EME 580: Integrative Design of Energy & Mineral Engineering Systems

Economic Comparison of Multi-Lateral Drilling over Horizontal Drilling for Marcellus Shale Field Development

Final Project Report

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Executive Summary

The demand for energy in the world has been ever increasing. This has led to the discovery of a number of different new technologies. With the focus of the energy demand shifting towards cleaner sources of energy there has been a surge in the demand for natural gas. Exploration has helped in finding a lot of different gas basins in the U.S and all over the world. One such important and prolific source of gas is the Marcellus Shale gas basin which has an estimated gas reserve of 168 – 516 TCF. This has led the petroleum industries to pursue novel techniques to improve the productivity of the wells that are drilled in the Marcellus to make it economically competitive for production.

This change in the outlook of the Oil and Gas companies has come about due to the introduction of latest technologies like Horizontal and Multi-lateral well completion and multi-stage hydraulic fracturing of the formation. The first horizontal was drilled in 1929 by Texon in Texas, but at that time the cost of drilling a horizontal was too high and didn't justify the increment in the production rates that accompanied it. As time progressed the technological advancements and reduction in the cost of drilling a horizontal well made it a viable option. A horizontal well coupled with a multi-stage fracturing job improves the productivity of the well significantly. Horizontal wells have proved to be highly beneficial in reservoirs with low permeability reservoirs as they improve contact with the formation. Multi-laterals work on the same line of increasing the contact with the reservoir and thereby improving production rates significantly.

In our project a number of different counties have been considered like Bradford, Steuben, Pike, etc to name a few. Based on our analysis with the help of exploratory Well logs, TOC and Ro values the decision was made to go ahead with the Hawley quadrangle of the Pike county as our exploratory site. Here the Marcellus Shale formation is at a depth of 7046 ft with a TOC of 0.64-1.8 and the Ro values(~4) indicates that the formation contained dry gas. The permeability of the reservoir is 10 nanodarcy with a gas porosity of 9% and the initial pressure of reservoir is 4500 psi while the reservoir temperature is 150 oF. For simulation of production values a dual porosity model has been built in CMG (GEM). Three different cases were simulated and a comparative study was presented between the models for a single horizontal, 2 horizontal wells and a multi-lateral well. A stimulation job was designed for all the 3 cases using Fracpro PT which models a fracture using PKN model. The PAD and carrier fluid employed in the modelling are Slickwater and Carbolite/Carboprop proppant. A multi-stage fracturing job was carried out in all the 3 cases. As observed in the Marcellus vertical, transverse fracture with infinite dimensionless conductivity is modelled. The fracture half length and height obtained from Fracpro PT are fed to the CMG model for obtaining improved production values. For a comprehensive

economic analysis, different aspects like well design, water management have also been taken into account. In the well design part, a new completion technique has been incorporated that is Open Hole Multi Stage Completion (OHMS) which has been proven to have resulted in better production values than cemented completions. A study has also been made for improving the drill bit design and optimizing the torque. For fracturing water is going to be made available from the Delaware river basin. A study was made to analyse the various treatment techniques for the flow back and the produced water. As a result Reverse osmosis proved to be the best suited for treating the water with TDS ~ 50,000mg/L.

From a farm in economic view point the economic analysis was performed. The breakeven point for drilling a horizontal well and a multilateral was found by employing a discounted cash flow analysis and rate of return. It was found that multi-lateral well completion was profitable than a 2 horizontal well completion model and it was found that a breakeven for the initial investment was reached at in 4 years.

1.0 Critical Literature Review

Introduction to Critical Literature Review:

Fossil Fuel resources namely coal, petroleum and natural gas account for more than three fourths of the energy consumption of US. Conventional sources of oil and gas have observed peak production phenomena in the recent times according to which it is believed that the production rates from these sources have started to decline.

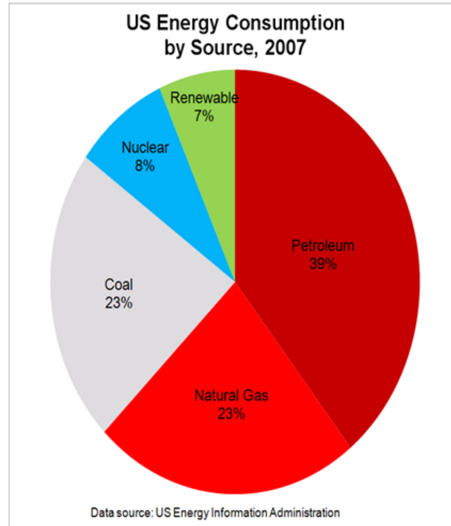


Figure 1.0: US Energy Consumption by Source

Natural gas is a gas consisting primarily of methane (CH_4), typically along with 0 – 20% of other C_2 and other higher carbon molecules. In earlier times, natural gas was produced as a by-product of oil drilling. Lack of infrastructure caused problems in exploitation of this natural resource in the olden times. With the technological advancements in drilling, transportation and processing, NG started to penetrate the domestic and industrial energy resource base. As per the data collected from US DOE- 900 out of 1000 upcoming power plants would be fired using Natural Gas. (Energy Sources 2009)

Domestically produced and readily available to end-users through the existing utility infrastructure, natural gas has also become increasingly popular as an alternative transportation fuel as well.

To meet the projected demand of natural gas, it is in the nation's best interest to ensure competitively priced domestic natural gas remain as a part of the US energy Portfolio.

Apart from conventional sources of Natural gas, the following unconventional sources have gained attention in the recent times: Tight gas accumulations, Coal Bed Methane, shale gas basins. (Geology of Natural Gas Resources 2011)

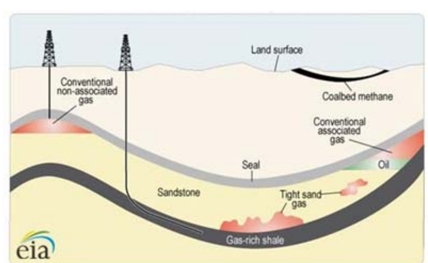


Figure 2: Location of NG Reserves

Driven by a new understanding of the size and availability of gas shales and unconventional gas reserves, there is a paradigm shift underway. This began with the discovery of coal bed methane gas in San Juan

Basin in Colorado followed by highly productive tight gas development in Wyoming and recently Barnett shale field development. The final segment of this is the development of huge shale gas reserves found in Appalachian Basin.

A $92 million research investment in the 1970s by the U.S. Department of Energy (DOE) is today being credited with technological contributions that have stimulated development of domestic natural gas from shales. (Oil and Natural Gas Supply 2011)

Development of new technologies like Horizontal, Multilateral Well Drilling, Hydraulic Fracturing/Stimulation, Well design, Waste Water Treatment and advances in Geologic Models, Prospecting Techniques, Reservoir Simulation Models(CMG), Drilling tools have spurred the interest in economic exploitation of the Shale Gas Basins. With these technological advancements these unconventional sources have proven to be economically competitive with the other conventional gas resources. Integration of all the new technologies seamlessly with a focus on sustainable development of the field is of utmost importance in Today's Energy scenario.

The U.S. Energy Information Administration projects that by 2030, half of the natural gas produced in the U.S. will be from unconventional sources. (2007 Annual Energy Outlook with Projects to 2030 2007) In 2005, approximately 10 trillion cubic feet (TCF) of conventional gas was produced in the U.S., versus 8 TCF of unconventional gas. Natural gas from shale accounted for about 6% of the gas produced in the U.S. (1.1 TCF). (The Rise in Unconventional Gas 2007).The majority of U.S. gas shale production came from four basins: (Pickering Energy Partners,Inc. 2005)

- San Juan Basin, New Mexico/Colorado - 55 million cubic feet per day (mmcf/d)
- Antrim Shale, Michigan - 384 mmcf/d
- Appalachian/Ohio shales – 438 mmcf/d
- Barnett Shale, Fort Worth Basin, Texas - 1,233 mmcf/d

Exploratory drilling has been started in and around Marcellus Shale. Various reports have been generated analysing/predicting the consequences of drilling/production in Marcellus with respect to the difficulty in gas extraction, environmental implications and economic viewpoints.

An attempt to put together all the new information to analyse the economic field development of Marcellus shale shall be made in this project.

1.1Geology of Marcellus Shale:

The Marcellus Shale, also referred to as the Marcellus Formation, is a Middle Devonian-age black, low density, carbonaceous (organic rich) shale that occurs in the subsurface beneath much of Ohio, West Virginia, Pennsylvania and New York. Small areas of Maryland, Kentucky, Tennessee, and Virginia are also underlain by the Marcellus Shale. (Marcellus Shale Geology 2009)

This geological formation was known for decades to contain significant amounts of natural gas but was never considered worthwhile to produce. Uneconomic resources, however, are often transformed into marketable assets by technological progress (Timothy Considine 2009)

The Marcellus shale spans a distance of approximately 600 miles, (Durham 2008) running from the southern tier of New York, through the western portion of Pennsylvania into the eastern half of Ohio and through West Virginia. (***See Figure 1.3***) (Engelder, Unconventional Natural Gas Reservoir In Pennsylvania Poised To Dramatically Increase US Production 2008) The areal extent of the Marcellus shale is about 54,000 square miles, (Mayhood 2008). The shale is extremely variable in thickness, ranging from a few feet to more than 250 feet in thickness, (D.G.Hill 2004)and generally becomes thicker to the east. (***See Figure 1.4***)

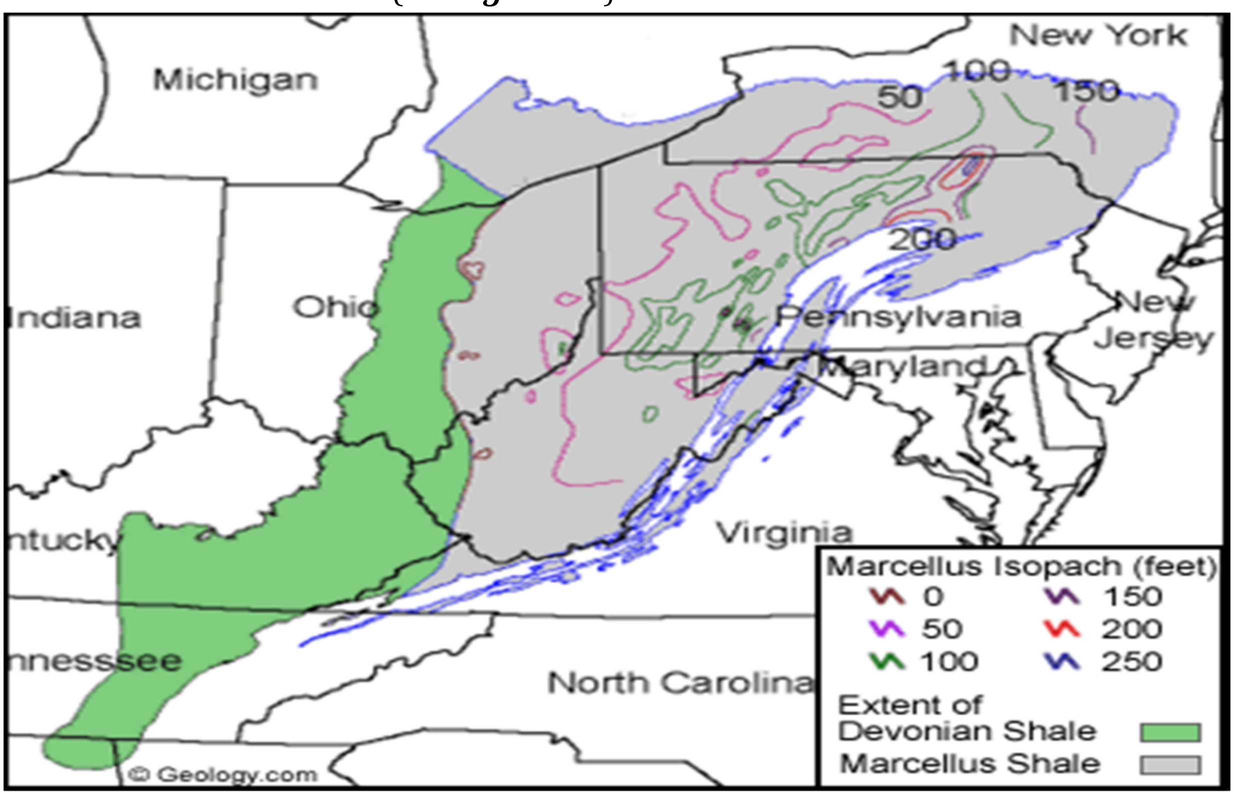


Figure 1.3: Depth of Marcellus Shale Formation

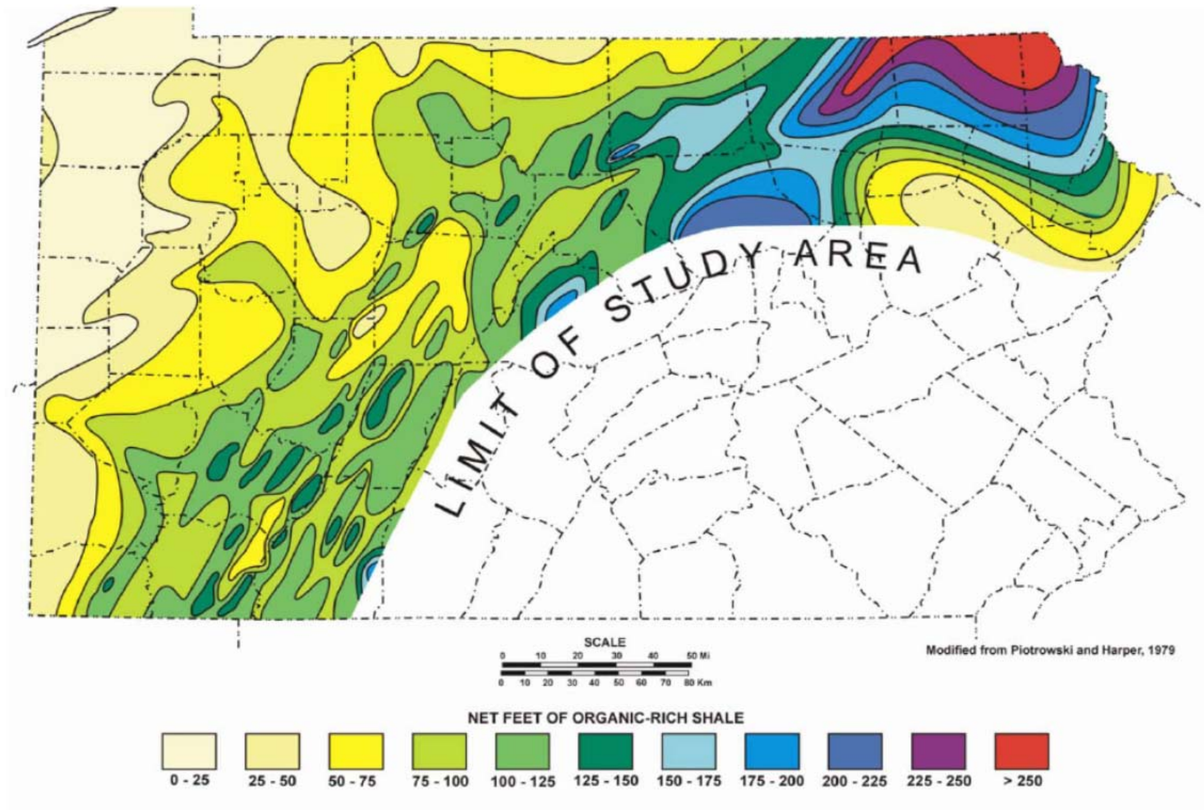


Figure1. 4: Net feet of organic-rich shale in the middle Devonian Marcellus formation in Pennsylvania

Black, organic-rich shales are common constituents of sedimentary deposits formed throughout geologic time. In Pennsylvania, black, organic-rich shales can be found in almost all of the Paleozoic systems, as well as in the Triassic rocks of the Newark and Gettysburg basins in the southeast. Some of these shales are the sources of the crude oil and natural gas found in Pennsylvania's sandstone and carbonate reservoirs. (J.B.Parrish 2008) Organic-rich shales (Marcellus) have higher radioactivity responses (Adams 1958) greater than 10 parts per million and that may approach 100 parts per million. (Schmoker 1981) The Marcellus shale is said to have "favorable mineralogy" in that it is a lower-density rock with more porosity, which means it may be filled with more free gas. (Operators Moving Towards Exploitation Phase in Marcellus Shale 2008)

- The Marcellus Formation underlies most of Pennsylvania, but the organic-rich portion reaches its maximum development in the north-eastern part of the state. Despite the long history of gas shows in the Marcellus, it took until recently for its potential as a commercial gas target to attract attention. (as shown in ***Figure1. 3***)
- The Marcellus formation is variable in depth and in some areas of New York it outcrops (appears at the surface). The Marcellus shale was actually named for an outcrop found near the town of Marcellus, NY, during a geological survey in 1839. The majority of the Marcellus shale, however, is more than a mile deep, and in some

areas it extends 9,000 feet below the surface.The depth of Marcellus in Pennsylvania increases from North-East to South-West .(Refer ***Figure 1.4***)

However the accuracy of the data plays a very important role in reservoir characterization. High confidence data is generated through several techniques like Geo Physical Logs, In situ Stress tests, Coring, TOC measurements, vitrinile reflectance tests. Geophysical prospecting is being carried out to determine the stratigraphy, porosity, brittleness and fracture pattern of the formation [(Dae Sung Lee 2010)].

Geology task can be summarized as the following activities: Selection of research area by evaluating production potential, Gathering of reservoir characteristics in the research area, Construction of reservoir data maps to select the best production site, providing a reservoir input data (Gas Saturations, Pressure, Temperature, Porosity, Permeability) to reservoir engineer to run the simulations

1.2 Drilling Methods:

To extract natural gas from Marcellus Shale, one should know the correct properties of the reservoir and the best completion strategy. There are several ways to increase gas recovery by using different types of drilling technologies such as vertical drilling, multilateral drilling and horizontal drilling. There are three types of drilling technologies. They are as follows:

- Vertical Drilling: Vertical drilling is traditional type of drilling in oil and gas drilling industry. Drilling a Vertical well is cheaper than drilling a horizontal well but the production from vertical wells is lesser than as compared to the horizontal wells/multilateral wells in Marcellus Shale, the reason behind this is that in Marcellus Shale there are vertical fractures, therefore, drilling a vertical well limits the frequency of intersecting a large number of fractures because of this the production of gas decreases.

- Horizontal Drilling: Horizontal drilling is the same as vertical drilling until the "kickoff point" which is located just above the target oil or gas reservoir, from that point deviating the drilling direction from the vertical to horizontal. Following are few of the limitations of horizontal drilling:
  a) Horizontal wells have a greater footprint compare to Multilateral wells
  b) For reservoir with multiple pay zones we need more than one horizontal well to produce effectively while in case of multilateral we can drain effectively through laterals which branch into different payzones.

- Multilateral Drilling: The TAML group (Technical Advancements of Multi-Laterals) defines multilaterals or multilateral wells as:

Wells having one or more branches (laterals) tied back to a mother wellbore, which conveys fluids to or from surface. The branch or lateral may be vertical or any inclination up to or greater than horizontal.

There are different types of multilateral wells. The type of multilateral well to be drilled depends upon the properties of the reservoir.

1.2.1 Geometry of Multi-Lateral and Multi-branched wells

We would now briefly talk about the different Multi-lateral well geometries. The number of laterals represents the geometry of the Multi-lateral like dual lateral, tri lateral, Stacked, Planar etc.

Different well configurations are shown in ***Figure 1.5*** (Technical Advancements of Multilaterals(TAML) 2008)

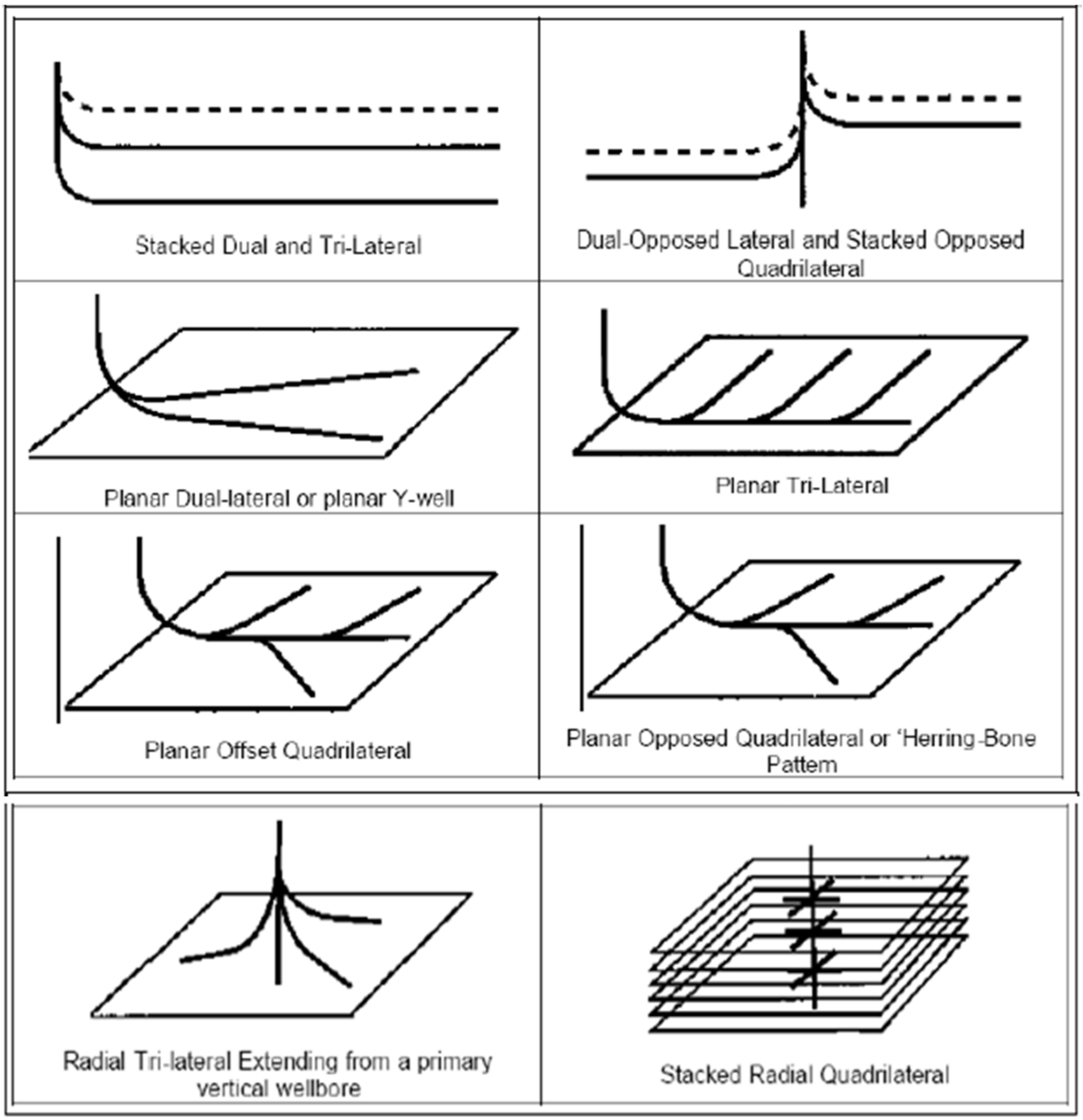
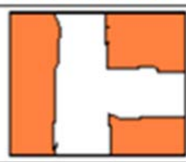
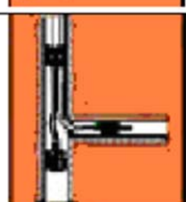
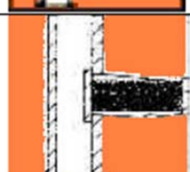


Figure1. 5: Well Configurations

1.2.2 Technical Advancements of Multi-laterals' (TAML) Classification System:

The level of a multilateral refers to the complexity of the junction and its properties. TAML classification reports six levels of multilateral junction. A number between 1 and 6 defines multilateral junction complexity. Table 2.1 illustrates the complexity ratings.

Table 1.1: Illustration of Complexity Ratings

Level	Illustration	Description
1	 (or) 	**Open/ Unsupported Junction** **Barefoot mother-bore & lateral or slotted liner hung-off in either bore**
2	 (or) 	**Mother-bore Cased and Cemented** **Lateral Open** **Lateral either barefoot or with slotted liner hung-off in open hole**
3	 (or) 	**Mother-bore Cased and Cemented** **Lateral Cased but not Cemented** **Lateral liner 'anchored' to mother-bore** **with liner 'hanger' but not cemented**
4	 (or) 	**Mother-bore and Lateral Cased and Cemented** **Both bores cemented at the junction**
5		**Pressure Integrity at the Junction** **Straddle packers or (integral) mechanical casing seal.** **(Cement is not acceptable)**
6		**Pressure Integrity at the Junction** **Achieved with the casing** **(Cement is NOT acceptable)**
6S		**Downhole Splitter** **Large main well bore with 2 (smaller) lateral wellbores of equal size**

1.2.3 Comparison of Horizontal and Multilateral Wells Using CMG:

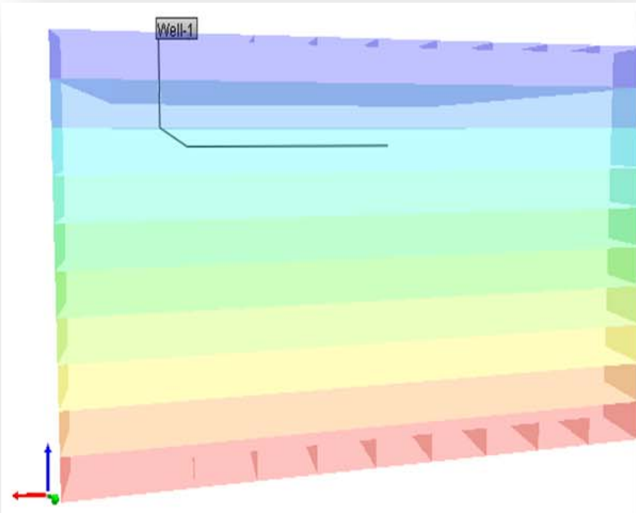


Figure1.6: Horizontal Well

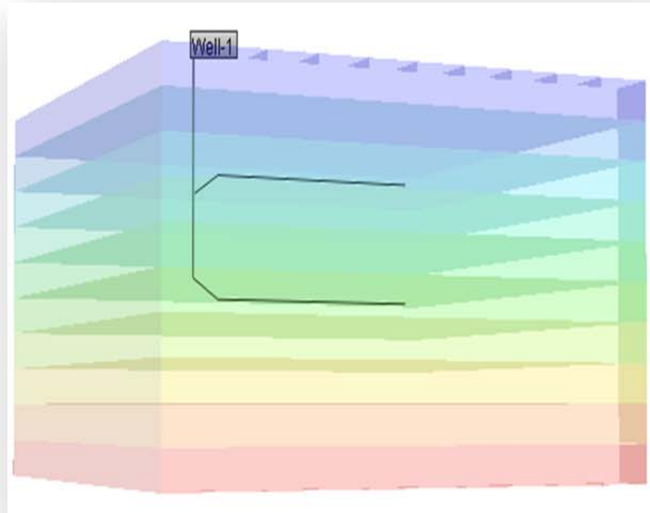


Figure1. 7: Multilateral Well

Figure 1.6 shows the single horizontal well modeled using CMG and ***Figure 1.7*** shows the Multilateral Well with two horizontal laterals. The main aim of this simulation is to compare the production from both these wells. The model when run, gave a difference of 2.00e+9 SCF between their respective cumulative productions over a period of five years. This result is shown in ***Figure 1.8.***

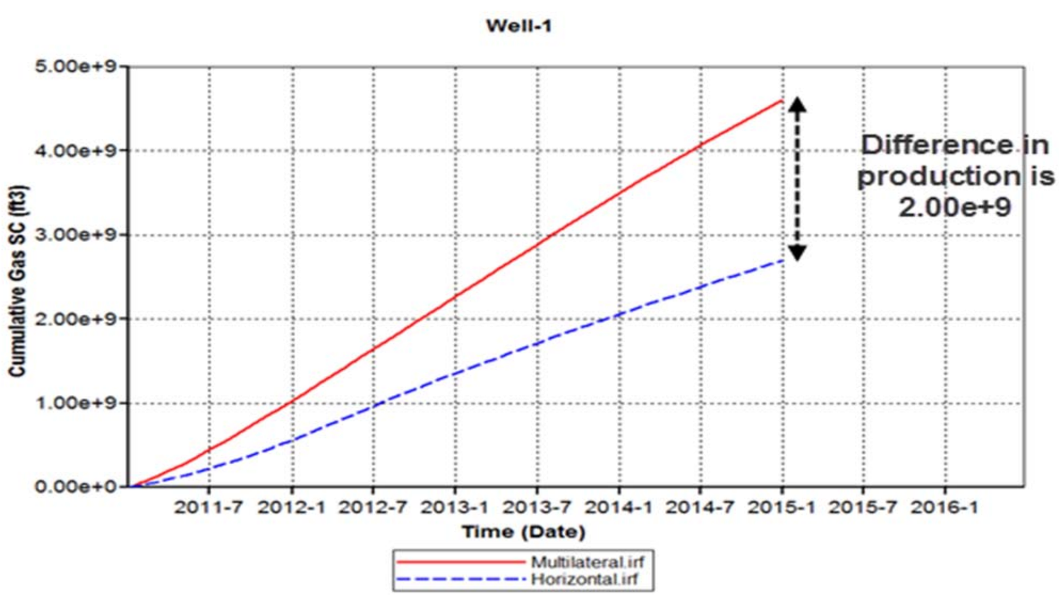


Figure 1.8: Comparison of Cumulative Gas produced from Multilateral & Horizontal Wells

1.2.4 Advantages of Multilateral Wells:

- Higher Production (Ph.A.Charlez 1999): In the cases where thin pools are targeted, vertical wells yield small contact with the reservoir which causes lower production. Drilling several laterals in thin reservoirs and increasing contact improves recovery.
- Decreased Water/Gas Coning (G. Ismail 1996): The position of the laterals within the producing formation provides enough distance to the water zone and to the gas zone. Therefore, gas/water conning can be prevented or reduced.
- Improved sweep efficiency: By using multilateral wells, the sweep efficiency will be improved and the recovery can be increased due to the area covered by the laterals.
- Fast Recovery (Ph.A.Charlez 1999): Production from the multilateral wells is higher than that in single vertical or horizontal wells; hence the reservoir contact is higher in multilateral wells
- Decreased environmental impacts: The volume of consumed drilling fluids and the generated cuttings during drilling multilateral wells are less than the consumed drilling fluid and generated cuttings from separated wells. Therefore, the impact of the multilateral wells on the environment is reduced.
- Saving time and cost (G. Ismail 1996): Drilling several laterals in a single well will result in substantial time and cost saving in comparison with drilling several wells in the reservoir.

1.2.5 Challenges and Complexity of Multilateral Wells:

- The installation and retrieving of some necessary tools during drilling or after completion of multilateral wells is associated with high risk. These tools may be whipstocks, packers etc.
- In drilling multilateral wells, the mother well bore can be cased to control sand production, however, the legs branched from the mother well bore are open hole. Therefore, the sand control from the legs is not easy to perform.
- There is a difficulty in modeling and prediction due to the sophisticated system of multilateral wells.
- Construction of multilateral wells is quite complex.
- Because of complexity of laterals, there is difficulty in stimulation and clean-up.

1.2.6 Selection criteria for Multilateral Wells (Pan Yan, M. Kamal Medhat, Kikani Jitendre, Chevron 2010):

- Case 1: Effect of Multilateral Length

To test the effect of length of multilateral, one 4,000ft horizontal well with a single lateral joined at the center of the mail trunk at 45 degree azimuth angle and 0 degree deviation angle was used. Four cases were considered as shown in ***Figure 1.9***. The lengths of the laterals in these four cases were 0, 800, 1000 and 2,000 ft.

Figure 1.9: Different Case of Multilateral Wells

For this case the response of Productivity Index (PI) is shown in ***Figure 1.10***.

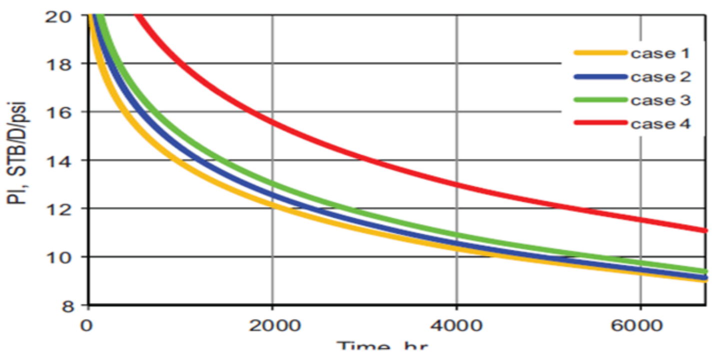


Figure1.10: Productivity Index for above cases

Apparently, the Productivity Index increases with the length of multilateral through the entire production period. The well performance of Case 4 is considerably better than the other cases because of its effective drainage area.

- <u>Case 2: Effect of Multilateral Azimuth Angle</u>

To test the effect of azimuth angle of multilateral wells, one horizontal well with a single lateral jointed at the center of the main trunk at 0 degree deviation angle and at different azimuth angles (Case 4: 45 degree; Case 5: 90 degree) was considered as shown in figure 2.7

Figure 1.11: Different cases for multilateral wells

For this case the response of Productivity Index is shown in F***igure 1.12***

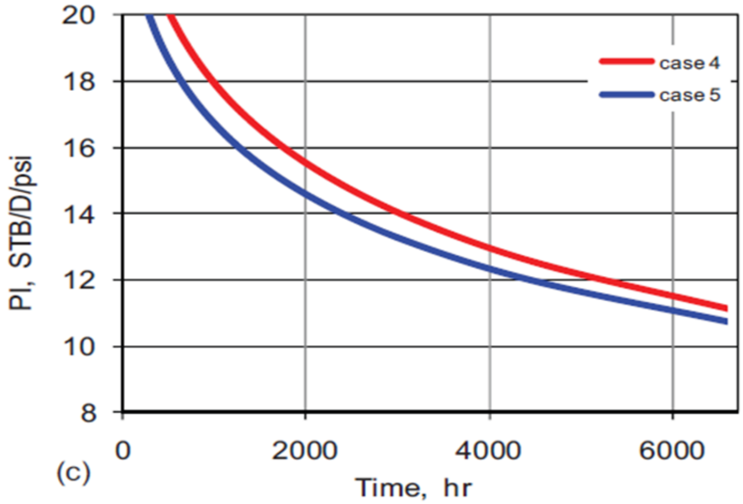


Figure 1.12: Productivity Index for above gases

As seen from ***figure 1.12*** the Productivity Index of the well with one multilateral joint at 45 degree azimuth angle is higher than that of the well with one lateral joint at 90 degree azimuth angle. For an anisotropic reservoir, drilling a horizontal well perpendicular to the direction of the maximum horizontal permeability is the best choice.

- <u>Case 3: If Vertical Permeability is more than the Horizontal Permeability:</u>

  In this case two different models are simulated; in one of the model laterals are in the same plane and in other case there are slanted laterals. These two models are shown in ***Figure 1.13*** and ***Figure 1.14*** respectively. The properties of the reservoir are same in both the cases. Permeability in 'k' direction is ten times the permeability in 'i' direction.

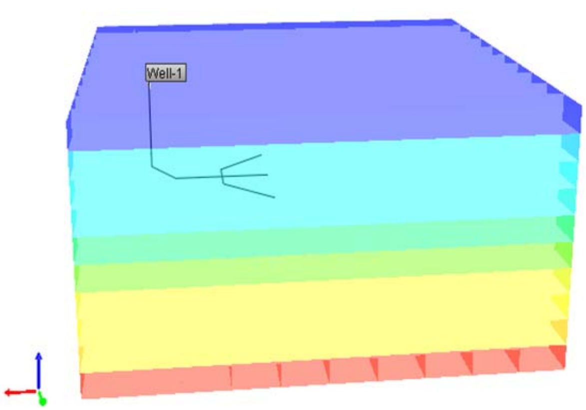


Figure 1.13: Multilaterals in same plane

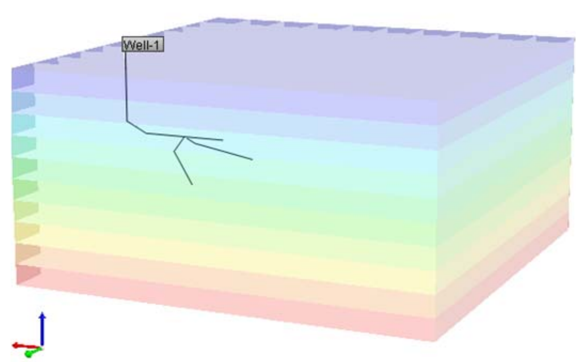


Figure 1.14: Slanted Multilateral

The result for this run is shown in F***igure 1.15***

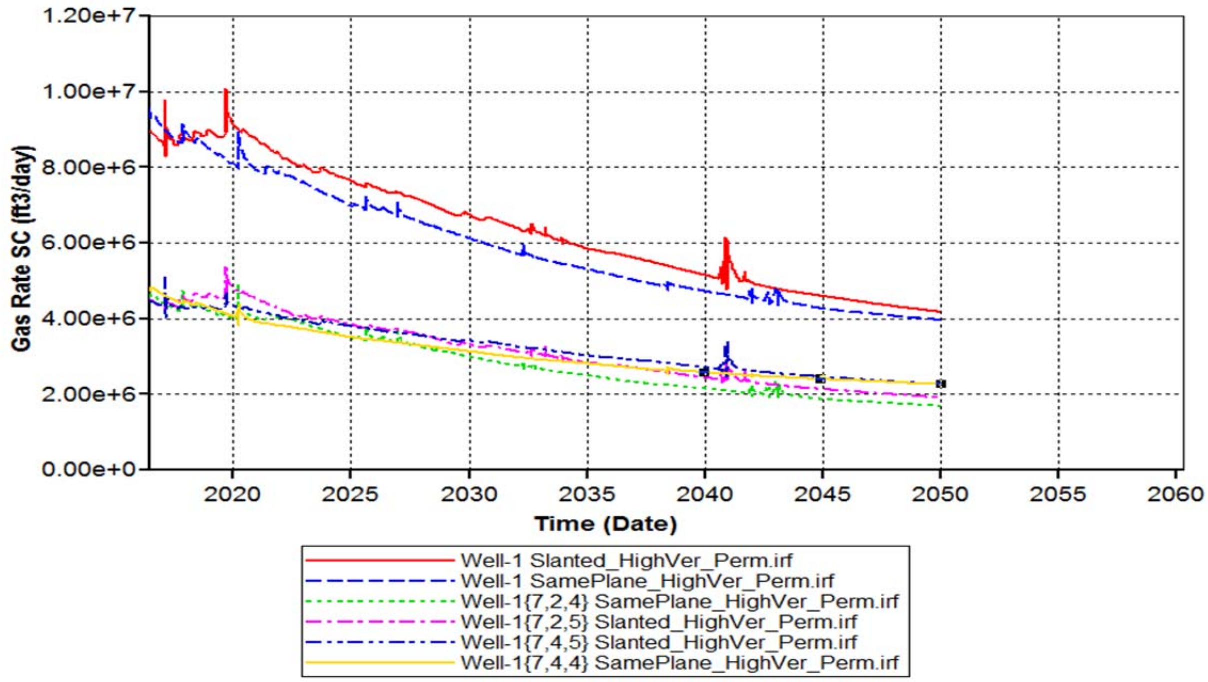


Figure 1.15: Comparison of Gas Rate of Same Plane and Slanted Multilateral

In case of the Slanted laterals, the Gas Rate is quite high than the Gas Rate in case of same plane laterals.

As we have seen from the above three cases; to optimize the production from multilateral wells one should be very clear about the reservoir properties. This would act as the deciding factor in selecting the type of multilateral to be drilled.

1.3 Reservoir Simulation:

For reservoir simulation in this project we are using commercially available reservoir simulator software called CMG. It helps determine the production profile of the reservoir. The module that will be used in this project is GEM. The properties which are required for the simulations are:

Reservoir Properties	
Pressure	Psi
Temperature	F
Initial Reservoir Pressure	Psi
Volume	SCF/ton
Matrix Permeability	mD
Fracture Permeability	mD
Matrix Porosity	Fraction
Fracture Porosity	Fraction
Fracture Spacing	Ft
Thickness	Ft
Depth	Ft
Compressibility of Formation	1/Psi
Reference Pressure for Compressibility	Psi
Gas Saturation	Fraction

1.4 Stimulation

1.4.1 Introduction:

As we are aware, Unconventional gas reservoirs can solve the energy problems of the U.S, at least for the next decade. The increasing demand for energy has compelled us to drill in Unconventional reservoirs. One of the biggest problems with these reservoirs is the low permeability (Dudley 1982). As a consequence of this, we need to improve the permeability of the area around the wellbore. This would resultantly improve the production rates, thereby rendering production from the Unconventional reservoir profitable (Bilgesu 2009).

The permeability of the area around the reservoir is improved by operations like Stimulation (Hydraulic fracturing) (Nathan Houston 2009). This operation creates a composite structure. This structure us as shown below –

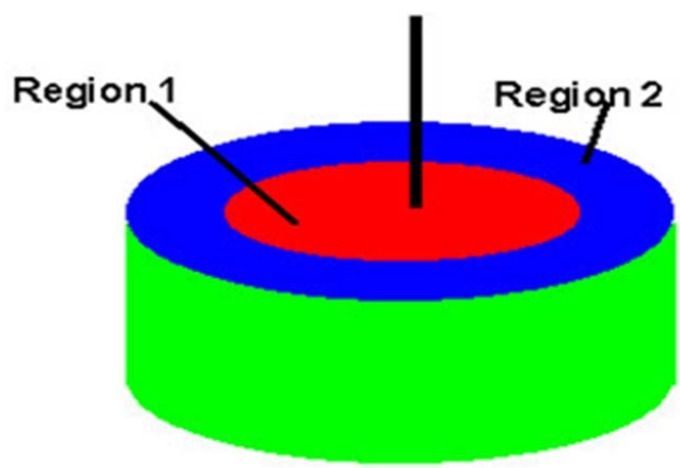


Figure 1.16: Composite Reservoir (Schlumberger 2009)

The region represented by the red zone is the one that has been hydraulically fractured and the remaining is referred to as the Matrix. The matrix is the lower permeability zone. Generally the permeability of the matrix in the Marcellus is in the tunes of nano-darcies(R.G. Agarwal 1979). Thus the fractures that are created are infinite conductivity fractures. And they also act as the source or conduit for the production of hydrocarbon to the wellbore.

1.4.2 Fracture Conductivity and Fracture type:

One of the reasons we carryout hydraulic fracturing is to improve the conductivity of the area around the wellbore. Conductivity is the product of the thickness of the zone times its permeability.

Conductivity is given by –

$$C_{rD} = \frac{k_f w_f}{\pi k_m L_f}$$ (John Lee 2003)

Where – C_{rD} = Dimensionless Conductivity

There are different ways of differentiating fractures. The ones that we are going to discuss are as follows –

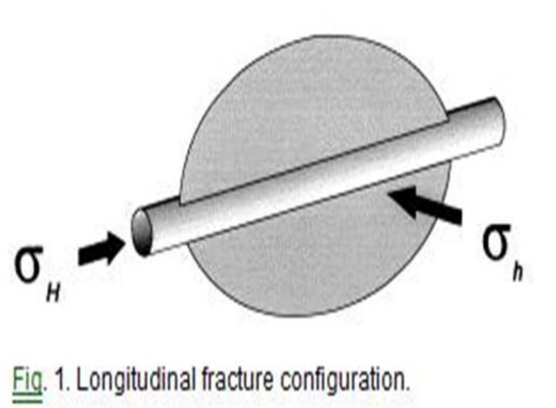
- Differentiation on the basis of Fracture Conductivity (John Lee 2003)
- Differentiation on the basis of Fracture Orientation (John Lee 2003)

Different types of fractures based on Fracture Conductivity are as follows –

- Infinite Conductivity (CrD > 100)
- Finite Conductivity (CrD < 100)
- Uniform Conductivity

The infinite conductivity fractures are the ones that we are focused on. In case of infinite conductivity fractures, the dimensionless conductivity ($C_{rD} > 100$) is greater than 100. The reason we are focused on this fracture type is due to the fact that this is the fracture that we encounter in the Marcellus Shale (N. R. Warpinski 2008). The other differentiating parameter is the fracture orientation. The stress pattern in the Marcellus is such that we observe that the minimum principal stress is in the horizontal direction. Thus the fractures that we observe in the Marcellus Shale are vertical fractures. The other orientation that we need take into consideration is the direction of propagation. Depending on this we have the following types of fractures –

- Transverse Fractures
- Longitudinal Fractures



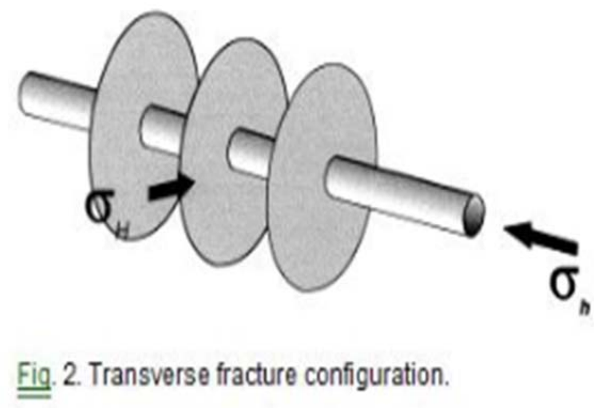


Figure 1.17: Longitudinal Fracture has less communication with the formation and this less increase in net production (Scientific Software Group 1998)`

Figure 1.18: Transverse Fractures are required as they increase the production tremendously (Scientific Software Group 1998)

The fracture type that we are concerned on is Transverse fracture. The advantage with this fracture is that it increases the production to a significant level. In case of longitudinal fractures, the production levels that are obtained (for horizontal wells) are similar to those obtained from vertical wells. Thus, if we intend to improve the production levels significantly using horizontal or multi-lateral wells we need to obtain an infinite conductivity transverse fracture [(K. Serra 1983)].

A problem faced in the stimulation modeling is the fact that in the Marcellus Shale, we have a dense network of fractures rather than a single fracture [(N. R. Warpinski 2008)]. One of the factors that contributes to this is the fact that the Marcellus Shale is a dual porosity system. The fracture spacing that is observed in most of the cases varies between 2 - 2.5 ft. A picture of a dual porosity system is given below –

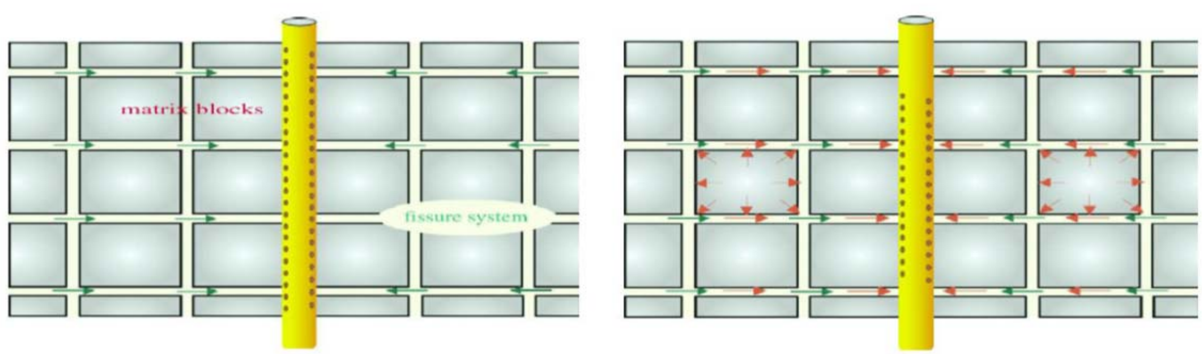


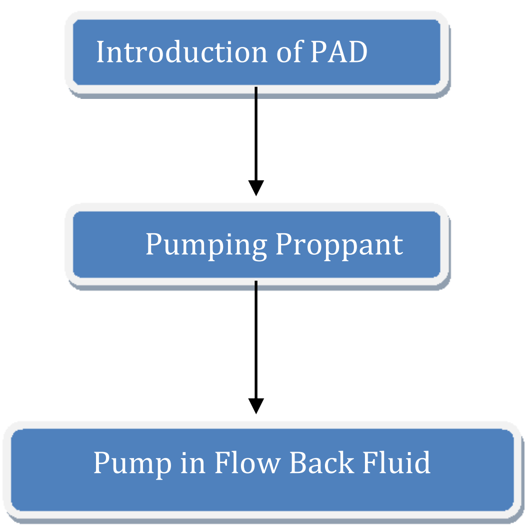
Figure 1.19: Dual Porosity System (fekete.com n.d.)

The simulation softwares that are available for stimulation modeling are able to model single fractures (using models like PKN). But modeling of a dense network of fractures is a complicated task. The advantage however, is that the production that we obtain from a dense network of fractures compared to a single fracture is higher. One of the reasons for is that at later times the entire fracture acts as the wellbore. The network of fracture helps increase the size of the wellbore at later times.

To overcome this problem, we are going to initially model the dense network of fractures in commercially available software that is CMG. Then we are going to account for the improvement in production that takes place due to this fracture job. Then with the help of this value we would account for the size of the single fracture that would give us similar production values. This estimation of the single hydraulic fracture size, we would do using commercial software called Fracpro PT. This software uses the PKN model for simulation purposes.

1.4.3. Procedure for Stimulation Operation:

The stimulation operation basically follows a certain protocol. This is as listed below–



As we can observe from the flow chart, the basic outline of the procedure that is followed during a fracturing operation. It is basically broken up into 3 stages –

- Introduction of PAD fluid – In this stage, water along with a few additives is pumped at high pressure (greater than fracturing pressures). This causes the formation to prop open. The PAD fluid is generally slick water. The reason for that is the fact that water is readily available and can be mixed with a lot of different additives (with greater ease). Also water doesn't react with the formation to cause any unwanted problems.
- Pumping Proppant – In this stage the proppant is pumped in along with the carrier fluid. This is quite important as the proppant is the means by which we keep the fractured propped open once the fracturing job is complete. The proppant is deposited (to a great extent uniformly) throughout the fracture (N. R. Warpinski 2008). The type of proppant selected is quite crucial. As it decides the conductivity of the fracture, which in turn governs the production rates.
- Pump in Flow back Fluid – In this stage water (without any additives) is flown in. The reason we do this, is to improve the flow back efficiency. We also add additives that reduce the viscosity of the carrier fluid, once we have completed the fracturing job.

  We need to improve flow back after the fracturing job because of the following 2 problems that it creates –
  - Obtain water in the hydrocarbon produced
  - Creates an additional skin factor

  Thus as a consequence of this the total production is reduced. Thus we need to resolve this issue.

1.4.4 Modeling the Stimulation Operation:

Previously we spoke about the procedure followed during a stimulation operation. Now we move on to simulating the operation. As we said, we would model the dense network of fractures using CMG. This would then give us an idea of the production levels that we have achieved using a dense network created by hydraulic fracturing. We would then input this information into the simulation software to simulate a single hydraulic fracture data. Helping us account for the amount of PAD fluid, proppant and carrier fluid that we would require for the desired job. The number of stages would be decided by the amount of fracturing fluid that we would require to pump in for the fracturing job. An image of the dense network of fracture that we are able to model using CMG is as shown below –

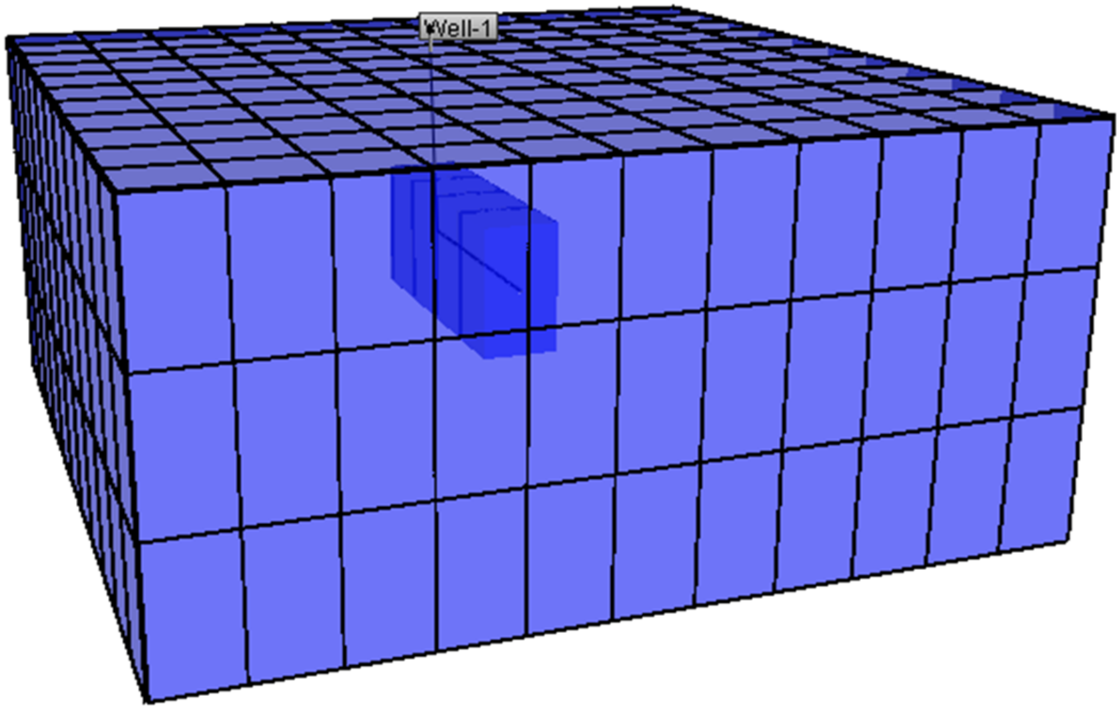


Figure 1.20: Hydraulic Fracture (3D image) modeled using CMG

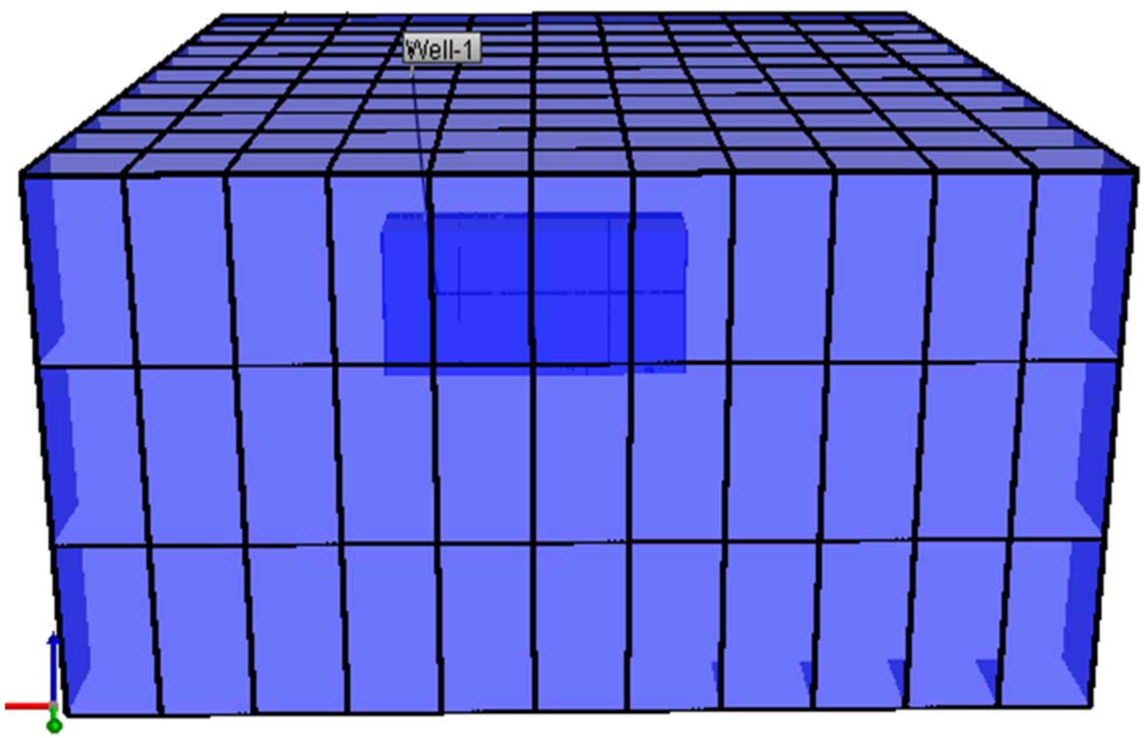


Figure 1.21: Hydraulic Fracture (3D image) modeled using CMG

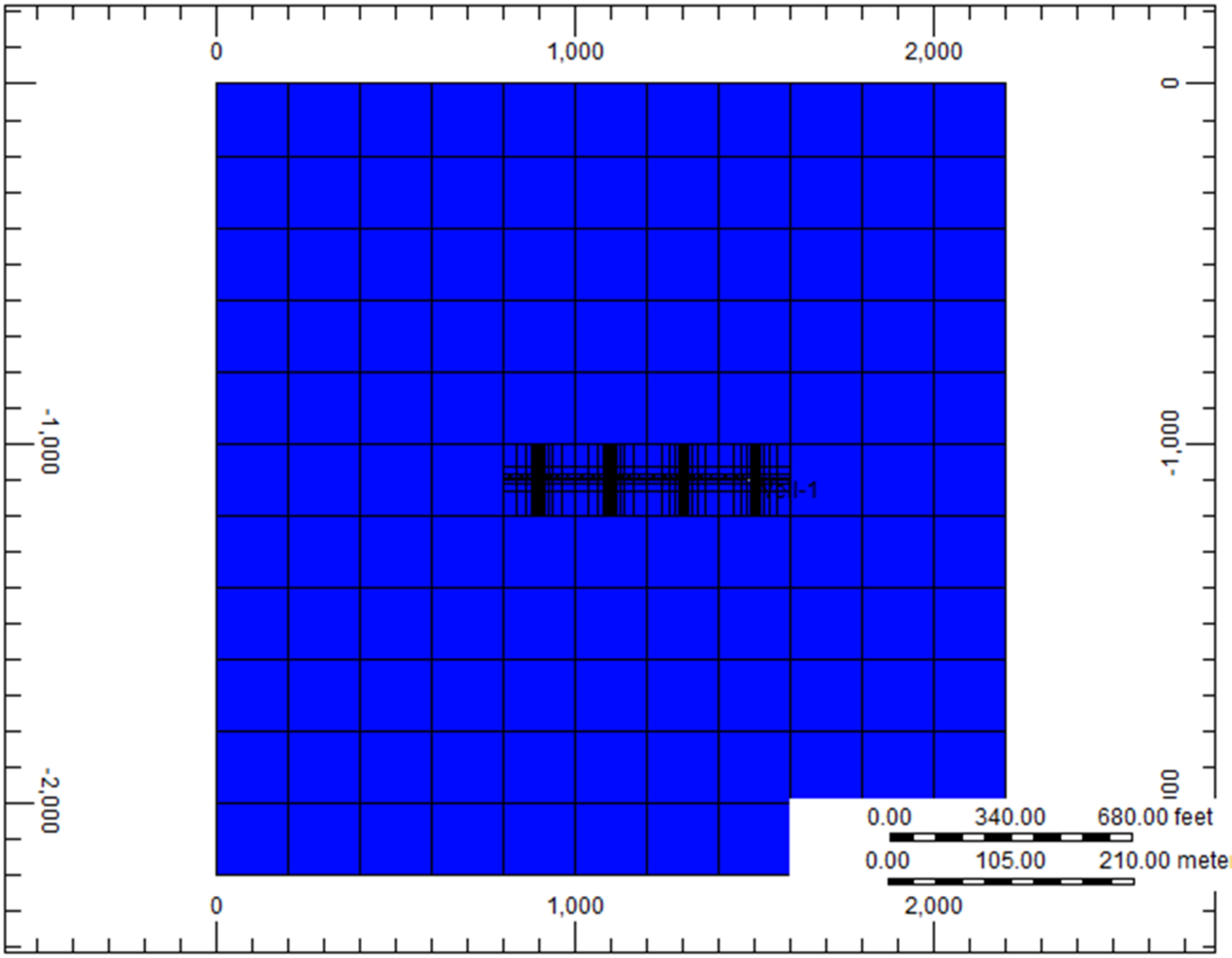


Figure 1.22: Hydraulic Fracture (2D image) modeled using CMG

As we observe the 2D image shows us a pattern in which there is a dense network of fractures around the wellbore. We would then use the production values generated using the model in CMG for Multi-lateral wells and input that data into Fracpro PT to obtain the best possible combination of the following parameters –

- PAD fluid
- Proppant
- Carrier Fluid
- Number of Stages

Thus by using the simulator softwares that are available, we can model the fracture network that we would encounter in the Marcellus Shale.

1.4.5 Issues to be addressed by the Study:

There are certain key issues that we need to look into in this study of the stimulation job in a multi-lateral completion. These issues include the following issue –

- Propagation of the dense fracture network
- Proppants, PAD fluids and Carrier Fluids to be used
- Number of Stages for the stimulation job
- Additives in the PAD fluid (Slick water)
- Optimizing stimulation design for a specific multi-lateral type
- Deciding the optimum Multi-lateral completion and stimulation job pair

An optimum stimulation design would look into the above aspects, which would ensure an optimum stimulation job for the specific completion (multi-laterals) that we are dealing with.

1.5 Well Design

1.5.1 Drill bit Design

Drill bit selection is important in order to have optimum drilling performance during the drilling process. A wrong bit selection can also cause an increase in tripping time to change the wearied drill bits, which is less economically efficient. Unfortunately, the typical selection process is based on experience from previous well sites. There are many types of drill bits that are used in the Marcellus Shale such as tungsten carbide drill bits, diamond-enhanced bits and steel drill bits. The purpose of this review is to ascertain whether there is compelling evidence that the Polycrystalline Diamond Compact (PDC) drill bit is an excellent selection for drilling a multi-lateral well in Marcellus Shale.

To demonstrate that the PDC drill bit is an exceptional selection multilateral drilling in Marcellus Shale formation several aspects will be analyzed. First, we seek to determine how PDC bits will affect the rate of penetration during drilling operation. Second issue in drill bit selection is how the torque management of PDC drill bit will help in drilling multilateral well. Final topic that needs to be discussed is the life time of the PDC drill bit when being used in the long and complex operation.

Note that the scope of this review is rather limited. Some of the aspects mentioned in the previous paragraph are not solely a function of type of drill bit used. In other words, there are also other parameters that also affect drill bit performance, such as type of mud weight and motor power used during the drilling operation. In addition, aspects such availability and the cost effectiveness of using such drill bits will not be discussed in this review. Nevertheless, I have included relevant examples of these studies to address this issue.

Rate of Penetration (ROP)

Rate of penetration is the rate of the depth that is being penetrated or drilled by a drill bit. A high ROP will cause the time required for drilling process to be reduced [A. T Jr, K.K Millheim & Chenevert 1991]. Based on research made by Bartlesville Energy Technology Center, the PDC drill bit will have two to six time faster than conventional diamond core bits in penetrating hard formation [Park 2008]. This is due the fact that PDC bits are generally stronger and harder than other materials in any other conventional drill bits. This allows hard formation to be cut easily in less time. In addition, Park also mentioned that full-face PDC drill bits showed improved penetration over roller cone bits when drilling medium and hard formations, but breakage of the nose cutters occurred when extremely hard formations were encountered.

Weller also mention PDC drill bits has higher rate of penetration than any other drill bit in the Oriskany Sandstone. In his research, he uses historical data from all wells drilled in Oriskany gas field that use different types of drill bit and found out that gradient between depths of formation drilled and rotating hours of the PDC is twice that of the other drill bit (T. F. Weller, Diamond-Enhanced hammer Bits Reduce Cost-per-Foot and Directional Problems in South Western Penssylvania Oriskany Well 2005).

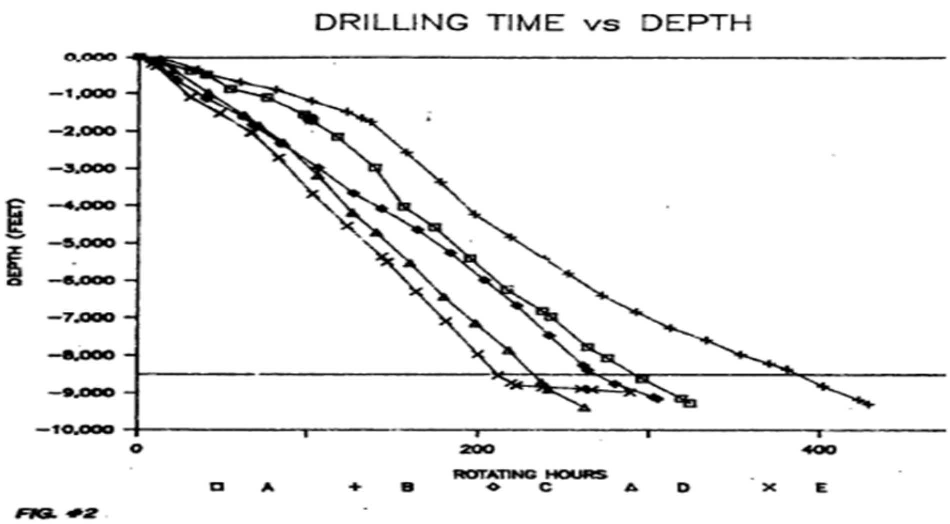


Figure 1.23: Drilling Time Vs Depth

Based from these two reviews, it can be said that PDC drill bits are the best drill bits in term of the rate of penetration. This can be applied to drilling Marcellus Shale formation as it contains hard formation like quartz arenite. This quartz arentie typically consist of well rounded, well sorted, medium-grained and mostly monocrytalline quartz, meaning some areas in the well strata that will have really hard formation. However, some of the formation especially the net pay zone –black shale formation – is very soft and brittle. The use of the high speed drill bit will be excessive and in some cases, if a formation is being drilled too fast, the formation will fracture and this can cause collapse formation problems (A. T Jr, K.K Millheim & Chenevert 1991). Thus, PDC drill bits most probably the best selection for Marcellus Shale but with more cautious procedures.

Torque Management

This section will discuss how PDC with optimized torque management technology will affect the torque management while drilling a multilateral well. This is crucial due to the fact that a high level of torque control is required especially when drilling complex fishbone multilateral well. Based on the research made by Baker Hughes, PDC can be used to manage and reduce torsional oscillation. As the torque management blocks wear, the PDC transforms into more aggressive bit when applied in soft formation, translating into a high ROP (Meckfessel 2010). Incorporating this advantage with precise calculation of kick off points (KOP), casing design and mud selection, the torque management can even be further enhanced.

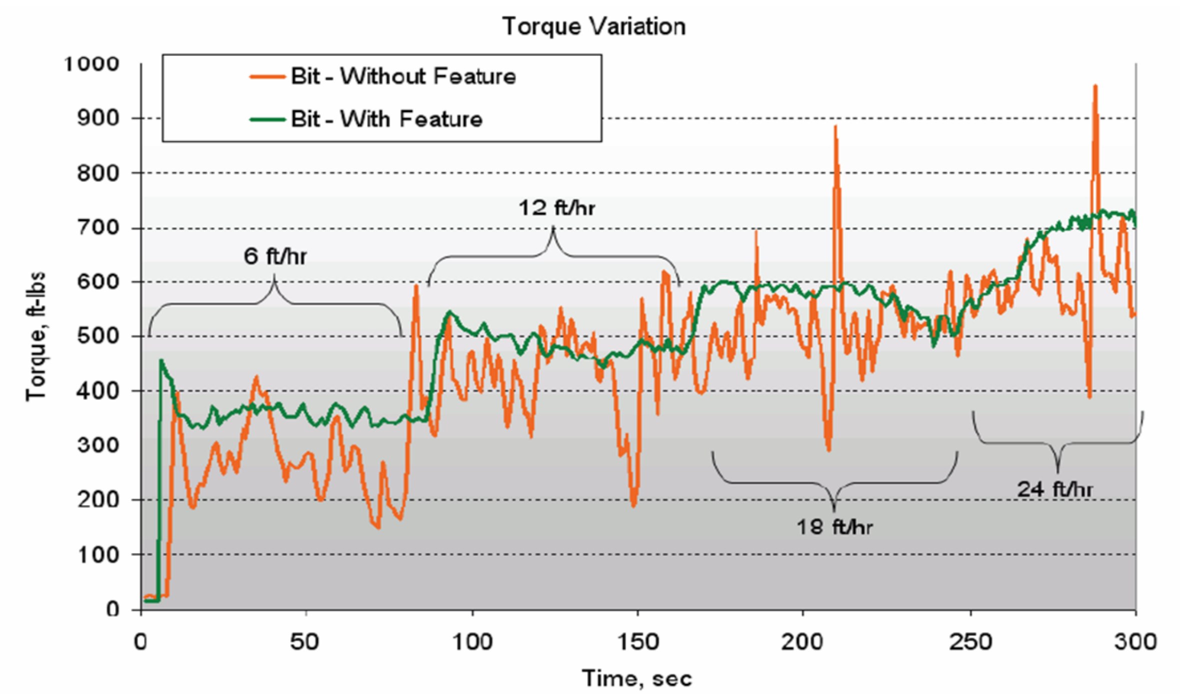


Figure 1.24: Torque Variation

Although this research significantly demonstrates that the level of torque control for PDC bits is more stable as drilling continues even after 24 hours, the types of rock that been used for this research might not be similar to the Appalachian Basin strata. Since the Marcellus Shale consists of formation like sandstone, dolomite, limestone and shale, the results of torque control may be different. Nevertheless, PDC has been proven to have better torque control for multilateral drilling than conventional drill bit like tungsten carbide and steel tooth drilled bit. Thus, the PDC is still the most suitable choice for multilateral drilling in Marcellus Shale.

Drill Bit Life Cycle

One of the main factors in selecting the most suitable drill bit is the drill bit life cycle. As the drill bit is being used, the bits will wear off and need to be replaced with a new one. Thus, a drill bit that has a long life cycle will be recommended. Based on Weller, although PDC bits costs 1.5 to 2 times more than conventional drill bit like tungsten carbide, it has 2 or 3 longer life time (2005). This is also been said by Arthur Park when his did PDC drill bit comparison in cutting hard formations like quartz arinite sandstone. Since the multilateral well is an operation that requires a longer period of time than typical horizontal drilling, then the PDC drill bit is the best selection for the operation.

1.5.2 Determination of Pore Pressure & Fracture Gradient for Mud Design

One of the most important aspects of drilling design is to identify the abnormal pore pressure zone. This piece of information is vital in order to determine the correct mud weight that have to be used for drilling purposes.

In order to design a good mud weight, both pore pressure gradient and fracture gradient curves need to be identified first. During first phase of our study, we have decided to use a pseudo reservoir in simulation. However, pore pressure determination must be determined using real set of data. To overcome this problem we are using well logs provided by East Resources Inc in Eastern Pennsylvania. This wells location is chosen since the formation stratigraphy is almost similar to Marcellus Shale. In our case, we chose graham #2 log as this log provides pore pressure, shale travel time and poison's ratio data needed to plot pressure and fracture gradient.

The log depicted by figure below provided data for our normal pore pressure gradient and overburden gradient. Another log from the same well was used to determine shale travel time. Shale travel time vs. depth was plotted on semi-log graph. Subsequently, a trend line was established on this plot to determine the normal shale travel time, Δt_n.

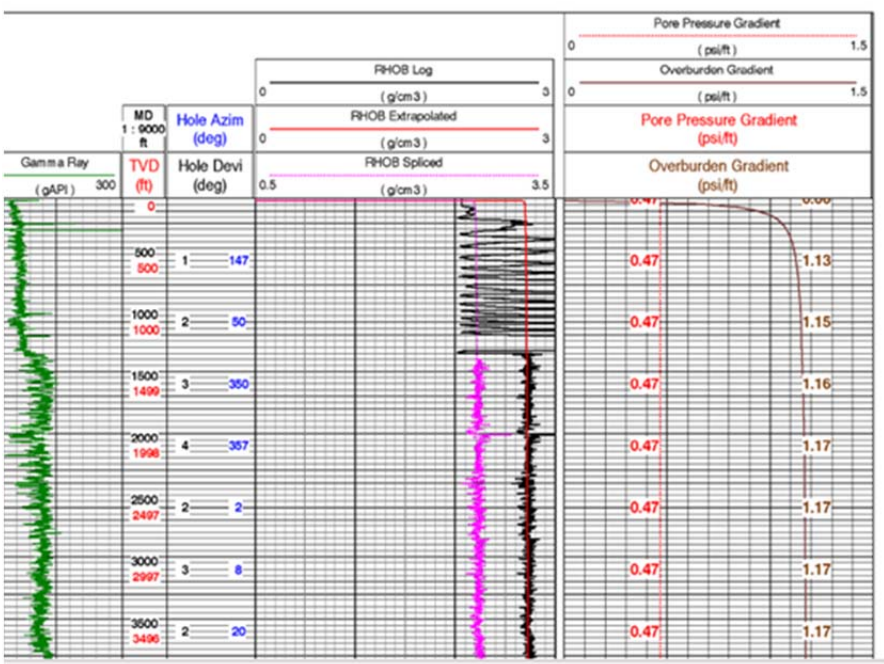


Figure 1.25: Graham # 2 Log

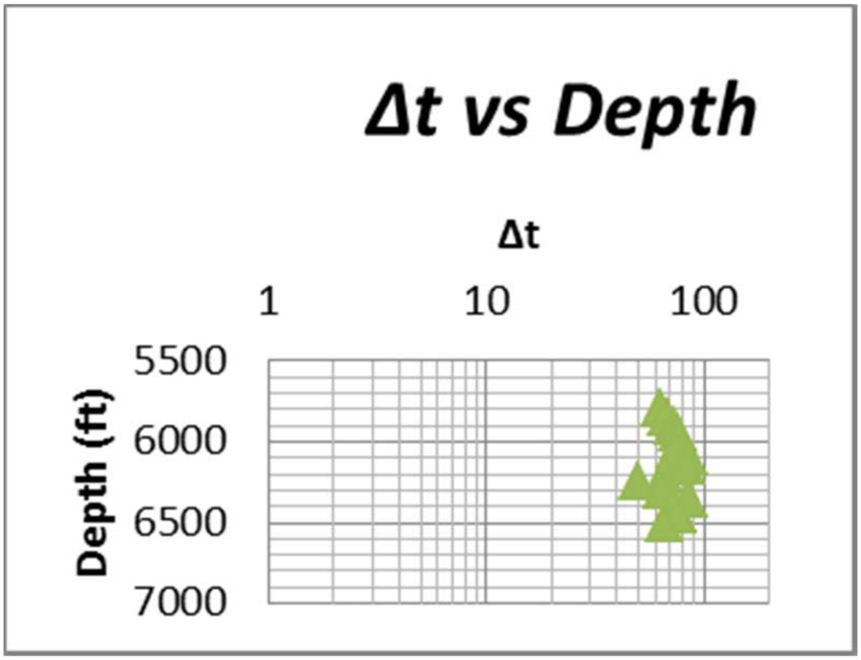


Figure 1.26 : Semi log plot of Shale travel time vs. depth

Based on the information above (***Figure 1.26***), abnormal pore pressure gradient can be computed by applying Ben Eaton's pressure gradient equation (1).

$$\frac{P}{D} = \frac{S}{D} - \left[\frac{S}{D} - \left(\frac{P}{D}\right)_n\right]\left(\frac{\Delta t_{obs}}{\Delta t_n}\right)^{3.0} \quad \text{--- (1)}$$

$\frac{P}{D}$ = Formation pressure gradient, psi/ft

$\frac{S}{D}$ = Overburden stress gradient psi/ft

Δt_{obs} = observed shale travel time, µs/ft

For the sake of comparison, Hubbert & Willis's equation was also used to compute the new pressure gradient.

$$F_{min} = \frac{1}{3}\left(1 + \frac{2P}{D}\right) \quad \text{--- (2)}$$

$$F_{max} = \frac{1}{3}\left(1 + \frac{P}{D}\right) \quad \text{--- (3)}$$

F = Fracture gradient, psi/ft

Next, poison's ratio data was taken from the above log from Graham #2 log. This data is used to compute fracture pressure gradient by applying Ben Eaton's fracture pressure equation (4).

$$F = \left(\frac{S-P}{D}\right)*\left(\frac{\gamma}{1-\gamma}\right) + \frac{P}{D} \quad \text{--- (4)}$$

γ = Poisson's ratio

Next, both pressure and fracture gradient curves were plotted onto pressure vs depth plot.

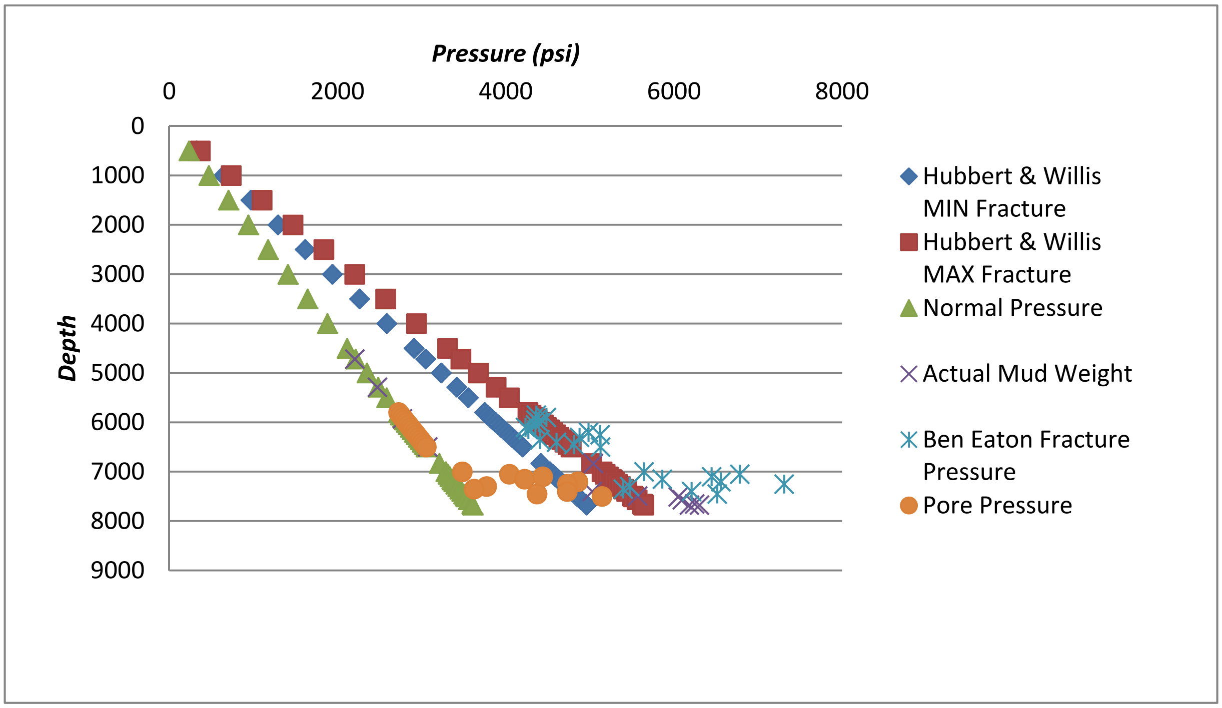


Figure 1.27 : Plots of Pressure Vs Depth

Based on ***Figure 1.27***, it can be observed that the pore pressure curve deviates around 6500 feet. This indicates the abnormal pressure zone. Thus, it can be deduced that gas might probably be at around 6500 feet (natural gas from Marcellus Shale). Subsequently, a plot of equivalent mud weight (EMW) vs depth was plotted in order to shed a light on what our mud weights ought to be.

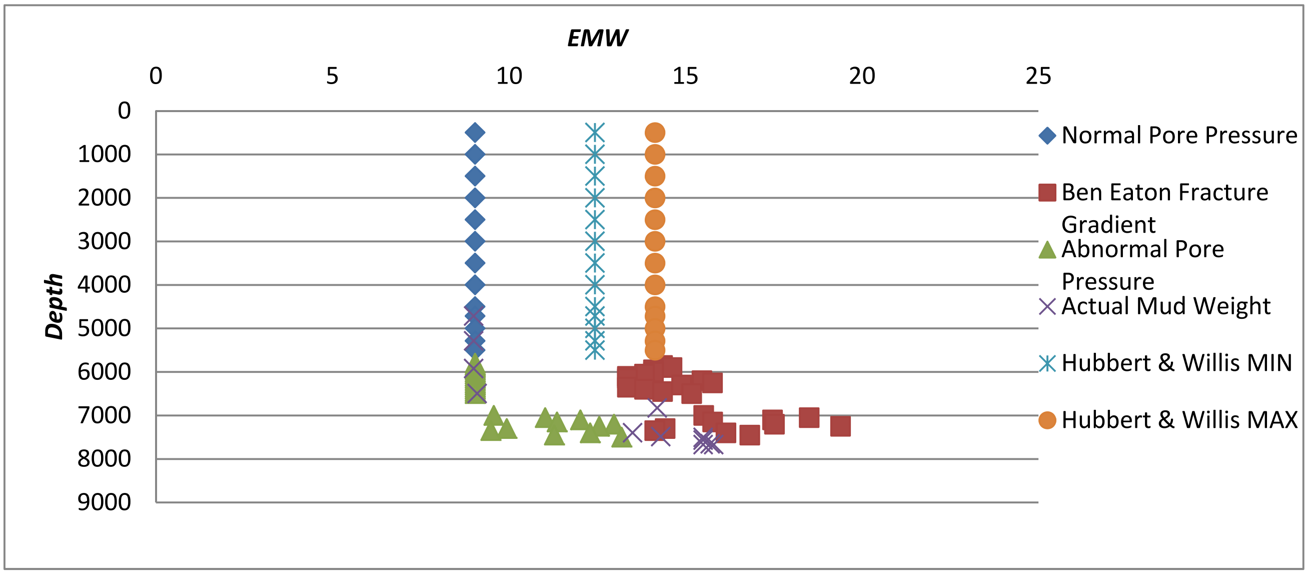


Figure 1.28: Equivalent Mud Weight Vs Depth

According to the plot generated above (***Figure 1.28***), mud weight needed at normal pore pressure zone (0 – 6500 feet) is approximate in the range of 9.04 to 12.44 ppg. Safe and responsible drilling practice dictates that the mud weight that will be used has to stay within the range of pore pressure and fracture pressure gradients. This is essential to having problems such as loss circulation or kicks.

Our study and analysis shows that the best way to drill is to implement air drilling at normal pore pressure zone (up to 6500 feet). Even though air drilling will be more costly than any other conventional mud, it provides increased rate of penetration, reduced formation damage and improves bit performance. Essentially, this will bring about economical return on the long run.

Figure 1.29: Photograph of a Drill Bit

1.5.3 Cementing

Cementing is the most fundamental process in drilling operations as improper practice of it could bring devastating effects to both the safety aspect and environment. The aftermath is most noticeable for the recent BP oil spill at the Gulf of Mexico, where the cementing job was poorly done and it led to loss of lives and significantly damaged the environment. Having said that, the main purpose of cementing is to protect and support the casing installed, to prevent the movement of fluid through the annular space out the casing, to stop the movement of fluid into vugular or fractured formations and finally to close out the abandoned portion of the well [Ravi and Bosma 2002].

Cement slurry is first obtained by mixing powdered cement and water at the surface. It is then being pumped into the well by hydraulic displacement to a desired location. The hardened cement would exhibit important strength characteristics for our main purpose. The best cement composition and placement technique selection are usually the biggest concern for drilling engineers where the cement chosen has to achieve certain target strength so that it could control the movement of pore fluid and at the same time not fracturing the formation [Ravi and Bosma 2002]. The main ingredient in producing cement is the Portland cement where it is made of a blend of limestone and clay [Jr., et al. 1991].

Before cement is being produced, several tests are ran to determine the thickening rate of slurry, the cement permeability, the tensile and compressive strength of the cement, the soundness of cement, fineness of cement. Usually the testing of slurry is not done at the site like drilling fluid, hence it is important for the drilling engineers to understand the tests and interpret the cement specifications. The American Petroleum Institution (API) has defined eight standard classes and three standard types of cements for use in wells. The eight classes are Class A to Class H and the three specified types are ordinary "O", moderate sulfate-resistant "MSR", and high sulfate-resistant "HSR" [Jr., et al. 1991]. In this field, class A cement is used as it could be used all the way from surface to 6000 ft and no special properties are required. With additives added, we could actually use it to the TD that we are looking at.

There are more than 40 chemical additives being used with various API classes of cement in the industry to actually provide slurry characteristics for almost any subsurface environment (Ravi and Bosma 2002). These additives are free-flowing powders and they could be either dry blended with cement before transporting it to the well or mixed at the job site. Currently, cement class G and H can be modified easily with the addition of additives to meet any specifications economically. There are few different functional groups that the cement additives could be classified into. They are the density control additives, the setting time control additives, the lost circulation additives, the viscosity control additives and also special additives for unusual problems (Schweitzer and Bilgesu 2009). Density control and setting time additives play a more important role as they are being considered in almost every cement job. By adding Bentonite, we would get a reduction in slurry density and it would increase the slurry yield because Betonite has low specific gravity and its ability to permit the use of hydrate permits the use of much higher water concentrations (Jr., et al. 1991). This would save us cost in a way as we do not have to include too much cement. However one of the cons in using Bentonite is that we would reduce the thickening time and cement strength. We could counteract the problem by adding sodium chloride and it acts as an accelerator. The maximum acceleration occurs at the concentration of 5% without Bentonite. It could also increase the early strength development of cement according to laboratory testing.

A sack of cement typically contains 94 lbm unless it is a blend of cement and other material (Jr., et al. 1991). The water content of slurry is also known as the water cement ratio in gallons per sack. The volume of slurry obtained per sack of cement is called the yield of the cement. It is calculated by adding the yield of cement A, Bentonite and Salt Water. Next, the annular capacity is first calculated by measuring the outer diameter of the casing and the inner diameter of the next casing. Slurry volume is calculated by multiplying the depth with the annular capacity. Finally, the amount of sacks needed is computed by dividing the slurry volume with the cement yield. Safety factor is included to ensure that the amount of cement is sufficient.

Different cementing technique and equipment are used to cement the casing strings, the liner strings, setting the cement plugs and squeeze cementing. Cement plugs are placed in open-hole or in casing before abandoning the lower portion of well. Cement is also squeezed into lost circulation zones, abandoned casing perforations, and leaking cemented zone to prevent undesired fluid movement. The conventional method in doing the cementing job is by using wiper plug and cement is pumped in between the 2 wiper plugs. Finally the cement slug is displaced down the casing by pumping drilling fluid into the casing behind the top wiper plug. In addition to the conventional placement method, there are several modified techniques that could be used in special situations. These include stage cementing, inner-string cementing, annular cementing through tubing, multiple-string cementing, reverse-circulation cementing and delayed-setting cementing [Jr., et al. 1991]. The detailed processes are not discussed here in the report.

One of the important aspects in the engineering design of the slurry properties is to determine the cementing time. The cementing time could be estimated by the actual slurry volume and pumping rates. This could give a more accurate results compared to the relationships between well depth and cementing time set by the API for the various cement classes as they only represent the average well conditions. At the end of the cementing job, the cement left in the wellbore is evaluated to ensure that the objectives of cementing have been accomplished. The maximum pressure for casing anticipated should be tested too after the cementing job. The evaluation could be done by acoustic logging device which usually operates behind the principle of sound travelling and rebounding back.

Result

Using the American Petroleum Institute (API) standard, the class of cement widen from A to H. These different types of cement have different properties that normally used depending on the types of situation of the drilled wells. Suitable class cement must be selected based on its properties such as, thickening time, slurry volume, depth of invasion, compressive strength and some distinguish properties. For this well, the major cement class that will be used is **cement class H.** The selection process of this cement class is discussed in thoroughly in this section.

One of the main reasons why class H cement is choose is widely used in the Pennsylvania drilling. This means that the cement availability is huge and can large amount of it can be obtained with less difficulty.

In terms of the properties, this cement is normally used up to 8000 ft depth and normally used when special condition is not required. This class of cementing has the fastest cementing time compared to other classes. This is a good point in cementing process as it will reduce the cementing process. Important information that should be realized is that the thickening time is reduced as is it used at deeper depth. The thickening time of class H in detail can be shown using the table below:

Class/ Depth	API Casing Test (hours:min)		
	4000'	6000'	8000'
H	3:00	2:25	1:40

The water requirement class H cement is 5.2 gal/sack and the slurry weight of the cement is 15.6 gal/sack which are quite moderate when compared to other type of cement available. However the compressive strength of this cement is among the lowest which 80psi at standard condition is.

Additive

One of the main concerns in deciding cement addictive is what properties that are needed and how the addictive will affect the cement properties. There are few types of additive will be discussed as a possible combination in this section.

Salt

Since there is a major concern about the fresh water contamination around the gas drilling operation around the PA, an additive like salt is selected as to avoid this from happening (Halliburton). There is also a shale formation in this operation which will likely need salt to avoid formation contamination. The amount decided for this well is around 5-10%. Note that however, that adding salt in class A cement will increase 9% thickening time, 19.4% of its compressive strength and 0.8 of its slurry volume.

GAS-CHECK®

Historically, the drilling industry has been plagued with problem of the annular gas flow flowing completion of cementing jobs. GAS-CHECK has been manufactures by Halliburton to provide an effective means of helping prevent gas flow into annulus after cement has been place. The additive also applicable for all type of formation zones and the entire standard cementing job requirement. As this addictive is perfect for gas drilling operation, Is advisable to use this type of addictive.

Calculating the amount of cement needed

The last part of the cement selection is to calculate the amount of cement required to complete the cementing job. The amount of the cement used is dependable on the size of casing used and the length of the casing. Thus the calculation made in this section is basically using the data provided in the casing selection section of this report.

The procedure of calculating the sacks of cement can be calculated as the following:

1. Calculate the yield volume of the component (cement and addictive);

$$V_{yeild} = \sum_{i}^{n} \frac{W}{SG * 62.4} \left(\frac{ft^3}{sack}\right)$$

Where W is the weight per sack of the component and SG is the specific gravity of the individual component.

2. Calculate the annular capacity with excess factor of 1.75:

$$A_a = \frac{\Pi}{4}(OD_{i+1}^2 - ID_i^2)\ \frac{sq\ ft}{144\ sq\ in}$$

$$V_{space} = 1.75\ A_a L_i$$

3. Calculate the slurry volume required for mixing;

$$V_{slurry} = \frac{V_{space}}{V_{yeild}}$$

4. Calculate all volume for each casing and sum them to get the total volume.

Note that since this project is implementing the open hole, multistage completion, and the cementing jobs will only covering from surface up until the first the intermediate casing. The possibility of the production casing collapse due to absence of the cement should not be a concern since the lateral length of the design is not exceed 6000ft and the grade that we choose for the production line – P110 – can withstand 110, 000 psi overburden; which is more than enough in the Marcellus Shale. The results of the calculation can be represented as the table below:

Section	Volume of Cement used (sacks)
Surface	236
Intermediate	802
Total	1038

1.6 Environmental Impacts of Marcellus Drilling

1.6.1 Introduction

The drilling of natural gas from Marcellus Shale, like other conventional techniques of drilling, has been known to have a significant impact on the environment and local flora and fauna. Many studies have been undertaken which have recorded the impact of shale drilling at various stages of the Marcellus shale development. The three major factors which are affected by the drilling activities are: Land, Air and Water.

According to a report prepared by the League of Women Voters of Pennsylvania in April 2009, the impact of drilling on the local climate and land usage in Pennsylvania has been recorded. Since the earliest drilling activity in the Marcellus Shale region in Pennsylvania started in around 2005, various federal and state agencies have monitored the effects and have reported periodically on the same.

1.6.2 Impact on Land

In Pennsylvania, the extraction of natural gas from Marcellus Shale has impacted the farmlands and forests where the drilling sites are located. Companies employ techniques such as vertical drilling or horizontal drilling which have their advantages and disadvantages. To access a particular underground reservoir, horizontal drilling has less land usage than required for vertical drilling. Vertical drilling takes up to sixteen different well pads to access a particular reservoir volume whereas for horizontal drilling the number of well pads is less. (Sandeep Janwadkar n.d.) As most of the equipment for horizontal drilling is situated below the ground and only the well head, separator and water tanks remain above ground. Thus the amount of production facilities, pipelines and also access roads are reduced by employing horizontal drilling techniques.

Agencies such as the Groundwater Protection Council and the Department of Environmental Protection have studied the impact of Marcellus Shale drilling on the farmlands and crops. Usually most of the drilling sites are located in farms in the countryside. Hence when heavy drilling and fracing equipment travels over farms, it affects the soil causing it to erode and become compact. As a result the soil loses its productivity and which in turn decreases percolation.

If the drilling sites are located in forests then it has a major impact on the local wildlife and flora and fauna. To build the access roads to these sites, large number of trees has to be cut down. This affects the habitat of birds and animals that have their abodes or nests in such trees. The risk to endangered species that are restricted to specific wildlife reserves is also high. Also due to the release of wastewater into the nearby streams or rivers, the aquatic and marine wildlife also gets affected.

1.6.3 Impact on Air

Even though natural gas is one of the cleanest burning fuels the production of natural gas has its impacts on the surrounding atmosphere. Pennsylvania Department of Environmental Protection. (2009), Oil and Gas Accountability Project (2010). and others have investigated the impacts of the emissions of harmful gases from the rigs and fracing engines such as methane, nitrogen oxides and volatile organic compounds which are released into the atmosphere. The Department of Environmental Protection and also the US Department of Energy have carried out studies and proposed ways to reduce the air pollution primarily being usage of electric motors instead of IC engines, effective processing of the natural gas at well site instead of venting and other guidelines.

- <u>Composition of Air Emissions</u>

Armendariz (2008 Barnett Shale Extraction – air pollution effects in Texas) has prepared a compilation of the following air emissions which are typically found during shale natural gas drilling and production.

- Methane (CH_4) which is the principal component of natural gas is a harmful greenhouse gas. It is released from the processing equipment and especially from pneumatic devices.
- Nitrogen Oxides (NO_x) result when coal is burned to provide power to machinery, compressor engines, and trucks and also during flaring. It is a precursor to ozone formation.
- Volatile Organic Compounds (VOCs), carbon containing substances that readily evaporate into the air.
- Benzene, toluene, ethyl benzene, and xylenes (BTEX), toxic compounds emitted in low quantities.
- Carbon Monoxide, which occurs during flaring and from incomplete combustion of carbon-based fuels used in engines.
- Sulfur Dioxide (SO_2) which may form when fossil fuels containing sulfur are burned. It contributes to acid rain and is regulated by the US Environmental Protection Agency (EPA) and contributes to acid rain.
- Particulate Matter resulting from dust or soil entering the air during construction from traffic on and off roads and from diesel exhaust of vehicles and engines.
- Hydrogen sulfide (H_2S), which exists naturally in some oil and gas formations. It may be released when gas is vented, leaked, or incompletely burned during flaring. It is toxic and smells of rotten eggs. Thus far, little has been found in Marcellus Shale.

1.6.4 Impact of drilling and drilling fluids

According to a report prepared by Environmental Science and Technology journal, At the Marcellus Shale, temperatures of 35-51 °C (120-150 °F) can be encountered at depth and formation fluid pressures can reach 410 bar (6000 psi). These factors enhance the impact of saturated brines and acid gases on drilling. The report further says that "the effect of higher temperature on cement setting behavior, poor mud displacement and lost circulation with depth makes cementing the deep exploration and production wells in the Marcellus Shale quite challenging." (Driscoll n.d.) The Department of Environment Protection and its inspectors discovered that the casings on some gas wells drilled by Cabot Oil & Gas were improperly cemented, potentially allowing contamination to occur (S.Mufson. 2009)

Drill cuttings contain shale, sand, clay and are also coated with contaminants from the drilling mud and borehole. At the surface, the drill cuttings are separated from the drilling mud, which is stored for reuse, while the drill cuttings are solidified and disposed of off-site. (McNabb, A. 2009)

Other possible impacts from drilling are the storage and treatment of refuse volume and muds. A horizontal well generates about twice the amount of drilling mud as that generated by a single vertical well (J. Daniel Arthur, Bruce Langhus and David Alleman n.d.). These require onsite treatment in steel tanks which have to be regulated effectively.

1.6.5 Current regulatory policies regarding oil and gas development in Pennsylvania

The oil and gas regulatory structure in Pennsylvania was created for vertical well development and is not adequate to manage the escalating development of horizontal shale formation well development throughout. The drilling and related activities such as withdrawal, transportation, injection and management of high volumes of water are not adequately covered by the existing regulatory policies which are applied in the hydraulic fracturing a deep Marcellus shale formation. (PEC n.d.). However the design, location, spacing, operation, and abandonment of these wells, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety are being regulated by the various Pennsylvanian agencies and authorities. (J. Daniel Arthur, Bruce Langhus and David Alleman n.d.)

On the national stage, as seen from the Barnett Shale natural gas extraction in Texas, most of the federal laws are administered by the U.S. Environmental Protection Agency (EPA) and whereas the drill sites which are located in the interior countryside farms and forests are regulated by the U.S. Department of Agriculture and the U.S Forest Service respectively.

1.7 Wastewater Treatment

1.7.1 Background

The major objectives of waste water management in the Marcellus shale operations are protection of the environment and the minimization of water transportation trucking requirements. State, local governments and shale gas operators due to the environmental concerns seek a water management system in order to protect surface and water resources and reduce fresh water demands for future.

Hydraulic fracturing is a very important step in the completion job of the wells to achieve high productivity and good well performance. This step requires between 1 and 4 million gallons of water for successful completion of each well. Vertical wells require approximately 1 million gallons and horizontal wells require 3-4 million gallons according to a recent survey among Barnett Shale Producer (Galusky, 2007). Similar amount of water is probably required in drilling and completion jobs in the wells drilled in Marcellus Shale Gas Reservoir. The quantity of produced water is usually less than the volume of fluid that is used during the treatment. Between 30 percent and 70 percent of the water used for fracture and completion returns back to the surface. This amount of water definitely should be used for future fracture, completion etc.

Table 3. Water Use and Flowback Water Collection Associated with Hydraulic Fracturing Completion of Shale Gas Wells

Location	Well Type	Total Vol. Frac Fluid Used, bbls	Cumulative Volume of Flowback Water, bbls				Percent Collected
			1 Day*	5 Days	14 Days	90 Days	
A	Vertical	40,046	3,950	10,456	15,023		37.5
B	Vertical	94,216	1,095	10,782	13,718	17,890	19.0
C	Horizontal	146,226	3,308	9,652	15,991		10.9
D	Horizontal	21,144	2,854	8,077	9,938	11,185	52.9
E	Horizontal	53,500	8,560	20,330	24,610	25,680	48.0
F	Horizontal	77,995	3,272	10,830	12,331	17,413	22.3
G	Horizontal	123,921	1,219	7,493	12,471	18,677	15.1
H	Vertical	36,035	3,988	16,369	21,282	31,735	88.0
K	Horizontal	70,774	5,751	8,016	9,473		13.4
M	Horizontal	99,195	16,419	17,935	19,723		19.9

** Days from the hydraulic fracturing event*

GTI Report, December 2009

However, this water, which returns to the surface, brings some contaminant such as; hydrocarbons, heavy metals radioactive materials, and high level of total dissolved solids (TDS). The TDS basically includes salts, potassium, sodium, chloride, carbonate and organic materials from shale formation.

According to the (A. W. Gaudlip 2008) paper, low TDS water can be used for future well completion and only the medium to high TDS water fractions are taken from the project area to be treated. However, in Marcellus Shale Gas Reservoir the water, used for fracturing or drilling, is very high TDS water. That is, it is indispensible to have wastewater management system in order to reuse wastewater in future jobs because if this high TDS water is reused for fracking jobs without treating, it will be very dangerous and may collapse the well.

New water treatment and new systems are being developed and used for the shale gas wastewater. There are some developments in treatment systems to reuse this wastewater for fracturing, water, and irrigation water and even for drinking, agriculture etc. However, this kind of treatment can be very expensive and risky because incomplete processing of this wastewater poses a contamination risk to drinking water. In that case, it would be more practical to treat the wastewater in such a way that it can be reused as a subsequent hydraulic fracturing job, or other industrial use.

1.7.2 Wastewater Management Systems

As we discussed above there are some main objectives in the wastewater management systems, which are protection of environment and minimization of water trucking requirements. In order to achieve those objectives the following criterion are to be considered:

- Reduction in brine volumes requiring transportation and disposal
- Oil and grease removal
- TDS reductions in product water
- Decreased concentration of benzene
- Decreased concentration of biological oxygen demand arising from soluble organics
- Control of suspended solids (A. W. Gaudlip 2008)

" In the management of Appalachian Shale gas waters, the most pressing issues are how to deal with the disposal of large volumes of brines that are anticipated from the completion wells. “” (A. W. Gaudlip 2008).

Some water treatment systems and disposal alternatives currently used in Appalachian Shale Gas water are the following:

- Deepwell Injection
- POTWs (Publicly Owned Treatment Works)
- Reuse for fracture job
- Reverse Osmosis

1. Deepwell Injection

According to some studies this process is very new and very hard to implement in PA because of the lack of good regulation/restriction. Because of this reason it is not useful to implement this process into our reservoir.

2. POTWs (Publicly Owned Treatment Works)

This water treatment system is for low and medium TDS fracture flow-back water. Since in Marcellus Shale, the water, which comes to surface after fracturing, is very high TDS, this process cannot be implemented in our application.

3. Reuse For Fracture Job

This application is actually very cheap compared to the other system and more practical. Flow-back water coming after fracturing can be used again for the future fracture job without having a huge treatment system. However, if the water coming to the surface has very high TDS, this system can be very dangerous for the well stability. Since we have to deal with very high TDS frac water in Marcellus Shale Reservoir, this process cannot be used in our application.

4. Reverse Osmosis (RO)

Reverse Osmosis is the type of a system that is capable of deminerilizing brines. The high pressure (600-900 psig) is used in this system to force brine through a membrane that retains salts on one side and allows produced water to flow to the other side. "The RO process is commonly used in industry and community water supply systems for the removal of salts. As of 1997, there were approximately 2000 RO plants in the world treating a total of 800 million gallons of water per day (MGD). Under ideal condition, RO should be capable of treating influent brines of up to 40000 mg/l TDS (about the strength of seawater). [(A. W. Gaudlip 2008)] Even tough high pressure is required and naturally more energy in RO treatment system, as it is described above, it is very effective system that can reduce TDS amount from the waste water.

1.7.3 Implementation Considerations

The implementation of wastewater management for shale gas reservoir involves some strategic goals such as; reduction of brine volume, water reuse, specification the minimum quality of water that will be used for frac jobs for future well completions. The considerations about these challenges are transportation and mobility.

- Transportation

As we mentioned above, minimization of water transportation is one of the most important objective in water management because this reduces also environmental impacts, decrease hydrocarbon footprint in well completion and obviously decreases the traffic congestion. " About 300 truck loads are needed to move a million gallons of water assuming each truck is limited to 80 bbls per truck." (A. W. Gaudlip 2008).Therefore, it is very necessary to design a management system to minimize the transportation of water within very significant distance. In this kind of system storage, pump, pipe and lift stations can be used to move water from a water supply to a nearby project area.

- Mobility

One method that can reduce the truck traffic is to bring the equipment to the brine. This can be implemented by using mobile treatment units. The systems using membrane (RO) are very appropriate for mobile application.

1.8 Economic Analysis

In the petroleum industry, exploration or development well costs are often broken into two components and referred to as intangible drilling costs (the costs of drilling oil and gas wells to the point of completion) and tangible well costs (the costs of tubing, producing equipment, tank batteries, separators and gathering pipelines necessary to bring the well into production. IDC is often used for intangible drilling costs in petroleum drilling project (Stermole and Stermole 2009). Tax reduction considerations are the primary differences in tangible and intangible well costs as discussed in detail for different types investors.

There are four general categories when considering oil and gas investment opportunities (Stermole and Stermole 2009). We can evaluate the project from the viewpoint of the party holding all rights to the property, which might be considered as "development economics," or drilling property "heads up." Both terms imply that the intent is to be held responsible for all the costs and profit pertinent to the investor's economics. Second, we the investor might consider passing the rights to develop to a second part who would take up all the drilling costs and well completions costs. In this case, the developer usually takes most of the revenues until the costs are recovered and we will back-in at the future point in time for a working interesting in the property. This is known as farm-out. Also, the opposite viewpoint, 'farm-in' is considered developing a property that someone else owns for an interest in the property. Finally, we could look at selling a property and keeping royalty, with no liability towards the development of property. This is referred to as "overriding royalty" in a property.

There are several decision criteria that will help investors to evaluate a variety of different investments. These parameters could be used as a measuring tool or guideline to analyze the feasibility of the project (Stermole and Stermole 2009).

1.8.1 Net Present Value (NPV)

Net present value is defined as the sum of all cash flows discounted to a specific point in time at the investor's minimum rate of return, or discount rate (Stermole and Stermole 2009). NPV is the measure of value created by investing in a project and not investing money elsewhere at a minimum rate of return. NPV greater than zero is acceptable compared to investing elsewhere at that minimum rate of return. A zero NPV means a breakeven with the investing elsewhere negative is unacceptable.

1.8.2 Rate of Return

Rate of return is the compound interest rate received on the unpaid portion of the dollars invested over the project life. It is also defined as the compound interest that makes the NPV equals zero. Solving for ROR involves a trial and error process and interpolation between the two interest rates that bracket a present worth equation equal to zero. ROR is often compared with other returns from other perceived opportunities to determine if a project is economically acceptable.

1.8.3 Growth Rate of Return

Growth Rate of Return considers the reinvestment of funds but not necessarily at the project rate of return. Instead, project positive cash flow is assumed to be reinvested at the project minimum rate of return which should reflect other perceived investment opportunities both now and in the future.

The fundamental driving force behind the drillings of the oil and gas wells is to generate revenue from the sales of the hydrocarbons. In order to gain profit from the producing well, the operating expenses and the capital costs have to be justified by the production and sales. Basically we could conclude the costs into two separate categories, the total intangible and the total tangible costs. The intangible costs include the fees for preparing the site such as obtaining the legal rights and documents, the surface damages done while clearing the site, building roads and fences. Besides, the intangible costs incurred would include drilling contractor services, materials and supplies, general services like the welding, dirt work and installation process. Specialized services such as open-hole evaluation, cementing, stimulation, fishing services and other services would contribute to the amount of intangible costs. Other miscellaneous cost would cover the drilling overhead, the general labor, insurance, company benefits and also taxes. In addition, there are also costs for materials and supplies, power fuel and water, completion and clean up and also environmental and safety causing.

1.8.4 Drilling Cost Analysis

The main function of the drilling engineer is to actually recommend proper drilling procedures that will result in the successful completion of the well as safely and inexpensively as possible. Recommendations concerning routine rig operations such as drilling fluid treatment, pump operation, bit selection, and any problems encountered in a drilling operation. In most cases, the drilling cost equation can be useful in deciding the recommendations where the usual procedures are to break the drilling costs into variable drilling costs and fixed operating expenses that are independent of alternatives being evaluated.

1.8.5 Drilling Cost Formula

$$C_f = \frac{C_b + C_r(t_b + t_c + t_t)}{D}$$

where C_f is drilled cost per unit depth, C_b is the cost of bit, and C_r is the fixed operating cost of the rig per unit time independent of the alternatives being used. Since the drilling cost function ignores the risk factors, the results of the cost analysis must sometimes be incorporated with engineering judgments. Risk of encountering drilling problems such as suck pipe, hole deviation, hole washout, etc, is increased greatly.

1.8.6 Drilling Cost Predictions

Often, the drilling engineers are call upon to predict the cost a well at a given location. Sound economic decisions are to be made based on those predictions. Evaluation of a given tract of land available for lease in some cases is required to estimate the approximate cost. In some cases, a more detailed cost estimate maybe required to drill a new well. Drilling cost depends primarily on the location of well and also the depth of it. The costs associated with the well often include the wellsite preparation, rig transportation, and the daily operating cost of the drilling operation. For example, a given lease offshore Louisiana requires expenditures that will costs about $30,000/day [(Jr., et al. 1991)]. Drilling costs tend to increase exponentially with depth thus when doing the curve fitting for drilling cost data, it is often convenient to assume a relationship between cost, C and depth, D given by

$$C = ae^{bD}$$

where the constants a and b depend primarily on the well location [(Stermole and Stermole 2009)]. Cost analysis based on a detailed well plan must be made for a more accurate drilling cost prediction. Tangible cost for well equipment like casing and the preparation cost of the surface location usually can be predicted accurately. Cost per day of the drilling operations then can be estimated from considerations of rig rental costs, other equipment rentals, transportation costs, rig supervision costs, and others. Required time to drill and complete the well is estimated based on the basis of rig-up time, drilling time, trip time, casing placement time, formation evaluation and borehole survey time, completion time and trouble time. Time spent on hole problems like stuck pipe, well control operations, formation fracture, etc are called trouble time. Drilling and tripping operations always require major time expenditures [(Stermole and Stermole 2009)].

If a dry hole is drilled, the total intangible costs is less than a completion well since no stimulation is needed to be done and there would be no water produced that would be added to the disposal costs. Aside from that, the tangible costs would comprise of the casings, tubing, sucker rods, subsurface equipment and also surface equipment. If a dry hole is drilled, the tangible cost is not significant since the surface production facility is not needed and no pipelines are installed. Otherwise, the cost would greatly increase due to the construction of surface facilities, tubing and production casings. On many wells, large fraction of well cost may be reflected on the unexpected drilling problems such as mud contamination, lost circulation, stuck drillstring, broken drillstring, ruptured casing, etc. These unforeseen costs usually cannot be predicted with degree of accuracy and in some cases it is not even included in the original cost estimate.

2.0 Selection of Reservoir Location

2.1Characteristics of Marcellus Shale

Marcellus shale is believed to be one of the largest sources for domestic natural gas (in US) ever discovered so far. It is Devonian age member of a geologic structure known as the Hamilton Group. Of all the Hamilton Group formations Marcellus is the deepest and oldest formation. It is mildly radioactive as indicated by certain well logs proving the existence or uranium along with the shale. The Marcellus formation is trapped between two Limestone layers namely Onondoga Limestone at the bottom and Tully Limestone on the top. These impervious layers have trapped natural gas in between these layers in the form of a shale gas. Even though Marcellus was known to contain a lot of gas since decades but only recently was the technology available for economic extraction of the Natural Gas from the shale

With this advancement in technology, it has become important to assess the Marcellus shale play depth for exploring the productivity of the shale. It was considered that Geological, Technological, Availability of Resources, Availability of market and Demographics are most critical factors to choose a county for development operation. An ideal drilling location (county) makes maximum profit production with minimum investment. Factors that could cause or contribute to profit maximization include, but are not limited to, fluctuations in the prices of oil and gas, uncertainties inherent in estimating qualities, quantities of oil and gas reserves and projecting future rates of production and

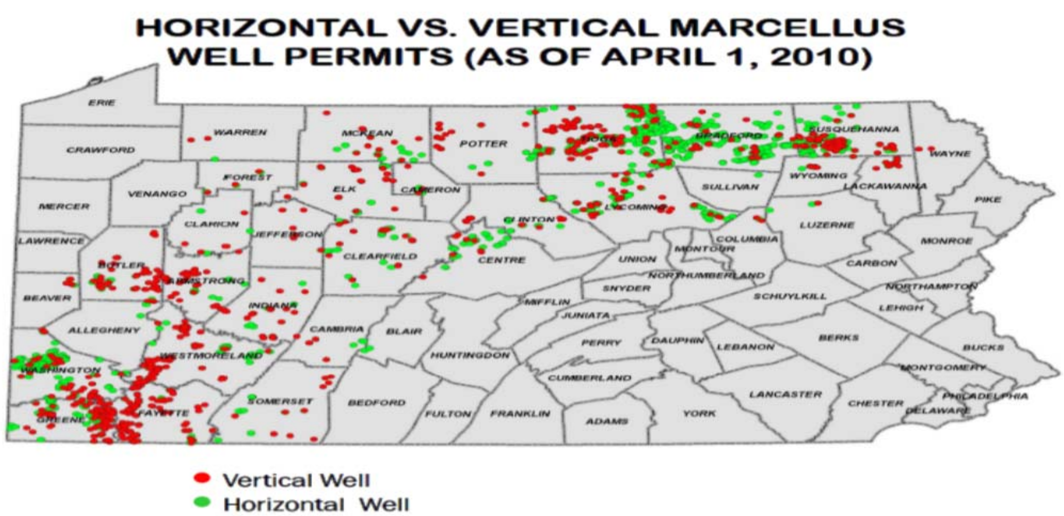


Figure 2.1: Horizontal wells and Vertical Wells drilled in PA

timing of development activities, competition, operating risks, acquisition risks, liquidity and capital requirements, the effects of governmental regulation, adverse changes in the market for the Company's oil and gas production, dependence upon third-party vendors, and other risks. This part of the report would target Quality and Quantity of gas in place in Marcellus shale play (Armstrong Agbaji 2010)

There has been Drilling activity is eight Pennsylvania counties as indicated in the figure 1 Susquehanna, Lycoming , Clearfield, Indiana, Allegheny, Washington, Green and Fayette, since late 2007 or early 2008. In some counties like Pike, Sullivan and Wayne, task force groups have been appointed to explore the possibility of drilling new wells. 1000 acres in Pike County have already been leased for drilling new exploratory wells. (Susan Beecher 2010) As we can clearly see that there are a lot of Horizontal wells are being drilled in Bradford and Susquehanna counties, it is planned that drilling activity shall extend to pike county and with multilateral well Technology.

The isopach indicates that the formation thickness grows from west to north east and south east and in the regions close Pike, Bradford, Susquehanna counties it is supposedly to be the thickest.

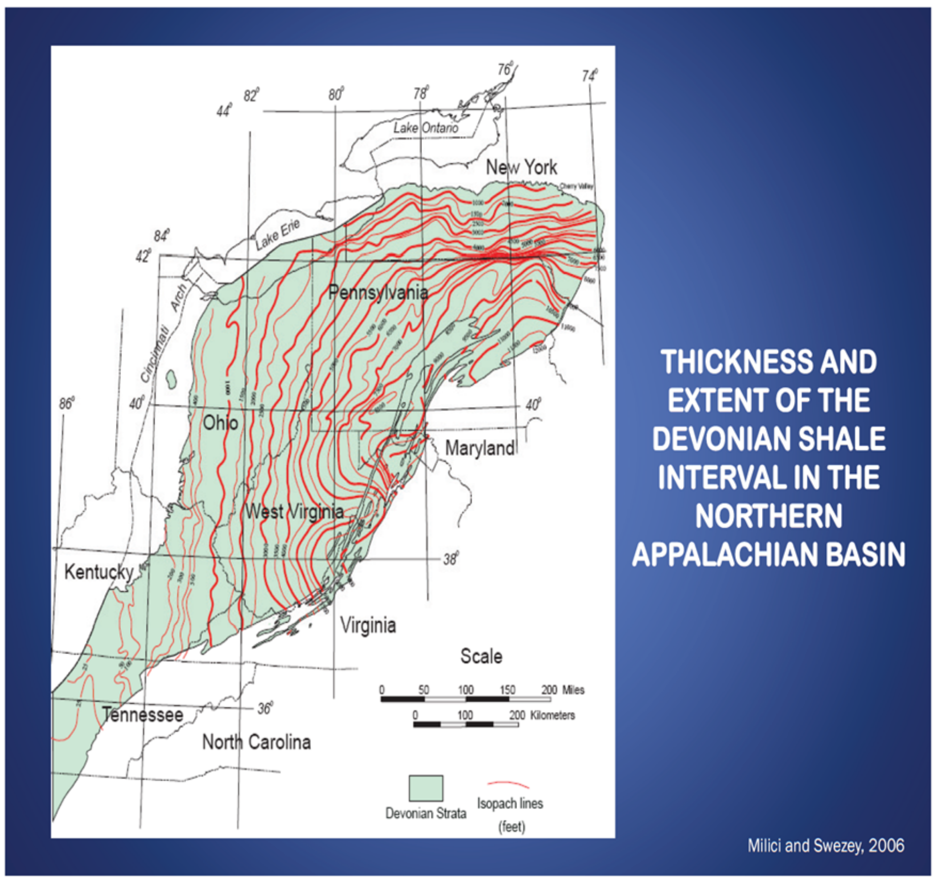


Figure 2.2: Thickness and Extent of Marcellus Shale in PA

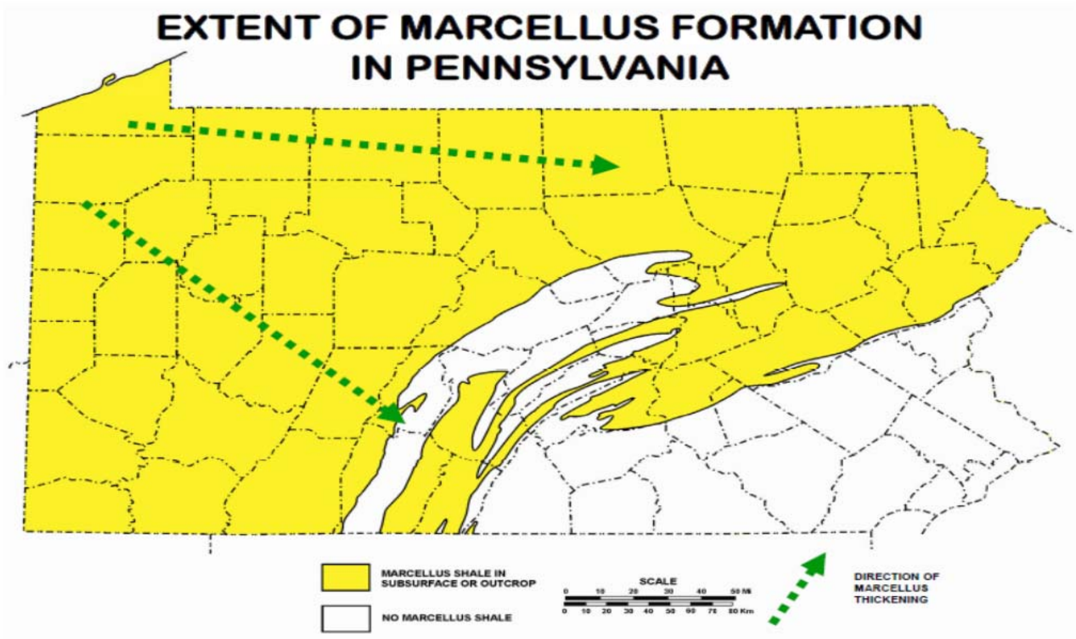


Figure2.3: Map indicating the thickening of Marcellus

Orientation of fractures in five cores from EGSP report (Harper 2008)

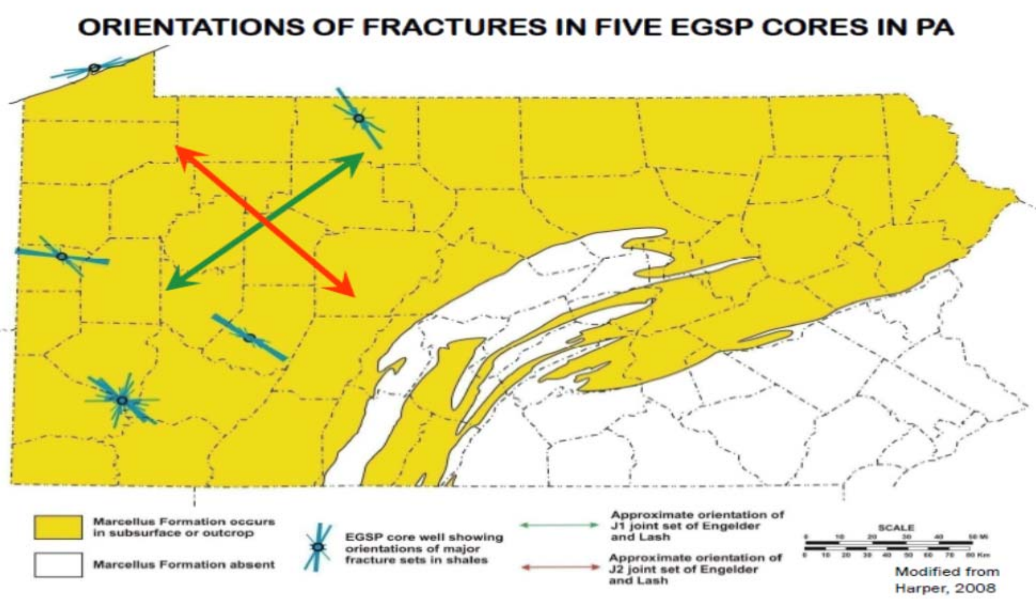


Figure 2.4: Orientation of Fractures in shales from EGSP core data

As for the location with highest potential, certain factors like Gas price, Depth of the Marcellus, Vitrinile reflectance, TOC remain the prime factors in identifying the location, but the permeability and porosity would significantly not change the decision of the location, owing to implementation of technologies like Multilateral Well Drilling and Optimized Hydraulic Fracturing. Certain factors are going to become less significant as from the earlier case of Vertical or Horizontal Wells. Nevertheless an attempt was made to compare the performance of Multilateral Well Drilling with Horizontal Well Technology.

It is difficult to find shale areas with high productivity because traditional well log techniques are based on conventional formation such as sandstone, limestone and dolomite, which is optimized to identify conventional reservoir parameters. The complexity of the mineral composition of shale and its variation in density, resistivity, and radioactivity could cause serious error in porosity and saturation calculation.

However the following factors were taken into consideration while selecting the location for our Reservoir.

2.2 Total Organic Content

Total organic content (TOC, wt %) describes the quantity of organic carbon in a rock sample and includes both the kerogen and bitumen. Geologically, TOC increases towards the maximum flooding surface; the organic matter types become more marine and therefore prone to oil/gas [S Creaney 1993]. An effort was made by USGS in 1983, to combine sequence stratigraphy and TOC from well logs, core, and cuttings to develop a model of TOC accumulation in marine source rock in Pennsylvania. Figure 4 shows TOC contours over the Pennsylvania [Roen 1983]. By directly looking into the contours it is evident that highest TOC areas are located in South-West (Fayette County) and North-East (Susquehanna and Pike Counties)Pennsylvania. North-west and central part of Pennsylvania rocks has low TOC with respect to the rocks found in the two above-mentioned regions. TOC, in central and Northwest part, is sufficiently good for hydrocarbon generation. TOC contours indicate preference for Northeast and Southwest Pennsylvania.

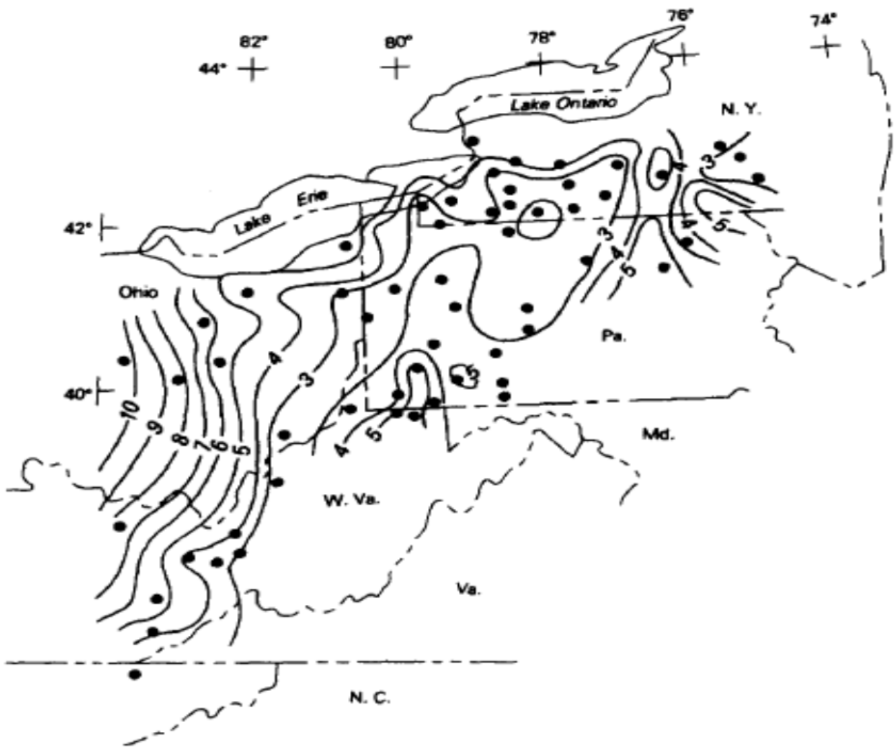


Figure 2.5: Average organic carbon of the black shales of middle and Late Devonian Age (G E Claypooi 1980)

TOC values were obtained for all the counties. The county with the highest TOC value is the ideal one. However, TOC is not a clear indicator of petroleum potential, for example, graphite is essentially 100% carbon but it will not generate petroleum. Alternatively, maturity index has been taken into account.

2.3 Vitrinile Reflectance:

A measurement of the maturity of organic matter with respect to criterion whether it has generated hydrocarbons or could be an effective source rock. The reflectivity of at least 30 individual grains of 23 vitrinite from a rock sample is measured under a microscope. The measurement is given in units of reflectance, % Ro, with typical values ranging from 0% Ro to 3% Ro. Strictly speaking, the plant material that forms vitrinite did not occur prior to Ordovician time, although geochemists have established a scale of equivalent vitrinite reflectance for rocks older than Ordovician (Schlumberger 2008) . Ro% values are consistent with thermal maturity indices commonly used to define the "window" of oil, wet gas, and dry gas generation and preservation (W Kalkreuth n.d.) . Bradford, Pike and Susquehanna Counties are located in a region where dry gas is the expected hydrocarbon type (CAI 3.5; %Ro 3). These anomalous oil occurrences imply either that locally the oil escaped from being converted to gas or that oil migrated into the region after the main phase of gas generation (J E Repetski 1999). Consistent with the higher thermal maturity is the high methane content of the Natural gas.

2.4 Fracture Porosity:

Tight gas formations like the Marcellus Shale have typically low permeability. The flow of gas to the wellbore is restricted by the formation. To achieve economic production of gas the flow path to the wellbore has to be enhanced. Natural fractures created by geological processes over time can provide the necessary permeability for economic production. The permeability created is anisotropic in nature.

Due to this the drainage area around the wellbore and the lateral tends to be elliptical (Teufel 2003) . This elongated drainage area creates more production interference from adjacent wells and can leave parts of the reservoir undrained. So it becomes imperative to figure out well spacing and placement based on a deep understanding of permeability anisotropy to achieve optimum production of natural gas. Although fracture porosity is important in economic recovery of gas it plays a lesser role as compared to other geological parameters in location selection. Fracture Porosity is important for sustained economical production as the production declines sharply. Artificial permeability has to be created regardless of the permeability of the natural fracture system. The higher the fracture porosity, the greater gas production rate will be at the start of production. However, production declines sharply and reaches a constant value over time similar to an artificially fractured formation. More importantly, the frac job, implemented in a naturally fracture formation with good fracture porosity, needs to create lesser artificial permeability.

In the Marcellus, black shales carry two regional joint sets namely, J1 and J2. J1 joints are trending in the ENE direction crosscut by NW-trending J2 joints (Engelder, Systematic joints in Devonian black shale 2007). The target of horizontal drilling should be the J1 joints because they are more densely developed. This can be achieved by drilling in the NNW direction, perpendicular to the plane of bedding. Fracture pattern and subsequent permeability affect location selection, significantly.

Fracture porosity was found out to be 0.1% for the quadrangle under consideration.

Thickness of the formation was observed to be 700 ft according to which the formation has sufficient initial gas in place(~5.75*1010 ft3 for a Drainage area of 80 Acres) to ensure a sustained production value for over 30 years.

2.5 Conclusion:

Finally with all considerations taken into account, Hawley Quadrangle in Pike County has been chosen for the production. The detailed Stratigraphy has been indicated in the Table 1. TOC(Total Organic Carbon) values for this region range from 0.6 – 1.8 and Ro (Vitrinile Reflectance)values close to 4. The fracture Porosity is assumed to be 0.1% and the gas porosity to be 0.9%. The permeability has been assumed to be 1*10-5 mD. For simplicity it has been assumed that whole layer of Marcellus would have uniform properties and a sensitivity analysis is carried out changing the gas porosity and permeability values. The following Lithography was obtained from Typelogs of DCNR website (Source Rock Sample Date from DCNR Website 2010) these belong to pike county and Hawley Quadrangle.

Formation	Depth to the Top (in Feet)	Depth to the Bottom (in Feet)	Thickness (in Feet)
CATSKILL	0	2945	2945
TRIMMERS ROCK	2945	5314	2369
TULLY	5314	5366	52
MAHANTANGO	5366	7046	1680
MARCELLUS	7046	7748	702
BUTTERMILK FALLS LIMESTONE	7748	8055	307
ESOPUS	8055	8510	455
RIDGELEY	8510	8527	17
SHRIVER CHERT	8527	8580	53
PORT EWEN SHALE	8580	8710	130
MINISINK LIMESTONE	8710	8725	15
NEW SCOTLAND	8725	8948	223
COEYMANS	8948	9085	137
RONDOUT	9085	9142	57
DECKER	9142	9224	82
BOSSARDVILLE LIMESTONE	9224	9322	98
POXONO ISLAND	9322	10254	932
BLOOMSBURG	10254	11148	894
SHAWANGUNK	11148	12560	1412
MARTINSBURG	12560	13178	618
UTICA SHALE	13178	13286	108
POINT PLEASANT	13286	13523	237
TRENTON LIMESTONE	13523	13724	201
BLACK RIVER LIMESTONE	13724	13763	39

Table 2.1: Stratigraphy of the Hawley Quadrangle, Pike County

3. Engineering Design and Analysis

3.1 Reservoir Simulation (without Hydraulic Fracturing)

CMG software was used for our numerical simulation. The flowing bottom hole pressure was maintained at 14.7 psia for the well. The GEM module which could handle compositional model was employed in this project. The key parameters in the production of gas are the Pressure, Permeability & Porosity of the reservoir. Since Shale reservoirs are considered as dual porosity reservoir systems therefore in the simulation a double porosity model was assumed. In this model there exist two different areas from where gas can be produced i.e. Fracture and Matrix. The fracture has relatively higher permeability as compared to the matrix. Gas flow can occur only in the fracture. Flow in fracture can be described by Darcy's Law. Due to extremely low permeability, gas stored in the matrix is governed by diffusion or Fick's Law. The definitions of Darcy's Law and the Fick's Law are given below:

Darcy's Law is given by:

$$v = -\frac{k}{\mu}\frac{\partial \Phi}{\partial s}$$

And Fick's Law is given by:

$$v = -\frac{DZ_{sc}RT_{sc}}{P_{sc}}\frac{\partial C}{\partial s}$$

Where, v= velocity (ft/s)

k= fracture permeability (mD)

μ= viscosity (cP)

C= molar concentration

S= distance between two points (ft)

As it is evident that the shale formation has very low permeability the gas flows only through the natural fracture of the reservoir owing to higher relative permeability compared to the permeability of the matrix. The matrix has extremely low permeability; therefore, gas flow inside matrices is not governed by Darcy's law. The gas flow in the matrix blocks is governed by diffusion i.e. Fick's Law. Since the gas production is very low as it is shown in the simulation results, and in economic analysis it is shown that it is not economical to develop the field only with natural fractures, therefore, well stimulation techniques must be applied to increase the permeability of the reservoir, and therefore the production of the field. There are some assumptions that are considered while doing reservoir simulation to simplify the problem and minimize modeling and computational time. The assumptions are:

1. The shale reservoir contains 90% mainly methane and 10% water.
2. The shale reservoir is considered to be homogenous.

In reservoir simulation, the naturally fractured reservoir will be assumed to be idealized. The model of matrix and natural fracture are described by Warren and Root (1963). The continuity equation for two dimensional flows in natural fracture with adsorbed gas is given below

$$\frac{k_x}{\mu}\frac{\partial^2 P_2}{\partial x^2} + \frac{k_y}{\mu}\frac{\partial^2 P_2}{\partial y^2} - \phi_1 C_1 \frac{\partial P_1}{\partial t} = \phi_2 C_2 \frac{\partial P_2}{\partial t}$$

Where, k = permeability (mD)

μ = viscosity(cP)

P2 = fracture pressure (psia)

⌀1, ⌀2= dimensionless porosity of matrix and fracture

C1, C2= total compressibility of matrix and fracture

The production rate and the cumulative production were not greatly affected by the assumption of idealized natural fractures because of the reason that there was a control over the fracture permeability and fracture spacing. To model the natural fracture the dual porosity model was used. In this porosity of matrix and natural fracture are assumed to be different.

Physical Attributes Used in CMG for the Simulation runs:

Reservoir Properties	
Pressure	4500 Psi
Temperature	150 F
Initial Reservoir Pressure	4500 Psi
Volume	SCF/ton
Matrix Permeability	0.00001 mD
Fracture Permeability	0.0001 mD
Matrix Porosity	9%
Fracture Porosity	0.1%
Fracture Spacing	0.9 Ft
Thickness	702 Ft
Top of Pay Zone Depth	7046 Ft
Bottom of Pay Zone Depth	7748 Ft
Compressibility of Formation	0.00001 1/Psi
Gas Saturation	90%

Table 3.1: Physical Attributes of the CMG Model

Comparisons of Horizontal and Multilateral Wells Using CMG (Without Hydraulic Fracture)

CASE 1: One Horizontal Well Model:

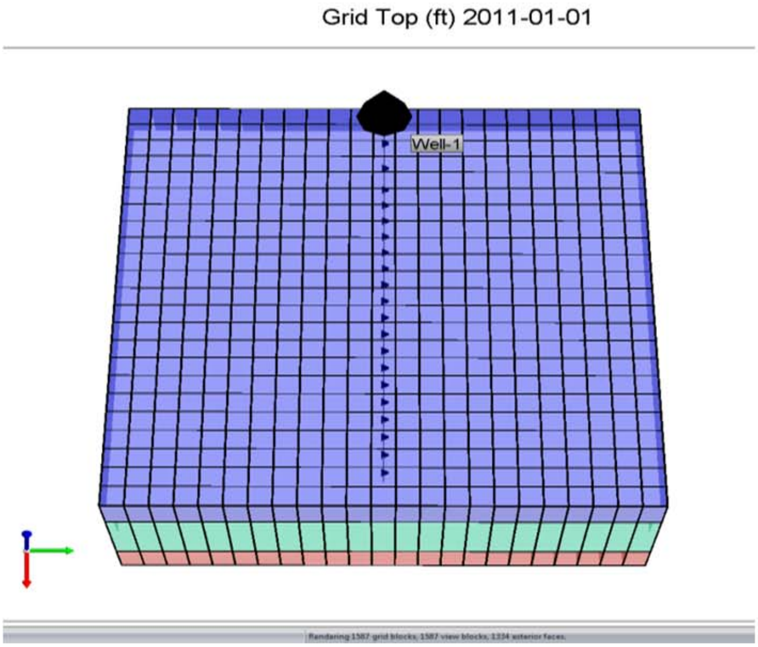


Figure 3.7: One Horizontal Well Grid Representation

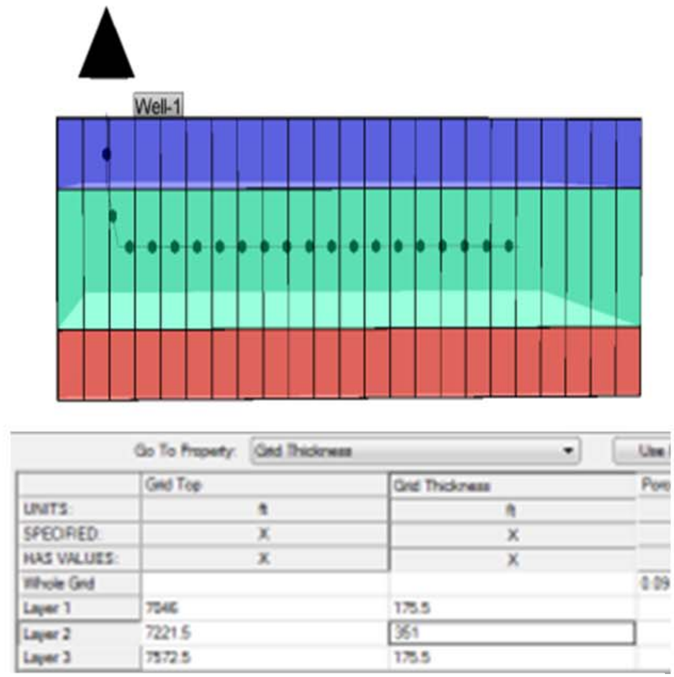


Figure 3.8: Properties Assumed

Result:

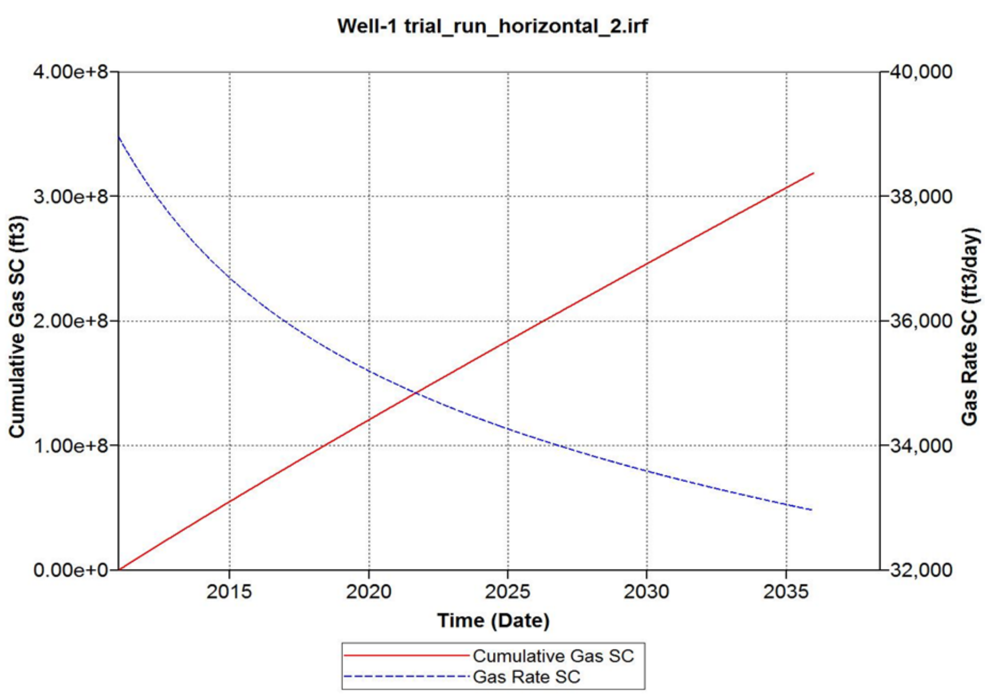


Figure 3.3: Production Rate and Cumulative Production-Case 1

CASE 2: Two Horizontal Wells Model:

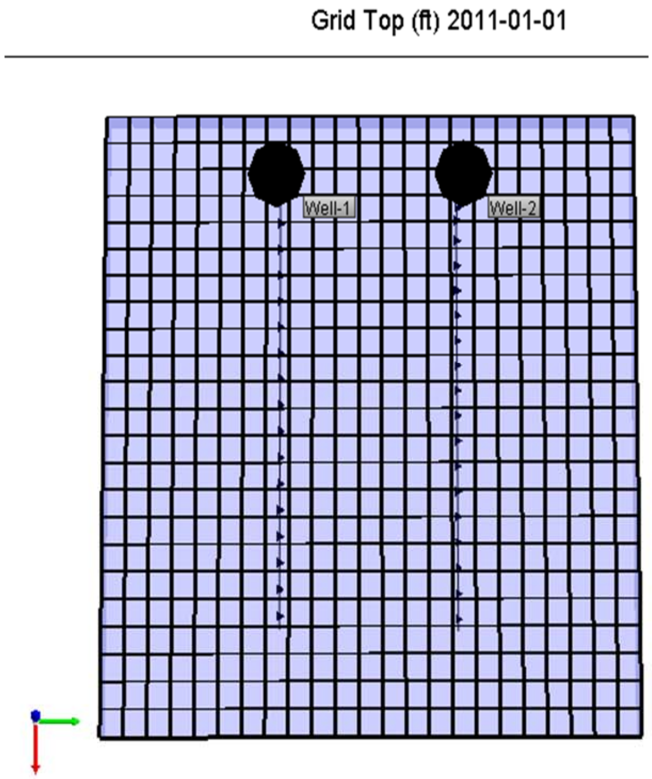
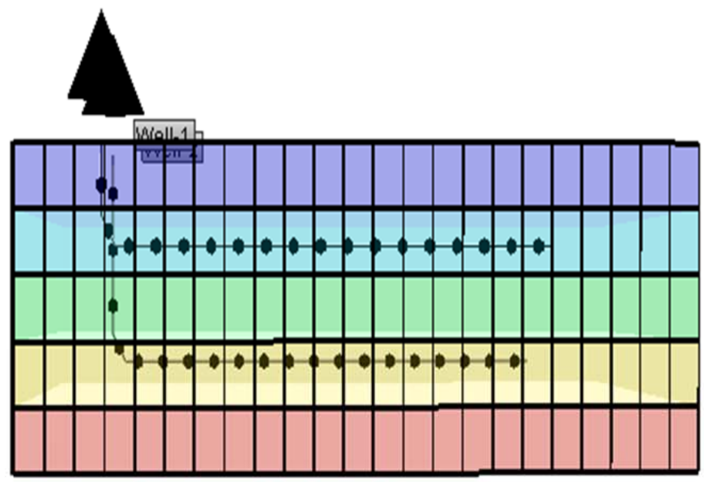


Figure 3.4: Two Horizontal Well Grid Representation



Layer 1	7046	140.4
Layer 2	7186.4	140.4
Layer 3	7326.8	140.4
Layer 4	7467.2	140.4
Layer 5	7607.6	140.4

Figure 3.5: Properties Assumed

Result:

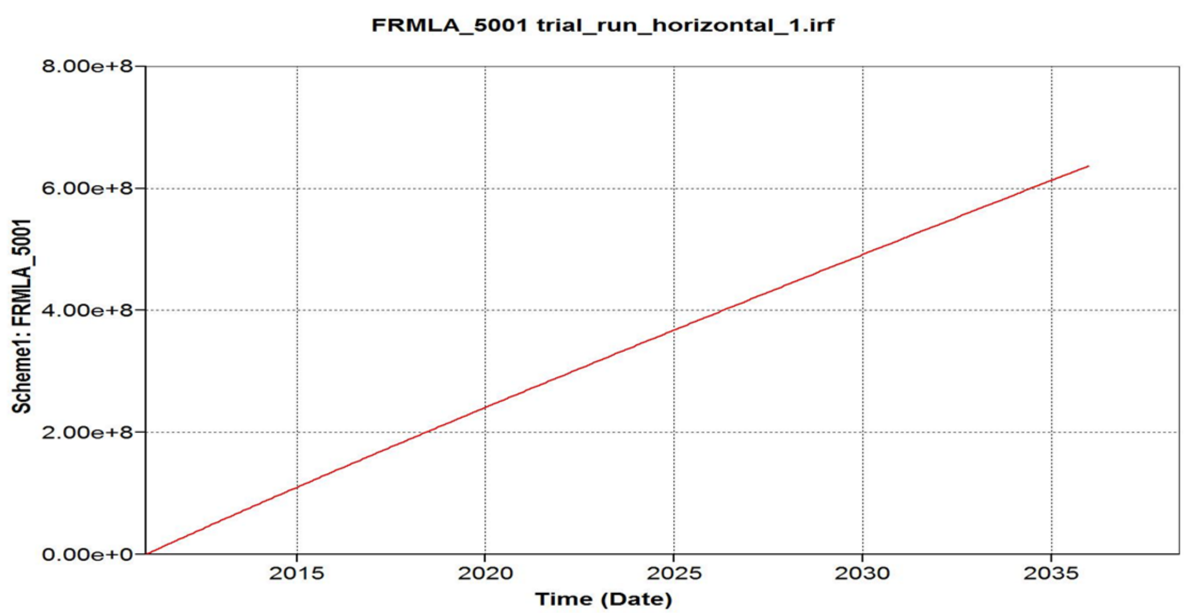
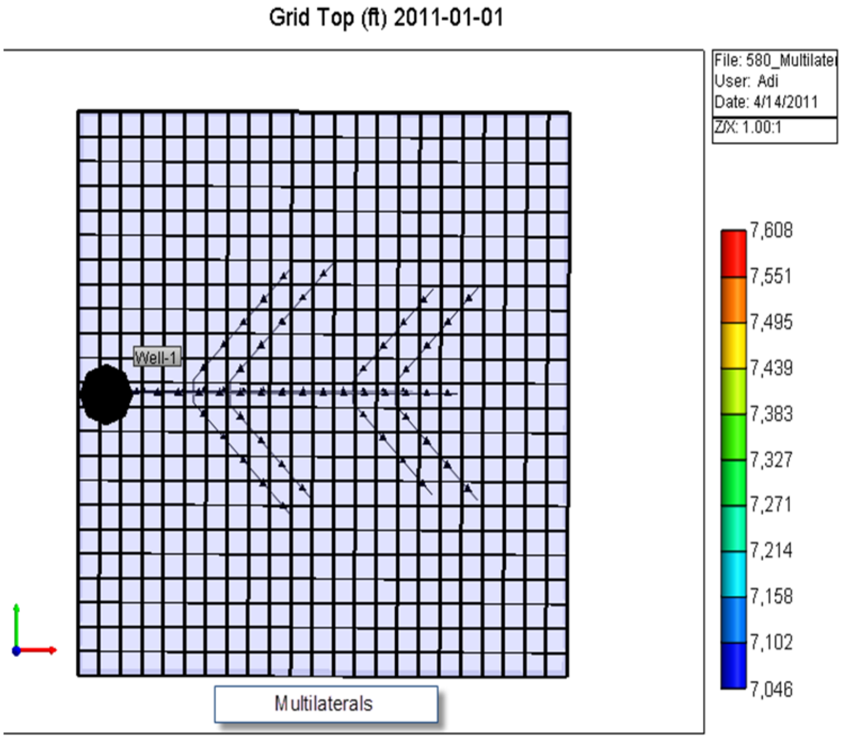
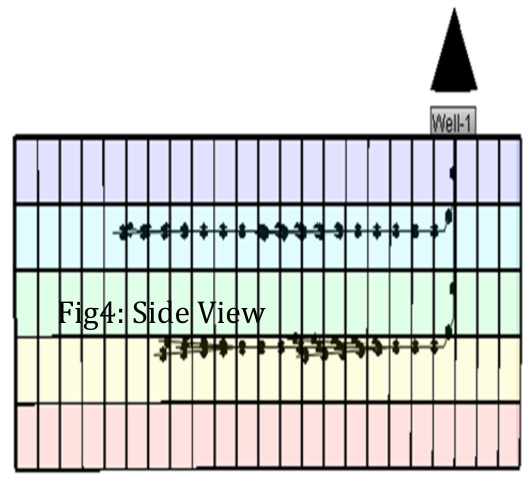


Figure 3.6: Production rates - Case 2

CASE 3: Multilateral Well Model:





Layer 1	7046	140.4
Layer 2	7186.4	140.4
Layer 3	7326.8	140.4
Layer 4	7467.2	140.4
Layer 5	7607.6	140.4

Figure 3.7: Multilateral Well Grid Representation

Figure 3.8: Properties Assumed

Result:

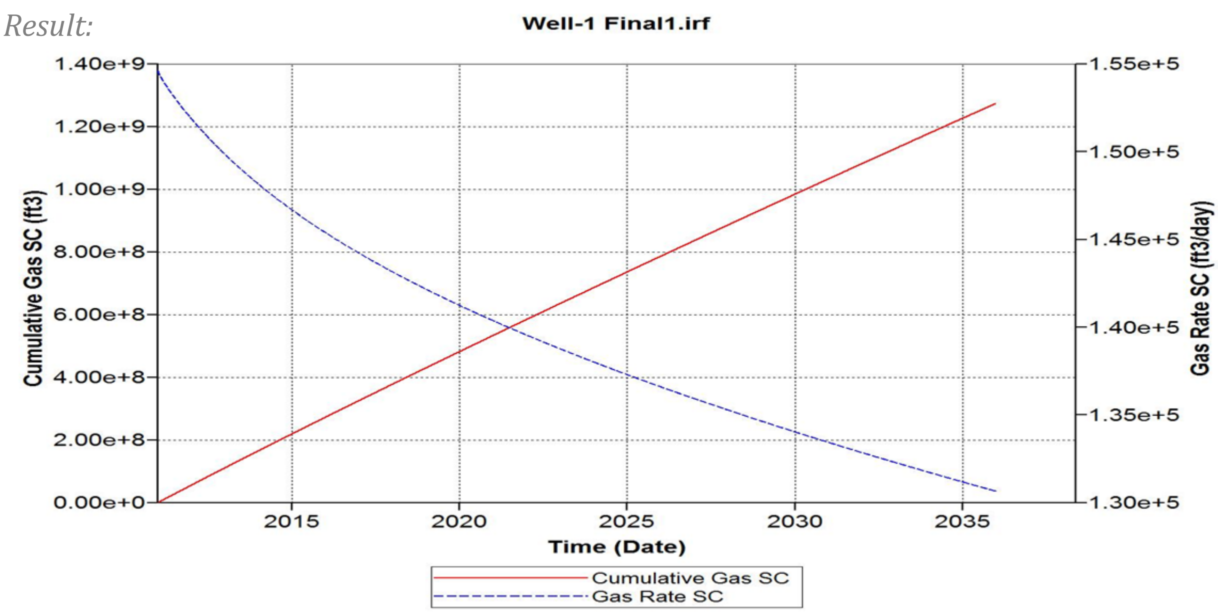


Figure 3.9: Production Rate and Cumulative Production - Case 3

Comparison:

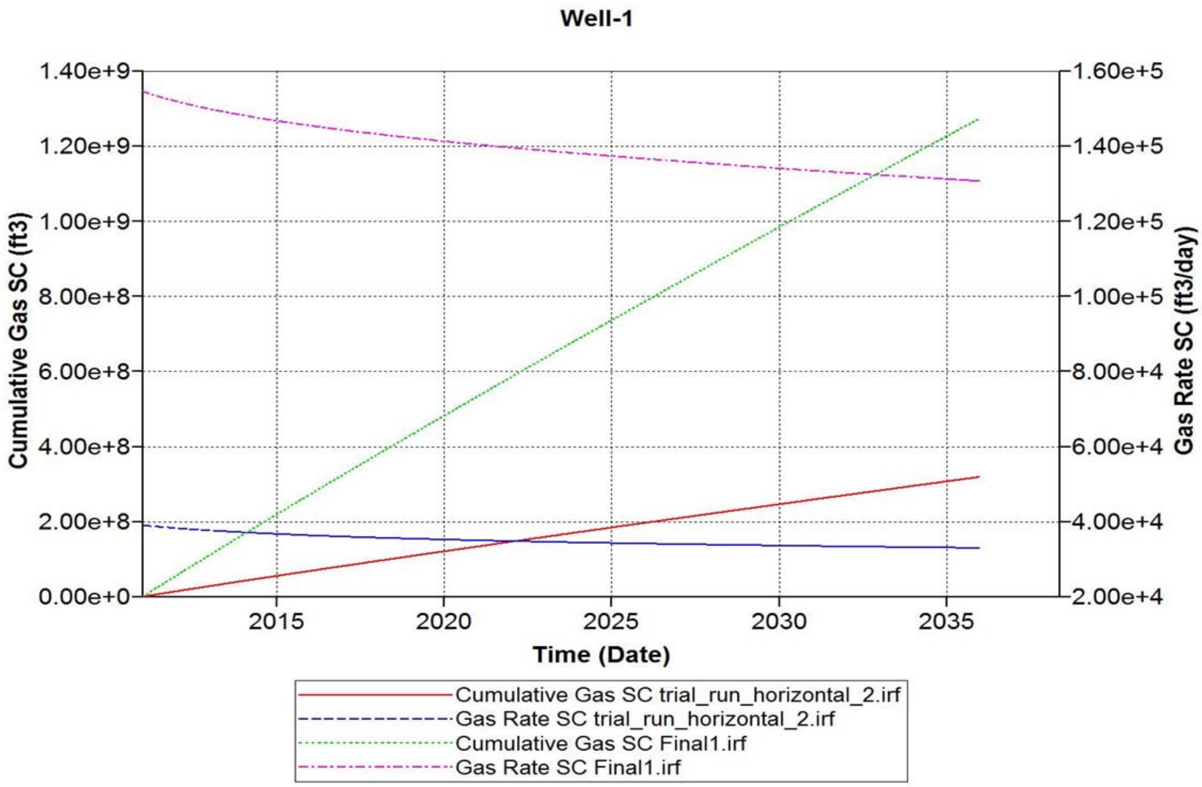


Figure3.10: Comparison of Production Rates from Case 1, 2, 3

3.2 Stimulation/Hydraulic Fracturing

3.2.1 Introduction:

Drilling the Marcellus Shale wasn't considered to be a profitable engagement until the introduction of technologies like horizontal drilling and hydraulic stimulation. One of the important reasons that horizontal well improves the productivity of the well is due to the increment in the direct area in contact with the reservoir (payzone). Now in our case we develop a technique to improve the production of the well and for that we resort to multi-lateral wells. This resultantly increases the production of the well compared to that obtained from horizontal wells.

But yet the production isn't to the levels that would render the production rates lucrative to drill in the Marcellus. Thus we turned our interest towards hydraulic stimulation to improve the productivity of the well. Initially stimulation was done to clean out the wax formation that formed around the perforations of the wellbore as a result of the paraffinic crude out that was produced using acid as the stimulating fluid. Now the purpose of stimulation has changed greatly in cases like hydraulic fracturing. The introduction of hydraulic fracturing was a step in the direction of improving the permeability of the matrix formation. The reason for the low production is the permeability of the Marcellus Shale which is in nanodarcies.

Hydraulic fracturing helped improve the permeability around the wellbore. This resultantly improved the production of the well. The efficiency of the stimulation job is accounted for by means of the term "Fracture Conductivity". Fracture Conductivity is the product of the half-length of the fracture to the permeability of the fracture. The expression for Dimensionless Fracture Conductivity is given as follow –

$$C_{fD} = \frac{k_f w}{k x_f}$$ (A.S. Demarchos 2004)

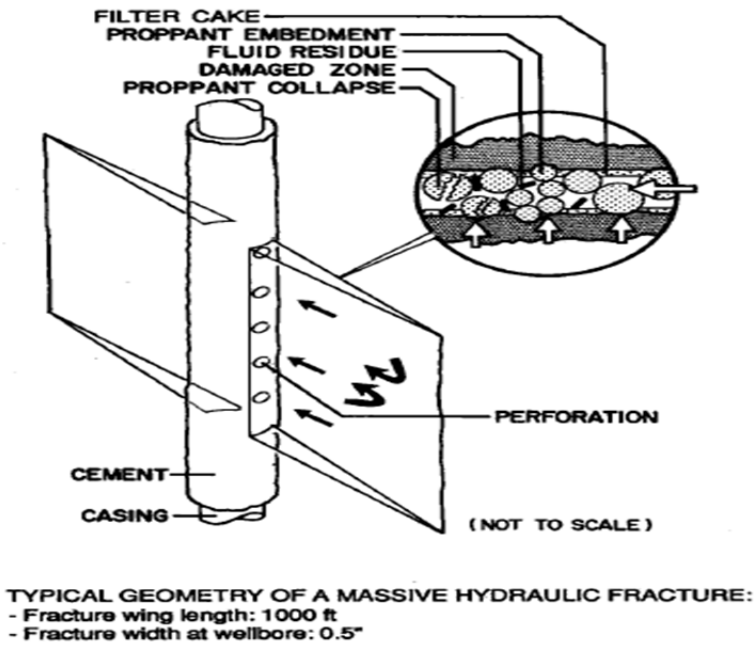
and fracture conductivity is given by -

$$C_{fD} \propto k_f b_f.$$ (Kulper 1998)

where - k_f = Fracture Permeability

w = width of Fracture

x_f = Fracture Half Length



(Kulper 1998)

Figure 3.11: Structure of a fracture

As we observe that the fracture acts as a conduit for the flow of the fluid into the wellbore. Now the Dimensionless Fracture Conductivity acts as a tool to different the types of fracture and that acts as a parameter to render the efficiency of the stimulation job. Thus the fracture is differentiated into the following types –

- Infinite Conductivity Fracture
- Finite Conductivity Fracture
- Uniform Conductivity Fracture (John Lee, Pressure Transient Analysis 2003)

In the Marcellus Shale, it's observed that we have infinite conductivity fractures. Thus the one that we intend to design is the same. Also the fracture orientation that is observed in the Marcellus below the depths of 2000ft is vertical.

Now to improve the conductivity of the fracture the 2 parameters that we need to enhance are –

- Fracture Permeability
- Width of Fracture

The fracture permeability and width depends on the permeability of the Proppant that is used in the stimulation job. For this we have made an extensive comparison of the permeability of the different proppants available in the fracpro PT library of proppants.

Another parameter that we have taken into consideration is the fracture orientation with respect to the wellbore. The fracture that we intend to model is a transverse fracture as the transverse fracture would improve the contact with the reservoir. The following is the orientation of the fracture that we intend to model –

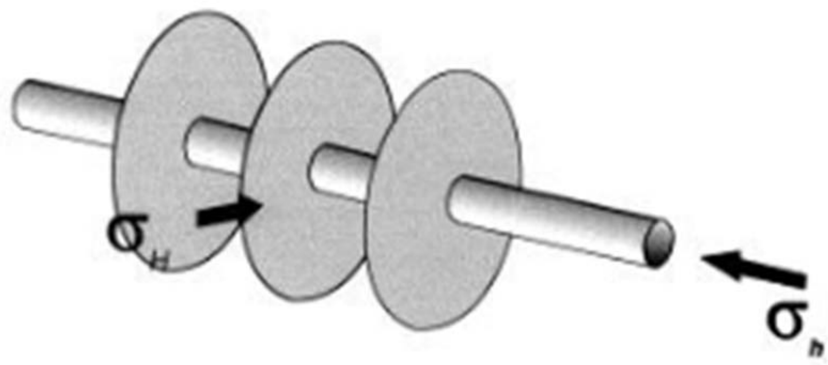


Fig. 2. Transverse fracture configuration.

Figure 3.12: Orientation of the fracture modeled

Now after our talk about the fracture orientation and design we shift our interest towards the tool that we are going to use during our design process. There are a number of different softwares available in the market like GOFHER, Fracpro PT, DecisionSpace, etc. The software that we have used in the analysis is Fracpro PT which is a lumped parameter stimulation software. It means it gives the value of the fracture half-length, width and height.

We have analyzed the various parameters that would play and important role in our design. So now we would talk about the procedure that we have followed in designing the fracture. In the model that we have built, there are certain assumptions that we have taken along with the physical attributes that we have considered to model the hydraulic fracture. The list of these physical attributes and assumptions is as given below –

3.2.2 : Model Assumtpions

Parameter	Value
Matrix Permeability (mD)	$1 * 10^{-5}$
Fracture Permeability (mD)	$1 * 10^{-4}$
Matrix Porosity	9%
Fracture Porosity	0.1%
Reservoir Drainage Area (acres)	80
Fracture Orientation	Vertical
Method of Flow	Convection
Fracture Density (1/ft)	0.9
Type of Reservoir	Dual Porosity
Depth of Payzone (ft)	7046
Reservoir Formation type	Marcellus
Reservoir Temperature (F)	150
Initial Reservoir Temperature (psia)	4500

Table 3.2: Physical Attributes of the Model

As we observe the physical attributes for the model are listed above. The formation that we have considered is the Marcellus Shale and the location is Pike county. The breakup of the formation that we have obtained from the log is as given below –

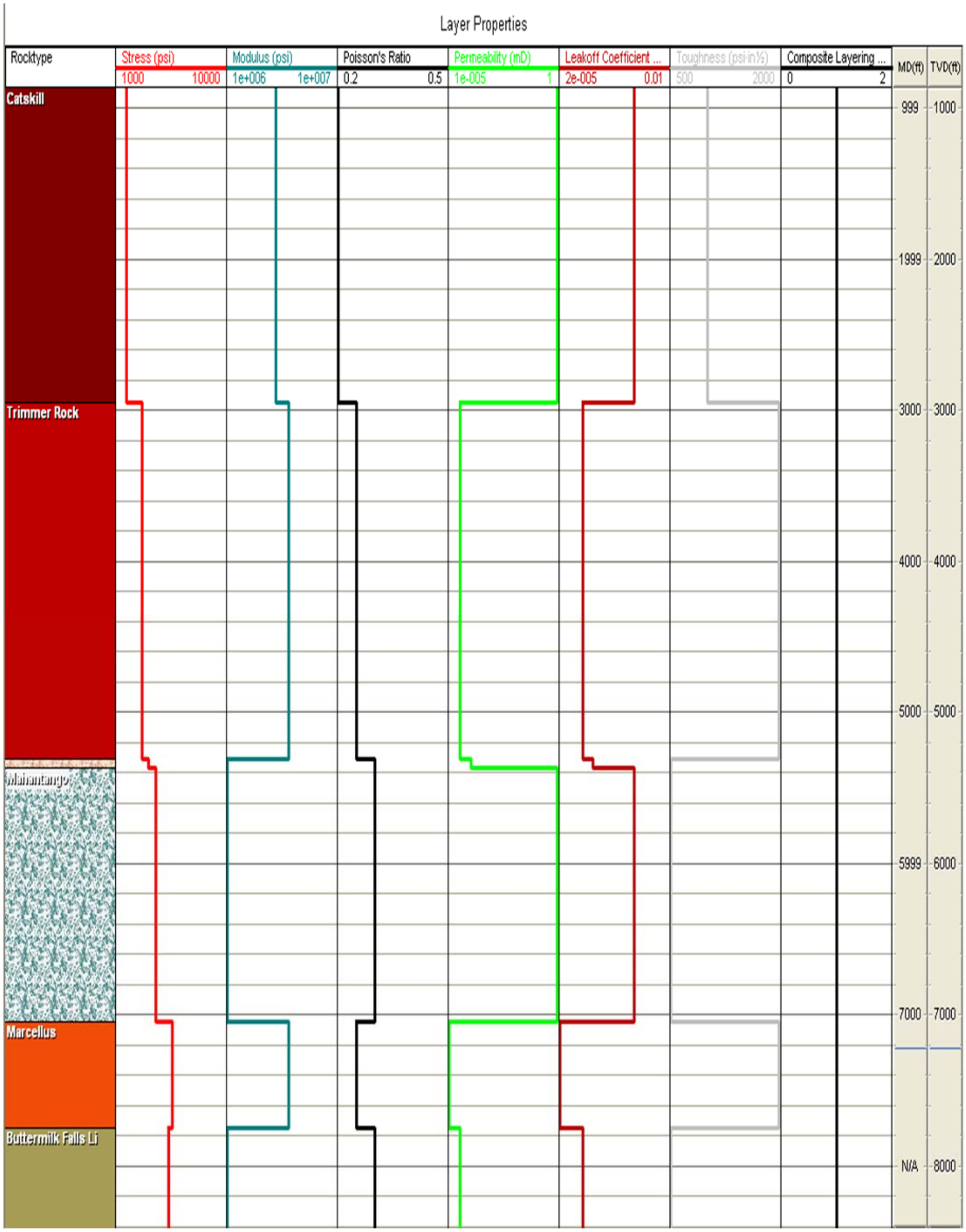


Figure 3.13: Properties of Different Layers assumed- Well Log

From this we can clearly figure out the zone that we need to stimulate and along with the depth and the thickness of the payzone. To start of the stimulation job we first analyzed the various proppants and their permeabilities –

3.2.3 Comparison of Various Proppants

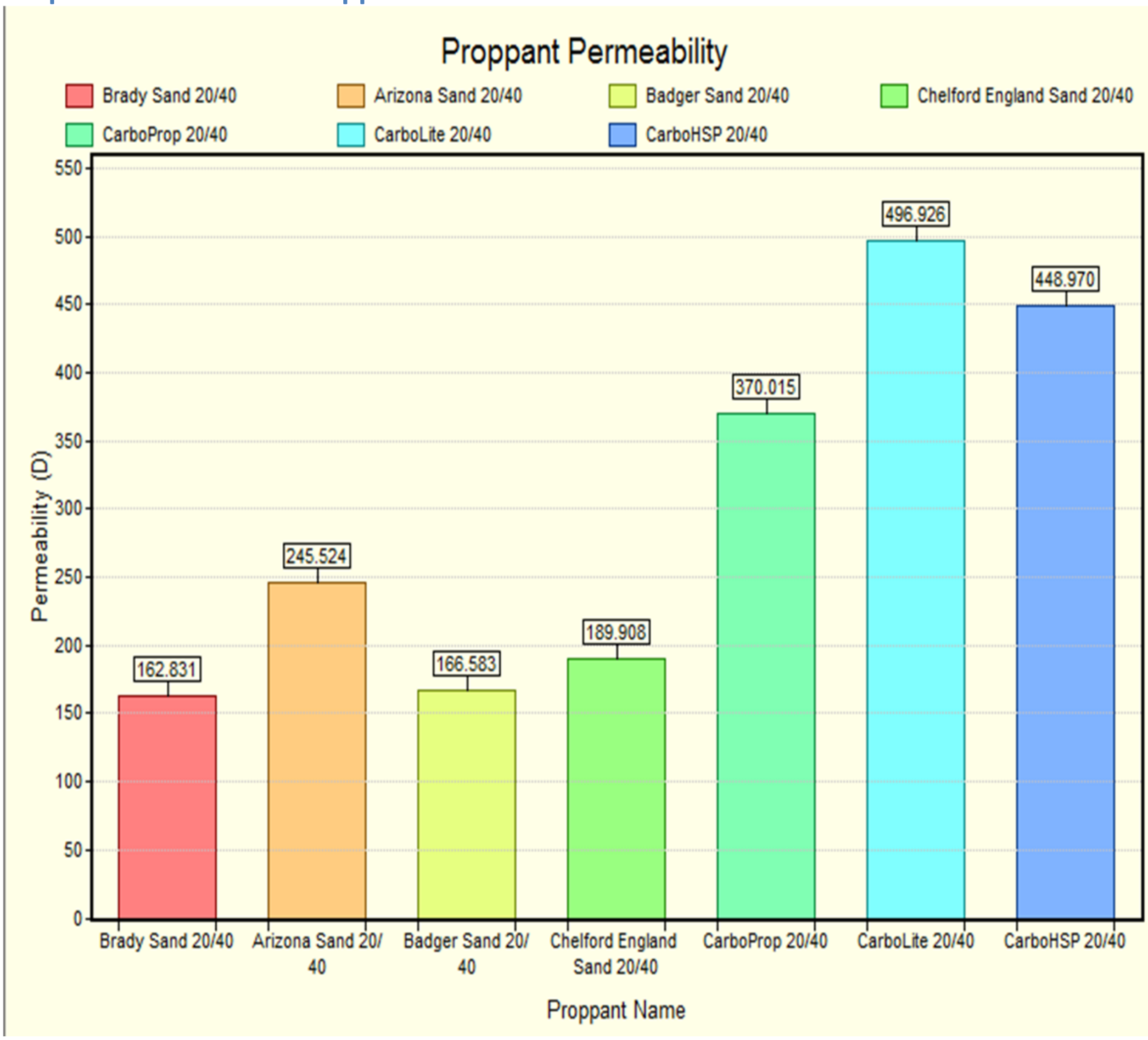


Figure 3.14: Comparison of Different Proppants

This clearly shows that the permeability of CarboLite (20/40) is the highest, then followed by CarboHSP and CarboProp (20/40). Thus in our model we have used CarboLite and CarboProp depending upon the availability and price of the Proppant. The next thing that we needed to decide is the PAD fluid and the propping fluid that we were going to use. Depending on the availability, price and reactivity with the formation we have used Slickwater in the stimulation job. The properties for Slickwater and CarboLite and CarboProp are given below –

Fluid Name	SLICKWATER
Vendor	**MISCELLANEOUS**
System	GENERAL
Description	SLICKWATER (20#/1000 GAL OF GEL IN WATER)
Initial Viscosity (cp)	3.08
Initial n'	0.900
Initial k' ($lbf\cdot s$^n/ft^2)	0.900
Viscosity @ 4.0 hours (cp)	3.08
n' @ 4.0 hours	0.900
k' @ 4.0 hours ($lbf\cdot s$^n/ft^2)	0.900
Base Fluid Specific Gravity	1.01
Spurt Loss (gal/ft^2)	0.0
Wall Building (ft/min½)	0.0
Flowrate #1 (bpm)	10.00
Fric Press #1 (psi/1000 ft)	6.10
Flowrate #2 (bpm)	20.00
Fric Press #2 (psi/1000 ft)	12.90
Flowrate #3 (bpm)	40.00
Fric Press #3 (psi/1000 ft)	27.30
Wellbore Friction Multiplier	1.000

Table 3.3: Final fracturing schedule

Proppant Name	CarboLite 20/40	CarboProp 20/40	CarboProp 30/60
Proppant Type	LOWDENSITYCERAMIC	MEDIUMDENSITY CERAMIC	MEDIUMDENSITY CERAMIC
Proppant Coating	None	None	None
Cost ($/lb)	0.0	0.0	0.0
Bulk Dens (lbm/ft^3)	97.00	117.0	117.0
Packed Porosity	0.427	0.428	0.428
Specific Gravity (sg)	2.72	3.28	3.28
Turbulence Coeff a	1.22	1.22	0.868
Turbulence Coeff b	0.439	0.297	0.026
Diameter (in)	0.029	0.026	0.017
Perm @ 0 psi (D)	972.124	535.611	251.019
Perm @ 2000 psi (D)	570.000	385.000	174.000
Perm @ 4000 psi (D)	480.000	345.000	152.000
Perm @ 6000 psi (D)	340.000	290.000	128.000
Perm @ 8000 psi (D)	210.000	250.000	104.000
Perm @ 10000 psi (D)	120.000	200.000	69.000
Perm @ 12000 psi (D)	91.259	150.000	49.000
Perm @ 14000 psi (D)	61.523	100.000	42.220
Perm @ 16000 psi (D)	41.476	94.236	32.728
Perm @ 18000 psi (D)	27.961	75.839	25.370
Perm @ 20000 psi (D)	18.850	61.033	19.667

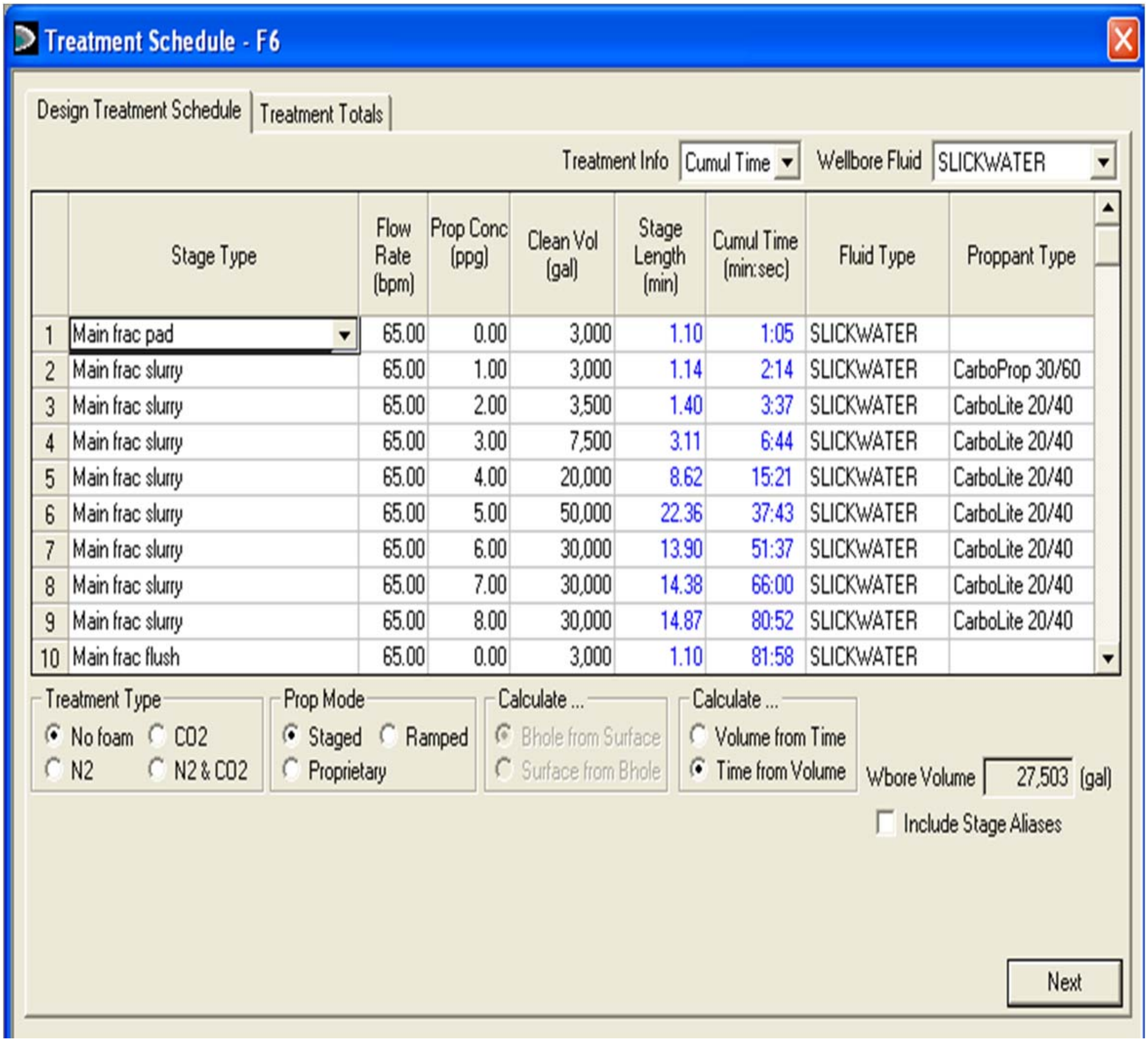
Table 3.4: Comparison of Different Proppants

Using this we have done a comparative study for a few different Proppant, PAD and Carrier fluid to analyze the best combination for carrying out the stimulation job. The following is the table for the comparative study that was carried out –

Sr. No.	Fluid and Proppant used	Pumping Rate + No. of Stages	Propped Half Length (ft)	Propped Height (ft)	Fracture Width (in)	FcD	Formation Permeability (mD)
1	Micropolymer (min. gel loading) + Brady (20/40)	30 bpm for 10 stages	211	421	0.61	400	1 * 10^-5
2	Purgel (max. gel loading) + Brady (20/40)	30 bpm for 10 stages	210	420	0.58	400	1 * 10^-5
3	Purgel (max. gel loading) + Brady (20/40)	100 bpm for 10 stages	215	430	0.82	400	1 * 10^-5
4	Purgel (max. gel loading) + Brady (20/40)	200 bpm for 10 stages	213	425	0.93	400	1 * 10^-5
5	Micropolymer (min. gel loading) + Carbolite (20/40)	250 bpm for 4 stages	293	672	1.22	400	1 * 10^-5
6	Micropolymer (min. gel loading) + Carbolite (20/40)	200 bpm for 4 stages	295	692	1.3	400	1 * 10^-5
7	Slick Water + WaterFrac + Carbolite(20/40) + CarboProp(30/60)	150 bpm for 4 stages	203	626	1.09	400	1 * 10^-5
8	Slick Water + WaterFrac + Carbolite(20/40) + CarboProp(30/60)	65 bpm for 10 stages	194	391	0.92	400	1 * 10^-5
9	Slick Water + CarboLite(20/40) + CarbolProp(30/60)	65 bpm for 10 stages	182	466	0.94	400	1 * 10^-5

Table 3.5: Comparison of Different Combinations

From the above table we can clearly see that the optimum fracture conductivity can be obtained using the pair of Slickwater, CarboLite (20/40) and CarboProp (30/60). The treatment schedule to obtain the following fracture dimensions is given in the table(***Figure 3.15)*** below –

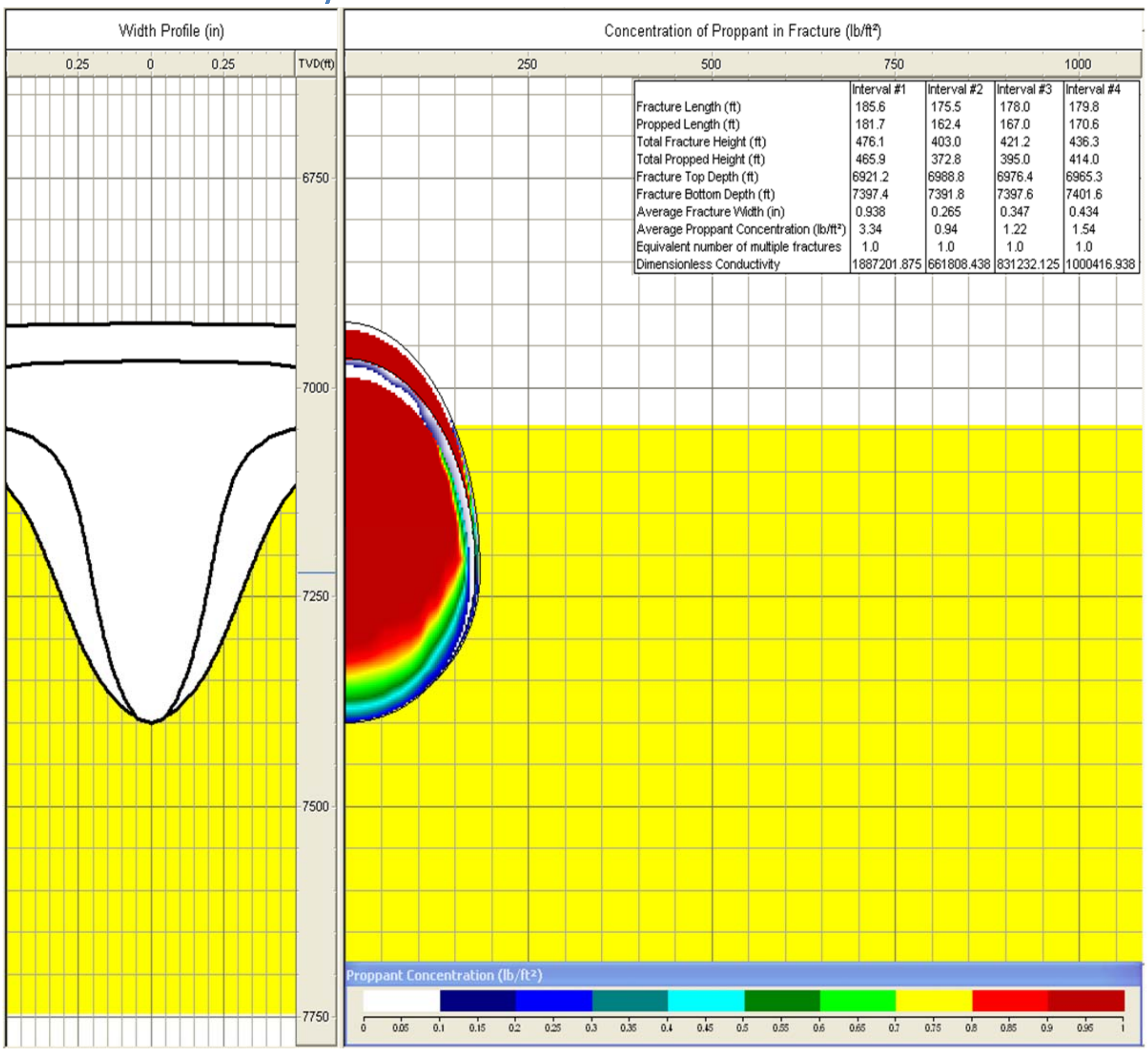


	Stage Type	Flow Rate (bpm)	Prop Conc (ppg)	Clean Vol (gal)	Stage Length (min)	Cumul Time (min:sec)	Fluid Type	Proppant Type
1	Main frac pad	65.00	0.00	3,000	1.10	1:05	SLICKWATER	
2	Main frac slurry	65.00	1.00	3,000	1.14	2:14	SLICKWATER	CarboProp 30/60
3	Main frac slurry	65.00	2.00	3,500	1.40	3:37	SLICKWATER	CarboLite 20/40
4	Main frac slurry	65.00	3.00	7,500	3.11	6:44	SLICKWATER	CarboLite 20/40
5	Main frac slurry	65.00	4.00	20,000	8.62	15:21	SLICKWATER	CarboLite 20/40
6	Main frac slurry	65.00	5.00	50,000	22.36	37:43	SLICKWATER	CarboLite 20/40
7	Main frac slurry	65.00	6.00	30,000	13.90	51:37	SLICKWATER	CarboLite 20/40
8	Main frac slurry	65.00	7.00	30,000	14.38	66:00	SLICKWATER	CarboLite 20/40
9	Main frac slurry	65.00	8.00	30,000	14.87	80:52	SLICKWATER	CarboLite 20/40
10	Main frac flush	65.00	0.00	3,000	1.10	81:58	SLICKWATER	

Figure3.15: Treatment Schedule for stimulation job

It has been observed that the total time that is required to obtain the fracture dimensions for a single fracture (in a multi stage fracture) is approximately 82 mins. The reason we have used CarboProp (30/60) is because of the fact that introducing a larger mesh size Proppant would resultantly help the fracture remain open at the tip. Thus using this treatment schedule, Proppant, PAD fluid and Carrier Fluid we were able to design an infinite conductivity fracture. The fracture dimensions and design of the multiple fracture design is given by the figure below–

3.2.4 Infinite Conductivity Fracture



	Interval #1	Interval #2	Interval #3	Interval #4
Fracture Length (ft)	185.6	175.5	178.0	179.8
Propped Length (ft)	181.7	162.4	167.0	170.6
Total Fracture Height (ft)	476.1	403.0	421.2	436.3
Total Propped Height (ft)	465.9	372.8	395.0	414.0
Fracture Top Depth (ft)	6921.2	6988.8	6976.4	6965.3
Fracture Bottom Depth (ft)	7397.4	7391.8	7397.6	7401.6
Average Fracture Width (in)	0.938	0.265	0.347	0.434
Average Proppant Concentration (lb/ft²)	3.34	0.94	1.22	1.54
Equivalent number of multiple fractures	1.0	1.0	1.0	1.0
Dimensionless Conductivity	1887201.875	661808.438	831232.125	1000416.938

Figure 3.16: No. of stages of fracture and the fracture dimensions

From the above figure we see that the multi stage fracturing is done in 4 stages for each lateral. The spacing between each fracture and the fracture dimensions are given in the figure above. The output that we obtain using this schedule is tabulated in the following table –3.6

Parameter	Value
Height of Fracture (ft)	476
Propped Height (ft)	466
Top Depth of Propped Fracture (ft)	6931
Bottom Depth of Propped Fracture (ft)	7397
Fracture Half Length (ft)	186
Propped Fracture Half Length (ft)	182
Average Fracture Width (ft)	0.94
Initial Fracturing Pressure (psia)	6390
Volume of Fluid for single job (gallon)	180,000
Total Volume of fluid required (gallon)	1,440,000

Table 3.6: Final Design Values

An analysis was made for the total amount of fracturing fluid that is required for the stimulation job and the number is given above. The amount is significantly lower than the value of fracturing fluid required to carry out a stimulation job for a horizontal well. Below one can see the amount of fluid that is required for the fracturing of a horizontal well.

WATER NEEDS FOR DRILLING AND FRACING

Shale Gas Play	Volume of Drilling Water per Well (gal)	Volume of Fracturing Water per Well (gal)	Total Volume of Water per Well (gal)
Barnett Shale	400,000	2,300,000	2,700,000
Fayetteville Shale	60,000	2,900,000	3,060,000
Haynesville Shale	1,000,000	2,700,000	3,700,000
Marcellus Shale	80,000*	3,800,000	3,880,000

* Drilling performed with an air "mist" and/or water-based or oil-based muds for deep horizontal well completions.
Note: These volumes are approximate and my vary substantially between wells.

Data from Groundwater Protection Council, 2009

Figure 3.17: Average fracturing fluid required for horizontal well (Kostelnik 2008)

From the above table indicates the amount of water required for fracturing a horizontal well

3.3 Reservoir Simulation (with Hydraulic Fracturing)

Comparison of Horizontal and Multilateral Wells Using CMG (With Infinite Conductivity Hydraulic Fracture):

Case1: One Horizontal Well

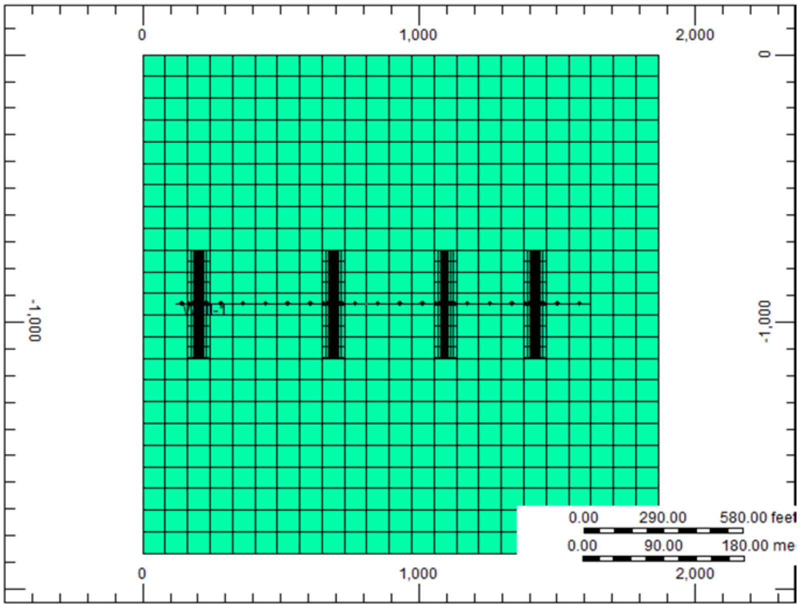
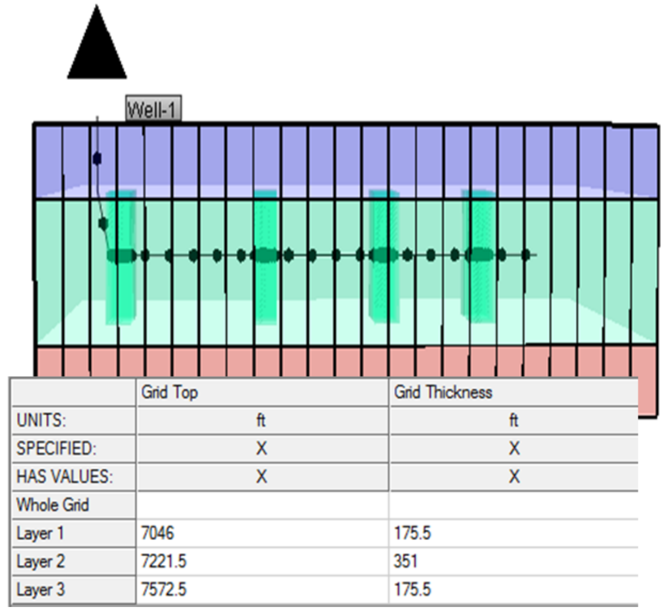


Figure 3.18: Horizontal Well Grid Representation



	Grid Top	Grid Thickness
UNITS:	ft	ft
SPECIFIED:	X	X
HAS VALUES:	X	X
Whole Grid		
Layer 1	7046	175.5
Layer 2	7221.5	351
Layer 3	7572.5	175.5

Figure 3.19: Properties Assumed

Result:

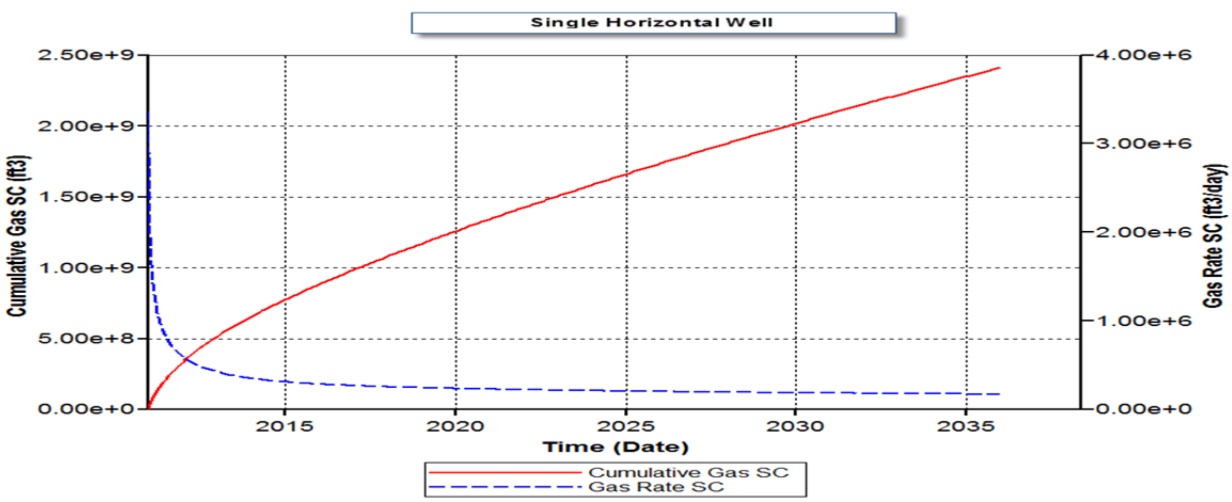
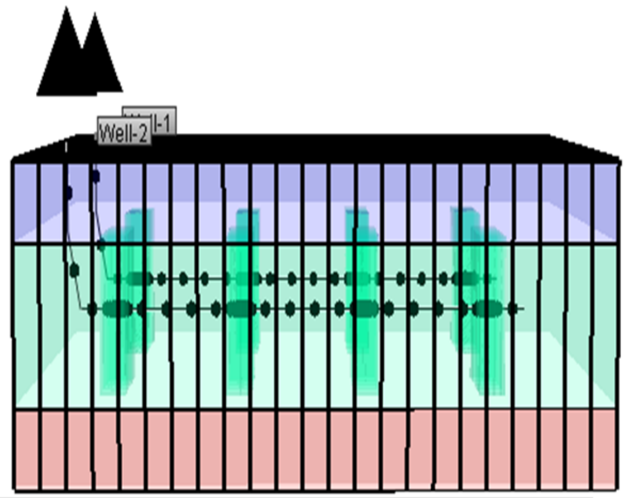


Figure 3.20: Production Rate and Cumulative Production - Case 1

CASE 2: Two Horizontal Wells

Figure 3.21: Two Horizontal Well Grid Representation



	Grid Top	Grid Thickness
UNITS:	ft	ft
SPECIFIED:	X	X
HAS VALUES:	X	X
Whole Grid		
Layer 1	7046	175.5
Layer 2	7221.5	351
Layer 3	7572.5	175.5

Figure 3.22: Properties Assumed

Result:

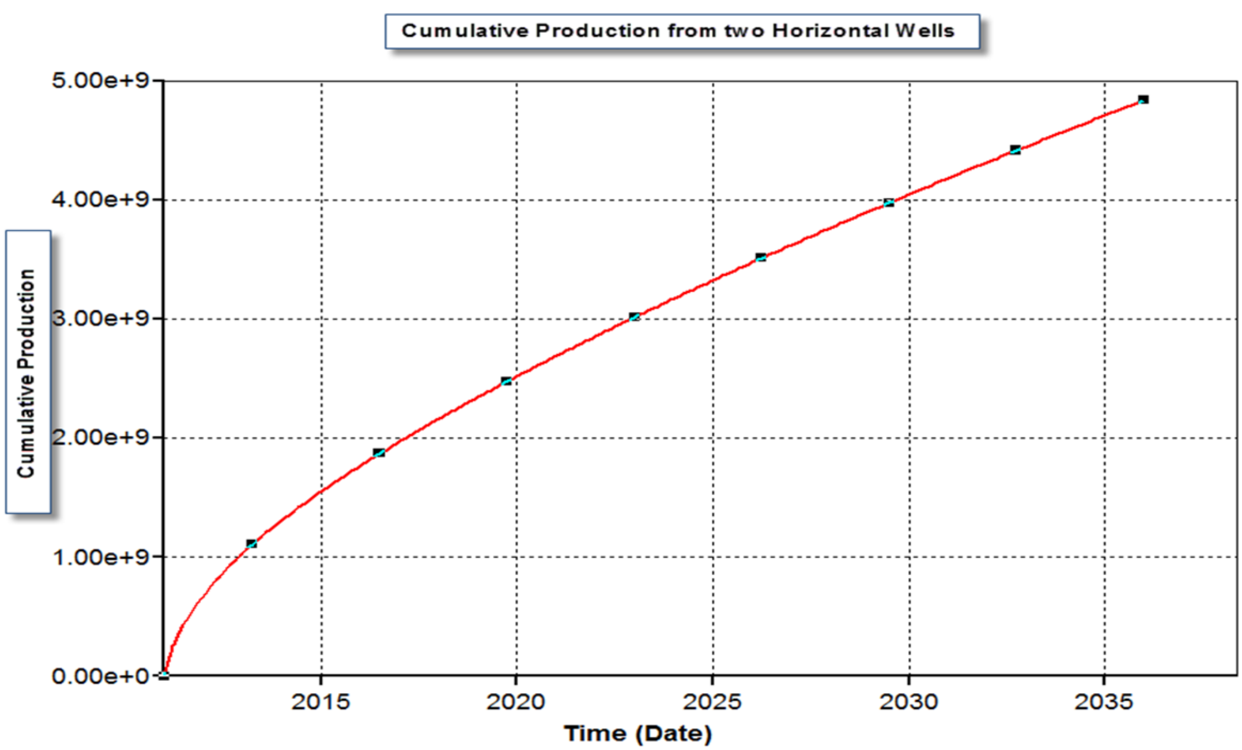


Figure 3.23: Cumulative Production - Case 2

CASE 3: Multilateral Model

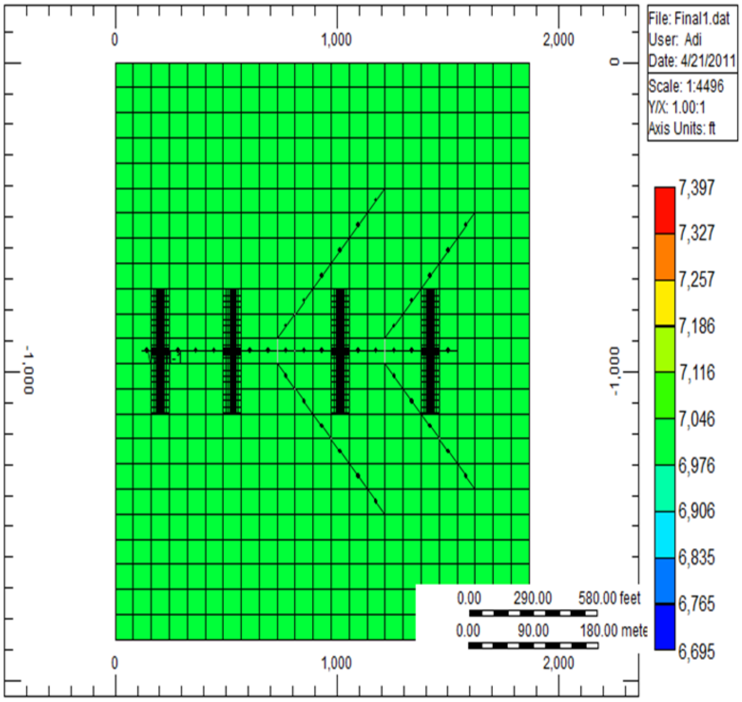
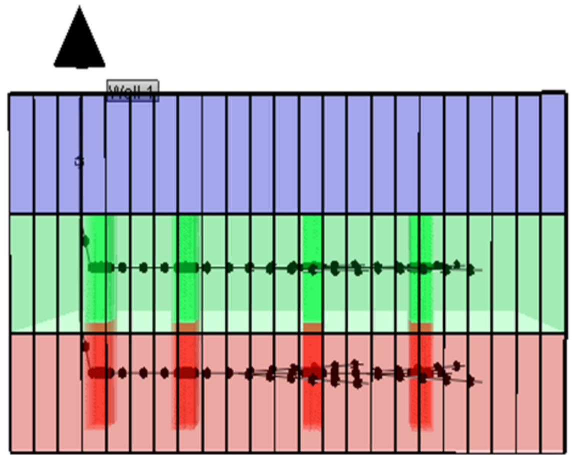


Figure 3.24: Multilateral Well Grid Representation



	Grid Top	Grid Thickness
UNITS:	ft	ft
SPECIFIED:	X	X
HAS VALUES:	X	X
Whole Grid		
Layer 1	6695	351
Layer 2	7046	351
Layer 3	7397	351

Figure 3.25: Properties Assumed

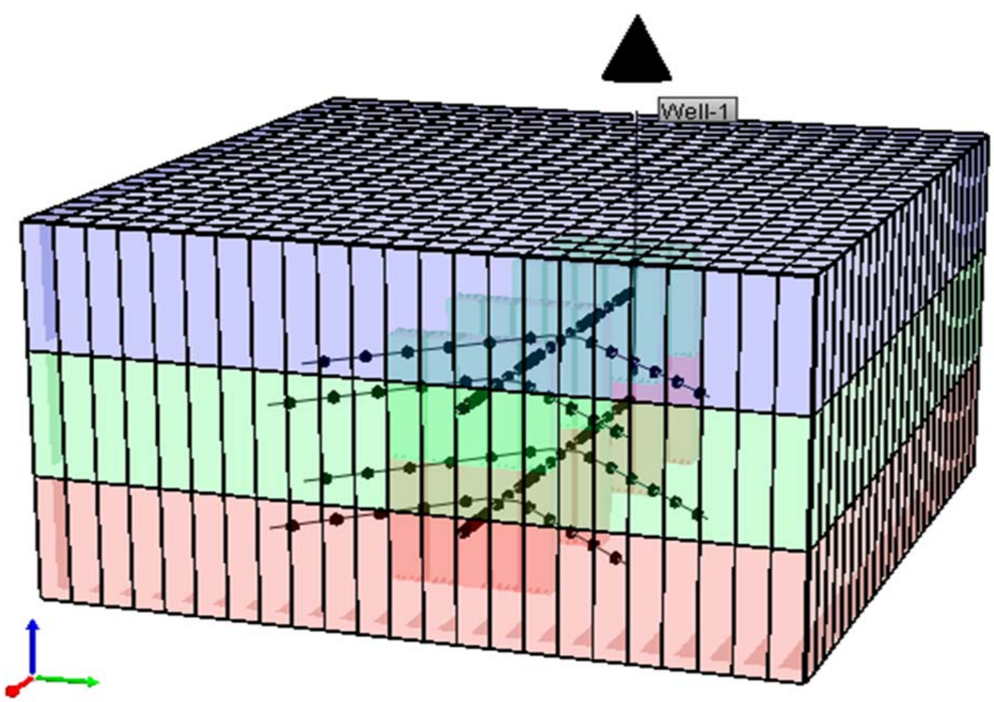


Figure 3.26: Multilateral Well Grid Representation

Result:

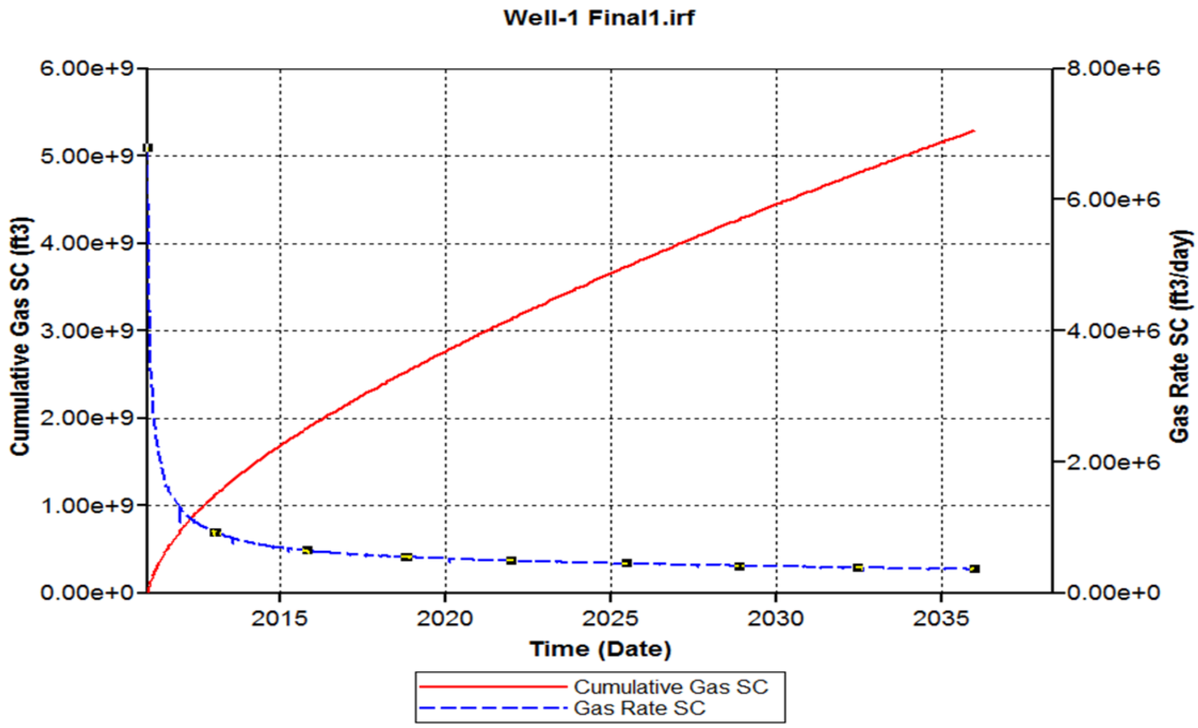


Figure 3.27: Production Rate and Cumulative Production-Case 3

Comparison:

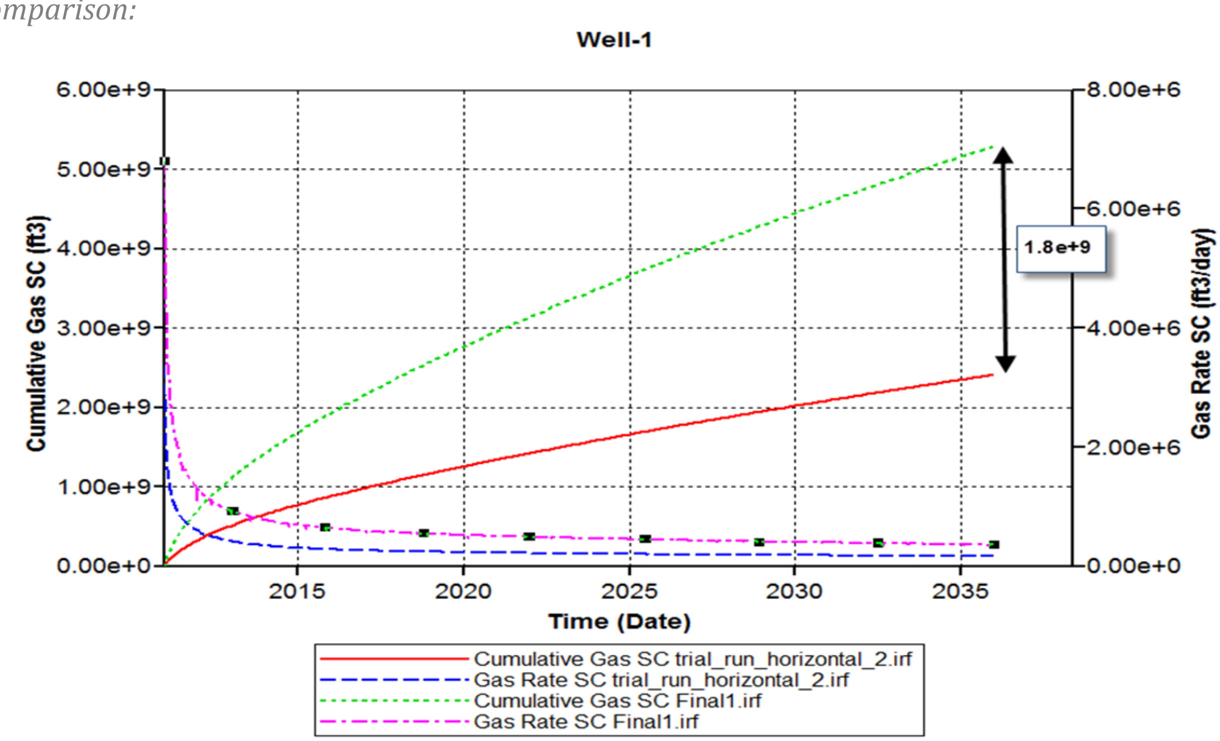


Figure 3.28: Comparison of Case 1, 2, 3

3.3.1 Sensitivity Analysis to account for variation of Physical Attributes:

For checking the sensitivity of the production, 4 different runs are done:

Physical Attributes Used in CMG for all these runs:

Reservoir Properties	
Pressure	4500 Psi
Temperature	150 F
Initial Reservoir Pressure	4500 Psi
Volume	SCF/ton
Matrix Permeability	0.000001mD
Fracture Permeability	0.00001mD
Matrix Porosity	10%
Fracture Porosity	0.1%
Fracture Spacing	0.9 Ft
Thickness	702 Ft
Top of Pay Zone Depth	7046 Ft
Bottom of Pay Zone Depth	7748 Ft
Compressibility of Formation	0.00001 1/Psi
Gas Saturation	90%

Table 3.7: Physical Attributes of the CMG Model

CASE1: One Horizontal Well:

Result:

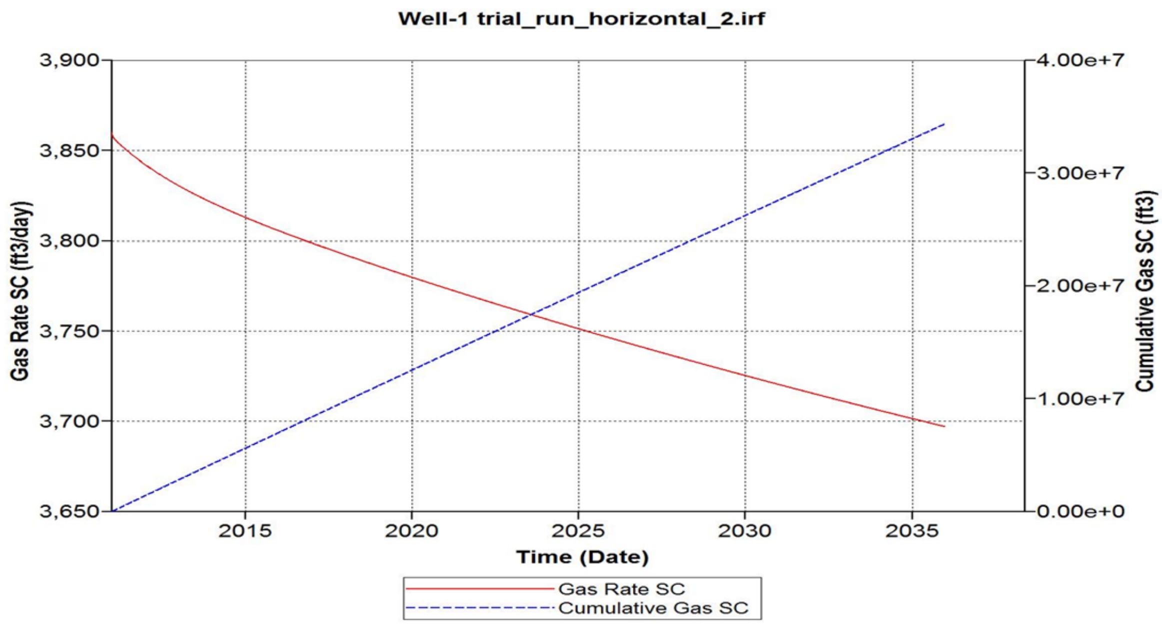


Figure 3.29: Production Rate and Cumulative Production - Case 1

CASE2: Two Horizontal Well:

Result:

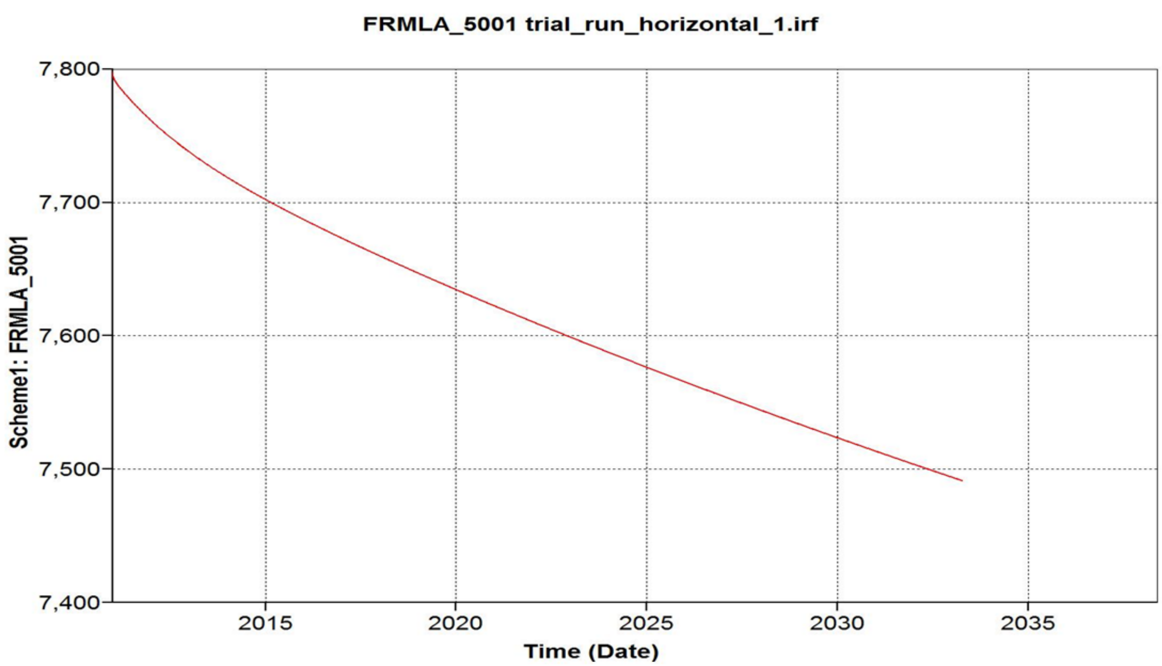


Figure 3.30: Production Rate - Case 2

CASE 3

Result:

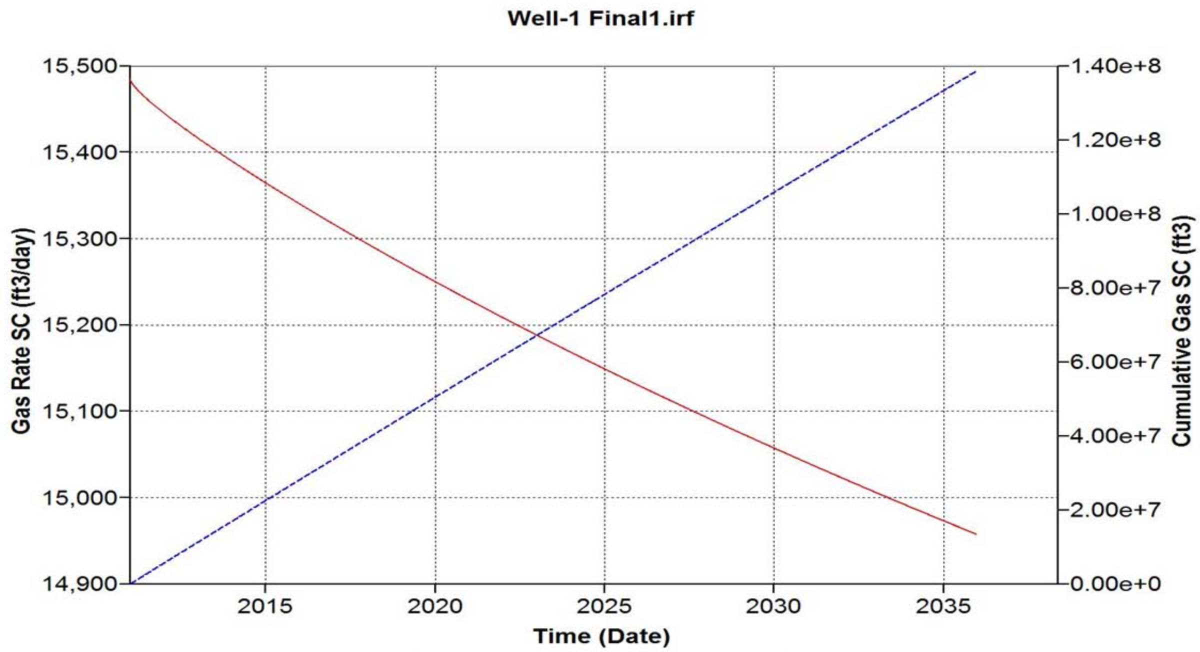


Figure 3.31: Production Rate and Cumulative Production - Case 3

Physical Attributes Used in CMG for all these runs:

Reservoir Properties	
Pressure	4500 Psi
Temperature	150 F
Initial Reservoir Pressure	4500 Psi
Volume	SCF/ton
Matrix Permeability	0.0001mD
Fracture Permeability	0.001mD
Matrix Porosity	10%
Fracture Porosity	0.1%
Fracture Spacing	0.9 Ft
Thickness	702 Ft
Top of Pay Zone Depth	7046 Ft
Bottom of Pay Zone Depth	7748 Ft
Compressibility of Formation	0.00001 1/Psi
Gas Saturation	90%

Table 3.8: Physical Attributes of the CMG Model

CASE 1: One Horizontal Well:

Result:

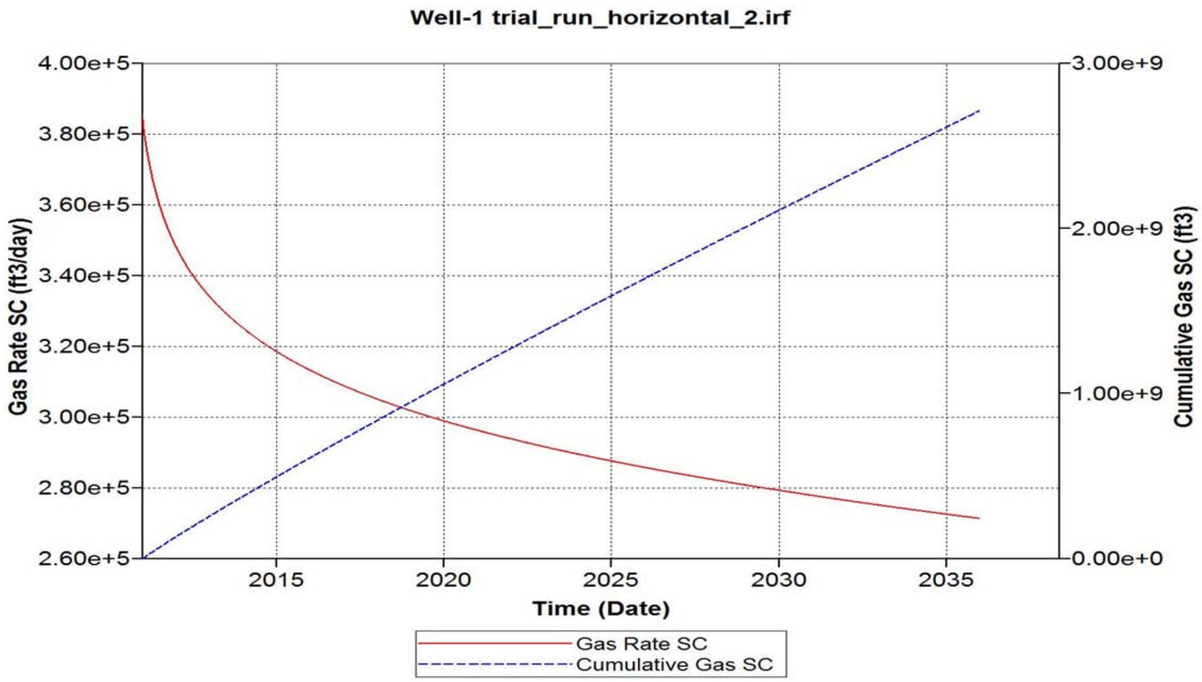


Figure 3.32: Production Rate and Cumulative Production - Case 1

CASE2: Two Horizontal Well:

Result:

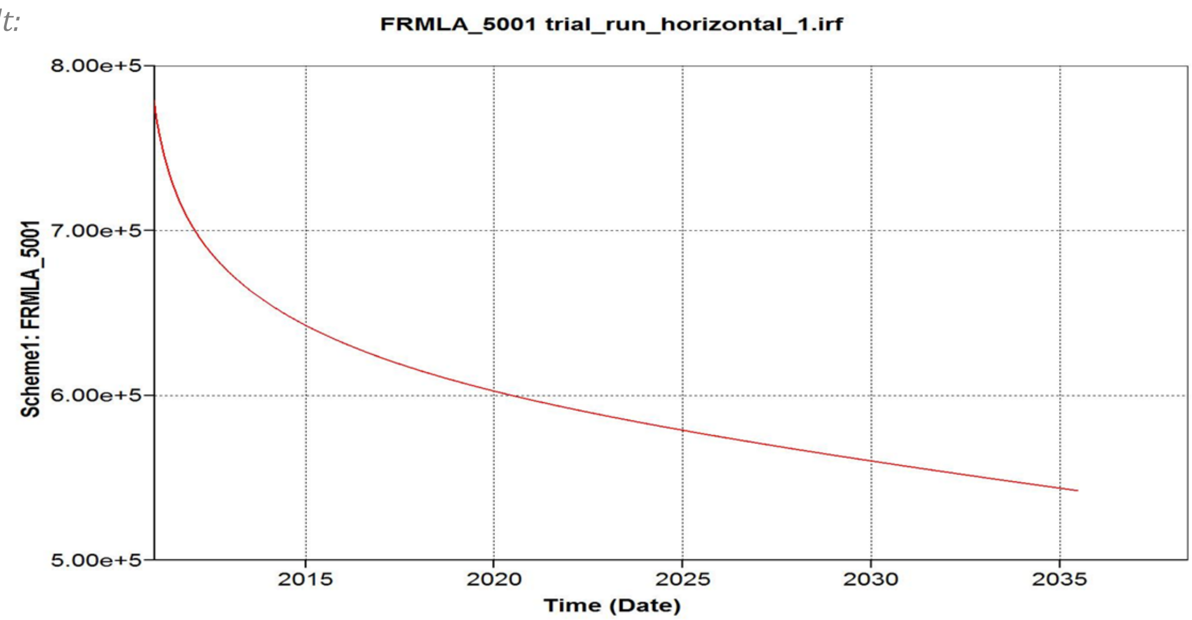


Figure 3.33: Production Rate - Case 2

CA

Result:

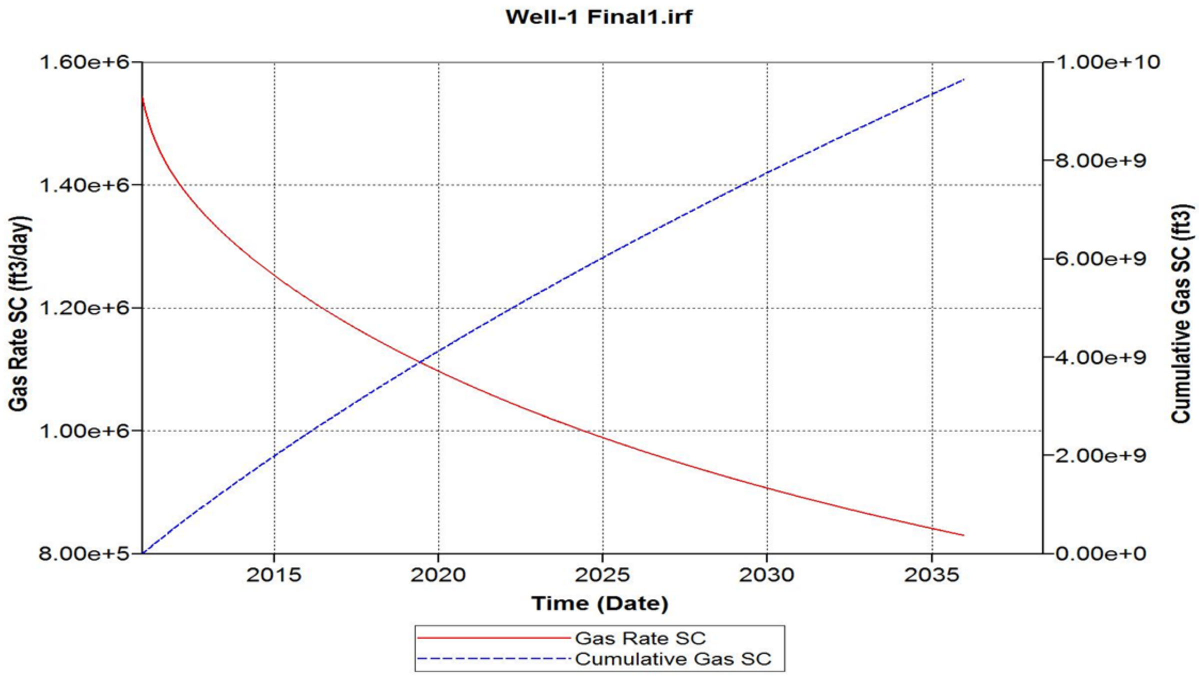


Figure 3.34: Production Rate and Cumulative Production - Case 3

Physical Attributes Used in CMG for all these runs:

Reservoir Properties	
Pressure	4500 Psi
Temperature	150 F
Initial Reservoir Pressure	4500 Psi
Volume	SCF/ton
Matrix Permeability	0.000001mD
Fracture Permeability	0.00001mD
Matrix Porosity	8%
Fracture Porosity	0.1%
Fracture Spacing	0.9 Ft
Thickness	702 Ft
Top of Pay Zone Depth	7046 Ft
Bottom of Pay Zone Depth	7748 Ft
Compressibility of Formation	0.00001 1/Psi
Gas Saturation	90%

Table 3.9: Physical Attributes of the CMG Model

CASE1: One Horizontal Well:

Result:

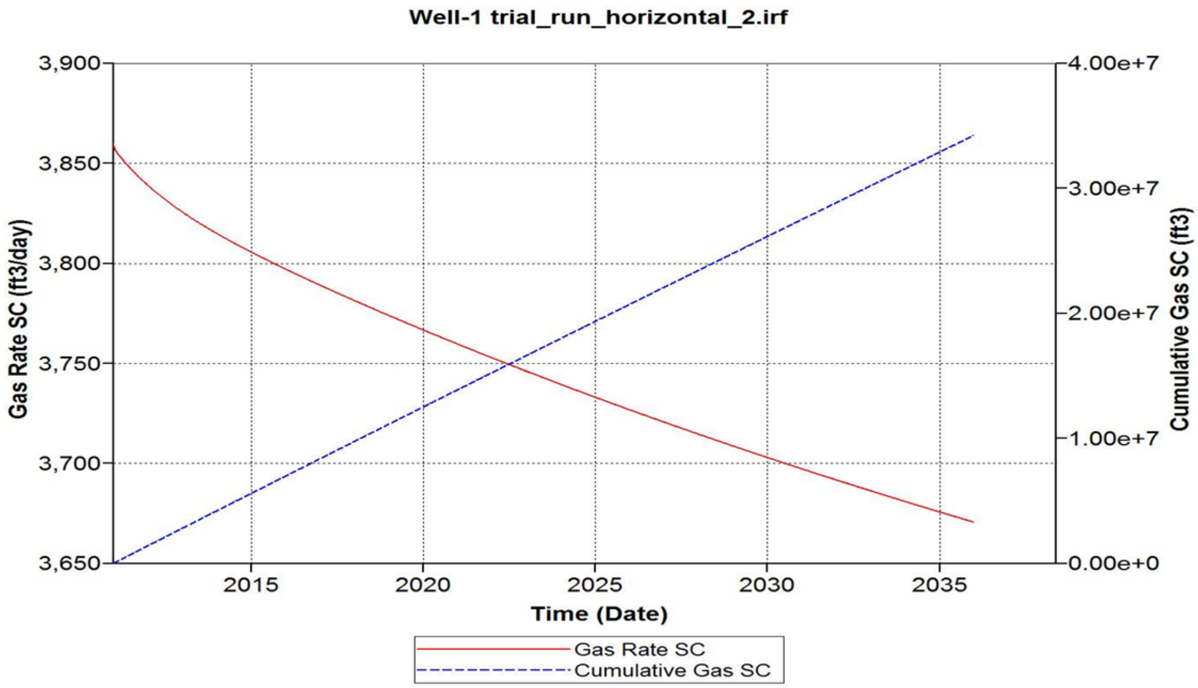


Figure 3.35: Production Rate and Cumulative Production - Case 1

CASE2: Two Horizontal Well:

Result:

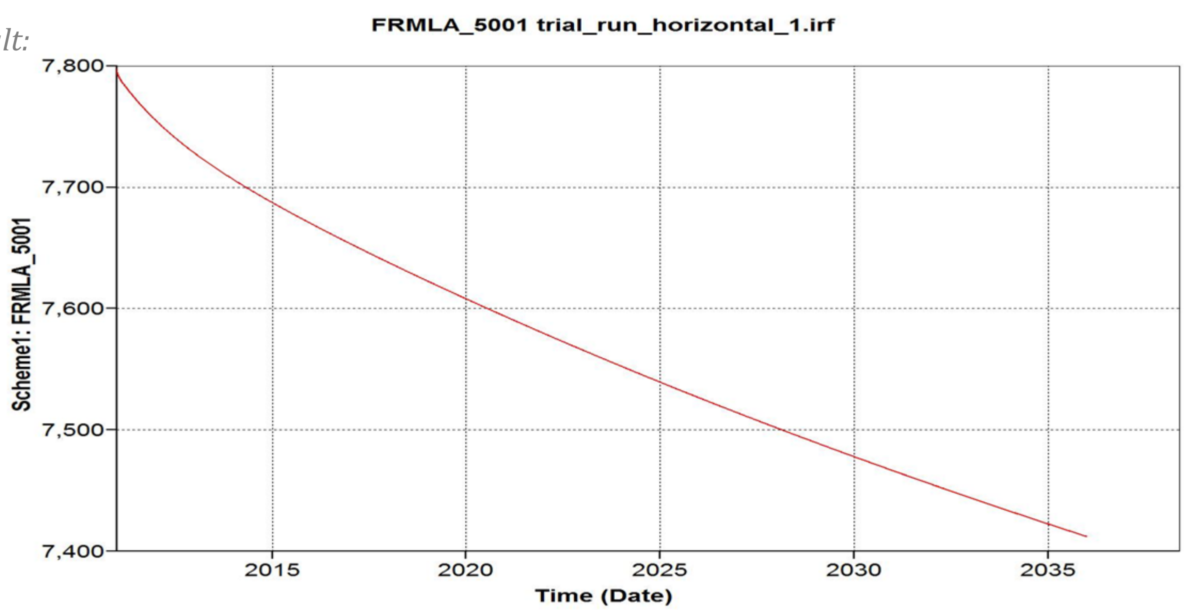


Figure 3.36: Production Rate - Case 2

CASE3

Result:

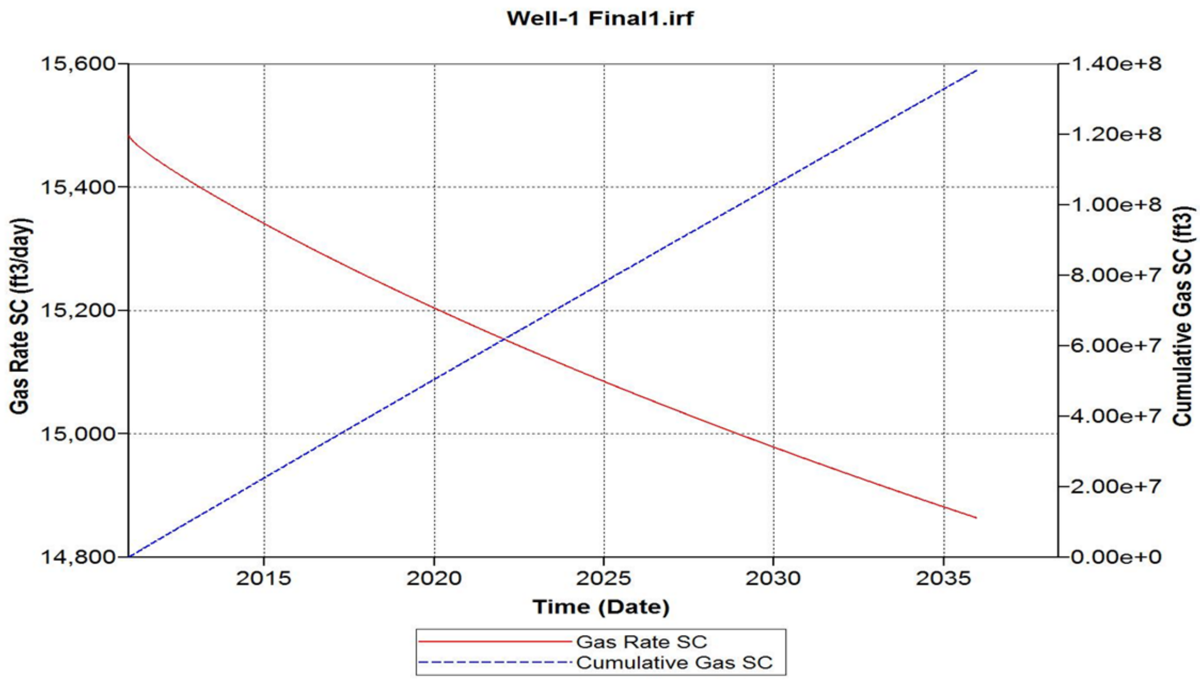


Figure 3.37: Production Rate and Cumulative Production - Case 3

Physical Attributes Used in CMG for all these runs:

Reservoir Properties	
Pressure	4500 Psi
Temperature	150 F
Initial Reservoir Pressure	4500 Psi
Volume	SCF/ton
Matrix Permeability	0.0001mD
Fracture Permeability	0.001mD
Matrix Porosity	8%
Fracture Porosity	0.1%
Fracture Spacing	0.9 Ft
Thickness	702 Ft
Top of Pay Zone Depth	7046 Ft
Bottom of Pay Zone Depth	7748 Ft
Compressibility of Formation	0.00001 1/Psi
Gas Saturation	90%

Table 3.10: Physical Attributes of the CMG Model

CASE 1: One Horizontal Well:

Result:

Figure 3.38: Production Rate and Cumulative Production - Case 1

CASE 2: Two Horizontal Well:

Result:

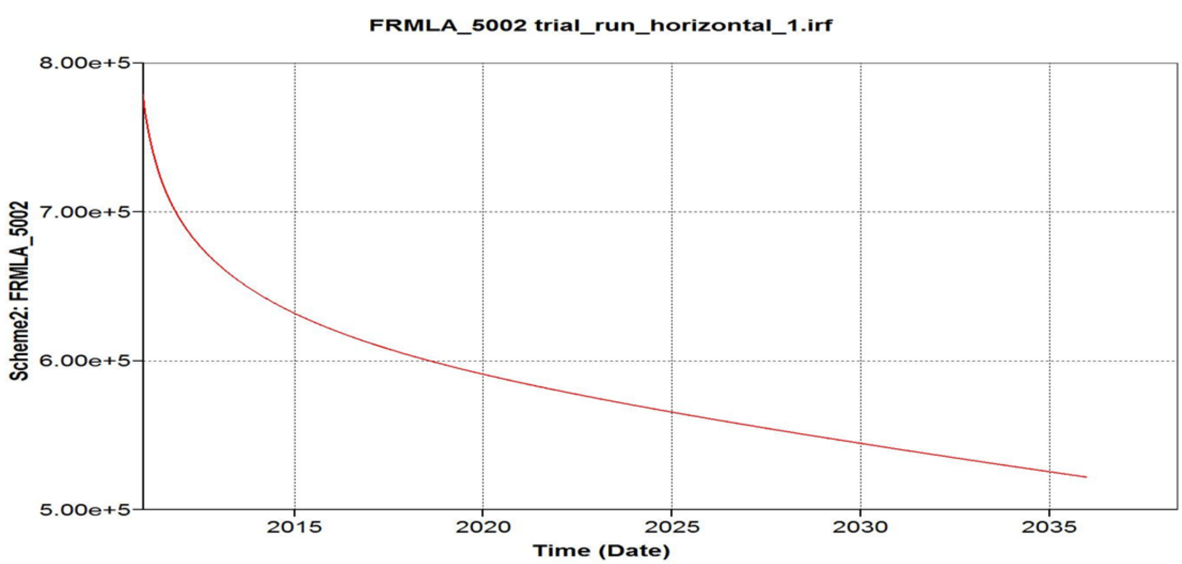


Figure 3.39: Production Rate - Case 2

CASE 3: Multilateral Model:

Result:

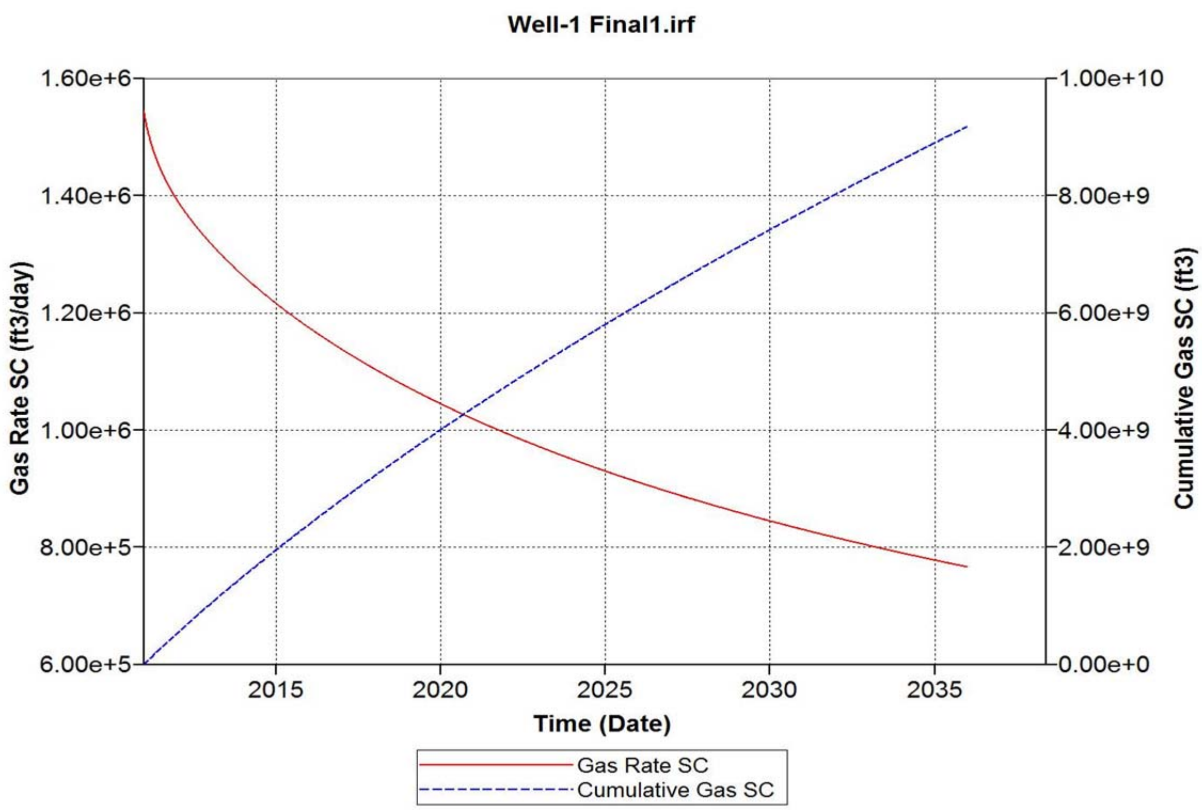


Figure 3.40: Production Rate and Cumulative Production - Case 3

3.4 Well Design

3.4.1 Casing Design

Casing is a crucial part in drilling in new well. This to ensure that the well integrity is good and the well can support production with the pressure exerted by the reservoir and formation. The casing design must be able to withstand three types of strain; axial tension burst pressure and collapse pressure. The axial tension is the stress created by its own weight when being suspended below a joint of interest. The burst pressure is the minimum internal pressure that causes the casing to rupture in the absence of axial loading and collapse pressure will cause the casing wall due to internal pressure. In the calculation of safety factor for each strain should be introduced. These safety factors are taken from the American Petroleum Institute for drilling purposes. Thus a table showing the safety factors can is shown below:

Factor	Safety Factor (API Standard)
Collapse	1.4
Burst	1.2
Tension	1.8

Five casing grades were considered in this project; J-55, C-75, N-80, C-90 and P-110. Note that as grade number increases the higher pressure the casing can withstand. However, this will increase the cost of the casing. Thus and optimum casing design is crucial so that the total drilling cost will be minimal. The following is the example calculation step for casing design:

Result and Discussion

Type of Casing	Depth (ft)	Type	Diameter (in)	Density (lb/ft)
Conductor	30	J-55	13-3/8”	21.85
Surface	1200	J-55	9-5/8”	21.85
Intermediate	5200	P-110	7-5/8”	15.2
Production liner	7250/7600	P-110	6”	14

Table 3.11: Casing Design

3.4.2 KOP calculation

In drilling a multilateral well, kick off points must be calculated to ensure that the lateral will penetrate the target zone. Based on the reservoir simulation, there are two target zones in the Marcellus shale formation; 7572.5 ft and 7221.5 ft. Thus using rate of build angle of 5 deg/50 ft, a table showing kick off point for each lateral can be shown as below:

Lateral	Kick Off Point (ft)
Lateral 1 (7572.5 ft)	6750
Lateral 2 (7221.5 ft)	6350

Table 3.12 : Location of Kick Off Point

Below is the well profile for both laterals:

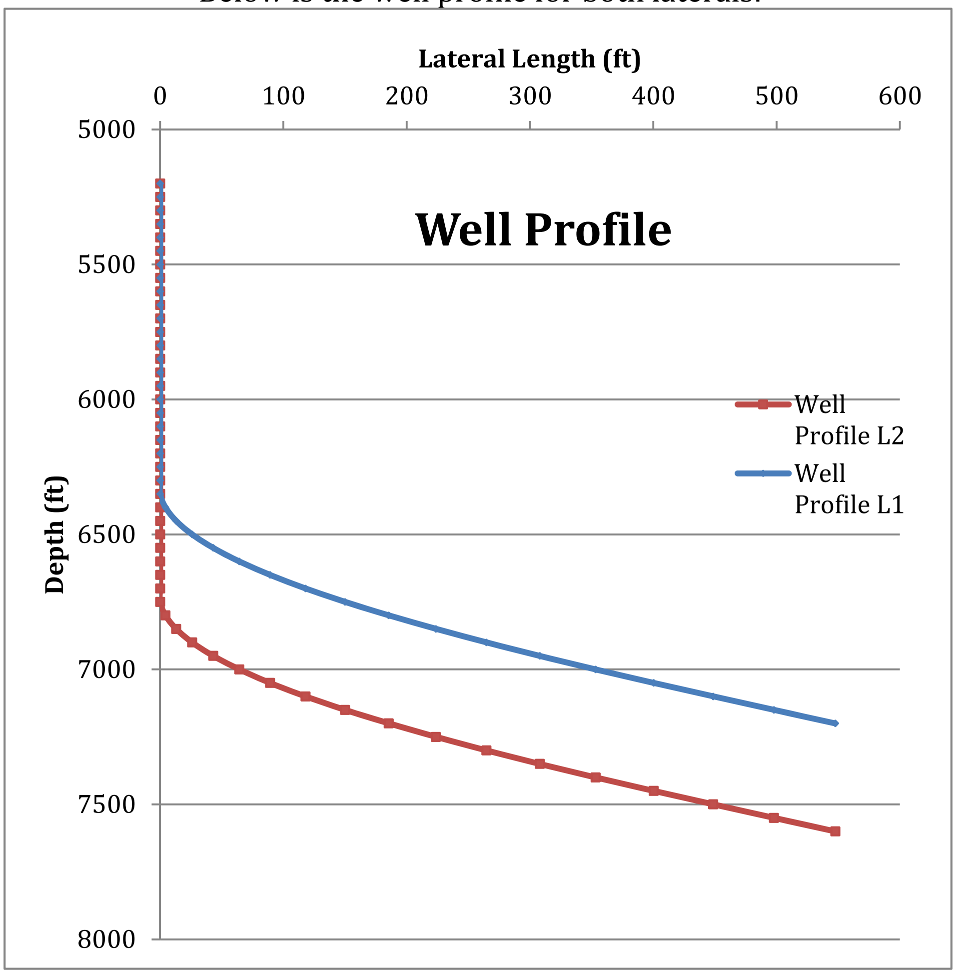
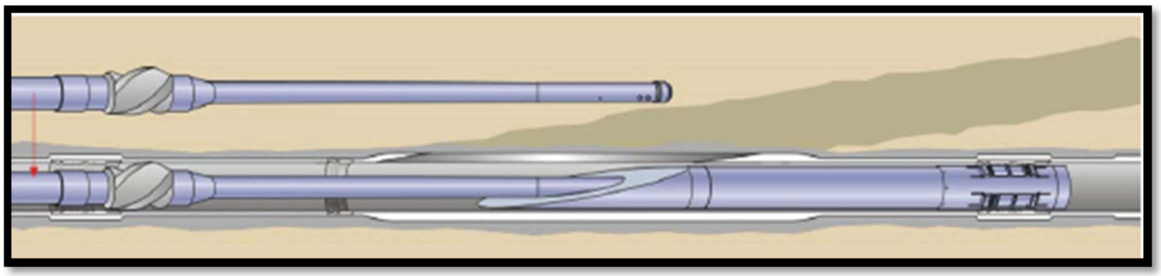


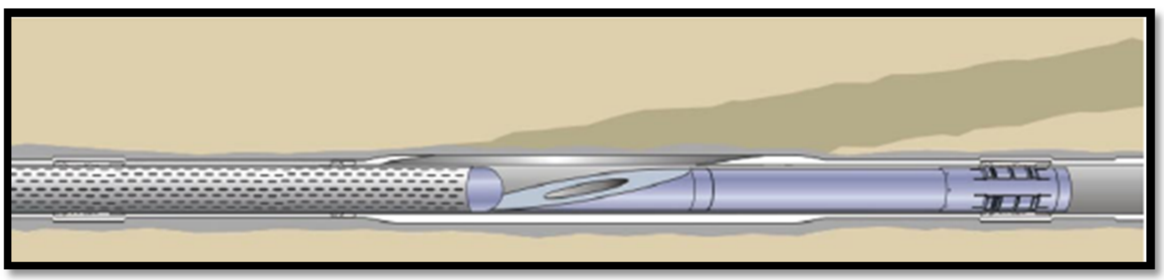
Figure 3.41: Well Profile indicating Kick off Points

3.4.3 Drilling Multilateral/Branch Procedure

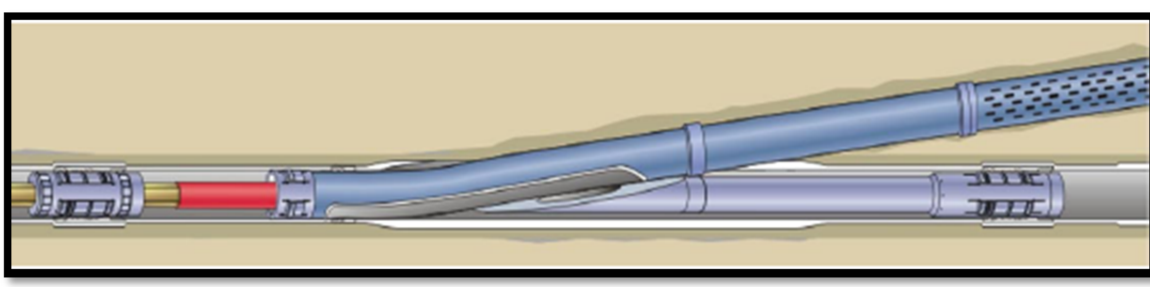
Since the drilling of the vertical part of the well is standard, this report would deal with the operational sequences of drilling the multilateral part of the well. Note that this method is repeated to drill every branch in the lateral system. These are the steps of multilateral well drilling right after completion of the vertical section:



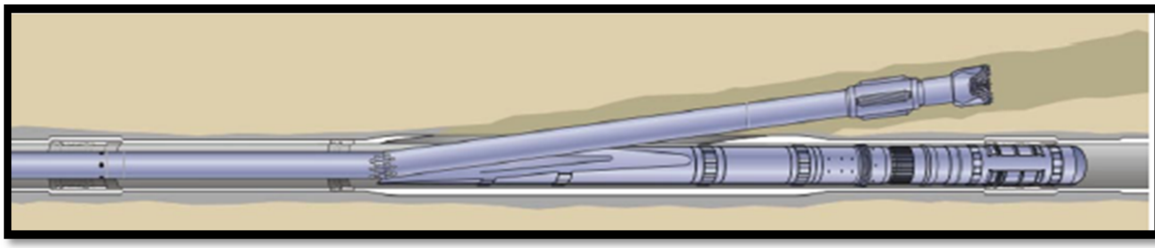
Step 1: Drilling the Lateral: The operation begins with creating the lateral wellbore. This can be done by a traditional horizontal method and whipstock. Once the lateral is being drilled and stable, the whipstock is removed so that the lateral liner can be placed in.



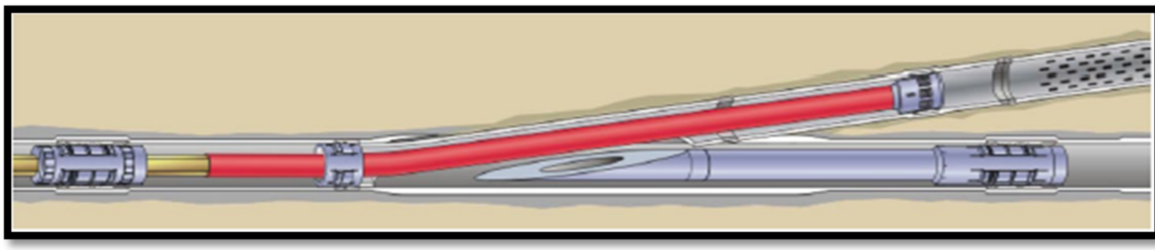
Step 2: Installing the Deflector: The system deflector is then run into the lower latch assembly. This Will cause the deflector automatically oriented towards the lateral windows.



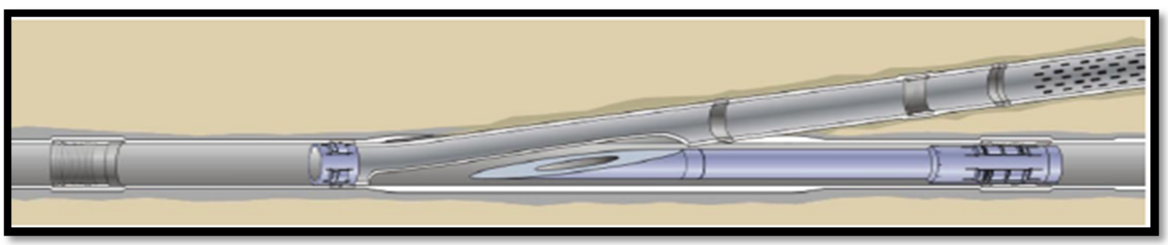
Step 3: Running the Lateral Liner: Both lateral liner and transition joint are run into the hole. A bullnose on the lateral liner deflectors will deflect the deflector assembly into the lateral wellbore. The complete length of the liner is continued into the well. In the same time, the casing will enter the wellbore.



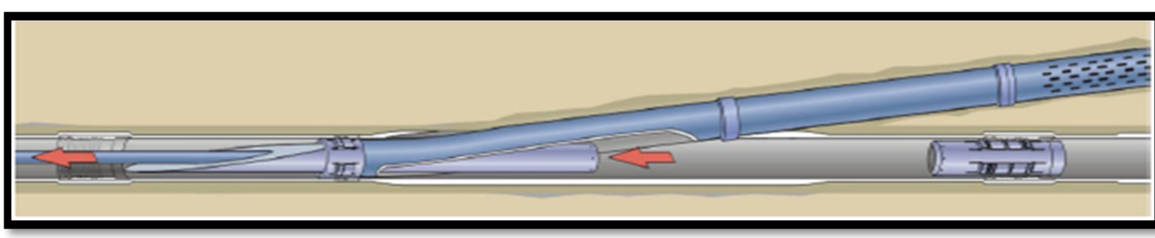
Step 4: Orienting the Liner Running Tool: The liner running tool engages the upper orienting latch coupling. The Kelly mandrel is released from the latch assembly and the running stroked will start.



Step 5: Setting the Transition Joint Assembly: The liner running tool strokes through the orienting latch assembly as it locks into a profile in the main casing. After that the liner running tool is released from the liner



Step 6: Removal of Liner Running and Deflection Tool: Both liner running and deflection tool are removed.



3.4.4 Multilateral Junction

Since the shale formation is brittle, in most multilateral drilling in Marcellus, unexpected plugging of the lower lateral by shale which ingresses through the milled casing window from the overlying cap rock. This in turn led to unsatisfactory economic performance of the streamlined multilaterals and prompted immediate action. The Tieback Junction Sleeve (TBJS) was developed and tested primarily to combat the shale ingression and to provide a sealing multi-lateral junction (Jonas Lindvall 2000)

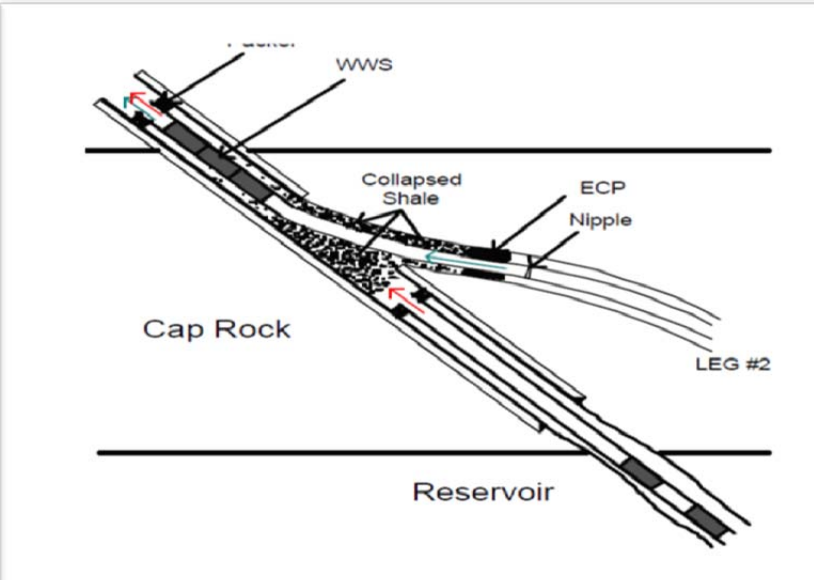


Figure 3.42 : Tieback Junction Sleeve

The TBJS is designed to have two tubes, inner tubes and outer tubes. Therefore this type of junction can be placed across the milled window, enabling the WWS to run through the inner tube, out through the window into the second lateral. Note that this TJBS will be latched into preoriented packer. This is important to make sure that it is facing the milled window. As a result this will completely seal the lower lateral junction; avoiding the unexpected plugging from happening.

In term of the availability, this kind of junction is right now available for most service company like Schlumberger and Baker Hughes. Since the design on the junction is rather simple compared to the other type of junctions; the cost of TJBS is cheaper; making it to be the most cost effective selection.

3.4.5 Open Hole, Multi-stage Fracturing System

This section will discuss about the multi-stage horizontal design for Marcellus shale operation. In typical operation in the unconventional reservoir, cemented liner with "plug and perf" method is normally used. However in this design, open hole, multi-stage fracturing system (OHMS) is used. Note that this method is relatively new and has only been performed several shale reservoir related operation like in Barnet Shale, Texas.

OHMS completion technology was originally designed for carbonate reservoir. In 2004, this technology has improved and right now this technology can be applicable for depth below 8000 ft. In Shale formation however, the growth of this technology is rather slow as drilling doing OHMS is limited to only several stages of fracturing.

In OHMS, the lateral is drilled and not cemented. This is the major different with the cemented liner where the lateral is sealed first with cement. One of the reasons for this decision is because both lateral in the same black shale formation. Thus not cementing the liner would increase the drainage area increase the gas flow since the fractures in not seal.

Based on the production data in the Barnett Shale (Zander 2011), after the first three months of production, the average cumulative production was increased by 79%. After the six months of production, the average production increased on average by 45%. Lastly, at 21 months of production, the gas production was increase by 30% compared to the cemented liner system. However the production of water also increased. The comparison of production between cemented liner and OHMS can be represented using the diagram below:

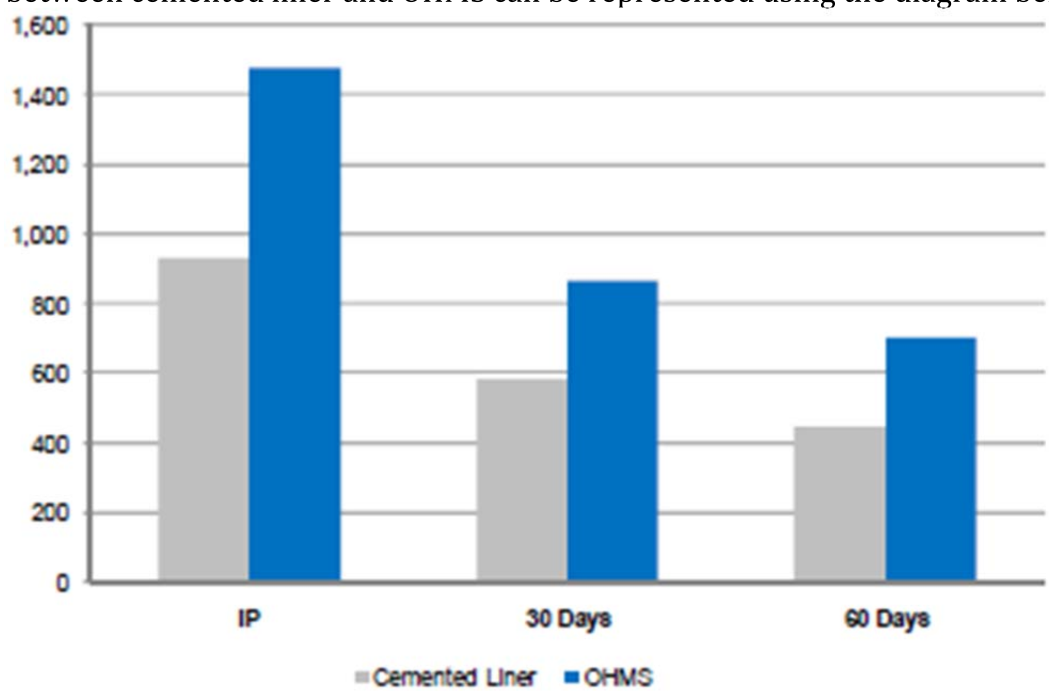


Figure 3.43: Comparison of Production Rates using Different Technologies

4. Water Management

4.1 Water Resources

The state of Pennsylvania, under which most of the Marcellus Shale formation lies, has six major watersheds. Out of these six watersheds, the three major rivers are the Ohio, Susquehanna and the Delaware which cover most of Pennsylvania's landmass. Also the other three smaller watersheds are the Erie, Genesse and the Potomac, which cover a small part of the state.

The drainage areas and the respective basins of these watersheds are described as follows:

'The Ohio basin forms a corridor from the southwestern corner of Pennsylvania to its north central border. This area is drained by the Allegheny and Monongahela Rivers that meet in Pittsburgh to form the Ohio River. The Susquehanna basin covers large parts of New York, Pennsylvania and Maryland before emptying into the Chesapeake Bay. The Delaware basin covers the eastern end of Pennsylvania as well as parts of New Jersey and Delaware and empties into the Delaware Bay. The Erie basin which includes parts of Michigan, Indiana, Ohio, Pennsylvania and New York, covers most of Erie County and is part of the Great Lakes system. The Genesee originates in Potter County in north central Pennsylvania and flows through New York before draining into Lake Ontario. The Potomac drains parts of the District of Columbia, Maryland, Virginia, West Virginia and Pennsylvania and empties into the Chesapeake Bay' (Pennsylvania August 2008)

Basin Name	Basin Size (sq. miles)	Area in PA (sq. miles)	Percent of Basin in PA	Percent of PA in Basin
Susquehanna	27,510	20,960	76%	46.25%
Ohio	164,000	15,614	10%	34.50%
Delaware	13,539	6,466	48%	14.25%
Potomac	14,670	1,584	11%	3.50%
Great Lakes	295,000	610	--	1.50%
Elk & Northeast	330	64	19%	--
Gunpowder	455	11	2%	--

Figure 4.1: Basin Wise Water Resource Distribution

According to the 2008 Pennsylvania Integrated Water Quality Monitoring and Assessment Report (April 2009), there is enough ground water in Pennsylvania to cover the state to a depth of eight feet. Pennsylvania's fresh water surface holdings include 86,000 miles of streams and rivers, 161,445 acres of lakes, 403,924 acres of wetlands, and 63 miles of Lake Erie shoreline. (Pennsylvania August 2008)

The Appalachian area with its precipitation of approximately 43 inches receives 10 inches more per year than the average for the continental United States. This precipitation is evenly distributed over the course of the year. It results in input of between 710,000,000,000 and 1,250,000,000,000 gallons of water in to Marcellus shale area. (Gaudlip, Paugh and Hayes n.d.)

4.2 Water Usage

As has been mentioned previously, the amount of water required for hydraulic fracturing is around 3-8 million gallons per well (Gaudlip, Paugh and Hayes n.d.), which if viewed with respect to the usage of water for other sources all over Pennsylvania is very insignificant. Calculations indicate that water use will range from less than 0.1 percent to 0.8 percent by basin (Pennsylvania August 2008). Comparing this with other uses, the consumptive use of fresh water for electrical generation in the Susquehanna River Basin alone is nearly 150 million gallons per day, while the projected total demand for peak Marcellus Shale activity in the same area is only 8.4 million gallons per day. (Gaudlip, Paugh and Hayes n.d.) Other water consumers that also affect water use in some parts of the Marcellus Shale include golf courses and agricultural producers; each golf course requires between 100,000 and 1,000,000 gallons of water per week. (Alliance for Water Efficiency April 2009)

Comparing the water usage in the other shale gas plays we have the following figures:

Shale Gas Play	Volume of Drilling Water per well (gal)	Volume of Fracturing Water per well (gal)	Total Volumes of Water per well (gal)
Barnett Shale	400,000	2,300,000	2,700,000
Fayetteville Shale	60,000*	2,900,000	3,060,000
Haynesville Shale	1,000,000	2,700,000	3,700,000
Marcellus Shale	80,000*	3,800,000	3,880,000

* Drilling performed with an air "mist" and/or water-based or oil-based muds for deep horizontal well completions.
Note: These volumes are approximate and may vary substantially between wells.

Figure 4.2: Estimated Water needs for drilling and fracturing (Consulting n.d.)

The success of any shale gas play including Marcellus shale depends on many factors. There should be effective communication between local water planning agencies, state agencies, and regional water basin commissions to design an effective water management plan as well as use of the resources. Also it is important to identify the sources of water supply which enable the drilling company to manage its water needs for fracturing and drilling, but which does not pose an obstacle to the usage of water resources for other needs especially by the local citizens and industrial units.

Also after the completion of the drilling and fracturing activities, there is production of water along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. (Groundwater Protection Council April 2009)

Water quality can be compromised at several stages of Marcellus Shale natural gas extraction. Gaining access to the proposed well site involves building access roads for the heavy equipment to transport the drilling rig, pipe, and water. Both transporting material to the site and site preparation can cause erosion and subsequent silting. Drilling through aquifers can contaminate water supplies. Approximately 15,000 gallons of chemicals are added to the fresh water for fracing. This water/chemical mix can leak onto the ground. The drilling slurry also contains cuttings of the native rock, which in the case of Pennsylvania's Marcellus Shale, includes uranium. The flow back that comes to the surface at the drill site is fracing fluid – complete with dissolved minerals and added chemicals. (Pennsylvania August 2008)

Drilling fluids are an important part of the drilling process as they circulate the rock cuttings to the surface to clear the borehole, cool and lubricate the drill bit as well as maintain downhole pressure. (Groundwater Protection Council April 2009) The frac fluid or flowback removed from the well after hydrofracing contains chemicals used by the company to facilitate gas recovery from the shale and subsequent gas flow in the pipe. The chemicals used may include oils, gels, acids, alcohols, and various man-made organic chemicals. The flowback is also site specific and some may contain diverse contaminants such as low levels of radioactive radon released from the underground rock formation. This flowback also contains hydrocarbons, heavy metals, and very high levels of total dissolved solids (TDS). TDS can include calcium, potassium, sodium, chloride, and carbonate. Because of its geology, Marcellus shale flowback tends to include more TDS than the flowback from other shale gas wells. Before disposal, it is necessary to treat drilling wastewater appropriately. (Pennsylvania August 2008)

Thus it becomes imperative to design an effective wastewater treatment and management plan which can not only alleviate the problems of water availability but also propose solutions for the disposal of the waste generated in accordance with the regulations and standards of the local community.

4.3 Regulations pertinent to the Delaware River and Pike County:

As per the analysis of the geology team, the location of the proposed reservoir has been finalized as Pike County. To be specific, the exact location would lie on the border of Pike and Wayne counties near the borough of Hawley. This location is approximately 35 miles from the county seat of Pike, which is the township of Milford.

As the location has been decided, the next step from the viewpoint of getting started with the pre-site assessments would be to identify the major sources of water availability for the drilling and fracing operations. Based on this criterion, we have found that the three major watersheds which surround the town of Milford and are near enough to our proposed site location. They are as follows:

1) Delaware River which flows beside Milford Township
2) Milford springs – serves the Borough of Milford and adjoining areas
3) Sawkill Creek and Vandermark Creek which empty into the Delaware river are also major watersheds

After the identification of the watersheds, the next step would be to analyze the catchment areas and the amount of water usage by the residents and other important industrial units so as to have a fixed plan about how we are going to go about procuring the water needs for the drilling and fracing uses of our project.

Located along the Old Milford & Owego turnpike west of the Borough in Milford Township at the base of a steep slope, Milford Springs produces over 1,000,0000 million gallons of water each day. The Milford Borough Municipal Authority water system currently serves a total of some 660 customers, primarily dwellings, but including about 100 commercial and institutional buildings. The total population served is about 1,500 and the average daily water demand ranges seasonally from 185,000 to 195,000 gallons. Information about the Sawkill and Vandermark creeks is limited.
Thus it becomes clear that the two resources (Milford Springs and the Sawkill creek and the Vandermark Creek) are primarily used for local residential and industrial purposes. Furthermore, based upon the calculations of the simulation team, using water for our fracing purposes would pose a great burden on these two resources to comply with other important needs.

A birds eye view of the Milford community township makes the picture clear as to the exact flowing patterns and locations of these watersheds –

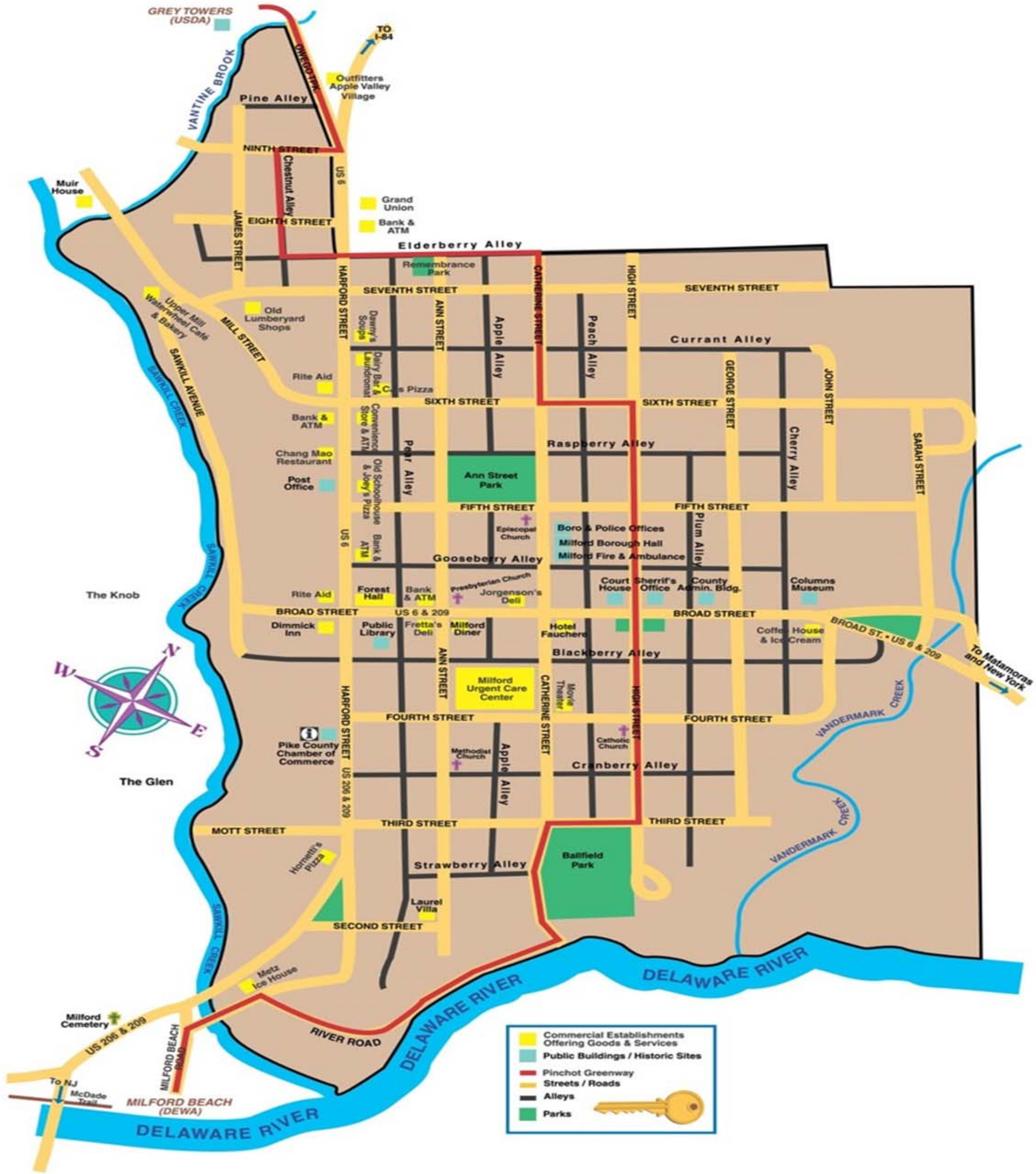


Figure 4.3: Bird's Eye View of the Milford Township

Hence we have decided that we will try and get our water supply sources from the Delaware River which flows just beside the township and and is fairly close to our site.

This is a map of the Delaware River Basin.

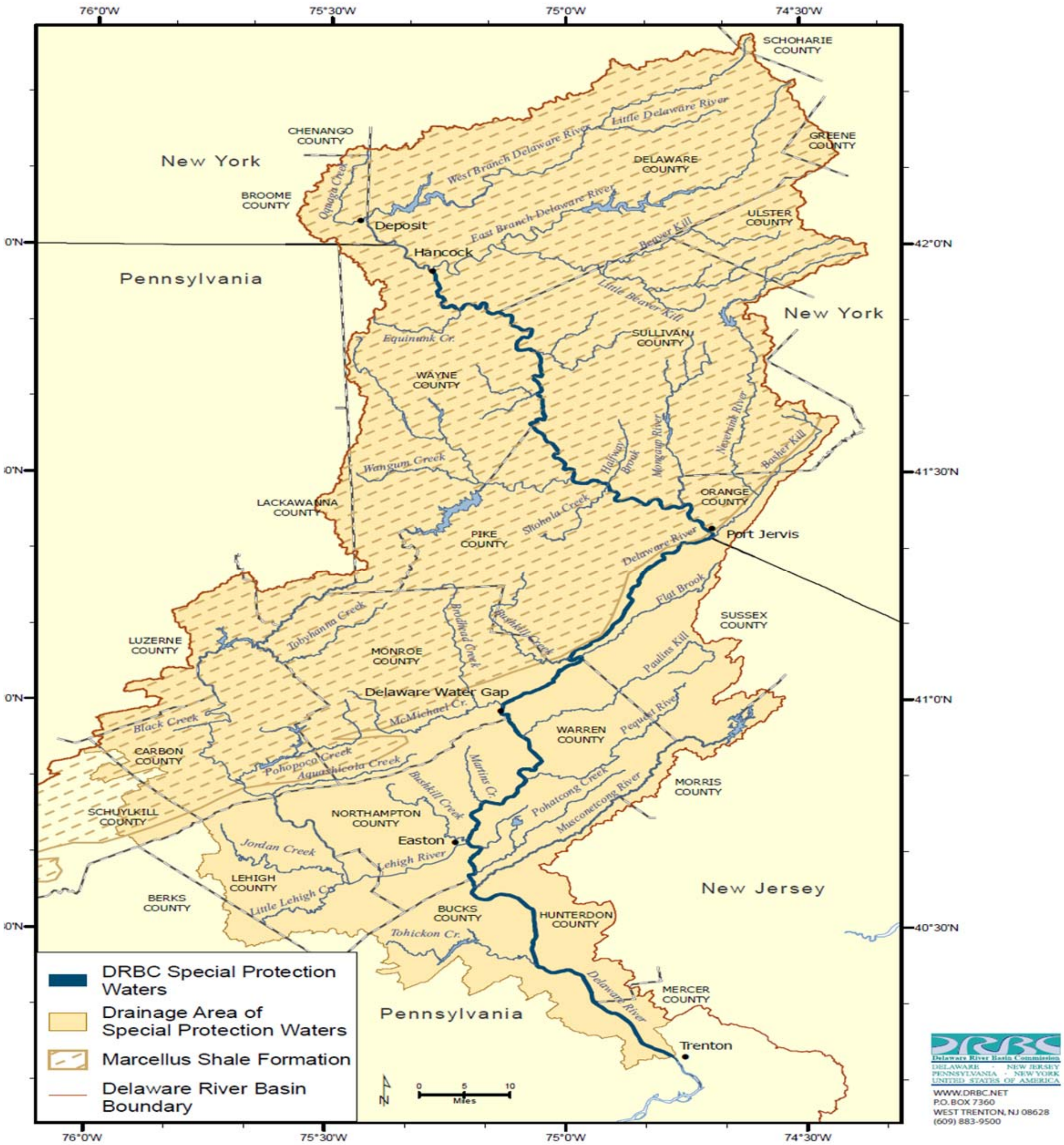


Figure 4.410: Map of Delaware River Basin

The Delaware River Basin Commission (DRBC) is the primary agency overseeing water-related activities in the DRB. The responsibilities of the commission include responsibilities include water quality protection, water supply allocation, regulatory review/permitting, water conservation initiatives, watershed planning. (J. Daniel Arthur, Mike Uretsky and Preston Wilson – ALL Consulting n.d.)

There are certain regulations pertaining to the industrial/commercial activities which require the use of the waters of the Delaware River, including large withdrawals such as the volumes required for hydraulic fracturing of the Marcellus Shale.

- The DRBC requires approval for surface water withdrawals exceeding 100,000 gallons per day (gpd), based on a 30-day average. (J. Daniel Arthur, Mike Uretsky and Preston Wilson – ALL Consulting n.d.)
- They also require approval for a withdrawal from groundwater wells in the DRB exceeding 100,000 gpd, based on a 30-day average, outside of the Southeastern Pennsylvania Groundwater Protection Area. (J. Daniel Arthur, Mike Uretsky and Preston Wilson – ALL Consulting n.d.)
- The DRBC also requires that any diversion or transfer of water into or outside of the DRB which exceeds 100,000 gpd be brought to the commission for approval (J. Daniel Arthur, Mike Uretsky and Preston Wilson – ALL Consulting n.d.)

Thus we have proposed the following plan to source water for our drilling and fracing activities

- We will use water trucks and trailers from the DRB to haul water to our sites
- The water will then be pumped into lined storage impoundments (pits) and stored until it is transported by temporary ground piping to the well pad locations for a fracture treatment. The description of such a pit is given below

Figure 4.5: A lined storage pit used for storage of water in Broome County NY

4.4 Drilling fluids and their disposal

As mentioned in the earlier paragraphs, drilling fluids with various combinations of water , mud and chemicals are used for the drilling operations. The problem arises when the drilling fluids are returned back to the surface. The fluids from drilling have a high salt content and contain minerals from the rocks penetrated by the drill and there are regulations pertaining to the efficient disposal of these fluids.

In rural areas, storage pits may be used to hold fresh water for drilling and hydraulic fracturing. In an urban setting, due to space limitations, steel storage tanks may be used. (Groundwater Protection Council April 2009). Thus similar to storage of fresh water in pits, we will employ steel tanks to store the waste drilling fluids before sending them to the nearest municipal treatment facility for purification and subsequent discharge under the Solid Waste Management act (Consulting n.d.)

In recent years, drilling with compressed air is becoming an increasingly popular alternative to drilling with fluids due to the increased cost savings from both reduction in mud costs and the shortened drilling times as a result of air based drilling. The air, like drilling mud, functions to lubricate, cool the bit, and remove cuttings. Air drilling is generally limited to low pressure formations, such as the Marcellus shale (Groundwater Protection Council April 2009). This remains an alternative which we could try at our site depending on the economic and environmental factors.

Sometimes, subsurface formations may contain low levels of radioactive materials such as uranium and thorium and their daughter products, radium 226 and radium 228. (Lisa Sumi May 2008). These chemicals are called as Normally Occurring Radioactive Materials (NORMs) which are present in trace concentrations all over the Marcellus shale region. Many times these NORMs are brought to the ground surface by gas wells when the drilling and waste fluids that enter the formations where these materials exist are pumped back.

Because the radioactive materials become concentrated on oil and gas-field equipment, the highest risk of exposure to oil and gas NORM is to workers employed to cut and ream oilfield pipe, remove solids from tanks and pits, and refurbish gas processing equipment. Thus it becomes imperative to treat/dispose off these drill fluids instead of keeping them in storage for a long period of time so they do not pose a bigger threat to the workers.

The use of storage tanks with special liners thus becomes significant after considering the above factors. These help in containing to some extent the spread of Naturally Occurring Radioactive Materials (NORMs) but then it is proposed to dispose them off in licensed disposal pits around PA which are equipped with radiation monitors.

Also after all our drilling and fracturing activities are completed, at the time of abandoning the well plugging would be considered. As has been the case once the well is no longer in production well would be decommissioned and plugged to prevent future groundwater pollution/contamination.

4.5 Waste Water Treatment

4.5.1 Reverse Osmosis Water Treatment System (RO)

Reverse Osmosis is basically a filtration process at molecular level. Feed water flows across a membrane surface. With the pressure force generated by the pump, water molecules permeate through the membranes while particle; dispersed oil, ions and some organic molecules are rejected by the mechanism of size competitive diffusion. The permeate water can be collected as purified water for beneficial uses (in our case for frac job, drilling job etc.)

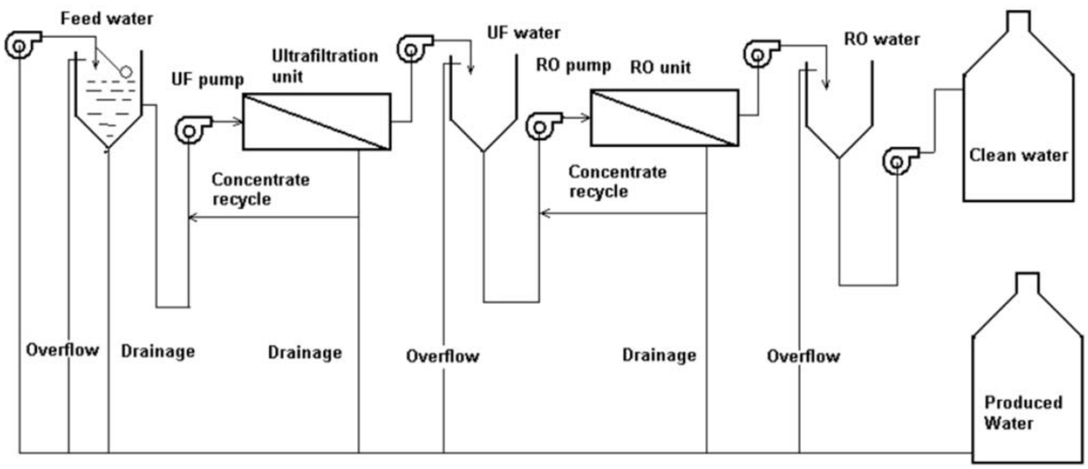


Figure 4.6: Schematic diagram of cross flow RO membrane with ultrafiltration pretreatment. * SPE 115952

The primary concern of the RO technology is the membrane fouling. The produced water contains both organics and high concentration of multivalent ion species can affect the membrane efficiency very severely. For this reason the membrane should be replaced and periodically cleaned with the chemicals. According to the SPE 115952 paper, most of the membrane fouling are irreversible and flux loses cannot be compensated by increasing the pumping pressure.

RO water treatment system can be the most effective and cheapest system in terms of capital and operation cost if the TDS amount is lower than 45,000 mg/L. Since most of the Marcellus Shale reservoirs don't have the TDS amount higher than 45,000 mg/L, we can safely use RO system to implement in our project.

In the table below commercial RO system provided by various companies for the shale gas basin are listed. There are currently three companies, which are Siemens, Veolia, MI SAECO, have RO system implemented in Marcellus Shale.

Treatment Company	Reverse Osmosis	Shale Gas Basin				
		Marcellus	Barnett	Haynesville	Fayetteville	Woodford
	GeoPure		√			
	Siemens	√			√	
	GPRI		√			
	Auxsol		√		√	
	Veolia	√				
	MI SWACO	√				
	Ecosphere		√		√	√
	GE Water & Process Tech.		√		√	
	Innovative Water Solutions		√			

Figure 4.7 Commercial RO Systems in Shale Gas Reservoirs. "Water Treatment Technology Fact Sheet"

4.5.2 Technical Capabilities of RO

In general, RO water treatment systems can treat water TDS concentration up to 45,000 mg/L and even some newer RO system this amount can be increased up to 55,000 mg/L. RO treatment also can be very effective in removing the sand, silt, clay, algae,protozoa, bacteria viruses, humic acids, organic and inorganic chemicals, salts, metal and nonmetal ions. There is a pilot test conducted by Newfield in the Woodford shale, which has the analysis of flowback water treated using RO system. The result indicated in the table below provides a good understanding about the efficiency of the RO systems. As it is evident from the data, the efficiency is very high so it is very appropriate and effective system to implement in our project.

	Before Treatment	After Treatment	Efficiency
TDS concentration (mg/L)	13,833	128	99.1 %
Chloride (mg/L)	8393	27	99.7 %
TSS (mg/L)	64,5	0	100 %
Barium (mg/L)	34,9	0	100 %

Table 4.1: Pilot Test Data of a RO Treatment Plant

4.5.3 Technical Limitations of RO

RO membranes are subject to fouling if the necessary pretreatment processes are not in place, where the pretreatment processes include media filters to remove suspended particles; ion exchange softening; temperature and PH adjustment to lower chemical solubilities etc, Also if membrane is subjected to fouling, the resulting efficiencies would be very low (around %40-65) and can have lower efficiency as well if TDS amount is higher than 45,000 mg/L. In this case, the result can be higher brine stream, which directly increases the disposal cost.

4.5.4 Cost

Factors Affecting the Cost of Produced Water Desalination

There are several factors affecting the cost of the water treatment system including amount of the produced water and the size and capacity of the plant. These factors are so crucial for the unit production cost.

Quality of feed water is also very important factor affecting the system design and economic efficiency. For example; if TDS amount is at very high range the system should be designed in such a way that it has enough capacity to treat that water which has high TDS. So this kind of system obviously will have a high cost compare to system, which treats water having lower TDS.

Pretreatment is indispensable part of RO system because otherwise the membrane may be subjected to fouling. According to the SPE 115952 the pretreatment cost ranges from \$0.2-\$0.7/m^3 depending on the produced water quality and unit cost of electricity.

Transportation is very crucial factor for the cost of the system as well. If the system is placed close to wellhead, long distance water transportation cost could be eliminated.

RO Cost

Ro treatment system requires less energy to operate when compared to thermal treatment processes or other membrane required technologies, such as electrodialyses reversal. Therefore, it is more cost effective as long as TDS amount is not higher than 45,000 mg/l. The cost of the RO system depends on the type of the RO system, size, location, construction costs, and feed water quality. (US Department of Energy n.d.)

The major elements of economic calculation of treatment system basically include direct capital cost, indirect capital cost and annual operating cost. The table published in SPE 115952 gives the definition of what is included in direct capital cost, indirect capital cost and annual operating cost.

The information given by the companies, which provide RO system for shale gas basins, capital costs range from \$3.0 to \$7.0/gps. For example, in Barnett Shale, Marathon Oil Company uses the RO system developed by GPRI. They constructed and operated the facility producing 714,000 gallons per day. The reported cost of the water treatment was (no infrastructure cost) less than $2.50 per 1,000 gallons. (Shankar Muraleedaaran n.d.)

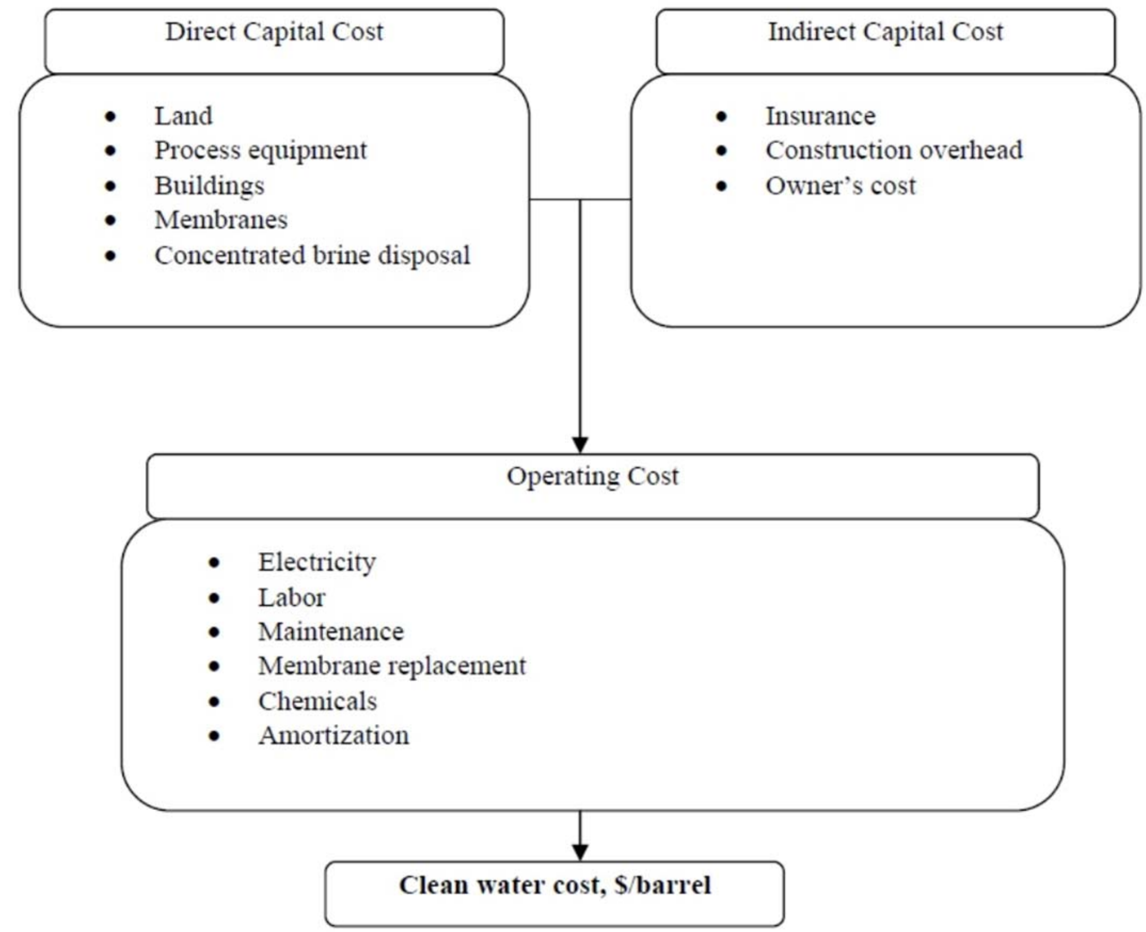


Figure: 4.8 Elements used for cost analysis of RO desalination * SPE 115952

5. Economic Analysis

5.1 Detailed Analysis of Methodology

As discussed earlier, there are four different economic viewpoints that could be identified. They are the 'development economics', 'farm out', 'farm in' and also 'overriding royalty'. Our project's economic analysis was based on 'farm in' viewpoint, assuming that a piece of land would be leased from an owner. The Project has been evaluated by employing the discounted cash flow analysis and rate of return.

By comparing the Net Present Value (NPV) of the projects for 25 years of production, the best production strategy could be concluded. With discounted cash flow analysis, the breakeven time for the project could be found for the project to be feasible. Besides, the rate of return of the project could also be determined by running several iterations to find out the discount rate that yields zero for the NPV. The discount rate is the minimum rate for the project to be deemed feasible.

5.2 Discounted Cash Flow Analysis

Discounted cash flow analysis has been incorporated in our project to account for the inflation and also depreciation of equipment over a period of time. The project is deemed feasible provided that the NPV of the resulting project yields positive result.

$$NPV = \sum_{i=0}^{n} \frac{Total\ Incoming\ Cashflow - Total\ Outgoing\ Cashflow}{(1+Discount\ Rate)^{n}}$$ (Stermole and Stermole 2009)

5.3 Rate of Return

A series of computations were run to determine the minimum rate of return for this entire project to be feasible. This is done by adjusting the discount rate for each iteration and when the NPV yields zero, which means it is at breakeven, the discount rate is known as the minimum rate of return. In deciding the project, it is sensible to proceed with the execution of the project if the actual discount rate is lower than the rate of return.

$$NPV = 0 = \sum_{i=0}^{n} \frac{Total\ Incoming\ Cashflow\ - Total\ Outgoing\ Cashflow}{(1 + Discount\ Rate)^{n}}$$

(Stermole and Stermole 2009)

5.4 Income

In our project, the sale of the gas production is assumed to be the only income source. The gas production data is obtained from the simulation and then the revenue is calculated by multiplying the gas production with the gas price. Since the forecasted price is only available up till 2017 by NYMEX (***Figure 5.1***).Further gas prices are predicted using certain model. In our project, the linear regression model has been employed to predict the price beyond 2017 up till 2036.

$$y_i = \beta_i x_{i_1} + \cdots + \beta_n x_{i_n} + \varepsilon_i = x_i' \beta + \varepsilon_i \quad where\ i = 1{:}\,25$$

(Stermole and Stermole 2009)

$y_i = Future\ Price$
$\beta = Regression\ Coefficient$
$x_i = Price\ before\ y_i$
$\varepsilon = Error\ Term$

5.5 Cost

The major costs involved in the project would be the drilling cost since it represents approximately 70% of the costs associated with the entire project. Besides, we also account for the cost of well stimulation, water disposal, land lease, royalties. All the costs are discounted over the period of production time to better estimate the actual costs.

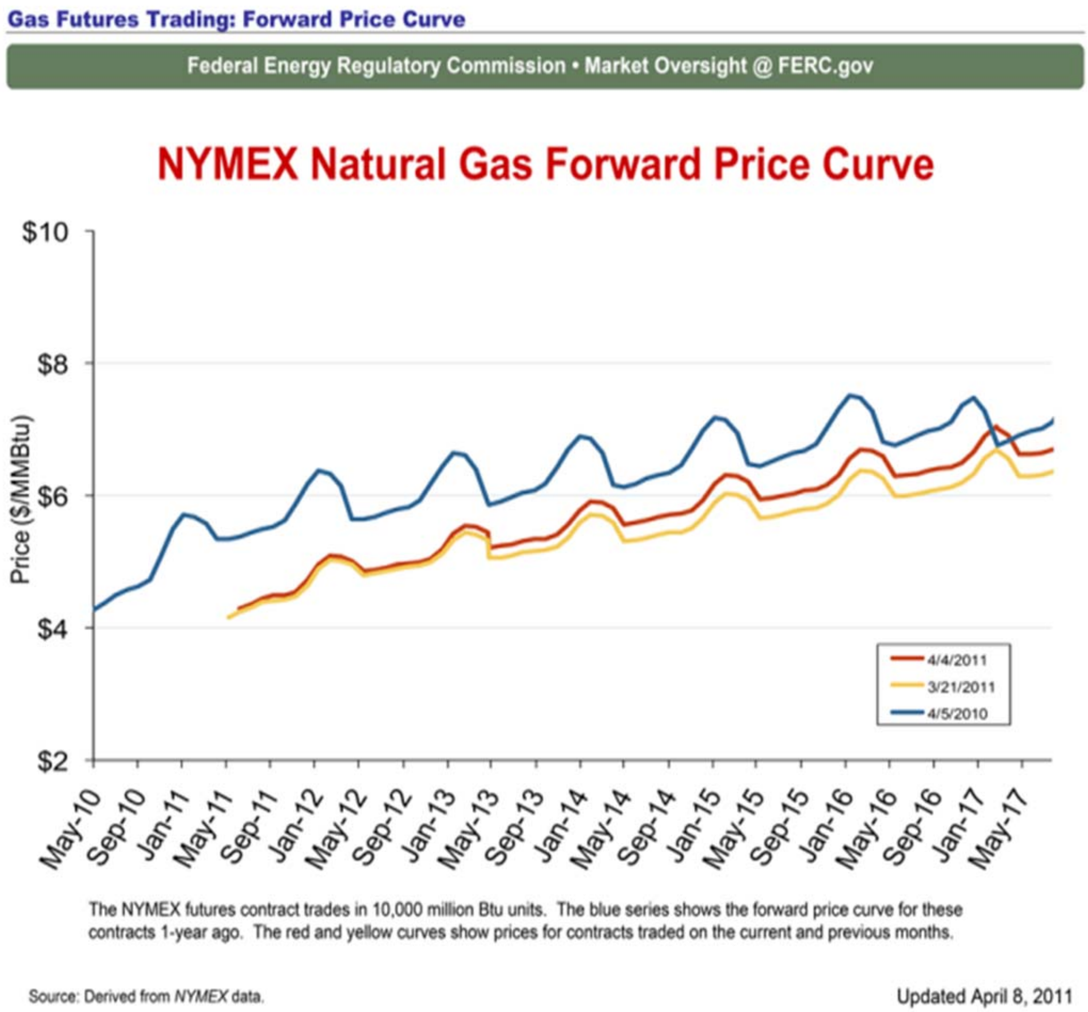


Figure5.1: Natural Gas Price Trend (U.S. Energy Information Administration 2011)

Also the costs are divided into 2 separate categories: the intangible costs and also the tangible costs.

Items	Costs ($)
Tangible Costs	
24' Conductor Casing	$62/ft
20' Intermediate Casing	$48/ft
9.625' Production Casing	$29/ft
Surface Production Facilities	$20000
Intangible Costs	
Site Preparation	$100000
Drilling Contractor Services	$120000
Materials & Supplies	$50000
Logging, Stimulation, Perforations	$400000
Power, Water Disposal	$3700000
Installation, Completion, Labor	$40000
Figure B : Costs from AFE provided by East Resources Inc.	

Table 5.1: Costs involved in the Project

Apart from this, the costs associated with the Horizontal Well Drilling and Multilateral Well Drilling are compared using relative analysis where it has been assumed that the length and depth for both wells would be the same and the additional costs of Multilateral Well Drilling would be depending on the number of the laterals it has. From the relative comparison, the multilateral well drilling is found to be around $11 million without hydraulic fracturing and $12 million with hydraulic fracturing. Horizontal drilling on the other hand is found to be around $5 million without hydraulic fracturing and $6 million with hydraulic fracturing. (Schweitzer and Bilgesu 2009)

'2008

AUTHORIZATION FOR EXPENDITURE
DRILLING/COMPLETION COST ESTIMATE

② 6/29/08- 7/8/08

DRILLING X____
RECOMPLETION ______
AFE No.: 052080108
Lease Name - Well #: TX Crk #104
Legal Description: Jackson Township

37-081
County or Parish, State: Lycoming PA
Field: Texas Creek 52
Prepared By: Jared Hall

AUTHORITY REQUESTED FOR:

Account Number 206	Intangible Costs Description	Dry Hole Costs	Completion Costs	Total Costs
	SITE PREPARATION			
011	LAND AND LEGAL	7,500		7,500
012	SURFACE DAMAGES / RIGHT OF WAY	10,000		10,000
013	LOCATION, ROADS, PITS, FENCES	80,000		80,000
019	OTHER SITE PREPARATION			0
	DRILLING CONTRACTOR SERVICES			0
041	TURNKEY DRILLING COSTS			0
042	FOOTAGE ' @ turnkey / ft (conductor)	12,000		12,000
043	DAYWORK @ $12,500	75,000		75,000
044	MOBILIZATION / DEMOBILIZATION	22,000		22,000
049	OTHER DRILLING CONTRACTOR SERVICES	10,000		10,000
	MATERIALS AND SUPPLIES			0
101	DRILL BITS	18,600		18,600
102	DRILLING MUD, CHEMICALS, COMPLETION FLUIDS	4,000		4,000
103	RENTAL TOOLS & EQUIPMENT	15,000	10,000	25,000
109	OTHER MATERIALS AND SUPPLIES			0
	GENERAL SERVICES			0
201	WELDING & ROUSTABOUT		4,000	4,000
202	DIRT WORK & HEAVY EQUIPMENT			0
203	TRUCKING & HOTSHOT	10,000	5,000	15,000
204	PIPELINE INSTALLATION			0
209	OTHER GENERAL SERVICES			0
	SPECIALIZED SERVICES			0
251	CEMENT AND CEMENTING SERVICES	9,800	10,100	19,900
253	P&A COSTS			0
255	LOGGING, PERFORATING & WIRELINE		55,000	55,000
257	OPEN HOLE EVALUATION			0
259	CASING & TUBULAR SERVICES -power tongs	1,800	3,400	5,200
261	FLUID SERVICES			0
263	SALT WATER DISPOSAL			0
265	STIMULATION (Acid)		325,000	325,000
267	OFFSHORE TRANSPORTATION			0
269	MUDLOGGER	8,250		8,250
271	FISHING SERVICES			0
273	TESTING SERVICES	2,500	15,000	17,500
299	OTHER SPECIALIZED SERVICES	6,000		6,000
	POWER, FUEL, AND WATER			0
301	POWER & FUEL	22,800		22,800
302	WATER (inc disposal)	8,000	220,000	228,000
	COMPLETION AND CLEANUP			0
501	PULLING & SWABBING UNIT			0
502	SNUBBING UNIT & COILED TUBING			0
503	BACKFILL PITS / RESTORE LOCATION		18,000	18,000
509	OTHER COMPLETION & CLEANUP			0
	ENVIRONMENTAL & SAFETY			0
551	ENVIRONMENTAL RESTORATION			0
52	SAFETY EQUIPMENT			0
553	ENVIRONMENTAL & SAFETY TRAINING			0
554	ENVIRONMENTAL & SAFETY FINES			0
559	ENVIRONMENTAL & SAFETY MISCELLANEOUS			0
	MISCELLANEOUS			0
711	COMPANY SUPERVISION (Consultant)	0	9600	9,600
721	DRILLING OVERHEAD			0
731	CONSTRUCTION OVERHEAD			0
741	WELL CONTROL INSURANCE			0
802	GENERAL LABOR	10000	5000	15,000
831	VEHICLE EXPENSE			0
861	DISTRICT & FIELD OFFICE EXPENSE			0
865	COMPANY BENEFITS			0
895	TAXES			0
	TOTAL INTANGIBLES	**$333,250**	**$680,100**	**$1,013,350**

Figure 5.2: AFE from East Resources Inc.

5.6 Results and Discussions

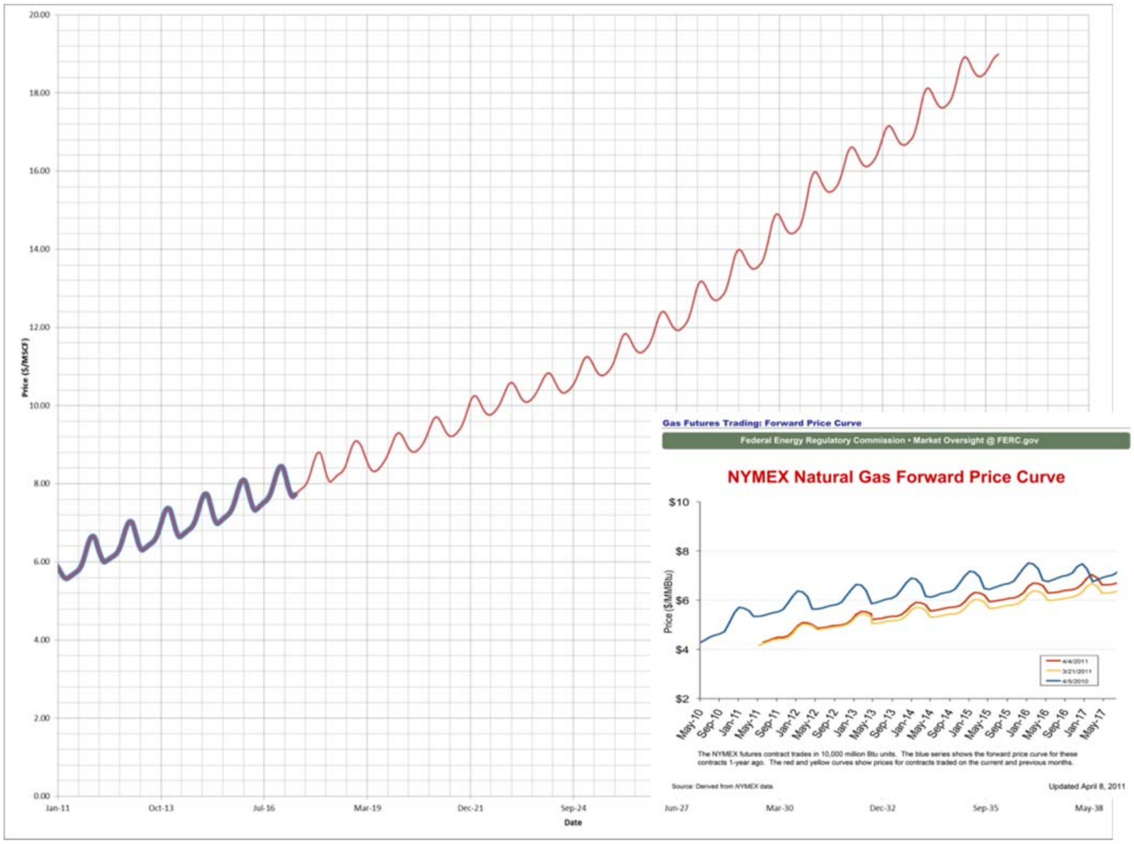
In our analysis, a total of 18 different cases were analyzed to have a better understanding the feasibility of project.

5.7 Sensitivity Analysis

Case	Type	Hydraulic Fracturing	Porosity	Fracture Porosity	Fracture Permeability	Permeability
1	1 Horizontal Well	Yes	0.09	0.1	0.00001	0.000001
2	1 Horizontal Well	Yes	0.09	0.1	0.0001	0.001
3	1 Horizontal Well	Yes	0.09	0.08	0.00001	0.000001
4	1 Horizontal Well	Yes	0.09	0.08	0.0001	0.001
5	1 Horizontal Well	Yes	0.09	0.01	0.0001	0.00001
6	1 Horizontal Well	No	0.09	0.01	0.0001	0.00001
7	2 Horizontal Well	Yes	0.09	0.1	0.00001	0.000001
8	2 Horizontal Well	Yes	0.09	0.1	0.0001	0.001
9	2 Horizontal Well	Yes	0.09	0.08	0.00001	0.000001
10	2 Horizontal Well	Yes	0.09	0.08	0.0001	0.001
11	2 Horizontal Well	Yes	0.09	0.01	0.0001	0.00001
12	2 Horizontal Well	No	0.09	0.01	0.0001	0.00001
13	Multilateral Well	Yes	0.09	0.1	0.00001	0.000001
14	Multilateral Well	Yes	0.09	0.1	0.0001	0.001
15	Multilateral Well	Yes	0.09	0.08	0.00001	0.000001
16	Multilateral Well	Yes	0.09	0.08	0.0001	0.001
17	Multilateral Well	Yes	0.09	0.01	0.0001	0.00001
18	Multilateral Well	No	0.09	0.01	0.0001	0.00001

Table 5.2 Sensitivity Analysis for 18 different cases

Using the linear regression model, we are able to predict the future price after year 2017. The model was run to the year of 2036 for a period of 25 years of production.



NPV vs. Discount Rate **Figure 5.3: Linear Regression Model for Future Gas Price Prediction**

6.0 Conclusion

Below is the graph showing all 18 cases of our different model. From there, it is evident that multilateral well for Case 14 yields the highest NPV.

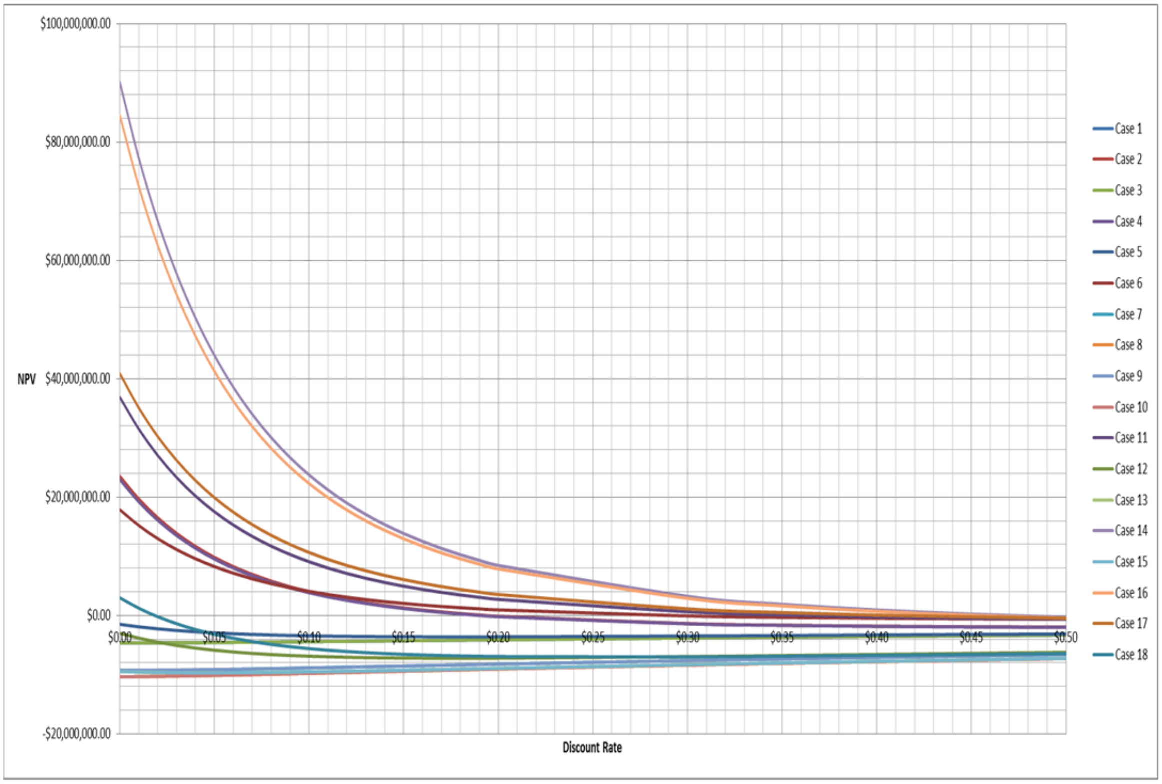


Figure 5.4: Comparison of NPV for Different Scenarios of Production

Case 14

Upon reviewed our detailed analysis, a conclusion that multilateral wells with hydraulic fracture yields the highest NPV could be derived. The minimum rate of return is also calculated to be around 42% per annum for the project to be feasible.

However, using an average of 10% for discount rate which is usually the reality, it was obtained that the date of 8/11/2015 to be the breakeven time and it is approximately 4 years.

Appendix

	1 Horizontal well					
Discount Rate	Case 5	Case 6	Case 1	Case 2	Case 3	Case 4
$0.00	-$1,494,714.95	$17,879,717.17	-$4,618,346.55	$23,565,252.57	-$4,620,191.50	$22,952,544.88
$0.01	-$1,912,142.37	$15,217,541.82	-$4,620,358.14	$19,728,392.74	-$4,621,911.15	$19,202,944.38
$0.02	-$2,251,303.87	$13,000,485.96	-$4,614,556.30	$16,549,342.82	-$4,615,870.27	$16,095,960.94
$0.03	-$2,527,199.66	$11,145,313.07	-$4,602,583.12	$13,903,369.36	-$4,603,700.53	$13,509,786.14
$0.04	-$2,751,763.28	$9,585,617.21	-$4,585,740.21	$11,691,178.87	-$4,586,695.33	$11,347,448.43
$0.05	-$2,934,523.80	$8,268,213.40	-$4,565,062.55	$9,833,429.58	-$4,565,883.10	$9,531,456.03
$0.06	-$3,083,118.38	$7,150,340.08	-$4,541,375.47	$8,266,483.31	-$4,542,084.00	$7,999,650.16
$0.07	-$3,203,690.21	$6,197,483.25	-$4,515,339.00	$6,939,105.66	-$4,515,953.88	$6,701,983.74
$0.08	-$3,301,198.76	$5,381,678.45	-$4,487,482.38	$5,809,894.15	-$4,488,018.63	$5,598,010.68
$0.09	-$3,379,662.23	$4,680,180.82	-$4,458,230.97	$4,845,266.95	-$4,458,700.95	$4,654,922.31
$0.10	-$3,442,347.82	$4,074,420.13	-$4,427,927.44	$4,017,884.62	-$4,428,341.32	$3,846,006.48
$0.11	-$3,491,921.47	$3,549,176.77	-$4,396,848.37	$3,305,407.66	-$4,397,214.59	$3,149,434.47
$0.12	-$3,530,566.14	$3,091,929.92	-$4,365,217.43	$2,689,515.02	-$4,365,542.97	$2,547,302.59
$0.13	-$3,560,075.47	$2,692,340.09	-$4,333,215.66	$2,155,126.43	-$4,333,506.35	$2,024,872.84
$0.14	-$3,581,928.24	$2,341,837.03	-$4,300,989.84	$1,689,783.94	-$4,301,250.56	$1,569,968.97
$0.15	-$3,597,347.78	$2,033,290.49	-$4,268,659.00	$1,283,158.83	-$4,268,893.83	$1,172,494.87
$0.16	-$3,607,349.44	$1,760,746.28	-$4,236,319.65	$926,656.90	-$4,236,532.04	$824,049.15
$0.17	-$3,612,778.72	$1,519,213.97	-$4,204,050.04	$613,101.70	-$4,204,242.91	$517,615.73
$0.18	-$3,614,341.93	$1,304,495.68	-$4,171,913.54	$336,479.50	-$4,172,089.34	$247,314.68
$0.19	-$3,612,630.98	$1,113,047.38	-$4,139,961.31	$91,733.18	-$4,140,122.16	$8,200.96
$0.20	-$3,608,143.42	$941,866.42	-$4,108,234.58	-$125,404.71	-$4,108,382.27	-$203,898.68
$0.30	-$3,477,843.44	-$71,409.46	-$3,808,076.92	-$1,363,111.81	-$3,808,150.96	-$1,411,149.59
$0.35	-$3,387,512.86	-$314,792.84	-$3,671,151.89	-$1,639,877.57	-$3,671,208.99	-$1,679,939.40
$0.40	-$3,293,371.16	-$472,524.19	-$3,542,899.73	-$1,809,962.37	-$3,542,945.56	-$1,844,320.84
$0.45	-$3,199,273.43	-$575,371.87	-$3,422,799.56	-$1,913,559.91	-$3,422,837.51	-$1,943,657.49
$0.50	-$3,107,191.56	-$641,629.76	-$3,310,250.27	-$1,974,011.29	-$3,310,282.46	-$2,000,812.93

2 Horizontal Wells					
Case 11	Case 12	Case 7	Case 8	Case 9	Case 10
-$2,989,429.93	$36,885,646.19	-$9,364,062.92	-$10,366,885.88	-$9,232,937.94	-$10,366,885.88
-$3,824,615.97	$31,529,732.11	-$9,340,794.19	-$10,333,318.18	-$9,237,375.56	-$10,333,416.14
-$4,503,182.74	$27,068,403.80	-$9,307,865.80	-$10,290,349.64	-$9,226,122.39	-$10,290,447.59
-$5,055,152.78	$23,334,335.82	-$9,267,220.17	-$10,239,906.10	-$9,202,473.98	-$10,239,931.88
-$5,504,409.70	$20,194,045.45	-$9,220,429.25	-$10,183,544.60	-$9,169,042.81	-$10,183,544.60
-$5,870,024.01	$17,540,632.90	-$9,168,768.19	-$10,122,527.00	-$9,127,906.18	-$10,122,527.00
-$6,167,279.26	$15,288,155.12	-$9,113,273.70	-$10,057,878.73	-$9,080,720.83	-$10,057,878.73
-$6,408,468.83	$13,367,250.18	-$9,054,790.36	-$9,990,433.83	-$9,028,811.69	-$9,990,433.83
-$6,603,516.83	$11,721,722.53	-$8,994,007.50	-$9,920,874.50	-$8,973,241.23	-$9,920,874.50
-$6,760,463.59	$10,305,868.91	-$8,931,488.67	-$9,849,755.79	-$8,914,863.46	-$9,849,755.79
-$6,885,846.45	$9,082,377.14	-$8,867,695.23	-$9,777,531.61	-$8,854,366.43	-$9,777,531.61
-$6,984,999.50	$8,020,669.44	-$8,803,005.30	-$9,704,573.51	-$8,792,305.57	-$9,704,573.51
-$7,062,290.29	$7,095,591.87	-$8,737,729.04	-$9,631,185.68	-$8,729,130.00	-$9,631,185.68
-$7,121,307.32	$6,286,374.12	-$8,672,120.97	-$9,557,617.24	-$8,665,203.43	-$9,557,617.24
-$7,165,009.12	$5,575,801.13	-$8,606,389.93	-$9,484,072.05	-$8,600,820.68	-$9,484,072.05
-$7,195,843.00	$4,949,551.22	-$8,540,707.24	-$9,410,716.79	-$8,536,220.87	-$9,410,716.79
-$7,214,698.89	$4,395,665.62	-$8,475,213.26	-$9,337,687.13	-$8,471,597.99	-$9,337,687.13
-$7,225,557.45	$3,904,121.82	-$8,410,022.80	-$9,265,093.90	-$8,407,109.31	-$9,265,093.90
-$7,228,683.87	$3,466,489.35	-$8,345,229.50	-$9,193,026.67	-$8,342,882.20	-$9,193,026.67
-$7,225,261.96	$3,075,651.26	-$8,280,909.49	-$9,121,558.06	-$8,279,019.58	-$9,121,558.06
-$7,216,286.84	$2,725,577.90	-$8,217,124.29	-$9,050,746.01	-$8,215,604.35	-$9,050,746.01
-$6,955,686.88	$631,237.88	-$7,615,668.84	-$8,385,048.53	-$7,615,542.73	-$8,385,048.53
-$6,775,025.71	$115,210.05	-$7,341,765.94	-$8,082,622.09	-$7,341,768.10	-$8,082,622.09
-$6,586,742.32	-$227,210.75	-$7,085,276.31	-$7,799,654.98	-$7,085,321.00	-$7,799,654.98
-$6,398,546.86	-$457,891.34	-$6,845,109.65	-$7,534,841.89	-$6,845,165.51	-$7,534,841.89
-$6,214,383.12	-$613,661.95	-$6,620,047.19	-$7,286,779.27	-$6,620,103.00	-$7,286,779.27

Multilateral					
Case 17	Case 18	Case 13	Case 14	Case 15	Case 16
$2,997,214.88	$40,891,865.16	-$9,458,784.78	$90,113,229.73	-$9,465,289.82	$84,496,656.92
$1,242,604.87	$35,102,699.32	-$9,558,056.37	$77,329,278.88	-$9,563,526.99	$72,539,127.50
-$198,131.26	$30,272,239.61	-$9,623,956.61	$66,683,093.73	-$9,628,580.40	$62,574,949.70
-$1,384,837.78	$26,221,884.01	-$9,663,176.16	$57,773,976.04	-$9,667,103.82	$54,231,199.41
-$2,365,136.83	$22,809,064.13	-$9,681,027.22	$50,282,360.21	-$9,684,380.26	$47,210,370.05
-$3,177,066.73	$19,919,528.82	-$9,681,741.86	$43,952,399.71	-$9,684,618.62	$41,274,199.15
-$3,851,123.93	$17,461,361.83	-$9,668,702.87	$38,578,472.73	-$9,671,183.22	$36,231,132.91
-$4,411,848.96	$15,360,327.45	-$9,644,622.96	$33,994,688.56	-$9,646,772.03	$31,926,576.28
-$4,879,062.32	$13,556,236.84	-$9,611,684.33	$30,066,698.91	-$9,613,555.40	$28,235,283.36
-$5,268,830.91	$12,000,101.28	-$9,571,647.76	$26,685,286.23	-$9,573,284.59	$25,055,397.78
-$5,594,226.24	$10,651,894.30	-$9,525,938.18	$23,761,326.10	-$9,527,376.84	$22,303,769.44
-$5,865,921.23	$9,478,786.54	-$9,475,711.97	$21,221,816.04	-$9,476,982.30	$19,912,261.68
-$6,092,661.64	$8,453,748.70	-$9,421,910.08	$19,006,734.37	-$9,423,036.84	$17,824,829.88
-$6,281,639.47	$7,554,442.16	-$9,365,300.07	$17,066,547.44	-$9,366,303.90	$15,995,202.34
-$6,438,789.92	$6,762,335.08	-$9,306,509.56	$15,360,224.93	-$9,307,407.71	$14,385,033.52
-$6,569,028.06	$6,061,995.82	-$9,246,052.82	$13,853,654.34	-$9,246,859.78	$12,962,428.28
-$6,675,298.43	$5,440,526.32	-$9,184,352.09	$12,518,370.44	-$9,185,080.05	$11,700,759.05
-$6,763,293.29	$4,887,106.12	-$9,121,754.61	$11,330,533.70	-$9,122,413.86	$10,577,714.47
-$6,834,715.70	$4,392,624.32	-$9,058,546.33	$10,270,106.37	-$9,059,145.62	$9,574,531.89
-$6,891,957.39	$3,949,381.53	-$8,994,963.03	$9,320,185.77	-$8,995,509.79	$8,675,376.18
-$6,937,032.71	$3,550,847.73	-$8,931,199.25	$8,466,463.12	-$8,931,699.82	$7,866,835.32
-$6,992,867.09	$1,116,797.57	-$8,308,196.15	$3,241,660.71	-$8,308,439.46	$2,908,109.65
-$6,887,975.81	$490,866.31	-$8,017,087.06	$1,878,425.49	-$8,017,271.81	$1,611,266.50
-$6,749,490.48	$60,938.77	-$7,742,301.44	$924,135.98	-$7,742,447.52	$703,034.10
-$6,594,735.03	-$241,469.83	-$7,483,670.10	$234,437.22	-$7,483,789.32	$46,752.62
-$6,433,247.85	-$457,391.48	-$7,240,441.84	-$276,300.05	-$7,240,541.63	-$438,839.56

Projected Future Price

1/1/2011	5.90	1/1/2013	7.01	1/1/2015	7.72	1/1/2017	8.42
2/1/2011	5.76	2/1/2013	6.75	2/1/2015	7.44	2/1/2017	8.15
3/1/2011	5.64	3/1/2013	6.48	3/1/2015	7.16	3/1/2017	7.86
4/1/2011	5.57	4/1/2013	6.31	4/1/2015	6.99	4/1/2017	7.68
5/1/2011	5.61	5/1/2013	6.34	5/1/2015	7.03	5/1/2017	7.72
6/1/2011	5.67	6/1/2013	6.41	6/1/2015	7.10	6/1/2017	7.80
7/1/2011	5.73	7/1/2013	6.47	7/1/2015	7.17	7/1/2017	7.87
8/1/2011	5.80	8/1/2013	6.54	8/1/2015	7.24	8/1/2017	7.94
9/1/2011	5.94	9/1/2013	6.69	9/1/2015	7.39	9/1/2017	8.08
10/1/2011	6.18	10/1/2013	6.93	10/1/2015	7.63	10/1/2017	8.32
11/1/2011	6.47	11/1/2013	7.19	11/1/2015	7.90	11/1/2017	8.60
12/1/2011	6.64	12/1/2013	7.36	12/1/2015	8.08	12/1/2017	8.78
1/1/2012	6.63	1/1/2014	7.34	1/1/2016	8.07	1/1/2018	8.78
2/1/2012	6.39	2/1/2014	7.08	2/1/2016	7.80	2/1/2018	8.50
3/1/2012	6.15	3/1/2014	6.82	3/1/2016	7.51	3/1/2018	8.22
4/1/2012	6.00	4/1/2014	6.65	4/1/2016	7.33	4/1/2018	8.05
5/1/2012	6.04	5/1/2014	6.68	5/1/2016	7.37	5/1/2018	8.10
6/1/2012	6.09	6/1/2014	6.75	6/1/2016	7.45	6/1/2018	8.19
7/1/2012	6.15	7/1/2014	6.82	7/1/2016	7.52	7/1/2018	8.25
8/1/2012	6.21	8/1/2014	6.89	8/1/2016	7.60	8/1/2018	8.31
9/1/2012	6.36	9/1/2014	7.04	9/1/2016	7.74	9/1/2018	8.46
10/1/2012	6.59	10/1/2014	7.28	10/1/2016	7.97	10/1/2018	8.70
11/1/2012	6.86	11/1/2014	7.55	11/1/2016	8.25	11/1/2018	8.94
12/1/2012	7.02	12/1/2014	7.73	12/1/2016	8.43	12/1/2018	9.08
1/1/2019	9.07	1/1/2021	9.65	1/1/2023	10.54	1/1/2025	11.19
2/1/2019	8.96	2/1/2021	9.71	2/1/2023	10.59	2/1/2025	11.25
3/1/2019	8.76	3/1/2021	9.64	3/1/2023	10.51	3/1/2025	11.19
4/1/2019	8.54	4/1/2021	9.48	4/1/2023	10.35	4/1/2025	11.04
5/1/2019	8.38	5/1/2021	9.32	5/1/2023	10.20	5/1/2025	10.88
6/1/2019	8.32	6/1/2021	9.23	6/1/2023	10.11	6/1/2025	10.79
7/1/2019	8.34	7/1/2021	9.22	7/1/2023	10.09	7/1/2025	10.77
8/1/2019	8.42	8/1/2021	9.26	8/1/2023	10.14	8/1/2025	10.81
9/1/2019	8.53	9/1/2021	9.35	9/1/2023	10.23	9/1/2025	10.90
10/1/2019	8.66	10/1/2021	9.47	10/1/2023	10.35	10/1/2025	11.02
11/1/2019	8.85	11/1/2021	9.68	11/1/2023	10.52	11/1/2025	11.23
12/1/2019	9.06	12/1/2021	9.92	12/1/2023	10.68	12/1/2025	11.48
1/1/2020	9.24	1/1/2022	10.15	1/1/2024	10.81	1/1/2026	11.73
2/1/2020	9.30	2/1/2022	10.25	2/1/2024	10.83	2/1/2026	11.84
3/1/2020	9.23	3/1/2022	10.20	3/1/2024	10.73	3/1/2026	11.80
4/1/2020	9.08	4/1/2022	10.05	4/1/2024	10.57	4/1/2026	11.65
5/1/2020	8.92	5/1/2022	9.89	5/1/2024	10.42	5/1/2026	11.49
6/1/2020	8.83	6/1/2022	9.79	6/1/2024	10.34	6/1/2026	11.38
7/1/2020	8.82	7/1/2022	9.76	7/1/2024	10.33	7/1/2026	11.35

8/1/2020	8.86	8/1/2022	9.80	8/1/2024	10.38	8/1/2026	11.39
9/1/2020	8.95	9/1/2022	9.89	9/1/2024	10.48	9/1/2026	11.48
10/1/2020	9.07	10/1/2022	10.01	10/1/2024	10.60	10/1/2026	11.60
11/1/2020	9.25	11/1/2022	10.19	11/1/2024	10.78	11/1/2026	11.81
12/1/2020	9.46	12/1/2022	10.38	12/1/2024	10.99	12/1/2026	12.06
1/1/2027	12.30	1/1/2029	13.81	1/1/2031	15.71	1/1/2033	17.05
2/1/2027	12.41	2/1/2029	13.98	2/1/2031	15.94	2/1/2033	17.16
3/1/2027	12.36	3/1/2029	13.97	3/1/2031	15.97	3/1/2033	17.11
4/1/2027	12.22	4/1/2029	13.83	4/1/2031	15.84	4/1/2033	16.96
5/1/2027	12.06	5/1/2029	13.66	5/1/2031	15.67	5/1/2033	16.80
6/1/2027	11.96	6/1/2029	13.54	6/1/2031	15.53	6/1/2033	16.70
7/1/2027	11.93	7/1/2029	13.50	7/1/2031	15.47	7/1/2033	16.67
8/1/2027	11.96	8/1/2029	13.52	8/1/2031	15.48	8/1/2033	16.71
9/1/2027	12.05	9/1/2029	13.60	9/1/2031	15.56	9/1/2033	16.79
10/1/2027	12.17	10/1/2029	13.72	10/1/2031	15.68	10/1/2033	16.91
11/1/2027	12.40	11/1/2029	13.98	11/1/2031	15.90	11/1/2033	17.17
12/1/2027	12.70	12/1/2029	14.32	12/1/2031	16.18	12/1/2033	17.52
1/1/2028	13.02	1/1/2030	14.69	1/1/2032	16.47	1/1/2034	17.90
2/1/2028	13.17	2/1/2030	14.88	2/1/2032	16.61	2/1/2034	18.10
3/1/2028	13.15	3/1/2030	14.89	3/1/2032	16.58	3/1/2034	18.11
4/1/2028	13.01	4/1/2030	14.75	4/1/2032	16.44	4/1/2034	17.98
5/1/2028	12.85	5/1/2030	14.58	5/1/2032	16.27	5/1/2034	17.81
6/1/2028	12.73	6/1/2030	14.45	6/1/2032	16.16	6/1/2034	17.68
7/1/2028	12.69	7/1/2030	14.40	7/1/2032	16.12	7/1/2034	17.62
8/1/2028	12.72	8/1/2030	14.42	8/1/2032	16.15	8/1/2034	17.65
9/1/2028	12.81	9/1/2030	14.50	9/1/2032	16.24	9/1/2034	17.72
10/1/2028	12.93	10/1/2030	14.62	10/1/2032	16.36	10/1/2034	17.84
11/1/2028	13.17	11/1/2030	14.90	11/1/2032	16.57	11/1/2034	18.09
12/1/2028	13.48	12/1/2030	15.28	12/1/2032	16.82	12/1/2034	18.40
1/1/2035	18.74						
2/1/2035	18.90						
3/1/2035	18.90						
4/1/2035	18.76						
5/1/2035	18.59						
6/1/2035	18.47						
7/1/2035	18.42						
8/1/2035	18.45						
9/1/2035	18.53						
10/1/2035	18.65						

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