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NEW STIMULATION TECHNOLOGIES FOR ULTRA-TIGHT GAS SANDSTONES

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ABSTRACT

Tight gas reservoirs are expected to contribute significantly to the gas and energy supply all over the world. One of the needed improvements in reservoir stimulation technology is in the advancement of fracturing fluids and techniques that can help create long and highly conductive fractures and reduce phase trapping at the face of the fracture. Introduction of aqueous based fluids in ultralow permeability sands during hydraulic fracturing decreases the effective gas permeability and ultimate gas recovery. Unfortunately most fracture fluids currently deployed are aqueous based owing to their ease of preparation and low cost. This research study aims to design a fracture treatment one that achieves a balance of minimal fluid retention, optimal fracture geometry and low cost for ultra-tight gas reservoirs.

In this paper, a dataset of reservoir properties, petrophysical properties, and fracture treatment parameters has been developed based on a complete review of published geological and engineering data of ultra-tight gas reservoir. Then based on numerical parametric studies, the effect of pertinent design factors on hydraulic fracture propagation and geometry is quantified with a fracture simulator. The factors investigated include volumetric injection rate, gel loading and proppant size. Parametric variation of seven different injection rates, seven different fracture fluids, and three different proppants was studied.

A final fracture treatment that achieves maximum fracture length, fracture width and proppant conductivity is determined to be optimal. Results from simulations show that optimal fracture

geometry and fracture conductivity based on pumping limitations is obtained at an injection rate of 100 bpm, a gel loading of 50 pptg of linear gel and a proppant size of 20/40 mesh sand.

This paper brings new understanding of fracture behavior in ultra-tight gas reservoirs and serves as a guide for improved hydraulic fracturing practices in ultra-tight gas basins throughout the United States.

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CHAPTER 1

INTRODUCTION

The exploitation of natural gas from unconventional resources is playing a more prominent role in the energy industry as the demand for energy keeps rising. Currently, coalbed seams, shales and low-permeability (tight) sandstones combined account for more than 40% of U.S natural gas supply (Haines, 2005). Natural gas found in tight gas sands and shales in the United States may contain about 460 trillion cubic feet (Tcf) of natural gas—almost three times the amount of U.S. proved gas reserves. The U.S. Geological Survey (USGS) estimates that low-permeability, deep gas have 135 Tcf of technically recoverable gas (Haines, 2005). Generally, unconventional gas resources are more difficult or less economical to extract because technology has not been fully developed or when developed too expensive to produce. High gas prices, tax incentives and/or advancement in stimulation technology are prerequisites for successful exploitation of these resources.

Tight-gas plays, often called "unconventional gas," refer to gas-bearing sandstones or carbonates with an *in situ* permeability to gas of less than 0.1 millidarcy. "Ultra-tight" gas reservoirs are a subclass of tight gas reservoirs that have *in situ* permeability as low as 0.001 millidarcy or smaller (Haines, 2005). However, no single value of permeability can be used to define tight gas sands as such a definition has little significance. The best definition of tight gas reservoirs are those that " cannot be produced at economic flowrates nor recover economic volumes of natural gas unless the well is stimulated by massive hydraulic fracture treatments, by a horizontal wellbore or by use of multilateral wellbores (Holditch, June 2006).

These reservoirs have a rock fabric consisting of inter-granular pore spaces with very small pore connections imparting very poor fluid-flow characteristics. Large volumes of gas can be stored in these rocks, and often these rocks are high in organic content and the source of hydrocarbon. However, gas flow in this type of reservoir is generally difficult. Even though tight gas sands tend to cover large areas and can support hundreds of wells, special attention must be given to the selection of sweet spots. Consideration of a lot of factors including reservoir thickness and distribution, structural position, reservoir pressures, water production and natural fractures must be weighed before a decision is taken, thus a good understanding of the subsurface is essential for effective development of tight gas sand reservoirs. Initial attempts to produce from these resources were met by very low flowrates and rapid decline.

In unconventional ultra-tight gas exploration, geologists look for basin-centered gas plays as opposed to traps and seals in conventional reservoirs. A deep basin-centered gas accumulation can become overpressured when the rate at which gas is generated is more than the rates it travels upwards by gravity. Most basin-centered are essentially water-free, with overpressured gas in low-permeability sands or shales. Such systems experience relatively high decline rates during initial production, but stabilize at very low decline rates, resulting in long life reservoirs (Haines, 2005).

Basin-centered gas systems are complex geological and petrophysical systems that exhibit heterogeneities at all scales. They have low initial water saturations and high capillary pressures, especially in deeper basins. The presence of water greatly reduces the mobility of the gas and can kill a tight-gas well. To be economic, tight-gas reservoirs are usually in a subnormal water-saturation condition. “Generally, if a tight-gas matrix is in equilibrium with a free-water contact, unless very large vertical relief is present, equilibrium water saturation reduces reserves and permeability to gas below the economic limit for production” (Haines, 2005). Gas plays with subnormal water of saturations in the United States include the Powder River Basin in

Montana/Wyoming, the Greater Green River Basin in Wyoming, the Denver-Julesburg Basin Colorado, and the Permian basin in Texas (Law, 2002).

Reservoir properties are important in selecting the best fracturing method. In shales, coals and many tight gas sands, natural fractures/fissures/cleats are the dominant flow conduits for liquids and gases (Zahid et al, 2007).These rocks are characterized by low leak off to the matrix. Because of the fissures, pressure dependent permeability and leak-off are often encountered during fracturing treatments. Fracturing fluid viscosity has a dominant influence on the leak-off to these pressure-sensitive fissures, low viscosity enhances and high viscosity diminishes leak off. Leak off enhances the potential for a wide zone of stimulation, including enhanced permeability due to shearing movements along the invaded fissure surfaces but increases the risk of proppant bridging at the fissure /hydraulic fracture nodes or intersections.

Water is used as a base fluid in most unconventional reservoir treatments. Water is economical and can be recycled especially if chemical quality control standards are broad as in waterfrac applications (Palisch, 2008). Water or slickwater fracture treatments are the most common fluid systems used today. The goal is to pump a large volume of water to create the fracture conductivity and geometry in low permeability, large net pay reservoirs. This water frac system is usually “slickened” with a polyacrylamide friction reducer or low concentration i.e. ~10 pounds per thousand gallons (pptg) linear gel to reduce fluid friction within the pipe. Unfortunately these water based fluids have low viscosity and hence poor proppant transport abilities. High injection rates can partially offset the impact of low fluid viscosities.

On the other hand, introducing a water phase into a low-permeability reservoir can lower the effective fracture half-length because of phase trapping pressure drops associated with retention of water based fluid in the formation. The problem is magnified due to the water wet-nature of most tight gas sands and becomes a major issue when ultra-tight gas sands are fractured (Zahid et al, 2007).

The goal of this research is to develop an optimum hybrid fracture fluid treatment for effective stimulation of moderate temperature ultra-tight gas reservoirs (bottom hole temperatures less than 250^{o}F).This would involve the design of new hybrid fluid systems that would best mitigate phase trapping issues, create adequate fracture geometry as well as provide reduced fluid cost for stimulation of ultra-tight gas sands.

Parametric evaluation of different fracture fluids, their rheological properties and different proppant sizes will be used to generate fracture geometries using a fracture simulator. The optimal treatment will be selected based on the highest fracture length and conductivity obtained. The future work would involve using these properties will be input into a reservoir simulator to predict gas production performance. Based on the predicted optimal recovery, a fracture treatment will be compared and analyzed.

CHAPTER 2

LITERATURE REVIEW

An important element of hydraulic fracturing is the fracturing fluid used in the fracturing treatment. The primary functions of fracturing fluids are to open the fracture, propagate the fracture and to transport propping agents i.e. proppants, along the length of the fracture. Therefore, it is easy to conclude that the rheological characteristic of the fluid is one important property of a fracture fluid. Other properties include low frictional pressure in the tubulars during pumping, low fluid leak-off into the formation, compatibility with the formation, and good cleanup properties. The fluid should also have minimum damage to the formation and proppant pack in the fracture and it should be as economical as is practical. Different fluid systems have been used over the years to meet these requirements.

Most reservoirs that are stimulated have variations in temperature, permeability, lithology, pore pressure thus the design of different fracture fluids that can stimulate these formations based on these variables is key to successful stimulation and recovery. This section will introduce fracture fluids and the different fluid systems currently employed in hydraulic fracturing.

2.1 Functions of Fracturing Fluids in Stimulation

As stated earlier, fracturing fluids perform two primary functions: open and propagate a fracture hydraulically and to transport and effectively place proppant along the fracture. Proppant refers to sand or synthetic granular materials like ceramic grains injected with the fracture fluids to prop the created fractures apart. They are collectively known as propping agents. Fluid properties, therefore strongly govern the fracture propagation behavior and placement of proppants.

Fluid viscosity is perhaps the most important property of a fracture fluid as it dictates the internal fracturing pressure and proppant carrying capacity. Fluid leakoff is another important property of a fracture fluid .Fluids that leak off rapidly into the formation during the fracturing process have a low efficiency in fracture extension and fracture width. They also result in deposition of fines in the fracture. Other desirable features that fracture fluids should possess include:

1. Good fluid loss control to obtain the required fracture extension and width with minimum fluid volumes.

2. Enough viscosity to create adequate fracture width and to effectively transport and distribute proppants in the fracture.

3. Minimal friction in the fracture.

4. Good temperature stability for the formation being stimulated.

5. Prevent swelling of clay in the formation.

6. Have low friction-loss behavior in the pipe.

7. Good cleanup and flowback behavior.

8. Cost effective.

2.2 Evolution of Hydraulic Fracturing Fluids

The first commercial fracture treatment was performed in 1949 by Halliburton Oil Service Company. The fluid used was gasoline based napalm gel frac fluids. This led to the establishment of the first primary design parameters: 1) Created fractures tend to close unless a propping agent was placed in it .2) Fracturing fluids required very high viscosities to create adequate width and proppant transport (Palisch et al, 2008).

By the late 1970's guar based linear gels and cross linked gels as well as other synthetic polymer based gels were introduced (Palisch et al, 2008). These synthetic polymers are chemical derivatives of the natural guar polymer. They include Hydroxyl –propyl guar (HPG), Carboxy methylhydroxy propyl guar (CMHPG) and Hydroxylethylcellulose (HEC).In the 1980's most operators were using these polymer frac fluids to place massive hydraulic fractures. Nevertheless, There was a massive reversal of this trend following the result of a 1997 study in East Texas Cotton Valley that purported that "we don't need no proppants" (Palisch et al, 2008).The paper suggests the use water fracture treatments over thier gel and crosslinked gel counterparts because water fracture treatments achieve the the same stimulation as a conventional fracture fluids achieve with inferior clean up at a lower cost.

A concomitant of this finding was a craze for slickwater by operators in the industry. It is estimated that slickwater fracturing composed over 40% of stimulating treatments pumped in 2004 (Cramer, 2008).The driving factors of the use of slickwater were tied to three reasons: firstly, there was a need to cut cost as commodity prices of crude oil and gas fell .Secondly, fractures generated from conventional crosslinked fluids gave “poor cleanup” due to gel residue in proppant pack and fracture face. Finally, there was the observance of a relative inefficient fracture performance compared to design expectations. Despite the popularity of water fracs, the use of slickwater as fracture fluid is not without its shortcomings as will be shown later.

2.3 Water Based Fracturing Fluids

Water-based fluids are the most widely used fluid systems by operators primarily because of their low cost, ease of preparation and handling. The simplest water fracs consist primarily of low viscosity water, friction reducers or low concentration (less than 10 pptg) and a few other additives. This fluid system is also referred to as slickwater frac . These additives are required to reduce friction and control compatibility with clay. Polyacrylamide is the major additive used to reduce friction or a while potassium chloride (KCl) and other clay stabilizers are added to prevent swelling of clay in the formation which comes in contact with water from water fracs.

Water frac treatments are usually carried out by pumping huge amounts of water to create the required fracture geometry and conductivity necessary to obtain economic recovery from low permeability reservoirs. Because of the low viscosity of water in this treatment, water fracs exhibit poor proppant transport into created fracture, quick proppant settling and narrower fracture widths compared to gel based fracture fluids. To overcome this deficiency, water fracs are designed with low proppants concentrations and are pumped at very high flowrates of about 100 barrels per minute (bpm).

The major benefit associated with the use of water fracs is the reduced gel damage potential in the fracture. The presence of unbroken gel residue after treatment has the ability to damage the proppant pack during flowback of the well. Typical gel frac treatments have a gel concentration of about 20~40 pptg of gel and metal crosslinker for crosslinked counterparts. This means that there is less degree of proppant damage due to gel residue in slickwater fracs compared to gel fracs. Despite this advantage there is concern about damage caused by the polyacrylamide friction reducer used in slickwater fracs. Also the large volume of water used in water fracs can deposit a significant amount of polymer in the fracture although not near the same levels as obtained in gel fracs (Palisch et al, 2008).

Another important advantage of water frac treatments is the cost and ease of preparation. Water fracs require far less chemicals and are much easier to handle and prepare. The fluids used can also be recycled which means higher cost savings. In areas with plentiful water supply such as in the Marcellus shale area of Pennsylvania, treatment costs are lower with water fracs. In areas where water supply is limited water fracs are more expensive. Other advantages of water fracs include an observed potential for fracture containment i.e. reduced fracture height growth and the ease of disposal of the fluid after use.

2.3.1 Disadvantages of Water Based Fluids

One of the biggest concerns regarding the use of water fracs is the poor proppant transport and placement in the fracture created. This is as a result of its low viscosity and limited ability to suspend proppants and thus transport them. Poor proppant transport is evident in both lateral and vertical coverage of the fracture. Poor lateral coverage means reduction in conductivity while poor vertical coverage indicates settling outside pay zone for thin intervals and poor height coverage for thick intervals (Sharma et al, 2004).

Water fracs also exhibit narrower hydraulic fracture width compared their crosslinked counterparts since fracture width is directly related to viscosity .Pumping at high rates may help achieve better fracture widths. Another disadvantage is the huge amount of water required for the treatment. Water fracs require tremendous amounts of water in many cases millions of gallons are required. This can be a big problem in areas of limited water supply and can lead to friction between operators and stakeholders (landowners, farmers, environmental groups etc) (Palisch et al, 2008).

Perhaps the biggest concern is its use in ultra-tight formations where leak off of the fluid can induce greater damage by causing fluid retention. Water present in small pore networks result in a high capillary pressure gradient and render gas flow immobile .This damage mechanism will be discussed in detail later in this literature review.

2.4 Linear Gel (Polymer based) Fracturing Fluids

Water-soluble based polymers can be added to water to improve its viscosity, decrease fluid loss and increase the fracture width as a result of increased viscosity. The earliest polymer used was guar-gum. Guar is a naturally occurring polymer consisting of long-chains of mannose and galactose sugars (Economides and Nolte, 1989).Polymers of sugar units are called polysaccharides and undergo hydration upon contact with water. These polymers uncoil and attach themselves with water. This interaction increases the viscosity of the mixture meeting the proppant suspending requirements for fracturing (Economides and Nolte, 1989).

Other derivatives of guar used in the industry as fracturing fluids today include hydroxypropyl guar (HPG), hydroxyethylcellulose (HEC), carboxymethyl HPG (CMHPG) and xanthum gum (REF holditch).These derivatives where introduced because of some deficiencies associated with use of guar. About 6-10% of guar is not soluble in water and results in damage causing residue. To minimize this problem guar can be derivatized with propylene oxide to produce hydroxypropyl guar (HPG), so HPG typically contains only about 2-4% insoluble residue. It is less damaging to fracture face and proppant pack than guar. Hydroxypropyl guar is more stable at elevated temperature than guar and thus suitable for high-temperature reservoir conditions. The reduction in gel residue is not beneficial for high permeability formations where gel residue is used to control fluid loss (Gidley et al, 1989).

Carboxymethyl hydroxypropyl guar (CMHPG) is another derivative of guar gum gotten from the reaction of HPG with sodium monochloroacetate. This product is only used in crosslinked applications and has no application in linear gel systems. Another linear gel system is hydroxyethylcellulose (HEC) which is used when a very clean fluid is desired. It is formed by treating cellulose with sodium hydroxide and reacting with ethylene oxide. It is considered a synthetic polymer as Guar is a natural polymer. HEC is a high viscosity polymer and yields a clear solution. But these high viscosity polymers are also costly and have difficulty in crosslinking. Xanthum gum is another viscosifier which is used as a thickener for fracturing fluids. It has applications in both linear gel systems and crosslinked fluids, but used more in drilling fluids. Its major use in stimulation is as a thickener for hydrochloric acid (Gidley et al, 1989).

Linear gels are relatively simple fluids to use and control. Excellent reproducible data are available for the viscosity of these fluids .Linear gels have two major problems the first being their insufficient viscosity to suspend proppant and the other being their temperature stability compared to crosslinked polymers. At higher temperatures above 180^0F they easily lose their viscosity

2.5 Crosslinked Fracture Fluids

Crosslinked fracturing treatments were the predominant fracture fluid system deployed by operators before the advent of slickwater fracturing, hence the name “Conventional Fracturing Treatments”. It was first used in the late 1960’s and was considered a major advancement in hydraulic fracturing technology. The use of this treatment technique has been on the decline since the advent of slickwater fracturing. However the use of this system still plays an important role in hydraulic fracturing especially for very complex low permeability pays with extreme pressures and temperature ranges where in most cases job sizes are large and fluid costs are high (Kuru, 2002). Conventional crosslinked fluids give a better predicted fracture network than their slickwater counterpart. It can be deployed either on its own or as a hybrid with water fracs (Cramer, 2008).

Crosslinked fracture treatments basically involve the use of guar based gels or synthetic polymers with either water or oil base (White et al, 1973). Crosslinking is carried out using organomettalic crosslinkers to increase the viscosity of the gel and improve its proppant transport abilities. The crosslinking reaction is one where the high molecular weight of the base polymer is substantially increased by tying together the various molecules of the polymer into a structure through metal or metal chelate- crosslinkers. The most successfully used crosslinkers are Titanium (Ti) or Zirconium (Zr) complexes. These crosslinkers serve to increase the molecular weight of the gels and consequently its viscosity dramatically (Abad et al, 2009).

The effect of crosslinking a polymer can contribute significantly to the success or failure of the treatment. Excessive crosslinking while the fluid is in the tubular can result in friction pressures that are too high and may prohibit design goals. Early crosslinking in the tubular can reduce the final gel strength and lead to screenout. On the other hand , crosslinking the gels after exiting the perforations may lead to fluids with insufficient proppant transport. **Figure 1** (Abad et al, 2009) illustrates this dilemma clearly.

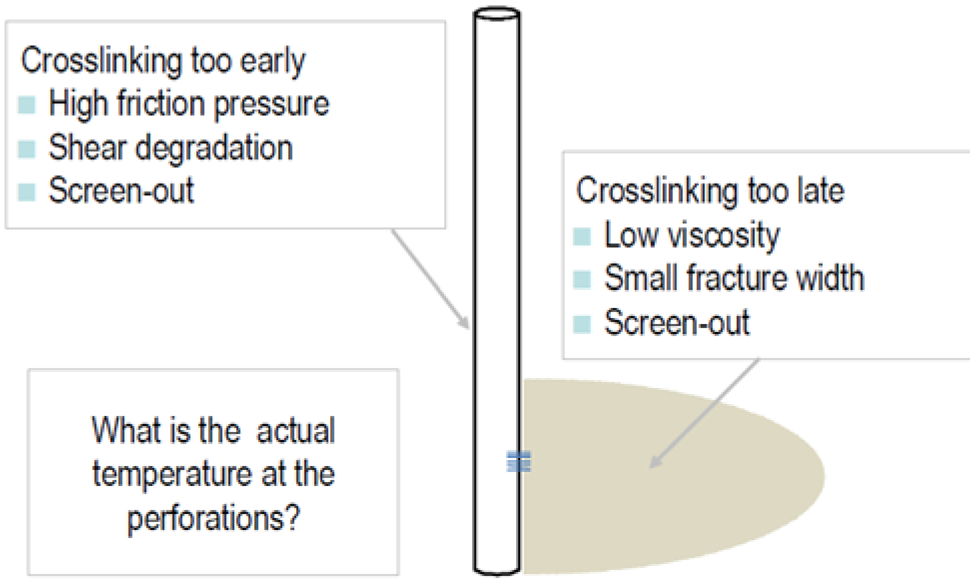

Figure 1. Effect of crosslinking time on fluid failure (Abad et al., 2009)

Determining the optimum temperature, mixture composition, tubular shear rate and transit time for optimal crosslinking has been a major challenge in the deployment of crosslinked gels. Gels have been developed that now achieve the balance between high temperature and low temperature fluid performance as well as achieve optimal crosslinking time (Abad et al, 2009).This new crosslinker is boron/manganese complex. The second metallic complex (manganese) can be combined with a compatible delay organomettalic like the boron crosslink to yield a single crosslinker package (Abad et al, 2009). This package gives the right balance and yields a crosslink that can break under shear but reform upon cessation of shear. A boron-manganese crosslinker package can be mixed with the requisite polymers, clay stabilizers and delayers and then pumped down the well as fracture fluid. This new fluid system prevents significant polymer degradation when exposed to high shear regimes which translates to maximized high temperature viscosity. An important application of this fluid system is in high temperature, low permeability reservoirs (Waalters et al, 2009)

2.6 Oil-Based Fracturing Fluids

Oil was the base fluid for the first fracturing fluids used in hydraulic fracturing. They were used primarily because of the perceived reduced damage they imparted compared to water based fluids and for their viscosity (Howard and Fast, 1970). In the 1960's the industry used aluminum salts of carboxylic acids like aluminum octoate to increase the viscosity of these hydrocarbon based fluids. Today the most common oil-based fracturing gel is a reaction product of aluminum phosphate ester and a base which is usually sodium aluminate (Malone and Anderson, 1956). Aluminum phosphate esters can be used to create fluids with enhanced stability at high temperature and good proppant carrying capacity especially in wells with a bottom hole temperature in excess of 260^0F (Hendrickson et al, 1957).Hydrocarbon based fracturing fluids have advantages over water based fluids especially in water sensitive formations .The primary disadvantages of this fluid system are the cost and fire hazards associated with its use.

2.7 Energized Fracturing Fluids

High-pressure hydrocarbon gases have been used to assist acid treatment flowback as early 1950's.The use of CO_2 and N_2 to assist flowback of treatment fluid was started in the late 1960's.This is referred to as energized fracture fluids. Energized fracturing fluids refer aqueous or hydrocarbon based fluids with a specific volume of CO_2 or N_2 gas. The energy imparted by gases enables more rapid removal of the of the fluid phase and assist in increasing the drawdown in formations with low bottom hole pressures. The entrained gas is also used to assist in fluid-loss control (Foshee and Hurst, 1965).

Careful consideration must be given to the choice used in energizing the fracture fluid. Using N_2 in small amounts without surfactant gives an inert additive that is inert and relatively immiscible in the fluid .Using CO_2 introduces a soluble reactive component to the fracturing fluid which can be converted to carbonic acid, which may be incompatible with fracturing fluids. The solubility of CO_2 becomes useful however, as the dissolved gas does not dissipate into the formation as is the case with less soluble N_2 gas. The result of the use of CO_2 gas is that stored energy is maintained in the most advantageous location. During flowback which results in reduced pressure the dissolved gas will evolve from the mixture in the fracture and contribute to a solution-gas drive which helps in removal of treating fluids (Gidley et al, 1989).

2.8 Fluid Retention and Phase Trapping

Phase-trapping effects are usually the most severe issues that plague the success of ultra-tight gas reservoirs. Since most ultra-tight gas sands fall into the classification of sub normally saturated or desiccated reservoirs, there is a huge amount of capillary pressure energy which wants to hold or imbibe a fluid in the porous media (Bennion et al, 2000). Phase trapping effects can occur in gas reservoirs in both water and hydrocarbon based fluids .In most cases the water is the wetting phase, which tends to eliminate the affinity for spontaneous imbibition of a hydrocarbon based liquid phase into the matrix surrounding the wellbore. **Figure 2** (Bennion et al, 2000) shows the relationship between water of saturation and capillary pressures for reservoirs of varying permeability. The capillary pressure decreases as the water of saturation increases but more importantly the capillary pressure increases with decreasing permeability. This illustrates the effect that increased water saturation has on very low permeability reservoirs. If a water-based fluid is introduced into the formation, a high water saturation in the flushed zone is generated and this severely impedes the flow of gas during flowback and production (Cramer, 1995). This process is more pronounced in the fracture face and reduces the conductivity of the propped pack. **Figure 3** (Bennion et al, 2000) shows the relative permeability of gas decreases with increasing water saturation. This illustrates how use of water based fracture fluids can impede gas flow during flowback and ultimate recovery fluids in stimulation of ultra-tight gas sands. Other issues that affect stimulation of ultratight gas formations include the damage on fracture conductivity packs when breakers are used to breakdown chemicals used in fracturing of ultra-tight gas sands (Warpinski, 1991).

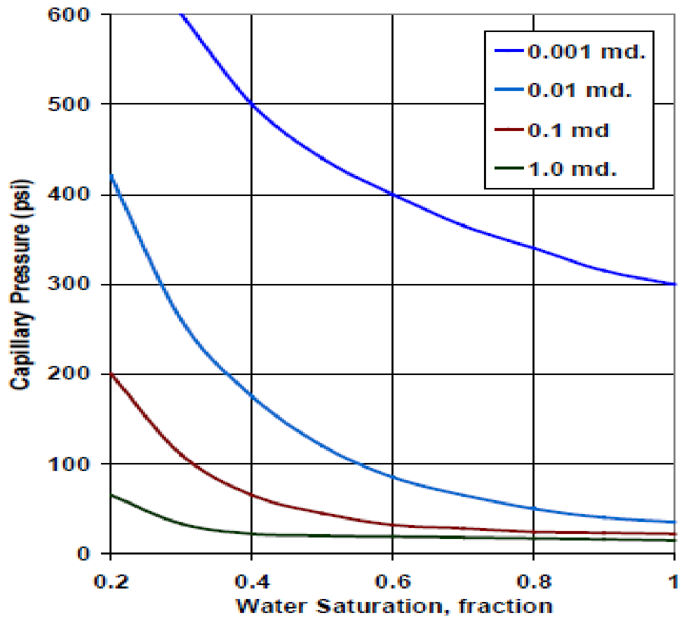

Figure 2. Effect of water of saturation on capillary pressure in low permeability sandstones

(Bennoin et al, 2000)

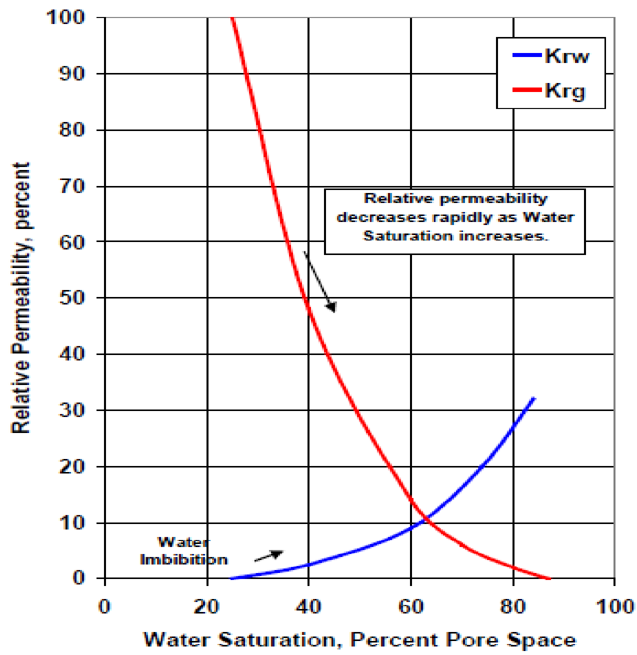

Figure 3. The effect of imbibition of water on gas relative permeability in low permeability sandstones (Bennoin et al, 2000)

An empirical equation was developed by Bennion *et al* to evaluate a reservoir's sensitivity to aqueous phase trapping (Bennion et al, 1996b). According to these authors, the aqueous phase trapping index APT_i is given by:

$$APT_i = 0.25\log k_a + 2.2\ S_{wi},$$

(Eqn .1)

Where,

APT_i = Aqueous Phase Trapping Index

k_a = uncorrected formation air permeability (md),

S_{wi} = initial (not irreducible) water.

Typical APT_i values vary from 0.3 to 1, although the lower limit may be as low as 0.**Table 1** shows the rule of thumb for interpreting APT_i values.

Table 1. APT_i Values and Associated Reservoir Characteristics (From Bennion et al, 1996b)

APT_i Range	**Reservoir Characteristics**
$APT_i > 1.00$	Formation **unlikely** to exhibit significant permanent sensitivity to aqueous phase trapping
$0.80 \leq APT_i \leq 1.00$	Formation **may exhibit** sensitivity to aqueous phase trapping
$APT_i \leq 0.80$	Formation **will likely exhibit** significant sensitivity to aqueous phase trapping

Another diagnostic equation uses the Bulk Volume water (%BVW) to estimate sensitivity to phase trapping. Bulk volume water is percentage of total volume (including rock) which is water. By comparing the bulk volume water within a given formation with water production from various fields, an estimate of water cut can be made (Davis, 2004). Average porosity and initial water saturation values gotten from well logs can be used to determine bulk volume water (BVW).

$$\%BWV=100* S_w *Ø \tag{Eqn .2}$$

Where,

%BWV = percent bulk volume water.

Ø = porosity of formation.

S_w = water saturation fraction.

Equations 1 and 2 are empirical and have exceptions especially in over-pressured reservoirs where capillary imbibitions effects are easily overcome. **Table 2** shows the rule of thumb for interpretation of BVW% values.

Table 2. Percent BVW and its effect on reservoir characteristics (From Davis and Wood, 2004)

% BVW Range	**Reservoir Characteristics**
% BWV ≥3.5	Formation **unlikely** to exhibit significant permanent sensitivity to aqueous phase trapping
3.5 ≤ %BWV≤ 2.00	Formation **may exhibit** sensitivity to aqueous phase trapping
%BWV< 0.80	Formation **will likely exhibit** significant sensitivity to aqueous phase trapping

2.9 Unconventional Fracturing Fluids

Unconventional fracturing fluids refer to novel fracture fluids recently developed and include non –polymer containing fluids such as viscoelastic surfactant fluids, methanol-containing fluids, liquid CO_2-based fluids and liquefied petroleum gas-based fluids (Gupta, 2009).These fluids have been developed to mitigate the issues associated with conventional fracture fluids and have unique properties.

2.9.1 Viscoelastic Surfactants Fluids

Ultralow permeability reservoirs require fracture treatments that combine the most recent innovations in fracturing technologies and fluid systems. Viscoelastic surfactant foams used in combination with ultralightweight proppants (ULWPs) have proven to be successful in tight gas plays (Gupta et al, 2009).

Viscoelastic Surfactant (VES) gel systems was developed as an alternative to conventional polymer/breaker fluids (Matthew et al, 2000). It is similar to those used in shampoos and liquid detergents, to develop the viscosity required to propagate fracture and transport proppant. The most commonly used formulation employs a quaternary ammonium salt with inorganic salt such as potassium chloride, ammonium chloride or ammonium nitrate. Organic salts such as sodium salicylate instead of brine can increase the high temperature performance of these fluids (Cawiezel and Gupta, 2010) .

Viscoelastic surfactant foams are well suited for ultra tight gas reservoirs because they minimize the interfacial tension and minimize the amount of water used in the fracturing fluids. Initially they were used as clean-up fluids especially in the Western Canadian Sedimentary Basin (WSCB) in 1998 (Cawiezel and Gupta, 2010).However, over time their applications spread widely in oil and gas wells in numerous fields and formations. The use of foamed surfactant gels has greatly improved the rheological and clean up characteristics of the fluid system especially in low pressure reservoirs. Foaming agents used include Nitrogen and Carbon (IV) oxide foamed treatments.

The viscoelastic surfactant fluid system is an inexpensive, logistically simple, two-surfactant based system that provides exceptionally low-shear viscosity and clean up characteristics. They do not cake wall building properties and have good retained permeability in both formation and proppant pack. Foaming of the base surfactant gel gives the fluid significant viscosity increase and leakoff control. The surfactant gels are prepared by adding a cationic surfactant and an anionic surfactant to water to form the surfactant gel. When both ionic surfactants are equal, they form a lamellar structure resulting in increased viscosity. The surfactant gel system can be foamed either with Nitrogen (N_2) or (CO_2) (Cawiezel and Gupta, 2010) .The viscosity increase from the lamellar structures can be degraded by various means. Hydrocarbon from the formation can disrupt the structure hence its viscosity. Additional water from the formation can result in dilution and viscosity decrease. Breakers can be added to control viscosity loss with time and temperature.

Optimal fracture treatments using viscoelastic surfactant gels can be achieved with ultralightweight proppants (ULWPs) (Cawiezel and Gupta, 2010).Very high gas production has been obtained from ultratight gas sands using this fluid/proppant combination .It is believed that this fluid/proppant system facilitates improved proppant placement thereby creating a significantly larger effective fracture area. Also, the use ULWP's allows partial proppant monolayer's to be placed successfully. Darrin and Huitt (1959) introduced this concept, proposing that "by reducing the proppant concentration to a partial monolayer of proppant, one could achieve a superior conductivity due to open porosity between the sparsely arranged grains" (Darin, 1959). Even though this concept is controversial and yet to be proven beyond reasonable doubt, it is believed that the use of ULWP's achieves a partially propped monolayer and thus maximizes fracture conductivity. Ultralightweight proppants can be used in a broad range of applications; temperatures of up to 275^{o}c and 8000 psi effective closure stress. Ultralightweight proppants have also proven to be very successful in slickwater fracturing treatments where poor proppant transport limits the ability to obtain the desired fracture geometry.

Different variations of this fluid system can be prepared to achieve different rheological properties. One important modification of this system is a hybrid of the surfactant gels with crosslinked gels and use of CO_2/N_2 as fluid energizer .This system had been successfully used for low pH, tight gas fields.

2.9.2 Viscoelastic Surfactant Foams

These fluids are the preferred fluid system in the fracture of ultra-tight gas sands because of their ability to minimize interfacial tension and the minimal amount of water used in its system (Cawiezel and Gupta, 2010).They are basically polymer free, two-surfactant-based systems that are an extension of VES fluid technology. Foaming the base surfactant gel provides significant increases in both viscosity and leak off control (Matthew et al, 2000). They have been successfully used in high temperature formations where temperatures can reach 250^0F (Gupta D.V.S, 2005). They are well suited to formations with potential to form water blocks as leak-off fluid surfactants, which reduce surface tension in the matrix help overcome capillary forces and help in recovery of the fluid. They have been used for the fracturing of coalbed methane wells that contain water because the foams control leak-off into the cleats without damage from polymer residue.

Breakers are required to control viscosity loss over time in VES foams. These breakers cause severe damage to packs .Also surfactant systems also migrate to the central portions of the rock matrix at the fracture face and prevent mobility of gas during production. Therefore, there is a need for advancements in water mobility and gas permeability enhancing chemicals to reduce the liquid trapping at these fracture faces (Gupta, 2009).

2.9.3 Emulsions of Carbon Dioxide with Aqueous Methanol Base Fluid

Certain formations are still sensitive to the limited water used in foams and VES foams of over 70 quality. Gupta et al. (2007) suggested that replacing 40% of the water phase used in conventional CO_2 foams (emulsions) with methanol can minimize the amount of water present (Gupta D.V.S, 2007). They showed that a 40% methanol aqueous system yielded the highest viscosity of aqueous methanol mixtures, has a freeze point close to -40^{O}C and surface tension of about 30 dynes/cm. Surfactants are used in place of conventional foamers which are methanol-compatible .A typical CO_2 quality of about 85% can give a high regained permeability and rapid clean up (Gupta D.V.S, 2007).

2.9.4 Non-Aqueous Methanol Fluids

Non-aqueous methanol fluids may be used in formations with severe aqueous and hydrocarbon trapping problems like in ultra-tight gas formations. The numerous advantages with this fluid system includes, low surface tension, low freezing point, a high solubility in water, a high vapor pressure and compatibility with formation. It makes this a fluid system of choice for formations with irreducible water and/or hydrocarbon of saturation (Bennion, 1994). The major concerns with use to methanol relate to it its safety; its low flash point, high vapor density and flame invisibility. Literature review shows that numerous authors such as Thompson *et al*. 1992 and Hernandez *et al*.,1994 have identified how this fluid system can be employed safely on the field (Thompson, 1992) and (Hernandez, 1994).

The proppant carrying ability of the fluid on its own is poor and as such viscosity has to be increased..Different means of improving the viscosity of methanol have been described in literature(Thomson *et al*.,1992;Hosasaini *et al*.,1989;Boothe and Martin ,1977;Crema and Alm,1985;and Gupta *et al*.,1997) .They range from foaming methanol to gelling with synthetic polymers(e.g polyacrymalide and polyethylene oxide) and modified guar (Gupta, 2009). Gupta *et al*., 1997 described a modified guar dissolved in anhydrous methanol crosslinked with a borate complexer and broken by an oxidizing breaker (Gupta et al, 2007). This system has been used successfully in the field. Methanol fluids energized with CO_2 and new polymers soluble compatible with both additives have   been identified. This non-aqueous gel base gel can be with borate at pseudo-high pH or with zirconium crosslinker at pseudo-low pH for CO_2 compatibility. These fluids do not require water for hydration or breaking. They should be used for selectively in gas formations with special safety considerations (Gupta, 2009).

2.9.5 Liquid Petroleum Gas Fracturing Fluids

Although slickwater fracturing is the predominant treatment system in the industry, it is not without its drawbacks. The use of water based fluids in tight gas reservoirs can result in loss of effective fracture length caused by phase trappings associated with retention of introduced water into the formation. This problem is aggravated by the water wet nature of most tight gas reservoirs (with no initial liquid hydrocarbon saturation) because of the strong coefficient of water in such situations. This retention of increased water saturation in the pore matrix can restrict the flow of produced gaseous hydrocarbon (Lestz et al, 2007).

Also, in low permeability reservoirs, capillary pressures of up to 10 to 20 MPA or higher can be present. The inability to generate enough capillary drawdown force using natural reservoir drawdown can result in extended fluid recovery times and permanent loss of effective fracture length. Moreover, the use of water in sub normally saturated reservoirs may also reduce permeability and associated gas flow through the increase in water of saturation.

Gelled Liquefied Petroleum Gas (LPG) based fracture fluids are designed to address all the aforementioned issues including phase trapping concerns by replacing the water with a mixture of LPG and volatile hydrocarbon fluid. During the flowback period of the treatment, some LPG potion is produced back as a miscible gas mixture using the gas drive mechanism. Thus by having LPG as a major part of the base fluid (80-90%) and eliminating water we have a fluid system that yields effective clean up at low permeability and pressure.

The LPG fluid system is a specially designed fracturing fluid system for gas well stimulation. It uses up to a 100% gelled LPG for the pad and flush stages. The sand slurry stages use about 90% LPG with the remaining being a volatile hydrocarbon based fluid. All the chemicals and proppant are added to the base fluid at the blender. Proppant at the blender is maintained at the maximum concentration throughout the treatment and this minimizes the volume of the resulting slurry. This fluid system provides an ideal solution for water sensitive formations provided one can recover majority of the introduced oil. Recovery of LPG itself is not a concern in this treatment because with sufficient drawdown, it will be produced as a gas. The composition of the base oil will determine the speed of the recovery. Generally, the lower the molecular weight of a hydrocarbon the more volatile it will be. However the need for volatility must be balanced with safety considerations because of the low flash point of low molecular weight hydrocarbons.

2.9.5.1 Advantages of LPG Fracture Fluids

- The fluids that are produced are all saleable eliminating the need for costly disposal and providing a revenue source to offset initial cost of treatment.
- The need for large volumes of water which is a growing concern is bypassed.
- Rapid recovery of the fracture fluids eliminates need for swabbing and thus reduces clean up costs.
- Friction pressures for gelled LPG fracture fluids are less than those for ungelled oils.
- The use of LPG fracture fluids with crosslinked surfactant gels provides a viscoelastic fluid.
- This system is not adversely affected by shear and retains the desired rheology regardless of shearing through pumping equipment, tubular and perforations.

2.9.5.2 Limitations of LPG Fracture Fluids

The following are the limitations encountered with the use of gelled liquefied petroleum gas fracturing fluids:

-Adequate consideration must be given to the safety of the LPG pumping units; this requires special LPG storage vessels

-Fracturing with LPF requires specialized laboratory equipment to carry out tests.

-LPG and base oils used are expensive (Lestz et al, 2007).

2.10 Proppants and Fracture Conductivity

Proppants are used to keep the fracture open after a treatment is complete. These highly conductive propped fractures serve as a conduit for flow of reservoir fluids from the rock matrix to the wellbore. Ideally, the proppant will provide a fracture conductivity large enough to make negligible pressure drops in the fracture during production but in reality this may not be achieved because of economic and practical concerns (Gidley et al, 1989).The propped fracture must have a conductivity at least high enough to eliminate radial flow pattern present in an unfractured well to one with a linear flow from formation matrix to the fracture expected in a fractured well. This requires unrestricted linear flow within the fracture to the wellbore and as such a propped fracture with permeability several orders of magnitude larger than that of the formation.

River sand was the first material used as proppant since the inception of hydraulic fracturing in the 1950’s (RP-56, 1983).Since then, different materials have been used. Some of the successful and commonly used propping agents include sand, resin-coated sand, intermediate strength proppant (ISP) ceramics, and high strength proppants such as sintered bauxite and zirconium oxide (Economides and Nolte, 1989).

Silica sand is the most commonly used propping material in the U.S. because of its ready availability and low cost especially in wells with low closure stress (Gidley et al, 1989).Sand in general has a wide range of particle sizes. **Table 3** shows the particle sizes of sand used in fracturing and the corresponding meshsize used in processing the sands specified by the American Petroleum Institute (API, 1983).

Table 3. API fracturing sand size designation (API 1983)

Mesh Range Designation	Range (µm)
Primary Sizes	
12/20	850 to 1,700
20/40	425 to 850
40/70	212 to 425
6/12	1,700 to 3,350
Alternates Sizes	
8/16	1,180 to 2,360
16/30	600 to 1,180
30/50	300 to 600
70/140	106 to 212

Mesh size refers to the number of openings per linear inch in the sieve, thus lower mesh size has a large particle size while a higher mesh size has smaller particle size distribution. Resin-coated sand is a type sand based proppant used for improved proppant strength. They are referred to as intermediate density proppants as they have their density requirements between sand and high density proppants like sintered bauxite. Here, sand is coated with resin with coating done to relieve the high stress caused by grain –to-grain contact. This resin is usually cured during the manufacturing process to from a nonmelting, inert film on the proppant. These resin-coated sands have a higher conductivity at high closure stresses than conventional sands (Economides and Nolte, 1989).Another type of proppant commonly used is sintered bauxite (aluminum oxide).It is significantly stronger than sand and is referred to as high-strength proppant, It is used in deep formations where high closure stresses severely crush sand. They find applications in formations at depths below the 8,000- to 10,000-ft range. Sintered Bauxite also has a higher density than sand with a density of 3.5 to 3.7 g/cc compared with 2.65 g/cc for sand.

2.11 Fracture Conductivity

Fracture conductivity or permeability refers to the measure of the fracture's ability to transmit fluids. A fracture can be visualized as two parallel plates and its "permeability' obtained by equating the driving force to drag resistance between the plates. This is represented by **equation 3**.

$$-\mu\,(hw)\frac{\partial^2 u}{\partial w^2} = \frac{\partial p}{\partial x}(hw)$$

(Eq.3)

Where *h*= is fracture height, *w* the fracture width, and *u* the velocity component in the x-direction.

For flow in a porous medium, Darcy's law states that:

$$u = -\frac{k}{\mu}\frac{dp}{dx}$$

(Eq.4)

Integrating equation 1 twice and substituting for *u* in **equation 4** we get **equation 5**.

$$k_f = \frac{w^2}{12}$$

(Eq.5)

In **Equation 5** k_f is an estimate of fracture permeability and *w* is the fracture width. After a fracture is closed, the fracture conductivity c_f is the preferred concept used by the petroleum industry .Fracture conductivity is given by:

$$c_f = k_{fl}\, w$$

(Eq.6)

Where;

k_{fl} is permeability of proppant pack

w is fracture width

As such, fracture conductivity is proportional to the cubic fracture width for an open, propped fracture (Economides and Nolte, 1989).

The purpose of the propping agent is to keep the walls of the fracture apart whilst creating a conductive path to the wellbore for flow of reservoir fluids from the matrix. Therefore, the proppant used must have conductivity large enough to eliminate any pressure losses in the reservoir. This requires unrestricted linear flow in the fracture to the wellbore and to achieve this, the fracture permeability and conductivity must be several orders of magnitude larger than that of the formation itself.

The relationship between fracture conductivity and well productivity can be expressed graphically. One useful graphical model is the Mc-Guire and Sikora chart *see* **Figure 4**. It is used for predicting performance from high productivity formations (McGuire and Sikora, 1960).

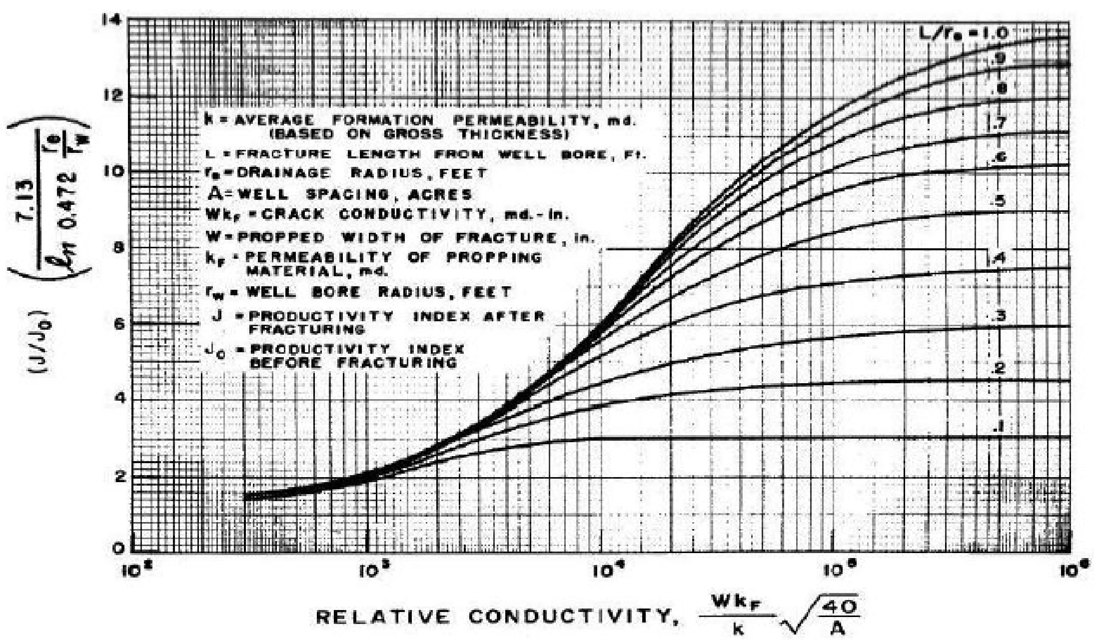

Figure 4. Increase in well productivity from fracturing (McGuire and Sikora, 1960)

Where J=Productivity after fracturing,

J_0= Productivity of unstimulated well,

r_e = effective drainage radius of well,

r_w = wellbore radius,

w = width of propped fracture,

k_f = permeability of proppant ,

k = average formation permeability,

A_d = well spacing for a square drainage area,

L = length of one wing of fracture.

J/J_0 = stimulation ratio.

$k_f\, w / k$ = conductivity ratio.

From **Figure 4**, we can determine the conductivity ratio that gives us a particular stimulation ratio. The selection of a particular proppant determines the fracture conductivity c_f and the conductivity ratio on the abscissa. Formations with high permeability values give low conductivity ratio with values on the left part of the abscissa. Stimulation benefit is achieved by changing the permeability of the proppant or increasing the width of the fracture. However, formations with low permeability such as ultra-tight gas sands have a higher value of conductivity ratio and have values on the right part of the abscissa. Stimulation benefit is achieve by increasing the length of the fracture as indicated by increases in L/r_e .

The McGuire-Sikora model assumes laminar flow regime of an incompressible fluid and pseudosteady-state flow conditions. Therefore predictions from the chart are just estimates and may require finite difference simulators to give more accurate estimates of productivity after fracturing.

2.12 Impact of Natural Fractures on Hydraulic Fracturing

Most tight gas reservoirs have some form of natural fractures system present in them. These natural fractures can be seen when samples of tight gas reservoirs are examined in thin slices under a microscope. Cramer (2008) identified three major fracture systems present in unconventional reservoirs. The first type consists of long, narrow and closely spaced pack of fractures that develop along the flanks of anticlines or fault related deformed structures. They are usually open and conductive and can dictate reservoir drainage and overall flow. A typical example is the fracture system in the Bakken Formation in west central North Dakota. A second type of fracture systems consists of reservoirs with uniform fractures that have small apertures that have been completely mineralized with calcite being the predominant mineral .This type of fracture system is present in the Barnet and Marcellus shale model. The third system is mainly characteristic of coalbed methane (CBM) reservoirs where fracture system has continuous high face permeability cleats often normal to the current minimum principal stress and discontinuous butt cleats at a sharp angle to the face cleats. These three systems each require a different completion and treatment strategy (Cramer, 2008).

Observed field diagnostic fracture injection tests have shown that the presence of natural fractures in a reservoir has affected the fluid leak-off and proppant transport in the fracture,. In injection tests, the pressure required to propagate the main fracture is used to inflate the natural fractures. This can lead to high leak off rates especially at high pump rates.   During hydraulic fracturing, as the main hydraulic fracture propagates, the pre-existing fissures tend to open. Leak-off into these fissures leads to the creation of shorter propagating hydraulic fractures. **Figure 5** shows the effect of pressure dependent leak off on fracture length for a typical tight gas formation during an injection test (Arukhe et al, 2009).

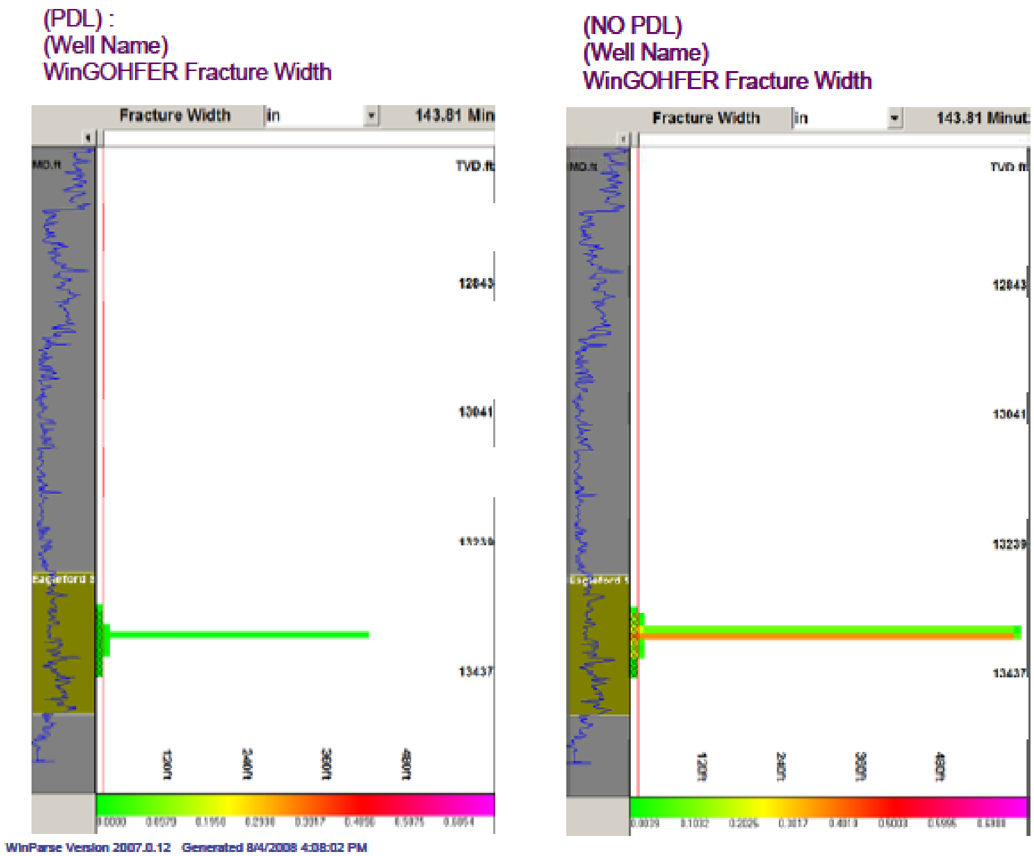

Figure 5. Pressure dependent leak off (PDL) and No PDL. (Arukhe et al, 2009)

Local high leakoff affects proppants transport and leads to early screenout. This is because pressurizing of natural fracture system causes the matrix to stiffen and this along with consumption of fluid pad leads to a high surface treating pressure (Arukhe et al, 2009).The pressurized fluid that leaks off from the main propagating fracture flows along the high conductivity channels formed by existing natural fractures. If the fluid pressures in theses natural fractures reach normal stress on the natural fractures will reopen. The leak off rate will often increase dramatically if when the pressure exceeds the critical fissure opening pressure (Arukhe et al, 2009) .When the objective of a treatment is to obtain a long conductive fracture especially for ultra-tight gas sands, it is important to prevent tip screen out of this kind as such natural fractures are detrimental to stimulation and a high volume of fluid pad is required.

However in the Barnet and Marcellus shale model, fracture complexity and areal coverage is more beneficial than a long bi-winged conductive fracture. In this model the healed fractures are believed to “reactivate” during treatment (Cramer, 2008).These fractures are usually at right angles to the current maximum principal horizontal stress (hydraulic fracture) azimuth. The use of low-viscosity slickwater can invade and widen the zone of stimulation by creating both fracture complexity and shear/slip events along the healed natural fractures. The shearing action can result in permanent misalignment and residual permeability as shown in **Figure 6.**The physics of this model requires a small contrast in the minimum and maximum principal horizontal stresses. Stimulation advantage achieved is a combination of shear enhanced formation permeability along these natural fracture networks and a limited number of propped fractures that serve as a trunk connection to natural fractures .This increases network complexity and gives a wider areal coverage. Apart from the conventional stimulation benefit of increase in effective wellbore radius, the reservoir permeability is also improved by creation of shear displacement of fluid invaded natural fracture systems (Cramer, 2008).

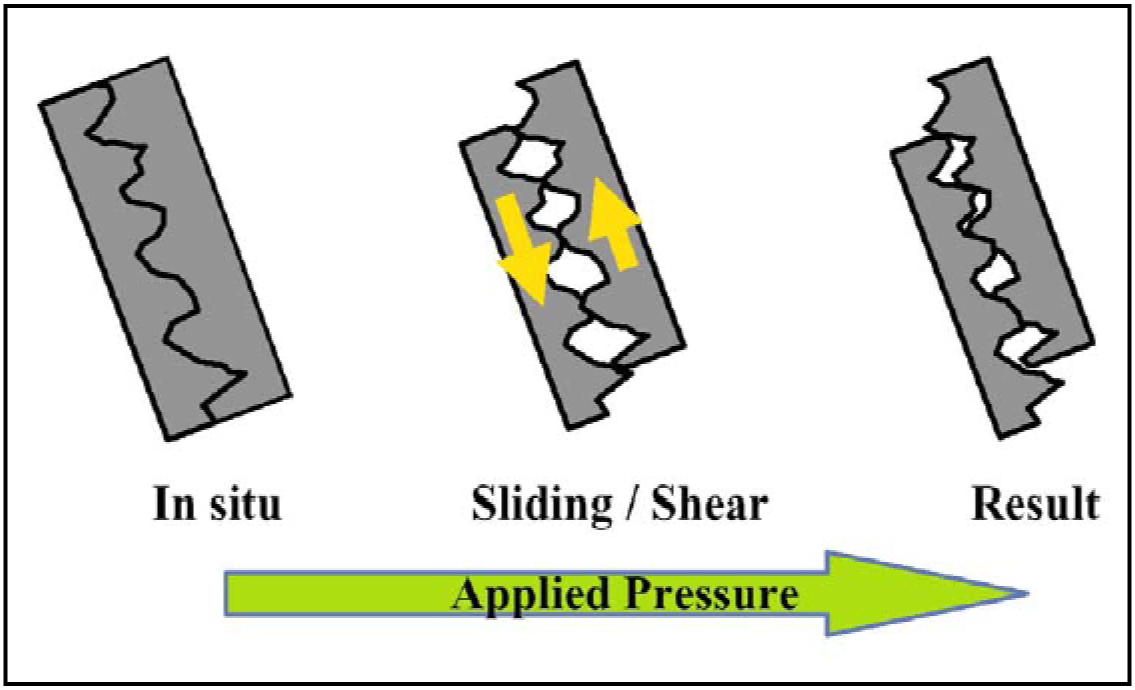

Figure 6. Shear Displacement results in Residual Permeability (Cramer et al, 2008)

2.13 Multi-Stage Hydraulic Fracturing

Hydraulic fracturing is characterized by changes of proppant concentration and fluids with time. This process is called a schedule. In most cases the first step is to pump a fluid with no proppant, this stage is called pad. The following stages are then pumped with increasing amounts of proppant and changes can be made to the fracture fluids used in each stage (Zahid et al, 2007).This process describes the multi-stage single hydraulic fracturing of a single reservoir zone thus multiple applications of frac fluid target one zone.

The term ‘Multi-stage fracturing’ may also be used to refer to the process of treating several unconnected zones or intervals in a reservoir. On such occasions, each zone becomes a distinct stage. Individual zones or multiple zones can be fractured during a treatment.

Multi-stage fracturing is often used to spur production from vertical stacked tight gas sands. Tight gas wells can encounter several intervals of gas bearing sands that need to be stimulated differently. Various staging technologies exist for fracturing of multiple intervals. Most operators need to maximize production by reducing the time required to fracture individual or multiple pay zones .One such approach is to isolate one fracture zone from another by means of bridge plugs. Bridge plugs are downhole tools that enable operators to pinpoint fracture treatments on a zone-by-zone basis. They can be retrieved by wireline or drilled out. A composite drill plug is one type of retrievable plug that is drilled out using a coiled tubing unit. Bridge plugs which allow fluid to flow past the plug are referred to as flow-through bridge plugs. **Figure 7** shows the configuration of such a plug.

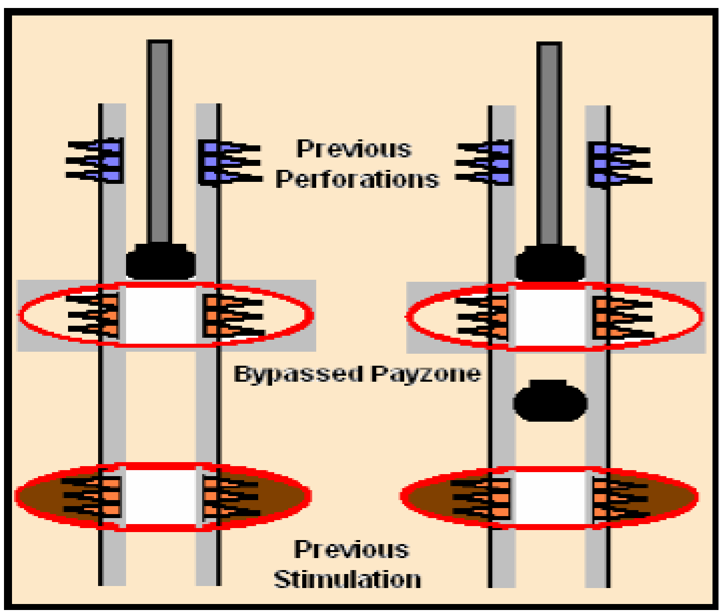

Figure 7. Single packer coiled tubing fracturing using bridge plug (Zahid et al, 2007)

The most popular is the multi-stage coiled tubing fracturing operation which uses packers to achieve zonal isolation during fracturing of each interval (Hejl, 2007). Typically a specialized packer is used for zonal isolation during fracture treatment where fluids are pumped down through either tubing of annulus depending on treatment used (Zahid et al, 2007). Packers are then used to seal fracturing fluid from regions outside the zone being treated. **Figure 8** shows a typical coiled tubing operation in multi-stage fracture treatment.

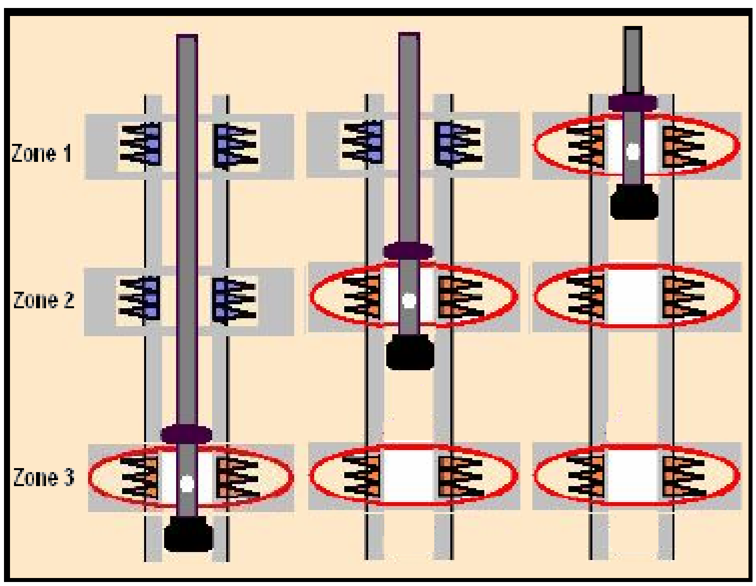

Figure 8. Multi-stage coiled tubing operation (Zahid et al, 2007)

In general, the combination of the right fracture fluid system and fracturing stages that gives a proper economic balance and best recovery is a key issue in the development of ultra-tight gas sands.

This thesis aims to design an optimal hybrid fracture fluid system that achieves a balance between low cost and effective stimulation for ultra-tight gas reservoirs. The project will focus on evaluating the effect of various fracture fluid systems on the created fracture geometries in ultra-tight sands during stimulation

CHAPTER 3

STATEMENT OF PROBLEM

3.1 Objectives of Research

The goal of this project is to develop an optimum hybrid fracture fluid treatment for effective stimulation of moderate temperature ultra-tight gas reservoirs (bottom hole temperatures less than 250^{o} F).This would involve the design of new hybrid fluid systems that would best mitigate phase trapping issues, create adequate fracture geometry as well as provide reduced fluid cost for stimulation of ultra-tight gas sands.

Evaluation of different fracture fluids, their resulting rheologies and compatibility with formation properties will be used to generate a fracture treatment that will create long extensive fractures, effective fracture conductivities whilst keeping fluid treatment cost at a minimum.

The project thesis is organized around the following research objectives:

1. Design of different fracture fluid treatments for a tight gas sand formation case study.

2. Parametric variation of rheological properties of qualifying fracture fluids and proppant size and analysis of fracture properties generated for each fluid/proppant combination.

3. Selection of a treatment that achieves the optimum fracture geometries.

3.2 Methodology

The procedure used to achieve the research objectives are:

1- Carry out a detailed literature review of all petrophysical and reservoir properties of ultra-tight gas sandstones as well as the production strategies and fracture treatments currently employed.
2- Model and simulate hydraulic fracture propagation and design fracture treatment for ultra-tight sand formations.
3- Run parametric study and quantify the effect of fracturing fluid injection rate, polymer concentration, and proppant on fracture geometry.
4- Analyze the simulated results from parametric study and recommend fracture treatment design criteria.
5- Document research findings into an M.S. thesis.

CHAPTER 4

RESERVOIR PROPERTIES FLUID PROPERTIES AND FRACTURE TREATMENT DESIGN

4.1 Fracture Design and Fracture Property Simulation

The design methodology used in this project assumes that the design calculations represent actual, quantitative fracture behavior. High speed computers can be used to solve the equations governing fracture growth and proppant transport calculations .A commercial fracture simulator (FracproPT) is used to simulate fluid design and fracture properties for this project.

Fracture design is done in the design mode of FracproPT. In this mode, users can generate a treatment schedule based on the reservoir parameters. The fluids and proppants suitable for the formation is selected and used to generate a treatment design. The user can then specify a dimensionless conductivity criterion and a pump schedule that achieves this target will be modeled. Fracture geometries and properties for the fracture treatment design is generated as simulator output.

4.2 Fracture Model used for Simulation

The behavior of hydraulic fracture growth can vary depending on the formation being stimulated. For example, in formations there is a large difference in the magnitude of horizontal principal stresses, the growth of long thin fractures in one direction is expected. FracproPT allows users to import a type of fracture growth behavior that may be unique to a certain formation.

In tight gas sandstones, extensive micro seismic fracture mappings have shown that there is more fracture height confinement than is expected from conventional confining mechanisms such as stress barriers and permeability facies (Wright et al, 1999).This phenomena as referred to as composite layering effect and was first adopted by Warpinsk et al (Warpinski, et al., 1998).This explains why it is easier for fractures to grow along layers i.e. fracture length than across layer interfaces i.e. fracture height. **Figure 9** shows a diagrammatic representation of the composite layering effect.

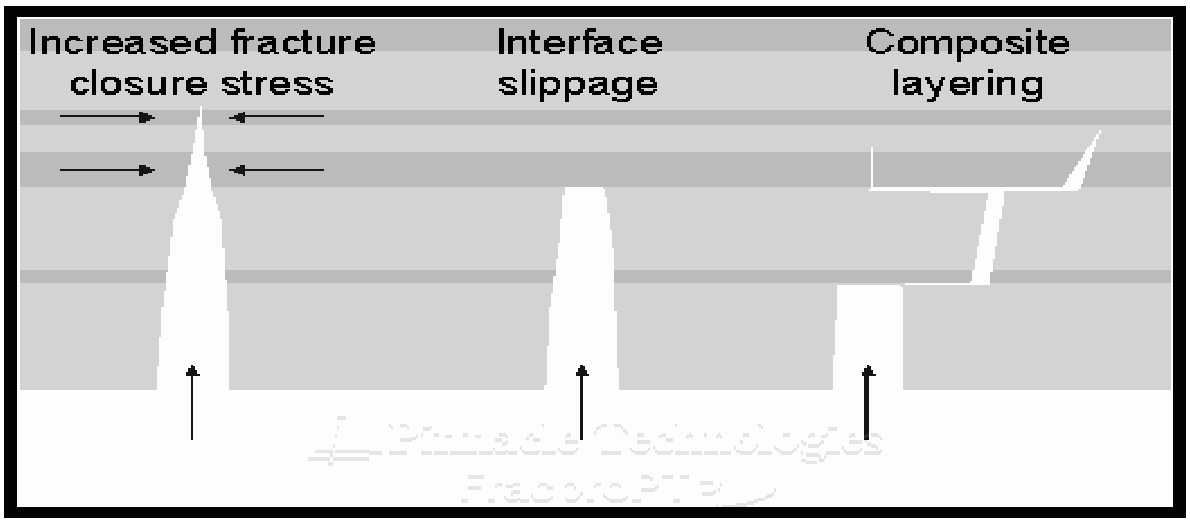

Figure 9. Diagrammatic representation of the Composite Layering Effect (,Pinnacle Technologies 2009)

In FracproPT , the 3D shear decoupled model is used to simulate this fracture growth behavior. The 3D shear-decoupled model predicts longer more confined hydraulic fractures caused by the introduction of a composite layering effect. This model is used to simulate fracture growth behavior for this research because layered tight gas sands have been shown to exhibit this behavior.

4.3 Reservoir and Petrophysical Parameters

The design and optimization of fracture treatment and prediction of fracture geometries starts with the evaluation of the reservoir to be stimulated. The reservoir properties determine the expected production response after fracturing. Reservoirs with high permeabilities do not show increase in productivity due to alteration in reservoir flow pattern. The productivity increase will be mainly due to damage correction or more aerial contact with pay zone. Low permeability reservoirs on the other hand benefit from fracturing by creation of long thin fractures. Other properties such as reservoir thickness, initial pressure etc, will also influence post stimulation response.

The reservoir parameters needed for fracture treatment design include effective permeability of pay zone (k), initial reservoir pressure (P_i), reservoir fluid viscosity (μ), reservoir fluid compressibility (C_g) and reservoir temperature (T). Other reservoir based properties include porosity (Ø), pay zone thickness (h) and fluid saturation (S_W).

Petrophysical properties refer to mechanical and chemical properties that define the lithology of the rock formation to be fractured. These properties influence the in-situ stress state of the rock, the deformation behavior of the reservoir rock and the fracture geometry of the fracture treatment. The most important mechanical properties in fracture design include Young's Modulus (E), Poisson's ratio (υ), Fracture toughness (K_{lc}), and closure stress gradient for the pay zone (σ_{Hmin}).

4.4 Reservoir Description

The formation used for this consists of a shale –sand –shale sequence. The payzone used in this formation is Almond sandstone with a reservoir permeability of 0.001 md and subsurface depth of 10,000 feet. The reservoir parameters for the ultra-tight permeability sandstone used in this study is presented in **Table 4.**The geophysical parameters for the reservoir case study is presented in **Table 5.**

Table 4. Reservoir data used for fracture design

Reservoir Parameters	
Initial reservoir pressure, psi	5811
Static reservoir temperature,^{o}F	200
Porosity, %	0.65
Net sand thickness, ft	40
Layer formation depth, ft	10,000
Permeability, md	0.001
Gas viscosity, cp	0.01
Water saturation, %	0.4
Gas gravity , dimensionless	0.7
Compressibility,psi^{-1}	0.000172

Table 5. Geophysical properties used for fracture design.

Geophysical Parameters	
Poisson's ratio, dimensionless	0.20
Young's modulus, psi	5,000,000
Toughness, psi-√in.	1000
Closure gradient, psi/ft	.8606
Average fracture gradient, psi/ft	.9105

FracproPT allows input of reservoir and petrophysical properties in the reservoir parameters page of the fracture design mode of the software. It provides a reservoir table where the layers that make up the reservoir can be defined by entering the depth to the top of each layer. All the reservoir and geophysical properties for each layer is also defined here. **Figure 10** shows a graphical representation of the three layer model showing the important geophysical properties used in this study. FracproPT was used to calculate the stress based on closure stress gradient of sandstone layer of the reservoir.

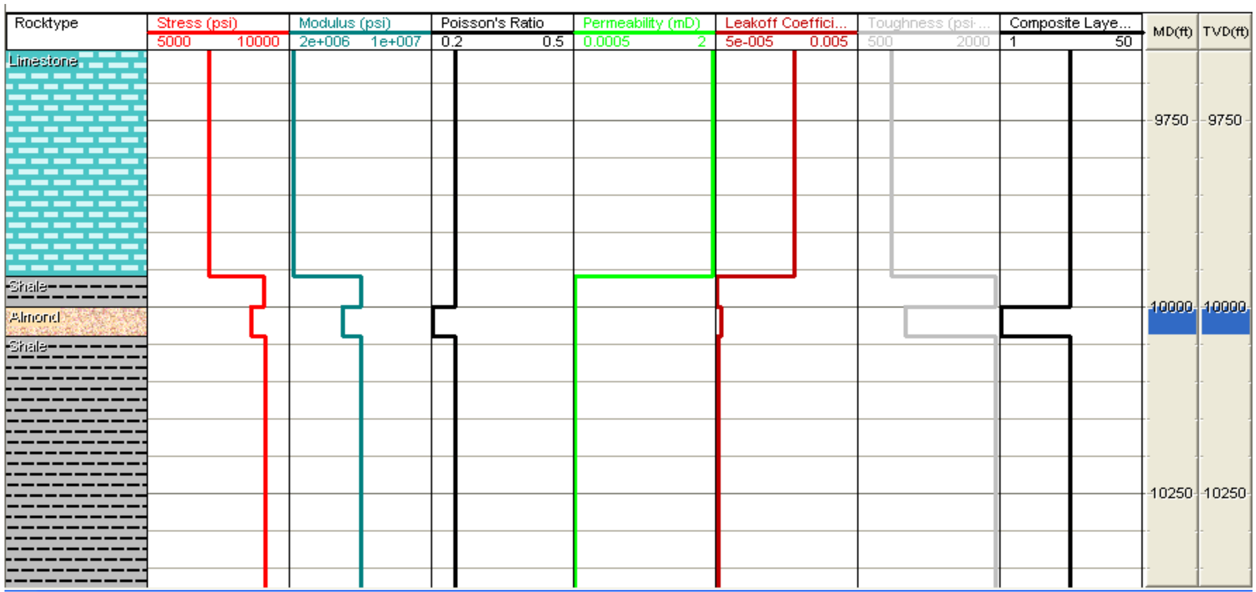

Figure 10. Graphical representation of geophysical properties of formation

4.5 Selection of Fracturing Fluid and Proppant

One of the most important aspects of fracture design is the choice of fracture fluid, additive and proppant. The choice of fluid and proppant used has major influence on the nature of propagation and geometry of the fracture .The factors that influence the choice of fluid and proppant in this project is presented in the following sections.

4.5.1 Factors that influence Fracture Fluid selection.

The major technical factors that influence the choice of fracturing fluid in any design include viscosity fluid loss, fluid friction loss, gel damage and compatibility with reservoirs. Other factors such as cost and availability are economical factors that also receive attention once the fluid meets the technical requirements for a particular stimulation job.

In this project emphasis will be placed on fluid viscosity and compatibility with rock formation. These two factors are the most important in selection of a fluid before other factors are considered. They are also the controllable parameters that determine the initial selection of fracture fluids that meet design criteria for this reservoir case study.

4.5.2 Viscosity. The viscosity of a fracture fluid affects the width and length profile of the created fracture as well as the proppant distribution in the fracture. In most designs moderate or high viscosity fluids are used because of their ability to create sufficient fracture width and proppant carrying capacity. The use of low viscosity fluids like slickwater is the predominant trend because of their low cost and availability.

At fracture flow conditions, proppants will be fully suspended if the fluid viscosity along the fracture is at least 50-100 cp during pumping (Gidley et al, 1989).On exposure to the reservoir after a pumping, the fluid can lose its viscosity allowing the proppant to settle before closure of the fracture resulting in a partially propped fracture and loss in effective fracture conductivity.

Gidley et al (Gidley et al, 1989) presented a fluid selection process based on viscosity (Gidley et al, 1989). It involves the following steps:

1. Select a fluid that meets the viscosity requirement for full proppant suspension after a specified time of exposure to the reservoir before closure of the fracture.
2. Reduce the viscosity of the fluid by decreasing the gel loading to achieve less than complete suspension yet place the treatment successfully.
3. Test lower viscosity fluids to form equilibrium banks if wider fractures are needed.

Final fluid selection is made once all other influencing factors are considered.

4.5.3 Reservoir Compatibility. Many reservoir rocks are sensitive to fluids and additives present in fracture fluids. Therefore, the sensitivity of the formation and formation fluids must be considered before the selection of a fracture fluid.

Clay containing formations are easily hydrated by water and swell. The use of aqueous based fluids can cause swelling of clay. The swelling of claying can lead to an unstable wellbore, stuck pipe and damage of the fracture by migration of fines. Fracture fluids should be selected to minimize the swelling of clay. The use of 2% KCL in water based fluids and other chemicals can prevent clay swelling.

Another factor is the precipitation of minerals, especially of iron on contact with fracture fluids .Chemical additives should be used when this is known. Oil based fluids should be used if formation is sensitive to water composition. In this study, there is a potential for clay swelling as the layers adjacent to the pay zone i.e. shale barriers contain clay. Therefore clay swelling was a factor considered in this treatment design.

4.5.4 Final Fluid Selection

The viscosity criterion used for selection of fluid for this study was: obtain 200 cp apparent viscosity at 40 s-1 after 1 hour of exposure to the reservoir temperature. The viscosity parameters for fluid selection are:

1. A minimum apparent viscosity of 50 cp.
2. A shear rate of 100 s^{-1} in the fracture.
3. An exposure time of one hour of fracturing fluid in fracture at 200 ^{o}F.

These values were input into Fracpro's fluid selection page to generate a list of potential fracture fluids. The study objective is to consider all possible fluids including low viscosity fluids like slickwater and linear gelled fluids as long as they achieve proppant placement at low costs. At this point the other factors such as cost, gel damage and fluid loss was used to narrow down the choice of fluids. This is desirable so as to avoid excessive design calculations. Emulsions and foams were eliminated because of their high treating pressures and high cost. The final group of selected fluids consists of slickwater and linear gel fluids of HPG (hydropropylguar) ranging from 10 pptg to 60 pptg of gel. The final group of fluids selected for this design is presented in **Table 6** below**.**

Table 6. Selected fluid systems and gel composition

Fluid System	**Gel Loading (pptg)**
5% Slickwater	5
10 pptg Linear Gel HPG	10
20 pptg Linear Gel HPG	20
30 pptg Linear Gel HPG	30
40 pptg Linear Gel HPG	40
50 pptg Linear Gel HPG	50
60 pptg Linear Gel HPG	60

4.5.5 Proppant Selection

The two major factors used to select proppant for this design are the proppant conductivity under stress and the damage factor as a result of gel residue. The effective permeability of proppant varies with stress. The higher the stress on the proppant, the lower its effective permeability. Proppants are selected based on its permeability at the stress in the pay zone. Proppant permeability is also dependent on gel damage and non darcy effects. Fracpro models this permeability reduction by assigning factor that accounts for damage to each proppant from both gel damage and non darcy effects. Gel damage of about 40% typical for gelled fluids can result to a total damage factor of about 20%.

Assuming a damage factor of 20% and specifying the stress in the pay zone calculated as 8624 psi, Fracpro outputs a list of proppants that achieves the highest conductivity under these conditions. The final proppant selection is presented in **Table 7.**

Table 7. Selected Proppants used in study

Proppant Type	Proppant Size	Proppant Permeability at 8624-psi Closure (md)	Total Damage Factor
Arizona Sand	12/20	73,000	0.27
Arizona Sand	20/40	78,000	0.22
Arizona Sand	40/70	43,500	0.29

4.6 Treatment Selection

The next step of fracture design process is the treatment selection. This involves an examination of the sensitivity of the hydraulic fracture growth behavior so that an optimal pump rate and maximum treatment size can be determined (Pinnacle Technologies, 2009). In FracproPT , this is achieved in two steps:

1. Specifying the desired injection rate
2. Specify the dimensionless fracture conductivity goal (***F_{CD} goal***). By setting a FCD goal you are indirectly defining a finite or infinite conductivity fracture. From literature when dimensionless fracture conductivity, $F_{CD} \geq 300\Pi$ (REF). Fracpro uses ***F_{CD} goal*** to specify this condition. In Fracpro an ***F_{CD} goal*** = 10 results in virtually an infinite conductivity fracture.

Fracpro uses these to parameters to calculate the required hydraulic fracture conductivities for different fracture half length increments. It goes on to determine the total hydraulic fracture treatment size and proppant concentration required to achieve each of these fracture half length increments.

Parametric variation of injection rate for this study is done in this step. Injection rates ranging from 20 to 100 bpm (barrel per minute) in increments of 20 bpm is input into the Fracpro treatment selection page. An ***F_{CD} goal*** of 10 (i.e. $F_{CD} \geq 300\Pi$) is specified to achieve an infinite conductivity fracture.

4.7 Optimal Treatment Selection

The next step of the fracture design process is the selection of the optimal hydraulic fracture treatment. For each fluid/proppant system and injection rate, there is a fracture length that gives highest possible hydrocarbon recovery .The optimal fracture treatment is calculated at this fracture length. The optimal fracture treatment maximizes increase in hydrocarbon production rates at a minimal cost. Economic criteria are used to determine the treatment that maximizes increase in production rates at a minimal cost. Different economic indicators are used to select the optimal treatment. Common economic indicators used are Net Present Value (NPV), Rate of return (ROR), Net Present Value to investment ratio, etc (Pinnacle Technologies, 2009).

The basic methodology for fracture treatment optimization consists of the following steps;

1. Determine the production revenues that can be obtained for step increments in fracture half-lengths, for example 25 feet increments in fracture half length, for different fracture conductivities and different drainage areas.
2. Obtain the treatment size versus fracture length for each increment in fracture half-length.
3. Estimate the treatment cost needed to obtain each treatment size.
4. Calculate the Net Present Value (NPV), the Rate of Return (ROR) or any other economic indicator chosen for each fracture half-length.
5. The maximum Net Present Value (NPV) gives the optimal fracture and corresponding optimal fracture treatment.

The fracture treatment optimization methodology is illustrated in **Figure 11.**

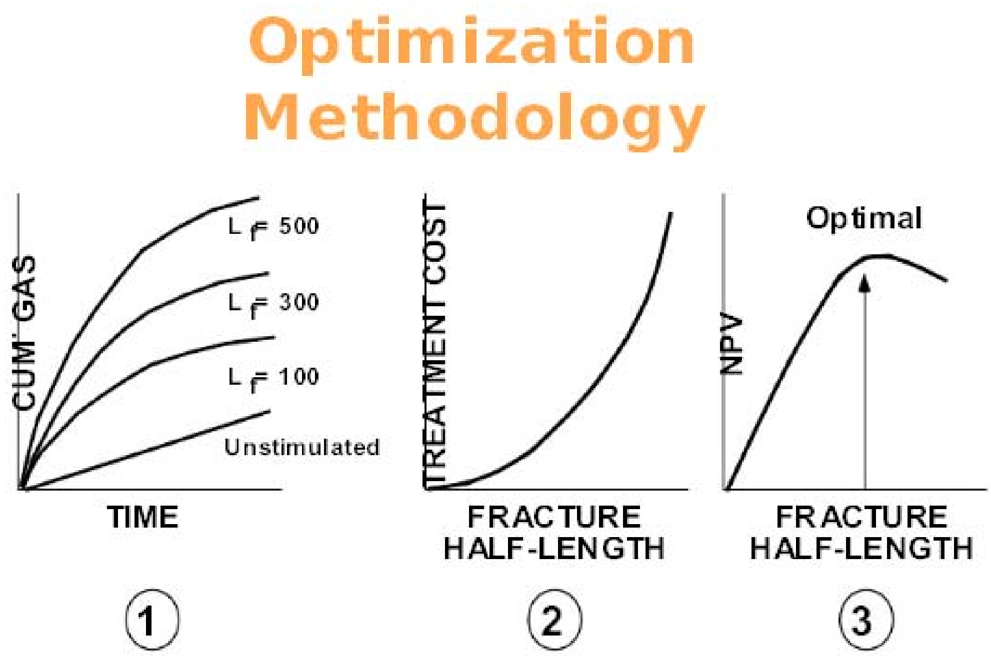

Figure 11. Diagram of basic fracture treatment optimization (Pinnacle Technologies, 2009)

For this study, economic optimization was done to define treatment cost and production revenues for the reservoir case study. Economics for the well is evaluated by setting production constraints for the reservoir case study. For this study, a total production time was set to 800 days, maximum hydrocarbon rate was set to 1,000 Mscf /day and minimum bottomhole pressure was set to 500 psi. Net Present Value (NPV) was the economic criterion used for the optimization process. These production constraints were used to select the fracture length and treatment size that gives the optimal Net Present Value (NPV).

With the selection of the optimal fracture treatment, the model is now ready to be run. The fracture simulator generates an ideal conductivity profile and iterates it to generate a effective fracture length, fracture conductivity, proppant concentration and a treatment schedule as simulator output.

4.8 Parametric Factors used for Simulator Input

Parametric variations of gel loading, injection rate and proppant size were used for this study. The approach used is to input different variations of gel loading, injection rate and proppant into the simulator. The fracture fluids used as input were selected as qualifying fluids for the reservoir by FracproPT simulator before the design simulation was run. The fluid selected was slickwater and linear gel of different gel loadings ranging from 10 pptg to 60 pptg. **Table 8** summarizes the fluids and their apparent viscosities at reservoir temperature of 200 ^{o}F used for this study as simulator input.

Table 8. Gel loading of fluids used for parametric study

Fluid System	**Apparent Viscosity at 200 ^{o}F (cp)**
Slickwater	3.22
10lb HPG Linear Gel	4.63
20lb HPG Linear Gel	6.31
30lb HPG Linear Gel	9.82
40lb HPG Linear Gel	24.23
50lb HPG Linear Gel	42.37
60lb HPG Linear Gel	66.85

Table 9 and Table 10 shows to different injection rates and proppant sizes used for this study as simulator input.

Table 9. Injection rates used for parametric study

Injection Rate (bpm)	$\mathbf{F_{CD}}$
20	10
40	10
60	10
80	10
100	10

Table 10. Proppant sizes and permeability used for parametric study

Proppant Type	**Proppant Mesh Size**	**Permeability (Darcy)**
Arizona Sand	12/20	43
Arizona Sand	20/40	35
Arizona Sand	40/70	19

The simulator output is the designed fracture geometry, conductivity and treatment schedule for each variation. The sensitivity of these fracture properties can be analyzed thereafter to make inferences and draw conclusions.

CHAPTER 5

SIMULATION RESULTS AND ANALYSES

Based on the reservoir properties, petrophysical properties and fracture treatment parameters described in chapter 4, I have carried out parametric studies and quantified the effect of pertinent factors on fracture propagation and geometries in ultratight gas reservoirs. These factors include seven different injection rates, seven different fracture fluids, and three different proppants. The simulation results will be analyzed in details in this chapter.

5.1 Effect of Volumetric Injection Rate

Simulations were run using the different fracturing fluids and injection rates and compared. The injection rates of 10, 20,40,50,60 80 and 100 barrels per minute (bpm) were tested and the corresponding propped fracture lengths were calculated for each injection rate. Results of simulated fracture length for each injection rate and gel loading is presented in **Table 1** of Appendix A. **Figure 12** shows the plot of various injection rates and simulated propped fracture lengths. For slickwater, the propped length of the fracture increased with injection rate. The same conclusions could be drawn for linear gelled fluids. As the injection rate increased, the viscous forces override the forces of gravity and the proppant placement efficiency increases.

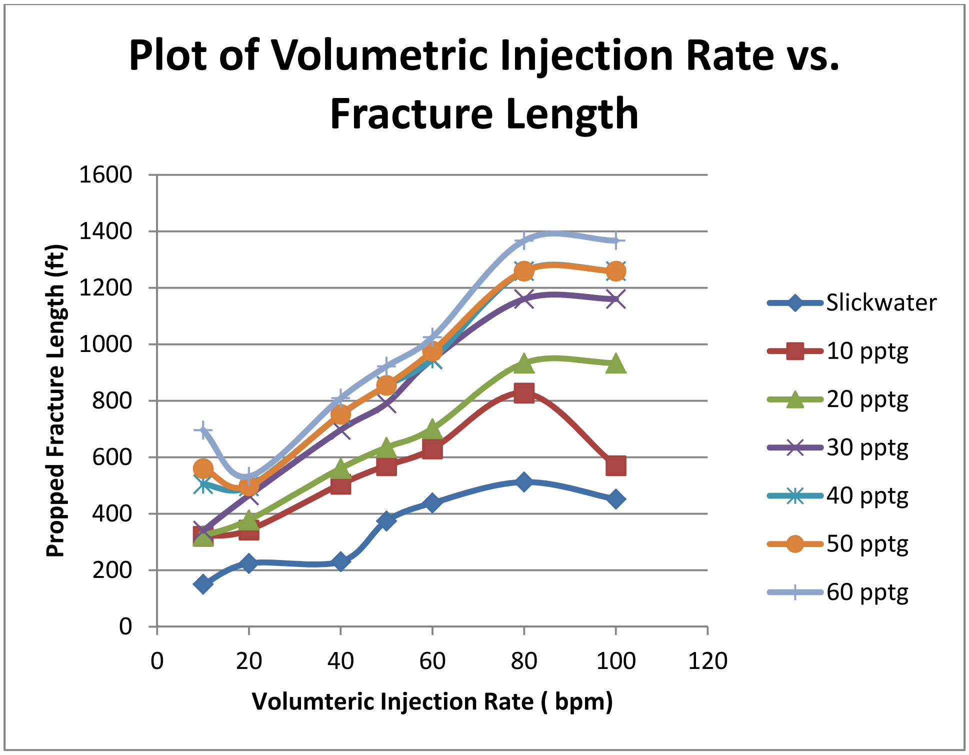

Figure 12. Plot of volumetric injection rate vs. propped fracture length

The volumetric injection rate also influences the created fracture width. **Figure 13** shows the plot of simulated fracture widths at various injection rates. It shows that the fracture width increases with injection rate. The highest fracture width results from an injection flowrate of 100 bpm .It is concluded that gelled fluids yield wider fractures than slickwater. Tabulated results of fracture width for injection rate and gel loading is presented in **Table A2.**

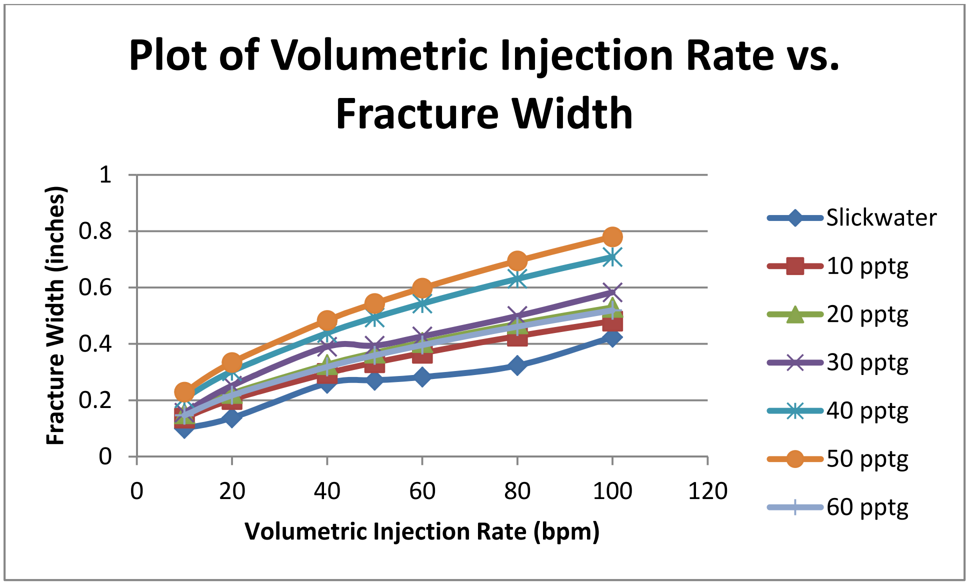

Figure 13. Plot of volumetric injection rate vs. pumped fracture width

5.2 Effect of Polymer Concentration/Gel loading

The propped fracture lengths and fracture widths were simulated for slick water and various concentrations of linear gel. **Table A.1** and **Table A.2** list the calculated fracture lengths and widths for the different fracture fluids. **Figure 14** shows the simulated propped lengths for different concentrations of linear gel and slickwater which is assumed to have no gel present i.e. 0 pounds per thousand gallons of gel. The propped length increases with gel loading. Gel loading is proportional to fluid viscosity, therefore more gel loading results in increased apparent fluid viscosity. It is observed that in low viscosity fluids i.e. fluids with < 20 pounds per thousand gallons, the propped length is shorter. In low viscosity fracturing fluids the settling rate of proppant is high. This is because the fluid does not have enough gel strength to carry proppants far into the fracture and gives shorter propped fractures. At gel loadings greater than 30 pptg a dramatic increase in propped fracture length is observed. High viscosity fluids allow little proppant settling, therefore fluid can carry proppant farther into the fracture. Propped fracture length for different for different proppant sizes are presented in **Table A.3** .

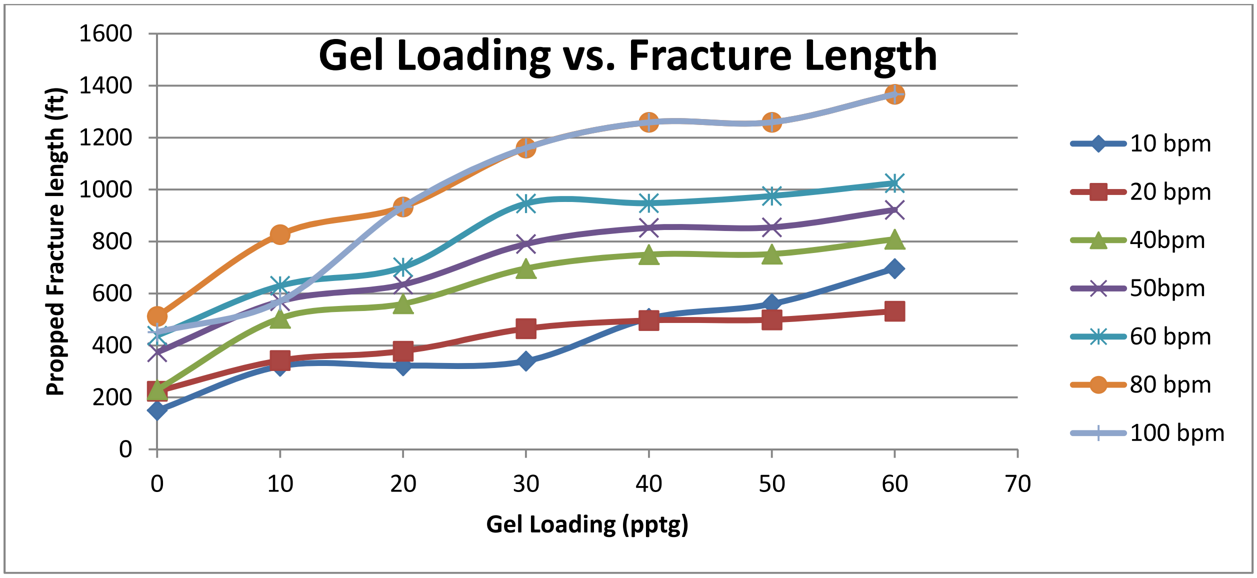

Figure 14. Plot of gel loading vs. propped fracture length

The pumped fracture widths were also simulated for the same concentrations of linear gel. **Figure 15** shows simulated fracture widths for slick water (0 pptg) and various concentrations of linear gel. It shows that fracture width is directly proportional to the gel loading of the fracturing fluids. Increasing the gel loading increases the fluid viscosity, which results in greater fracture widths. However, there is a sharp reduction in fracture width at a gel loading of 60 pptg. This is as attributed to the formation of a filter cake which reduces the effective width of the fracture.

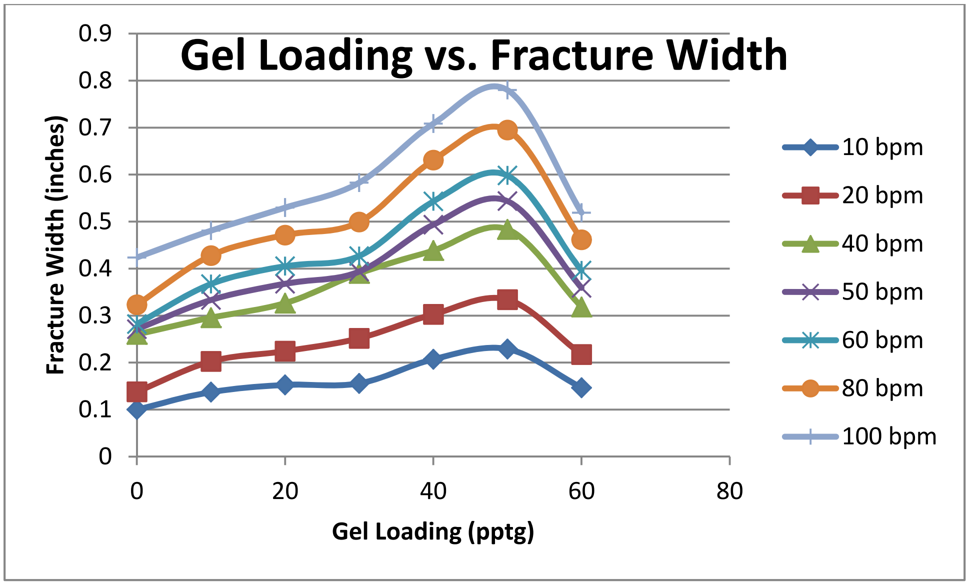

Figure 15. Plot of gel loading vs. pumped fracture width

5.3 Effect of Proppant Size

The effect of proppant size on fracture properties was also simulated in this study. The propped fracture half length at different gel loadings were simulated for various proppant sizes. The proppant sizes include 12/20 mesh, 40/70 mesh and 20/40 mesh sizes. Table A.3 and Table A.4 shows the simulated results of propped half lengths and propped fracture conductivity for the three proppant sizes at 50 bpm. **Figure 16** shows a plot of propped length vs. proppant size for different gel loadings. The 40/70 mesh proppant have a greater propped length than larger sized proppants of 12/20 mesh. This shows that smaller proppants are easier to transport deeper into the fracture than larger proppants. No simulations were run for effect of proppant size on pumped width and dimensionless fracture conductivity. The pumped fracture width is depends on fluid rheology not proppant size, while the conductivity of proppant are fixed .Larger sized proppants have greater pack permeability than smaller sized proppants.

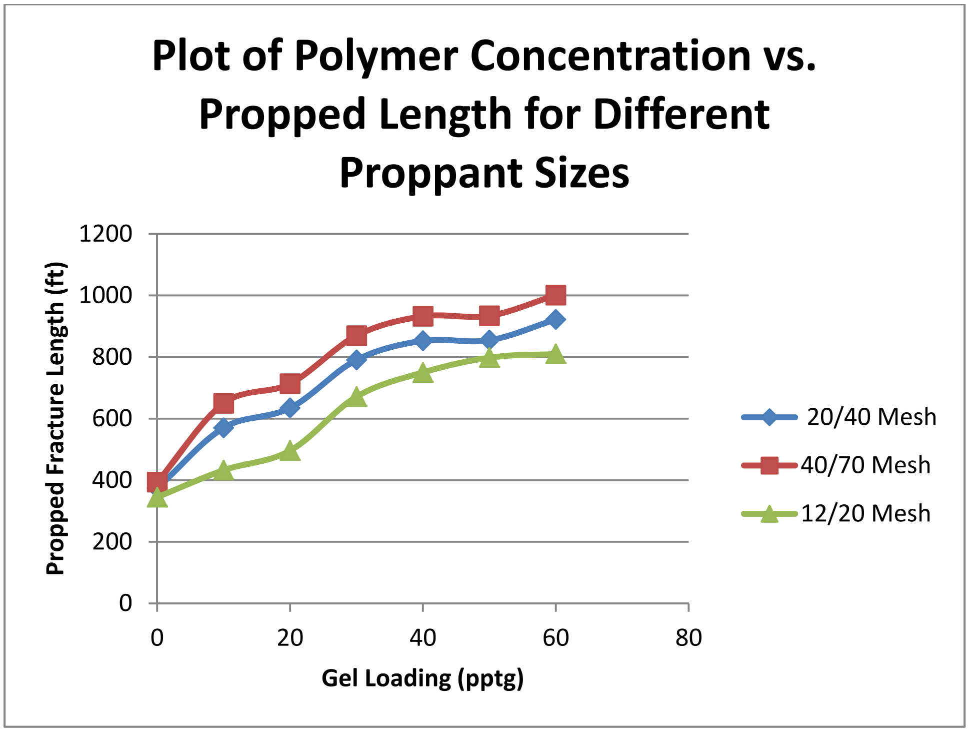

Figure 16. Plot of gel loading vs. propped fracture length for various proppant sizes.

Figure 17 shows the effect of proppant sizes on proppant conductivity for different gel loadings at 50 bpm **.** From this figure we can see that the proppant that achieves the best conductivity is the 12/20 proppant because of its large particle size relative to the 20/40 and 40/70 proppant. This trend is the same for all injection rates, since fracture width increases linearly with injection rate.

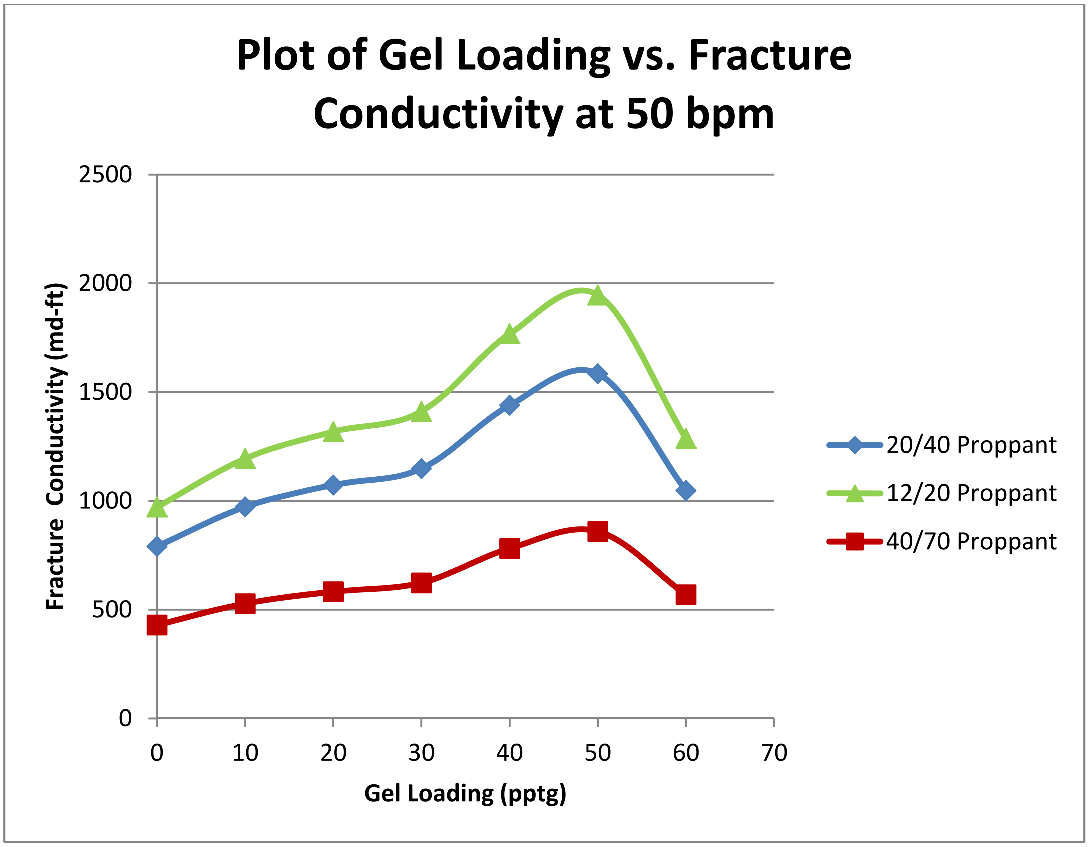

Figure 17. Plot of gel loading vs. fracture conductivity for various proppant sizes.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

A new fracture treatment for ultra-tight gas sandstones was developed. Parametric variations of rheological properties such as fluid properties and proppants were used to design an optimal fracture treatment. The following conclusions were gathered from this research.

1. The created fracture length increases with increasing volumetric injection rate.
2. Fracture width is directly proportional to volumetric injection rate .Increasing the injection rate serves to increase the net pressure, fracture volume and expands the fracture width.
3. The created fracture length is directly related to the gel loading. Increasing the gel loading increases the apparent viscosity of the fracturing fluid which in turn reduces leakoff, increases the net pressure which in turn increases the fracture length.
4. Hydraulic fracture width is directly related to the fluid viscosity gel loading. Lower gelled fracturing fluids exhibit smaller fracture widths than higher gelled fluids.
5. Increasing volumetric injection rate may serve to offset narrow fracture widths, since fracture widths are obtained by increasing the injection rate.
6. At lower gel loading (20 pptg), increasing the injection rate does not significantly increase fracture length. At higher gel loadings (40 pptg), increasing the injection rate significantly increases the fracture width.

7. Optimum fracture width is obtained at a gel loading of 50 pptg. Further increase in gel loading results in loss in fracture width because of the formation of a filter cake on fracture walls.
8. Increasing the fluid viscosity increases proppant transport. Thus longer propped fracture lengths are obtained at higher gel loadings.
9. Maximum propped fracture length is obtained at 60 pptg for any proppant size.
10. Decreasing proppant size improves proppant transport and increases the propped fracture length. A 40/70 mesh proppant has the largest propped fracture length while a 12/20 mesh size proppant has the least propped fracture length.
11. On the other hand, reducing the proppant size results in lower propped fracture conductivity. Smaller sized proppants have less permeability than larger sized proppants.
12. Optimum fracture conductivity is obtained at 50 pptg, further increase in gel loading results in reduced fracture conductivity.
13. Parametric analysis of the results suggest that the design criteria for optimal stimulation of tight gas sands is:
    - an injection rate of 100 bpm
    - a gel loading of 50 pptg of linear HPG
    - a proppant size of 20/40 mesh sand

The future work for this research project will be to input fracture properties obtained from the fracture simulator into a finite difference simulator to assess the post-fracture well performances of each treatment design. This is a more comprehensive approach to post-fracture evaluation, since finite difference simulators do not rely on pseudo-steady state assumptions. They also offer the prospect of modeling the effects of fracturing and reservoir heterogeneity. Different fracture properties and designs should be modeled to understand the well's response and help prepare better recover strategies.

This research leads to a better understanding of fracture treatments in ultra-tight gas reservoirs. The new knowledge obtained will help engineers design better fracture treatments and production strategies in the future..

NOMENCLATURE

A_d	well spacing for a square drainage area	[ft^2]
c	unit conversion factor	[0.001127]
c_f	product of fracture conductivity	[md-ft]
C_g	rock compressibility	[psi^{-1}]
E	Young's Modulus	[psi]
FCD	dimensionless fracture conductivity	[dimensionless]
h	fracture height	[ft]
J	Productivity after fracturing	[bbl/psi]
J_0	Productivity of unstimulated well	[bbl/psi]
k	average formation permeability	[md]
k_a	uncorrected formation air permeability	[md]
k_f	permeability of proppant	[md]
K_{lc}	fracture toughness	[psi-√in]
L	length of one wing of fracture	[ft]
pptg	pounds per thousand gallon	

P_i	initial reservoir pressure	[psi]
$q_{p,k}$	volumetric flowrate	[bbl/day]
r_e	effective drainage radius of well	[ft]
r_w	wellbore radius	[ft]
S	skin factor	[dimensionless]
S_w	water saturation fraction	[fraction]
S_{wi}	initial (not irreducible) water	[fraction]
T	temperature	[^oF]
u	velocity component	[ft/s]
w	width of propped fracture	[ft]
ø	porosity	[fraction]
υ	Poisson's ratio	[fraction]
µ	fluid viscosity	[cp]
σ_{Hmin}	closure stress gradient	[psi/ft]

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Appendix

SIMULATED FRACTURE PROPERTIES

Table A.1. Simulated propped fracture length (ft) for injection rates and gel loading

Injection Rate (bpm)	**Fracturing Fluids with Different loading of gel in pounds per thousand gallons (pptg)**						
	Slickwater	**10 pptg**	**20 pptg**	**30 pptg**	**40 pptg**	**50 pptg**	**60 pptg**
10	150	320	322	340	504	560	696
20	224	342.37	378	464.7	496.26	498.68	532
40	230	504.52	560.58	696.54	749.97	751.9	809
50	373.9	570.12	634.36	790.43	852.94	854.64	922
60	437.9	629.7	701.069	946.27	947.65	975.44	1024.7
80	512	827.1	933.26	1160.1	1258.9	1259.2	1367
100	451.5	570.12	933.26	1160.1	1258.9	1259.2	1367

Table A.2. Simulated pumped fracture width (in) for injection rate and gel loading

Injection Rate (bpm)	**Fracturing Fluids with Different loading of gel in pounds per thousand gallons (pptg)**						
	Slickwater	**10 pptg**	**20 pptg**	**30 pptg**	**40 pptg**	**50 pptg**	**60 pptg**
10	0.1002	0.1373	0.1526	0.1558	0.2071	0.2289	0.1465
20	0.1379	0.2027	0.2244	0.2518	0.3028	0.3342	0.2175
40	0.2601	0.2957	0.3266	0.39	0.4386	0.4835	0.3184
50	0.2711	0.3333	0.3678	0.3937	0.4934	0.5437	0.3591
60	0.2822	0.3673	0.4051	0.42681	0.543	0.5981	0.3959
80	0.3233	0.4277	0.4713	0.4991	0.6309	0.6948	0.4614
100	0.4237	0.4809	0.5297	0.5829	0.7084	0.7799	0.5191

Table A.3. Simulated propped fracture lengths (ft) for various proppant sizes at 50 bpm

Gel Loading (pptg)	Propped Length in feet for Various Proppant Size		
	12/20 Mesh	**20/40 Mesh**	**40/70 Mesh**
0	345	373.9	392.9
10	432.5	570.12	649.37
20	495.9	634.36	713.61
30	671.2	790.43	869.68
40	750	852.94	932.19
50	798.2	854.64	933.89
60	810	922	1001.25

Table A.4. Simulated propped fracture conductivities (md-ft) for various proppant sizes at 50 bpm

Gel Loading (pptg)	Propped conductivity in md-ft for various proppant Size		
	12/20 Mesh	20/40 Mesh	40/70 Mesh
0	971.4416667	790.7083333	429.2416667
10	1194.325	972.125	527.725
20	1317.95	1072.75	582.35
30	1410.758333	1148.291667	623.3583333
40	1768.016667	1439.083333	781.2166667
50	1946.466667	1584.333333	860.0666667
60	1286.775	1047.375	568.575