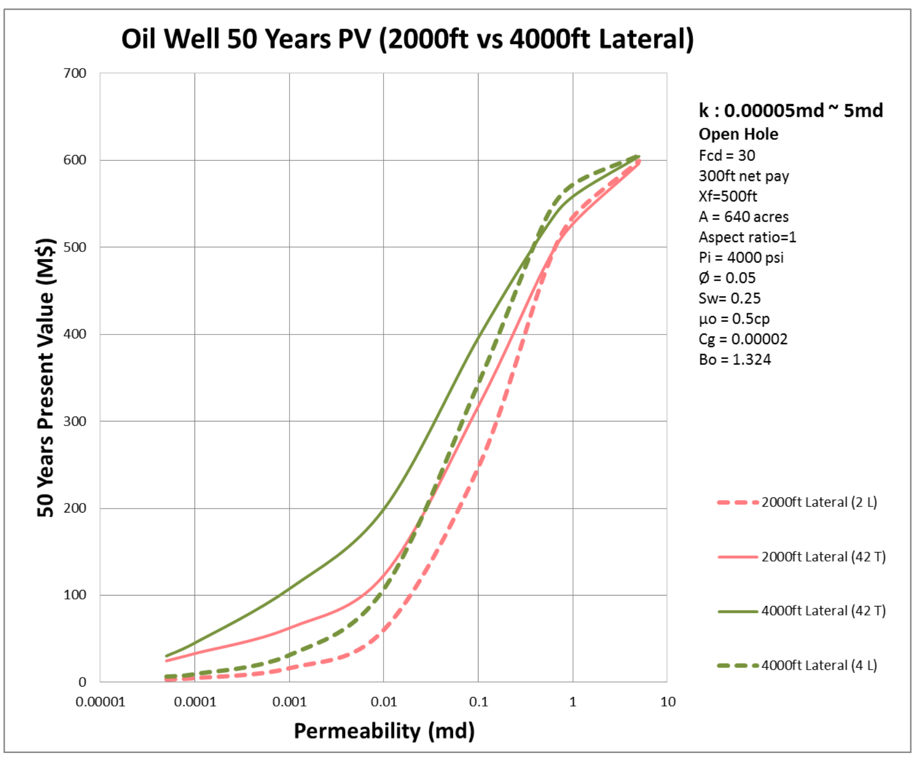

Figure 4.78. Oil Well 50-year PV Comparison (2000 ft vs. 4000 ft Lateral)

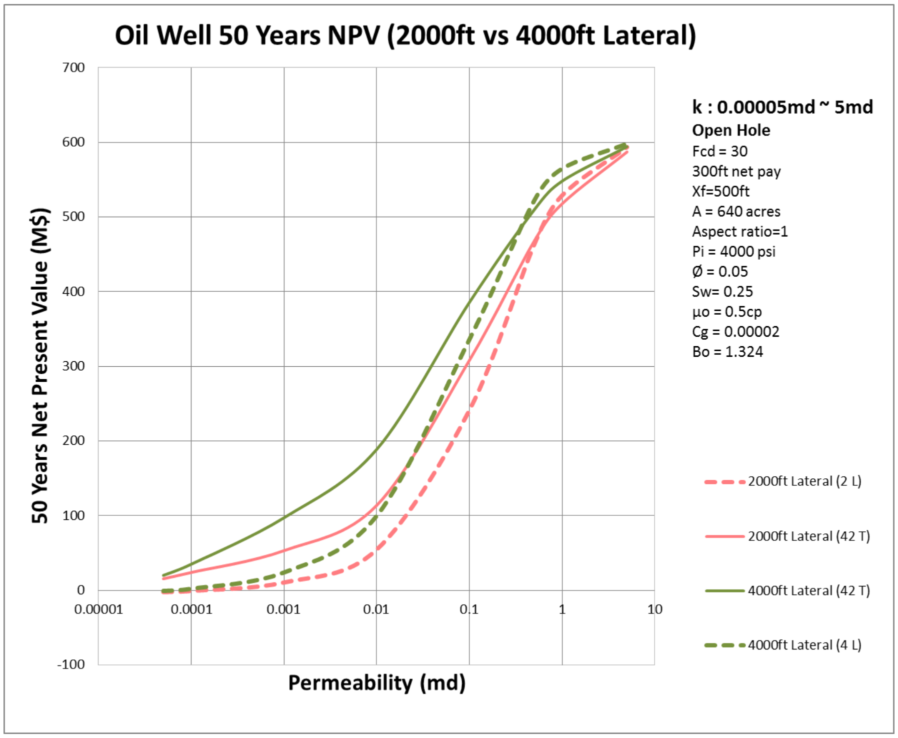

Figure 4.79. Oil Well 50-year NPV Comparison (2000 ft vs. 4000 ft Lateral)

The critical reservoir permeability identified from the 50-year PV comparison is 0.4 md for the 4000 ft lateral cases and 0.6 md for the 2000 ft lateral cases. Shortening the lateral length slightly increases the critical permeability.

For oil reservoir between 0.00005 md to 5 md, higher lateral leads to higher cumulative recovery, PV, and NPV.

When the reservoir permeability is very high (e.g. 5 md), increasing lateral length does not improve well performance significantly for a given drainage area.

For gas reservoir, at reservoir permeability below 0.1 md, a transverse fractured horizontal well performs better than a longitudinal one. At reservoir permeability above 1 md, a longitudinal fractured horizontal well performs better.

4.3.2.4 Fracture half-length (250 ft vs. 500 ft). Two fracture half-lengths were studied: 250 ft and 500 ft (Table 4.5).

Figure 4.80 ~ 84 compare IP, 5-year recovery, EUR, PV and NPV.

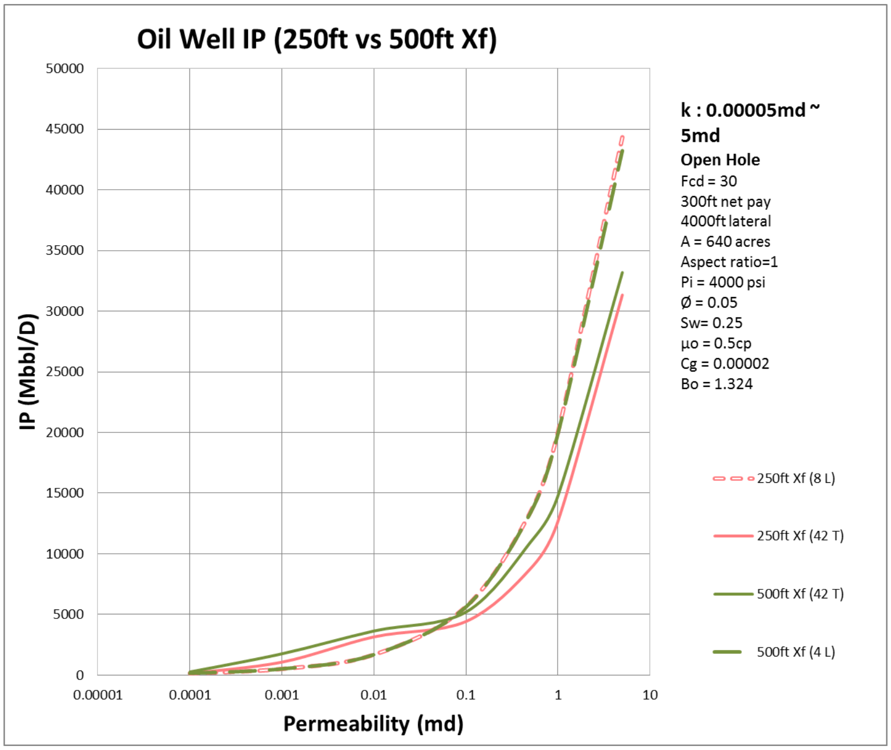

Figure 4.80. Oil Well IP Comparison (250 ft vs. 500 ft X_f)

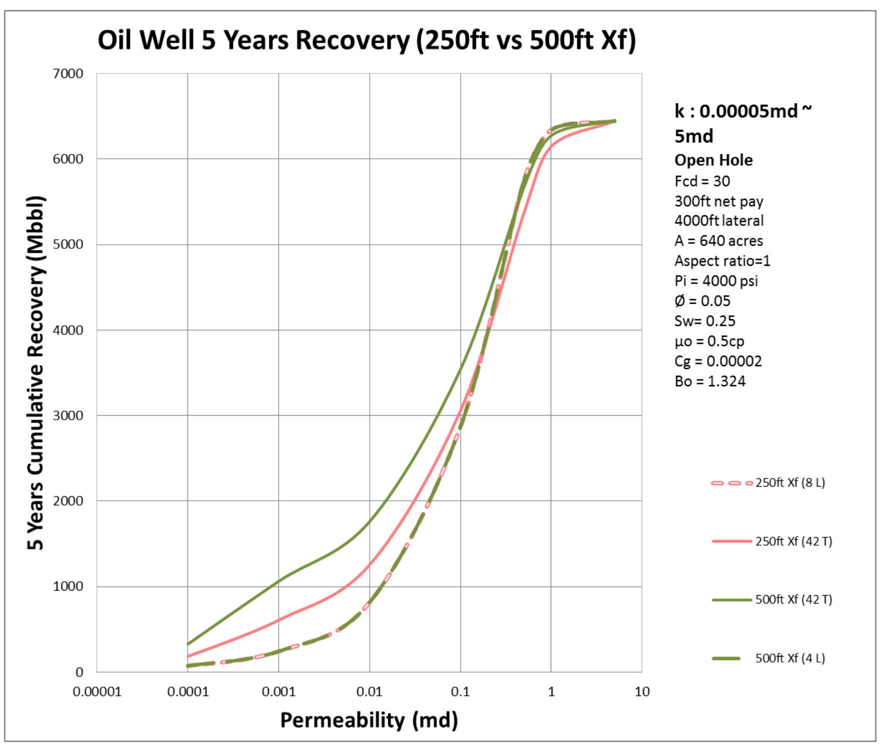

Figure 4.81. Oil Well 5-year Recovery Comparison (250 ft vs. 500 ft X_f)

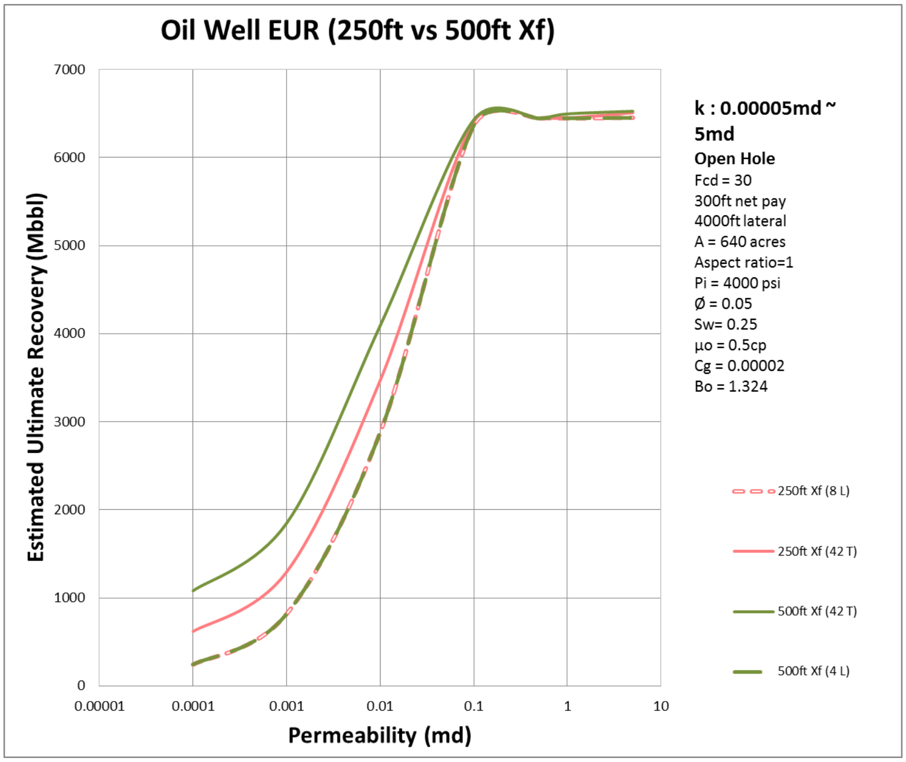

Figure 4.82. Oil Well EUR Comparison (250 ft vs. 500 ft X_f)

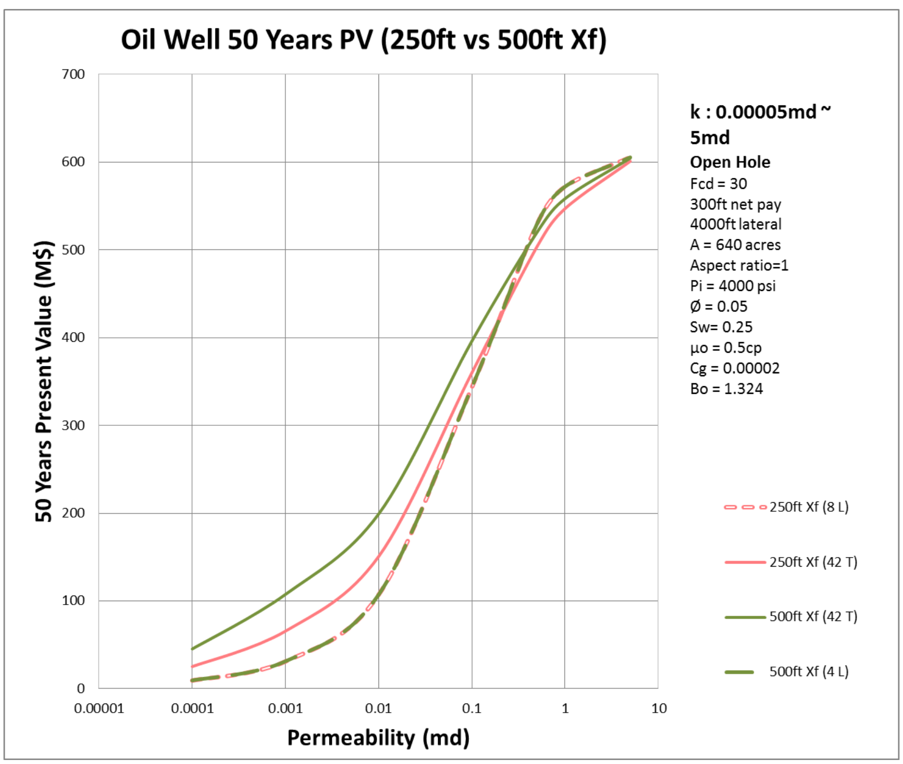

Figure 4.83. Oil Well 50-year PV Comparison (250 ft vs. 500 ft X_f)

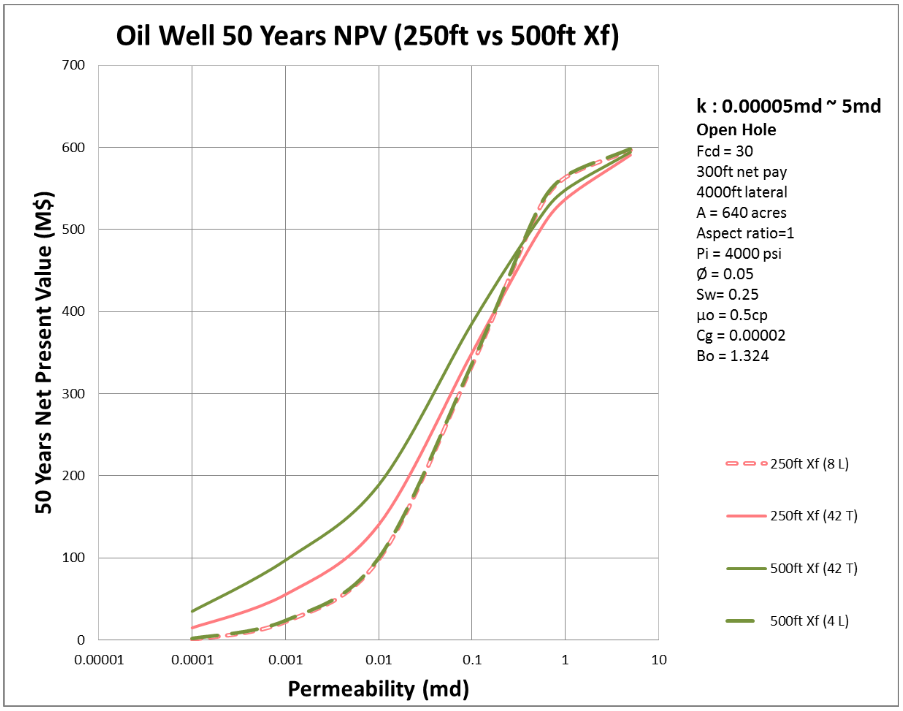

Figure 4.84. Oil Well 50-year PV Comparison (250 ft vs. 500 ft X_f)

The critical reservoir permeability identified from the 50-year PV comparison is 0.2 md for the 250 ft lateral cases, and it is 0.4 md for the 500 ft lateral cases.

In an oil reservoir, the two fracture half-length cases have similar performance for longitudinally fractured horizontal wells. Changing the fracture half-length does not affect the performance of longitudinal fracture configuration because the dimensionless fracture conductivity is the same. However, it affects transverse fracture configuration at reservoir permeability below 0.1 md, the longer the fracture length, the better the performance of the transverse fractured horizontal well.

Generally, transverse fractured wells performs better than longitudinal ones when the reservoir permeability is below 0.1 md, and longitudinal fracture shows advantage over transverse ones when the reservoir permeability is over 1 md.

4.3.2.5 Completion method (Cased Hole vs. Open Hole). A series of cases with cased hole completion were simulated under varied reservoir permeability (Table 4.2). Figure 4.85 ~ 89 compare the performance of cased hole completion and open hole completion in terms of IP, 5-year cumulative production, EUR, PV and NPV.

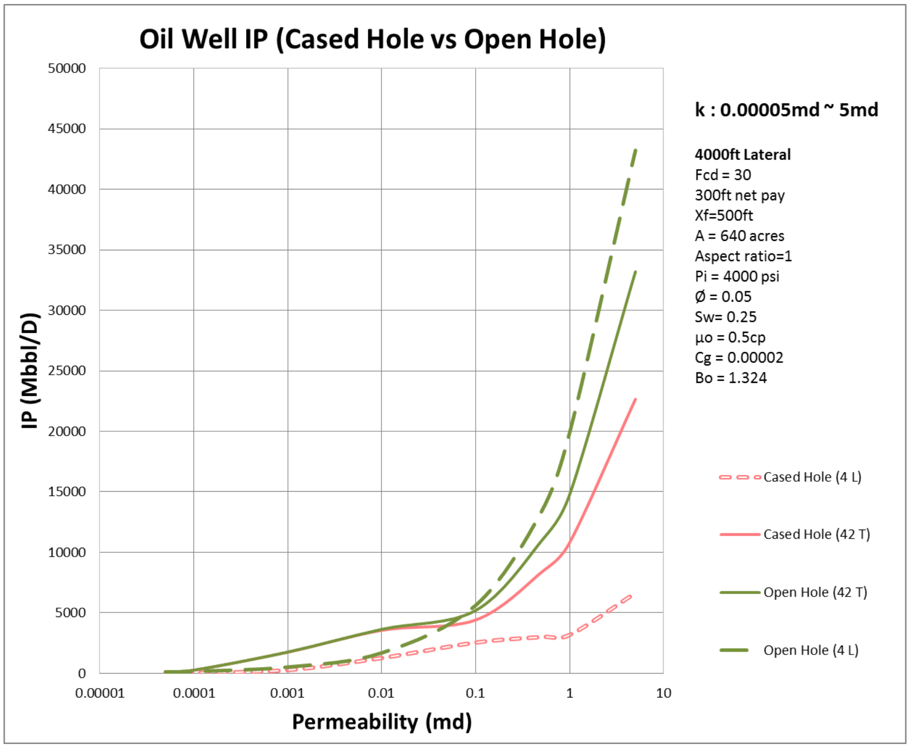

Figure 4.85. Oil Well IP Comparison (Cased Hole vs. Open Hole)

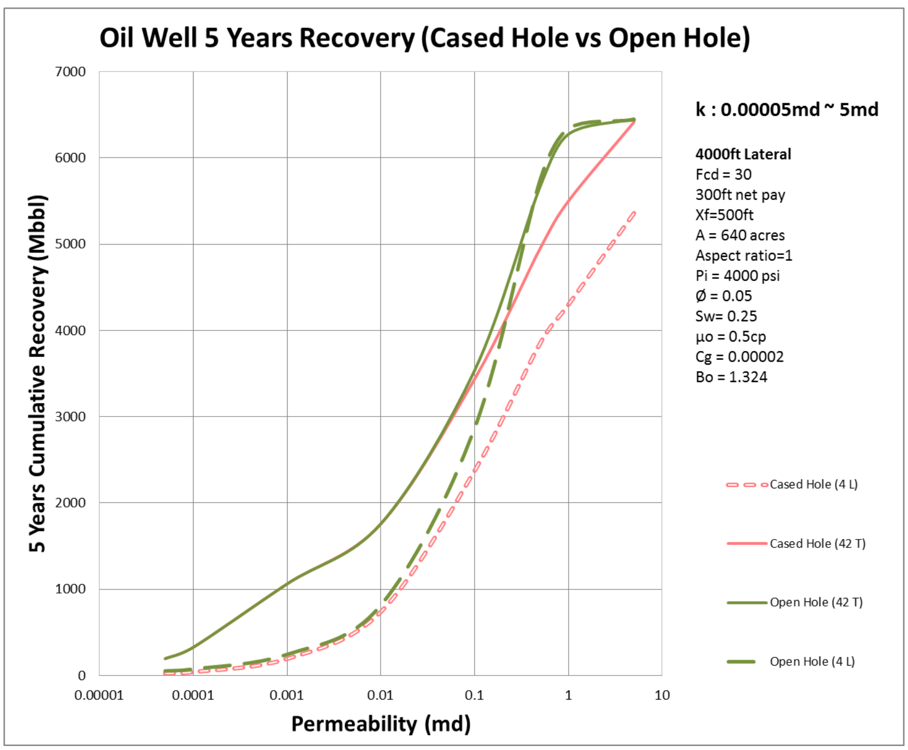

Figure 4.86. Oil Well 5-year Recovery (Cased Hole vs. Open Hole)

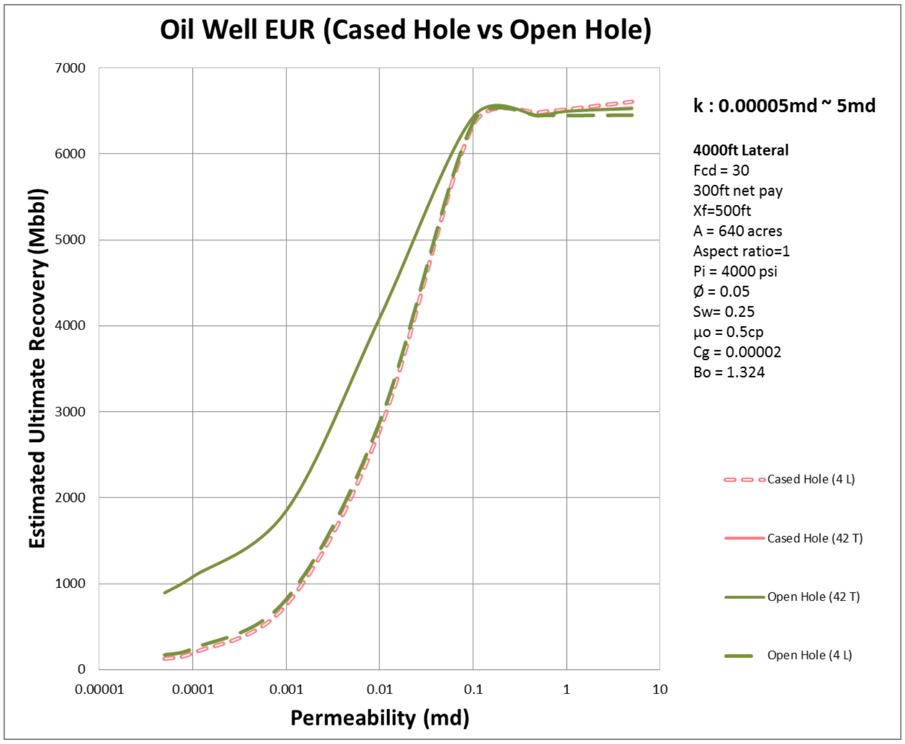

Figure 4.87. Oil Well EUR Comparison (Cased Hole vs. Open Hole)

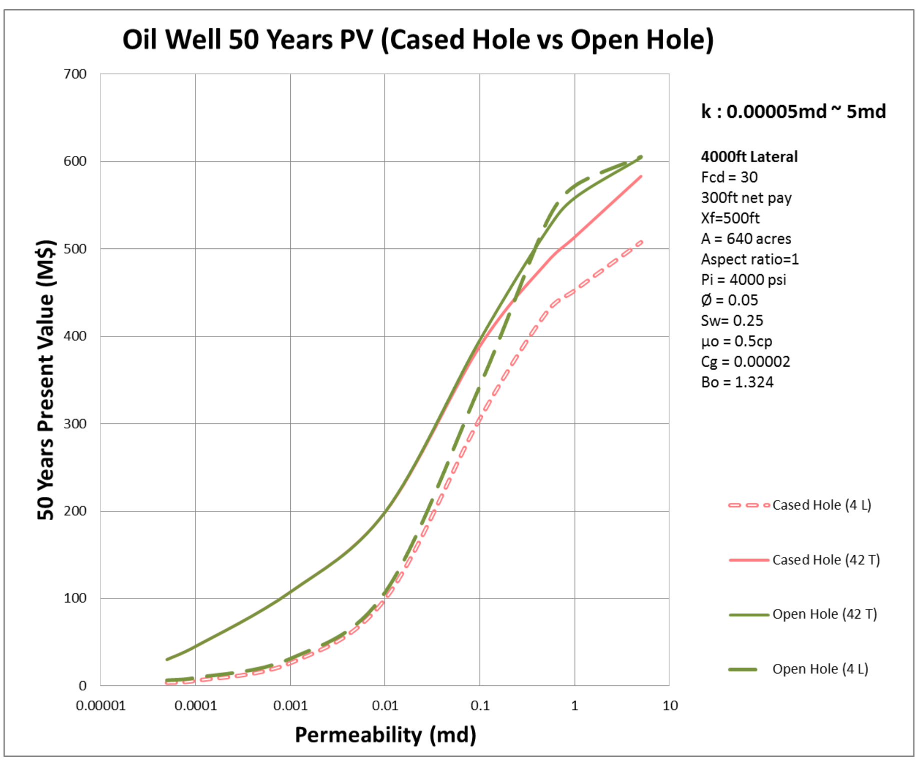

Figure 4.88. Oil Well 50-year PV Comparison (Cased Hole vs. Open Hole)

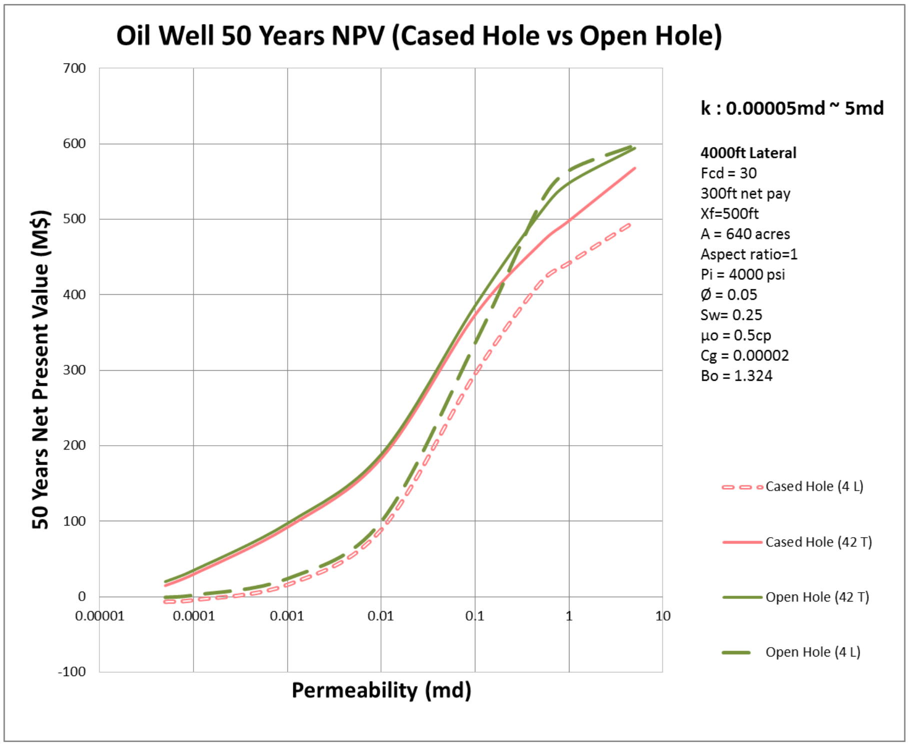

Figure 4.89. Oil Well 50-year NPV Comparison (Cased Hole vs. Open Hole)

For oil reservoir, open hole completion performs better than cased hole completion.

For transverse fracture configuration, open hole completion shows advantage at reservoir permeability higher than 0.1 md.

For longitudinal fracture configuration, open hole system performs better, and show more advantage as reservoir permeability increases.

4.3.2.6 Oil price. Hydrocarbon price is involved in the calculation of PV, which determines the optimal reservoir permeability range for longitudinal fracture configuration of this study.

Based on the West Texas Intermediate (WTI) Crude Oil price published over the past 10 years, three different WTI spot gas price were picked to evaluate the impact: the highest crude oil price from 2004 to 2014, the lowest crude oil price during this period and the current crude oil price in July 2014 (Figure 4.90).

Both PV and NPV were calculated at each price and compared (Figure 4.91 ~ 94).

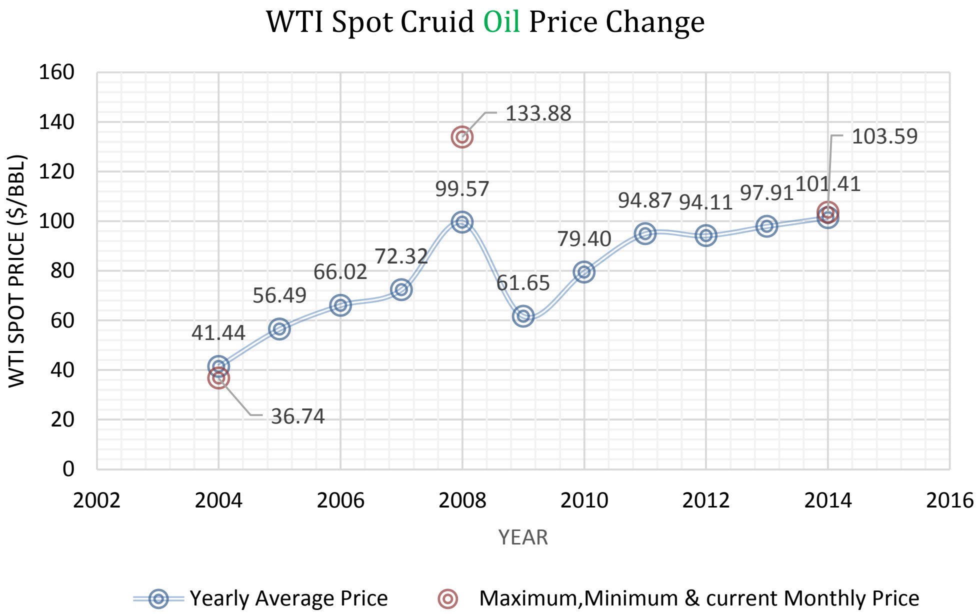

Figure 4.90. WTI Cruid Oil Price from 2004 to 2014

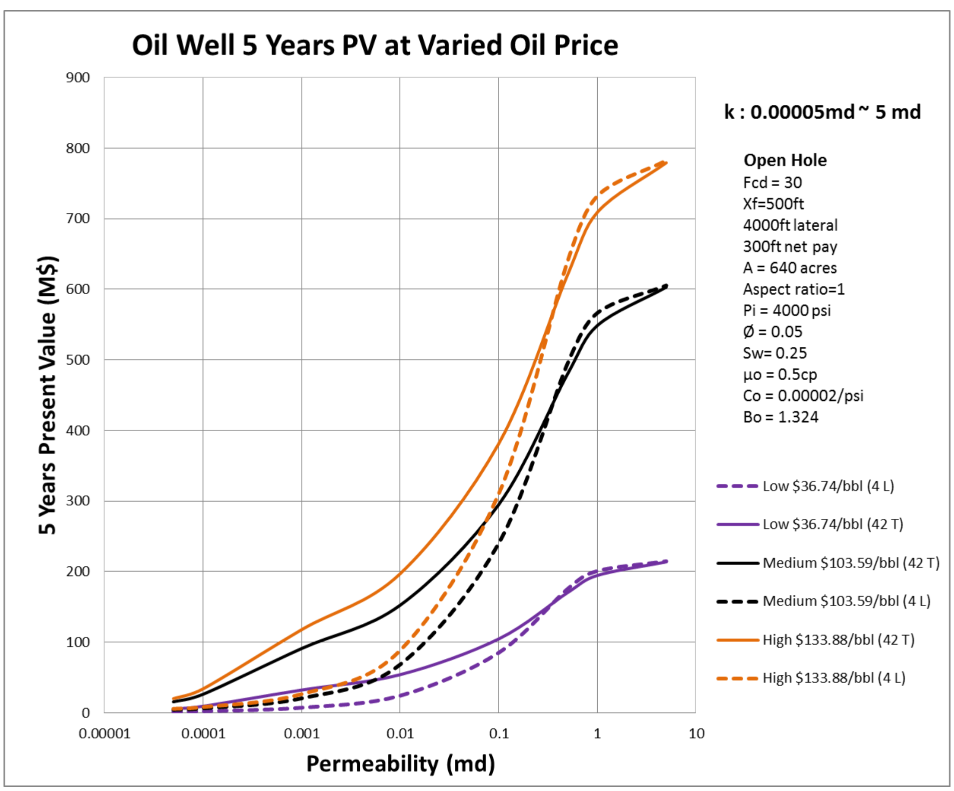

Figure 4.91. Oil Well 5-year PV at Varied Oil Price

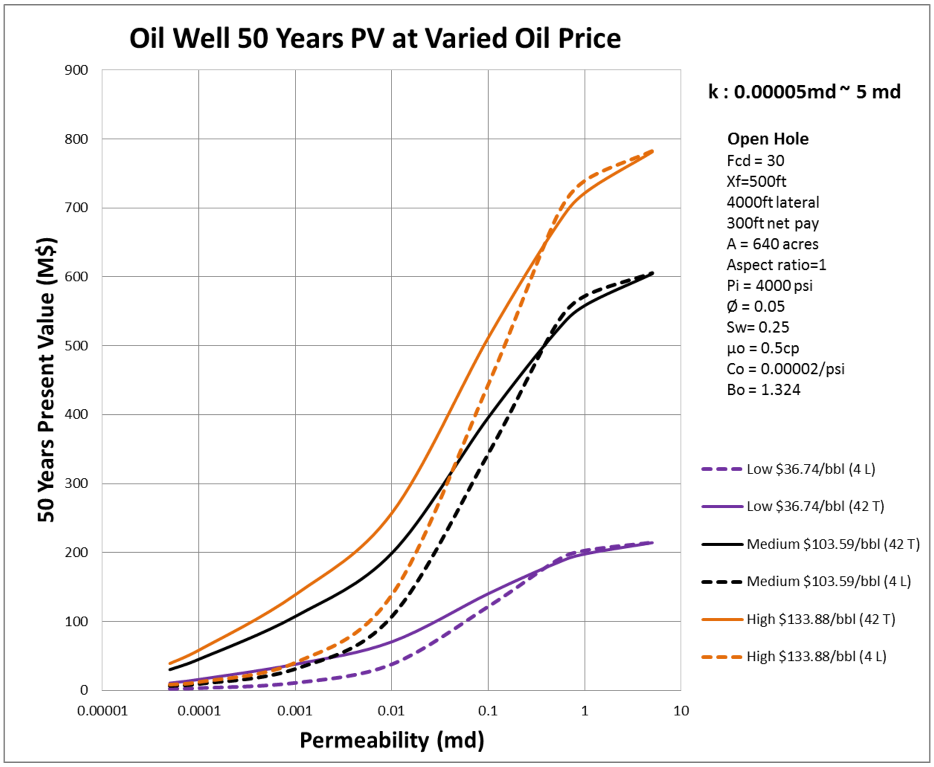

Figure 4.92. Oil Well 50-year PV at Varied Oil Price

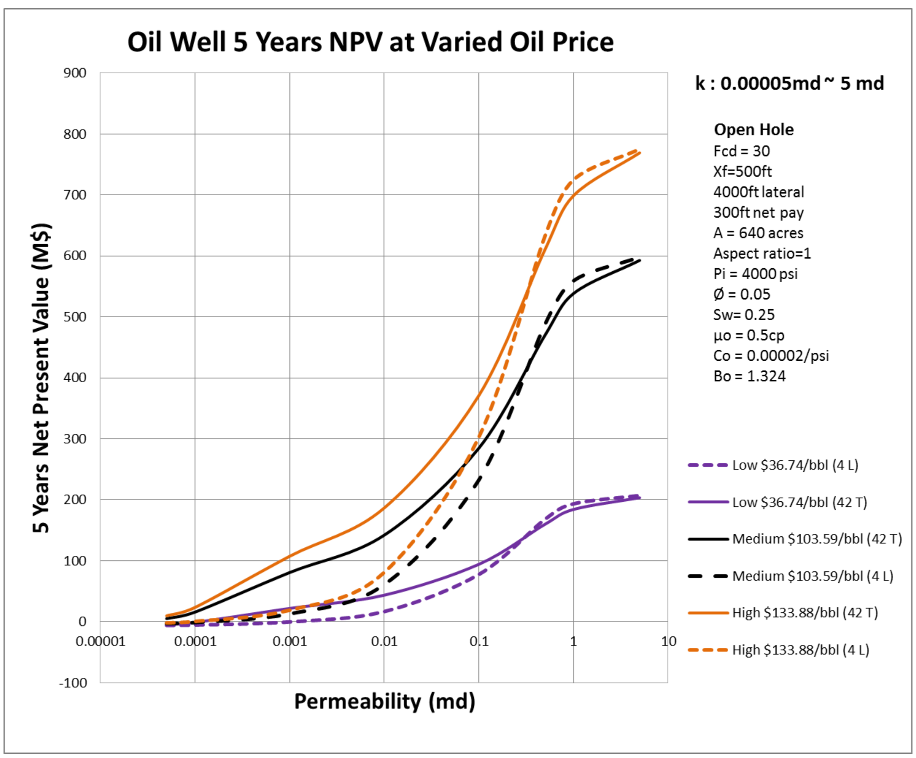

Figure 4.93. Oil Well 5-year NPV at Varied Oil Price

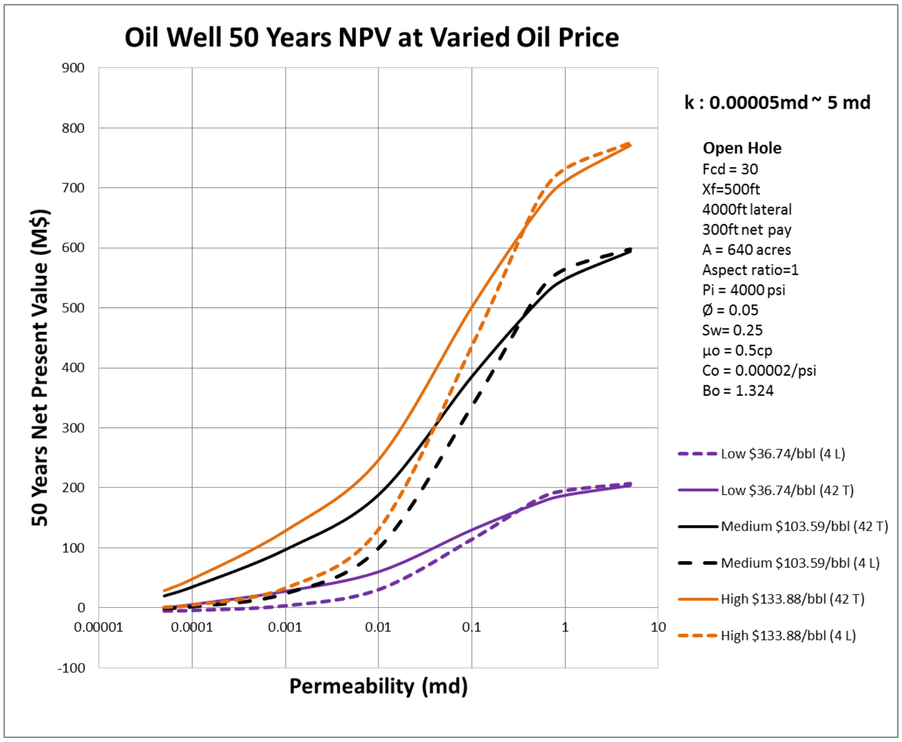

Figure 4.94. Oil Well 50-year NPV at Varied Oil Price

According to the 50-year PV comparison, the critical permeability identified at the highest, current, and lowest price is 0.5 md, 0.4 md and 0.5 md respectively.

The critical permeabilities identified from the 5-year PV comparison at three different prices are very close to each other.

Oil price has negligible effect on the determination of critical reservoir permeability.

4.3.3. Critical Reservoir Pemeability. This section summarizes the critical permeability for oil wells in terms of each criterion compared (Table 4.8).

The critical reservoir permeability represents the reservoir permeability range within which longitudinal fractured horizontal well is preferred. It is the permeability at the cross point of longitudinal and transverse fractured horizontal well performance curve.

Table 4.7. Critical Reservoir Permeability for Oil Wells Simulated

Critical Reservoir Permeability Identified for Oil Well in terms of Varied Comparison Criterion					
Comparison Criterion	Open Hole				Cased Hole
	42T vs. 4L (L=4000 ft X_f =500 ft F_{CD}=30)	42T vs. 2L (L=2000 ft)	42T vs. 8L (X_f =250 ft)	42T vs. 4L (F_{CD}=2)	42T vs. 4L (L=4000 ft X_f =500 ft F_{CD}=30)
IP	0.08 md	0.6 md	0.05 md	0.01 md	N/A
Annualized 1st Year Rate	0.2 md	0.5 md	0.08 md	0.1 md	N/A
EUR	N/A	N/A	N/A	N/A	0.4 md
5-year Recovery	0.4 md	0.7 md	0.2 md	0.3 md	N/A
50-year DR	0.4 md	0.6 md	0.2 md	0.3 md	N/A
5-year DR	0.4 md	0.6 md	0.2 md	0.3 md	N/A
50-year PV	**0.4 md**	**0.6 md**	**0.2 md**	**0.3 md**	**N/A**
5-year PV	0.4 md	0.6 md	0.2 md	0.3 md	N/A
50-year NPV	0.4 md	0.6 md	0.2 md	0.3 md	N/A
5-year NPV	0.4 md	0.6 md	0.2 md	0.3 md	N/A
Beyond critical permeability, longitudinal configuration outperforms transverse configuration. (0.00005 md ~ 5 md studied)					

The lateral length, fracture half-length, fracture conductivity, and gas price have negligible effect in identifying critical reservoir permeability. However, completion method has a significant impact.

According to 50-year PV in an oil reservoir, with open hole completion, longitudinal fractured horizontal well outperforms transverse fractured well when the reservoir permeability is over 0.4 md. However, with cased hole completion, longitudinal fractured horizontal well performs better at reservoir permeability over the reservoir permeability range of this study (0.00005 md to 5 md).

In an oil reservoir, with cased hole completion, longitudinal fractures yields higher EUR at reservoir permeability over 0.4 md.

5. FIELD CASE STUDY

5.1. GAS WELL FIELD STUDY

5.1.1. Barnett Shale Gas Field. The objects of this field study are four horizontal fractured wells from the Barnett Shale producing pool located in Newark East field, New Dawn lease unit, in Tarrant county, Northeast Texas (Figure 5.1).

Newark East field became one of the most productive gas field in Texas in terms of daily production in December 2001. In 2007, the field produced more than 1.3 Bcf/day of gas. More than 99% of Barnett production in north Texas was from this field. The matrix permeability of the Barnett is measured in nanodarcys (Bowker 2007).

Among the four wells studied, three of them are transversely fractured, the other one is longitudinally fractured. The fracture configuration is identified from the well map of New Dawn lease unit, which is proprietary and not shown here, and the Barnett formation stress map (Figure 5.2)

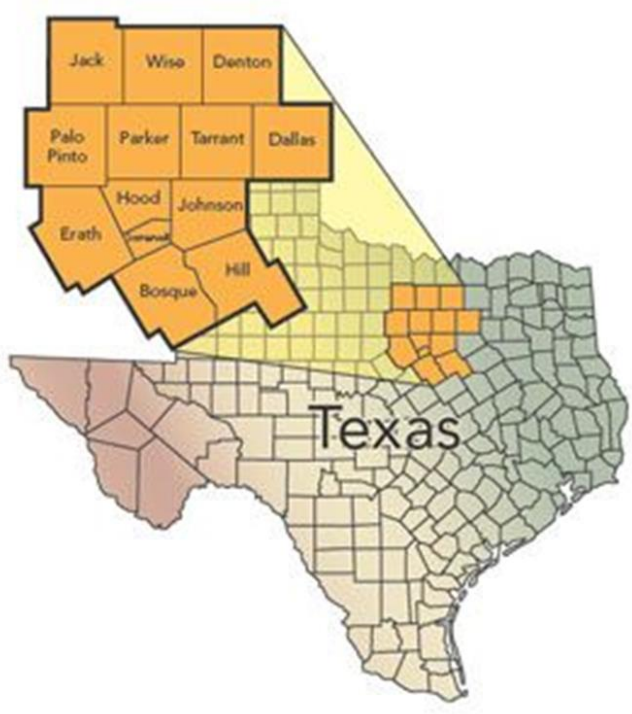

Figure 5.1. Barnett Shale Play (Oil & Gas Journal 2014)

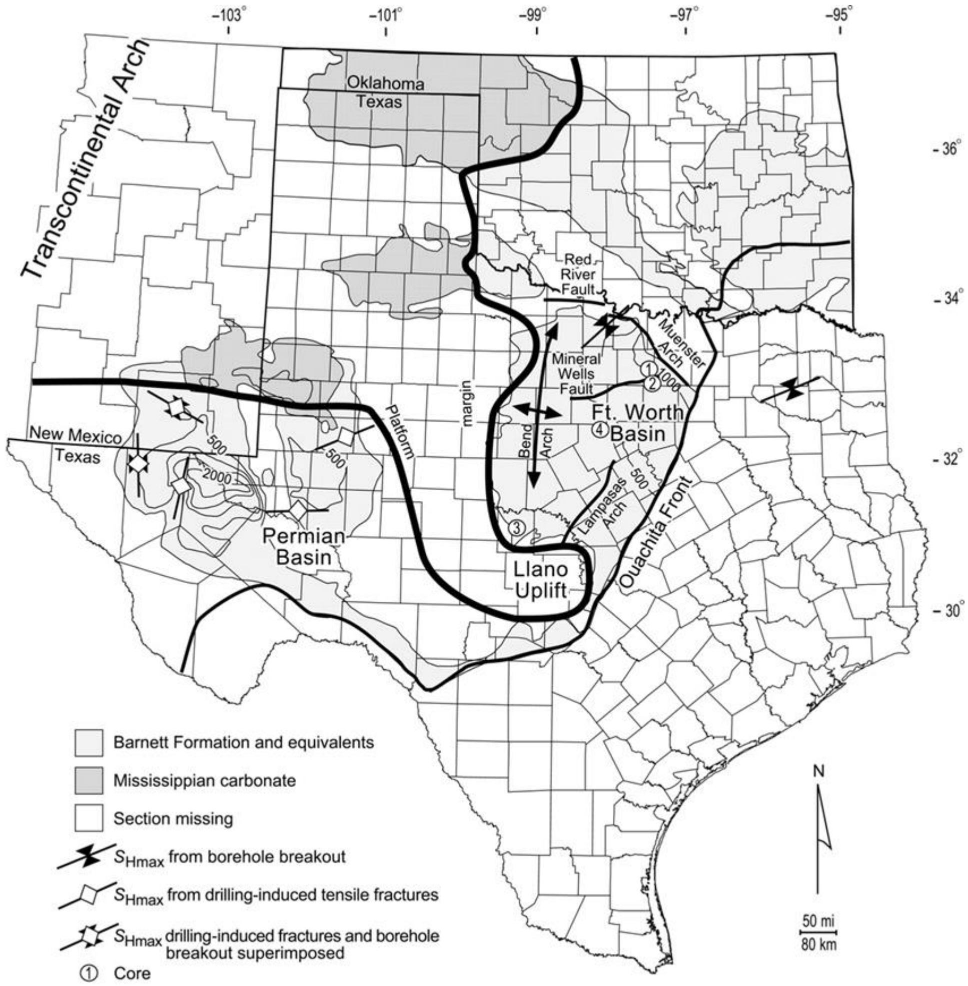

Figure 5.2. Barnett Formation Stress Map (GeoScienceWorld 2014)

The production data of the four wells are available from Dec 2007 to July, 2014 (Table 5.1), including the cumulative production and first month production rate.

Both the cumulative production and 1st month production rate are normalized with respect to the well lateral length and the comparison is shown in Figure 5.3 and Figure 5.4.

Table 5.1. Barnett Shale Well Production Data

Well Name	New Dawn #1H	New Dawn #4H	New Dawn #2H	New Dawn #3H
Lateral length (ft)	2009	2208	2294	2088
Fracture configuration	Transverse fractures	Transverse fractures	Transverse fractures	Longitudinal fractures
Start Production Date	12/1/2007	12/1/2007	12/1/2007	12/1/2007
Available data end Date	7/31/2014	6/30/2014	7/31/2014	7/31/2014
Total production time of study (year)	8	8	8	8
1st Month Gas IP (Mscf/d)	882	627	633	594
1st Month Gas Cum (Mscf)	26469	18799	18977	17831
2007 Annual Gas (Mscf)	26469	18799	18977	17831
2008 Annual Gas (Mscf)	618391	601264	723103	558236
2009 Annual Gas (Mscf)	391116	266801	331149	184319
2010 Annual Gas (Mscf)	357169	207190	180051	100853
2011 Annual Gas (Mscf)	228086	125401	207204	22302
2012 Annual Gas (Mscf)	172638	81394	187069	65335
2013 Annual Gas (Mscf)	145572	894	100940	190101
2014 Annual Gas (Mscf)	68584	37	51631	76447

The transversely fractured wells has higher cumulative production (up to 70% more) than the longitudinally fractured well. The initial production rates are similar except that of the #1H well with transverse fractures, which is about 60%more than the others.

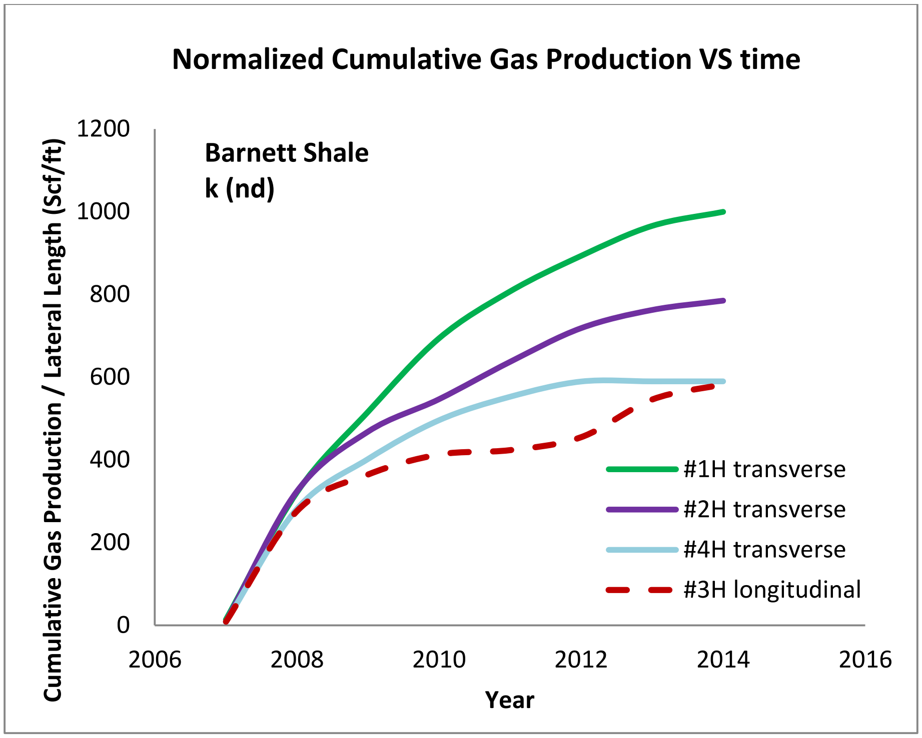

Figure 5.3. Barnett Gas Well Cumulative Production Comparison

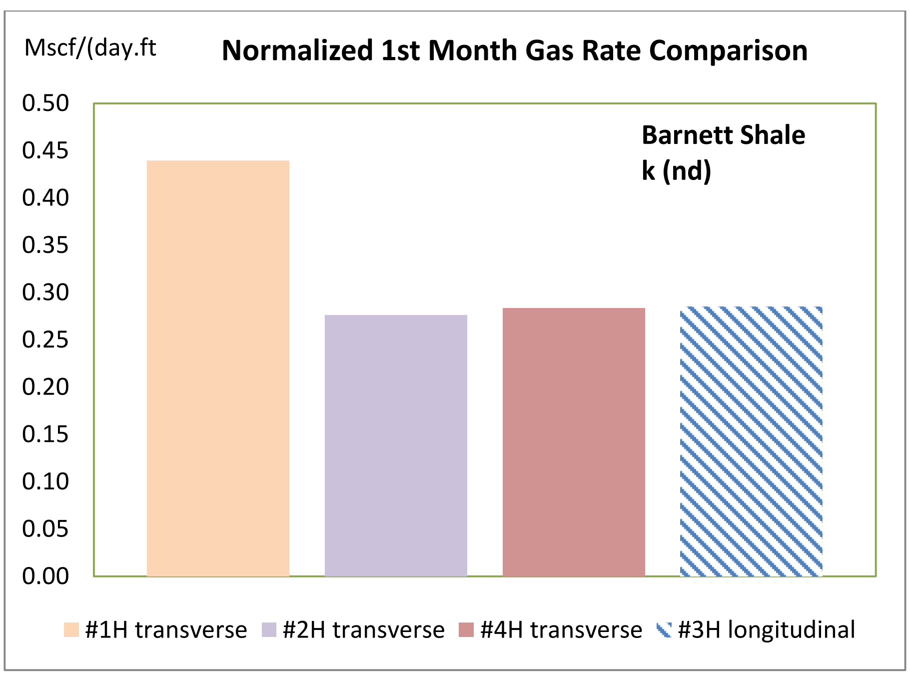

Figure 5.4. Barnett Gas Well IP Comparison

Generally, in Newark East field of Barnett Shale where the reservoir permeability is extremely low (nanodarcys), horizontal wells (#1H, #2H, #4H) with transverse fractures show higher cumulative gas production than the one (#3H) with longitudinal fractures.

5.1.2. Hugoton Gas Field. The session briefly reviews the field case study of eight horizontal wells in the Hugoton gas field by Larry K. Britt in 2010.

The Hugoton field was the largest natural gas field in North America and the second largest in the world in terms of natural gas production in 1996, according to Kansas Geological Survey.

The study area, Chase, has a high permeability of 0.1 to 50 md in Southwest Kansas. Over 16 years production data from Jan 1993 to July 2009 was investigated (Figure 5.5). The horizontal well with longitudinal fractures had higher cumulative gas production.

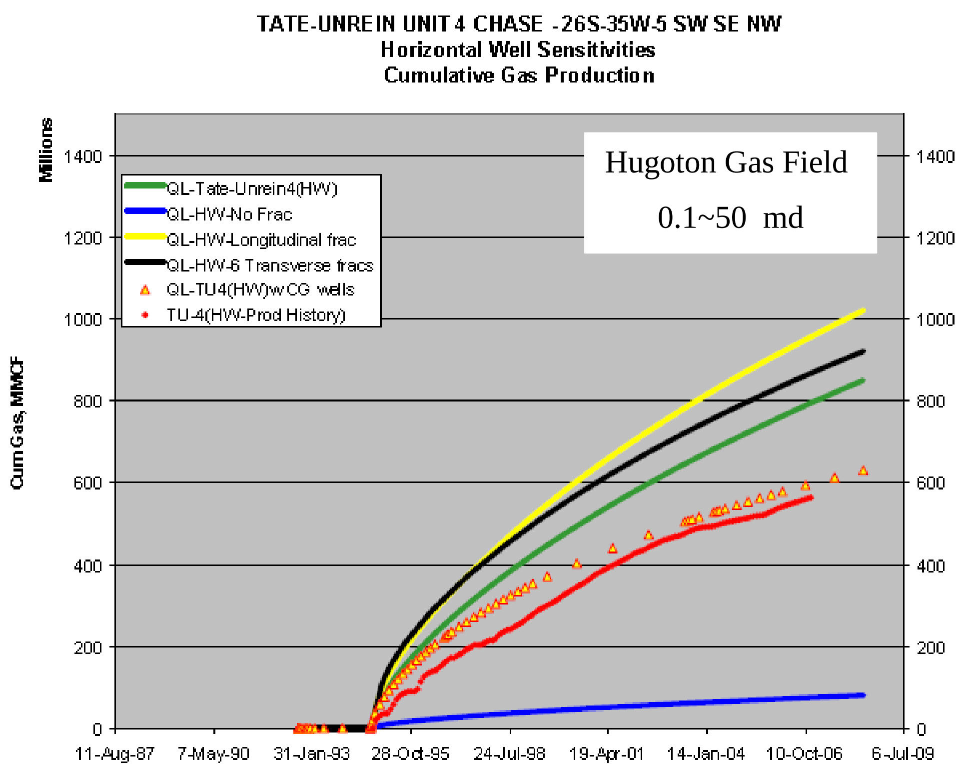

Figure 5.5. Hugoton Gas Well Field Study (Britt 2014)

In summary, two gas fields were studied, including unconventional reservoir (Barnett Shale), and conventional gas reservoir (0.1~50 md, Hugoton gas field).

In the unconventional reservoir, transverse fractures yields higher cumulative gas production than longitudinal fractures; however, in the conventional reservoir, longitudinal fracture configuration results in higher cumulative gas production.

5.2. OIL WELL FIELD STUDY

5.2.1. Eagle Ford Shale Oil Field. The Eagle Ford formation is one of the most actively drilled targets for oil and gas in the U.S. in 2010 (Gulf Oil & Gas 2014)

It is 50 miles wide and has an average thickness of 250 ft at a depth from 4000 to 12000 ft. It underlies 30 counties in Texas covering millions of acres (Figure 5.6). The shale contains a high amount of carbonate, which makes it brittle and easier to use hydraulic fracturing to produce the oil or gas. The first well was drilled by Petrohawk in 2008, in La Salle county, Texas (Wikipedia 2014).

This study investigated two wells from the Red Hawk area, Zavala County (blue rectangle in Figure 5.6). The reservoir permeability of this area is 50nd (Gong et al. 2013)

Figure 5.6. Eagle Ford Shale Play Location (Texas File 2014; Thomas 2013)

The fracture configuration was identified from the local stress map (Figure 5.7) and the well map which is proprietary and not shown here.

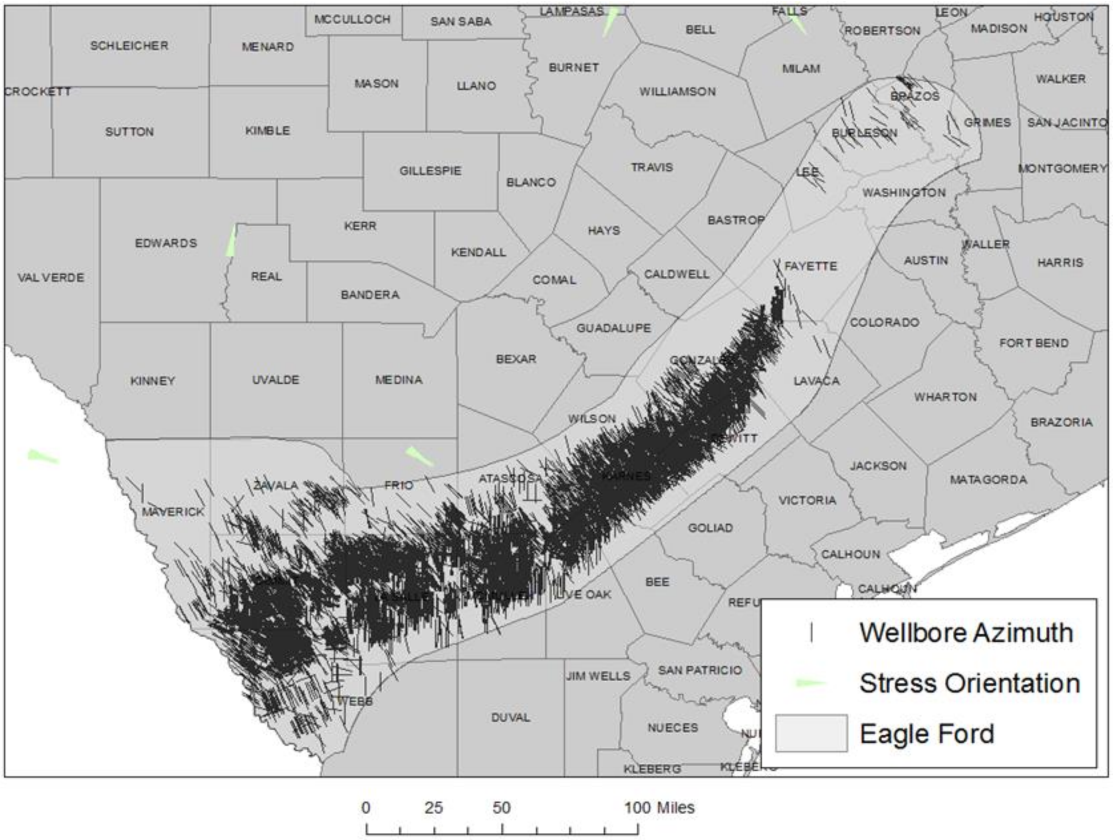

Figure 5.7. Eagle Ford Shale Stress Map (Drillinginfo 2014)

Table 5.2 summarizes the cumulative production and the first month production rate of the well wells from March 2010 to May 2014.

The cumulative oil production, cumulative gas production and maximum oil IP are normalized with regard to the well lateral length and shown in Figure 5.8 ~ Figure 5.10.

Table 5.2. Eagle Ford Well Production Data

Well Name	**Mustang Ranch #1H**	**Mustang Ranch C #1H**
Lateral length (ft)	5303	5824
Fracture configuration	Longitudinal fractures	Transverse fractures
Start Production Date	3/1/2010	7/1/2010
Available data end Date	5/31/2014	5/31/2014
Total production time of study (month)	51 months	47 months
Max Oil IP (bbl/d)	381	355
Max Gas IP (scf/d)	0	181
1st year Oil Cum (bbl)	20141	49579
2 years Oil Cum (bbl)	31312	74813
3 years Oil Cum (bbl)	39248	95501
Total Oil Production (bbl)	42485	111019
Average Oil Production (bbl/month)	833	2362
1st year Gas Cum (bbl)	0	10475
2 years Gas Cum (bbl)	0	16359
3 years Gas Cum (bbl)	768	24805
Total Gas Production (bbl)	1424	32939
Average Gas Production (bbl/month)	28	701

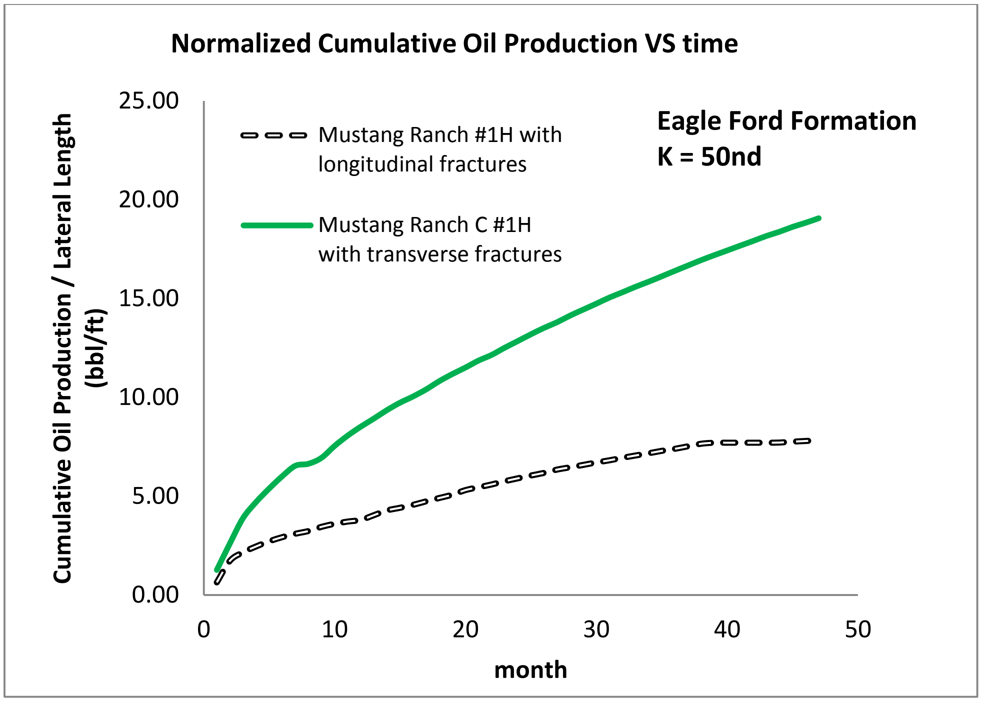

Figure 5.8. Eagle Ford Oil Well Cumulative Oil Production Comparison

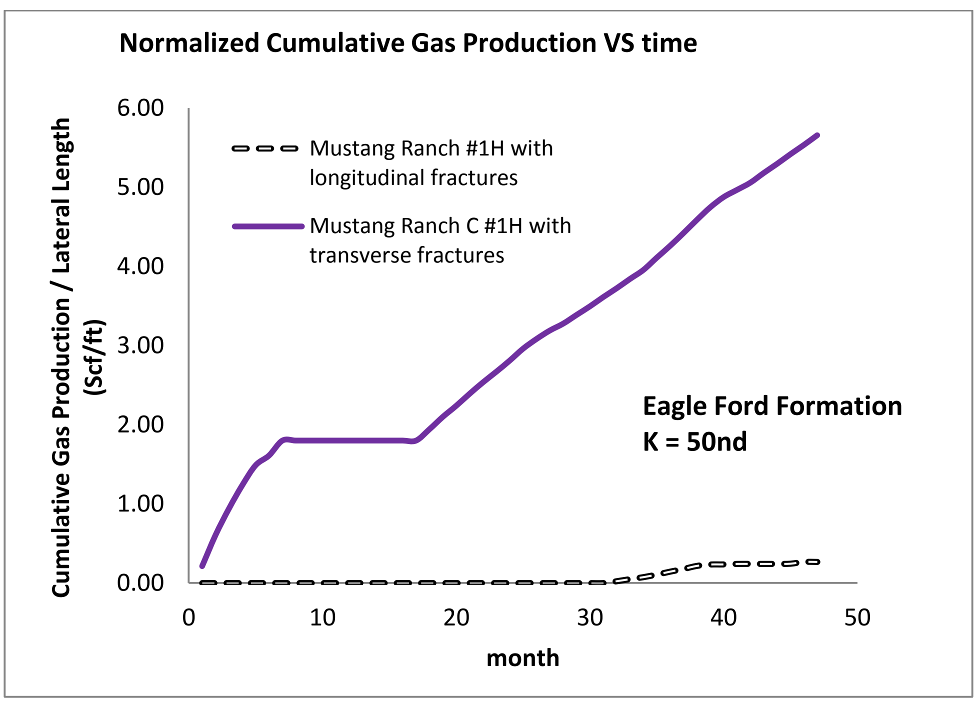

Figure 5.9. Eagle Ford Oil Well Cumulative Gas Production Comparison

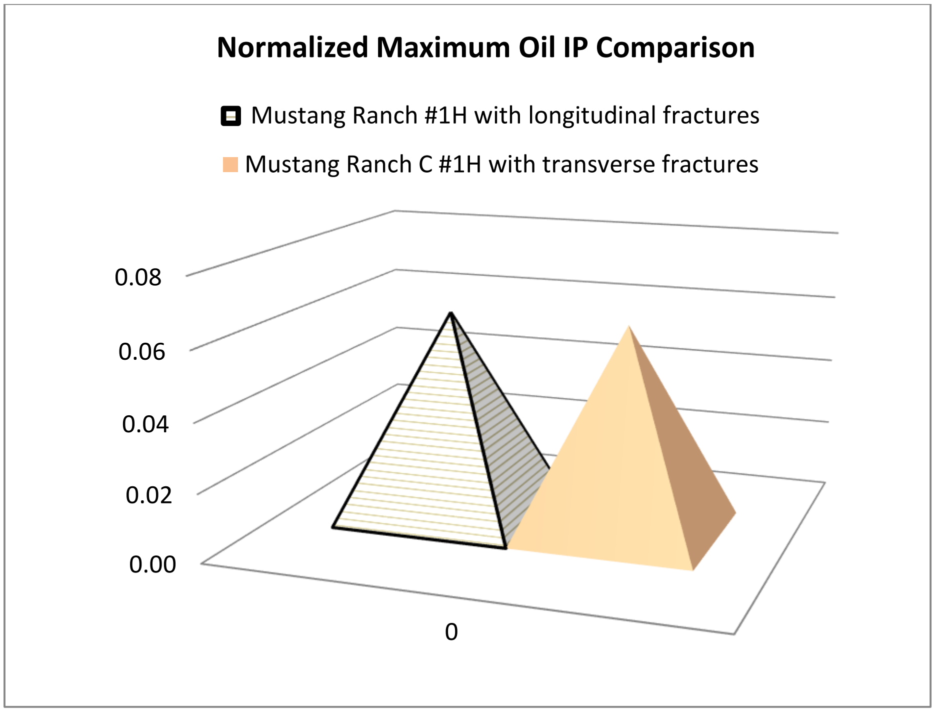

Figure 5.10. Eagle Ford Oil Well Maximum Oil IP Comparison

In the red hawk area of Eagle Ford formation where the average reservoir permeability is 50nd, transverse fractures yielded much higher cumulative Oil production than longitudinal fractures.

5.2.2. Bakken Shale Oil Field. The Bakken Shale, also referred to as the North Dakota Shale, is a rock unit from the Late Devonian to Early Mississippian age, which stretches down from Canada into North Dakota and Montana (Figure 5.11).

The Bakken Shale covers the area of 200,000 square miles. The average permeability is 0.04 md.

The first horizontal well in the Bakken formation was drilled by Meridian Oil in 1987. By the end of 2010, oil production rates of Bakken Shale had reached 458,000barrels per day outstripping the capacity to ship oil out of the Bakken (Gulf Oil & Gas Webpage)

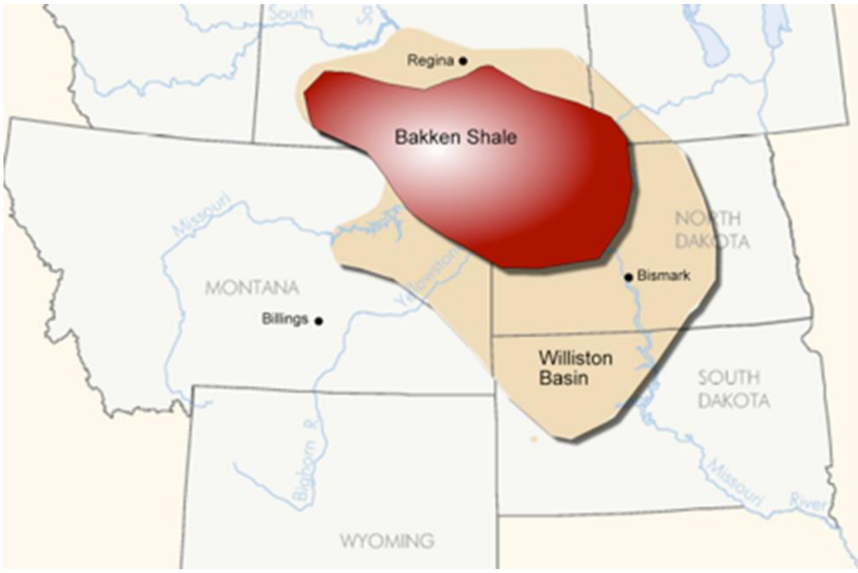

Figure 5.11. Bakken Location Map (InvestingDaily 2014)

Eight horizontal fractured oil wells from the Bakken Shale were investigated.

Two oil wells (16275 & 16623) in Divide County of North Dakota were compared separately from other wells. The two wells are producing from the Bakken producing pool. They were both drilled and completed in 2007. The other six fractured horizontal oil wells were from McKenzie Mountrail and Williams County. They were completed between 2005 and 2009.

The maximum horizontal stress direction on Divide County is shown in the Bakken Stress map (Figure 5.12). The wellbore direction was identified from the well location map (Figure 5.13 and Figure 5.14) provided by North Dakota Industrial Commission (NDIC), Department of Mineral Resources, Oil and Gas Division.

Well 16725 was drilled in the direction of maximum horizontal stress, which indicates longitudinal fractures were created after hydraulic fracturing. Well 16623 is normal to well 16725, transverse fractures were created after stimulation (Figure 5.14).

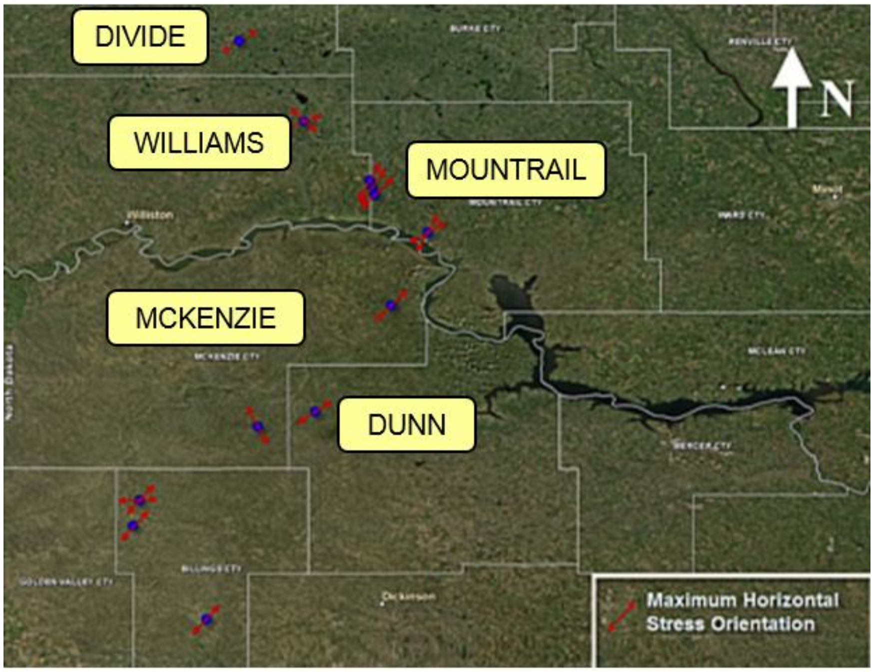

Figure 5.12. Bakken Stress Map (NETL 2014)

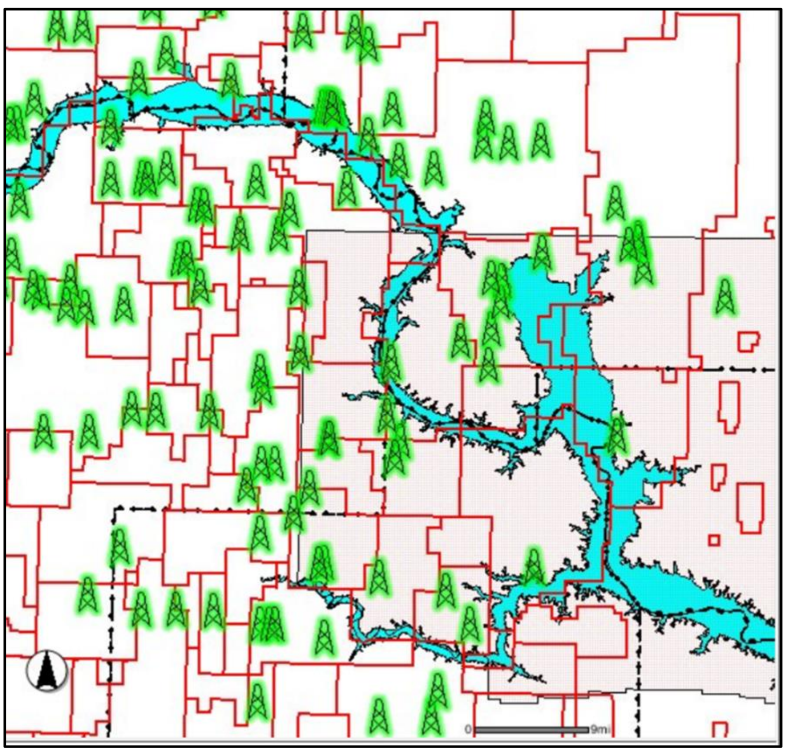

Figure 5.13. North Dakota Well Map (NDIC 2014)

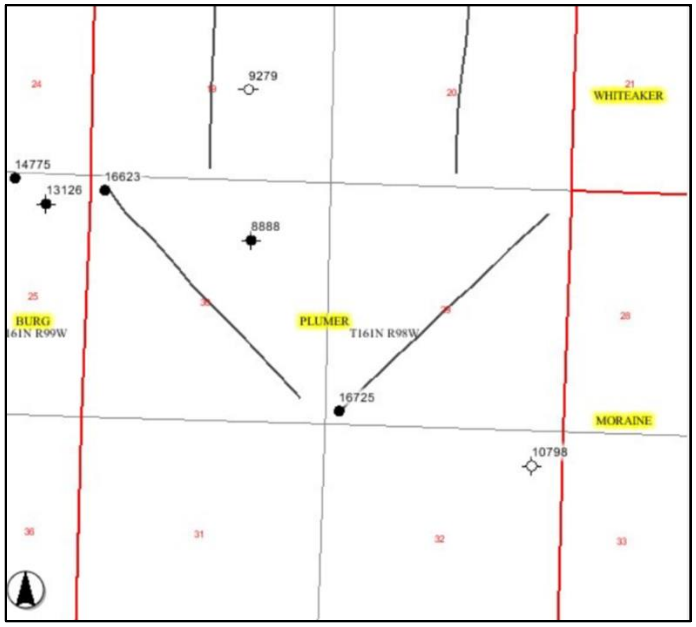

Figure 5.14. Oil Well 16725 & 16623 Map (NDIC 2014)

Table 5.3 lists the production data for these two wells.

Table 5.3. Production History of Bakken Oil Wells 16623 &16725

Well file No.	**16623**	**16725**
County	Divide	Divide
Lateral length (ft)	5706	5735
Fracture configuration	Transverse fractures	Longitudinal fractures
Start Production	9/24/2007	11/17/2007
Available data end on	8/31/2014	8/31/2014
Total producing time of study (day)	1973	2073
Total producing time period of study	Sep, 2007 – Aug, 2014	Nov, 2007 – Aug, 2014
Total Oil Production (bbl)	31152	17547
Average Oil Cum (bbl/day)	15.8	8.5
Total Gas Production (Mscf)	36867	43330
Average Gas Cum (Mscf/day)	18.7	20.9
Oil IP (bbl/d)	182	119
Gas IP (Mscf/d)	114	65

The cumulative production and IP of well 16623 and 16725 were normalized with regard to the well lateral length and compared in Figure 5.15 and 5.16

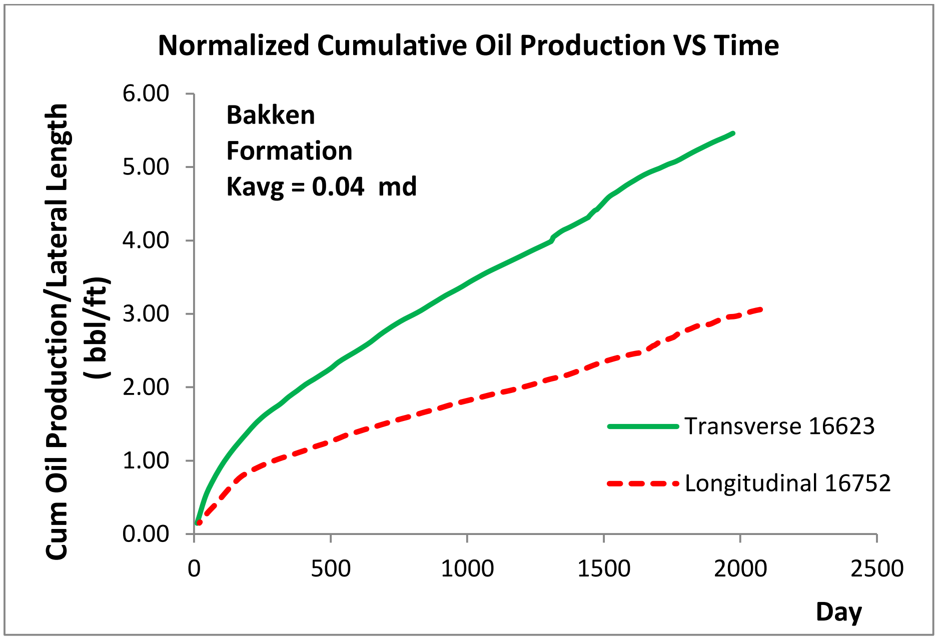

Figure 5.15. Cumulative Oil Production Comparison of Bakken Two Wells

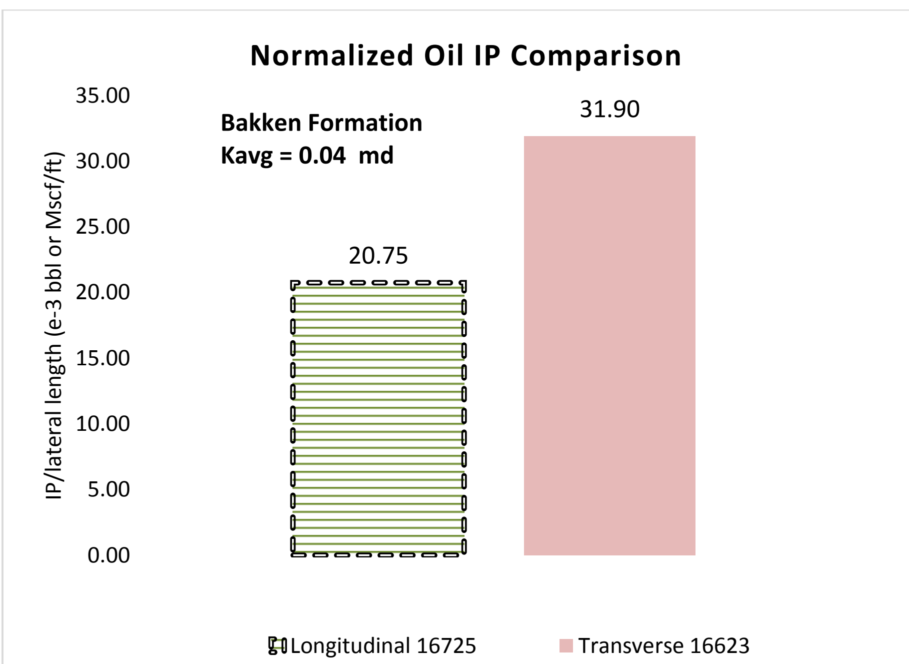

Figure 5.16. IP Comparison of Bakken Two Wells

Similarly, three more transverse fractured wells and three more longitudinal fractured wells from McKenzie Mountrail and Williams County were identified. Table 5.4 lists the production information for these wells.

Table 5.4. Production History of Bakken Six Oil Wells

Bakken Horizontal Well with Transverse Fractures						
Well file No.	1st year production (bbl)	2nd year production (bbl)	3rd year production (bbl)	Lateral Length (ft)	Start Production	County
18105	128456	57986	42311	9301	11/29/2009	McKenzie
17472	40401	15889	10553	5075	2/24/2009	McKenzie
17387	25753	17092	10597	5485	10/25/2008	McKenzie
Bakken Horizontal Well with Longitudinal Fractures						
Well file No.	1st year production (bbl)	2nd year production (bbl)	3rd year production (bbl)	Lateral Length (ft)	Start Production	County
17077	43844	15204	12034	10387	3/31/2008	Mountrail
16617	5999	2490	1768	8650	7/12/2007	Williams
15905	7243	3526	2508	3793	8/6/2005	Divide

Based on the available production data, the first three years cumulative production of these six wells are compared (Figure 5.17). The cumulative production is normalized with regard to the lateral length of each well.

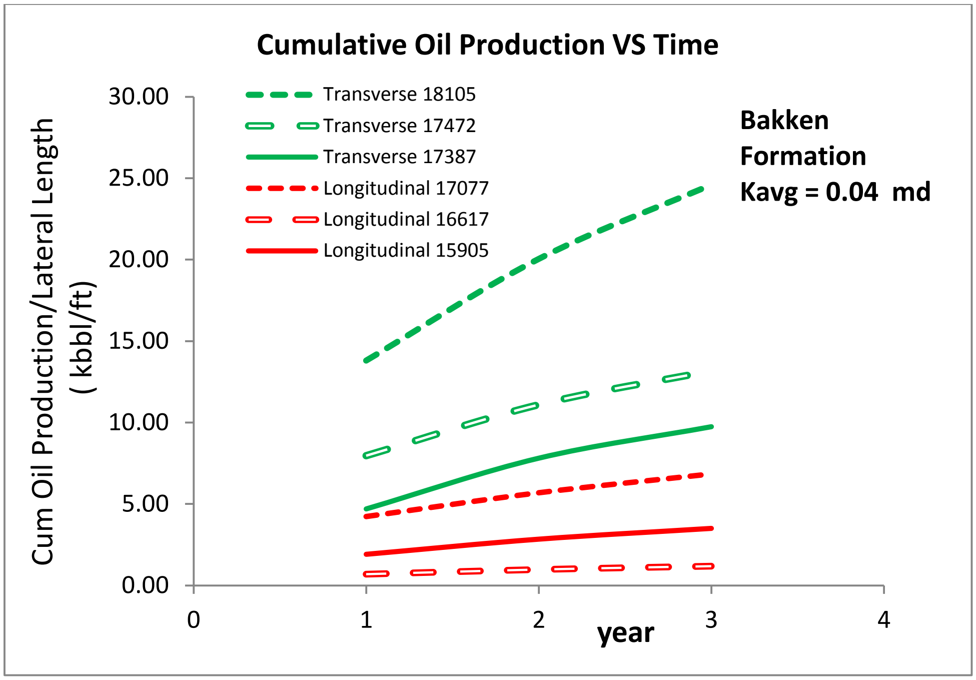

Figure 5.17. Cumulative Oil Production Comparison of Bakken Six Wells

In the Bakken formation where the average reservoir permeability is about 0.04 md, horizontal wells with transverse fractures have higher cumulative Oil production and higher oil IP than the horizontal wells with longitudinal fractures.

5.2.3. Delaware Basin Oil Field. This Study investigates four wells from the Bone Spring formation in the Delaware Basin. The reservoir permeability in the area of study is within 0.5~7.2 md and require artificial stimulation to produce.

The Delaware basin is one part of the Permian Basin in West Texas (Figure 5.18). The Permian basin is one of the oldest and most widely recognized oil and gas producing regions in the US. It covers approximately 86,000 square miles and encompasses 52 counties in New Mexico and Texas (Shale Experts webpage). It is comprised of several smaller basins: Delaware Basin, Midland Basin and Marfa Basin. Within these basins there are a number of "pay zones" including the Spraberry, Wolfberry, Wolfcamp, Bone Spring, and Avalon & Leonard Shales. The reservoir thicknesses range up to 50 ft.

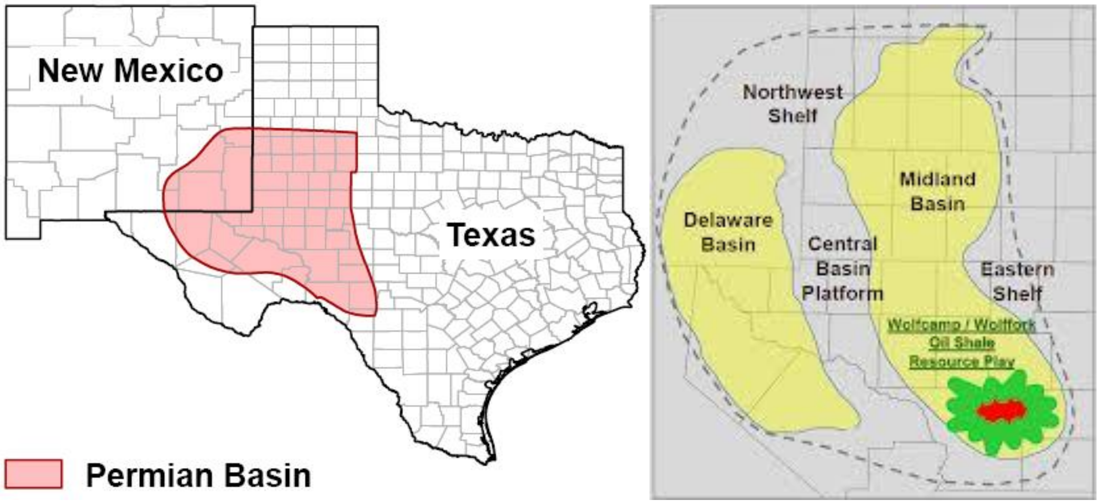

Figure 5.18. Delaware Basin Location (Shale Experts webpage)

The maximum horizontal stress direction is east west, determined from the US stress map (Figure 5.19).

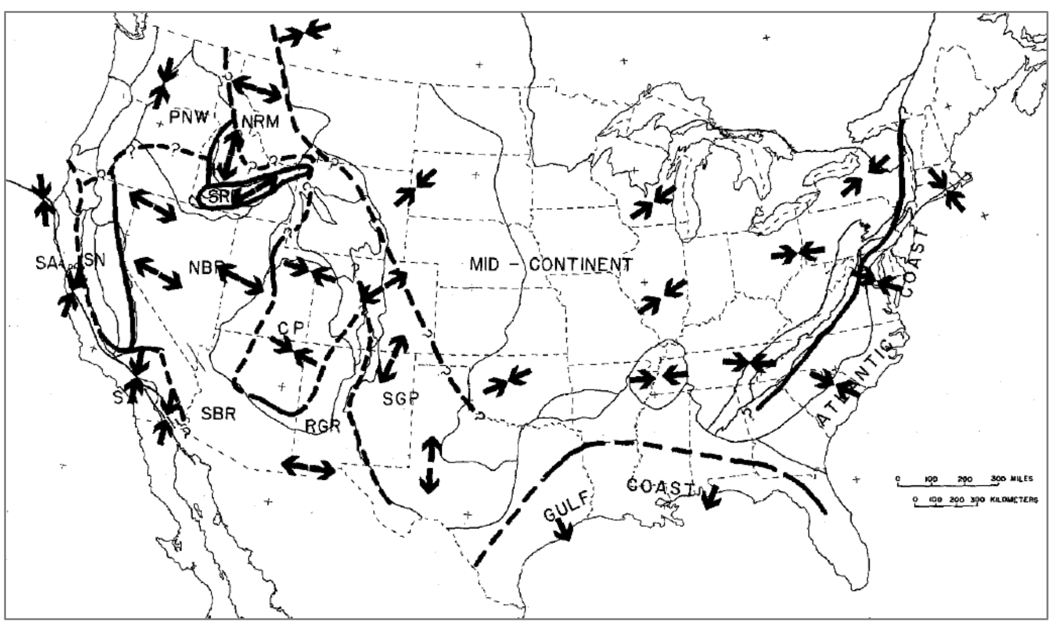

Figure 5.19. State of Stress in Conterminous U.S. (Zoback & Zoback 1980)

The wellbore direction is determined from the proprietary well map in the area of study and not shown here. Based on above two maps, the fracture configuration is identified, which is listed in Table 5.5.

The production data is summarized in below table.

Table 5.5. Production History of Delaware Basin Four Oil Wells

	LOS MEDANOS #1H	James Ranch #119H	James Ranch #120H	James Ranch #121H
Lateral length (ft)	4174	7102	6961	4479
Fracture configuration	Transverse fractures	Longitudinal fractures	Longitudinal fractures	Longitudinal fractures
Start Production	2/1/2013	3/1/2011	8/1/2011	4/1/2011
Available data end on	6/30/2014	6/30/2014	6/30/2014	6/30/2014
Total production time of study (month)	17 months	40 months	35 months	39 months
1st Month Oil IP (bbl/d)	369	329	57	135
1st Month Gas IP (scf/d)	307	276	132	127
1st Month Water IP (bbl/d)	402	1747	2413	1280
17 month Oil Cum (bbl)	43943	112419	108505	102067
Average Oil Production (bbl/day)	95	233	226	202
17 month Gas Cum (scf)	221166	219835	222267	236078
Average Gas Production (bbl/day)	476	455	463	467

The production history data is normalized with respect to the well lateral length. The comparison of cumulative production and 17 months average production rate among these four wells are presented in Figure 5.20 and Figure 5.21.

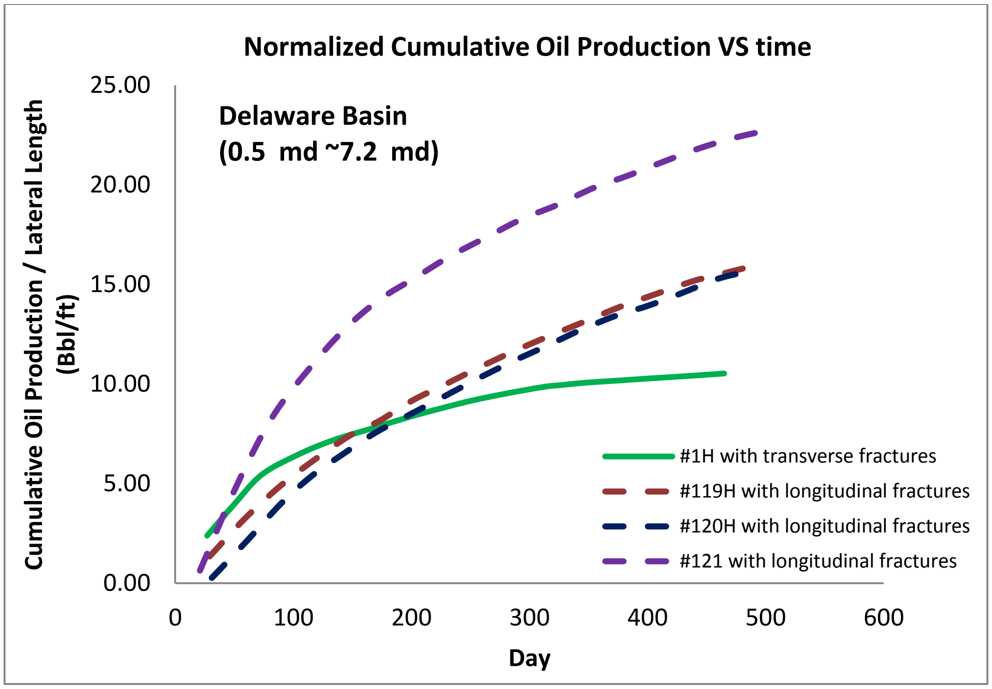

Figure 5.20. Delaware Oil Wells Cumulative Production Comparison

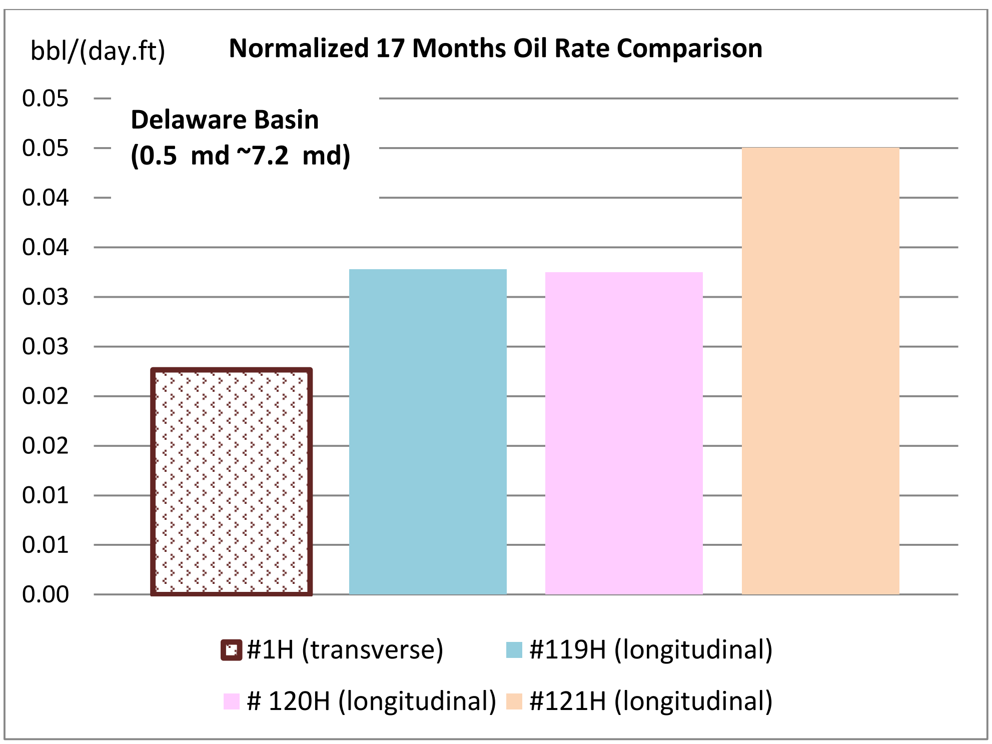

Figure 5.21. Delaware Oil Wells IP Comparison

In the Bone Spring formation of Delaware basin where the reservoir permeability is ranging from 0.5 md to 7.2 md, horizontal wells with longitudinal fractures (#119H, #120H & #121H) have higher cumulative Oil production and higher average oil rate than the well with transverse fractures (#1H).

In summary, three oil fields were studied, including an unconventional reservoir (50 n D, Eagle Ford Shale), a tight reservoir (0.04 md, Bakken Shale) and a moderate reservoir (0.5~7.2 md, Delaware Basin).

In low permeability formation, transverse fractures yielded higher cumulative oil production than longitudinal fractures. In high permeability formation, longitudinal fracture configuration resulted in higher cumulative oil production.

6. CONCLUSIONS AND DISCUSSIONS

This study compares the performance between transverse and longitudinal fractured horizontal well in gas and oil reservoir respectively. The main well performance indicators (IP, EUR, DR, PV & NPV) are evaluated over varied permeability through simulating the production of a series of transverse and longitudinal fractured horizontal gas and oil wells.

The results of this study demonstrate that a critical reservoir permeability exists. Longitudinal fractured horizontal wells outperform transverse fractured horizontal wells in reservoirs with permeability above this threshold. Below this critical permeability, a transition zone occurs; within which longitudinal may still perform better depending on the number of fractures of the transverse horizontal well compared.

The study also shows that the critical reservoir permeability is dependent on the horizontal well and fracture design. Generally, altering the lateral length (L), fracture half-length (X_f) or dimensionless fracture conductivity (F_{CD}) slightly changes the critical reservoir permeability. However, different completion methods creates a much different critical reservoir permeability.

6.1. FRACTURE CONFIGURATION IN GAS RESERVOIRS

This session discusses the optimal fracture configuration for gas reservoir and the impact of different well and fracture design.

Generally, transverse horizontal well is more attractive at low permeability reservoir, while longitudinal fracture well shows advantage at high permeability reservoir.

With open hole completion, transverse fracture configuration is optimal for gas reservoir with permeability below 0.01 md. Longitudinal fractured horizontal well is preferred in gas reservoirs with permeability over 0.04 md in terms of 50-year PV (Figure 4.17).

With cased hole completion, longitudinal fracture has advantage over transverse fractured well in gas reservoir with permeability over 1.5 md, according to the comparison of 50-year PV (Figure 4.41). However, in terms of EUR, longitudinal fractured horizontal well outperforms transversely fractured horizontal well when the gas reservoir permeability is over 0.5 md (Figure 4.40). This is in accordance with the recommendation from Economides and Martin that longitudinal fractured well should be considered for gas reservoir with permeability above 0.5 md due to higher productivity (Economides and Martin 2007)

It is shown that in low permeability gas reservoir (k<0.001 md), completion method does not make much different for both fracture configurations. For reservoir with permeability over 0.01 md, open hole completion results in higher performance for both transverse and longitudinal fractured horizontal well (Figure 4.41).

For gas reservoir between 0.00005 md to 1 md, higher lateral leads to higher performance for gas wells. However, when the reservoir permeability is very high (e.g. 1 md), increasing lateral length does not improve well performance that much for a given drainage area (Figure 4.31).

According to the evaluation on F_{CD}, given the fracture half-length unchanged, decreasing the fracture conductivity does not affect the performance longitudinal fracture configuration. However, it affects transverse fracture configuration at gas reservoir permeability below 0.01 md, within this range, higher fracture conductivity, better well performance (Figure 4.26).

Gas field study on unconventional reservoir (Barnett Shale, Figure 5.3) and conventional gas reservoir (0.1~50 md, Hugoton gas field, Figure 5.5) testifies that in unconventional gas reservoir, transversely fractured horizontal well outperforms longitudinally fractured horizontal well in terms of cumulative gas production. While in conventional reservoir, longitudinal fracture configuration results in higher cumulative gas production.

6.2. FRACTURE CONFIGURATION IN OIL RESERVOIRS

This session discusses the optimal fracture configuration for oil reservoir and the impact of different well and fracture design.

Generally, transverse horizontal well is more attractive at low permeability reservoir, while longitudinal fracture well shows advantage at high permeability reservoir.

With open hole completion, transverse fracture configuration is optimal for oil reservoir with permeability below 0.1 md, longitudinal fractured horizontal well is preferred in gas reservoirs with permeability over 0.4 md in terms of 50-year PV (Figure 4.62).

With cased hole completion, under the reservoir permeability range studied, which is 0.00005 md to 5 md, longitudinal fracture configuration has no advantage over transverse fracture configuration in term of all comparison criteria (Figure 4.85~ Figure 4.89). Economides et al suggested that longitudinal fracture well has higher productivity at reservoir permeability over 10 md (Economides et al. 2010). This permeability has not been investigated in this work, which can be further studied in future work.

It is shown that in low permeability oil reservoir ($k<0.01$ md), completion method does not make much difference for both fracture configurations. In oil reservoir with permeability over 0.1 md, open hole completion results in higher performance for both transverse and longitudinal fractured horizontal well (Figure 4.88).

For oil reservoir between 0.00005 md to 5 md, higher lateral leads to higher performance. When the reservoir permeability is very high (e.g. 5 md), increasing lateral length does not improve well performance that much for a given drainage area (Figure 4.78).

According to the evaluation on F_{CD} (Figure 4.73), given the fracture half-length unchanged, decreasing the fracture conductivity does not affect the performance longitudinal fracture configuration. However, it affects transverse fracture configuration, higher fracture conductivity, better well performance. In addition, the advantage of higher fracture conductivity increase as reservoir permeability decreases.

The oil field on unconventional reservoir (50 n D, Eagle Ford Shale, Figure 5.8), tight reservoir (0.04 md, Bakken Shale, Figure 5.15 and Figure 5.17) and moderate reservoir (0.5~7.2 md, Delaware Basin, Figure 5.20) validates that in low permeability formation, transversely fractured horizontal oil well outperforms longitudinally fractured horizontal oil well in terms of cumulative oil production. While in high permeability formation, longitudinal fracture configuration results in higher cumulative oil production.

7. FUTURE WORK

The comparison on the performance of transverse and longitudinal fractured horizontal well can be extended in the following areas.

First, multi phase reservoir fluid flow. This work assumes single-phase flow for all the simulations. Often times, the fluid flow in the fracture and the formation are multiphase and complex. It will improve the understanding of this topic to simulate multi-phase fluid in both transversely and longitudinally fractured horizontal well.

Second, multi horizontal laterals, well drainage optimization as well as fracture spacing optimization. In this study, one horizontal well is designed for all the simulation cases. Changing the drainage area, increasing the number of lateral or adjusting the spacing between fractures may affect the well performance of transverse and longitudinal configurations. As mentioned in the recent study on the comparison of transversely and longitudinally fractured horizontal well in moderate-permeability gas reservoirs, the optimization of drainage may improve the well performance in the greater degree than the well architecture (Liu et al. 2012). It is necessary to investigate the impact of well spacing and fracture spacing to guide the well and fracturing design.

Third, more field cases. Simulation results can be better validated with sufficient field data. Large amounts of field cases provide valuable practical references, especially when they cover a wide permeability range, various completion methods, and the economics.

Finally, fractured horizontal well with in-between well azimuth. In practice, many wells cannot be drilled in the desired direction due to lease boundaries or variations in localized stress regimes. Investigating the performance of fractured horizontal well with in-between well azimuth would be particularly useful for operators.

APPENDIX A.

GAS WELL SIMULATION RESULTS

Table A 1. Simulation Results & Calculated Value for Gas Well (6 T)

Horizontal Gas Well with 6 Transverse Fractures

Open Hole

F_{CD} = 30
X_f = 500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	398	0.9
case 2	0.0001	634	1.5
case 3	0.001	1565	3.9
case 4	0.01	3283	8.3
case 5	0.1	12882	31.4
case 6	0.5	22947	57.2
case 7	1	25579	64.1
case 8	5	28390	71.01

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	122	462	787	1533	2476
case 2	0.0001	194	728	1232	2377	3814
case 3	0.001	520	2176	3854	7629	11957
case 4	0.01	1110	4687	8309	16685	26248
case 5	0.1	4185	16155	25814	39488	46182
case 6	0.5	7623	27545	39575	47750	48190
case 7	1	8543	30361	42628	48167	48199
case 8	5	9466	33123	45500	48215	48276

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	359	513	697	1.5	2.1	2.9	-5.4	-4.8	-4.0
case 2	0.0001	565	804	1087	2.4	3.4	4.5	-4.6	-3.6	-2.4
case 3	0.001	1675	2470	3396	7.0	10.3	14.2	0.1	3.4	7.2
case 4	0.01	3606	5323	7370	15.0	22.2	30.7	8.1	15.3	23.8
case 5	0.1	12540	17165	20464	52.3	71.6	85.3	45.4	64.6	78.4
case 6	0.5	21570	27407	29505	89.9	114.3	123.0	83.0	107.4	116.1
case 7	1	23821	29800	31340	99.3	124.3	130.7	92.4	117.3	123.8
case 8	5	26032	32098	32956	108.6	133.8	137.4	101.6	126.9	130.5

Table A 2. Simulation Results & Calculated Value for Gas Well (12 T)

Horizontal Gas Well with 12 Transverse Fractures

Open Hole

F_{CD}=30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	782	1.8
case 2	0.0001	1223	2.8
case 3	0.001	2894	7.2
case 4	0.01	4812	12.2
case 5	0.1	14117	34.6
case 6	0.5	23331	58.3
case 7	1	25764	64.6
case 8	5	28421	71.08

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	241	910	1545	2972	4621
case 2	0.0001	377	1415	2382	4421	6512
case 3	0.001	966	3860	6379	11006	15452
case 4	0.01	1628	6581	11274	21337	31657
case 5	0.1	4608	17641	27869	41543	47269
case 6	0.5	7766	28044	40194	47952	48188
case 7	1	8612	30604	42926	48188	48229
case 8	5	9477	33158	45542	48266	48370

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	706	1008	1357	2.9	4.2	5.7	-4.6	-3.3	-1.9
case 2	0.0001	1099	1559	2056	4.6	6.5	8.6	-2.9	-1.0	1.1
case 3	0.001	2987	4188	5321	12.5	17.5	22.2	4.9	10.0	14.7
case 4	0.01	5085	7313	9762	21.2	30.5	40.7	13.7	23.0	33.2
case 5	0.1	13708	18611	21910	57.2	77.6	91.4	49.7	70.1	83.9
case 6	0.5	21964	27862	29877	91.6	116.2	124.6	84.1	108.7	117.1
case 7	1	24013	30020	31505	100.1	125.2	131.4	92.6	117.7	123.9
case 8	5	26060	32130	32987	108.7	134.0	137.6	101.2	126.5	130.0

Table A 3. Simulation Results & Calculated Value for Gas Well (18 T)

Horizontal Gas Well with 18 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1162	2.7
case 2	0.0001	1837	4.2
case 3	0.001	4182	10.4
case 4	0.01	6251	15.7
case 5	0.1	15131	37.1
case 6	0.5	23639	59.1
case 7	1	25914	65.0
case 8	5	28443	71.14

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	357	1346	2272	4184	6058
case 2	0.0001	564	2094	3434	5854	7929
case 3	0.001	1386	5150	7986	12520	16715
case 4	0.01	2089	8090	13459	24297	34511
case 5	0.1	4945	18785	29407	42932	47754
case 6	0.5	7881	28438	40673	48062	48193
case 7	1	8668	30799	43161	48208	48267
case 8	5	9484	33186	45576	48313	48431

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	1045	1485	1950	4.4	6.2	8.1	-3.7	-1.9	0.0
case 2	0.0001	1628	2267	2856	6.8	9.5	11.9	-1.3	1.4	3.8
case 3	0.001	4017	5375	6492	16.7	22.4	27.1	8.7	14.3	19.0
case 4	0.01	6276	8830	11459	26.2	36.8	47.8	18.1	28.7	39.7
case 5	0.1	14610	19706	22969	60.9	82.2	95.8	52.8	74.1	87.7
case 6	0.5	22275	28218	30159	92.9	117.7	125.8	84.8	109.6	117.7
case 7	1	24167	30195	31636	100.8	125.9	131.9	92.7	117.8	123.8
case 8	5	26083	32155	33012	108.8	134.1	137.7	100.7	126.0	129.6

Table A 4. Simulation Results & Calculated Value for Gas Well (24 T)

Horizontal Gas Well with 24 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1543	3.6
case 2	0.0001	2431	5.6
case 3	0.001	5428	13.3
case 4	0.01	7597	18.8
case 5	0.1	16008	39.2
case 6	0.5	23904	59.8
case 7	1	26044	65.4
case 8	5	28463	71.19

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	475	1785	2958	5123	6977
case 2	0.0001	748	2728	4301	6781	8687
case 3	0.001	1774	6141	9033	13296	17345
case 4	0.01	2500	9317	15116	26261	36116
case 5	0.1	5226	19717	30633	43934	47965
case 6	0.5	7977	28764	41059	48113	48190
case 7	1	8716	30965	43355	48208	48289
case 8	5	9491	33211	45605	48327	48463

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	1387	1945	2471	5.8	8.1	10.3	-2.9	-0.6	1.6
case 2	0.0001	2127	2880	3485	8.9	12.0	14.5	0.2	3.3	5.9
case 3	0.001	4825	6216	7271	20.1	25.9	30.3	11.4	17.3	21.6
case 4	0.01	7254	10017	12716	30.3	41.8	53.0	21.6	33.1	44.4
case 5	0.1	15346	20588	23798	64.0	85.9	99.2	55.3	77.2	90.6
case 6	0.5	22533	28507	30383	94.0	118.9	126.7	85.3	110.2	118.0
case 7	1	24298	30341	31741	101.3	126.5	132.4	92.7	117.9	123.7
case 8	5	26102	32177	33029	108.8	134.2	137.7	100.2	125.5	129.1

Table A 5. Simulation Results & Calculated Value for Gas Well (30 T)

Horizontal Gas Well with 30 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1922	4.4
case 2	0.0001	3018	7.0
case 3	0.001	6621	15.9
case 4	0.01	8844	21.5
case 5	0.1	16770	41.0
case 6	0.5	24131	60.4
case 7	1	26157	65.7
case 8	5	28480	71.24

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	593	2204	3557	5814	7566
case 2	0.0001	930	3288	4981	7385	9124
case 3	0.001	2126	6899	9718	13738	17713
case 4	0.01	2868	10324	16388	27601	37076
case 5	0.1	5465	20488	31629	44665	48055
case 6	0.5	8059	29038	41379	48144	48198
case 7	1	8758	31107	43517	48204	48303
case 8	5	9498	33235	45632	48346	48498

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	1715	2361	2909	7.2	9.8	12.1	-2.1	0.6	2.9
case 2	0.0001	2574	3387	3976	10.7	14.1	16.6	1.5	4.9	7.3
case 3	0.001	5458	6818	7814	22.8	28.4	32.6	13.5	19.2	23.3
case 4	0.01	8065	10958	13671	33.6	45.7	57.0	24.4	36.4	47.8
case 5	0.1	15957	21311	24460	66.5	88.9	102.0	57.3	79.6	92.7
case 6	0.5	22750	28749	30568	94.9	119.9	127.5	85.6	110.6	118.2
case 7	1	24410	30464	31828	101.8	127.0	132.7	92.5	117.8	123.5
case 8	5	26121	32197	33047	108.9	134.3	137.8	99.7	125.0	128.6

Table A 6. Simulation Results & Calculated Value for Gas Well (36 T)

Horizontal Gas Well with 36 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2287	5.3
case 2	0.0001	3534	8.2
case 3	0.001	7491	17.8
case 4	0.01	9992	24.0
case 5	0.1	17425	42.5
case 6	0.5	24323	61.0
case 7	1	26252	66.0
case 8	5	28494	71.28

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	704	2574	4042	6302	7939
case 2	0.0001	1089	3729	5469	7752	9359
case 3	0.001	2372	7365	10081	13949	17876
case 4	0.01	3195	11151	17371	28535	37683
case 5	0.1	5666	21123	32435	45200	48093
case 6	0.5	8126	29262	41636	48158	48204
case 7	1	8792	31225	43651	48202	48324
case 8	5	9503	33253	45652	48351	48515

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	2007	2710	3260	8.4	11.3	13.6	-1.5	1.5	3.8
case 2	0.0001	2931	3768	4330	12.2	15.7	18.1	2.4	5.9	8.2
case 3	0.001	5855	7168	8125	24.4	29.9	33.9	14.6	20.1	24.0
case 4	0.01	8737	11708	14408	36.4	48.8	60.1	26.6	39.0	50.3
case 5	0.1	16461	21900	24989	68.6	91.3	104.2	58.8	81.5	94.4
case 6	0.5	22928	28944	30716	95.6	120.7	128.1	85.8	110.9	118.3
case 7	1	24503	30567	31901	102.2	127.5	133.0	92.3	117.6	123.2
case 8	5	26135	32213	33056	109.0	134.3	137.8	99.2	124.5	128.0

Table A 7. Simulation Results & Calculated Value for Gas Well (42 T)

Horizontal Gas Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2660	6.1
case 2	0.0001	4093	9.4
case 3	0.001	8817	20.4
case 4	0.01	11063	26.2
case 5	0.1	18030	43.9
case 6	0.5	24502	61.4
case 7	1	26342	66.2
case 8	5	28511	71.32

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	820	2930	4478	6693	8216
case 2	0.0001	1260	4146	5894	8041	9548
case 3	0.001	2725	7932	10483	14219	18122
case 4	0.01	3491	11850	18158	29224	38107
case 5	0.1	5849	21691	33144	45617	48115
case 6	0.5	8188	29464	41866	48164	48208
case 7	1	8825	31333	43773	48204	48331
case 8	5	9508	33272	45674	48385	48565

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	2291	3034	3575	9.6	12.7	14.9	-0.9	2.2	4.5
case 2	0.0001	3274	4117	4647	13.7	17.2	19.4	3.2	6.8	9.0
case 3	0.001	6350	7585	8508	26.5	31.6	35.5	16.1	21.2	25.1
case 4	0.01	9310	12325	15002	38.8	51.4	62.6	28.4	41.0	52.1
case 5	0.1	16913	22423	25133	70.5	93.5	104.8	60.1	83.1	94.4
case 6	0.5	23089	29120	30432	96.3	121.4	126.9	85.9	111.0	116.5
case 7	1	24589	30661	31967	102.5	127.9	133.3	92.1	117.4	122.9
case 8	5	26150	32229	33074	109.0	134.4	137.9	98.6	124.0	127.5

Table A 8. Simulation Results & Calculated Value for Gas Well (100 T)

Horizontal Gas Well with 100 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	6038	11.0
case 2	0.0001	8817	19.0
case 3	0.001	16195	33.1
case 4	0.01	18118	39.3
case 5	0.1	21789	52.0
case 6	0.5	25634	64.2
case 7	1	26918	67.7
case 8	5	28609	71.59

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	1803	5054	6537	8027	9045
case 2	0.0001	2535	6226	7534	8899	10145
case 3	0.001	4415	9531	11419	14907	18723
case 4	0.01	5242	15047	21239	31489	39379
case 5	0.1	6935	24858	36824	47002	48147
case 6	0.5	8562	30610	43113	48153	48250
case 7	1	9025	31962	44439	48203	48388
case 8	5	9544	33397	45807	48705	49141

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	4061	4782	5154	16.9	19.9	21.5	0.9	3.9	5.5
case 2	0.0001	5079	5718	6061	21.2	23.8	25.3	5.2	7.8	9.3
case 3	0.001	7897	8805	9661	32.9	36.7	40.3	16.9	20.7	24.3
case 4	0.01	12024	14992	17472	50.1	62.5	72.9	34.1	46.5	56.8
case 5	0.1	19448	25227	27775	81.1	105.2	115.8	65.1	89.2	99.8
case 6	0.5	24004	30096	31553	100.1	125.5	131.6	84.1	109.5	115.6
case 7	1	25090	31188	32330	104.6	130.1	134.8	88.6	114.0	118.8
case 8	5	26248	32334	33198	109.5	134.8	138.4	93.4	118.8	122.4

Table A 9. Simulation Results & Calculated Value for Gas Well (4 L)

Horizontal Gas Well with four longitudinal Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1374	2.1
case 2	0.0001	1995	2.9
case 3	0.001	6694	9.5
case 4	0.01	16286	27.5
case 5	0.1	24257	54.4
case 6	0.5	27194	67.0
case 7	1	27929	69.6
case 8	5	28871	72.15

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	274	634	910	1458	2087
case 2	0.0001	393	907	1297	2084	3001
case 3	0.001	1265	2974	4293	7048	10299
case 4	0.01	3661	9799	14568	23954	32812
case 5	0.1	7256	24794	36067	46024	48021
case 6	0.5	8926	31409	43714	48179	48189
case 7	1	9282	32560	44940	48180	48182
case 8	5	9619	33590	45998	48181	48182

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	514	646	781	2.1	2.7	3.3	-5.4	-4.8	-4.3
case 2	0.0001	735	921	1115	3.1	3.8	4.7	-4.4	-3.7	-2.9
case 3	0.001	2407	3036	3714	10.0	12.7	15.5	2.5	5.1	8.0
case 4	0.01	7840	10114	12392	32.7	42.2	51.7	25.2	34.7	44.2
case 5	0.1	19472	24924	27398	81.2	103.9	114.2	73.7	96.4	106.7
case 6	0.5	24665	30675	31967	102.9	127.9	133.3	95.3	120.4	125.8
case 7	1	25581	31641	32640	106.7	131.9	136.1	99.2	124.4	128.6
case 8	5	26405	32493	33204	110.1	135.5	138.5	102.6	128.0	130.9

Table A 10. Simulation Results & Calculated Value for Gas Well (42)- F_{CD} = 2

Horizontal gas Well with 42 Transverse Fractures

Open Hole

F_{CD} =2
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005		
case 2	0.0001		
case 3	0.001	3792	9.0
case 4	0.01	9878	23.3
case 5	0.1	17883	43.4
case 6	0.5	24482	61.3
case 7	1	26335	66.2
case 8	5	28509	71.32

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005					
case 2	0.0001					
case 3	0.001	1202	4246	6547	10597	14710
case 4	0.01	3109	10663	16543	27262	36398
case 5	0.1	5782	21436	32794	45331	48094
case 6	0.5	8176	29412	41795	48155	48178
case 7	1	8820	31312	43743	48162	48165
case 8	5	9508	33270	45669	48155	48177

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001									
case 3	0.001	3325	4425	5422	13.9	18.5	22.6	3.5	8.0	12.2
case 4	0.01	8367	11175	13771	34.9	46.6	57.4	24.5	36.2	47.0
case 5	0.1	16713	22176	25218	69.7	92.5	105.2	59.3	82.1	94.7
case 6	0.5	23048	29071	30809	96.1	121.2	128.5	85.7	110.8	118.1
case 7	1	24573	30640	31943	102.5	127.8	133.2	92.1	117.4	122.8
case 8	5	26149	32227	33025	109.0	134.4	137.7	98.6	124.0	127.3

Table A 11. Simulation Results & Calculated Value for Gas Well (4 L)- F_{CD} = 2

Horizontal gas Well with four longitudinal Fractures

Open Hole

F_{CD} =2
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005		
case 2	0.0001		
case 3	0.001	5265	8.2
case 4	0.01	15400	26.2
case 5	0.1	24076	54.0
case 6	0.5	27155	66.9
case 7	1	27913	69.6
case 8	5	28865	72.10

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005					
case 2	0.0001					
case 3	0.001	1088	2746	4043	6764	9992
case 4	0.01	3493	9516	14239	23586	32477
case 5	0.1	7201	24639	35890	45942	48012
case 6	0.5	8913	31370	43670	48179	48193
case 7	1	9276	32541	44918	48180	48182
case 8	5	9617	33587	45995	48180	48181

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001									
case 3	0.001	2208	2826	3496	9.2	11.8	14.6	1.7	4.3	7.1
case 4	0.01	7601	9852	12122	31.7	41.1	50.5	24.2	33.6	43.0
case 5	0.1	19348	24788	27283	80.7	103.4	113.8	73.2	95.9	106.3
case 6	0.5	24634	30641	31943	102.7	127.8	133.2	95.2	120.3	125.7
case 7	1	25567	31625	32629	106.6	131.9	136.1	99.1	124.4	128.6
case 8	5	26403	32490	33202	110.1	135.5	138.5	102.6	128.0	130.9

Table A 12. Simulation Results & Calculated Value for Gas Well (6 T)-L=2000 ft

Horizontal Gas Well with 6 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
2000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	391	0.9
case 2	0.0001	613	1.4
case 3	0.001	1460	3.7
case 4	0.01	2467	6.3
case 5	0.1	8645	21.1
case 6	0.5	19410	48.5
case 7	1	23500	59.0
case 8	5	28636	71.49

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	120	455	773	1493	2353
case 2	0.0001	189	708	1195	2249	3392
case 3	0.001	487	1974	3326	6012	8924
case 4	0.01	836	3481	6182	12784	21078
case 5	0.1	2816	11463	19368	33067	42422
case 6	0.5	6461	23936	35446	46205	48161
case 7	1	7868	28211	40182	47864	48205
case 8	5	9530	33098	45208	48216	48287

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	353	504	681	1.5	2.1	2.8	-4.4	-3.7	-3.0
case 2	0.0001	550	781	1039	2.3	3.3	4.3	-3.5	-2.6	-1.5
case 3	0.001	1526	2169	2829	6.4	9.0	11.8	0.5	3.2	6.0
case 4	0.01	2681	3960	5583	11.2	16.5	23.3	5.3	10.7	17.5
case 5	0.1	8847	12614	15914	36.9	52.6	66.4	31.1	46.8	60.5
case 6	0.5	18692	24251	26902	77.9	101.1	112.2	72.1	95.3	106.3
case 7	1	22112	27928	29915	92.2	116.5	124.7	86.4	110.6	118.9
case 8	5	26034	31972	32899	108.6	133.3	137.2	102.7	127.5	131.4

Table A 13. Simulation Results & Calculated Value for Gas Well (24 T)-L=2000 ft

Horizontal Gas Well with 24 Transverse Fractures

Open Hole

F_{CD} =30
Xf=500 ft
2000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1533	3.5
case 2	0.0001	2417	5.5
case 3	0.001	5318	12.0
case 4	0.01	6772	15.7
case 5	0.1	12666	30.4
case 6	0.5	21335	53.6
case 7	1	24559	61.9
case 8	5	28810	71.96

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	471	1644	2464	3604	4408
case 2	0.0001	735	2313	3216	4332	5192
case 3	0.001	1596	4403	5795	8153	10916
case 4	0.01	2089	7042	11168	19955	29225
case 5	0.1	4050	15712	25469	39883	46766
case 6	0.5	7146	26225	38243	47600	48218
case 7	1	8255	29513	41726	48181	48358
case 8	5	9593	33322	45477	48395	48604

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	1289	1683	1962	5.4	7.0	8.2	-2.2	-0.6	0.6
case 2	0.0001	1834	2271	2547	7.6	9.5	10.6	0.1	1.9	3.1
case 3	0.001	3543	4214	4798	14.8	17.6	20.0	7.2	10.0	12.4
case 4	0.01	5530	7493	9633	23.1	31.2	40.2	15.5	23.7	32.6
case 5	0.1	12184	16850	20311	50.8	70.3	84.7	43.2	62.7	77.1
case 6	0.5	20505	26324	28675	85.5	109.8	119.6	77.9	102.2	112.0
case 7	1	23143	29086	30830	96.5	121.3	128.6	88.9	113.7	121.0
case 8	5	26211	32172	33066	109.3	134.2	137.9	101.7	126.6	130.3

Table A 14. Simulation Results & Calculated Value for Gas Well (42 T)-L=2000 ft

Horizontal Gas Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
2000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2665	6.0
case 2	0.0001	4155	9.0
case 3	0.001	8574	17.3
case 4	0.01	10190	21.8
case 5	0.1	15292	35.9
case 6	0.5	22470	56.4
case 7	1	25196	63.6
case 8	5	28927	72.27

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	801	2364	3169	4071	4709
case 2	0.0001	1194	3036	3786	4639	5417
case 3	0.001	2301	4998	6169	8460	11214
case 4	0.01	2903	8537	12828	21757	30797
case 5	0.1	4781	17977	28470	42417	47498
case 6	0.5	7523	27421	39617	47965	48275
case 7	1	8478	30228	42515	48238	48443
case 8	5	9635	33466	45633	48609	49059

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	1888	2278	2502	7.9	9.5	10.4	-1.4	0.2	1.1
case 2	0.0001	2465	2830	3043	10.3	11.8	12.7	1.0	2.5	3.4
case 3	0.001	4131	4692	5258	17.2	19.6	21.9	7.9	10.3	12.6
case 4	0.01	6792	8835	11006	28.3	36.8	45.9	19.0	27.5	36.6
case 5	0.1	13981	19009	22363	58.3	79.3	93.3	49.0	70.0	83.9
case 6	0.5	21457	27371	29519	89.5	114.1	123.1	80.2	104.8	113.8
case 7	1	23712	29698	31291	98.9	123.8	130.5	89.6	114.5	121.2
case 8	5	26324	32294	33187	109.8	134.7	138.4	100.5	125.4	129.1

Table A 15. Simulation Results & Calculated Value for Gas Well (2 L)-L=2000 ft

Horizontal Gas Well with 2 Longitudinal Fractures

Open Hole

F_{CD} =30
X_f=500 ft
2000 ft Lateral

Production Rate

Case No.	K (md))	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	686	1.0
case 2	0.0001	995	1.5
case 3	0.001	3361	4.9
case 4	0.01	10501	16.1
case 5	0.1	20921	43.8
case 6	0.5	26022	63.4
case 7	1	27491	68.4
case 8	5	29557	73.55

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	138	320	461	744	1075
case 2	0.0001	198	460	661	1074	1564
case 3	0.001	654	1556	2279	3853	5836
case 4	0.01	2151	5725	8873	16036	24207
case 5	0.1	5839	20034	30338	42501	47020
case 6	0.5	8458	29833	41917	48064	48194
case 7	1	9114	31893	44087	48184	48189
case 8	5	9805	33922	46074	48181	48182

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	259	327	397	1.1	1.4	1.7	-4.7	-4.5	-4.2
case 2	0.0001	372	468	570	1.6	2.0	2.4	-4.3	-3.9	-3.5
case 3	0.001	1257	1601	1990	5.2	6.7	8.3	-0.6	0.8	2.5
case 4	0.01	4572	6067	7818	19.1	25.3	32.6	13.2	19.5	26.8
case 5	0.1	15699	20654	23613	65.5	86.1	98.5	59.6	80.3	92.6
case 6	0.5	23417	29304	30961	97.7	122.2	129.1	91.8	116.4	123.3
case 7	1	25063	31025	32227	104.5	129.4	134.4	98.7	123.5	128.6
case 8	5	26692	32662	33346	111.3	136.2	139.1	105.5	130.4	133.2

Table A 16. Simulation Results & Calculated Value for Gas Well (42 T)-X_f=250 ft

Horizontal Gas Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f =250 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005		
case 2	0.0001	2698	5.9
case 3	0.001	7802	16.2
case 4	0.01	10702	23.5
case 5	0.1	17766	42.1
case 6	0.5	24405	60.8
case 7	1	26291	65.9
case 8	5	28502	71.30

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005					
case 2	0.0001	785	2411	3383	4745	5951
case 3	0.001	2155	5370	7104	10305	13900
case 4	0.01	3139	10075	15466	25697	34896
case 5	0.1	5618	20689	31820	44673	48001
case 6	0.5	8112	29133	41468	48148	48191
case 7	1	8790	31172	43576	48182	48184
case 8	5	9505	33253	45650	48247	48352

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001	1915	2383	2720	8.0	9.9	11.3	-2.4	-0.5	0.9
case 3	0.001	4360	5192	5980	18.2	21.7	24.9	7.8	11.2	14.5
case 4	0.01	7947	10519	12999	33.1	43.9	54.2	22.7	33.5	43.8
case 5	0.1	16133	21483	24594	67.3	89.6	102.6	56.9	79.2	92.1
case 6	0.5	22830	28827	30628	95.2	120.2	127.7	84.8	109.8	117.3
case 7	1	24464	30517	31861	102.0	127.3	132.9	91.6	116.8	122.4
case 8	5	26135	32212	33036	109.0	134.3	137.8	98.6	123.9	127.4

Table A 17. Simulation Results & Calculated Value for Gas Well (8 L)-X_f=250 ft

Horizontal Gas Well with 8 Longitudinal Fractures

Open Hole

F_{CD} =30
X_f =250 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005		
case 2	0.0001	1920	2.9
case 3	0.001	6561	9.4
case 4	0.01	16237	27.4
case 5	0.1	24263	54.4
case 6	0.5	27211	67.0
case 7	1	27949	69.7
case 8	5	28883	72.18

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005					
case 2	0.0001	380	893	1284	2072	2992
case 3	0.001	1249	2957	4276	7032	10286
case 4	0.01	3651	9788	14557	23947	32811
case 5	0.1	7257	24798	36069	46026	48027
case 6	0.5	8930	31421	43723	48182	48194
case 7	1	9287	32573	44951	48184	48186
case 8	5	9623	33602	46007	48182	48183

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001	723	909	1104	3.0	3.8	4.6	-5.7	-4.9	-4.1
case 3	0.001	2392	3020	3699	10.0	12.6	15.4	1.3	3.9	6.8
case 4	0.01	7830	9799	12382	32.7	40.9	51.6	24.0	32.2	43.0
case 5	0.1	19476	24927	27401	81.2	103.9	114.3	72.5	95.3	105.6
case 6	0.5	24675	30683	31974	102.9	127.9	133.3	94.2	119.3	124.7
case 7	1	25592	31651	32648	106.7	132.0	136.1	98.0	123.3	127.5
case 8	5	26415	32501	33210	110.2	135.5	138.5	101.5	126.9	129.8

Table A 18. Simulation Results & Calculated Value for Gas Well (42 T)-Cased Hole

Horizontal gas Well with 42 Transverse Fractures

cased Hole

F_{CD} =30
X_f =500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2647	6.1
case 2	0.0001	4129	9.5
case 3	0.001	8664	20.2
case 4	0.01	9688	23.5
case 5	0.1	10042	26.0
case 6	0.5	10629	28.1
case 7	1	11027	29.1
case 8	5	12014	31.64

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	816	2924	4472	6689	8214
case 2	0.0001	1269	4164	5913	8064	9578
case 3	0.001	2690	7898	10467	14211	18118
case 4	0.01	3135	11208	17574	28858	37933
case 5	0.1	3462	14736	25119	41743	47930
case 6	0.5	3743	16113	27271	44197	48233
case 7	1	3886	16631	27991	44772	48293
case 8	5	4218	17832	29647	45895	48395

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	2286	3029	3570	9.5	12.6	14.9	-6.0	-2.9	-0.7
case 2	0.0001	3288	4132	4663	13.7	17.2	19.4	-1.8	1.7	3.9
case 3	0.001	6317	7561	8486	26.3	31.5	35.4	10.8	16.0	19.8
case 4	0.01	8764	11805	14534	36.5	49.2	60.6	21.0	33.7	45.1
case 5	0.1	11340	16289	20220	47.3	67.9	84.3	31.7	52.4	68.8
case 6	0.5	12396	17719	21691	51.7	73.9	90.5	36.2	58.4	74.9
case 7	1	12801	18224	22160	53.4	76.0	92.4	37.8	60.5	76.9
case 8	5	13742	19388	23208	57.3	80.8	96.8	41.8	65.3	81.2

Table A 19. Simulation Results & Calculated Value for Gas Well (4 L)-Cased Hole

Horizontal gas Well with four longitudinal Fractures

cased Hole

F_{CD} =30
X_f =500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	401	0.8
case 2	0.0001	690	1.4
case 3	0.001	3323	6.1
case 4	0.01	5951	13.6
case 5	0.1	7215	19.1
case 6	0.5	12561	26.0
case 7	1	17268	32.0
case 8	5	25798	54.51

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	112	374	603	1095	1681
case 2	0.0001	184	588	930	1654	2521
case 3	0.001	819	2405	3679	6358	9547
case 4	0.01	1818	6724	11206	20684	30299
case 5	0.1	2550	10994	19446	35681	46117
case 6	0.5	3465	14047	23944	40766	48434
case 7	1	4264	16206	26767	43039	48698
case 8	5	7267	23850	35664	47621	48896

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	293	402	523	1.2	1.7	2.2	-9.4	-8.9	-8.4
case 2	0.0001	463	626	804	1.9	2.6	3.4	-8.7	-8.0	-7.2
case 3	0.001	1909	2516	3176	8.0	10.5	13.2	-2.6	-0.1	2.7
case 4	0.01	5230	7360	9665	21.8	30.7	40.3	11.2	20.1	29.7
case 5	0.1	8440	12455	16321	35.2	51.9	68.1	24.6	41.3	57.5
case 6	0.5	10836	15550	19533	45.2	64.8	81.5	34.6	54.3	70.9
case 7	1	12565	17606	21455	52.4	73.4	89.5	41.8	62.8	78.9
case 8	5	18746	24434	27337	78.2	101.9	114.0	67.6	91.3	103.4

Table A 20. Simulation Results & Calculated Value for Gas Well (42 T)- Low Price

Horizontal Gas Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f =500 ft
4000 ft Lateral
gas: $2.01/scf

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2660	6.1
case 2	0.0001	4093	9.4
case 3	0.001	8817	20.4
case 4	0.01	11063	26.2
case 5	0.1	18030	43.9
case 6	0.5	24502	61.4
case 7	1	26342	66.2
case 8	5	28511	71.32

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	820	2930	4478	6693	8216
case 2	0.0001	1260	4146	5894	8041	9548
case 3	0.001	2725	7932	10483	14219	18122
case 4	0.01	3491	11850	18158	29224	38107
case 5	0.1	5849	21691	33144	45617	48115
case 6	0.5	8188	29464	41866	48164	48208
case 7	1	8825	31333	43773	48204	48331
case 8	5	9508	33272	45674	48385	48565

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	2291	3034	3575	4.6	6.1	7.2	-5.8	-4.3	-3.2
case 2	0.0001	3274	4117	4647	6.6	8.3	9.3	-3.8	-2.1	-1.1
case 3	0.001	6350	7585	8508	12.8	15.2	17.1	2.4	4.8	6.7
case 4	0.01	9310	12325	15002	18.7	24.8	30.2	8.3	14.4	19.7
case 5	0.1	16913	22423	25133	34.0	45.1	50.5	23.6	34.7	40.1
case 6	0.5	23089	29120	30432	46.4	58.5	61.2	36.0	48.1	50.8
case 7	1	24589	30661	31967	49.4	61.6	64.3	39.0	51.2	53.8
case 8	5	26150	32229	33074	52.6	64.8	66.5	42.2	54.4	56.1

Table A 21. Simulation Results & Calculated Value for Gas Well (42 T)- High Price

Horizontal Gas Well with 42 Transverse Fractures

Open Hole
F_{CD} =30
X_f =500 ft
4000 ft Lateral
gas: $13.07/scf

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	2660	6.1
case 2	0.0001	4093	9.4
case 3	0.001	8817	20.4
case 4	0.01	11063	26.2
case 5	0.1	18030	43.9
case 6	0.5	24502	61.4
case 7	1	26342	66.2
case 8	5	28511	71.32

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	820	2930	4478	6693	8216
case 2	0.0001	1260	4146	5894	8041	9548
case 3	0.001	2725	7932	10483	14219	18122
case 4	0.01	3491	11850	18158	29224	38107
case 5	0.1	5849	21691	33144	45617	48115
case 6	0.5	8188	29464	41866	48164	48208
case 7	1	8825	31333	43773	48204	48331
case 8	5	9508	33272	45674	48385	48565

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	2291	3034	3575	29.9	39.7	46.7	19.5	29.2	36.3
case 2	0.0001	3274	4117	4647	42.8	53.8	60.7	32.4	43.4	50.3
case 3	0.001	6350	7585	8508	83.0	99.1	111.2	72.6	88.7	100.8
case 4	0.01	9310	12325	15002	121.7	161.1	196.1	111.3	150.7	185.7
case 5	0.1	16913	22423	25133	221.1	293.1	328.5	210.6	282.7	318.1
case 6	0.5	23089	29120	30432	301.8	380.6	397.7	291.4	370.2	387.3
case 7	1	24589	30661	31967	321.4	400.7	417.8	311.0	390.3	407.4
case 8	5	26150	32229	33074	341.8	421.2	432.3	331.4	410.8	421.9

Table A 22. Simulation Results & Calculated Value for Gas Well (4 L)- Low Price

Horizontal Gas Well with four longitudinal Fractures

Open Hole

F_{CD} =30
X_f =500 ft
4000 ft Lateral
gas: $2.01/scf

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1374	2.1
case 2	0.0001	1995	2.9
case 3	0.001	6694	9.5
case 4	0.01	16286	27.5
case 5	0.1	24257	54.4
case 6	0.5	27194	67.0
case 7	1	27929	69.6
case 8	5	28871	72.15

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	274	634	910	1458	2087
case 2	0.0001	393	907	1297	2084	3001
case 3	0.001	1265	2974	4293	7048	10299
case 4	0.01	3661	9799	14568	23954	32812
case 5	0.1	7256	24794	36067	46024	48021
case 6	0.5	8926	31409	43714	48179	48189
case 7	1	9282	32560	44940	48180	48182
case 8	5	9619	33590	45998	48181	48182

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	514	646	781	1.0	1.3	1.6	-6.5	-6.2	-5.9
case 2	0.0001	735	921	1115	1.5	1.9	2.2	-6.0	-5.7	-5.3
case 3	0.001	2407	3036	3714	4.8	6.1	7.5	-2.7	-1.4	0.0
case 4	0.01	7840	10114	12392	15.8	20.3	24.9	8.2	12.8	17.4
case 5	0.1	19472	24924	27398	39.1	50.1	55.1	31.6	42.6	47.6
case 6	0.5	24665	30675	31967	49.6	61.7	64.3	42.1	54.1	56.7
case 7	1	25581	31641	32640	51.4	63.6	65.6	43.9	56.1	58.1
case 8	5	26405	32493	33204	53.1	65.3	66.7	45.6	57.8	59.2

Table A 23. Simulation Results & Calculated Value for Gas Well (4 L)- High Price

Horizontal Gas Well with four longitudinal Fractures

Open Hole

F_{CD} =30
X_f =500 ft
4000 ft Lateral
gas: $13.07/scf

Production Rate

Case No.	K (md)	IP (Mscf/d)	Anualized 1st year rate (Mscf/d)
case 1	0.00005	1374	2.1
case 2	0.0001	1995	2.9
case 3	0.001	6694	9.5
case 4	0.01	16286	27.5
case 5	0.1	24257	54.4
case 6	0.5	27194	67.0
case 7	1	27929	69.6
case 8	5	28871	72.15

Cummulative Production

Case No.	K (md)	1st year (Mscf)	5 years (Mscf)	10 years (Mscf)	25 years (Mscf)	50 years (Mscf)
case 1	0.00005	274	634	910	1458	2087
case 2	0.0001	393	907	1297	2084	3001
case 3	0.001	1265	2974	4293	7048	10299
case 4	0.01	3661	9799	14568	23954	32812
case 5	0.1	7256	24794	36067	46024	48021
case 6	0.5	8926	31409	43714	48179	48189
case 7	1	9282	32560	44940	48180	48182
case 8	5	9619	33590	45998	48181	48182

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mscf)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	514	646	781	6.7	8.4	10.2	-0.8	0.9	2.7
case 2	0.0001	735	921	1115	9.6	12.0	14.6	2.1	4.5	7.1
case 3	0.001	2407	3036	3714	31.5	39.7	48.5	24.0	32.2	41.0
case 4	0.01	7840	10114	12392	102.5	132.2	162.0	95.0	124.7	154.4
case 5	0.1	19472	24924	27398	254.5	325.8	358.1	247.0	318.2	350.6
case 6	0.5	24665	30675	31967	322.4	400.9	417.8	314.9	393.4	410.3
case 7	1	25581	31641	32640	334.3	413.6	426.6	326.8	406.0	419.1
case 8	5	26405	32493	33204	345.1	424.7	434.0	337.6	417.2	426.5

APPENDIX B.

OIL WELL SIMULATION RESULTS

Table B 1. Simulation Results & Calculated Value for Oil Well (6 T)

Horizontal oil Well with 6 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	22	0.1
case 2	0.0001	39	0.1
case 3	0.001	261	0.6
case 4	0.01	605	1.5
case 5	0.1	1439	3.4
case 6	0.5	4649	9.6
case 7	1	7789	15.7
case 8	5	26129	39.00

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	7	29	51	105	175
case 2	0.0001	12	49	85	171	280
case 3	0.001	76	265	433	801	1218
case 4	0.01	198	793	1334	2377	3434
case 5	0.1	452	1749	2956	5148	6295
case 6	0.5	1282	4082	5621	6436	6444
case 7	1	2097	5418	6312	6444	6452
case 8	5	5200	6444	6448	6457	6472

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	22	33	46	2.3	3.4	4.8	-4.6	-3.5	-2.2
case 2	0.0001	38	55	76	3.9	5.7	7.9	-3.0	-1.2	1.0
case 3	0.001	207	287	377	21.5	29.7	39.1	14.5	22.8	32.1
case 4	0.01	613	870	1126	63.5	90.2	116.6	56.5	83.2	109.7
case 5	0.1	1355	1929	2448	140.4	199.9	253.6	133.5	192.9	246.7
case 6	0.5	3227	3978	4195	334.3	412.0	434.6	327.4	405.1	427.6
case 7	1	4396	4844	4885	455.4	501.8	506.1	448.4	494.9	499.2
case 8	5	5733	5735	5737	593.8	594.1	594.3	586.9	587.1	587.3

Table B 2. Simulation Results & Calculated Value for Oil Well (12 T)

Horizontal oil Well with 12 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	43	0.1
case 2	0.0001	77	0.2
case 3	0.001	513	1.1
case 4	0.01	1121	2.7
case 5	0.1	2146	4.9
case 6	0.5	5963	11.6
case 7	1	9310	18.0
case 8	5	27654	40.41

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	14	57	101	207	344
case 2	0.0001	25	97	168	335	542
case 3	0.001	149	513	803	1255	1627
case 4	0.01	363	1260	1852	2837	3836
case 5	0.1	651	2328	3731	5802	6408
case 6	0.5	1546	4576	5986	6442	6444
case 7	1	2399	5724	6402	6446	6454
case 8	5	5388	6449	6452	6465	6487

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005			91			9.4			1.9
case 2	0.0001			150			15.5			8.0
case 3	0.001			652			67.5			60.0
case 4	0.01			1517			157.1			149.6
case 5	0.1			2978			308.5			301.0
case 6	0.5			4471			463.1			455.6
case 7	1			5046			522.7			515.2
case 8	5			5764			597.1			589.6

Table B 3. Simulation Results & Calculated Value for Oil Well (18 T)

Horizontal oil Well with 18 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	64	0.2
case 2	0.0001	115	0.3
case 3	0.001	762	1.7
case 4	0.01	1635	3.8
case 5	0.1	2820	6.2
case 6	0.5	7146	13.3
case 7	1	10655	19.9
case 8	5	28991	41.56

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	21	85	150	306	503
case 2	0.0001	36	144	249	489	755
case 3	0.001	221	718	1021	1399	1735
case 4	0.01	512	1502	2039	2981	3958
case 5	0.1	827	2745	4203	6028	6423
case 6	0.5	1768	4931	6183	6442	6444
case 7	1	2651	5927	6431	6447	6452
case 8	5	5540	6453	6457	6469	6492

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005			135			13.9			5.8
case 2	0.0001			220			22.8			14.7
case 3	0.001			807			83.6			75.5
case 4	0.01			1692			175.3			167.2
case 5	0.1			3295			341.3			333.3
case 6	0.5			4652			481.9			473.9
case 7	1			5156			534.1			526.0
case 8	5			5785			599.3			591.2

Table B 4. Simulation Results & Calculated Value for Oil Well (24 T)

Horizontal oil Well with 24 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	85	0.2
case 2	0.0001	153	0.4
case 3	0.001	1013	2.2
case 4	0.01	2150	4.8
case 5	0.1	3463	7.4
case 6	0.5	8229	14.7
case 7	1	11859	21.5
case 8	5	30185	42.50

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	27	113	200	405	644
case 2	0.0001	48	191	331	627	901
case 3	0.001	294	866	1132	1461	1786
case 4	0.01	644	1624	2130	3052	4019
case 5	0.1	984	3046	4494	6122	6428
case 6	0.5	1961	5198	6288	6442	6445
case 7	1	2867	6067	6439	6449	6458
case 8	5	5666	6454	6458	6477	6495

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	87	128	178	9.0	13.3	18.5	0.3	4.6	9.8
case 2	0.0001	148	214	286	15.3	22.2	29.6	6.7	13.5	20.9
case 3	0.001	692	822	903	71.7	85.1	93.6	63.0	76.4	84.9
case 4	0.01	1321	1563	1790	136.9	161.9	185.4	128.2	153.3	176.8
case 5	0.1	2412	3107	3502	249.8	321.8	362.8	241.2	313.1	354.1
case 6	0.5	4191	4736	4784	434.1	490.6	495.5	425.4	481.9	486.9
case 7	1	5039	5235	5237	522.0	542.3	542.5	513.3	533.6	533.9
case 8	5	5794	5796	5801	600.2	600.4	600.9	591.5	591.8	592.3

Table B 5. Simulation Results & Calculated Value for Oil Well (30 T)

Horizontal oil Well with 30 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	106	0.3
case 2	0.0001	191	0.5
case 3	0.001	1265	2.7
case 4	0.01	2658	5.7
case 5	0.1	4075	8.4
case 6	0.5	9218	16.0
case 7	1	12944	22.9
case 8	5	31270	43.28

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	34	141	249	496	754
case 2	0.0001	61	239	409	736	992
case 3	0.001	363	962	1190	1495	1817
case 4	0.01	757	1691	2182	3094	4054
case 5	0.1	1124	3264	4678	6168	6430
case 6	0.5	2129	5399	6343	6442	6446
case 7	1	3054	6163	6442	6451	6465
case 8	5	5770	6449	6454	6474	6500

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005			220			22.8			13.5
case 2	0.0001			344			35.7			26.4
case 3	0.001			965			100.0			90.8
case 4	0.01			1852			191.8			182.6
case 5	0.1			3645			377.5			368.3
case 6	0.5			4882			505.8			496.5
case 7	1			5300			549.0			539.8
case 8	5			5809			601.7			592.5

Table B 6. Simulation Results & Calculated Value for Oil Well (36 T)

Horizontal oil Well with 36 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	127	0.3
case 2	0.0001	228	0.5
case 3	0.001	1510	3.2
case 4	0.01	3154	6.4
case 5	0.1	4652	9.4
case 6	0.5	10115	17.1
case 7	1	13915	24.1
case 8	5	32269	43.91

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	41	167	295	573	832
case 2	0.0001	72	283	477	815	1045
case 3	0.001	425	1022	1221	1515	1835
case 4	0.01	852	1732	2215	3120	4076
case 5	0.1	1247	3421	4799	6195	6431
case 6	0.5	2275	5551	6372	6442	6447
case 7	1	3213	6229	6443	6460	6477
case 8	5	5854	6451	6458	6482	6517

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005			257			26.6			16.7
case 2	0.0001			393			40.7			30.9
case 3	0.001			1007			104.3			94.4
case 4	0.01			1892			196.0			186.2
case 5	0.1			3746			388.1			378.3
case 6	0.5			4958			513.6			503.8
case 7	1			5350			554.2			544.4
case 8	5			5821			603.0			593.1

Table B 7. Simulation Results & Calculated Value for Oil Well (42 T)

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	148	0.4
case 2	0.0001	266	0.6
case 3	0.001	1760	3.6
case 4	0.01	3642	7.0
case 5	0.1	5204	10.2
case 6	0.5	10946	18.1
case 7	1	14803	25.2
case 8	5	33189	44.46

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	48	195	342	643	894
case 2	0.0001	84	328	542	878	1081
case 3	0.001	485	1063	1242	1531	1849
case 4	0.01	933	1761	2240	3140	4093
case 5	0.1	1358	3540	4884	6212	6431
case 6	0.5	2408	5672	6389	6442	6450
case 7	1	3356	6276	6444	6461	6497
case 8	5	5927	6454	6469	6498	6527

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	150	220	293	15.6	22.8	30.3	5.2	12.4	19.9
case 2	0.0001	254	356	437	26.3	36.9	45.3	15.9	26.5	34.9
case 3	0.001	880	967	1038	91.2	100.2	107.5	80.8	89.7	97.1
case 4	0.01	1473	1701	1922	152.5	176.2	199.1	142.1	165.8	188.7
case 5	0.1	2850	3498	3824	295.2	362.3	396.1	284.8	351.9	385.7
case 6	0.5	4637	5003	5020	480.4	518.3	520.0	470.0	507.9	509.6
case 7	1	5297	5386	5391	548.7	558.0	558.4	538.3	547.6	548.0
case 8	5	5821	5828	5835	603.0	603.7	604.5	592.6	593.3	594.1

Table B 8. Simulation Results & Calculated Value for Oil Well (100 T)

Horizontal oil Well with 100 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	351	0.9
case 2	0.0001	633	1.5
case 3	0.001	4124	6.2
case 4	0.01	7825	9.2
case 5	0.1	9327	14.5
case 6	0.5	16061	24.0
case 7	1	20078	31.3
case 8	5	39293	47.08

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	114	433	669	946	1066
case 2	0.0001	198	647	875	1061	1169
case 3	0.001	829	1164	1305	1581	1896
case 4	0.01	1223	1856	2322	3206	4148
case 5	0.1	1937	3945	5146	6258	6429
case 6	0.5	3201	6092	6422	6443	6457
case 7	1	4179	6401	6443	6481	6555
case 8	5	6277	6488	6514	6592	6705

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005			518			53.7			37.7
case 2	0.0001			670			69.4			53.4
case 3	0.001			1146			118.8			102.7
case 4	0.01			2020			209.2			193.2
case 5	0.1			4103			425.1			409.1
case 6	0.5			5293			548.3			532.2
case 7	1			5578			577.9			561.8
case 8	5			5910			612.3			596.2

Table B 9. Simulation Results & Calculated Value for Oil Well (4 L)

Horizontal oil Well with four longitudinal Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	114	0.2
case 2	0.0001	161	0.2
case 3	0.001	520	0.8
case 4	0.01	1689	2.6
case 5	0.1	5625	8.9
case 6	0.5	13369	21.3
case 7	1	19936	30.3
case 8	5	43219	47.14

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	23	53	75	120	172
case 2	0.0001	32	75	107	172	245
case 3	0.001	106	244	350	569	819
case 4	0.01	348	817	1196	1983	2882
case 5	0.1	1189	2870	4113	5793	6366
case 6	0.5	2843	5751	6354	6443	6444
case 7	1	4035	6342	6442	6445	6447
case 8	5	6285	6444	6445	6447	6452

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	43	53	64	4.4	5.5	6.7	-3.1	-2.0	-0.8
case 2	0.0001	61	76	92	6.3	7.9	9.5	-1.2	0.4	2.0
case 3	0.001	198	249	303	20.5	25.8	31.3	13.0	18.2	23.8
case 4	0.01	661	842	1036	68.5	87.2	107.3	61.0	79.7	99.8
case 5	0.1	2319	2914	3317	240.2	301.8	343.6	232.7	294.3	336.1
case 6	0.5	4782	5086	5113	495.3	526.9	529.6	487.8	519.4	522.1
case 7	1	5469	5522	5523	566.6	572.0	572.1	559.1	564.5	564.6
case 8	5	5844	5845	5846	605.4	605.5	605.5	597.9	598.0	598.0

Table B 10. Simulation Results & Calculated Value for Oil Well (42 T)- F_{CD} = 2

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =2
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005		
case 2	0.0001		
case 3	0.001	217	0.5
case 4	0.01	1632	3.5
case 5	0.1	4344	8.9
case 6	0.5	8070	16.1
case 7	1	11726	22.5
case 8	5	31853	42.78

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005					
case 2	0.0001					
case 3	0.001	72	300	517	941	1348
case 4	0.01	471	1311	1824	2756	3739
case 5	0.1	1191	3298	4656	6125	6423
case 6	0.5	2145	5544	6363	6440	6440
case 7	1	2995	6219	6438	6440	6441
case 8	5	5703	6440	6441	6446	6453

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001									
case 3	0.001	231	334	438	23.9	34.6	45.4	13.5	24.2	35.0
case 4	0.01	1051	1298	1527	108.9	134.5	158.2	98.5	124.0	147.8
case 5	0.1	2640	3293	3651	273.5	341.1	378.2	263.1	330.7	367.8
case 6	0.5	4497	4913	4936	465.8	508.9	511.3	455.4	498.5	500.9
case 7	1	5197	5314	5314	538.4	550.5	550.5	527.9	540.1	540.1
case 8	5	5789	5790	5791	599.7	599.8	599.9	589.3	589.4	589.5

Table B 11. Simulation Results & Calculated Value for Oil Well (4 T))- F_{CD} = 2

Horizontal oil Well with four longitudinal Fractures

Open Hole

F_{CD} =2
X_f=500 ft
4000 ft
Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005		
case 2	0.0001		
case 3	0.001	390	0.6
case 4	0.01	1585	2.4
case 5	0.1	5586	8.6
case 6	0.5	13415	21.0
case 7	1	20030	29.9
case 8	5	46002	47.00

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005					
case 2	0.0001					
case 3	0.001	85	219	323	540	788
case 4	0.01	322	785	1161	1942	2839
case 5	0.1	1153	2827	4070	5769	6360
case 6	0.5	2798	5726	6348	6443	6444
case 7	1	3990	6335	6441	6444	6444
case 8	5	6272	6444	6444	6445	6447

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001									
case 3	0.001	176	226	279	18.2	23.4	28.9	10.7	15.9	21.4
case 4	0.01	634	812	1005	65.7	84.1	104.1	58.2	76.6	96.6
case 5	0.1	2280	2875	3283	236.2	297.8	340.1	228.7	290.3	332.6
case 6	0.5	4754	5068	5096	492.5	525.0	527.9	485.0	517.5	520.4
case 7	1	5457	5513	5514	565.3	571.1	571.2	557.8	563.6	563.7
case 8	5	5843	5843	5844	605.3	605.3	605.4	597.8	597.8	597.9

Table B 12. Simulation Results & Calculated Value for Oil Well (42 T))-L=2000 ft

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
2000 ft Lateral

Production Rate

	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	147	0.4
case 2	0.0001	266	0.6
case 3	0.001	1749	2.9
case 4	0.01	3394	4.6
case 5	0.1	4249	7.4
case 6	0.5	7920	13.3
case 7	1	10363	18.9
case 8	5	24276	39.00

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	48	188	302	460	540
case 2	0.0001	84	291	416	537	606
case 3	0.001	388	602	690	864	1068
case 4	0.01	620	1032	1348	2033	2892
case 5	0.1	992	2530	3774	5621	6333
case 6	0.5	1769	4836	6114	6441	6447
case 7	1	2524	5803	6418	6453	6473
case 8	5	5199	6453	6464	6511	6578

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	146	200	239	15.1	20.8	24.7	5.8	11.5	15.4
case 2	0.0001	229	289	320	23.7	29.9	33.1	14.4	20.6	23.8
case 3	0.001	517	559	602	53.6	57.9	62.4	44.2	48.6	53.1
case 4	0.01	868	1019	1188	89.9	105.6	123.1	80.6	96.2	113.8
case 5	0.1	2030	2624	3065	210.3	271.8	317.5	201.0	262.5	308.2
case 6	0.5	3878	4511	4606	401.7	467.3	477.1	392.4	458.0	467.8
case 7	1	4761	5077	5088	493.2	525.9	527.1	483.9	516.6	517.8
case 8	5	5741	5746	5757	594.7	595.2	596.4	585.4	585.9	587.1

Table B 13. Simulation Results & Calculated Value for Oil Well (2 L))-L=2000 ft

Horizontal oil Well with 2 Longitudinal Fractures

Open Hole

F_{CD} =30
X_f=500 ft
2000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	57	0.1
case 2	0.0001	81	0.1
case 3	0.001	261	0.4
case 4	0.01	861	1.4
case 5	0.1	2977	4.9
case 6	0.5	7492	13.4
case 7	1	11491	20.7
case 8	5	28253	42.35

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	11	26	38	61	88
case 2	0.0001	16	38	41	88	125
case 3	0.001	54	125	181	300	441
case 4	0.01	180	439	661	1161	1813
case 5	0.1	657	1807	2844	4751	5962
case 6	0.5	1783	4703	5933	6431	6444
case 7	1	2758	5898	6394	6444	6446
case 8	5	5646	6444	6445	6447	6451

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	21	27	32	2.2	2.8	3.4	-3.6	-3.1	-2.5
case 2	0.0001	31	38	47	3.2	3.9	4.9	-2.6	-1.9	-1.0
case 3	0.001	101	128	157	10.5	13.3	16.3	4.6	7.4	10.4
case 4	0.01	354	459	583	36.7	47.5	60.4	30.8	41.7	54.6
case 5	0.1	1437	1930	2386	148.9	200.0	247.2	143.1	194.1	241.3
case 6	0.5	3787	4393	4528	392.3	455.1	469.1	386.5	449.2	463.2
case 7	1	4894	5147	5162	507.0	533.2	534.7	501.1	527.3	528.9
case 8	5	5784	5785	5785	599.2	599.3	599.3	593.3	593.4	593.4

Table B 14. Simulation Results & Calculated Value for Oil Well (42 T))-X_f=250 ft

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=250 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005		
case 2	0.0001	152	0.4
case 3	0.001	1074	2.1
case 4	0.01	3155	4.9
case 5	0.1	4424	8.6
case 6	0.5	8768	15.7
case 7	1	12704	22.2
case 8	5	31337	42.95

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005					
case 2	0.0001	48	183	300	487	619
case 3	0.001	280	608	751	1009	1296
case 4	0.01	656	1255	1685	2535	3472
case 5	0.1	1144	3057	4384	5995	6408
case 6	0.5	2090	5370	6316	6442	6443
case 7	1	2958	6149	6439	6446	6451
case 8	5	5726	6446	6449	6471	6509

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001	142	198	243	14.7	20.5	25.2	4.3	10.1	14.8
case 3	0.001	502	571	634	52.0	59.1	65.7	41.6	48.7	55.3
case 4	0.01	1041	1245	1455	107.8	129.0	150.7	97.4	118.6	140.3
case 5	0.1	2451	3087	3476	253.9	319.8	360.1	243.5	309.4	349.7
case 6	0.5	4349	4825	4863	450.5	499.8	503.8	440.1	489.4	493.3
case 7	1	5126	5279	5281	531.0	546.9	547.1	520.6	536.4	536.6
case 8	5	5795	5796	5802	600.3	600.4	601.0	589.9	590.0	590.6

Table B 15. Simulation Results & Calculated Value for Oil Well (8 L))-X_f=250 ft

Horizontal oil Well with 8 Longitudinal Fractures

Open Hole

F_{CD} =30
X_f=250 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005		
case 2	0.0001	153	0.2
case 3	0.001	517	0.8
case 4	0.01	1687	2.6
case 5	0.1	5647	8.9
case 6	0.5	13432	21.3
case 7	1	20063	30.3
case 8	5	44335	47.13

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005					
case 2	0.0001	31	73	81	171	243
case 3	0.001	105	242	348	567	818
case 4	0.01	347	815	1195	1982	2882
case 5	0.1	1187	2870	4113	5793	6366
case 6	0.5	2842	5751	6354	6443	6444
case 7	1	4033	6342	6442	6444	6446
case 8	5	6283	6444	6445	6448	6453

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005									
case 2	0.0001	59	75	91	6.2	7.7	9.4	-2.5	-1.0	0.7
case 3	0.001	197	247	301	20.4	25.6	31.2	11.7	16.9	22.5
case 4	0.01	660	841	1034	68.4	87.1	107.2	59.7	78.4	98.5
case 5	0.1	2318	2913	3316	240.1	301.8	343.5	231.4	293.1	334.8
case 6	0.5	4781	5086	5112	495.3	526.9	529.6	486.6	518.2	520.9
case 7	1	5469	5522	5523	566.5	572.0	572.1	557.9	563.4	563.5
case 8	5	5844	5845	5846	605.4	605.5	605.6	596.7	596.8	596.9

Table B 16. Simulation Results & Calculated Value for Oil Well (42 T))-Cased Hole

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	147	0.4
case 2	0.0001	264	0.6
case 3	0.001	1752	3.6
case 4	0.01	3558	6.9
case 5	0.1	4412	9.1
case 6	0.5	8355	13.4
case 7	1	10821	18.0
case 8	5	22661	34.91

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	48	195	341	642	893
case 2	0.0001	84	327	541	877	1081
case 3	0.001	484	1062	1242	1531	1849
case 4	0.01	923	1759	2239	3139	4093
case 5	0.1	1216	3439	4826	6203	6431
case 6	0.5	1783	4954	6289	6441	6447
case 7	1	2402	5501	6420	6455	6496
case 8	5	4654	6417	6456	6484	6538

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	150	220	292	15.5	22.7	30.2	0.0	7.2	14.7
case 2	0.0001	253	355	437	26.2	36.8	45.3	10.7	21.2	29.7
case 3	0.001	879	966	1038	91.1	100.1	107.5	75.6	84.6	92.0
case 4	0.01	1470	1699	1920	152.3	176.0	198.9	136.7	160.5	183.4
case 5	0.1	2749	3417	3755	284.8	354.0	389.0	269.2	338.4	373.4
case 6	0.5	3955	4623	4671	409.7	478.9	483.9	394.2	463.4	468.3
case 7	1	4475	4949	4959	463.6	512.7	513.7	448.0	497.1	498.2
case 8	5	5601	5623	5629	580.2	582.4	583.1	564.7	566.9	567.6

Table B 17. Simulation Results & Calculated Value for Oil Well (4 L))-Cased Hole

Horizontal oil Well with four longitudinal Fractures

cased Hole

F_{CD} =30
X_f=500 ft
4000 ft
Lateral

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	22	0.0
case 2	0.0001	38	0.1
case 3	0.001	272	0.5
case 4	0.01	1271	2.1
case 5	0.1	2549	5.4
case 6	0.5	3005	7.6
case 7	1	3179	8.6
case 8	5	6636	13.90

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	7	25	42	81	128
case 2	0.0001	11	41	67	125	194
case 3	0.001	67	193	295	508	753
case 4	0.01	277	739	1112	1892	2787
case 5	0.1	725	2376	3684	5609	6337
case 6	0.5	1014	3854	5720	6477	6482
case 7	1	1149	4301	6139	6512	6518
case 8	5	1852	5361	6581	6601	6608

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	19	27	37	2.0	2.8	3.8	-8.6	-7.7	-6.8
case 2	0.0001	32	44	59	3.3	4.6	6.1	-7.3	-6.0	-4.5
case 3	0.001	154	202	254	15.9	20.9	26.3	5.3	10.3	15.8
case 4	0.01	592	769	961	61.3	79.7	99.5	50.7	69.1	89.0
case 5	0.1	1869	2494	2954	193.6	258.4	306.0	183.0	247.8	295.4
case 6	0.5	2998	3905	4121	310.6	404.5	426.9	300.0	393.9	416.3
case 7	1	3351	4253	4370	347.1	440.6	452.7	336.5	430.0	442.1
case 8	5	4273	4894	4901	442.6	507.0	507.7	432.1	496.4	497.1

Table B 18. Simulation Results & Calculated Value for Oil Well (42 T)-Low Price

Horizontal oil Well with 42 Transverse Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral
Oil: $36.74/bbl

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	148	0.4
case 2	0.0001	266	0.6
case 3	0.001	1760	3.6
case 4	0.01	3642	7.0
case 5	0.1	5204	10.2
case 6	0.5	10946	18.1
case 7	1	14803	25.2
case 8	5	33189	44.46

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	48	195	342	643	894
case 2	0.0001	84	328	542	878	1081
case 3	0.001	485	1063	1242	1531	1849
case 4	0.01	933	1761	2240	3140	4093
case 5	0.1	1358	3540	4884	6212	6431
case 6	0.5	2408	5672	6389	6442	6450
case 7	1	3356	6276	6444	6461	6497
case 8	5	5927	6454	6469	6498	6527

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	150	220	293	5.5	8.1	10.8	-4.9	-2.3	0.3
case 2	0.0001	254	356	437	9.3	13.1	16.1	-1.1	2.7	5.7
case 3	0.001	880	967	1038	32.3	35.5	38.1	21.9	25.1	27.7
case 4	0.01	1473	1701	1922	54.1	62.5	70.6	43.7	52.1	60.2
case 5	0.1	2850	3498	3824	104.7	128.5	140.5	94.3	118.1	130.1
case 6	0.5	4637	5003	5020	170.4	183.8	184.4	160.0	173.4	174.0
case 7	1	5297	5386	5391	194.6	197.9	198.0	184.2	187.5	187.6
case 8	5	5821	5828	5835	213.9	214.1	214.4	203.5	203.7	204.0

Table B 19. Simulation Results & Calculated Value for Oil Well (42 T)-High Price

Horizontal oil Well with 42 Transverse Fractures

Open Hole
F_{CD} =30
X_f=500 ft
4000 ft Lateral
Oil: $133.88/bbl

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	148	0.4
case 2	0.0001	266	0.6
case 3	0.001	1760	3.6
case 4	0.01	3642	7.0
case 5	0.1	5204	10.2
case 6	0.5	10946	18.1
case 7	1	14803	25.2
case 8	5	33189	44.46

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	48	195	342	643	894
case 2	0.0001	84	328	542	878	1081
case 3	0.001	485	1063	1242	1531	1849
case 4	0.01	933	1761	2240	3140	4093
case 5	0.1	1358	3540	4884	6212	6431
case 6	0.5	2408	5672	6389	6442	6450
case 7	1	3356	6276	6444	6461	6497
case 8	5	5927	6454	6469	6498	6527

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	150	220	293	20.1	29.5	39.2	9.7	19.1	28.8
case 2	0.0001	254	356	437	34.0	47.7	58.6	23.6	37.3	48.2
case 3	0.001	880	967	1038	117.8	129.4	139.0	107.4	119.0	128.6
case 4	0.01	1473	1701	1922	197.1	227.7	257.4	186.7	217.3	247.0
case 5	0.1	2850	3498	3824	381.5	468.2	511.9	371.1	457.8	501.5
case 6	0.5	4637	5003	5020	620.9	669.9	672.1	610.4	659.5	661.7
case 7	1	5297	5386	5391	709.1	721.1	721.7	698.7	710.7	711.3
case 8	5	5821	5828	5835	779.3	780.2	781.2	768.9	769.8	770.8

Table B 20. Simulation Results & Calculated Value for Oil Well (4 L)-Low Price

Horizontal oil Well with four longitudinal Fractures

Open Hole
F_{CD} =30
X_f=500 ft
4000 ft Lateral
Oil: $36.74/bbl

Production Rate

-

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	114	0.2
case 2	0.0001	161	0.2
case 3	0.001	520	0.8
case 4	0.01	1689	2.6
case 5	0.1	5625	8.9
case 6	0.5	13369	21.3
case 7	1	19936	30.3
case 8	5	43219	47.14

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	23	53	75	120	172
case 2	0.0001	32	75	107	172	245
case 3	0.001	106	244	350	569	819
case 4	0.01	348	817	1196	1983	2882
case 5	0.1	1189	2870	4113	5793	6366
case 6	0.5	2843	5751	6354	6443	6444
case 7	1	4035	6342	6442	6445	6447
case 8	5	6285	6444	6445	6447	6452

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	43	53	64	1.6	2.0	2.4	-5.9	-5.6	-5.1
case 2	0.0001	61	76	92	2.2	2.8	3.4	-5.3	-4.7	-4.1
case 3	0.001	198	249	303	7.3	9.1	11.1	-0.2	1.6	3.6
case 4	0.01	661	842	1036	24.3	30.9	38.0	16.8	23.4	30.5
case 5	0.1	2319	2914	3317	85.2	107.0	121.9	77.7	99.5	114.4
case 6	0.5	4782	5086	5113	175.7	186.9	187.8	168.2	179.4	180.3
case 7	1	5469	5522	5523	200.9	202.9	202.9	193.4	195.4	195.4
case 8	5	5844	5845	5846	214.7	214.7	214.8	207.2	207.2	207.3

Table B 21. Simulation Results & Calculated Value for Oil Well (4 L)-High Price

Horizontal oil Well with four longitudinal Fractures

Open Hole

F_{CD} =30
X_f=500 ft
4000 ft Lateral
Oil: $133.88/bbl

Production Rate

Case No.	K (md)	IP (Mbbl/d)	Anualized 1st year rate (Mbbl/d)
case 1	0.00005	114	0.2
case 2	0.0001	161	0.2
case 3	0.001	520	0.8
case 4	0.01	1689	2.6
case 5	0.1	5625	8.9
case 6	0.5	13369	21.3
case 7	1	19936	30.3
case 8	5	43219	47.14

Cummulative Production

Case No.	K (md)	1st year (Mbbl)	5 years (Mbbl)	10 years (Mbbl)	25 years (Mbbl)	50 years (Mbbl)
case 1	0.00005	23	53	75	120	172
case 2	0.0001	32	75	107	172	245
case 3	0.001	106	244	350	569	819
case 4	0.01	348	817	1196	1983	2882
case 5	0.1	1189	2870	4113	5793	6366
case 6	0.5	2843	5751	6354	6443	6444
case 7	1	4035	6342	6442	6445	6447
case 8	5	6285	6444	6445	6447	6452

Economic Parameters

Case No.	K (md)	Discounted Recovery (Mbbl)			PV(M$)			NPV(M$)		
		5 years	10 years	50 years	5 years	10 years	50 years	5 years	10 years	50 years
case 1	0.00005	43	53	64	5.7	7.1	8.6	-1.8	-0.4	1.1
case 2	0.0001	61	76	92	8.1	10.2	12.3	0.6	2.7	4.8
case 3	0.001	198	249	303	26.5	33.3	40.5	19.0	25.8	33.0
case 4	0.01	661	842	1036	88.5	112.7	138.6	81.0	105.2	131.1
case 5	0.1	2319	2914	3317	310.4	390.1	444.1	302.9	382.6	436.6
case 6	0.5	4782	5086	5113	640.2	680.9	684.5	632.7	673.4	677.0
case 7	1	5469	5522	5523	732.2	739.3	739.4	724.7	731.8	731.9
case 8	5	5844	5845	5846	782.5	782.5	782.6	775.0	775.0	775.1

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