2013-08-20

Successful Application of Channel Fracturing in Canada in Reducing Screenout Rate

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Successful Application of Channel Fracturing in Canada in Reducing Screenout Rate

by

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A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF ENGINEERING

DEPARTMENT OF CHEMICAL AND PETROLEUM ENGINEERING

CALGARY, ALBERTA

JULY, 2013

Abstract

This thesis focuses on two areas for successful placement with a channel fracturing technique: one in Wild River multiple formations with casehole completion and the other in cardium openhole multiple stages completion. This thesis is an attempt to analyze why channel fracturing can actually reduce a screenout rate.

To do so, the thesis starts with both conventional and channel fracturing introduction, fracturing mechanism, and fracturing geometry simulation. The proppant transport mechanism horizontally and vertically is carried out to better conclude the condition that proppant can be transport without settling and bridging. Different causes of screenout are illustrated in detail. An analysis on why channel fracturing helps to reduce the screenout rate and increase successful placement is performed theoretically and then the theory is illustrated with all jobs pumped in Canada so far without screenout.

Channel fracturing by itself has advantages over conventional fracturing to ensure successful placement.

Acknowledgements

I would like to express my sincere gratitude and appreciation to my supervisor Dr. Zhangxing (John) Chen for his tremendous guidance and support, for providing the opportunity to conduct this research and excellent advice during my project.

I would also thank Dr. Brij Maini, Dr. Hassan Hassanzadeh and Dr. Mario Costa Sousa for serving on my examination committee.

I am very grateful to Fred Boyko and Peter Rottler for all the support and help on this project and for allowing me to use Schlumberger FracCADE Software and treatment data to perform the simulation and evaluation.

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List of Symbols, Abbreviations and Nomenclature

Symbol	Definition
A	An element of the fracture area (ft^2)
C_c	Fluid leakoff coefficient in reservoir zone ($ft/min^{0.5}$)
C_L	Total fluid-loss coefficient ($ft/min^{0.5}$)
C_t	Total compressibility (1/psi)
C_v	Fluid leakoff coefficient in filtrate zone ($ft/min^{0.5}$)
C_w	Fluid leakoff coefficient in wall filter cake ($ft/min^{0.5}$)
d	Least dimension of the fracture length and height (ft)
d_{prop}	Median proppant particle diameter (in)
E	Static young's modulus (psi)
E'	Plane strain modulus (psi)
F_H	Horizontal force (N)
F_V	Vertical force (N)
frac	Fracture, fracturing
g	Gravitational acceleration (32.174 ft/s^2)
h_f	Fracture height growth (ft)
h_L	Permeable fracture height (ft)
k	k prime of power law fluid
K	Bulk moduli of the rock constituents (grains) (ksi)
K_{cake}	Filter cake permeability (md)
K_{fil}	Filtrate permeability (md)
K_r	Reservoir rock permeability (md)
Ks	Bulk moduli of the rock bulk (ksi)

Symbol	Definition
L	Fracture half length (ft)
n	n prime for power law fluid
Nc'	Dimensionless value, ratio of proppant horizontal force vs. vertical force
P_b	Breakdown pressure (psi)
P_{bh}	Bottomhole pressure (psi)
P_c	Closure pressure (psi)
P_{ext}	Fracture extension pressure (psi)
P_{frac}	Fracturing pressure (psi)
P_h	Hydrostatic pressure (psi)
P_{ISIP}	Instantaneous shut-in pressure (psi)
$P_{near\ wellbore}$	Total near-wellbore pressure loss (psi)
P_{net}	Net pressure (psi)
P_0	Formation pore pressure (psi)
P_{perf}	Perforation friction pressure (psi)
P_{surf}	Surface treating pressure (psi)
P_{tf}	Tubular friction pressure (psi)
P_{tip}	Pressure required at the fracture tip to open new fracture area and keep the fracture propagating forward (psi)
P_{tort}	Tortuosity pressure (psi)
q	Injection rate divided by height (bbl/min/ft)
q_i	Total injection rate at time i (bbl/min)
S_p	Spurt loss (gal/100ft^2)
q_L	Fluid loss rate to formation (bbl/min)
$SG._{Prop}$	Proppant specific gravity
$SG._{Fluid}$	Fluid specific gravity
S_h	Minimum horizontal stress (psi)
S_H	Maximum horizontal stress (psi)

Symbol	**Definition**
S_V	Overburden stress (psi)
t	Time measured from the start of pumping (min)
t_p	Pumping time for a treatment (min)
T	The time when each small area element of a fracture is created and open (min)
Ŧ	Shear stress (lb/ft^2)
U	Slurry horizontal velocity (ft/s)
μ	Fracturing fluid viscosity (cp)
μ_{fil}	Filtrate viscosity (cp)
μ_{fluid}	Fluid viscosity, centipoises (cp)
μ_r	Reservoir fluid viscosity (cp)
V	Proppant settling velocity (ft/s)
Vt	Slurry final settling velocity (ft/s)
w	Fracture width (in)
w_{max}	Maximum fracture width (in)
$\Delta\rho$	Density difference between fluids injected and fluid in slot (lb/gal)
ΔP_c	Pressure drop between the filtrate/reservoir interface and the far-field reservoir (psi)
ΔP_{Cake}	Pressure drop across the filter cake (psi)
ΔP_v	Pressure drop across the filtrate zone (psi)
$\Delta\sigma$	Stress difference between layers (psi)
α	Ratio of fluid volume to cake thickness
α_b	Biot's constant
ϕ	Reservoir porosity (%)
σ_{ext}	Tectonic stress (psi)
ρ_{prop}	Proppant density (lb/gal)

Symbol	**Definition**
ρ_{fluid}	Fluid density (lb/gal)
κ	Constant
γ	Shear rate (sec^{-1})
Γ	Tensile strength of the rock (psi)
τ	The time when each small area element of a fracture is created and opened (min)
ν	Poisson's Ratio
η	Poroelastic Coefficient

CHAPTER ONE: INTRODUCTION

Hydraulic fracturing being the inevitable technology to unlock the potential of unconventional oil and gas reservoirs is more and more important nowadays due to the diminishing of conventional reservoirs. The purpose of hydraulic fracturing is to create a high conductive path or network to increase connectivity between a reservoir and wellbore so oil and gas can flow at an economic rate to wellbore. Due to the complexity of hydraulic fracturing mechanisms, lack of data for better design, and unpredicted stress field conditions, screenout is always a concern. Technically, screenout refers to a condition where continued injection of a fluid inside the fracture requires pressure in excess of the safe limitations of the wellbore or wellhead equipment. Screen out will happen when there is proppant pumped and never happened without proppant (Daneshy, 2011). This issue becomes more costly when it comes to horizontal multiple stages completion. Screenout can result in non productive time and additional standby cost on operators, and skip some zones or even loss of some portion of the horizontal wellbore. While completion engineers are always looking for a better solution to reduce the risk of screenout, channel fracturing seems a proven technique to help operators to achieve the goal. Channel fracturing is an invention compared to conventional fracturing by creating proppant pack (pillar) supported channels to allow oil and gas flow through highly conductive channels that help a reservoir to connect with wellbore dramatically. Figure 1.1 illustrates the difference of the two fracturing techniques. While production increased by channel fracturing is already observed and studied intensively, this thesis will focus on the fact that the channel fracturing technique also helps to reduce the risk of screenout in Canada.

Successfully placing all designed amount of proppant is not always achievable, and a failure rate of hydraulic fracturing jobs varies. From observed facts the channel fracturing technique is capable in helping proppant placement. This thesis is an attempt to analyze why the channel fracturing technique can help reduce a screenout rate. In chapter one, the author will first introduce hydraulic fracturing and channel fracturing mechanisms in general from all aspects related to job placement. The mechanisms include breakdown pressure definition, orientation of hydraulic fracturing, fracturing geometry, fluid leakoff and fluid rheology.

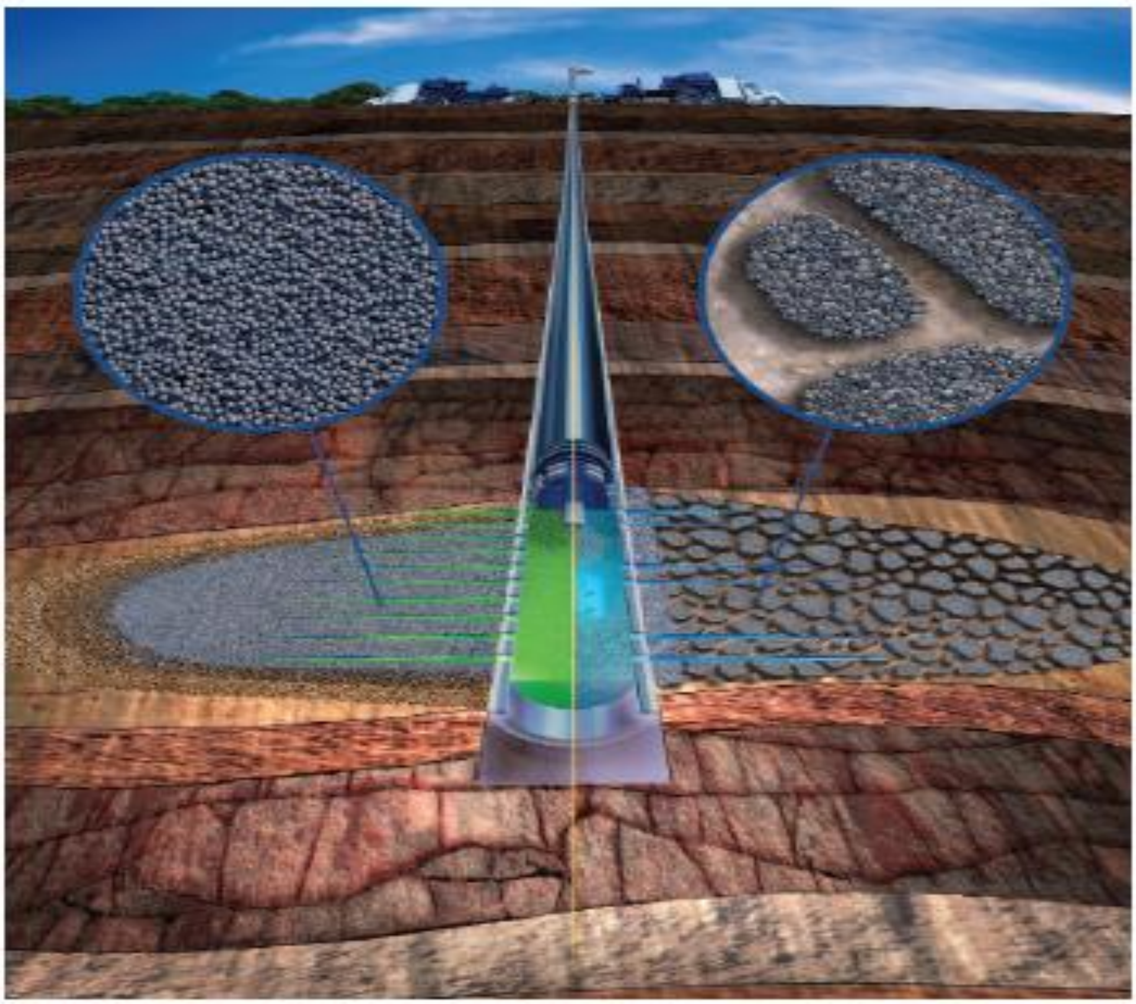

Figure 1.1: Conventional fracturing (left) and channel fracturing technique (right) (Courtesy of Schlumberger)

1.1 CONVENTIONAL HYDRAULIC FRACTURING

Hydraulic fracturing treatment is achieved by pumping a clean fluid called Pad first, when the fluid volume pumped from surface is bigger than the volume leaks into formation, pressure accumulated in fluid will break formation rock and initiate fractures (Economides, et al., 2000). After fractures are initiated, more pad fluid will be pumped into formation; as long as fluid leaks off into formation is less than what is injected from surface, fractures will extend. But if nothing is injected rather than a fluid, once stopping pumping, the fluid will leak into a reservoir and there is nothing inside fractures to keep them open, so fractures will close leaving very low to non-conductive fractures for gas or oil to flow. That is why proppants are needed after pad created fractures to support them. "*A proppant is a solid material, typically treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment*" (Wikipedia). The fluid carrying proppants is called a slurry fluid (Economides, et al., 2000). Proppants are normally added from low concentration to high concentration, which is called at different sand stages.

For conventional hydraulic fracturing, in slurry stages, proppants can be pumped either by ramp up which means proppant concentration increases continuously until all proppants are pumped as the green line in Figure 1.2. Or proppants can be pumped as a stair step which is achieved by holding proppant concentration for some time and then going to higher concentration as the green line in Figure 1.3. Both figures are real jobs pumped, red line is treating pressure, light blue line is 10% of pump rate so it can be placed on the same Y-Axis as treating pressure. Proppant concentration is the concentration measured at surface from blender and proppan con (BH) is propant concentration at reservoir condition. If there is no nitrogen or CO2 gas added to fracturing fluid, or in another word, proppant is not diluted downhole, proppant concentration and proppant concentration BH should be the same. However, if either nitrogen or CO2 is pumped as part of fracturing fluid, because the gas is added after proppant is mixed with fracturing fluid, so it shows difference between the two concentrations and bottomhole proppant concentration is lower because addition of nitrogen or CO2. More nitrogen or CO2 added, more difference of the two concentrations.

Independent how proppant concentration is changed for traditional hydraulic fracturing, in slurry stages, proppants are always mixed homogeneously with a carrying fluid at certain concentration.

After slurry stages, because wellbore is full of slurry, a clean fluid will be pumped to replace slurry in wellbore and push it down to formation; this fluid is called a flush fluid.

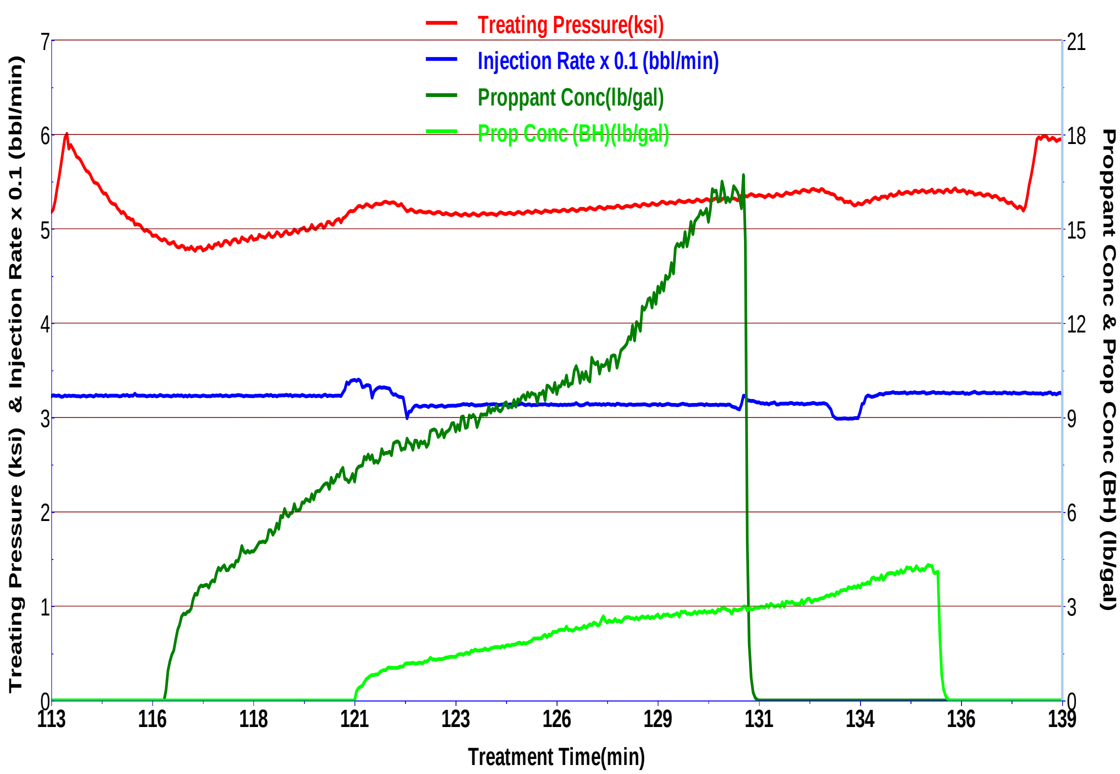

Figure 1.2: Continuously ramp-up proppant concentration illustration (Treatment data from Schlumberger fracturing job database)

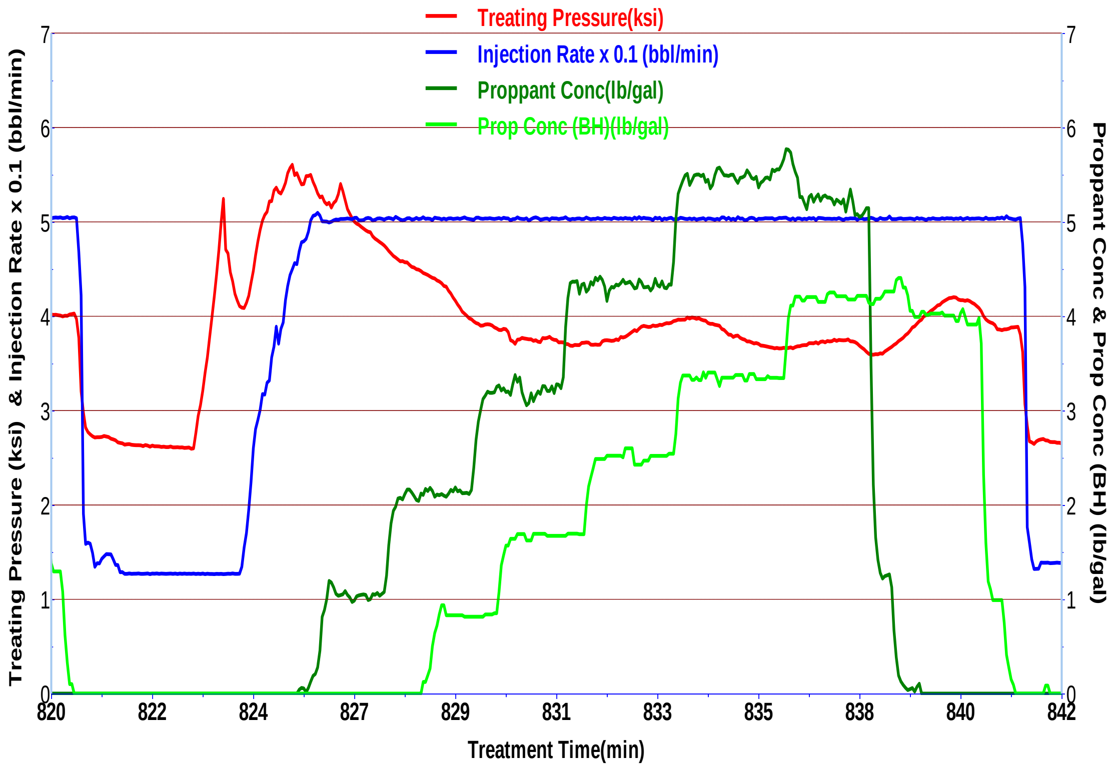

Figure 1.3: Stair step proppant concentration illustrations (Treatment data from Schlumberger fracturing job database)

1.2 CHANNEL FRACTURIG

Channel fracturing is a fracturing stimulation technique that relies on the intermittent pumping of a proppant-laden and proppant-free gelled fluid at a high frequency to generate a network of highly conductive channels (Johnson, et al., 2011). The channels are created by pulsing a pump schedule. A proppant-laden pulse will create a pillar and a proppant-free pulse will create channels as demonstrated in Figure 1.4. The channels are supported by pillars of proppants created during fracturing (Kayumov, et al., 2012). To make sure the pillars will keep channels open at reservoir conditions with fluid flow through the channels and stress that applies on them, fibrous materials are added into the carrying fluid at engineered concentrations. The fibrous materials are degradable at certain temperature, which will not reduce fracture permeability

(Kayumov, et al., 2012). The fibrous material helps to consolidate pillar structure before fractures are closed (Gillard, et al., 2010).

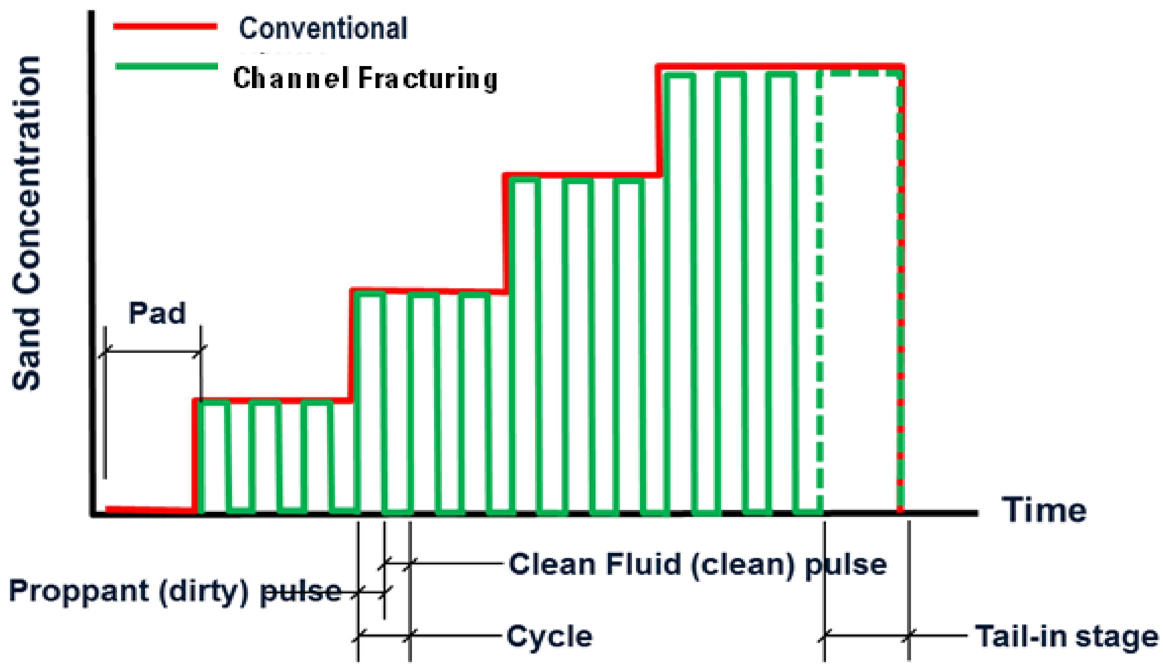

Figure 1.4: Channel fracturing proppant concentration illustrations (Courtesy of Schlumberger)

1.3 MECHANICS OF HYDRAULIC FRACTURING

Rock mechanics, fluid mechanics and proppant transportation mechanics that apply to conventional fracturing should still apply to the channel fracturing technique given the fact that both will pump a clean pad fluid to initiate fractures and create fracture geometry. Though there are differences between the two techniques on proppant stages as stated above, which will be analyzed in more detail later, for the treatment using a viscous fluid, pad volumes will determine fracture geometry, while a slurry stage fluid is to carry proppants to the tips of fractures (Economides and Nolte, 2000)

1.3.1 Breakdown Pressure

For the hydraulic fracturing treatment, *breakdown pressure by definition means a pressure at which the rock matrix of an exposed formation fractures and allows fluid to be injected* (Breakdown pressure, Schlumberger website).

For different formations, the breakdown pressure could vary dramatically. Before a well to be hydraulically fractured, we need to be sure the breakdown pressure can be overcome within a treating pressure limit. For a wellbore in porous rock if the borehole fluid penetrates the formation, a breakdown pressure equation derived by Haimon (1967) and Fairhurst (1970) is

$$P_b = \frac{3S_h - S_H - 2\eta P_0 + \Gamma}{2(1-\eta)} \tag{1.1}$$

$$\eta = \frac{\alpha_b(1-2\nu)}{2(1-\nu)} \tag{1.2}$$

$$\alpha = 1 - K/K_s \tag{1.3}$$

where:

P_b: Breakdown pressure

S_h : Minimum horizontal stress (psi)

S_H : Maximum horizontal stress (psi)

η : A poroelastic coefficient

P_0 : Formation pore pressure (psi)

Γ : Tensile strength of the rock (psi)

α_b: Biot constant

ν: Poisson's ratio

K: Bulk moduli of the rock constituents (grains)(ksi)

Ks: Bulk moduli of the rock bulk (ksi)

Normally breakdown pressure is not a big concern unless it is in a high in-situ stress region with a weak frac string. Frac string is the pipe that a fracturing job is pumped down. Depends on completion design, frac string could be casing, tubing, casing/tubing annulus or coiled tubing. Sometimes the breakdown pressure can be observed easily from the surface treating pressure. Sometimes formation might have already been broken down during drilling, so no clear indication of formation breakdown during fracturing (Figure 1.5 for illustration). No difference on breakdown pressure was observed and reported as expected on conventional and channel fracturing.

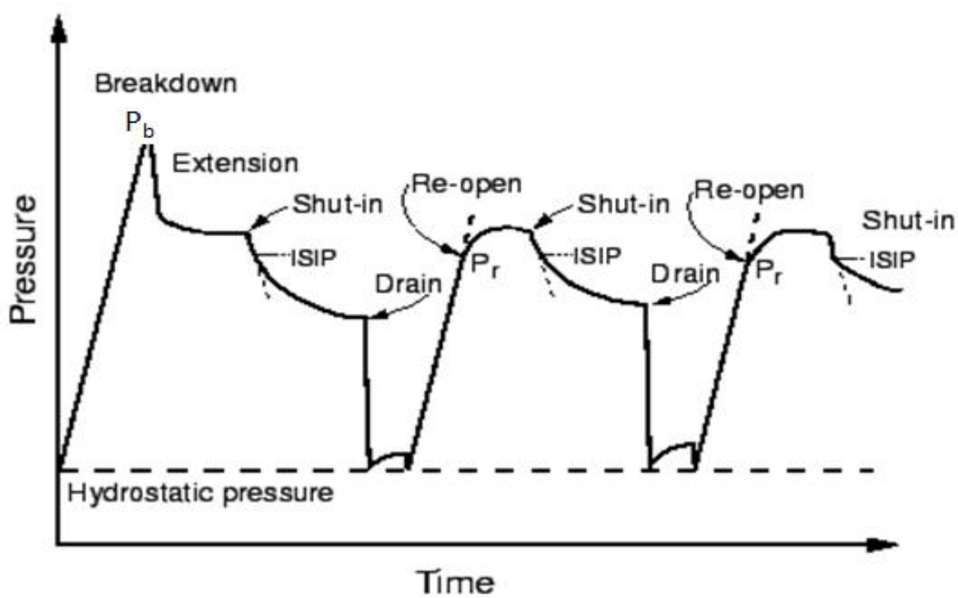

Figure 1.5: Pressure-time curve of a typical hydraulic fracturing experiment showing three pressurization cycles. The first cycle achieves a breakdown of the formation, whereas the two following cycles reopen the newly created fracture. During the shut-in phase the instantaneous shut-in pressure (ISIP), is observed which is identical to the least principal stress (From Brudy, 1995).

1.3.2 Orientation of Hydraulic Fracturing

The general stress underground has three stresses perpendicular to each other as Figure 1.6. The magnitudes of these three stresses are different (Hubbert and Willis, 1956); they are labelled as the overburden stress (S_V), minimum horizontal stress (S_h), and maximum horizontal stress (S_H). Depending on geological conditions, for deep wells, for example, deeper than 1,500 ft (Shah, et al., 2010), the vertical stress due to overburden is normally the maximum of the three. On the other side, if wells are shallow, it is more possible to have one of the horizontal stresses as the maximum stress of the three, while the vertical overburden stress is the minimum of the three. Hydraulic fractures will follow the least resistant rule and develop fractures perpendicular to the minimum stress while the fracture plane will be parallel to the plane of the two bigger stresses. Fractures may not initiate in the orientation as described above due to a localized stress change, e.g., the presence of natural fractures and the orientation of perforation not aligned with the preferred fracture plane, but the final fracture orientation is dictated by the far field stress regime and will develop fractures that follow the rules eventually. So there are mainly two types of fracture orientations; the first and most seen is a vertical fracture that will develop when the overburden stress (S_V) is the dominant stress of the three (See Figure 1.6). In figure 1.6, it is a vertical fracture that is perpendicular to minimum horizontal stress (S_h) with fracture height growth as h_f, fracture half length is L. Horizontal fractures will develop when the overburden is the minimum of the three stresses.

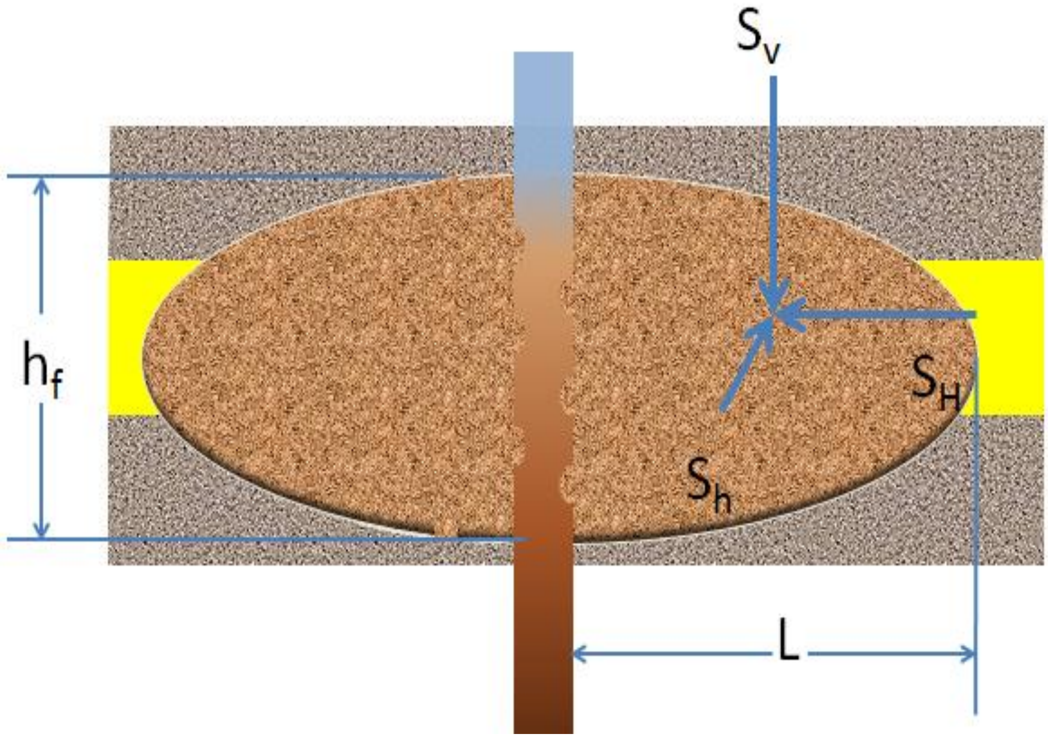

Figure 1.6: Underground stresses direction and vertical fracture geometry when overburden is maximum stress (By author)

1.3.3 Hydraulic Fracturing Geometry

Fracture dimensions and geometry (half-length L, width w, and height growth h_f) are controlled by rock and fluid mechanics. Rock mechanics is defined as “the theoretical and applied science of the mechanical behaviour of rock”. In fracturing, fluid mechanics describes the flow of one, two or three phases within the fracture (Economides, et al., 2000). Fundamentals of fracture geometry also follow rules of material balance, which means the fluid injected to formation will leak off to a reservoir dynamically and whatever is left in the reservoir will be effective to create a fracture geometry volume. The fracture volume is the combination of fracture half length, width and height (Economides, et al., 2000). The net pressure concept raised by Nolte (1982) directly links rock mechanics with fluid mechanics.

1.3.3.1 Net Pressure

Net pressure (Figure 1.7 for all pressures on fracturing treatment) by definition is the fluid pressure inside fracture geometry that keeps fractures open during hydraulic fracturing treatment. Net pressure is related to Young's Modulus, fracture height and length growth, fluid viscosity, pump rate and fracture tip pressure (Economides, et al., 2000). The net pressure equation is

$$p_{net} \approx \left[\frac{E'^3}{h_f^4} \{ \kappa \mu q_i L \} + p_{tip}^4 \right]^{1/4} \tag{1.4}$$

where

P_{net}: Net pressure inside fracture geometry (psi)

E': Plane strain modulus and can be expressed as $E'=E/(1-\nu^2)$

E: Static Young's modulus (psi)

ν: Poisson's ratio

κ : Constant

μ: Fracturing fluid viscosity (cp)

q_i: Total injection rate at time i

L: Fracture half length (ft)

P_{tip}: Pressure required at the fracture tip to open new fracture area and keep the fracture propagating forward (psi)

Net pressure has two components: a viscous component and a fracture tip-effect component.

The net pressure can also be calculated as

$$P_{net} = P_{frac} - P_{c.} \tag{1.5}$$

where P_{frac} is the fracturing pressure inside fractures.

P_{frac} is related to an injection rate, fracture width and length or radius by fluid mechanics (Poulsen, 1990).

Pc is the closure pressure that is exerted by the formation on the proppant. For a single layer, it is equal to minimum horizontal stress S_h. For multiple layers, it is some kind of average S_h involving all the layers (Economides, et al., 2000). S_h is the minimum in-situ stress and is directly related to rock mechanics by the following formula:

$$S_h = (\nu/(1-\nu))(Sv - \alpha_b P_0) + \alpha_b P_0 + \sigma_{ext} \quad (1.6)$$

where

ν: Poisson's ratio

Sv : Overburden stress (psi)

α_b: Biot's constant typically range from 0.5 to 1.0

P_0: Pore pressure (psi)

σ_{ext}: Tectonic stress (psi)

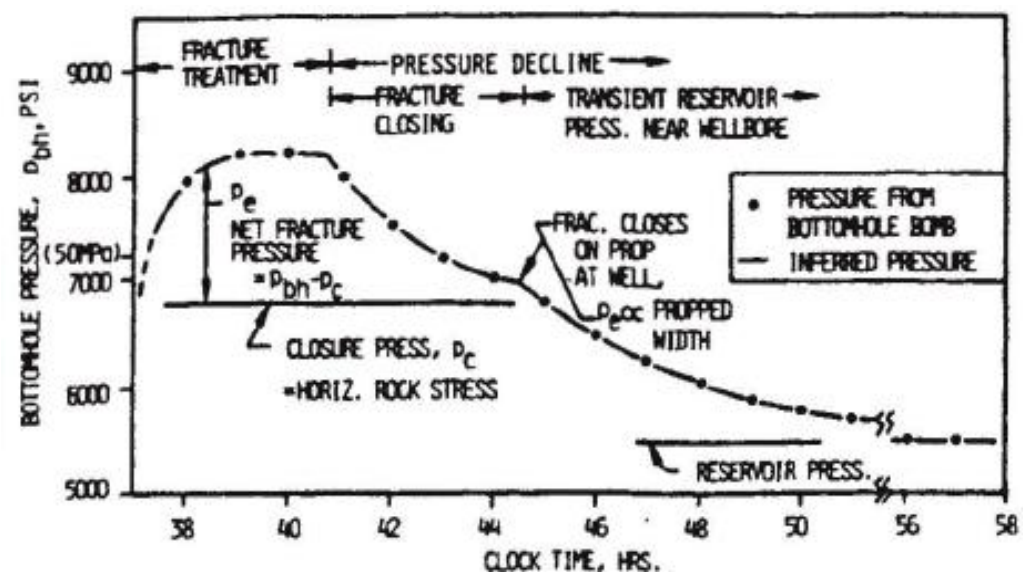

Figure 1.7: Example of fracturing-related pressures (Nolte, 1988)

The Log-Log slope of the net pressure vs. pumping time was introduced by Nolte (1982) and has been widely used as a diagnosing tool during the treatment (see Figure 1.8 and Table 1.1). By a proper interpretation slope of the plot, engineers can predict fracture geometry, observe abnormalities, adjust job parametres and increase job successful placement rates.

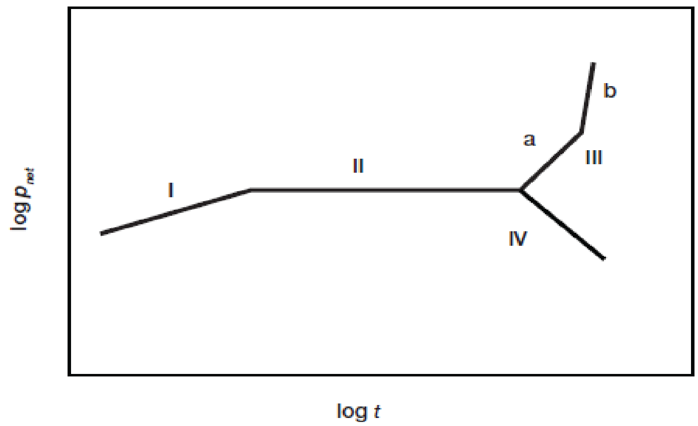

Figure 1.8: Nolte-Smith analysis pressure response (Economides, et al., 2007)

I	Propagation with PKN fracture Geometry.
II	Slope =0 represents height growth in addition to length growth, or increased fluid loss, or both. Can also be explained by a change in the relationship between net pressure and fracture width.
IIIa	Slope =1 means Net Pressure is now directly proportional to time. This behaviour is usually associated with additional width growth but no length growth, such as during a tip screenout.
IIIb	Slope>2. Screenout, usually a near-wellbore event with a very rapid rise in pressure.
IV	Negative slope. Rapid height growth. Potentially KGD or radial fracture geometry.

Table 1.1: Interpretation of Log-Log Plot fracture pressure slopes (Modified after Economides, et al., 2007)

1.3.3.2 Fracture Width

If we assume that fractures are initiated as a slit and open into an elliptical shape, the fracture width derived by Economides and Nolte (2000) can be expressed as

$$w_{max} = \frac{2 p_{net} d}{E'} \tag{1.7}$$

where

w_{max}: Maximum fracture width (in)

E': Plane strain modulus and can be expressed as $E'=E/(1-\nu^2)$

E: Static Young's modulus (psi)

ν: Poisson's ratio

d: The least dimension of the fracture length and height (ft)

If fractures are confined in height with a fracture length (2L) longer than height growth (h_f), d equals h_f (Economides and Nolte, 2000). From the formula we can estimate that higher Young's modulus will result in narrower fracture width given that other parameters are constant. Higher fracture net pressure will help to create more width. Net pressure is the difference of fracturing pressure and minimum in-situ stress as noted above, so the fracture width is also directly related to the two pressures.

1.3.3.3 Fracture Half-length

Net pressure also defines propagation of fractures. For the fractures to propagate, the condition $P_{net} > P_{ext}$ must be achieved (Economides, et al., 2007). Material balance means the fluid volume injected from surface will lose some portion to reservoir; only the remaining fluid in fracture will help to develop fracture geometry. The fluid volume remaining in fracture will create fracture volume (length, width and height) (Economides, et al., 2000). Based on material balance, fluid mechanics and rock mechanics, the fracture half-length derived by Economides and Nolte (2000) can be expressed as following:

$$L \cong \frac{q_i t_p}{6C_L h_L \sqrt{t_p} + 4h_L S_p + 2wh_f} \tag{1.8}$$

where

L: Fracture half length (ft)

q_i: Total injection rate at time i (bbl/min)

t_p: Pumping time for a treatment (min)

C_L: Fluid-loss coefficient (ft/min$^{0.5}$)

h_L: Permeable fracture height (ft)

S_p: Spurt loss (gal/100ft^2)

w: Average width of the fracture (in)

h_f: Average fracture height (ft)

1.3.3.4 Fracture Height Growth

Fracture height is controlled by in-situ stresses contrast between the layers. More precisely, height is controlled by the ratio of net pressure (P_{net}) to stress difference ($\Delta\sigma$) (Economides, et al., 2000). Higher net pressure to the stress difference between layers ratio ($P_{net} >> \Delta\sigma$) tends to lead to fracture height growth. According to the material balance theory, one can also make an judgement based on formula (1.7); when there is an excessive height growth (h_f increases dramatically), given a pump rate, a fluid leakoff coefficient and spurt staying the same, fractures will sacrifice either width (w) or half length (L) or both to make the formula work.

1.3.4 Fluid Leakoff Mechanism

The function of a fracturing fluid is to create fracture geometry in pad stages and then carry proppants at designed concentration and tonnage throughout the job to make sure placement can be executed successfully. After the breakdown is achieved, if one keeps pumping from surface, fractures will propagate. The propagation rate and fluid flow rate are controlled by fluid-loss behaviour. Reservoir properties including permeability to reservoir fluids, relative permeability to the fracturing fluid filtrate, total system compressibility, porosity, reservoir fluid viscosity and reservoir pressure all play a role in fluid loss while pumping (Economides and Nolte, 2000). The following fluid loss rate equation is derived by Carter (1957):

$$q_L \approx \frac{2C_L A}{\sqrt{t-\tau}}, \tag{1.9}$$

where

q_L: Fluid loss rate to formation (bbl/min)

C_L: Total leakoff coefficient (ft/min$^{0.5}$)

A: An element of the fracture area (ft^2)

t: Time measured from the start of pumping (min)

τ : The time when each small area element of a fracture is created and opened (min)

The rate of fluid loss to formation q_L is controlled by the total leakoff coefficient C_L. The total leakoff coefficient can be determined from mini-frac tests (Yew et al., 2000). A bigger fluid leakoff coefficient means more fluid loss to an area in a given time which indicates less fracturing fluid efficiency. For a polymer type of fluid, there are three zones along fracture walls developed after the fracturing fluid is injected as in Figure 1.9. Inside fracture walls, because fluid penetrates quicker than solids in the fracturing fluid, a filter cake formed (Grey color) along fracture wall. The quicker leaked off fracturing fluid will develop a filtrate zone (Brown color), while the area far from filtrate will be un-invaded formation (Green color).

There are three types of fluid leak off mechanisms for the three zones (Economides, et al., 2000):

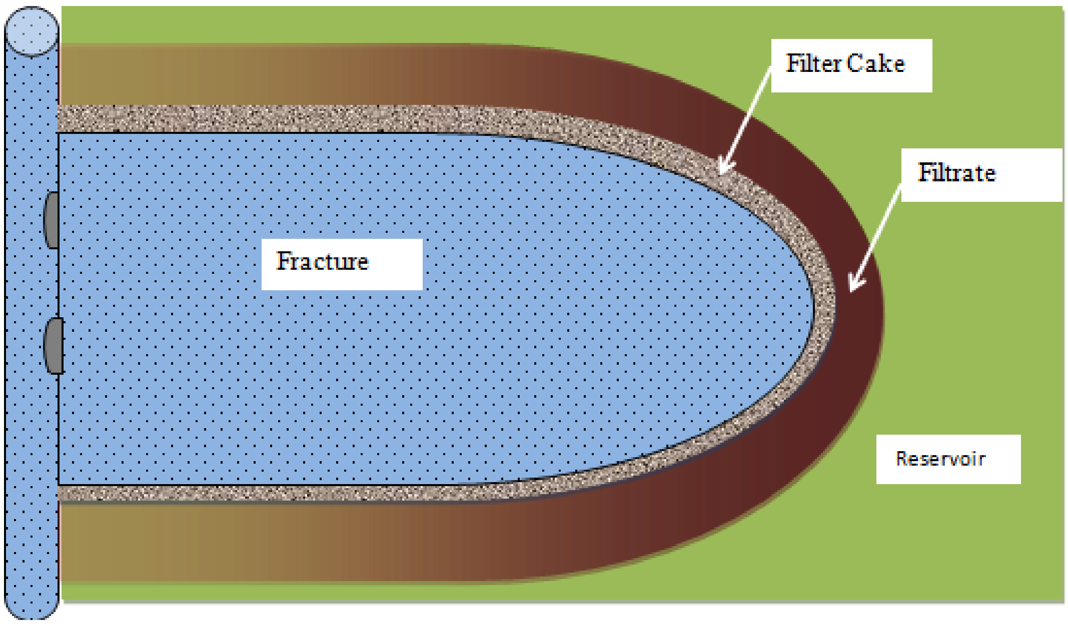

Figure 1.9: Fluid leakoff three regions (By author)

1.3.4.1 Fluid Leakoff Coefficient in Wall Filter Cake

The fluid leakoff coefficient through the wall filter cake is filter cake controlled leakoff (Economides, et al., 2000):

$$C_w = \sqrt{\frac{k_{cake}\alpha\Delta p_{cake}}{2\mu_{fil}}}. \tag{1.10}$$

where

C_w: Wall building fluid leakoff coefficient (ft/min$^{0.5}$)

K_{cake}: Filter cake permeability (md)

ΔP_{Cake}: Pressure drop across the filter cake (psi)

μ_{fil}: Viscosity of the filtrate (cp)

α: Ratio of fluid volume to cake thickness

The wall building effect fluid leakoff coefficient will increase with an increase of filter cake permeability, pressure drop across the filter cake and the ratio of the fluid volume to cake thickness. It will decrease with an increase of filtrate viscosity.

1.3.4.2 Fluid Leakoff Coefficient in Filtrate Zone

It is viscosity controlled leakoff (Economides, et al., 2000):

$$C_v = \sqrt{\frac{k_{fil}\phi\Delta p_v}{2\mu_{fil}}} \tag{1.11}$$

where

C_v: Viscosity control leakoff coefficient (ft/min$^{0.5}$)

ϕ: Reservoir porosity (%)

K_{fil}: Filtrate permeability (md)

ΔP_v: Pressure drop across the filtrate zone (psi)

μ_{fil}: Viscosity of the filtrate (cp)

The viscosity controlled fluid leakoff coefficient will increase with an increase of filtrate permeability, reservoir porosity, and pressure drop across the filtrate zone and decrease with an increase of filtrate viscosity.

1.3.4.3 Fluid Leakoff Coefficient in Reservoir Zone

It is the compressibility control leakoff (Economides, et al., 2000):

$$C_c = \sqrt{\frac{k_r c_t \phi}{\pi \mu_r}} \Delta p_c \tag{1.12}$$

where

C_c: Compressibility control leakoff coefficient (ft/min$^{0.5}$)

K_r: Reservoir rock permeability (md)

C_t: Total compressibility (1/psi)

ϕ: Reservoir porosity (%)

ΔP_c: Pressure drop between the filtrate/reservoir interface and the far-field reservoir (psi)

μ_r: Reservoir fluid viscosity (cp)

The compressibility controlled fluid leakoff coefficient will increase with an increase of reservoir permeability, total compressibility, porosity and pressure drop and will drop with an increase of reservoir fluid viscosity.

The total fluid leak off coefficient for a wall building fluid is the sum of the three leakoffs. Williams et al. (1979) derived the total leakoff coefficient equation:

$$C_L = C_{wcv} = \frac{2 C_c C_v C_w}{C_v C_w + \sqrt{C_w^2 C_v^2 + 4 C_c^2 \left(C_v^2 + C_w^2 \right)}} \tag{1.13}$$

where

C_L: Total fluid leakoff coefficient (ft/min$^{0.5}$)

C_{wcv}: Total fluid leakoff coefficient of C_w, C_v and C_c (ft/min$^{0.5}$)

C_w: Wall building fluid leakoff coefficient (ft/min$^{0.5}$)

C_v: Viscosity control leakoff coefficient (ft/min$^{0.5}$)

C_c: Compressibility control leakoff coefficient (ft/min$^{0.5}$)

1.3.5 Fracturing Fluid Rheology

Most of fracturing fluids are a power law fluid whose viscosity decreases as the shear rate increases. There is no linear relationship between the shear rate and shear stress. The relationship between the shear rate (ɣ), shear stress (Ŧ), n prime and k prime is as following equation 1.14.

$$Ŧ=kɣ^n \tag{1.14}$$

where

ɣ : shear rate (sec^{-1})

Ŧ : shear stress (lb/ft^2)

k: k prime of power law fluid

n: n prime of power law fluid

For the log-log plot of the shear stress and shear rate, k is the intercept of the log Ŧ axis and n is the slope of the plot. n increases with increasing time and temperature while k decreases with increasing time and temperature.

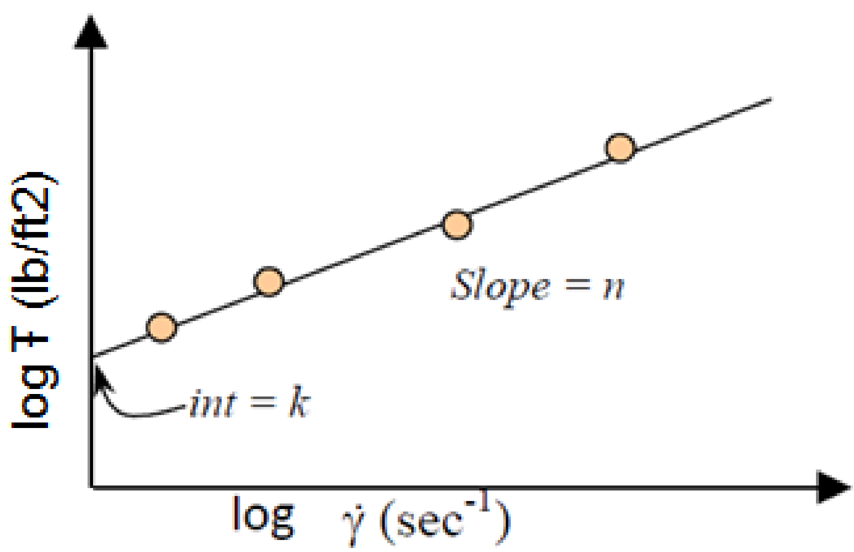

Figure 1.10: Log-Log Power Law fluid shear stress vs. shear rate (From Fracturing Fluid Main Functions, website)

CHAPTER TWO: PROPPANT TRANSPORT, ADMITTANCE MECHANISM AND MODELLING

2.1 INTRODUCTION

As discussed and observed in Chapter One, fracture geometry is related to fluid mechanics, rock mechanics and material balance. After fracture geometry is created in pad stages based on the three theories, hydraulic fracturing uses various power law fracturing fluids at different viscosity to carry proppant. Proppant concentration is normally designed from low to high as illustrated in Chapter One. This chapter will cover proppant transport mechanism vertically and horizontally. The proppant transport in fractures includes proppant settlement to the bottom of the fractures. There are two types of downward settlement being observed and studied, individual particle settles due to gravity and slurry convection transports downward due to the gravity difference on the slurry fluid from bottom to top; the proppant uniformity over total fracture height might be lost (Unwin and Hammond, 2006). It also includes the proppant laden slurry fluid travelling along the fracture length. The prediction of proppant transport along fracture penetration geometry is intricate because when the slurry travels from the wellbore, the proppant concentration increases but fluid velocity decreases (Novotny, 1977). Poor proppant transport can result in excessive proppant settling to the lower regions of the created fractures (Brannon, et al., 2007) and might bridge the path of the following slurry which will result in high treating pressure or even failure of the placement. The proppant admittance is also related to if the proppant placement is successful or not, so it will also be briefly discussed. Since hydraulic fracturing placement is greatly related to fracture geometry and is a complex process, while laboratory tests can only observe some mechanisms, fracturing modelling is heavily utilized to help predict fracture geometry and job placement. This chapter will discuss the type of fracture modelling as well as proppant transport modelling to assist further analysis.

2.2 PROPPANT TRANSPORT MECHANISM

Both vertical and horizontal transport will be discussed in this section.

2.2.1 Vertical Transport

2.2.1.1 Stoke's Law

It is about an individual proppant particle settling rate far from any walls in a stagnant Newtonian fluid (Modified after Economides, et al., 2000).

$$V=1.15x10^{3}(d^{2}_{prop}/\ \mu_{fluid})\,(SG._{Prop-}\ SG._{Fluid}) \qquad (2.1)$$

where

V: Proppant Settling Velocity (ft/s)

d_{prop}: median proppant particle diameter (in)

μ_{fluid}: Fluid viscosity (cp)

$SG._{Prop}$: Proppant specific gravity

$SG._{Fluid}$: Fluid specific gravity

Stoke's law shows that a single proppant particle settling velocity is related to the proppant size, fluid viscosity, and specific gravity difference of proppant vs. fracturing fluid (Brannon, et al., 2006). From the above formula, a single particle will settle slower if the proppant size is smaller, the fluid viscosity is higher, and the specific gravity difference between proppants and the carrying fluid is smaller. When the fluid viscosity is low, proppants will deposit at the bottom of fractures and build up a bank of proppants and Stoke's law-type of settling dominates (Clark, 2006). If a fracturing fluid retains 50 to 100 cp viscosity by the end of fracturing treatment at reservoir temperature at a shear rate of 170 s^{-1}, it will provide essentially perfect proppant transport if Stoke law is the only settlement mechanism (Economides, et al., 2000). This type of settlement might be applicable for a very low viscosity fracturing fluid (water) after pumping is stopped.

Most of hydraulic fracturing fluids are a power law fluid. To better describe the gravity settlement of a proppant particle in a power law fluid, Economides and Nolte (2000) developed a generalized form of Stoke's law

$$V=(((\rho_{prop}-\rho_{fluid})gd_{prop}^{(n+1)})/(3^{(n+1)}18k))^{(1/n)} \tag{2.2}$$

where

V: Proppant settling velocity (ft/s)

ρ_{prop}: Proppant specific gravity (lb/gal)

ρ_{fluid}: Fluid specific gravity (lb/gal)

d_{prop}: Median proppant diameter (in)

g: Gravitational acceleration (32.174 ft/s^2)

k: k prime of power law fluid

n: n prime of power law fluid

2.2.1.2 Convection

This type of proppant settlement is first raised by Clifton and Wang (1988) and included in a fully three-dimensional (3D) planar model. It is controlled by density differences (i.e., buoyancy) between fluids. For the hydraulic fracturing application, proppants are added from low concentration to high concentration to avoid screenout, which result in the density differences at different stages. The heavier slurry will fall quicker than the lighter slurry due to a convection effect (Economides, et al., 2000). Proppant settlement due to gravity (Stoke's law) and convection due to density difference can both happen during hydraulic fracturing. If proppant particles have migrated to the centre of the fractures forming a close-packed sheet, convection proppant transport is stronger compared to if proppant remain uniformly distributed across the fracture width. There are wellbore configurations that will affect the final proppant distribution. If the perforation interval is small compared to fracture height, flow into the fractures can be considered to flow from a point source and will be more possible to have non-uniform proppant concentration. If the perforation interval is big compared to the fracture height, it will result in a uniform slurry distribution from top to bottom (Clark, 2006). High suspending fluid viscosity, small fracture width and a high injection rate can help to reduce proppant settlement due to a downward convection effect (Unwin, et al., 1995). A dimensionless value N_c' which is the ratio of proppant horizontal transport force vs. vertical transport force was derived by Clark (2006) for a power-law fracturing fluid as in equation 2.3(Clark, 2006). If N_c' is less than one, which means horizontal transport force is less than vertical transport force, then convection dominates the flow. A value of N_c' greater than one indicates that the distribution of slurry in the fractures will be more uniform (Clark, 2006), and then there will be less convection effect.

$$N'_c = \frac{F_H}{F_V} = 2\left(4 + \frac{2}{n}\right)^n \frac{\mathrm{k}\, q^n}{g w^{2n+1} \Delta\rho} \tag{2.3}$$

where

N'_c: Dimensionless value, ratio of proppant horizontal force vs. vertical force

F_H: Proppant horizontal transport force (N)

F_V: Proppant vertical transport force (N)

n: n prime of power law fluid

k: k prime of power law fluid

q: The injection rate divided by the height (bbl/min/ft)

g: Gravitational acceleration (32.174 ft/s^2)

w: Fracture width (in)

Δρ: The density difference between the injected fluid and the fluid in the slot (lb/gal)

2.2.2 Horizontal Transport of Fracturing Slurry

The horizontal slurry flow velocity within a fracture is dependent on the injection rate, the fracture geometry development (fracture half length, height and width), type of fluid and the fluid leakoff volumes to formation (Brannon, et al., 2006). Due to the complicated fracture geometry prediction process, lateral slurry velocity prediction will have to rely on computer modeling.

2.2.3 Biot-Medlin Analysis

Hydraulic Fracturing treatment is a dynamic process; it involves not only the slurry settlement, but also the slurry horizontal movement with clean fluid leakoff into formation simultaneously. To better evaluate fracturing fluid carrying capability on proppant travelling along fractures, the Biot-Medlin analysis is introduced, which is based upon evaluating the ratio of proppant final settling velocity (Vt) compared to the slurry horizontal velocity (U) (Brannon, et al., 2007). The final settlement velocity is a combination effect of particle fall, convection downward transport and fluid migration. From the criteria set by Biot-Medlin, the critical condition for particle “pick-up” occurs at the horizontal velocity when Vt/U is 0.9. For Vt/U values of greater than 0.9, transport is by rolling or sliding. For Vt/U values less than 0.5, but greater than 0.1, a condition of bed load transport occurs. In this case, at least some portion of proppants is moving in a traction carpet across the top of an immobile bed. For Vt/U values less than 0.1, proppants will suspend with the fracturing fluid and there is mobile bulk slurry (Brannon and Wood, 2007). Proppant transport evaluation should always take into account the fracture geometry factor (Economides, et al., 2000).

2.3 PROPPANT ADMITTANCE

Besides the fracturing fluid capable of carrying proppants from the surface to fracture geometry, there is another factor directly associated with placement of fracturing treatment, proppant admittance.

Smith (1991) investigated that both a minimum perforation diameter and a minimum fracture width depending on the proppant diameter and proppant concentrations are crucial in fracturing job placement (Smith 1991).

In Figure 2.1, Gruesbeck and Collins (1978) have demonstrated the correlation of the minimum perforation diameter required for different sand concentrations. From Figure 2.1, we can conclude that the perforation hole diametre must be six times the average particle (proppant) diametre if proppant concentration is higher than 10 lb/gal.

In Table 2.1, van der Vlis et al. (1975) have performed series of tests to correlate the minimum fracture width vs. proppant diameter ratio required for different proppant concentration so it does not bridge. Based on similar findings on the perforation diametre required for successful placement, higher proppant concentration requires higher fracture width for successful placement.

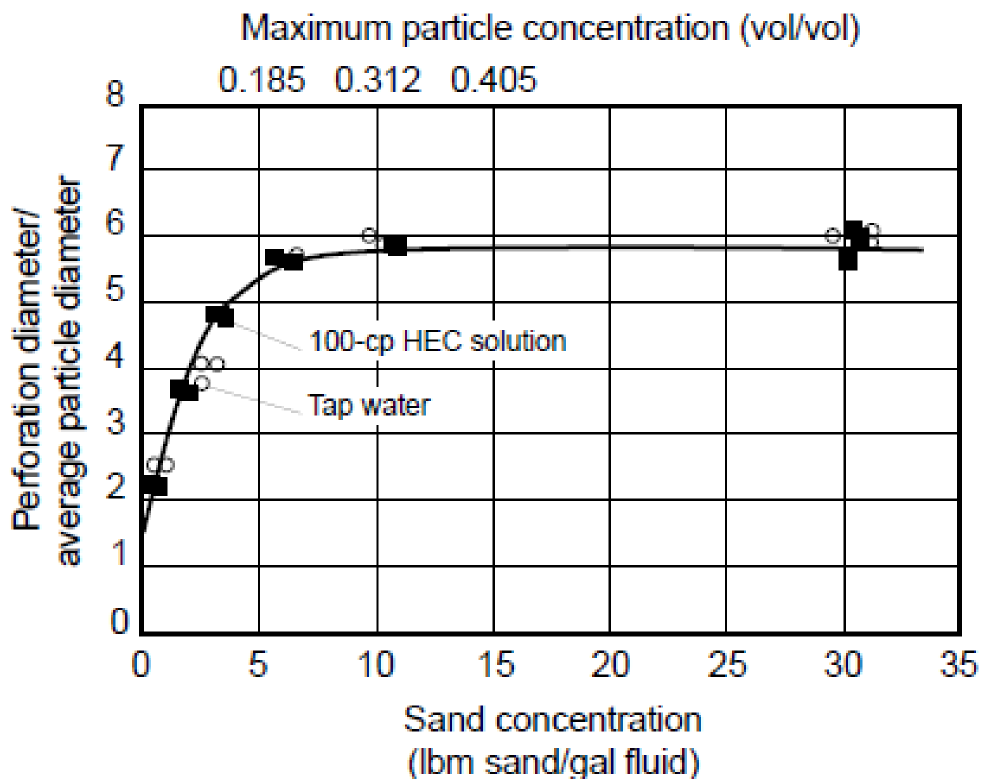

Figure 2.1: Proppant admittance through perforations (Gruesbeck and Collins, 1978)

Proppant† Concentration (lbm proppant/gal fluid)	**$\overline{w}/d_{prop}$**	
	Experimental Bridge Formation‡	**Correlation Bridge**
0.5 to 2	1.8	1.15 to 2.0
2 to 5	2.2	2.0 to 3.0
5 to 8	2.6	3.0

† Sand as proppant
‡ Data from van der Vlis *et al.* (1975)

Table 2.1: Proppant admittance criteria (Economides, et al., 2000)

2.4 FRACTURE GEOMETRY MODELLING

As mentioned previously, prediction of proppant placement in fracture geometry needs the aid of simulator and is affected by fracture geometry. There are four engineering models to simulate fracture geometry, from a simplified version with a lot of assumptions to an advanced model with fewer assumptions that simulate a real case. They are:

- Two-dimensional (2-D) model
- Pseudo three-dimensional (P-3-D) model
- Planar 3D model
- Fully three-dimensional (3-D) model

2.4.1 Two-dimensional Model

The most popular 2-D analytical models are the PKN model (named after Perkins and Kern, 1961 and Nordgren, 1972), the KGD model (named after Khristianovich and Zheltov, 1955 and Geertsma and de Klerk, 1969) (Hou and Zhou, 2007) and a radial fracture model. Both PKN and KGD models have a rectangular extension mode. The PKN model uses an elliptical cross section, while the KGD model has a rectangular cross section. The radial model has a circular shape and propagates in the radial direction (Guo, et al., 1994). All 2-D models fix fracture height growth to the perforated zone and do not include vertical fluid flow.

2.4.1.1 PKN Model

It assumes that each vertical section pressure change is dominated by the height of the section rather than the length of the fracture. This assumption is true if the fracture half length is much greater than the height, so the PKN model is more applicable for height confined fracture geometry prediction. It is also used when the overburden stress is the largest in-situ stress so vertical fractures will develop; it assumes cracks' opening is in the vertical plane perpendicular to the direction of fluid flow (Economides and Nolte, 2000).

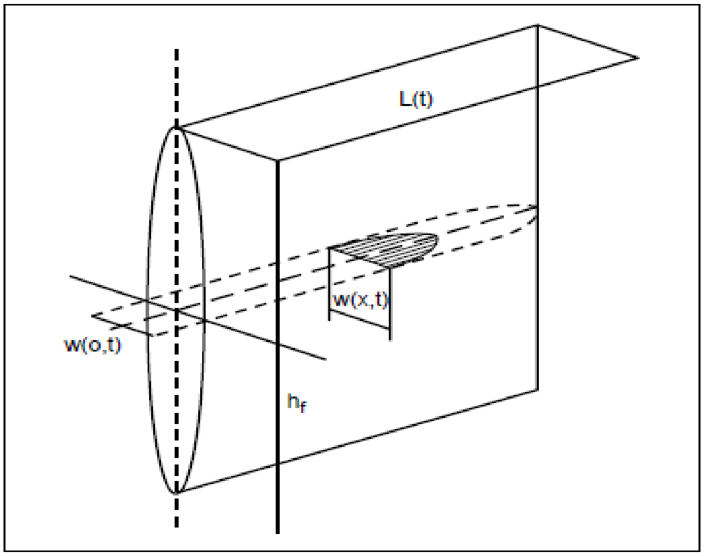

Figure 2.2: PKN model (Economides, et al., 2000)

2.4.1.2 KGD Model

The KGD model assumes all horizontal cross sections act independently and all sections are identical. This is true when the fracture height is much greater than the length. So the KGD model is suitable for fracture geometry simulation when the fracture height is greater than the length and the fracture width from top to bottom is constant. It assumes that cracks' opening is in a horizontal plane with the same direction as fluid flow (Economides and Nolte, 2000).

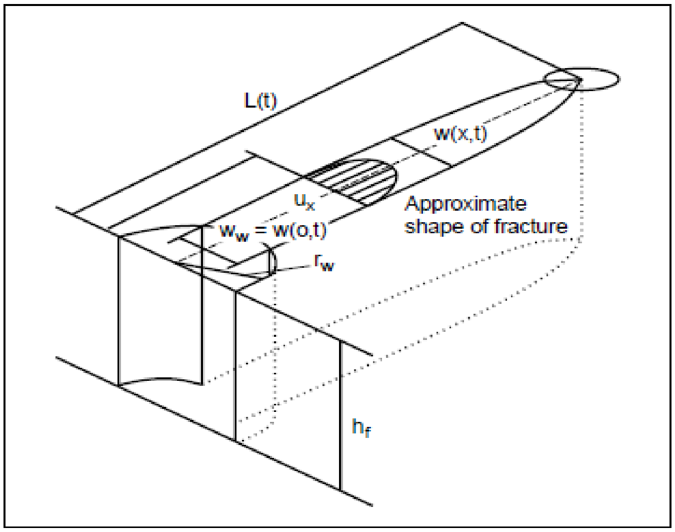

Figure 2.3: KGD model (Economides, et al., 2000)

2.4.1.3 Radial Fracture Model

A radial fracture model is applicable when there are no barriers constraining height growth or when a horizontal fracture is created.

2.4.2 Pseudo Three-dimensional Model (P3D)

P3D models the behaviour of planar fractures with a simplified version. It includes fracture height growth across zones. Fracture geometry is subdivided into cells and pressure in each cell is assumed to be constant. Figure 2.4 is an illustration of P3D model. The left brown shape is to illustrate the subdivided cells. The stress profile y-axis is the formation depth in ft, x-axis is minimum in-situ stress in psi, and reading is from left to right (low to high). The fracture width shows the width is different from top to bottom. On fracture Half-length plot, x-axis is fracture half length in ft, different color on the plot along fracture half length shows proppant concentration in lb/ft^2. Red is highest proppant concentration, blue is lowest proppant concentration and other colours are proppant concentrations in between lowest and highest. From the plot we can conclude that fracture is not constrained in one perforated interval like 2-D model, there is height growth into several intervals. Proppant concentration is not uniform across fracture geometry.

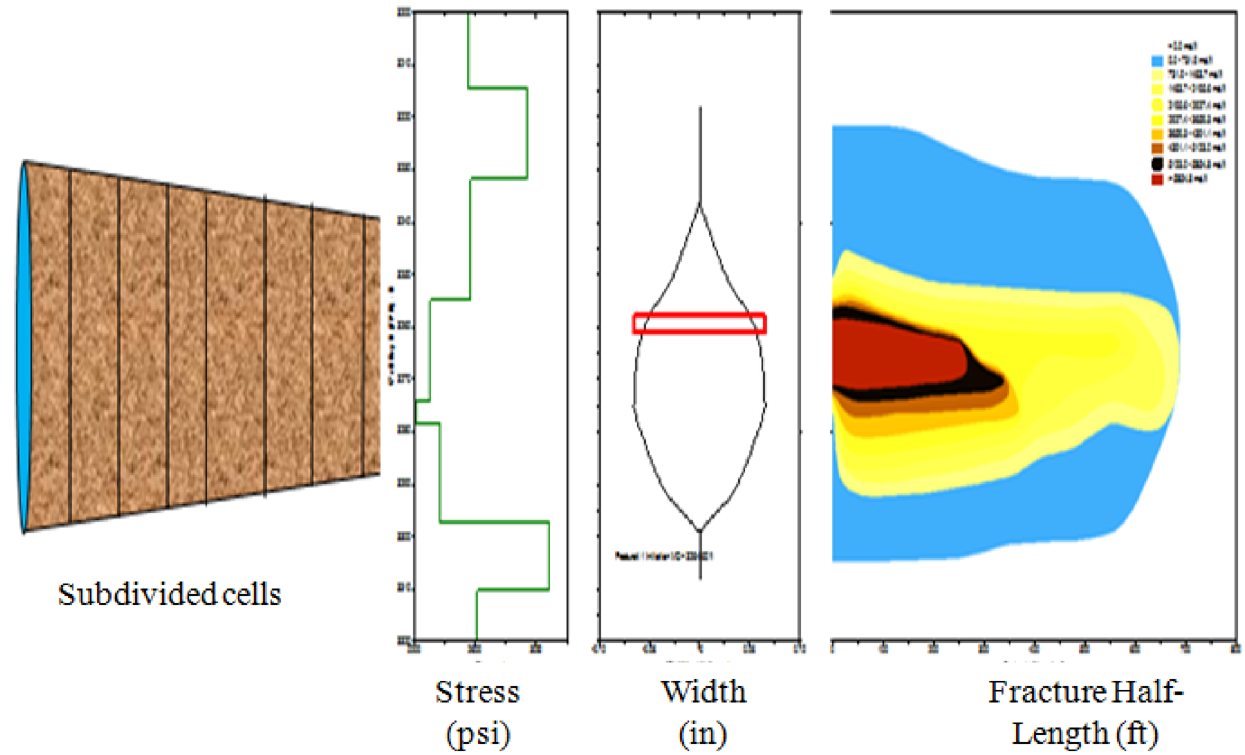

Figure 2.4: Pseudo 3-D model (By Schlumberger FracCADE Simulator)

2.4.3 Planar 3D Model

A planar fracture is a narrow channel of a variable width fracture that allows fluid to flow. A planar 3D model assumes that a fracture is planar and oriented perpendicular to the far-field minimum in-situ stress. Fractures remain in a single plane and are divided into small cells. Fluid, proppant flow and fracture propagation are fully 2-D within the fracture plane. It involves more computation than P3D and can predict pinch point, packing/bridging, and fracture containment more accurately than the previous discussed simplified models (Economides et al., 2000). Like in Figure 2.5, left figure is to show the small cells feed into simulator; right hand figure is the fracture geometry by planar 3D simulator.

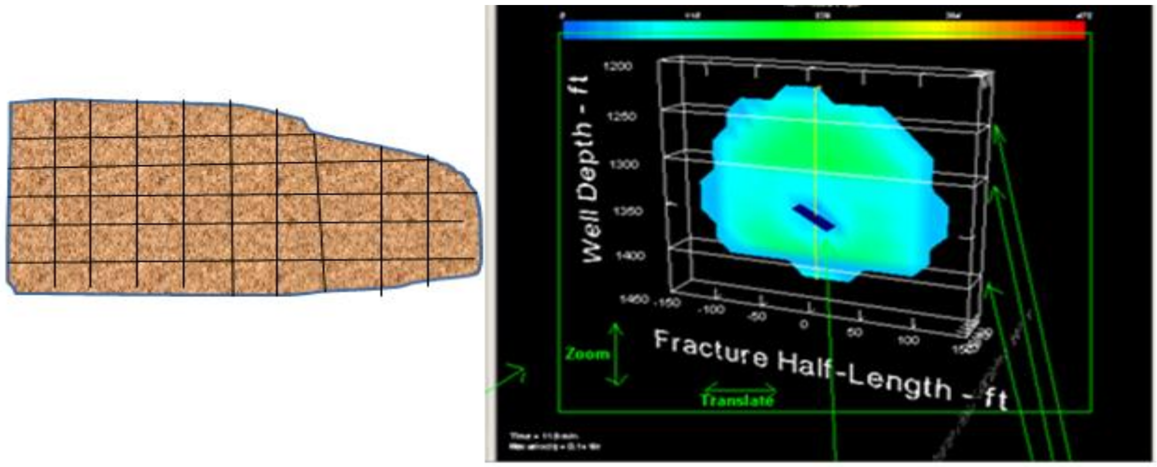

Figure 2.5: Planar 3-D model (By Schlumberger Planer3D simulator)

2.4.4 General Three-dimensional Model

This model simulates both horizontal and vertical propagation of fractures (Meyer, 1996). It does not make any assumptions about the orientation of the fractures. The wellbore orientation of a perforation pattern may cause the fractures to initiate in a particular direction. It requires intensive computation and requires a specialist to obtain and interpret the results. Due to the complicity and hard to achieve, this model is for research purpose (Economides and Nolte, 2000). 3D numerical models have the advantage of simulating the actual fracture initiation and propagation as a function of time (Hou and Zhou, 2006).

2.5 PROPPANT TRANSPORT MODELING

For 2-D and P3D models, 2-D flow could be optional for some simulators depending on how a simulator is built. If 2-D flow is not included in the simulator, the proppant vertical transport is quite simple, volume out from a well, and then proppants just settle at the bottom of fractures because of each particle gravity effect before fractures closed. However, if the 2-D model is built into the simulator, both convection and the gravity effect will be included in settlement. Six scenarios were run as follows for different fluid viscosity with and without 2-D flow included given that all other parameters are the same. All simulations are run with FracCADE simulator and in P3D Model. Three different type of fluid with viscosity from low to high as shown in table 2.2 is simulated while all other input data the same. The color coding on fracture half-length figure indicates different proppant concentration in lb/ft^2.

Some conclusions can be made after the simulations:

- Fracture growth and fracture non-uniformities that restrict flow to regions of the fractures have a big effect on proppant transport in vertical fractures (Clark, 2006). This is proved by the 6 simulation figures. For different type of fluid, fracture geometry is different; proppant distribution varies for all scenarios.
- For these simulations, the perforated interval has wider fracture width compared to a lower portion of the fracture geometry; without a convection effect, proppants are more uniformly distributed in the perforated interval; while with convection effect, proppant uniformity is highly related to fluid viscosity.
- A low viscosity fluid has a more downward convection effect than a high viscosity fluid. Figure 2.6 & Figure 2.7 both are with low viscosity fluid; Figure 2.6 doesn't include convection effect, proppant distributed around perforation interval. However, Figure 2.7

when convection effect is included, proppant travels downwards and fall on the bottom of the fracture geometry.

- The convection effect should be always included in simulation; it might be the dominant mechanism (Cleary, et al, 1992)
- High viscosity fluid will help to carry proppant along horizontal fracture before it settles down to the bottom, so proved from the simulations, high viscosity fluid scenario proppant distribution with and without convention looks more like each other than when fluid viscosity is low or medium.

Figure #	Figure 2.6	Figure 2.7	Figure 2.8	Figure 2.9	Figure 2.10	Figure 2.11
Without 2-D Flow	**Low Viscosity**		**Medium Viscosity**		**High Viscosity**	
With 2-D Flow		**Low Viscosity**		**Medium Viscosity**		**High Viscosity**
n prime	**1**	**1**	**0.54**	**0.54**	**0.65**	**0.65**
k prime ($lbf.s^n/ft^2$)	1.41E-05	1.41E-05	9.83E-03	9.83E-03	3.19E-02	3.19E-02
Viscosity at 170 S^{-1} (cp)	0.68	0.68	44.04	44.04	250.77	250.77
Prop Frac Half Length (ft)	517.1	517.1	786.6	821.7	886.3	789.8
EOJ Hy Height at well (ft)	121.5	121.5	246.0	246.0	282.1	282.1
Propped Width at Well (in)	0.070	0.001	0.036	0.026	0.043	0.030
Fluid Efficiency	0.192	0.192	0.787	0.787	0.938	0.938

Table 2.2: Summary of simulations on different fluid viscosity with and without 2-d model

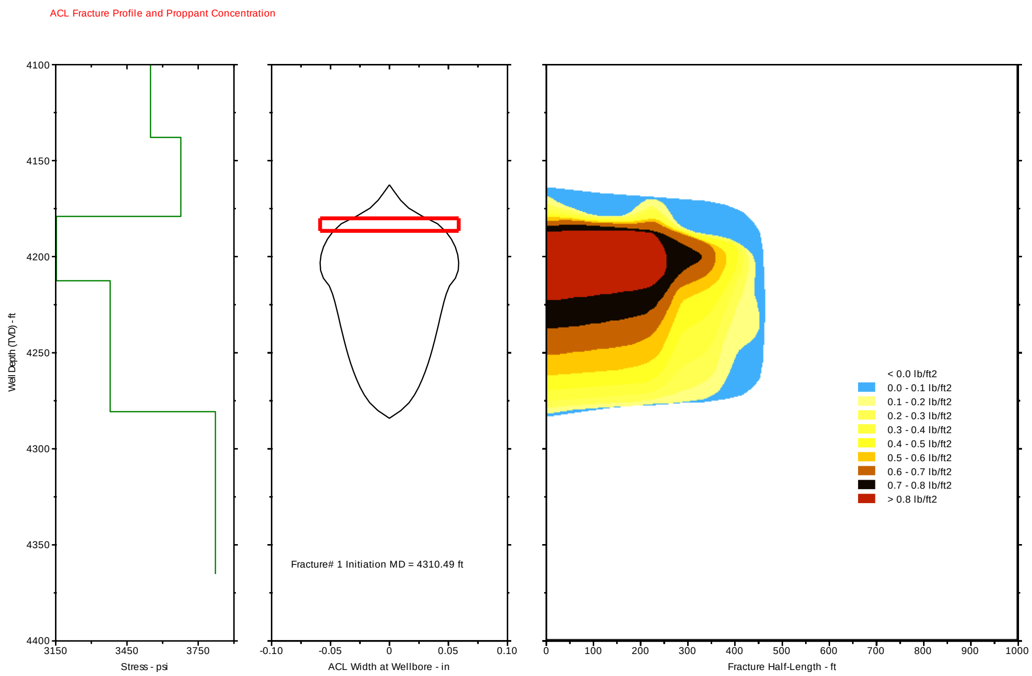

Figure 2.6: Low viscosity fluid without 2-D flow proppant distribution after closure

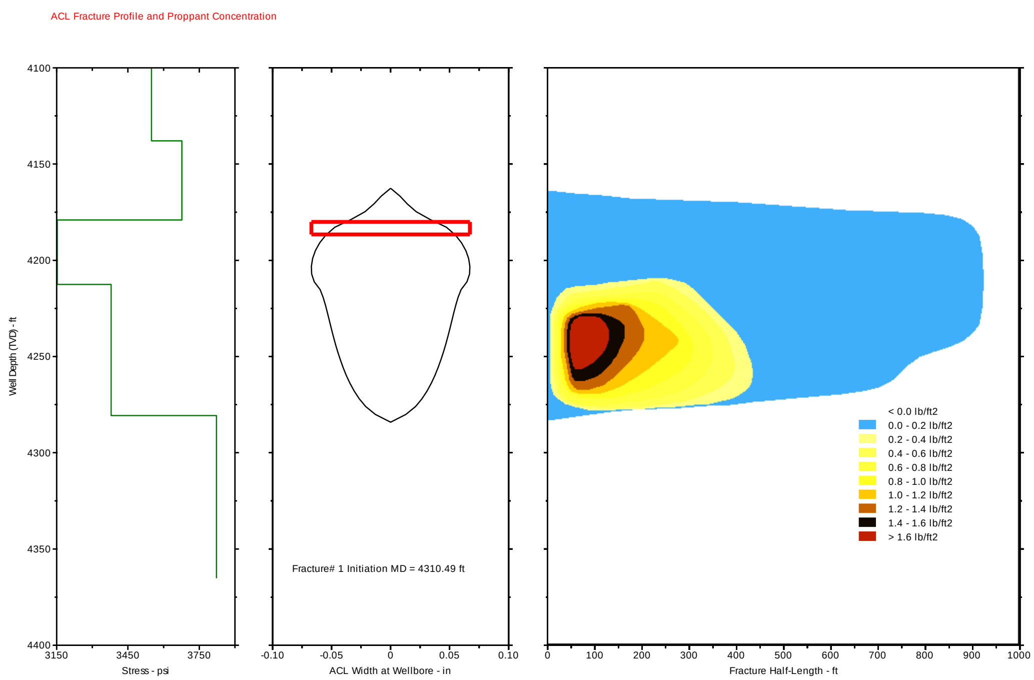

Figure 2.7: Low viscosity fluid with 2-D flow proppant distribution after closure

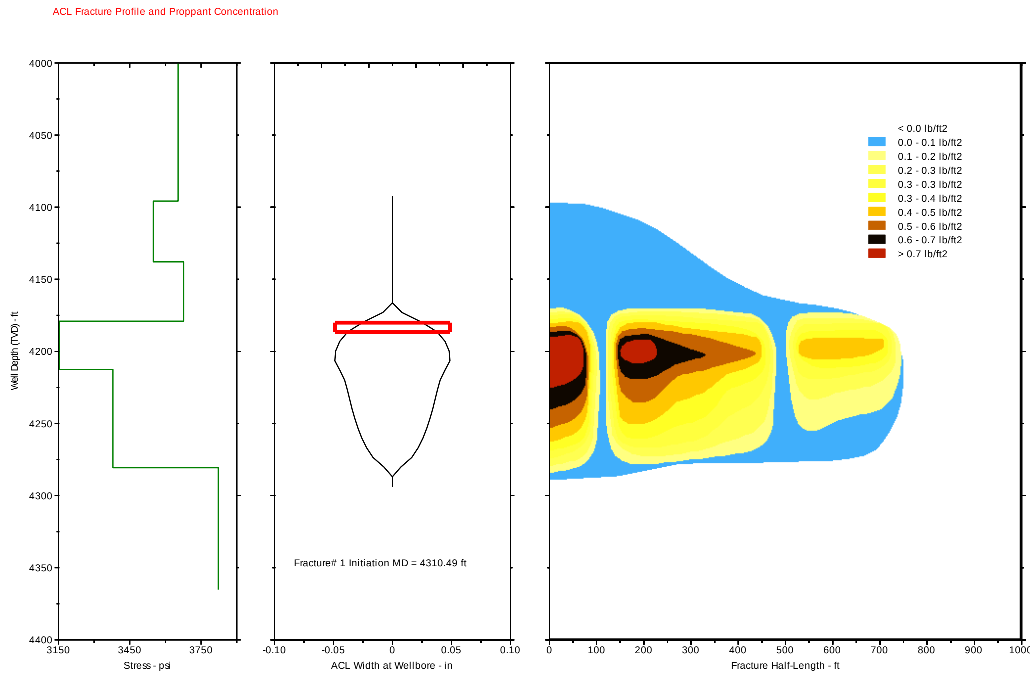

Figure 2.8: Medium viscosity fluid without 2-D flow proppant distribution after closure

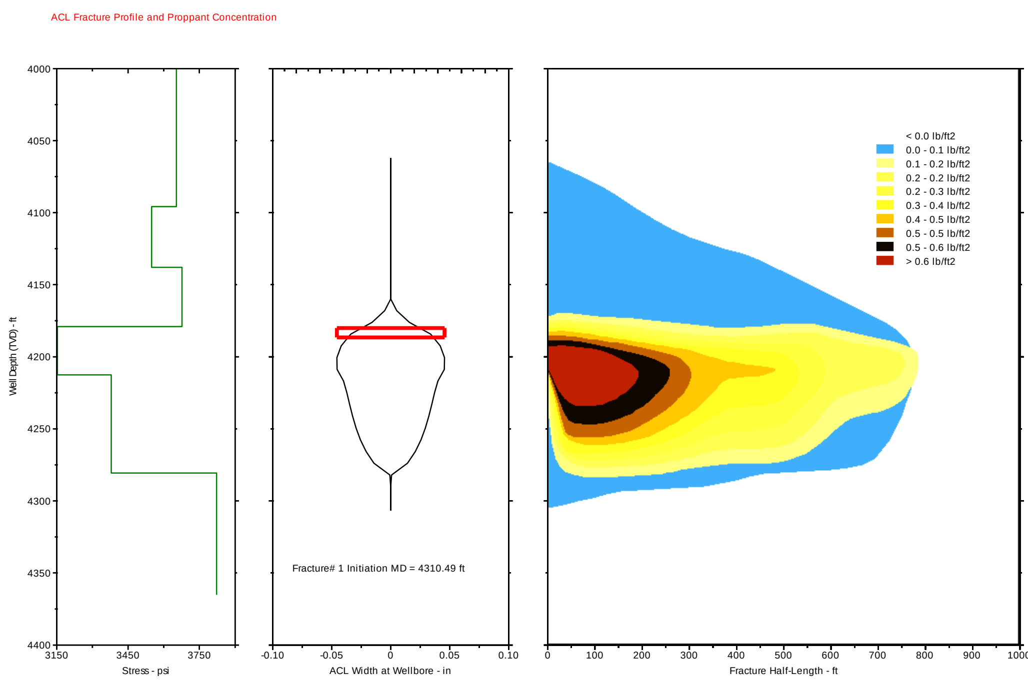

Figure 2.9: Medium viscosity fluid with 2-D flow proppant distribution after closure

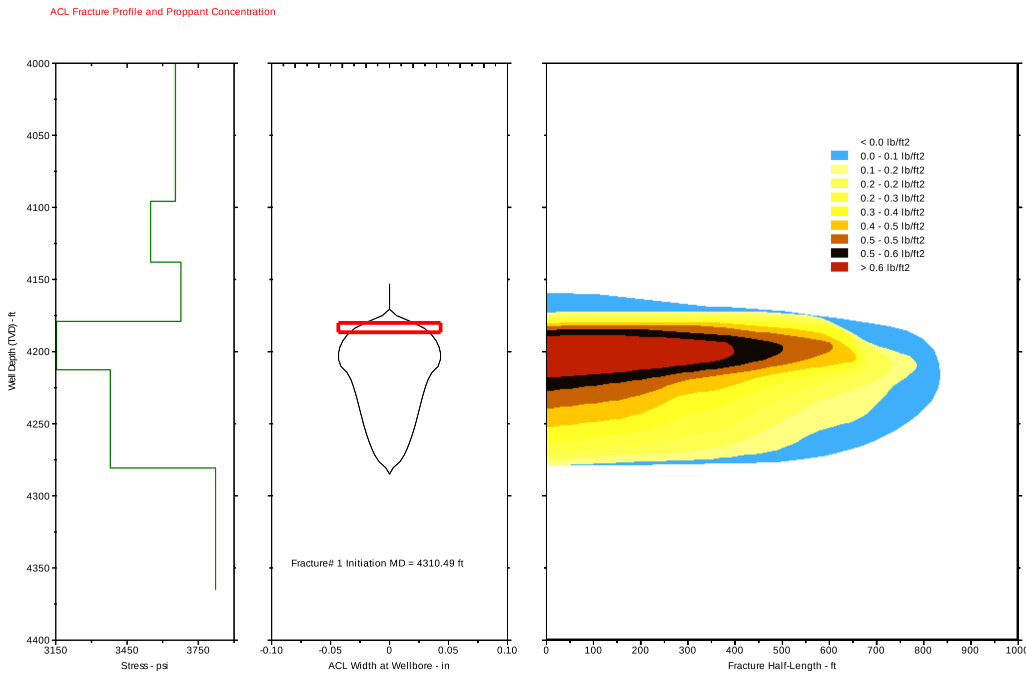

Figure 2.10: High viscosity fluid without 2-D flow proppant distribution after closure

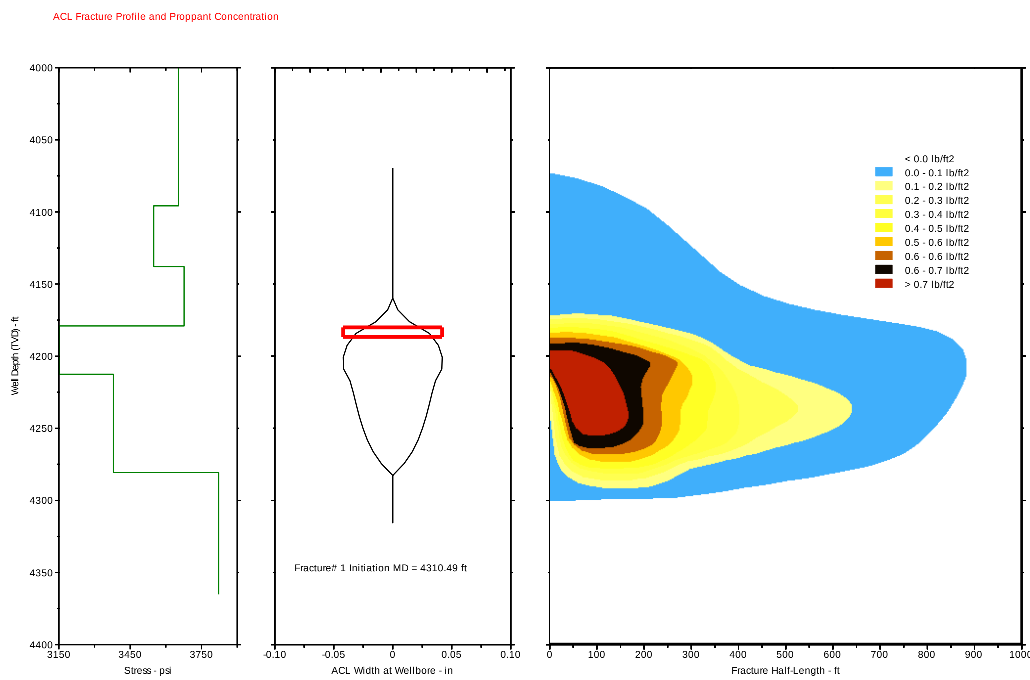

Figure 2.11: High viscosity fluid with 2-D flow proppant distribution after closure

CHAPTER THREE: CHANNEL FRACTURING REDUCES SCREENOOUT

3.1 INTRODUCTION

It is widely accepted that a proppant gravity effect, fluid loss, layered fluid loss and late-time fracture changes will affect proppant placement (Smith, et al., 2001). The causes of screenout or pressure out could be fracture width restrictions, slurry dehydration or pad depletion (Baree, et al., 2001). For hydraulic fracturing jobs, fracturing engineers will try their best to design job parameters to make sure jobs can be executed successfully. However, independent of the efforts by engineers, due to the complicated nature of hydraulic fracturing, many unknown parameters are involved; there are always cases where jobs cannot be completed as designed. Especially with the rapid development of unconventional reservoirs, there is a trend to frac more and more stages along horizontal wellbore or try to place more and more proppants; it is even more challenging to execute jobs smoothly. The channel fracturing technology, besides its advantage to create high conductive fractures for fluid flow, can greatly reduce the risk of screenout. More than 10,000 channel fracturing treatments have been performed in over 1,000 wells during the last three years in shale-carbonate and sandstone-rich reservoirs worldwide. The collective dataset on job execution and well performance shows lower occurrence of near wellbore screenouts (>99.9) (Medvedev, et al., 2013). This is a great success and has outperformed all other hydraulic fracturing techniques. Depending on formation properties, hydraulic fracturing job design, and experience of fracturing engineers, conventional hydraulic fracturing jobs did always have minor to severe screenout issues like Kayumov, et al., (2012) reported screenout incidence is 12% on conventional jobs.

This chapter will first introduce screenout effects on operations then discuss how to perform a pressure analysis during a job. The causes of screenout will be summarized afterwards. The author will also try to analyze why channel fracturing has a lower risk of screenout from the proppant transport and fluid leakoff mechanism. Simulations and laboratory tests done by other people will also be provided to support the conclusion.

3.2 SCREENOUT EFFECTS ON OPERATIONS

Depending on types of fracturing treatments, fracturing job pumping down, and the type of completion, the effects of screenout could be very minor to very costly.

3.2.1 One Stage Fracturing

Different scenarios could happen after a screenout occurred. One benefit with one stage fracturing operation is that it is a single operation; whatever happened on this zone will not have an effect on other sides. The following are some examples:

- Pump down casing with foam fracturing fluid or if a reservoir is overpressured. If screenout is light, a well might be able to flow back by itself and clean out the proppants left in wellbore.
- Pump down casing without foam or if a reservoir is underpressured. If screenout occurred, one might have to clean out wellbore with a coiled tubing unit.
- Pump down annulus/tubing/coiled tubing. After screenout occurred, one might be able to establish back circulation and clean out the proppants left in wellbore.

3.2.2 Multiple Stages Operation

Severity and consequence of disruptions caused by screenouts in multiple stages operation depends on the type of completions (Daneshy, 2011) and also type of fracturing job. However, it is always challenging to deal with the multiple stages screenout issue because it is a continuous event. Once interruption occurs, it will affect other operations.

3.2.2.1 Multiple Stages Openhole Operation

If screenout occurs in fractures, the pressure will initiate and extend new fractures without a major disruption of the operation. However, if this results in wellbore screenout, proppants accumulate in the annulus between openhole and a liner. After the annulus is filled, proppants will accumulate in wellbore; this type of screenout can be very costly (Daneshy, 2011). If screenout is in early stages close to the toe section of the wellbore with no foam fluid, the well can hardly flow back the proppants settled on the wellbore, and a coiled tubing unit will have to be utilized to clean out the wellbore. Sometimes, if the wellbore is very deep and out of a coiled tubing length limit, or if the ball seat size is too small for coiled tubing unit to clean out the proppant, several stages might have to be abandoned. On the other hand, similar to one stage screen out with foam fracturing fluid or the well is over pressured, sometime the well can flow back the proppant itself without intervention of expensive coiled tubing unit.

3.2.2.2 Multiple Stages Cemented Liner

3.2.2.2.1 Plug and Perforation

This completion is with a wireline plug and a perforation gun in the same string. After fracturing is completed, a wireline will set up a plug to isolate the zone completed and perforate the next zone. If screenout occurs in this completion and cannot be flowed back, coiled tubing will be used. Plug and perforation operation from author's experience is more applied in deep wells, so screenout could be very costly because of fracturing, wireline crew and other parties on standby plus coiled tubing clean out costs more for longer operation hours.

3.2.2.2.2 Coiled Tubing Involved

Mainly two types of fracturing with coiled tubing involved: first one is with coiled tubing abrasive jetting perforations and then frac down annulus; second one is to use coiled tubing to switch a frac port pre-installed in a liner for each stage and then frac down liner/coiled tubing annulus. Whenever there is coiled tubing in wellbore, screenout could be solved more easily by reversing the sand out of wellbore with less delay.

3.3 PRESSURE ANALYSIS DURING A JOB

During fracturing execution, the well never responds as designed, simulated and expected (Economides, et al., 2007). To better understand the screenout signature, two types of pressure analyses are introduced. The first one is when bottomhole pressure can be directly (indirectly) measured, which is always preferable but not always available. The second one is the pressure analysis when there is no direct or indirect bottom hole pressure available, and surface treating pressure has to be utilized to either calculate bottomhole pressure (and then net pressure is used to make judgement) or just make decisions based on surface treating pressure.

3.3.1 Bottomhole Pressure Measurement Available

As illustrated in Appendix A, during a fracturing job, fracturing job is pumped from surface at treating pressure. If the fracturing job is pumped down casing and tubing (coiled tubing) annulus, while filling tubing with a known fluid (in most cases it is water), tubing pressure is an indirect measurement of bottomhole pressure. Because water is incompressible, bottomhole pressure will be transmitted to tubing pressure. The only difference between bottomhole pressure and tubing pressure measured is hydrostatic pressure.

When bottomhole pressure is available, if closure pressure could be estimated from offset Instantaneous Shut in Pressure (P_{ISIP}), Net Pressure (P_{net}) can be calculated assuming that perforation friction pressure (P_{perf}) and tortuosity friction pressure (P_{tort}) are not significant. Net pressure is a critical parameter to help engineers to make a judgement on the downhole event or even on fracture geometry generated (Nolte, 1981). When Net Pressure is plotted vs. treatment time on a log-log scale plot (Nolte Smith Plot), the slope of the plot can help the engineer to estimate fracture geometry, predict early screenout and mitigate screenout risks (Refer Table 1.1 for slope interpretation). To summarize, engineers should be cautious about slope change of Nolte Smith log-log plot.

3.3.2 Bottomhole Pressure Measurement Unavailable

If fracturing treatment is pumped down one string only and without deadstring, bottomhole pressure measurement is not available. This is the most common case in the real word. In this case, bottomhole pressure can be estimated using the formula in Appendix A. Compared to direct bottomhole pressure measured, tubular friction pressure (P_{tf}) and hydrostatic pressure (P_h) are part of the calculation. These two pressures are dynamic for hydraulic fracturing because of the addition of proppants at different concentration, a pump rate change at surface and a fracturing fluid viscosity change. This case is much more challenging for engineers to make a judgement compared to when bottomhole pressure measurement is available. It is quite surprising to see the different trends of surface treating pressure (in Red) and Deadstring Pressure (in black) by looking at Figure 3.1. Surface treating pressure fluctuated dramatically, which might mislead engineers' judgement without bottomhole pressure measurement.

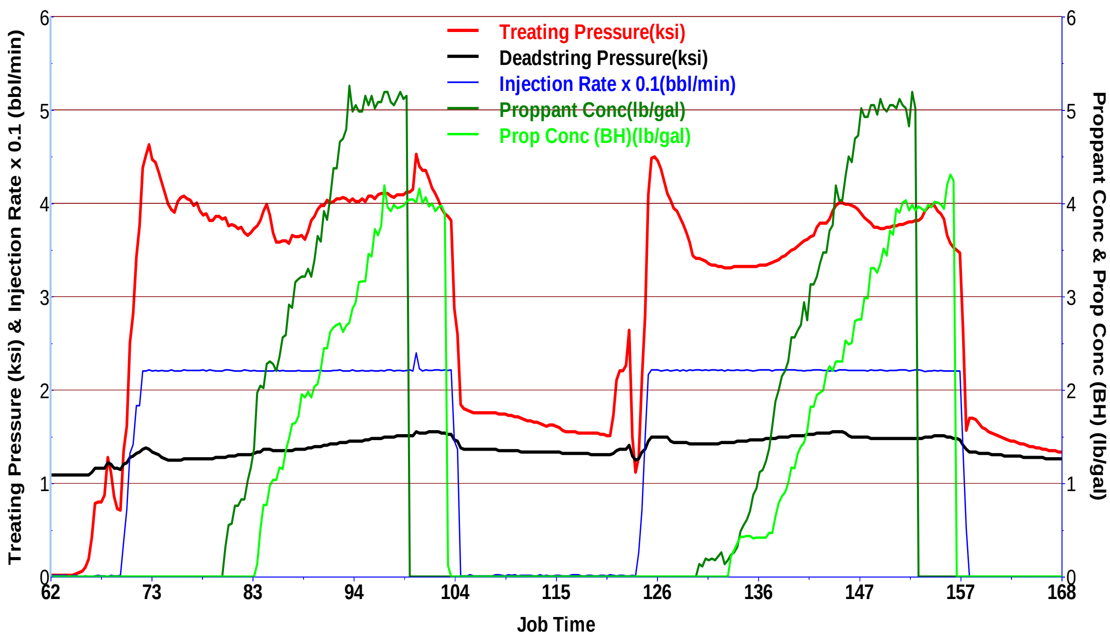

Figure 3.1: Treatment plot for 2 stages fracturing (Surface pressure vs. Deadstring pressure, treatment data from Schlumberger fracturing job database)

3.4 CAUSES OF SCREENOUT

Two types of screenout occur. The first type is gradual screenout behaviour and is caused by inability of proppants to pass through the near wellbore area. The pressure increases gradually and in a concave upward fashion. This is also referred to as Tip Screenout (Massaras, et al., 2012). It is the blockage to fluid movement and is indicated by the rate of a pressure increase at the wellbore. The faster the rate increase, the closure the obstruction is to the wellbore (Ali, 2007). Involuntary Tip Screen Out could be overcome if recognized before fracturing treatment by increasing a fracture rate in an effort to exceed the leakoff rate during the treatment (Economides, et al., 2007). During the job, the pressure increases gradually, if bottomhole pressure measurement is available; the job can be terminated early before it exceeds a surface treating pressure limit to avoid screenout. The second type is referred to as a “wellbore screenout” (Figure 3.2). Abrupt Screenout behaviour is caused by proppants which do not enter fractures but are diverted, fall to the bottom of the well (or openhole section) and slowly fill the interval below the perforations. Once the interval bellow the perforation is filled, the perforation area is filled up slowly; once the entire interval has been completely blocked by proppants, an abrupt pressure increase is noted (Massaras, et al., 2012). This type of screenout does not have any indication and is hard to prevent (Aud, et al., 1994). Once pressure starts climbing, it is already late to reduce a pump rate or cut proppants from surface to push the proppants into the fractures, and screenout is unavoidable. While a cause of screenout probably like fracture geometry is far more complicated than what people observed, efforts here will just cover the most often happening ones associated with the channel fracturing application types of screenout.

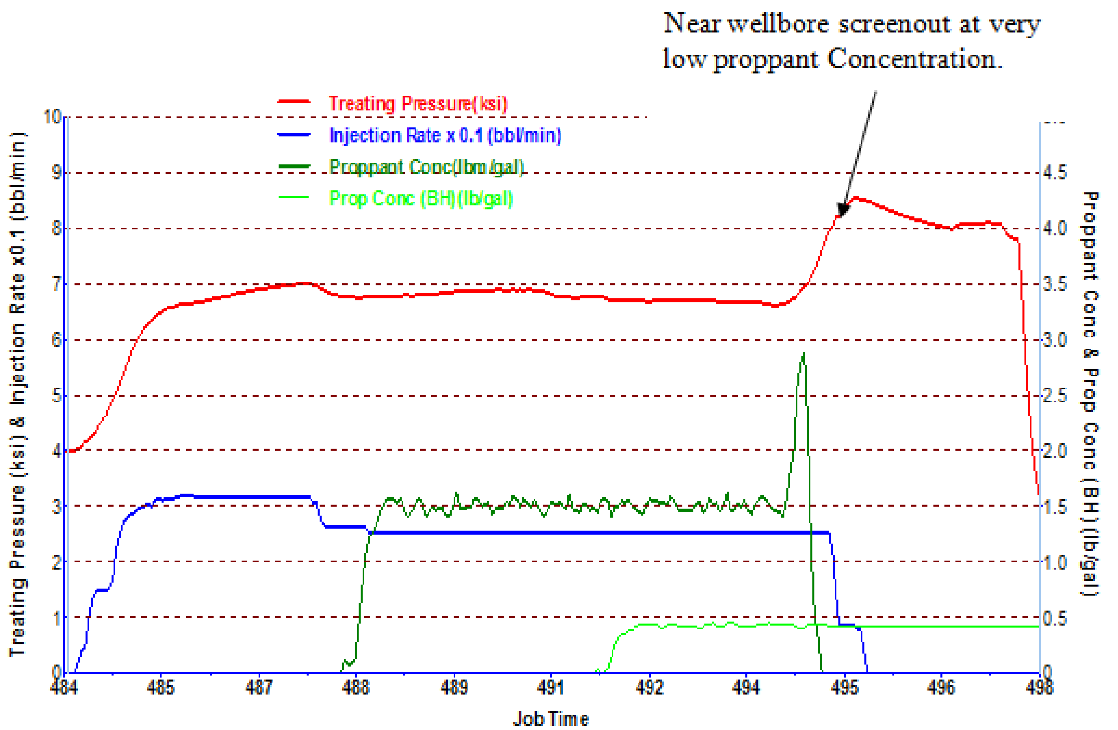

Figure 3.2: Wellbore screenout treatment plot (Treatment data from Schlumberger fracturing job database)

The causes of screenout are listed as follows:

3.4.1 High Fluid Leakoff in Pad and Slurry Stages

As discussed in Section 1.3.4., a fluid leakoff coefficient is crucial to fracture geometry and success of job placement. Many factors can contribute to high fluid leakoff during fracturing treatment, including but not limited to a high pressure drop between a filter cake, a filtrate zone and a reservoir; high permeability in the filter cake, filtrate zone and reservoir; high reservoir porosity; and low filtrate and reservoir fluid viscosity.

It has been tested and shown in labs that a fracture of virtually any width can be packed by injecting even a low concentration slurry, if leakoff is high enough (Baree, et al., 2001). If it happens in a pad stage, fracture geometry will be smaller than designed, not enough space for slurry stages and result in screenout. Overwhelming fluid leakoff can happen in any slurry stages as well. For tight oil and gas reservoirs, fluid leakoff resultant screenout is still a big issue. The reason is that most “tight” reservoirs have some natural fractures when examined in thin sections under microscope. During hydraulic fracturing, leakoff will increase when fractures intersects with open fissures (Figure 3.3) (Keshavarzi, 2012). Locally high leakoff will affect proppant transport, narrow fracture width and lead to early screenout (Arukhe, et al., 2009).

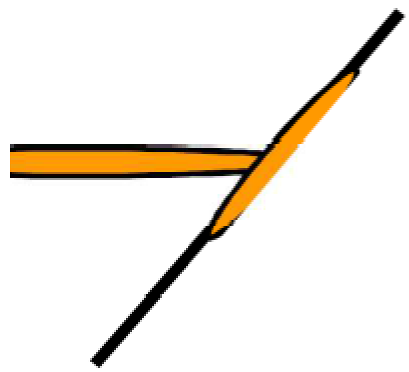

Figure 3.3: Hydraulic fracture opens the natural fracture and propagates along the natural fracture (From Keshavarzi, 2012)

After fracture geometry is created in a pad stage, proppant laden slurries will flow laterally into natural fissures, cause proppants to migrate to the fracture wall and build up a dense proppant pack at the leakoff site. If the leakoff is high, the proppant holdup is severe enough to completely fill the main fracture channel and lead to screenout even at low proppant concentrations. This is also called proppant dehydration (Baree, et al., 2001). When this happens, bottomhole pressure will increase as shown in Figure 3.4, the pressure difference with and without pressure-dependant leakoff could be from small to very severe. If no effective fluid loss control intervenes, treatment will have to be terminated to prevent pressure over a surface pressure limit when excessive fluid leakoff occurs.

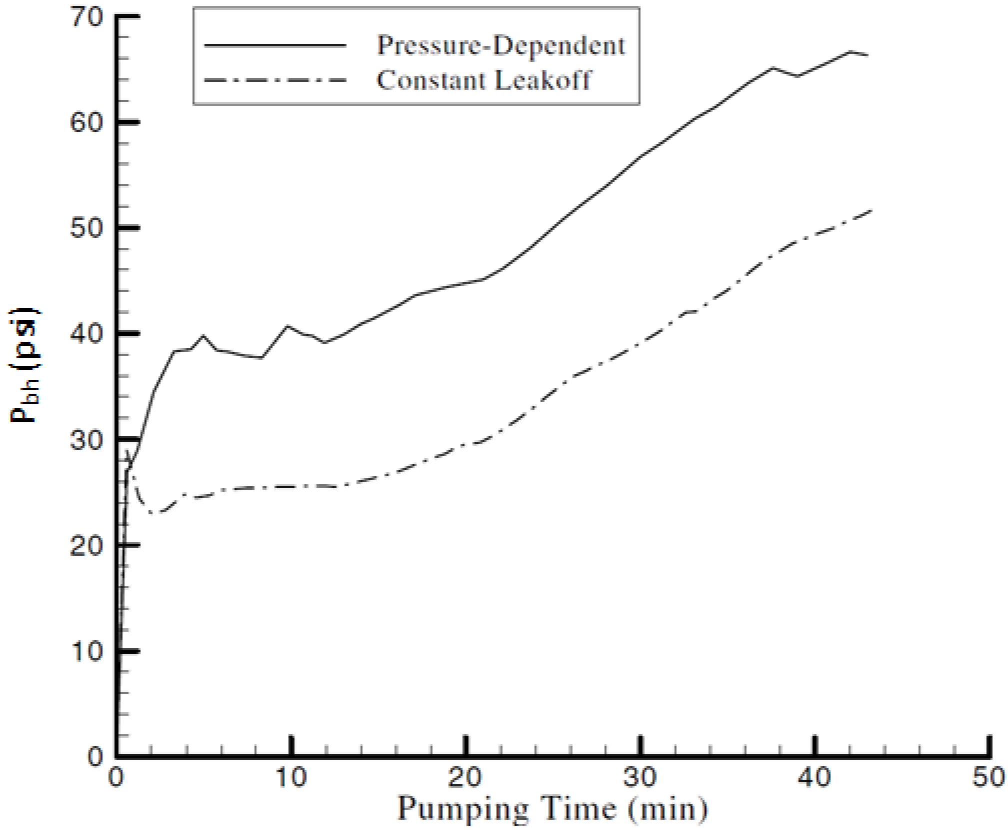

Figure 3.4: Bottom-hole pressure (P_{bh}) history – a circular fracture (From Yew et al., 2000)

3.4.2 Narrow Fracture Width

It has been discussed in Section 2.3 that proppant admittance for fracture width is required to place a job without screenout. It shows clearly that with a proppant concentration increase, fracture width required will need to be increased to ensure no bridging will occur. Fracture width is dependent on net pressure (P_{net}), height h_f (PKN type of fractures) or half length L (KGD type of fractures) and formation plain strain modulus. Higher P_{net} and height will create more width. However, high plain strain modulus will result in narrower width. Besides the factors above, multiple competing fractures will divide P_{net} between fractures and lead to narrow fracture width. When this happens, the net pressure required for all fractures is high compared to that just for one fracture and results in high treating pressure. For a cased-hole completion, multiple fractures could be from a long perforated interval with too many perforations while perforations are misaligned with a preferred fracture plane. This will be more obvious if wellbore is deviated, or even if a perforation interval is not big but the reservoir has natural or induced fractures near wellbore as shown in Figure 3.5 (Weijers, et al., 2000). For an openhole completion, multiple fractures are more related to the weakest stress point. Nowadays, spacing between stages on openhole completion for conventional reserves could be as long as 493 ft with a lot of weak points exposed to high fracturing pressure and tend to initiate multiple fractures simultaneously. As in figure 3.6, with number of fractures increase, individual fracture width decreases, to some point, the width is too narrow to take proppants and screenout is unavoidable.

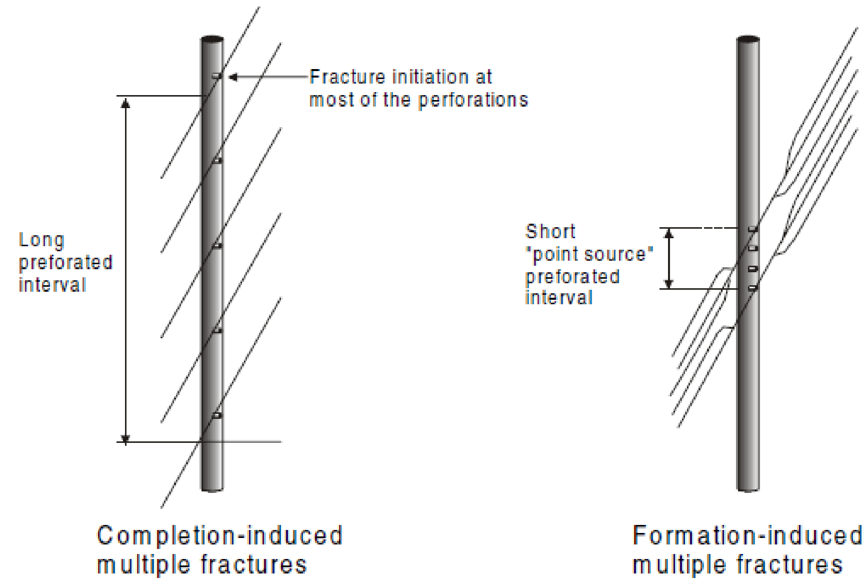

Figure 3.5: Cased-hole multiple hydraulic fractures: (left) A long perforated interval with numerous perforations can provide multiple fracture initiation points; (right) A naturally fractured formation can cause bifurcation of the hydraulic fractures as it intersects these natural fractures (From Weijers, et al., 2000).

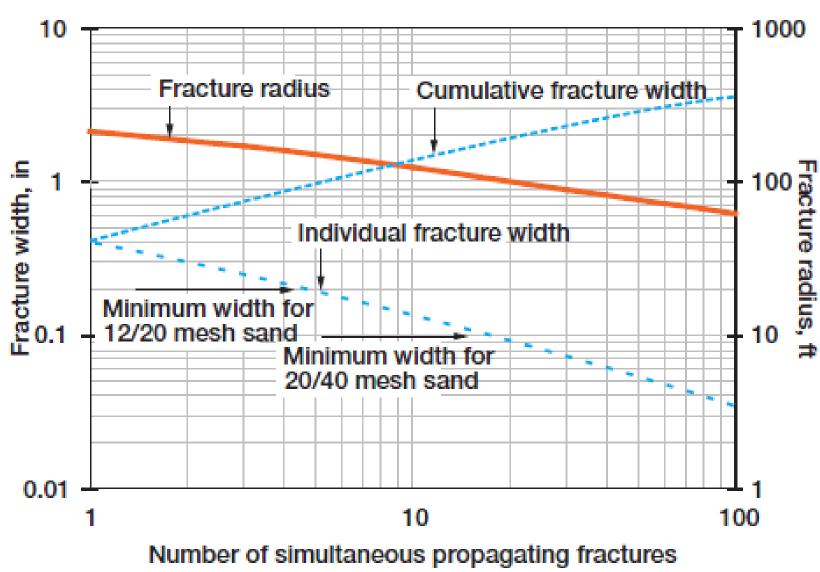

Figure 3.6: Change in individual fracture width, cumulative fracture width and fracture radius with a change in the equivalent number of simultaneous propagating multiple fractures (From Weijers, et al., 2000)

3.4.3 Fluid Horizontal Velocity Loss

As discussed in Section 2.2.2 "Horizontal Transport of Fracturing Slurry", a slurry lateral flow rate inside fractures is highly dependent on a leakoff volume; the more the fluid loss, the slower the lateral flow rate. A fracture tip will always experience higher leakoff compared to later stages (Economides, et al., 2000); a slurry rate along fractures will drop accordingly. This is proved by Brannon et al. (2007) as in Figure 3.7. From the Biot-Medlin analysis, for fracturing fluid to be able to carry proppants uniformly, a vertical settlement rate should be less than or equal to 10% of the horizontal velocity. From the chart below, if fracture geometry is 5 to 1 ratio type of elliptical fractures, at wellbore the horizontal velocity is 17.1 ft/sec while at 500 feet fracture half length, the horizontal velocity is only 0.015 ft/sec (99.99% velocity loss) which requires vertical settlement be to lower than 0.0015 ft/sec to satisfy the relationship. The fracturing fluid is a power law fluid which indicates that fluid viscosity will be degraded as exposed to shear. While the fracturing fluid flows though surface equipments, frac string, along the wellbore and then within the fractures, it will experience lots of shear, so fluid rheology might be degraded resulting in lower viscosity. If the ratio of the vertical proppant settlement velocity vs. the fluid horizontal velocity is greater than 0.1 but less than 0.5, portion of proppants will separate from the carrying fluid and form a bed on the fracture bottom. If the ratio is greater than 0.9, more proppants will fall on the fracture bottom. At a certain point, the proppant bank will block fluid path and result in a treating pressure increase and finally screen out. For a horizontal wellbore, the rate required to keep the proppants in suspension is even higher because there will be rate loss as the fluid travels along horizontal wellbore (Daneshy, et al., 2011).

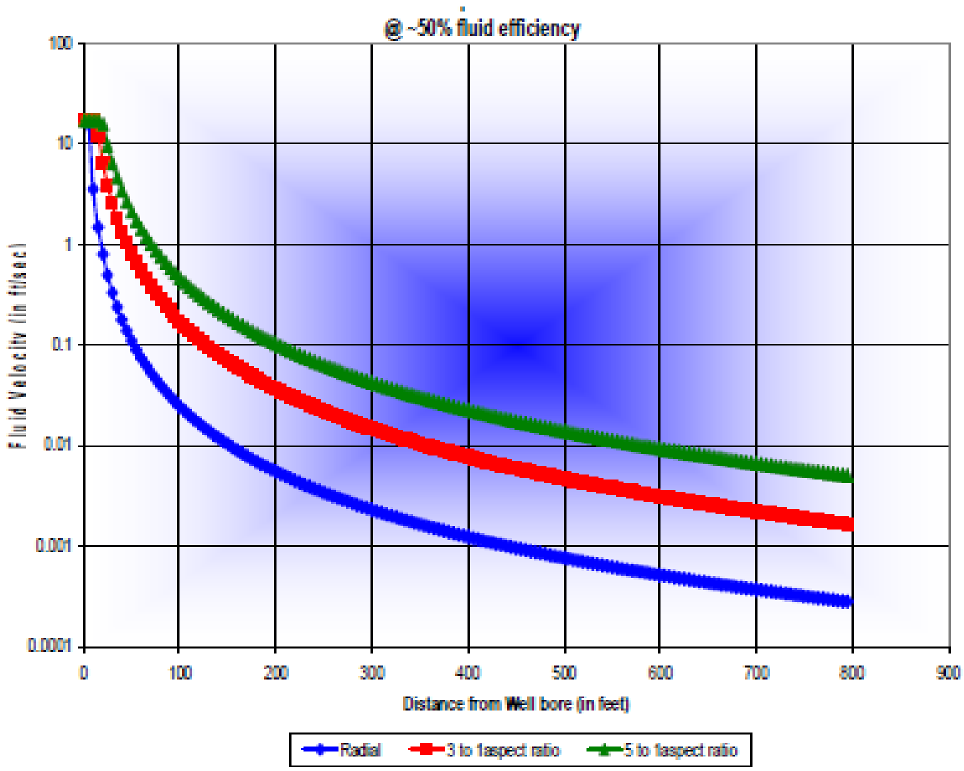

Figure 3.7: Slurry velocity decay vs. distance from wellbore (10 bpm Injection Rate, 10 ft of Height @ Wellbore Velocity 17.1ft/sec @ Wellbore) (From Brannon, et al., 2007)

3.4.4 Near Wellbore Tortuosity

There are three types of near wellbore tortuosity. The first type is already discussed in Section 3.4.2, when wellbore is deviated and perforation interval is long, the fracture plain might be misaligned with wellbore. The second type is the curvature of the fracture pathway leading from the wellbore to the far-field fractures (Figure 3.8). It is well accepted that independent of where fractures are initiated near wellbore, they will align themselves in the direction of the maximum horizontal stress (Aud, et al., 1994). While fractures are trying to bypass the near-wellbore area and align themselves with the maximum horizontal stress, the near-wellbore area will normally have a narrow width. This will possibly cause screenout in higher proppant concentration stages due to the narrower width. The third type of near-wellbore tortuosity is associated with openhole completion. If the wellbore is drilled parallel to the minimum horizontal stress to hope multiple stage fractures will be transverse which means to be perpendicular to horizontal wellbore (minimum stress orientation), in the absence of added factors, the state of stress around the wellbore is such that it promotes initiation of a longitudinal (axial) fracture but will re-orient itself to be perpendicular to minimum horizontal stress far field. It could take few minutes up to more than an hour to re-orient itself. High treating pressure will be observed at the beginning of the job, and then the pressure will drop greatly after it is re-oriented. This re-orientation could result in the treating pressure to exceed maximum allowable treating pressure and result in screenout (Daneshy, 2011).

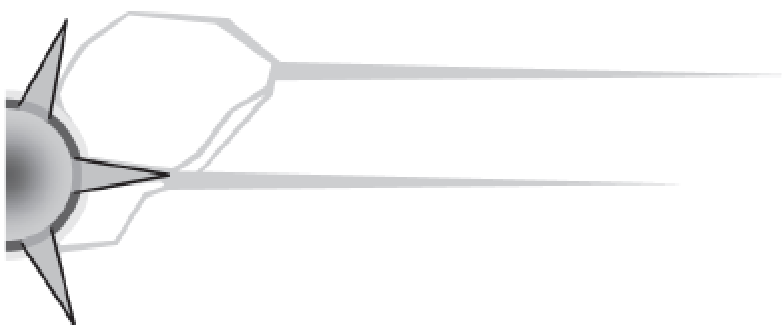

Figure 3.8: Diagrammatic illustration of the restricted flow paths between the perforations and the main fractures that cause tortuosity (From Economides, et al., 2007)

3.5 CHANNEL FRACTURING LOWERED SCREENOUT RATE

3.5.1 Fiber Helps Control Fluid Leakoff

Channel fracturing will add dissolvable fiber throughout a job. The proppant pulse with fiber will stick proppants together (pillar). For a natural fractured reservoir, once fracture pressure exceeds the natural fracture opening pressure, without any fluid loss control mechanism, the fracture fluid will leak off into natural fractures and result in shorter fracture half length and narrow fracture width (Arukhe, et al., 2009). The widths of natural fractures range from $3.9x10^{-4}$ to $2x10^{-2}$ inch for shallow depths (less than 3280 ft) and $3.9 \ x10^{-6}$ to $3.9 \ x10^{-3}$ inch for reservoir depths (4,920 to 23,000 feet) (Nelson, 1949 & 1985). A conventional fracturing job design has utilized 100 mesh sands to block natural fractures by adding the 100 mesh sands before the main treatment. This technique does not work some time because the proppants does not stick together and if natural fractures are in the wider range, excessive fluid leakoff will still occur and result in failure of the job. While channel fracturing pumps fiber throughout the job, the fiber sticks proppants together and creates a net to seal off natural fractures of different sizes (Figure 3.9).

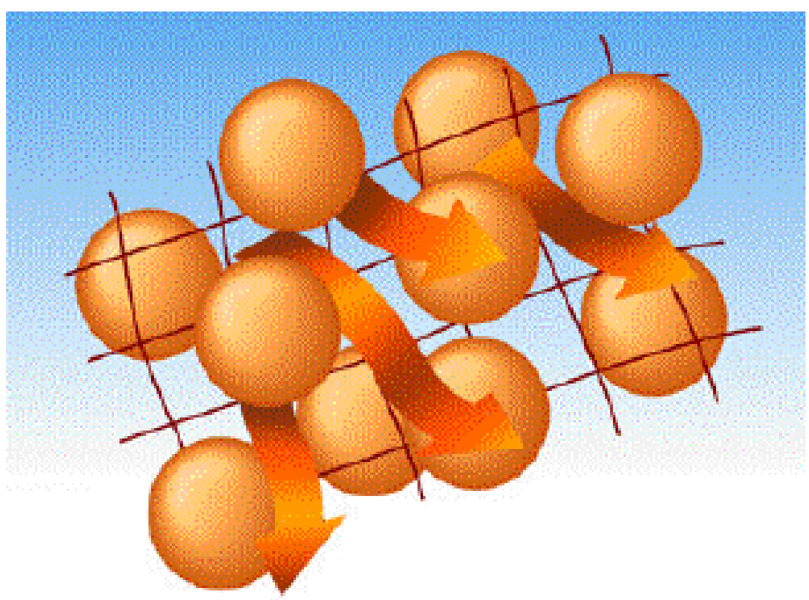

Figure 3.9: Fiber network interlocking proppant (From Heitmann, et al., 2002)

3.5.2 Fiber Helps Carry Proppant

The added fiber throughout treatment can mitigate the dispersion of the proppant-laden pulses as they travel throughout the surface equipment and lines, along the wellbore and within the fractures (Medvedev, et al., 2013). With the addition of fiber, a proppant settle-down rate is greatly reduced (Figures 3.10 and 3.11). From Figure 3.10, proppants are suspended without separation from the fracturing fluid for a long time with the channel fracturing technique which adds fiber to both clean and proppant laden stages. From Figure 3.11, the width of the slot was 0.4 in. A borate-crosslinked gel with 25 lb/1000gal guar loading was used along with 5 lb/1000 gal of oxidative breakers. Both experiments are with the same material except fibers. The group with fiber shows a strong suspension effect (after six hours only a small drop of proppants settled), while the group without fiber shows majority of proppants settling down to the bottom of the pipe (Medvedev, et al., 2013). As discussed in Section 3.4.3, a slurry rate will be cut by a huge amount as slurry travels along horizontal fracture geometry. This put a challenging requirement for fracturing fluid carrying capability on proppant settlement to ensure that a Biot-Medlin ratio is less than or equal to 0.1 so the fracturing fluid can carry proppant uniformly, reduce the amount of proppants settling down to the bottom of fractures, and, furthermore, reduce the chance of proppant deposit blocking the fluid path and inducing screenout.

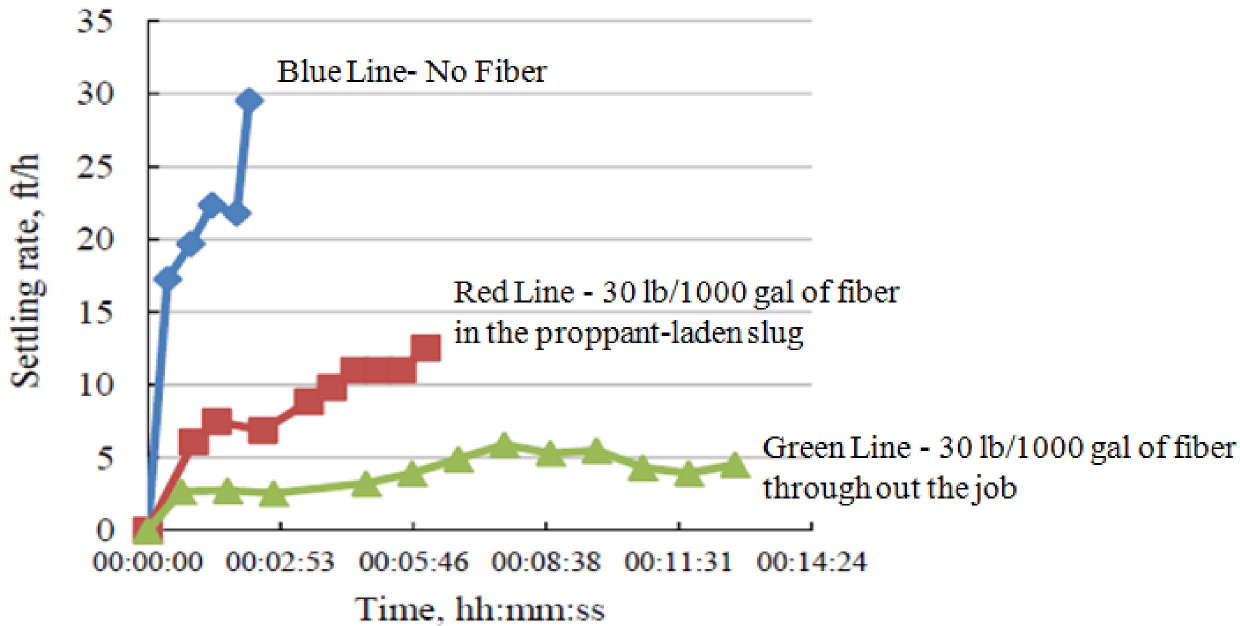

Figure 3.10: Settling rate of front of 12 lb/gal added proppant slug in a slot with different fiber concentration as shown in the plot (From Medvedev, et al., 2013).

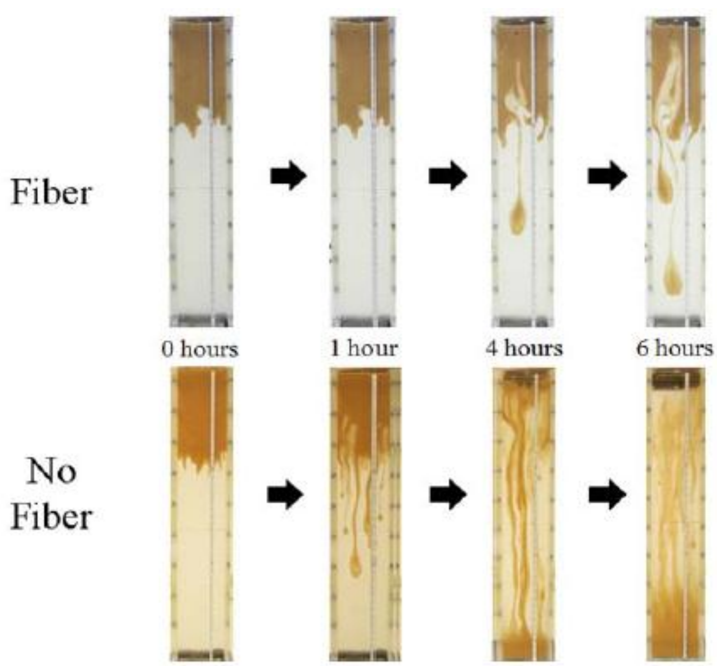

Figure 3.11: Proppant slug setting with and without fiber (From Medvedev, et al., 2013)

3.5.3 Pulse Stages Help Release Screenout

The low incidence of screenout with channel fracturing is the result of the combination of the reduced usage of proppants and intermittent pumping of proppant-free, fiber laden slugs (‘sweeps”) which mitigate an accumulation of proppants in the near-wellbore area (Medvedev, et al., 2013). The average density of different stages for channel fracturing is lower than conventional hydraulic fracturing as the proppants are added to about half of the job leaving the other half with a clean fluid during the intermittent proppant adding process. It has been studied in the lab that lower slurry density will settle slower. With a mitigated slurry density decrease, a convection effect will be smaller between stages which could also be the factors that help to place the job. The intermittent pumping of proppant-free and fiber laden slug’s stages contribute more on preventing screenout. Figure 3.12 shows a pressure difference between two tests; for the Red line - injection of proppant laden fluid, a 0.03 gal proppant laden slug was injected through the slot and for the Blue line – pulsed injection of alternate slugs of proppant-laden and proppant free fluid with borate –crosslinked gel with 25 lb/1000 gal guar loading was used as a clean fluid and carrier fluid for proppants. From this plot we can tell that bridging can be delayed by 50% with channel fracturing pulse injection of proppants compared to conventional continuous injection.

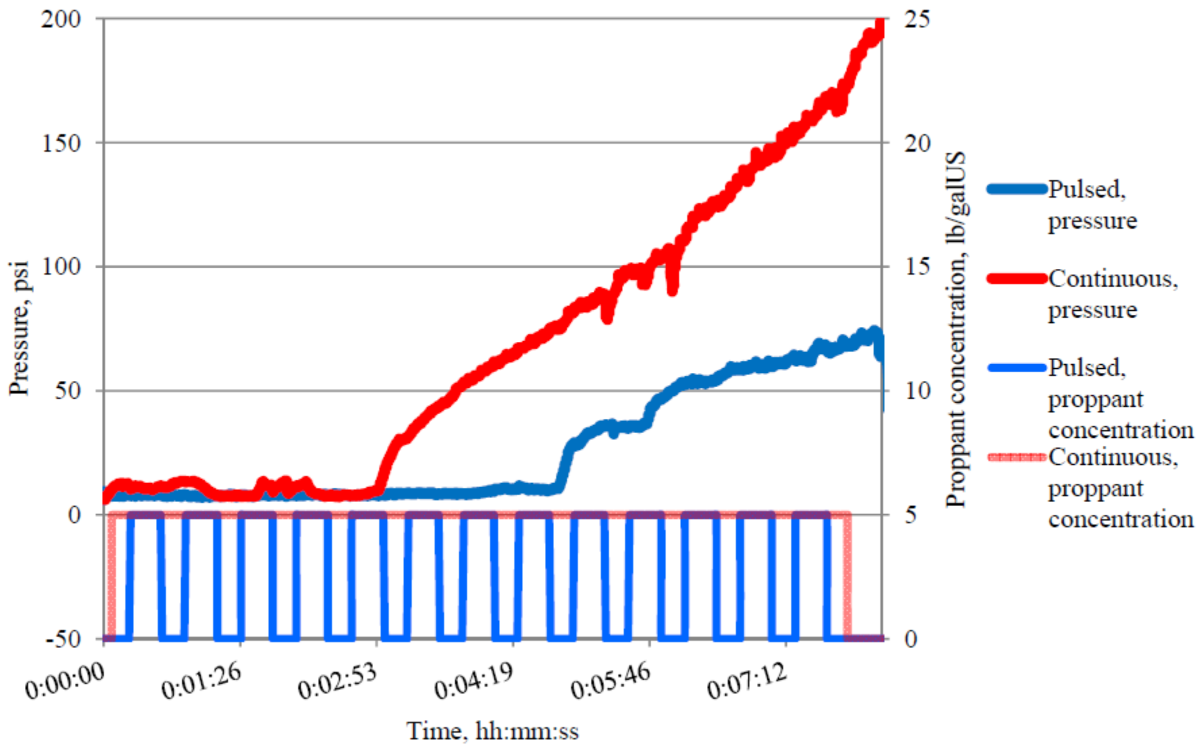

Figure 3.12: Comparison of screenout characteristics of continuous and pulsed injection proppant (From Medvedev, et al., 2013)

3.5.4 Viscous Fluid Reducing Multiple Fractures and Mitigating Near Wellbore Tortuosity

For deviated wellbore with a multiple long perforation interval or openhole completions with induced or natural near-wellbore fractures, there is a trend to develop several competing fractures. A complex near-wellbore geometry composed of multiple fractures competing for opening space results in narrower width per fracture. For a proppant laden fluid to pass through, fracture width has to satisfy the ratio discussed in Section 2.3. Higher proppant concentration requires wider width to allow proppants to propagate without bridging the path. High viscosity of the fluid entering a fracture will affect the pressure drop inside fractures. If this pressure drop is sufficient to cause flow through the fractures or if the viscosity is high enough and the fracture width is small enough, it may not cause the viscous fluid to flow down the fractures, reducing the total number of fractures that are propagated. Also, the viscoelastic nature of crosslinked fluids will make it difficult for the fluid flow to be split between fractures, so high viscous fluid will help to reduce the number of fractures created simultaneously (Aud, et al., 1994)

Tortuosity is caused by restricted flow paths between the perforations and the main body of the fractures; it can often be difficult to pump even moderate proppant concentrations into the fractures. Proppant bridging in the near-wellbore area is all too common. The crosslinked fluid due to its excellent carrying capability, together with an increased rate and pressure, can help to create wider width and cure tortuosity.

After all the analysis, some conclusions can be made:

- Cannel fracturing can reduce fluid leakoff dramatically because fiber can help to seal off natural fractures.
- Channel fracturing technique can also help transport proppant due to its excellent proppant carrying capability with fibrous materials.
- Channel fracturing can help to mitigate tortuosity due to its high viscosity and carrying capability
- Channel fracturing can reduce possibility of creating multiple fractures.
- Channel fracturing can clean the temporary proppant hold up by clean pulse stages, clean the path for later stages.

So, it is predictive that channel fracturing will increase successful placement rate compared to conventional hydraulic fracturing job.

CHAPTER FOUR: RESULTS AND DISCUSSIONS

Since the first channel fracturing job was introduced in Canada in year 2011, there have been eight formations and 389 stages pumped with 100% successful placement. Channel fracturing can help place a job as designed. This chapter will focus on two areas that used to have the screenout issue; with implementation of the channel fracturing technique, “0” screenout is achieved on both areas. The two areas are representative with the current two popular completion techniques; the first area is Wild River field that is completed with vertical multiple stages cased-hole plug and perforation; the second area is Western Canadian Sedimentary Basin cardium formation and is completed with horizontal open-hole multiple stages completion.

4.1 CASE STUDY 1: WILD RIVER MULTIPLE FORMATIONS

Up to today, there are 21 wells and 56 stages fractured with the channel fracturing technique in Western Canadian Deep Sedimentary Basin Wild River field (Figure 4.1 for field location). Formations completed include Cadomin, Blueksy, Gething, Wilrich, Falher, Notikewin and Viking (Figure 4.2 for a cross-sectional diagram of the formations). All the formations are unconventional tight gas and the wells are producing commingled from all formations completed.

4.1.1 Geology

Wild River is located in South West of Alberta as in Figure 4.1. It is an early Cretaceous, basin-centered, tight gas sand with multiple stacked tight sandstone and conglomerate gas reservoirs. Geological parameters are given as in the following table (Colwell et al, 2006). Cadomin formation is present in every Wild River well, and is a braided channel deposit, sources by conglomeratic and sandstone alluvia fans to the west (Tamayo et al, 2008).

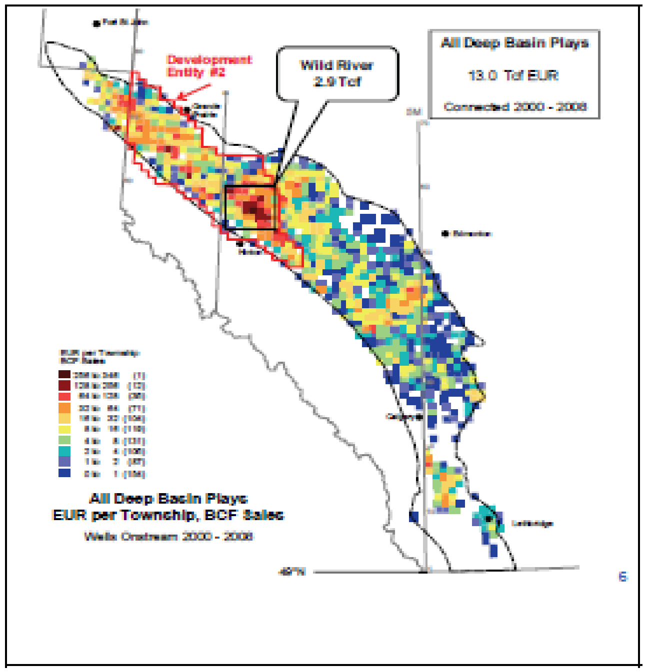

Figure 4.1: Wild River field location (From Dixon, et al., 2010)

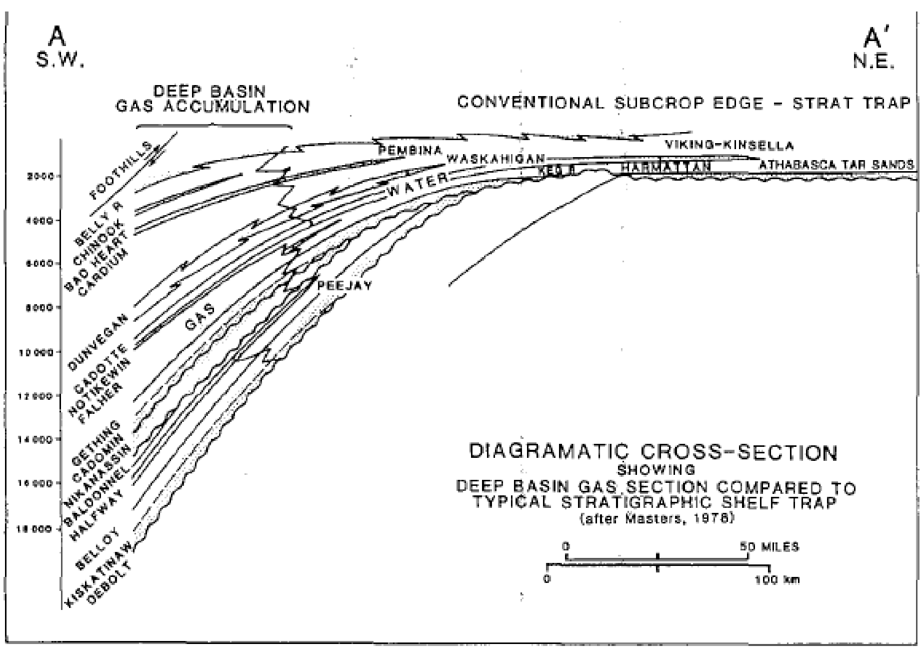

Figure 4.2: Diagrammatic cross section showing Deep Basin Gas Section compared to typical stratigraphic shelf trap (From Maters, 1978)

Formation	Depth	Temperature	Pressure	Permeability and Porosity
Viking	7,800–8,500 ft	185–194°F	4,350–5,100 psi	0.5–1 md 10–12%
Mannville	8,200–9,500 ft	185–212°F	3,500–4,800 psi	0.05–1 md 6 –10%
Falher	9,200–9,800 ft	203–212°F	3,900–4,100 psi	0.05–1 md 6–10%
Bluesky	9,500 ft	203–212°F	3,600–4,200 psi	0.5–1 md 6–12%.
Gething	8,900–10,500 ft	203–221°F	3,200–4,650 psi	≈0.01 md 6–12%
Cadomin	9,200–10,500 ft	203–230°F	2,900–3,350 psi	0.01–1 md 6–10%

Table 4.1: Wild River geological parametres (From Colwell et al., 2008)

4.1.2 Completion History

Vertical or deviated wells were drilled into all formations as in the above table and produce all formations as commingled is a common practice in the wild river area. Due to the low permeability tight reservoir characteristic of all formations in this field, hydraulic fracturing is a must to make the wells production economic. From the above table formations properties are quite different which pose a challenge to hydraulic fracturing treatment. The wells in Wild River are completed with cased-hole, then used plug and perforation to frac some or all target zones (Colwell et al., 2006). Depending on the barriers in between zones, sometimes it is feasible to combine two or even three zones together to save completion costs and be more efficient.

Conventional hydraulic fracturing parameters in Wild River are:

- Pumped down: Casing or annulus
- Pump Rate: 25.2 to 50.3 bbl/minute
- Maximum Proppant Concentration: 3.8 lb/gal
- Fracturing Fluid: Borate crosslinked water

- Proppant: 20/40 or 30/50 Econoprop with 100 mesh sand for fluid leakoff control in Pad stage
- Job size: 66140 lbs to 176370 lbs per zone based on thickness of pay

4.1.3 Conventional Hydraulic Fracturing Placement Issue in Wild River

It has been always challenging to frac the tight gas formations in the Wild River area before the introduction of a channel fracturing technique. Engineers have tried different types of techniques to mitigate the risk of screenout or have to cut the job earlier, such as to pump more viscous fluid, pump a smaller mesh size sand plug before the real job, and pump at a higher rate; though the success rate was increased with a better understanding of this area and lessons learnt, successful placement is still not always achievable. There are cases that screened out very badly with only a small portion of designed proppants being placed (Figure 4.3) and there are more cases where engineers have to terminate the job earlier due to pressure climbing and fear of screenout (Figure 4.4) with only a portion of the designed job being placed. The red line in the figures is the surface treating pressure that includes the tubular friction pressure and the hydrostatic pressure to calculate the bottomhole pressure. As discussed in Section 3.3.2, if we use the surface pressure to estimate the bottomhole pressure, the conclusion is very vague. Luckily these two jobs have the tubing pressure as deadstring because the jobs were pumped down annulus, so the tubing pressure is a vivid bottomhole pressure measurement except a hydrostatic pressure difference. From both plots, we can see that the bottomhole pressure keeps climbing after added proppants until the job has to be terminated early or screenout occurred due to several possible causes. It was estimated that 10% of fracturing jobs in that area has screened out and 12% of jobs were cut early, so total 22% of jobs were not placed as designed.

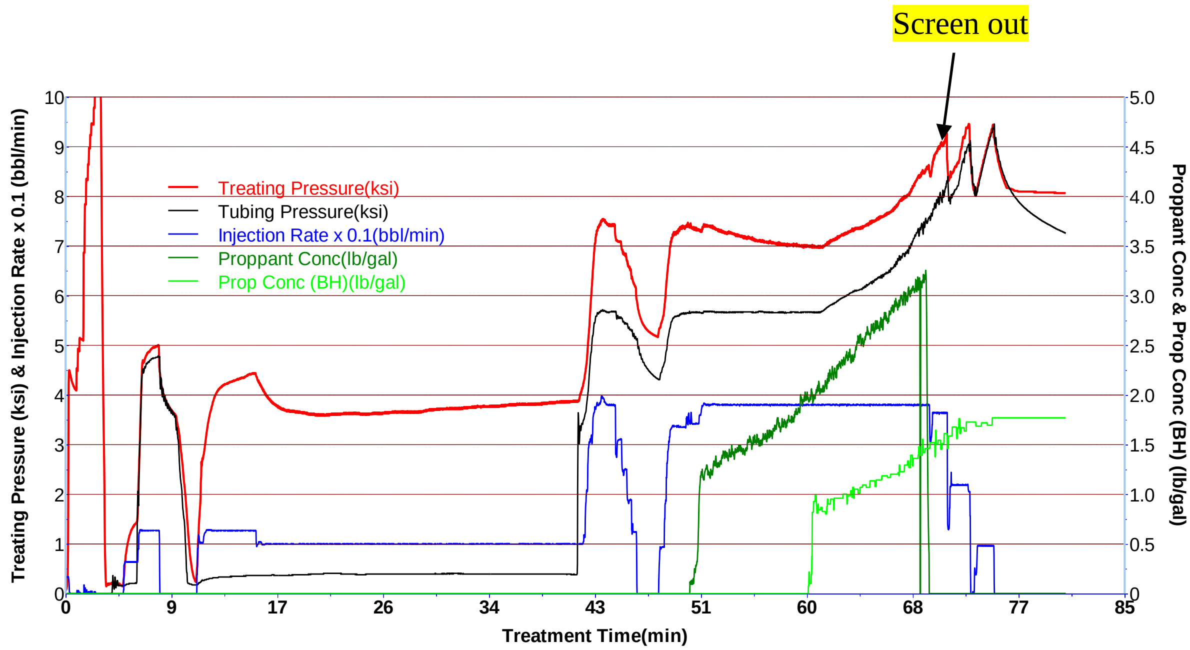

Figure 4.3: Wild River Cadomin formation screen out with 11,023 lbs pumped out of 88,185 lbs designed (Treatment data from Schlumberger fracturing job database)

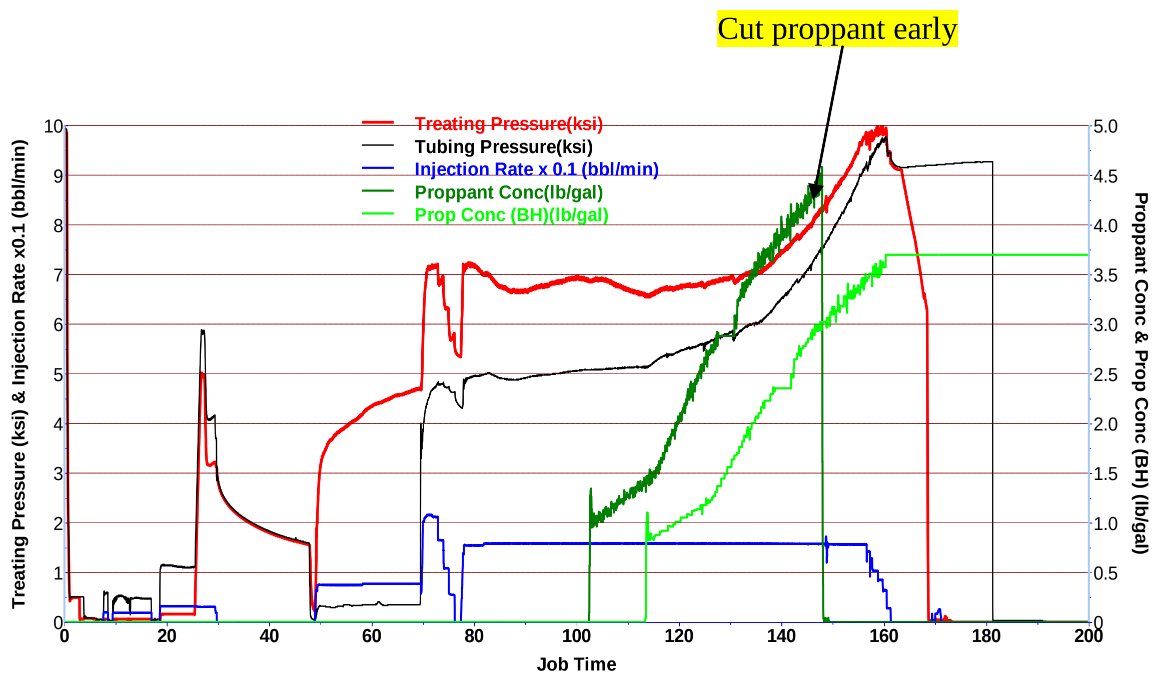

Figure 4.4: Wild River Cadomin formation cut sand with 57,320 lbs pumped out of 132,277 lbs designed (Treatment data from Schlumberger fracturing job database)

4.1.4 Cause of Screenout in Wild River field

4.1.4.1 Near-wellbore Tortuosity

A phasing of 180^0 on perforation was used in this area, which could result in turning of fracture wings to align with the maximum horizontal stress. That could result in higher than normal treating pressure as reported by Colwell (2008). The oriented perforation technique and 60^0 phasing would help to reduce the risk of near-wellbore tortuosity so to lower the risk of higher treating pressure or pressured out to make sure that the job will be placed successfully. A borate crosslinked fluid is always a popular fluid in this area due to its high carrying capability when passing through the near-wellbore restricted area and its high viscosity to keep fractures width wider. However, there are still cases, when orientated perforation is not available, the field will still observe a certain degree of the tortuosity effect during the placement and may result in job failure.

4.1.4.2 Excessive Fluid Leakoff to Natural Fractures.

Tight gas reservoirs tend to have some natural fractures. Pressure dependent leak-off has been also observed and reported in tight gas reservoirs (Arukhe, et al., 2009). Fluid leak off will increase dramatically if there are a lot of natural fractures once fracturing pressure is higher than opening pressure of the natural fractures. Fluid is easy to leak into natural fractures with very small throat to take proppants, leaving proppants behind. The densitified proppant slurry will need more energy to move, so treating pressure will start climbing. To a certain point, the slurry stops moving or moving pressure exceeds the maximum surface treating pressure and causes pressure out or screenout.

4.1.4.3 Multiple Competing Fractures

Most of wells in this area are highly deviated and with big perforation intervals while companies are trying not to miss any sweet spot or combine two and three zones together to save completion costs, so a big perforated interval with highly deviated wellbore, together with natural fractures in wellbore area, will tend to create multiple competing fractures. While competing for energy to keep fractures open, surface treating pressure will keep climbing until reaching the point where frac engineers have to terminate the job to stay below the maximum treating pressure.

4.1.5 Channel fracturing Candidate Selection, Job Design, Simulation, Optimization and Execution

To ensure channel fracturing treatment can be executed successfully and create high conductive fractures, engineering design must be incorporated.

4.1.5.1 Candidate Selection

Several criteria and considerations were applied to select proper candidates including:

- Cased-hole wells not perforated yet, so an engineering design on a perforation interval and the number of perforations can apply to facilitate a channel fracturing design with open channels. This needs optimization on the perforation interval and the number of clusters per interval with the assistance of a simulator.
- Rock stiffness: Ratio of Young’s modulus over closure stress should be above certain number.
- Offset wells with the same types of conventional jobs performed available, so execution and production can be evaluated over these two techniques.

4.1.5.2 Simulation

P3D simulation software is utilized to help optimize treatment parameters including perforation intervals, the number of clusters, shot density, a pump rate, proppant ramp up and maximum proppant concentration. Compared to conventional fracturing, a channel fracturing perforation strategy used is typically designed to cover a larger portion of the fracture height, which is important to achieve more uniform distribution of proppant pillars across the height and achieve the optimum geometry of the channels (Gillard, et al, 2010). The following data are inputs for Schlumberger FracCADE simulator to complete the simulation.

4.1.5.2.1 Well Data

- Treatment pumped down: casing
- Well total depth: ft
- Reservoir temperature: ^{0}F
- Deviation survey
- Casing size and depth
- Perforation top and bottom depth: ft
- Shot density: shot per foot
- Entrance diameter: in
- Tunnel length: ft

4.1.5.2.2 Zone Data

For a channel fracturing technique, formation mechanical properties are critical to select the proper well, predict fracture geometry and optimize a channel fracturing job design. The stress profile is required from processed DSI logs or Image Scanner logs, and then calibrated with core analysis and injection tests (Figure 4.5 for Wild River Open Hole Logs).

- Formation top depth: ft
- Type of rock: Shale/Sand Stone/Dirty Sandstone/Dolomite/limestone/Coal
- Formation leakoff Height for each interval: ft
- Net Height: ft
- Permeability: md
- Porosity: %
- Fracture gradient, psi/ft
- Young's Modulus: ksi
- Poisson's Ratio
- Fracture Toughness: psi.in$^{0.5}$
- Spacing: acres
- Gas/Oil/Water Saturation: %
- Rock/Total Compressibility: 1/psi
- Heat Capacity: Btu/lb/^{0}F

4.1.5.2.3 Fracturing Fluid

Crosslinked gels as a carrying fluid for the fracturing jobs is the main fluid for a channel fracturing job (Samuelson et al., 2012). For the jobs in the Wild River area, the crosslinked fluid is also the main fluid. Based on a bottomhole temperature range from 185 to 203 ^{0}F, 25 lb/1000 gal of gel was selected and lab-tested. Fluid viscosity is 170 cp at shear rate 170 s^{-1} and reservoir temperature condition. Fluid leakoff control is total of three leakoff control mechanism as discussed in 1.3.4, and a total leak off is used as 0.003 ft/min$^{0.5}$.

4.1.5.2.4 Proppants

Due to the depth of the reservoirs and high closure stress, ceramic proppants were pumped into conventional jobs and are also selected for channel fracturing jobs with the same mesh size as conventional jobs for different zones, either 20/40 or 30/50, respectively. 100 mesh sand is also added to the pad stage as scour, together with fiber to better control the fluid leakoff issue.

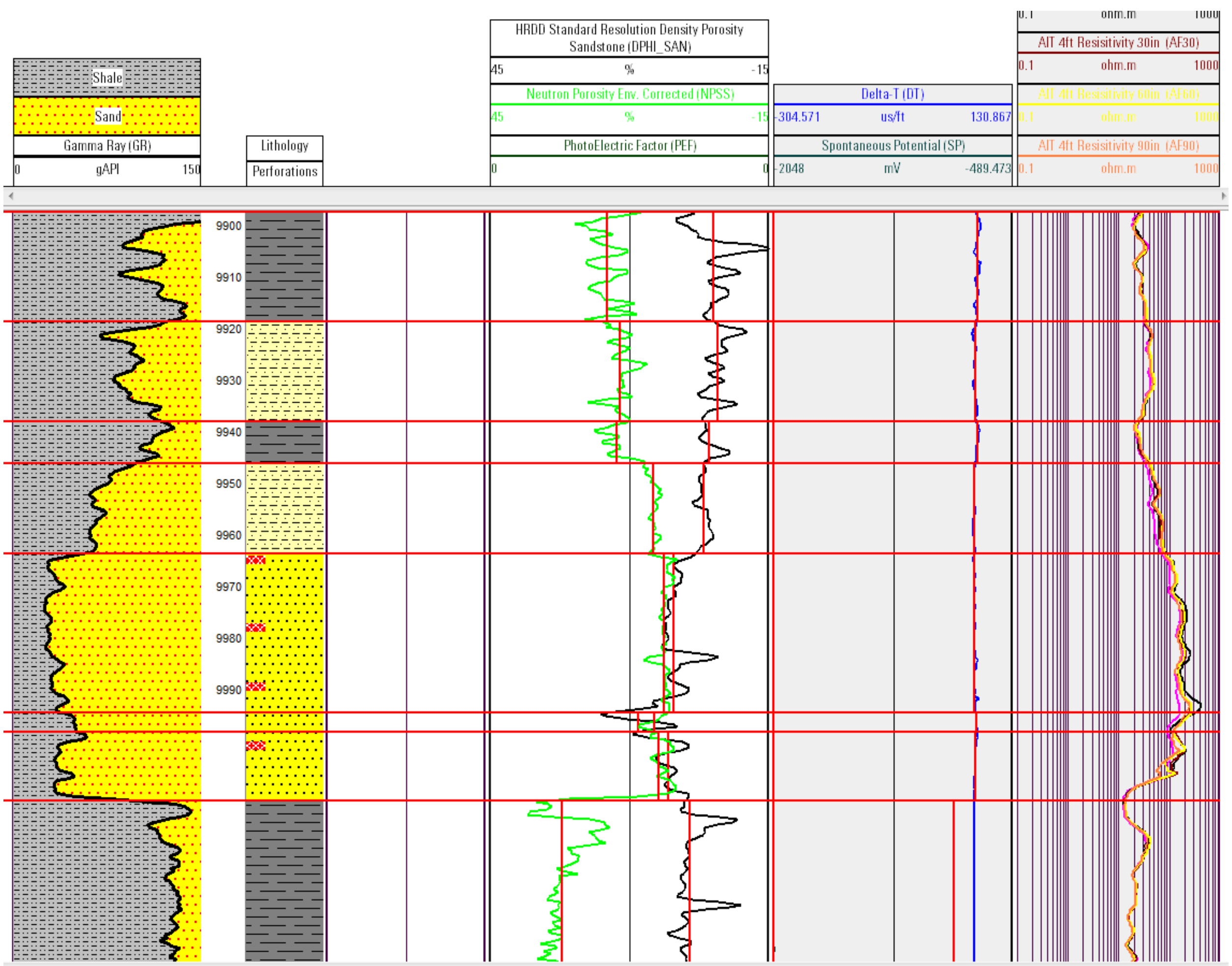

Figure 4.5: Wild River Cadomin formation openhole logs (From GeoSCOUT public database)

4.1.5.2.5 Pumping Schedule

For channel fracturing compared to conventional fracturing, pump clean pulse and dirty pulse after the pad stage, a pumping schedule must be generated by a simulator after optimizing all parameters. In Table 4.2, due to the pulsing clean and dirty stages, proppant mass does not follow material balance as for conventional fracturing; for example, at the Stage 3 (1 lb/gal stage) which is highlighted in yellow, if it were a conventional stage, proppant mass should be 1 lb/gal x 5574 gal =5574 lb, not 2734 lb. The reason is because the addition of clean fluid pulse in cycles. In the last tail-in stage that is highlighted in green, however, there is no pulse to ensure a stable, uniform and reliable connection between the channelled fracture and the wellbore (Gillard et al., 2010).

4.1.5.2.6 Optimization

Channel fracturing simulation is based on conventional P3D model and then adding a channel fracturing model to optimize job design parameters to create open channels by simulation results. The percent of pad fluid, proppant ramp up, and a pump rate will affect simulation results regarding if there are open channels from a tip to a near-wellbore section. Numerous iterations of the above listed parameters finally result in open channels from wellbore to the tip (Figure 4.6). On this figure, the very left track is the stress profile for different zones, scale is from left to right (low to high). Y-axis is depth in ft for different zones. The middle track is fracture width profile and the figure shows that the middle of the fracture (perforated zone) developed wider width. The right track is the fracture width in inch along fracture geometry.

BOTTOMHOLE PUMPING SCHEDULE

Stage Name	Injection Rate (bbl/min)	Fluid Name	Fluid Volume (w/Gas) (bbl)	Prop Name	BH Prop Con. (lb/gal)	Prop Mass (lb)	Cum Prop Amt (lb)	N2 Volume Factor (scf/bbl)	Slurry Volume (bbl)	CumSlurry Volume (bbl)	Pump (min)
PAD	18.9	YF125LGM N2	220.1		0	0.0	0.0	1791.5	220.1	220.1	11.7
PAD - Scour	18.9	YF125LGM N2	105.0	100 mesh Sand	1	4418.1	4418.1	1791.5	110.1	330.2	5.8
Stage 3	18.9	YF125LGM	132.7	30/50 Econoprop	1	2735.9	7154.0		135.9	466.1	7.2
Stage 4	18.9	YF125LGM	217.0	30/50 Econoprop	2	8741.3	15895.3		226.4	692.5	12.0
Stage 5	18.9	YF125LGM	202.5	30/50 Econoprop	3	11966.7	27862.0		215.1	907.6	11.4
Stage 6	18.9	YF125LGM	235.2	30/50 Econoprop	4	18152.8	46014.8		254.1	1161.7	13.5
Stage 7	18.9	YF125LGM	103.2	30/50 Econoprop	5	9729.0	55743.8		113.2	1274.9	6.0
TAIL-IN	18.9	YF125LGM	12.6	30/50 Econoprop	5	2645.5	58389.4		15.1	1290.0	0.8
FLUSH	18.9	WF110	156.6		0	0.0	58389.4		156.6	1446.7	8.3
Totals			**1385.0**			**58389.4**	**58389.4**		**1446.7**	**1446.7**	**76.7**

SURFACE PUMPING SCHEDULE

Stage Name	Clean Fluid Volume (gal)	Cumulative Clean Fluid (gal)	Blender Prop Conc (lb/gal)	Breaker 1 Conc. (lb/1000gal)	Breaker 2 Conc. (lb/1000gal)	Breaker 3 Conc. (lb/1000gal)	Stabilizer Conc. (gal/1000 gal)	N_2 Foam Quality (%)	Clean Fluid Rate (bbl/min)	Slurry Rate (bbl/min)	N_2 Rate (scf/min)	N_2 Volume (scf/min)
PAD	7406.1	7406.1	0	4.17	0.83		0.0	19.9	15.11	15.11	6722.6	78654.9
PAD - Scour	3494.0	10900.1	1	4.17	0.83		0.0	20.8	14.94	14.95	6722.3	39213.3
Stage 3	5574.0	16474.1	1	4.17	1.67		0.0	0.0	18.86	18.87	0	0
Stage 4	9113.9	25588.1	2	4.17	2.50		0.0	0.0	18.86	18.87	0	0
Stage 5	8506.3	34094.4	3	4.17	2.50		0.0	0.0	18.85	18.87	0	0
Stage 6	9880.0	43974.4	4	4.17	3.33		0.0	0.0	18.84	18.87	0	0
Stage 7	4332.4	48306.9	5	4.17	3.33		0.0	0.0	18.83	18.87	0	0
TAIL-IN	528.3	48835.2	5	4.17	4.17		0.0	0.0	18.83	18.87	0	0
FLUSH	6577.9	55413.1	0	0.00	0.00	1.67	0.0	0.0	18.87	18.87	0	0
Totals	**55413.1**			**203.5**	**112.0**	**11.0**	**0.00**					**117868**

Table 4.2: Cadomin channel fracturing pumping schedule

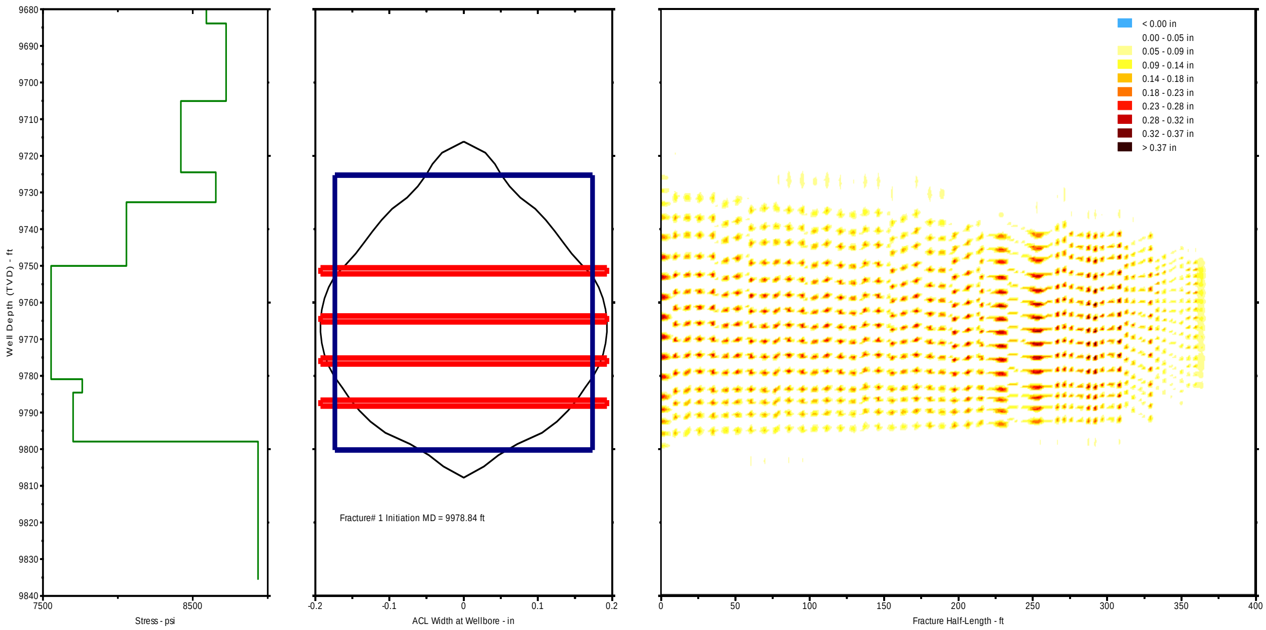

Figure 4.6: Channel fracturing geometry (By Schlumberger FracCADE simulator)

4.1.5.2.7 Field Execution

For the channel fracturing technique, treating pressure is lower than that for conventional fracturing as shown in Figure 4.7. Compared to conventional hydraulic fracturing treatment, successful placement is achieved. Higher maximum proppant concentration of 5.0 lb/gal was placed with no dramatically pressure increase on channel fracturing treatment, while conventional hydraulic fracturing could hardly place maximum bottomhole proppant concentration of 3.75 lb/gal. The reasons that the channel fracturing technique works on the wells in the Wild River tight gas formations can be concluded as follows:

- Fiber together with 100 mesh sand helped fluid leakoff control, especially plugged fluid leakoff to natural fractures.
- High viscosity fluid together with 100 mesh helped to mitigate the effect of near-wellbore tortuosity and reduced the possibility of multiple competing fractures.

- Fiber helped carry proppants horizontally and slow proppant settlement due to gravity and convection effect.
- Pulse stages helped release screenout.

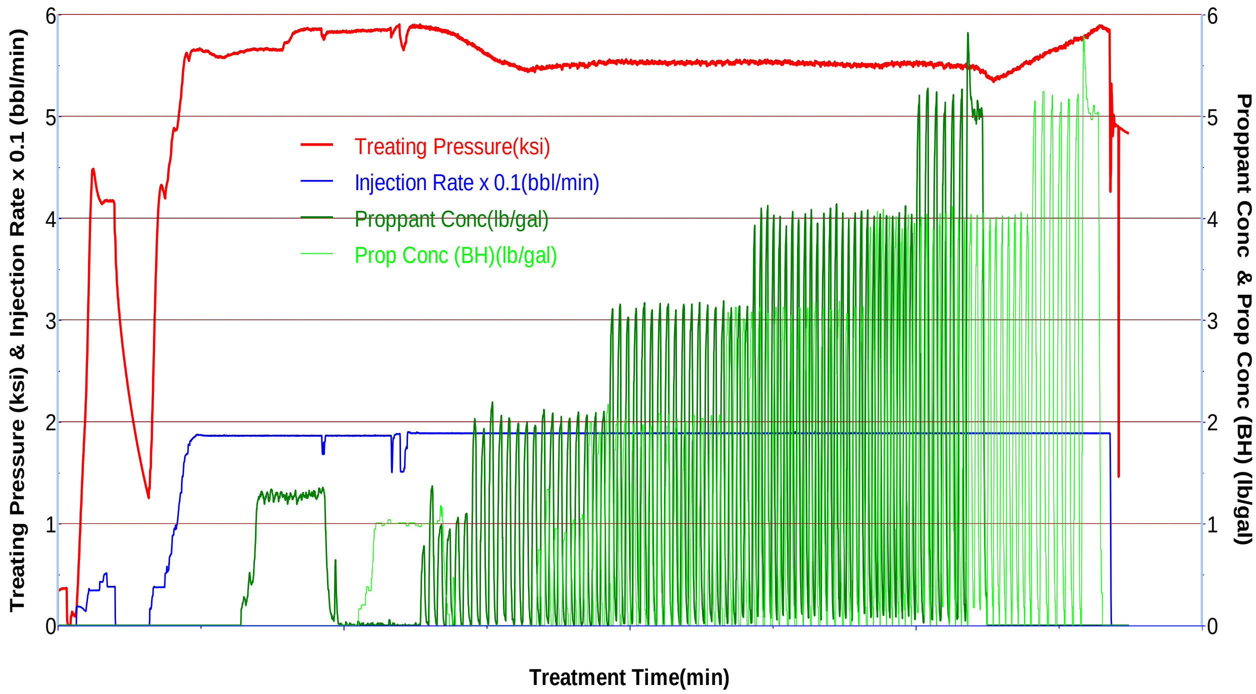

Figure 4.7: Wild River Cadomin formation channel fracturing treatment plot (Treatment data from Schlumberger fracturing job database). Note: treatment time is hidden for confidentiality reason

4.2 CASE STUDY 2: WESTERN CANADIAN SEDIMENTARY DEEP BASIN CARDIUM FORMATION

Up to today, there are 15 horizontal and three vertical cardium wells with total 97 channel fracturing stages pumped in Canada and all jobs placed successfully. The well locations are shown in Figure 4.8 and highlighted with a yellow circle.

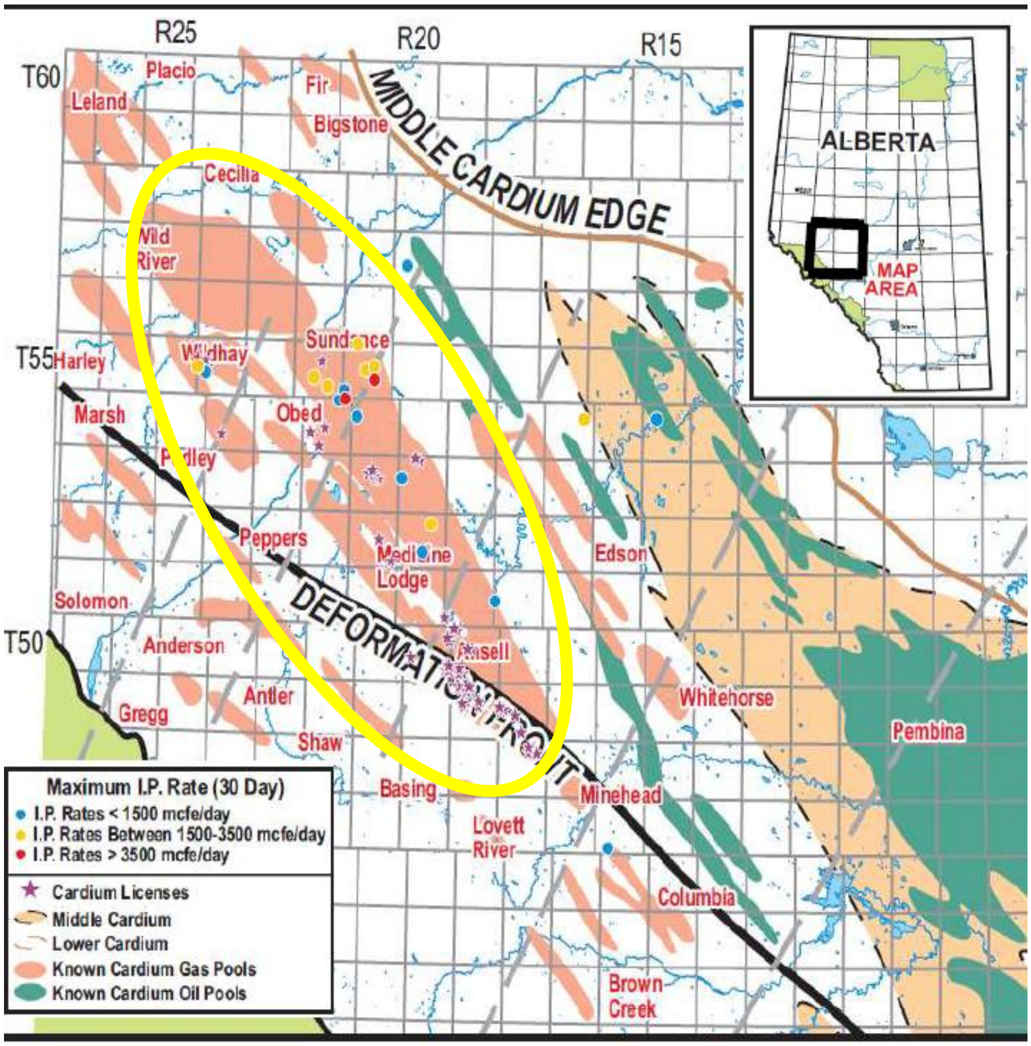

Figure 4.8: Cardium wells location (From CIBC resource Play watch March Report)

4.2.1 Geology

Chapter 2 of the Geological Atlas of the Western Canada Sedimentary Basin includes a detailed description of the cretaceous Cardium Formation. The formation has been described as a clastic wedge that protruded into the western interior seaway during Turonina - Coniacian time (Plint et al., 1986; Krause et al., 1994). In the target area, the formation is encountered at an approximate depth of 7,545 ft. It was deposited in a marine-to coastal setting consisting of a continuum of muddy and sandy shelf facies. The formation is composed of the two sediment units (Hoch et al., 2003):

- Basal Cardium Sand – Hydrocarbon reservoir from shales to sandstones and variably thick conglomerates.
- Upper Cardium – Hydrocarbon seal mainly shale with lesser amounts of fine-grained sandstone.

The Cardium formation is dominated by a fine-grained sandstone with interpartical porosity that is typically less than 9%. Matrix permeability is typically less than 1 md (Hoch et al., 2003).

4.2.2 Completion History

In recent years, there are more and more horizontal wells drilled into Cardium formation with openhole completion. Because the reservoir is tight gas formation, permeability is low, hydraulic fracturing is required. Multiple stage ball dropping continuous operation fracturing is normal in this area with a number of stages varying from 4 to 10 along the horizontal wellbore. Each stage varies from 260 ft up to 656 ft. Horizontal wellbore could be 4,921 ft long. The total measured depth is around 14,760 ft in some areas. Cardium like all tight gas reservoir formation is a natural fracture rich reservoir. The primary goal of completion is to connect the natural fractures (Hoch et al., 2003).

Conventional hydraulic fracturing parameters in Cardium

- Pumped down: Casing or Tubing
- Pump Rate: 25.0 to 31.5 bbl/minute
- Maximum Proppant Concentration: 4.2 lb/gal
- Fracturing Fluid: Borate crosslinked water

- Proppant: 30/50 Econoprop with 100 mesh sand for fluid leakoff control in pad stage
- Job size: 132,277 lbs to 176,370 lbs per stage

4.2.3 Conventional Hydraulic Fracturing Placement Issue in Cardium formation

Screenout is also a big concern in Cardium horizontal wells with conventional fracturing (Figure 4.9). The reason is because the wells are multiple stage completion; screenout in early stages will result in delay of the remaining stages. Also, because it is hard to flow back once screenout happened, one has to use coiled tubing to clean up while with fracturing and other parties waiting on location; it is very costly and inefficient. Screenout in Cardium openhole completion is more likely to be in wellbore (Daneshy, 2011). Once pressure starts climbing, it might be already too late to call flush and terminate a job. Most of times it will just screen out leaving wellbore full of high concentration proppants and with less chance to flow back. It was estimated that 5% of fracturing jobs in the Cardium area screened out and 24% of jobs were cut early, so total 29% of jobs were not placed as designed.

4.2.4 Cause of Screen out issue in Cardium Formation

4.2.4.1 Excessive Fluid Leakoff to Natural Fractures

This is similar to the Wild River area multiple formations 4.1.4.2 and will not be discussed in detail.

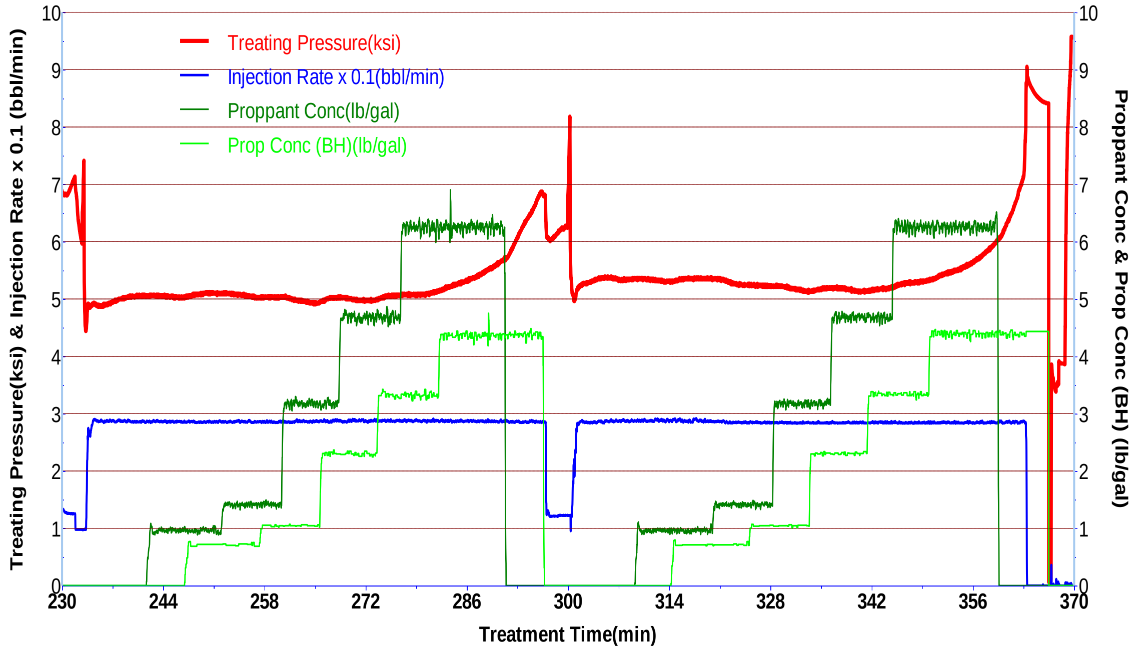

Figure 4.9: Cardium horizontal multiple stages conventional fracturing treatment plot (Treatment data from Schlumberger fracturing job database)

4.2.4.2 Multiple Competing Fractures

Because the wells are openhole completion with a lot of natural fractures, hydraulic fracturing will create multiple fractures if natural fractures are open. Competing multiple fractures will have less width for each set of fractures and at a higher concentration stage may result in screenout.

4.2.4.3 Fracture Re-orientation

Openhole horizontal wellbore fracturing may easily initiate a longitudinal (axial) fracture because of the near-wellbore stress; if horizontal wellbore is drilled along the minimum horizontal stress, in far field fractures will re-orient to follow the maximum horizontal stress and be perpendicular to the minimum horizontal stress (Daneshy et al., 2011). Before fractures align themselves with the maximum horizontal stress (or when they are perpendicular to the horizontal stress), pressure is high and fracture width is narrow which can cause screenout. This is similar to a near-wellbore tortuosity effect with casehole perforation completion discussed previously.

4.2.4.4 Horizontal Velocity vs. Vertical Velocity

The fracturing fluid will travel 13,120 feet to the first frac port with a 3,280 feet of horizontal section, initiate fractures and then travel inside hydraulic fractures for three to six hundred feet depending on fracture geometry. As discussed and illustrated in Figure 3.7., the horizontal fluid velocity drops dramatically when travelling horizontally. If the proppant settlement and convection rate is higher than 90% of the horizontal velocity, proppants will settle on the bottom of the wellbore or inside fracture geometry, slowly block the path of later stages and cause screenout.

4.2.5 Channel Fracturing Pumping Schedule and Execution

Due to a similar fracturing job design and simulation process with the Wild River multiple formations, they will not be repeated in detail on the Cardium formation. Table 4.3 is a pumping schedule for a Cardium horizontal well.

Execution of all channel fracturing on the Cardium formation is with 100% success. Treating pressure is 700 psi to 1000 psi lower than conventional hydraulic fracturing given that all other treatment parameters are the same including pumping down same pipe, at the same rate with the same fluid system, and the same proppant concentration. This further proved that channel fracturing helps job placement. Figure 4.10 is a treatment plot on the Cardium horizontal multiple stages.

BOTTOMHOLE PUMPING SCHEDULE

Stage	Fluid Type	Fluid Volume (w/Gas) (bbl)	Cumulative Fluid Volume (w/Gas) (bbl)	Prop Type	BH Prop Conc (lb/gal)	Prop Per Stage (lb)	Cum Prop Amt (lb)	N_2 Volume Factor (scf/bbl)	Stage Volume (w/Prop) (bbl)	Cumulative Volume (w/Prop) (bbl)	Pump Time (min)	Injection Rate (bbl/min)
Pad	YF125FlexD + N2	402.55	402.55		0.0	0	0	1567	402.55	402.55	14.22	28.30
Pad	YF125FlexD + N2	295.99	698.54	100 Mesh	0.7	8819	8819	1567	305.49	708.03	10.79	28.30
3	YF125FlexD + N2	200.14	898.68	30/50 EconoProp	0.8	3444	12262	1567	203.78	911.81	7.20	28.30
4	YF125FlexD + N2	206.81	1105.49	30/50 EconoProp	1.9	7831	20093	1567	215.08	1126.90	7.60	28.30
5	YF125FlexD + N2	213.41	1318.90	30/50 EconoProp	2.9	12295	32388	1567	226.41	1353.30	8.00	28.30
6	YF125FlexD + N2	209.51	1528.42	30/50 EconoProp	4.0	16030	48418	1567	226.45	1579.76	8.00	28.30
7	YF125FlexD + N2	195.55	1723.97	30/50 EconoProp	5.0	18508	66926	1567	215.11	1794.86	7.60	28.30
8	YF125FlexD + N2	51.14	1775.10	30/50 EconoProp	5.4	5196	72122	1567	56.63	1851.49	2.00	28.30
Tail In	YF125FlexD + N2	22.83	1797.94	30/50 EconoProp	5.4	5196	77318	1567	28.32	1879.81	1.00	28.30
Ball Spacer	YF125FlexD + N2	31.45	1829.38		0.0	0	77318	1567	31.45	1911.26	1.11	28.30
					Launch Ball							
Totals		**1829.38**	**1829.38**			**77318**	**77318**		**1911.26**	**1911.26**	**67.53**	

Pad:	**698.54 bbl**
Frac:	**829.88 bbl**
Pad%:	**46%**

SURFACE PUMPING SCHEDULE

Stage	Clean Fluid Volume (gal)	Cumulative Clean Fluid (gal)	Blender Prop Conc (lb/gal)	BH Prop Conc (lb/gal)	N_2 Foam Quality (%)	Clean Fluid Rate (bbl/min)	Slurry Rate (bbl/min)	N_2 Rate (scf/min)	N_2 Volume (scf)	Breaker 1 Con (gal/1000 gal)	Breaker 2 Con (gal/1000 gal)	
Pad	14181.60	14181.60	0.0	0.0	16.12	23.74	23.74	7144	101607	0.00	2.08	0.00
Pad	10364.28	24545.88	0.9	0.7	16.63	23.59	23.60	7141	77075	0.00	2.08	0.00
3	7000.48	31546.36	1.0	0.8	16.72	23.56	23.57	7146	51445	0.00	2.08	0.00
4	7169.40	38715.76	2.3	1.9	17.46	23.35	23.37	7143	54279	0.00	2.08	0.00
5	7332.03	46047.79	3.6	2.9	18.20	23.13	23.16	7140	57117	0.00	2.08	0.00
6	7132.05	53179.84	4.9	4.0	18.95	22.91	22.95	7142	57141	0.00	4.17	0.00
7	6595.13	59774.96	6.2	5.0	19.70	22.69	22.74	7143	54289	0.83	4.17	0.00
8	1718.17	61493.14	6.8	5.4	20.00	22.60	22.65	7144	14293	0.83	4.17	0.00
Tail In	767.16	62260.30	6.8	5.4	20.00	22.60	22.65	7144	7149	1.67	4.17	0.00
Ball Spacer	1107.94	63368.23	0.0	0.0	16.12	23.74	23.74	7144	7938	1.67	4.17	0.00
					Launch Ball							
Totals	**63368.23**	**63368.23**							**482332**	**10.05**	**168.10**	**0.00**

Table 4.3: Cardium horizontal multiple stages channel fracturing pumping schedule

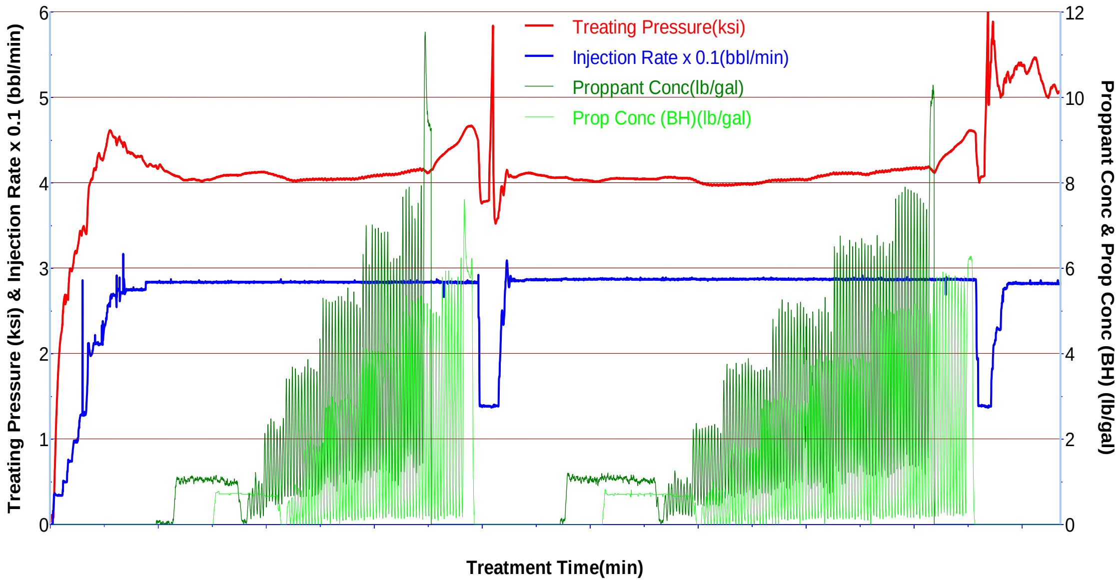

Figure 4.10: Cardium horizontal multiple stages channel fracturing treatment plot (Treatment data from Schlumberger fracturing job database). Note: Treatment time is hidden for confidentiality reason.

The reasons that the channel fracturing technique works on the wells in the cardium formations can be concluded as follows:

- Fiber together with 100 mesh sand helped fluid leakoff control, especially plugged fluid loss to natural fractures.
- High viscosity fluid together with 100 mesh helped to mitigate the effect of fracture re-orientation and promoted a transverse fracture quicker.
- Fiber helped proppants suspend and slowed proppant settlement due to the gravity and convection effect so to satisfy the Biot-Medlin analysis critical ratio.
- Pulse stages helped release screenout or temporary proppant holdup

4.3 SCREENOUT COST SAVINGS WITH CHANNEL FRACTURING

It has been strongly proved with real jobs that almost 400 stages were successfully pumped in Canada without screenout issue, and channel fracturing can greatly reduce the risk of screenout. However, with conventional hydraulic fracturing treatment, there is still a screenout risk. By utilizing the channel fracturing technique, there is a direct cost saving to companies on screenout clean out.

Table 4.4 is a rough estimation on how much channel fracturing could have saved operators with no screenout rates compared to conventional hydraulic fracturing with a certain degree of screenout. Note that in this table the screenout rate is the average of high screenout rate areas/formations and low screenout rate areas/formations. The cost of a cleanout per stage is also averaged.

	Conventional	Channel Fracturing
Screenout Rate	5 %	0%
Early Flush Rate	10 %	0%
Screenout stages	20	0
Early Flush Stages	40	
Success Placement	85 %	100 %
Average Cost per Cleanout	$ 200 K	$ 200 K
Screenout Additional Costs	$ 4,000 K	$ -
EUR/Reserves Changes/Reduction	$?	$ -

Table 4.4: Screenout cost savings for 400 stages

CHAPTER FIVE: CONCLUSIONS AND FUTURE RECOMMEDATIONS

5.1 CONCLUSIONS

This study reviewed all channel fracturing jobs pumped in Canada so far and tried to identify the issues with conventional fracturing job placement on two key placement areas, and then analyzed the benefits with the channel fracturing technique on successful placement. It is very encouraging for companies that seek for a safe placement solution to try this technique given the fact that it is 100% placed with channel fracturing in Canada.

- For channel fracturing pumping a high viscous fluid with degradable fiber added throughout the job and clean pulse and dirty pulse intermittent, this technique is innovative compared to conventional hydraulic fracturing which adds proppant continuously after starting sand stages.
- Channel fracturing still needs to be properly designed with an intensive engineering study to greatly reduce the chance of screenout and help job placement.
- All channel fracturing jobs pumped were with lower treating pressure compared to the same type of conventional jobs and with higher maximum proppant concentration achieved.
- Job placement can be simulated with a proper design and incorporate fracture geometry simulations, but it is very challenging to predict real job events. The simulation will include rock mechanism, fluid flow mechanism, proppant transport mechanism and material balance. Fracture geometry has a big effect on prediction of the job placement.
- Cause of screenout is always more complicated than one can imagine because there are normally more than one event going on at one time. Without bottomhole pressure

measurement, it is very tough for people to predict real downhole pressure trend, as well as how the job is happening downhole.

- A field study has to be conducted to identify the cause of screenout, and then one can come out with solutions on screenout rate control and modify job design parameters to mitigate the risk of screenout.
- The main mechanism of channel fracturing in helping job placement is from better leak-off control, good fluid suspension capability on proppants and the pulse stage that releases temporary proppant bridging.
- Proppant dehydration due to higher leak-off to natural fractures is causing more screenout than other types of causes in an unconventional tight gas reservoir.
- Proppant transport in fracture geometry includes horizontal travel and a vertical settlement and convection effect. To help place the job, the ratio of horizontal velocity vs. vertical velocity should be kept as big as possible, so proppants do not settle down on the bottom of the wellbore and fractures to block the path of later stages.
- The cost of screenout could be very severe if not planned and designed properly.

5.2 FUTURE RECOMMENDATION

- Both fields studied in this paper should perform a Datafrac analysis to confirm that a natural fracture fluid leak-off is a big issue. A calibration test should also be performed to calculate fracturing fluid efficiency and better design future jobs.
- The two case studies in the paper only focus on individual wells placement behaviour without field stress available; this should be looked at based on an intensive geomechanical study to come out with more convincing solutions.

- For this paper, the author did not study a placement issue with a complex fracture network module which is very common nowadays; however, this should be taken into account in the future.
- The author identified that channel fracturing helps placement by good leak-off control to natural fractures, but did not go in depth on mechanisms to different types of natural fractures. This could be studied to better understand why channel fracturing helps job placement.
- Simulation and calculations involved in a channel fracturing fiber laden fluid and pulsation helping job placement should be conducted.

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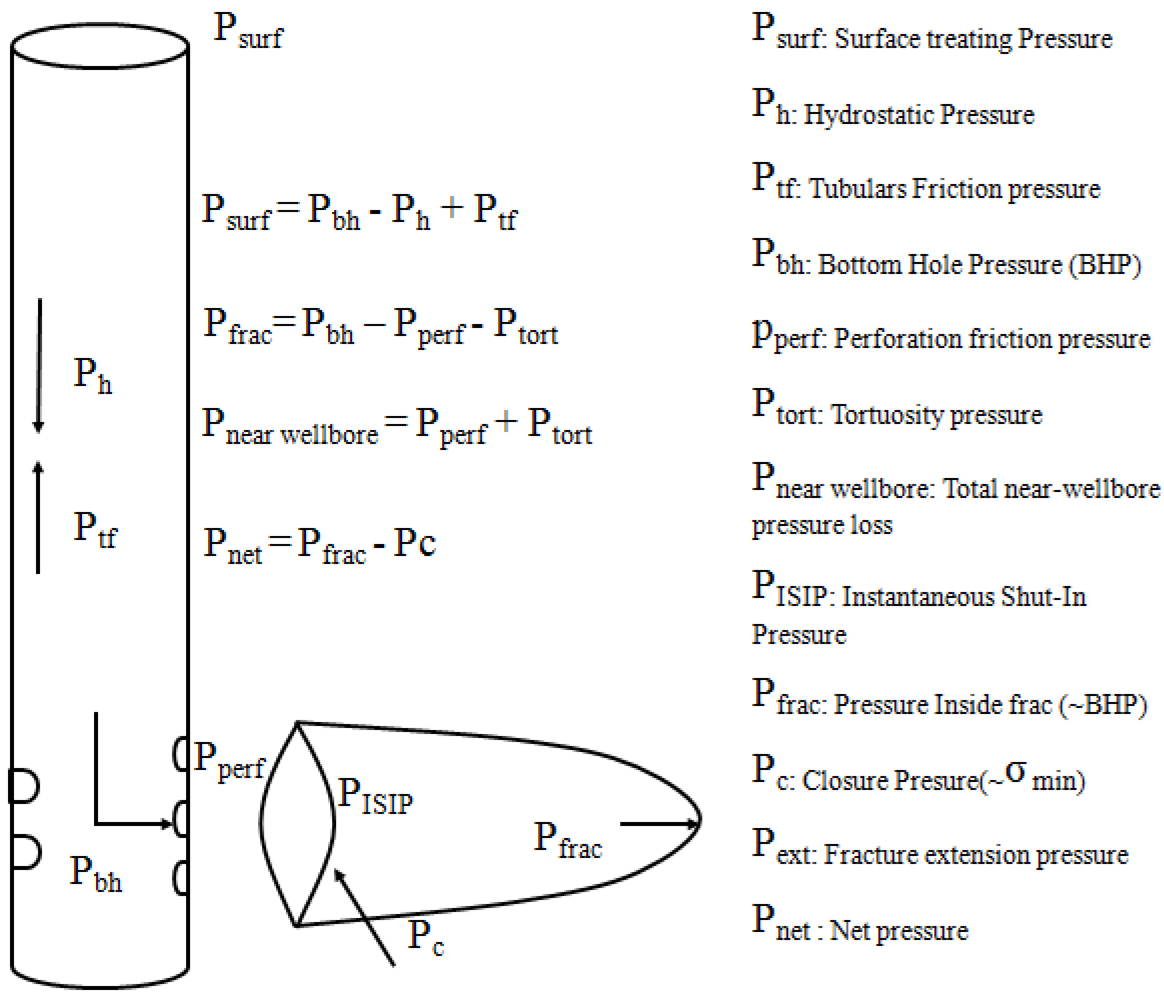
APPENDIX A: PRESSURES DEFINITION



P_{surf}: Surface treating pressure. It is the pressure at the wellhead and the frac pumps must act against.

P_h: Hydrostatic pressure. It is the pressure due to fluid density and its depth.

P_{tf}: Tubular friction pressure. It is the energy loss in the tubular when fluid travels along the tubular.

P_{bh}: Bottomhole pressure. It is the bottohole pressure measured at the centre of the frac'd zone.

P_{perf}:Perforation friction pressure. It is the friction pressure when fluid passes through the perforations.

P_{tort}: Near wellbore tortuosity pressure. It is the pressure loss when fluid passes through the narrowed near wellbore region and try to align with maximum horizontal stress in far field

$P_{near\ Wellbore}$:Near well bore total pressure. It is the sum of perforation pressure and tortuosity pressure.

P_{ISIP}: Instantaneous Shut In Pressure. It is the pressure measured same time stop pumping. All pump rate related friction pressure including tubular friction pressure (P_{tb}), perforation friction pressure (P_{perf}), and tortuosity pressure (P_{tort}) are excluded.

P_{frac}: Fracturing fluid pressure. It is the pressure inside the fracture geometry.

P_c: Closure pressure. It is pressure exerted by the formation on the proppant. For a single layer, P_c is equal to σ_{min} (Economides, et al 2007).

P_{ext}: Extension pressure. It is the pressure inside fracture geometry high enough so fracture can grow. It is bigger than P_c.

P_{net}: Net pressure. It is the pressure inside fracture geometry to keep fracture open. It is the difference between fracture pressure and closure pressure.