FRACTURE STIMULATION FOR TIGHT GAS RESERVOIR

By

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Dissertation submitted in partial fulfillment of

the requirements for the

Bachelor of Engineering (Hons)

(Petroleum Engineering)

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Universiti Teknologi PETRONAS

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

Petroleum Engineering Programme

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOHD ZAKI BIN MD YUSOP

ABSTRACT

This project was a study on tight gas reservoir. Tight gas reservoirs have been known to be difficult to produce due to its low permeability. And several studies had been made on fracture stimulation so that this tight gas reservoir productivity can be increased. Because of that, this project will be on fracture stimulation for tight gas focusing on the proppant diameter. In fracture stimulation, several fracture parameters plays a vital role in improving the production of a reservoir. We need to identify the fracture half length and dimensionless fracture conductivity that can generate a high absolute permeability and also the proppant median diameter for doing the fracturing job.

Thus, the objectives of this project were to determine and analyze the value of dimensionless fracture conductivity that can result in a high value of fracture half length which will be used for doing simulation with 4 different sizes of proppant (median diameter) and its permeability on the production responses. In the early stage of this project, research will be done on tight gas reservoir, and fracture stimulation. After that, the reservoir parameters including the rock, fluids, and PVT parameters that is needed to do the simulation will be constructed as our input. This project requires the use of software (WellFlo) to do simulation on the fracture.

After the project had been conducted it was acquired that the fracture half-length will increase as we decrease the FCD, thus we had chosen FCD = 1 to be used for doing simulation using the WellFlo. Using this value of FCD, the simulation on fracturing is conducted to see the trend of AOF after we had introduce fracturing using different size of proppant median diameter. As the end result, the value of proppant median diameter chosen is 0.691mm as it gave us the highest value of AOF where the AOF increases from 50.299MMscf/d before fracture to 140.385MMscf/d after fracture.

As the conclusion, the productivity of the tight gas reservoir can be enhanced by conducting fracture stimulation on the reservoir and it depends on several fracture parameters such as the dimensionless fracture conductivity, fracture half-length, fracture width, proppant permeability, proppant median diameter and etc.

ACKNOWLEDGEMENT

I am grateful to Allah, my Lord and Cherisher, for guiding me to conceptualize, develop and complete my final year project, Fracture Stimulation for Tight Gas Reservoir. Indeed, without His Help and Will, nothing is accomplished.

I would like to express my tremendous appreciation to my supervisor, Dr. Sonny Irawan for his guidance and support throughout the process of completing this thesis. His willingness to spend his valuable time to supervise my project despite his workload is highly appreciated.

Thank you to my parents and family, for understanding the amount of time that I need to spend in order to complete this project. Without their support, I will not have the strong will to complete this project.
And finally, thank you to my friends, classmates and others who had assisted me throughout completion of this project.

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Nomenclature

A = Drainage Area, ft^2

b = Arps' decline-curve exponent

B_g = Gas formation volume factor, RB/Mscf

B_w = Water formation volume factor

c_t = Total compressibility, psi^{-1}

c_w = Water compressibility, psi^{-1}

c_g = Gas compressibility, psi^{-1}

c_f = Formation compressibility, psi^{-1}

D_i = Initial decline rate, day^{-1}

G = Original gas in place, Mscf

$G_{p(t)}$ = Cumulative gas production at time t, MMscf

k = Effective permeability to gas, md

P_i = Initial reservoir pressure, psia

$\overline{P}$ = Average reservoir pressure, psia

P_{wD} = Dimensionless wellbore pressure

q_t = Gas flow rate at time t, MMscf/day

q_i = Initial gas flow rate, MMscf/day

Q_{DA} = Dimensionless cumulative production based on area (A)

S_w = Water saturation, fraction

t = Time, days

t_{pss} = Time to pseudo steady state, days

t_a = Pseudoequivalent time, days

t_{DA} = Dimensionless time based on area (A)

T = Reservoir temperature, ^{0}R

t_{Dxf} = Dimensionless time based on fracture half length

ΔV_w = Change in water volume, res bbl

ΔV_f = Change in formation reservoir volume, res bbl

W_e = Cumulative water influx volume, STB

W_p = Cumulative water influx volume, STB

x_f = Fractured half length, feet

z_i = gas compressibility factor at P_i

$\bar{z}$ = gas compressibility factor at $\bar{P}$

$\emptyset$ = Porosity, fraction

μ = Viscosity, cp

$\Delta m(\bar{P}) = m(P_i) - m(\bar{P})$, psi^2/cp

$\Delta m(P) = m(P_i) - m(P_{wf})$, psi^2/cp

Chapter 1

Introduction

1.1 Background Study

Tight gas reservoirs are often perceived as entailing higher costs and risks than conventional reservoirs. Geologist find that techniques such as regional facies mapping and sequence stratigraphy, which are useful for finding and delineating conventional reservoirs, are often ineffective for tight reservoirs. Engineers look unfavorably on them because they are difficult to evaluate and recovery techniques must be judiciously chosen and carefully applied to avoid production problem. This is also due to the low permeability of the reservoir.

In the other hand, fracturing is a practice used to stimulate the production of oil and natural gas from hard rock formations. It involves forcing large amounts of pressurized water, a proppant (usually sand or ceramic), and very small amounts of chemicals down the wellbore to create tiny fissures in the rock so the oil and gas can flow through the wellbore to the surface. From that, this study will be focusing on fracture stimulation that can enhance the production of tight gas reservoir.

1.2 Problem Statement

1.2.1 Problem Identification

Tight gas reservoirs have been known to be difficult to produce due to its low permeability. Several studies had been made on fracture stimulation so that this tight gas reservoir productivity can be increased. Because of that, this project will be focusing on fracture stimulation. For fracture stimulation, it is important to identify the fracture half-length and at what dimensionless fracture conductivity we will acquire a high value of fracture half length. After acquiring the FCD, we will use it to evaluate the proppant median diameter that can get a high value of proppant permeability that will finally increase the productivity in terms of the AOF of the reservoir.

1.2.2 Significant of the project

Through this project, data such as the absolute open flow (AOF) of the well will be generated using analytical solutions. Using the data that had been acquired, performance of a producing tight gas reservoir related to fracture stimulation can be determine.

1.3 Objective

- To determine and analyze dimensionless fracture conductivity that can generate the highest fracture half length.
- To determine and analyze proppant median diameter and proppant permeability on the production responses.

1.4 Scope of Study

This project will be mainly done by doing research on the topic and gathering data necessary. From the data gathered, calculation will be made using appropriate formulas such as calculating the dimensionless fracture conductivity and etc. Necessary graph will then be plotted to see the trend of the result acquire. Beside than that, WellFlo will also be utilized to conduct simulation for the reservoir before and after fracturing. A lot of reading, analyzing and calculating will be involved in this project.

1.5 The Relevancy of the Project

The enormous volume of unconventional oil and gas (namely tight gas reservoir) is important and will be available to fill the gap once conventional oil and gas begins to decline in the next 5 to 20 years, this large volume and long-term potential, attractive gas prices and unprecedented interest in the world markets, brings the unconventional gas into the for front of our energy future. Some experts also believe that gas consumption may exceed that of the oil by the year 2025.

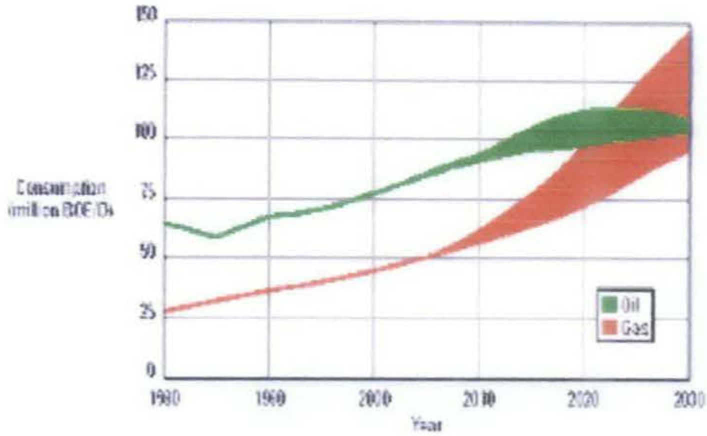


Figure 1.1: Expected oil and gas consumption. Some experts believe gas consumption will exceed that of oil by about 2025, when put into consistent units of barrels of oil equivalent per day (BOE/D). Future estimates indicate prediction ranges. [3]

Because of that, future energy resources of the world, particularly gas will be found in what we consider today as unconventional reservoirs, especially low-permeability reservoirs in shale, siltstones, fine-grained sands, and carbonates. These are not, in fact, undiscovered resources, since their occurrences are fairy well known. Due to that, this project is important so that those unconventional gas namely in tight gas reservoir can be produce optimally and economically feasible to fill in those entire gaps.

1.6 Feasibility of the Project

This project mainly based on research and stimulation using software that are available in UTP itself such as WellFlo. And with the time frame of 20 weeks approximately, I believe that this project can be completed and the objective of this project can be achieved.

Chapter 2

Theory and Literature Review

2.1 Tight Gas Reservoir

Tight gases exist in underground reservoir with microdarcy-range permeability and have huge future potential for production. It is also considered as 'Unconventional Energy Source'. Most of the time, for a tight gas reservoir there are 4 basic criteria of the reservoir which are having low permeability, abnormal pressure, gas saturated reservoir and also no down dip water leg. And gas production from a tight-gas well will be low on per-well basis compared with gas production from conventional reservoirs.

Tight reservoirs are affected by the effective porosity, viscosity, fluid saturation and the capillary pressure. These parameters are important in controlling the effective permeability of a reservoir. *Law and Curtis (2002)* define low-permeability (tight) reservoir and having permeabilitites less than 0.1 millidarcies. Therefore, the term 'Tight Gas Reservoir' has been coined for reservoirs of natural gas with an average permeability of less than 0.1 mD ($1x10^{-16}$ m^2). Recently the *German Society for Petroleum and Coal Science and Technology (DGMK)* announced a new definition for tight gas reservoir elaborated by the German petroleum industry, which includes reservoirs with average effective gas permeability less than 0.6 mD. [3]

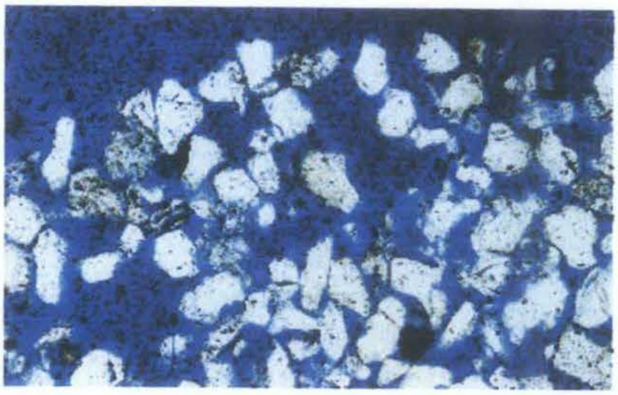


Figure 2.1a: Thin section of a conventional sandstone reservoir that has been injected with blue epoxy. The blue areas are pore space and would contain natural gas in a producing gas field. The pore space can be seen to be interconnected so gas is able to flow easily from the rock. [3]

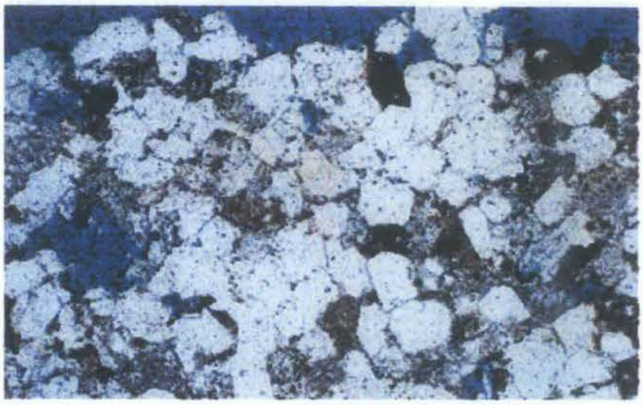


Figure 2.1b: Thin section photo of a tight gas sandstone. The blue areas are pores. The pores are irregularly distributed through the reservoir and the porosity of the rock can be seen to be much less than the conventional reservoir. [3]

Figure 2.1a and 2.1b shows the comparison between the permeability and pore volume between the conventional reservoir and also the tight gas reservoir.

Tight gas reservoirs are often perceived as entailing higher costs and risks than conventional reservoirs. Geologist find that techniques such as regional facies mapping and sequence stratigraphy, which are useful for finding and delineating conventional reservoirs, are often ineffective for tight reservoirs. Engineers look unfavorably on them because they are difficult to evaluate and recovery techniques must be judiciously chosen and carefully applied to avoid production problem.

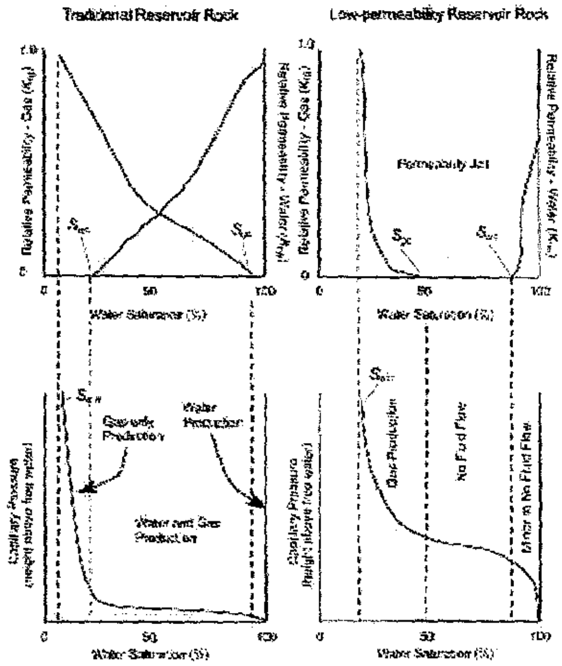


Figure 2.2: Schematic illustration of capillary pressure and relative permeability relationship in traditional and low-permeability reservoirs rocks (Shanley et al., 2004) Critical water saturation (S_{wc}), critical gas saturation (S_{gc}), and irreducible water saturation (S_{wirr}) are shown.[3]

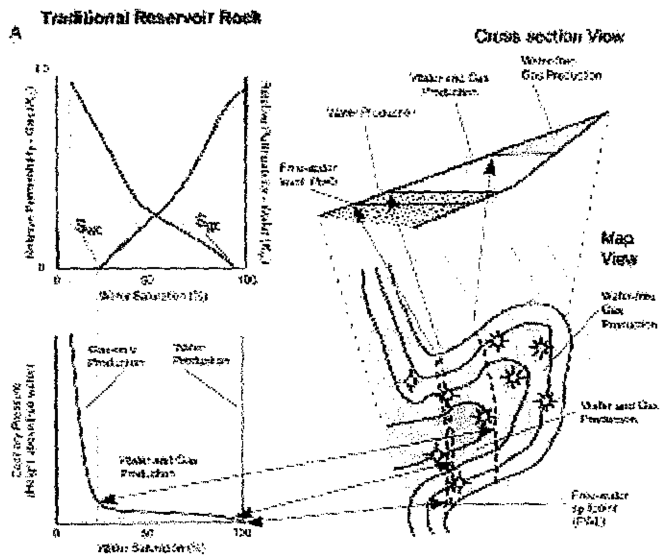


Figure 2.3a: Schematic illustration highlighting relationships between capillary pressure, relative permeability, and position within a trap, as represented by map and cross section views for a reservoir with traditional rock properties. The map illustrates a reservoir bodythat thins and pinches out in a structurally up dip direction. (Shanley et al., 2004)[3]

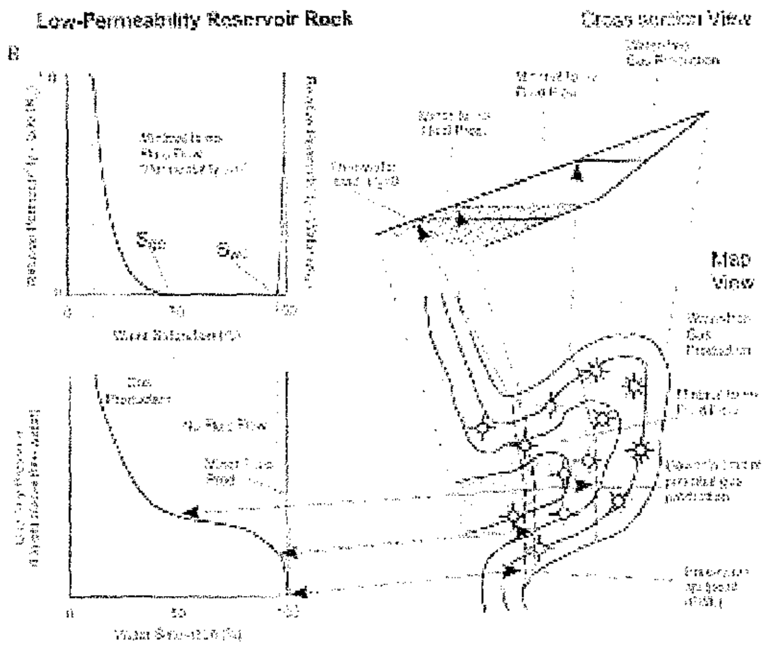


Figure 2.3b: Schematic illustration highlighting relationships between capillary pressure,relative permeability, and position within trap, as represented by map and cross sectionviews for a reservoir with low-permeability. The map illustrates a reservoir body that thinsand pinches out in a structurally updip direction. [3]

2.3 Fracture Stimulation

Fracturing is a practice used to stimulate the production of oil and natural gas from hard rock formations. It involves forcing large amounts of pressurized water, a proppant (usually sand), and very small amounts of chemicals down the wellbore to create tiny fissures in the rock so the oil and gas can flow through the wellbore to the surface.

In a low permeability reservoir, understanding the fracture geometry and azimuth is the key factor in effectively exploiting the reserves. By utilizing logs, microseismic mapping, production analysis and reservoir simulation, and optimum drilling pattern can be established and the reservoir can be developed to its full potential. Effective fracture length and azimuth will have the greatest impact on the recovery factors in a very low permeability sands for a particular drilling pattern.

Other than that, the varying fractures lengths and fracture asymmetries create a complex simulation scenario. A multi-layer finite difference reservoir simulation provides the flexibility to model the production response from the observed fracture geometries. The shorter fracture half-length and symmetric geometries have a large impact on production rates and recoverable reserves in very low permeability reservoirs. [7]

	Observed Fracture half-length (ft)	Fracture Conductivity (md-ft)	Formation Permeability (md)
Stage 6	205	16	0.0055
Stage 5	220	88	0.0047
Stage 4	404	12	0.0014
Stage 3	411	24	0.0012
Stage 2	254	N/A	N/A
Stage 1	221	68	0.0039

Table 2.1: Example of summary result from production matching. [7]

In order to optimize the hydraulic fracture design, a 1-D geomechanics study was requested to estimate hydraulic frac-ability of the rock. A 1-D Mechanical Earth Model (MEM) was constructed and fracture breakdown pressure was estimated as an outcome of the model. Mechanical properties are derived from logs data and calibrated against core with rock mechanics test data. Advanced sonic processing conducted before and after the fracing which give estimated pre and post hydraulic minimum and maximum horizontal stress. The shear radial profiling was carried out allowing for identifications of the existence of stress within the rock. The advanced sonic processing also revealed the characteristic of stress anisotropy in the formation. Hydraulic fracture design and procedure was then developed based on the results of the model. [8]

- The pad (neat fluid) is pumped first to create the fractures and to establish propagation - the fracture grows up and down as well as out
- Then, the proppant laden slurry fluid is pumped - this slurry continues to extend the fractures and concurrently carries and place the proppants deep into the fractures
- The carrier fluid chemically breaks back to a lower viscosity and flow back out of the well

Highly conductive propped fractures for oil and/or gas to flow easily from the extremities of the formation into the well

Figure 2.4: Basic fracturing process

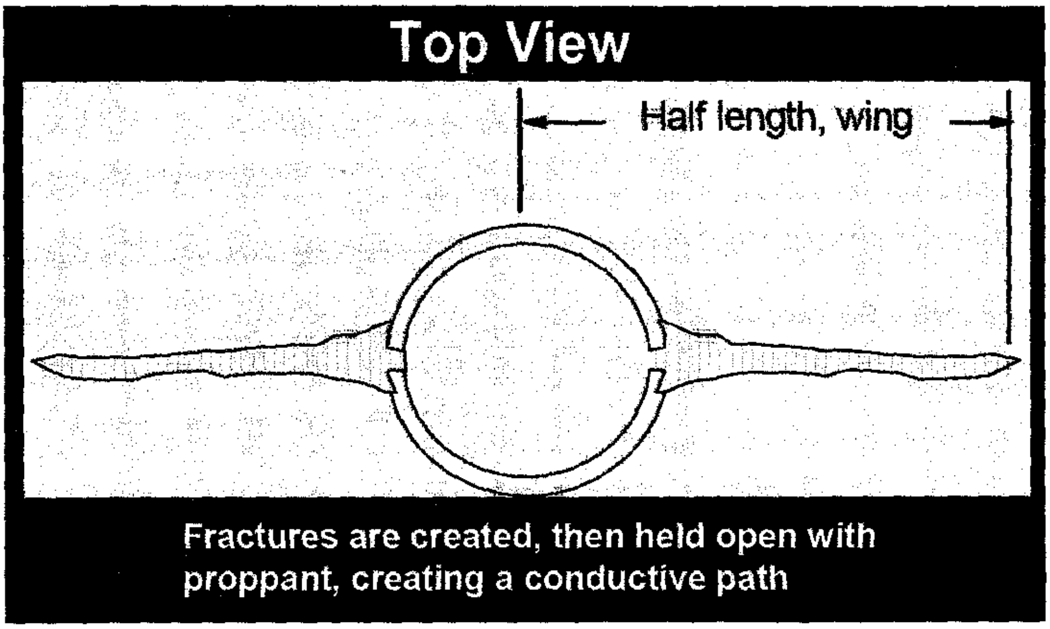


Figure 2.5: Fracture half-length

2.4 Formula's and Calculation

a) Dimensionless Fracture Conductivity [13]

$$FCD = \frac{k_f w_f}{k_r x_f} \quad \text{...} (1)$$

The dimensionless fracture conductivity equation will be utilized to calculate the fracture half-length. For this project we will assume that the fracture width and the reservoir permeability are constant.

b) Rate-time Decline curve analysis[5]

Table-2.2 provides a brief summary of decline curve equations.

Exponential	$q_{(t)} = q_{(i)} e^{-D_i t}$	$G_{p(t)} = -\frac{1}{Di} q_{(t)} + \frac{q_{(i)}}{D_{(i)}}$
Hyperbolic (for 0<b<1)	$q_{(t)} = \frac{q_{(i)}}{(1 + bD_i t)^{1/b}}$	$G_{p(t)} = \left[\frac{q_{(i)}^{b}}{D_i(b-1)}\right]\left[q_{(t)}^{(1-b)} - q_{(t)}^{(1-b)}\right]$
Harmonic (for b=1)	$q_{(t)} = \frac{q_{(i)}}{(1 + D_i t)}$	$G_{p(t)} = 2.303\frac{q_{(i)}}{D_i}\left[\log q_{(i)} - \log q_{(t)}\right]$

Table 2.2: Decline Curve Equation

The decline curve analysis technique is based on the assumption that past performance trends can be characterized mathematically and used to predict future performance. Several assumption will be made when the decline-curve equation which are;

- The past operating conditions will remain unchanged
- The well is produced at or near capacity
- The well's drainage remains constant
- The well is produced at a constant bottom hole pressure

In most cases, tight gas reservoir wells are producing at capacity and approach a constant bottom hole pressure, if produced at a constant line pressure. However, it can be quite challenging to determine when a tight gas well has defined its drainage area.

Decline curve analysis should only be attempt after the well has defined drainage area and/or has reached a pseudo-steady state flowing condition. The pseudo-steady state flow period has been defined as the point in time when pressure change with time is constant at all points in the reservoir for constant production rate. Theory states that the time to pseudo-steady state can be estimated from the equation below;

$$t_{pss} = \frac{\phi \mu c_t A}{0.006328k} (t_{DA})_{pss} \quad \text{..} (2)$$

$$c_t = S_w c_w + (1 - S_w) c_g + c_f \quad \text{..................................} (3)$$

c) Material Balance[5]

The calculation are based on the premise that the void created in the reservoir through the production of reservoir fluids is immediately and completely filled by the expansion of the remaining fluids and rock. The equation below represents the general material balance equation for gas reservoirs including water and rock compressibility and aquifer influx.

$$GB_{gi} = (G - G_p)B_g + \Delta V_w + \Delta V_f + (W_e - W_p)B_w \quad \text{..........} (4)$$

$$\Delta V_w = c_w(P_i - \overline{P}) \frac{S_{wi} G B_{gi}}{1 - S_{wi}} \quad \text{..} (5)$$

$$\Delta V_f = c_f(P_i - \overline{P}) \frac{G B_{gi}}{1 - S_{wi}} \quad \text{..} (6)$$

For normally pressured reservoirs with no water influx, the equation will be reduces to a volumetric depletion form given by the below equation.

$$\frac{\bar{p}}{\bar{z}} = \frac{p_i}{Z_i}\left(1 - \frac{G_p}{G}\right) \quad \text{......} \quad (7)$$

Several assumptions will also be made when applying the material balance analysis.

- Reservoir hydrocarbon fluids are in phase equilibrium at all times, and equilibrium is achieved instantaneously after any pressure change.
- Accurate fluid properties and production data are available.
- The reservoir can be represented by a single weighted-average pressure at any time.
- Fluid saturations are uniform throughout the reservoir at any time.

In the case of tight gas, it is difficult to accurately estimate the average reservoir pressure through time. If the pressures obtained during shut-in do not reflect the average reservoir pressure the resulting analysis will be inaccurate. The shut-in time required to obtain an accurate reservoir pressure is excessive for tight gas reservoirs due to practical economic considerations.

To obtain a reasonable estimate of average reservoir pressure, pressure build-up analysis techniques have employed. The straight line portion of the Horner plot can be extrapolated to a false reservoir pressure referred to as P*. This pressure can than be corrected for boundary condition to provide an accurate estimate of the average pressure. However, in order to obtain a meaningful estimate of P* from the pressure transient analysis, the well must be shut-in long enough to reach pseudo radial flow. The resulting estimate of P* must be corrected to an average reservoir pressure before it can be used for material balance calculations. The shut-in time required to reach pseudo radial flow can be estimated by using the below equation for a hydraulically fractured well.

$$t_{Dxf} = \frac{0.006328kt}{\emptyset \mu c_t x_f^2} \cong 3 \quad \text{......} \quad (8)$$

2.6 Literature Review

In many reservoirs, the fracture stimulation is the primary operation for optimizing the production response. If proppant induced pressure response negatively affect the distribution of proppant in a fracture, then they definitely have a negative affect on the production response.[1]

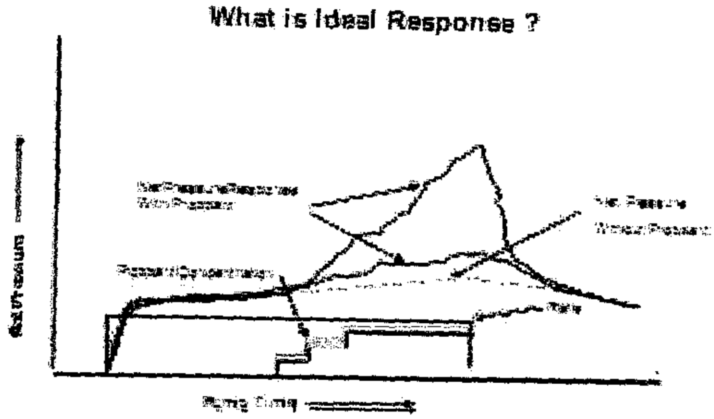


Figure 2.6: Typical stimulation pressure response [1]

Figure 2.6 shows a comparison of three fracture treatment pressure responses. The pressure response without proppant is representative of what would happen if no proppant induced friction occurred. Because there is no proppant induced pressure effect, this would imply, if proppant was present, it is easily entering and distributing in the fracture. The two pressure responses with proppant are typical of what occur. In our investigation we asked our self if the production response was affected by the character of the proppant induced pressure response. Can a fracture treatment modeling and design process be developed to control the level of proppant friction that occurred? If so, will this maximize the production response? The answer is yes.

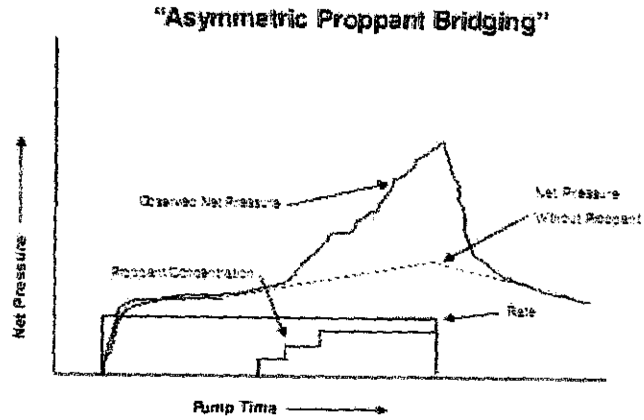


Figure 2.7: Poor Proppant Distribution

Figure 2.7 shows what is called commonly called asymmetric proppant bridging. The proppant enters the fracture, the pressure inflects and the proppant continues bridging in the fracture. The rapid pressure decline after shut down shows that the proppant bridged asymmetrically within the fracture. With this pressure response, the proppant is not well distributed. A high proppant concentration exists for a short distance.

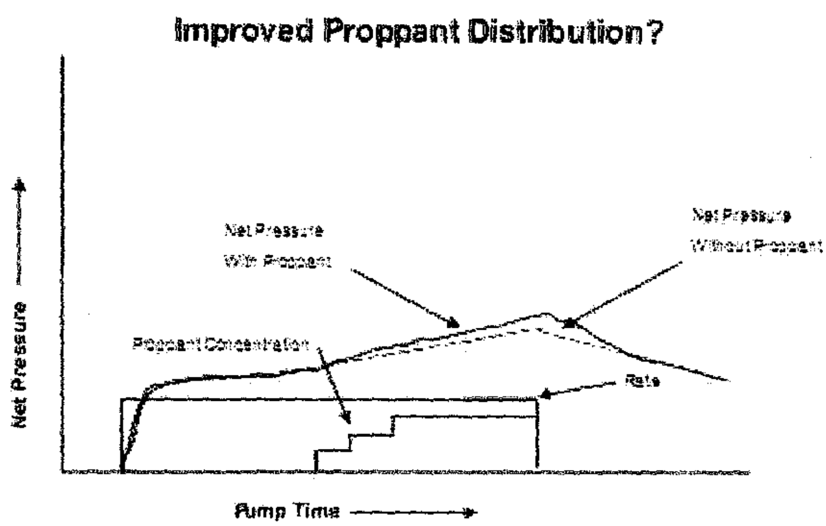


Figure 2.8: Less proppant-induced friction.

Figure 2.8 is termed "improved proppant distribution?" The pressure still inflects upon proppant entry, but climbs less gradually. Intuitively, the proppant distribution with this response would be expected to be better than the response observed in figure 2.7. However, the fracture imaging data shows fracture height growth with small proppant induced pressure increase. A look at the M-Site data tells a story that fits those specific conditions. The height growth started almost the same time the pressure inflected. The total magnitude of the pressure inflection may not be the critical variable. If small proppant induced pressure inflections negatively affect lateral proppant distribution, the figure 2.8 may not be the desired response either. Further work is needed.[1]

Stem lab had conducted a long-term conductivity evaluation of 4 sample of proppant which have different proppant median diameter size. The samples were evaluated at 2.0 lb/ft^2 at 250^{0}F and 2000, 4000, 6000, 8000, and 10000 closure stresses for 50hours.[2]

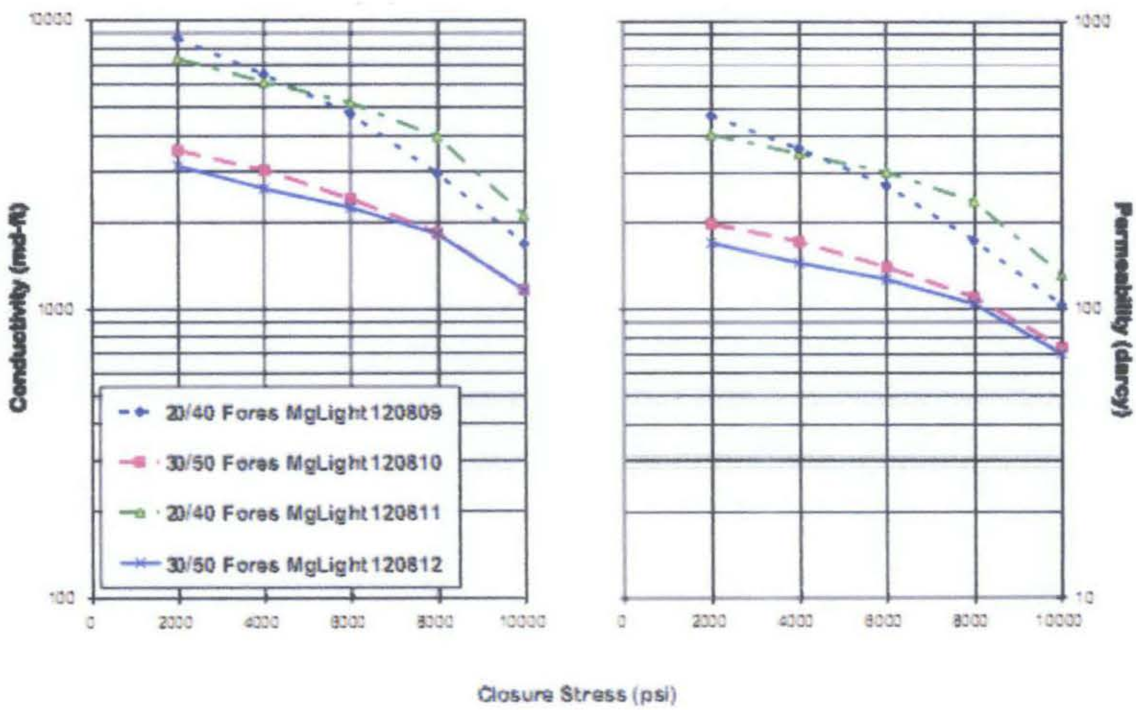
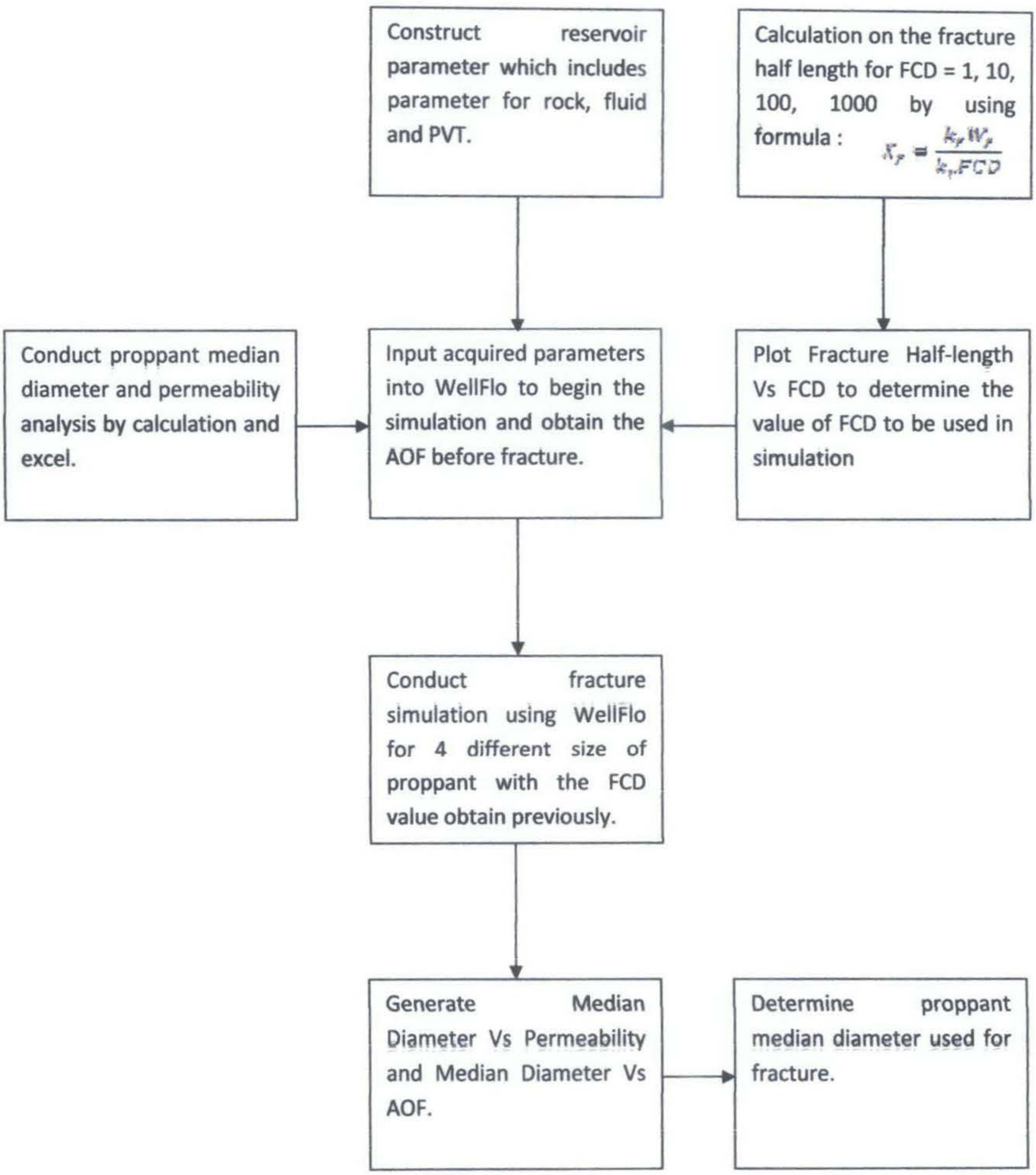


Figure 2.9: Long-term Conductivity and Permeability.[2]

Chapter 3

Methodology

3.1 Research Methodology



3.2 Project Activities

Activities	Starting date	Finishing date
Construct reservoir parameters and calculation. (obj. 1 & 2)	1/March/2011	15/March/2011
Conduct analysis on FCD and fracture half-length (obj. 1)	16/March/2011	23/March/2011
Data comparison and evaluation. Determine FCD (obj. 1)	24/March/2011	7/April/2011
Conduct proppant median diameter and permeability analysis (obj. 2)	8/April/2011	21/May/2011
Conduct simulation on fracture simulation. (Obj. 2)	22/May/2011	16/July/2011
Generate necessary Graph for analysis and determine proppant median diameter (Obj.2)	17/July/2011	30/July/2011
Research Documentation	21/July/2011	13/August/2011

3.3 Gantt Chart and Key Milestone

	FYP1				FYP2			
Activities	2	3	4	5	6	7	8	9
Construct reservoir parameters and calculation. (obj. 1 & 2)								
Conduct analysis on FCD and fracture half-length (obj. 1)								
Data comparison and evaluation. Determine FCD (obj. 1)								
Conduct proppant median diameter and permeability analysis (obj. 2)								
Conduct simulation on fracture simulation. (Obj. 2)								
Generate necessary Graph for analysis and determine proppant median diameter (Obj.2)								
Research Documentation								
Milestone								
Completion in constructing reservoir parameters and calculation								
Completion in determination of FCD with respect to its fracture half-length.								
Completion of simulation for fracture stimulation								
Project completion								

3.4 Material, Software and Equipment

For this project, most of the work will be done on computers which consist of calculation and simulation. For simulation, WellFlo software will be utilized for fracture stimulation.

Chapter 4

Result and Discussion

4.1 Result and Discussion

I. Reservoir Parameter

Formation top, ft	7800
Reservoir Pressure, psi	4500
Average porosity, %	10
Net Pay, ft	2700
Average water Saturation, %	25
Gas Specific Gravity	0.65
Water Specific Gravity	1.05
Reservoir Temperature, °F	220
Water compressibility, 1/psi	$3E^{-6}$
Rock Compressibility, 1/psi	$3E^{-6}$
Permeability, md	0.05
Perforation detail	7800 – 10500
Reservoir size, acre	640
Base Temperature, °F	60
Base Pressure, psia	14.4
Wellbore radius, ft	0.354
Drainage area	$5E^{07}$
Well depth	10500
External radius, ft	4000
Dietz shape factor	31.620

Table 4.1: Reservoir Parameter

The table above shows our reservoir parameter that will be used for calculation and simulation using software.

II. Data Acquired from WellFlo

WGR, STB/MMSCF	0.871
Bg, ft^3/scf	0.0042
Bw, bbl/STB	1.0410
Ug, cp	0.023
Rho g, lb/ft^3	11.87
Uw, cp	0.2824
Rho w, lb/ft^3	62.9653
Siqma w, dyne/cm	44.654

Table 4.2: Data calculated by WellFlo

Table shows us several data that are calculated by using WellFlo at pressure 4500 psia and temperature 220^0F.

III. Gas Initially In Place (GIIP) Calculation.

From calculation using formula (manually), we get the **GIIP** to be **1376.6Bscf**

IV. Water Gas Ratio (WGR) calculation using McKetta Wehe Spreadsheet.

At

Reservoir Temperature = 220^0F

Gas Specific Gravity = 0.650

Water Salinity = 72160.09 ppm

pressure, psig	pressure, psia	McKetta Wehe Calculation (Tr=220 deg F)					MMSCF water vapor/MMSCF dry gas	STB water vapor/MMSCF dry gas
7000	7015	-5.21312	0.005445	0.992573	0.961164	0.005194	0.005209886	0.705
6000	6015	-5.15006	0.005799	0.992573	0.961164	0.005532	0.00555089	0.751
5000	5015	-5.06143	0.006336	0.992573	0.961164	0.006045	0.006068467	0.821
4485	4500	-5.00235	0.006722	0.992573	0.961164	0.006413	0.006440201	0.871
4000	4015	-4.93574	0.007185	0.992573	0.961164	0.006855	0.006886814	0.932
3500	3515	-4.85297	0.007805	0.992573	0.961164	0.007446	0.007485604	1.013
3000	3015	-4.75147	0.008639	0.992573	0.961164	0.008242	0.008291888	1.122
2500	2515	-4.62441	0.009809	0.992573	0.961164	0.009359	0.009425984	1.275
2000	2015	-4.46028	0.011559	0.992573	0.961164	0.011028	0.011125925	1.505
1500	1515	-4.23758	0.014443	0.992573	0.961164	0.013779	0.013940088	1.886
1000	1015	-3.90796	0.020081	0.992573	0.961164	0.019158	0.019489185	2.637
950	965	-3.86524	0.020958	0.992573	0.961164	0.019994	0.020357103	2.754
900	915	-3.82	0.021928	0.992573	0.961164	0.02092	0.021319236	2.884
850	865	-3.77196	0.023007	0.992573	0.961164	0.021949	0.022391987	3.030
800	815	-3.72078	0.024215	0.992573	0.961164	0.023102	0.023595836	3.193
750	765	-3.66604	0.025578	0.992573	0.961164	0.024402	0.024956698	3.377
700	715	-3.60725	0.027126	0.992573	0.961164	0.025879	0.02650787	3.587
650	665	-3.54382	0.028903	0.992573	0.961164	0.027574	0.028292871	3.828
600	615	-3.47501	0.030962	0.992573	0.961164	0.029538	0.030369721	4.109
550	565	-3.39987	0.033378	0.992573	0.961164	0.031843	0.032817568	4.440
500	515	-3.3172	0.036254	0.992573	0.961164	0.034588	0.035747336	4.837
450	465	-3.2254	0.03974	0.992573	0.961164	0.037913	0.039319564	5.320
400	415	-3.12233	0.044054	0.992573	0.961164	0.042029	0.043775849	5.923
350	365	-3.00496	0.049541	0.992573	0.961164	0.047263	0.049497822	6.697
300	315	-2.86888	0.056763	0.992573	0.961164	0.054153	0.057126684	7.729
250	265	-2.70722	0.066722	0.992573	0.961164	0.063655	0.067831314	9.178

Table 4.3: MacKetta Wehe Spreadsheet.

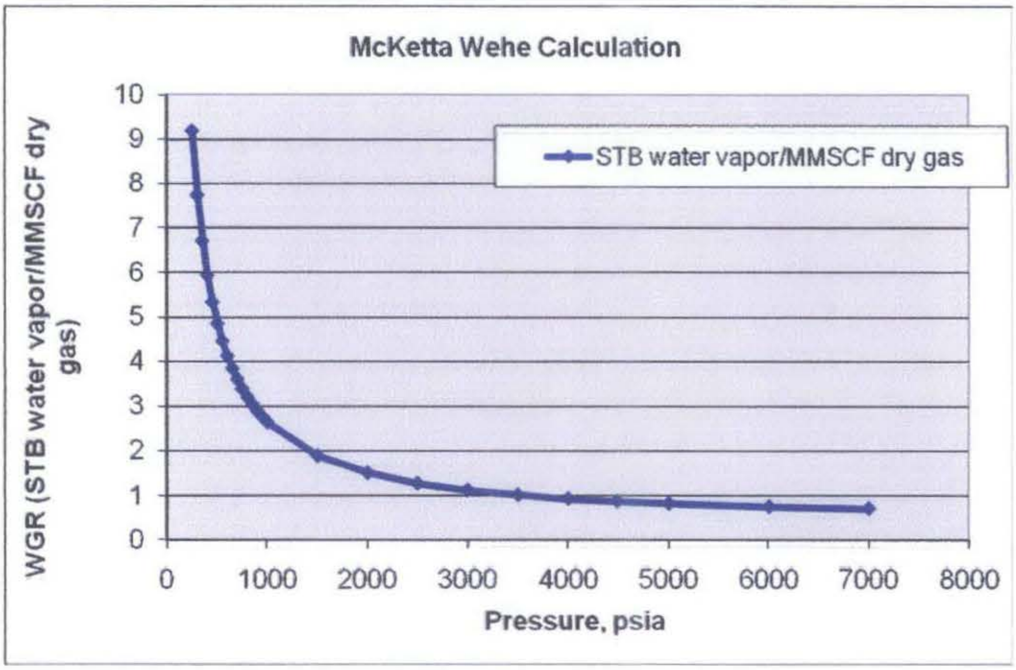


Figure 4.1: WGR Vs Pressure graph

From the spreadsheet, at pressure of 4500 psia (reservoir pressure) we get **<u>WGR</u>** to be **<u>0.871 STB/MMSCF.</u>**

V. IPR curve before fracturing.

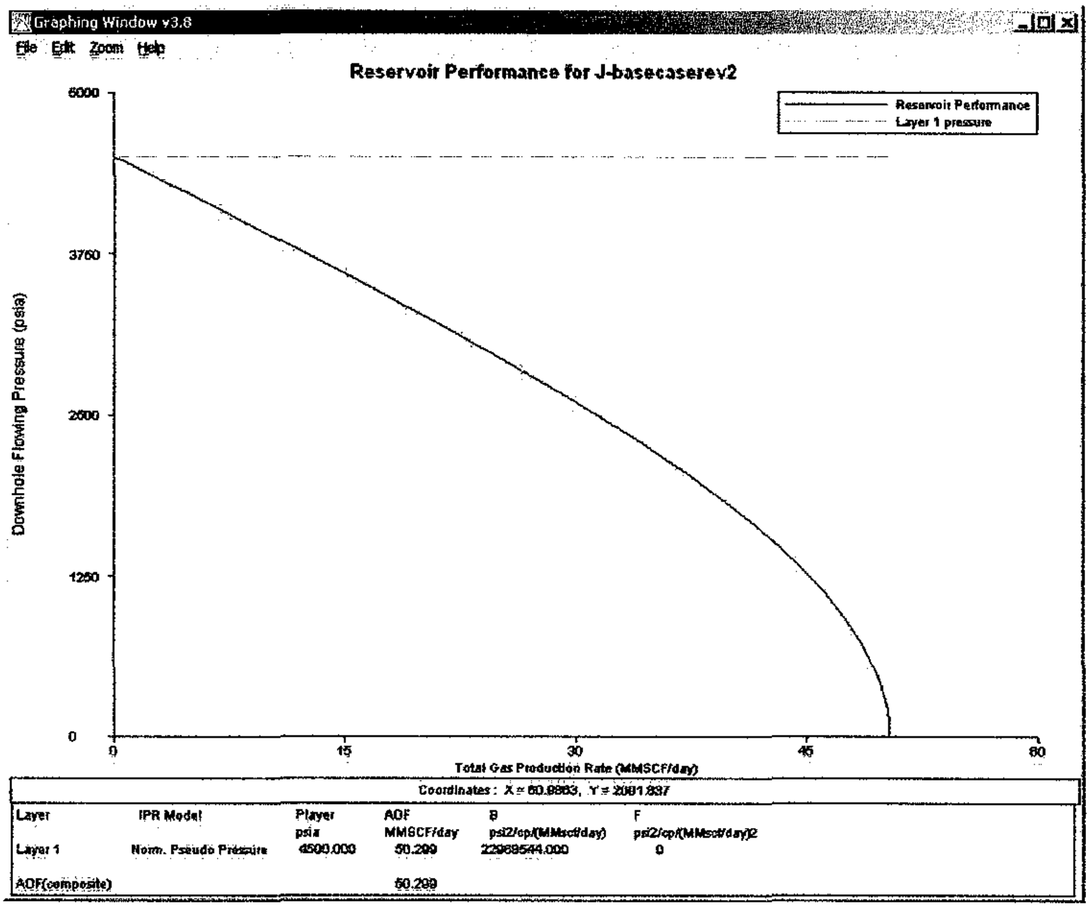


Figure 4.2: IPR curve

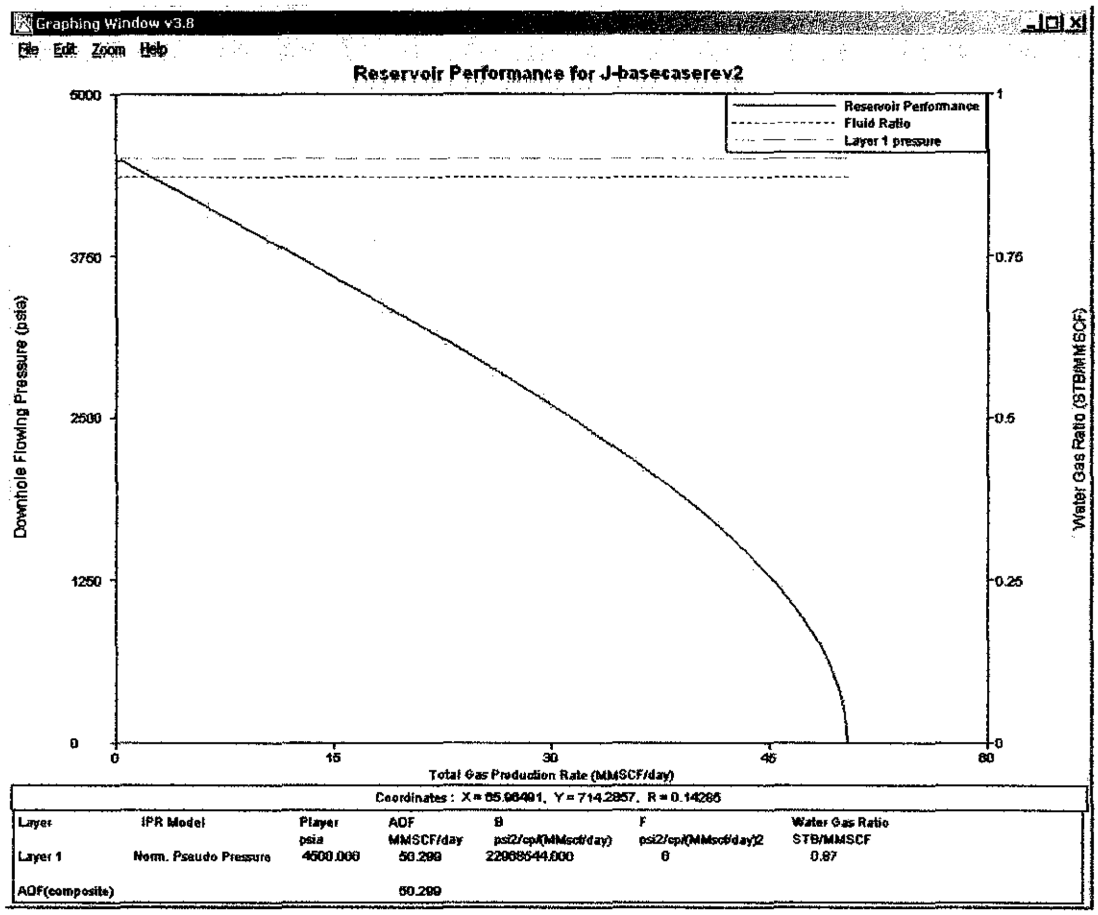


Figure 4.3: IPR curve with WGR

From the IPR cure, we can obtain the **AOF** of the reservoir which is **50.299 MMscf/d.** This AOF indicates the AOF of the reservoir before fracture is introduce to the production interval.

VI. Proppant permeability and Median Diameter analysis

Median Diameter = 0.440mm		
Pressure (psi)	Conductivity (md-ft)	Permeability (md)
2000	3138	170
4000	2615	145
6000	2245	127
8000	1818	104
10000	1164	70

Table 4.4: Conductivity and Permeability for Median Diameter 0.440mm

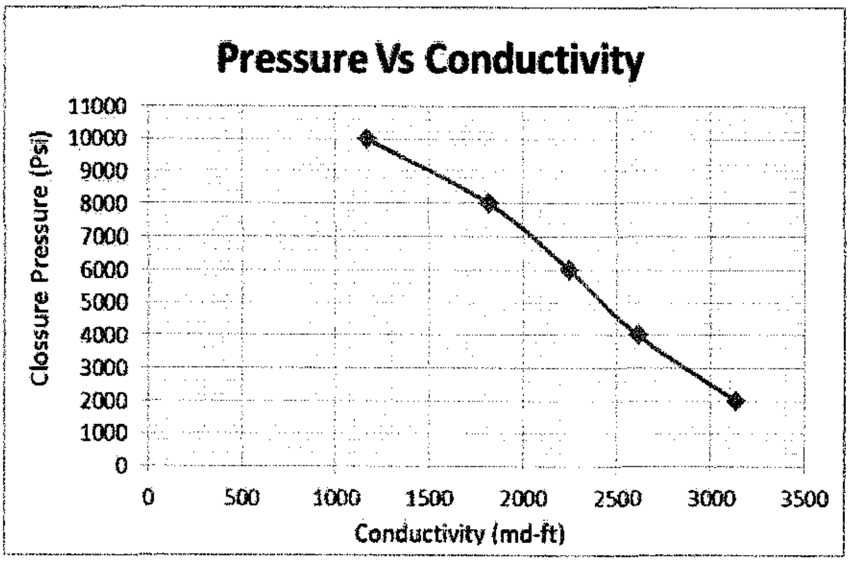


Figure 4.4: Pressure Vs Conductivity for median diameter 0.440mm

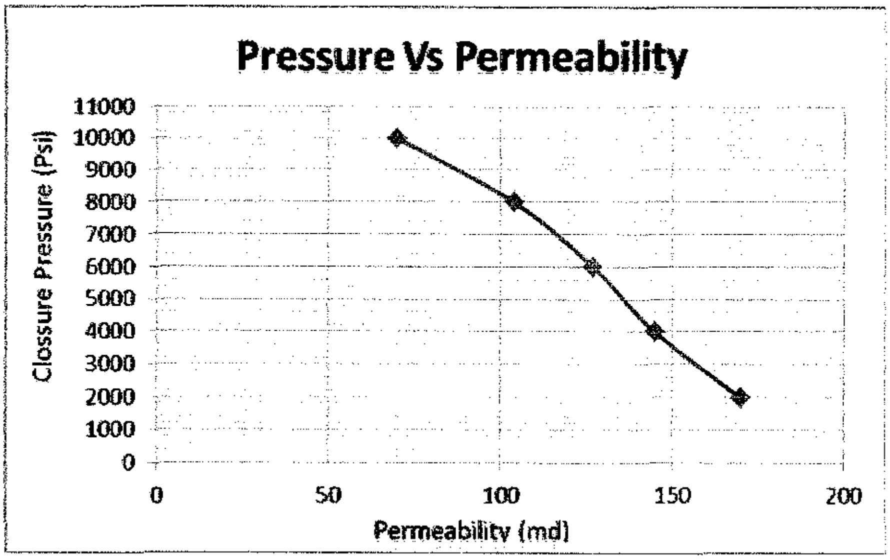


Figure 4.5: Pressure Vs Permeability for median diameter 0.440mm

Median Diameter = 0.508mm		
Pressure (psi)	Conductivity (md-ft)	Permeability (md)
2000	3552	198
4000	3032	172
6000	2408	140
8000	1835	110
10000	1160	73

Table 4.5: Conductivity and Permeability for Median Diameter 0.508mm

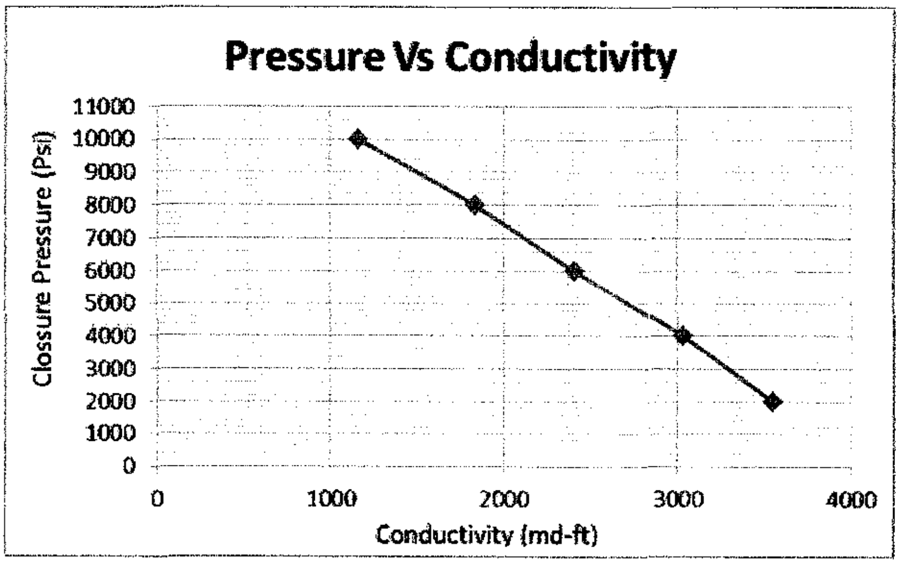


Figure 4.6: Pressure Vs Conductivity for median diameter 0.508mm

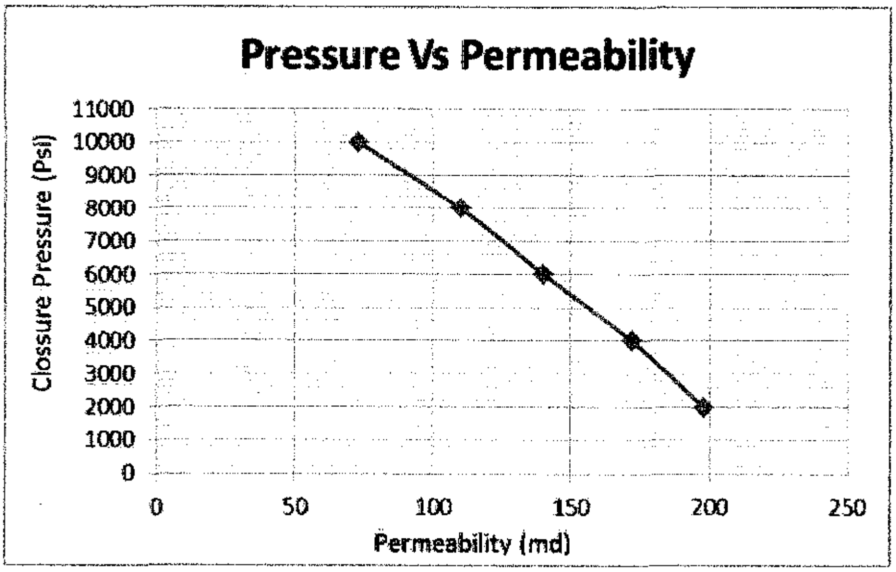


Figure 4.7: Pressure Vs Permeability for median diameter 0.508mm

Median Diameter = 0.648mm		
Pressure (psi)	Conductivity (md-ft)	Permeability (md)
2000	7339	406
4000	6130	349
6000	5188	301
8000	3970	237
10000	2108	132

Table 4.6: Conductivity and Permeability for Median Diameter 0.648mm

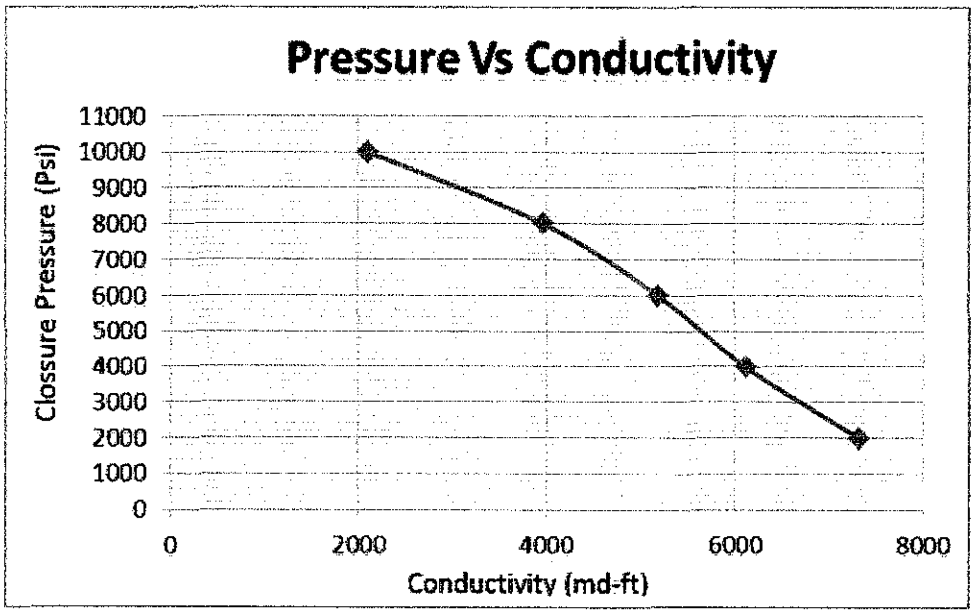


Figure 4.8: Pressure Vs Conductivity for median diameter 0.648mm

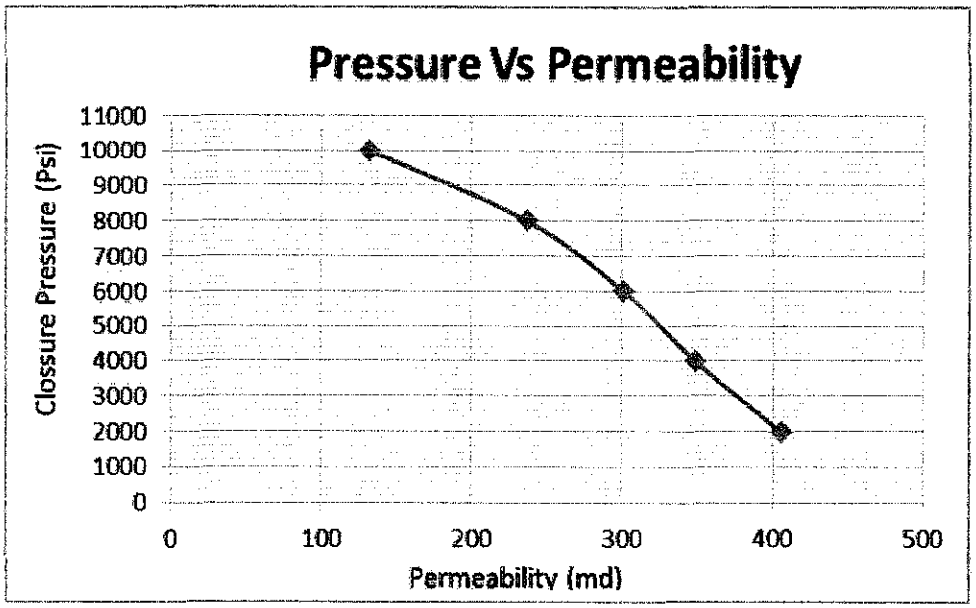


Figure 4.9: Pressure Vs Permeability for median diameter 0.648mm

Median Diameter = 0.691mm		
Pressure (psi)	Conductivity (md-ft)	Permeability (md)
2000	8656	472
4000	6477	363
6000	4744	270
8000	2952	174
10000	1683	103

Table 4.7: Conductivity and Permeability for Median Diameter 0.691mm

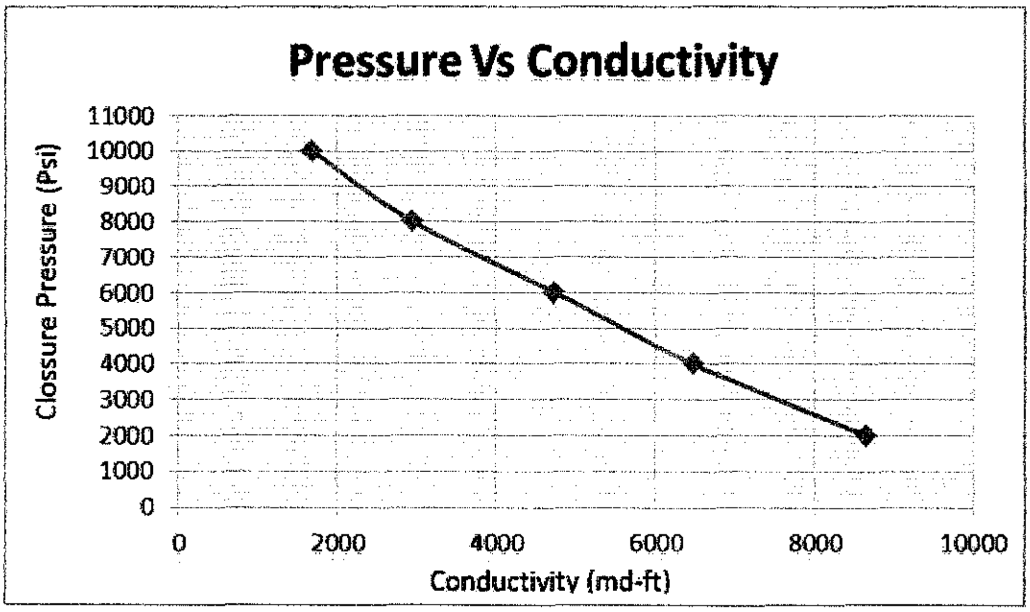


Figure 4.10: Pressure Vs Conductivity for median diameter 0.691mm

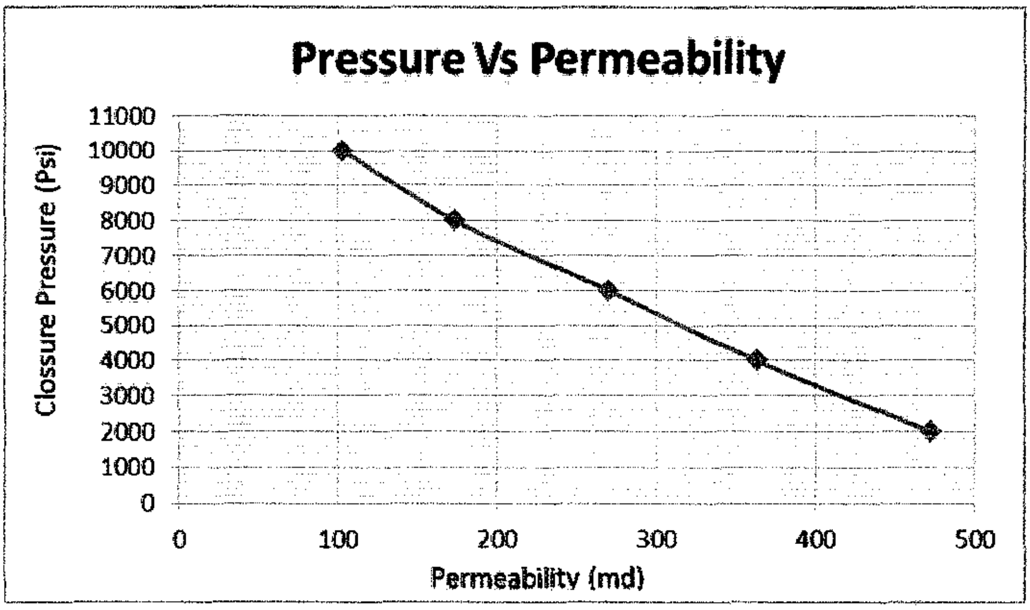


Figure 4.11: Pressure Vs Permeability for median diameter 0.691mm

Based on figure 4.4 to 4.11 and table 4.4 to 4.7, we can determine the proppant median diameter and permeability that will be used at pressure of 4500 psi as per table 4.8.

Proppant Median Diameter (mm)	Proppant Permeability (md)
0.440	140
0.508	164
0.648	336
0.691	340

Table 4.8: Proppant permeability with relative to its median diameter.

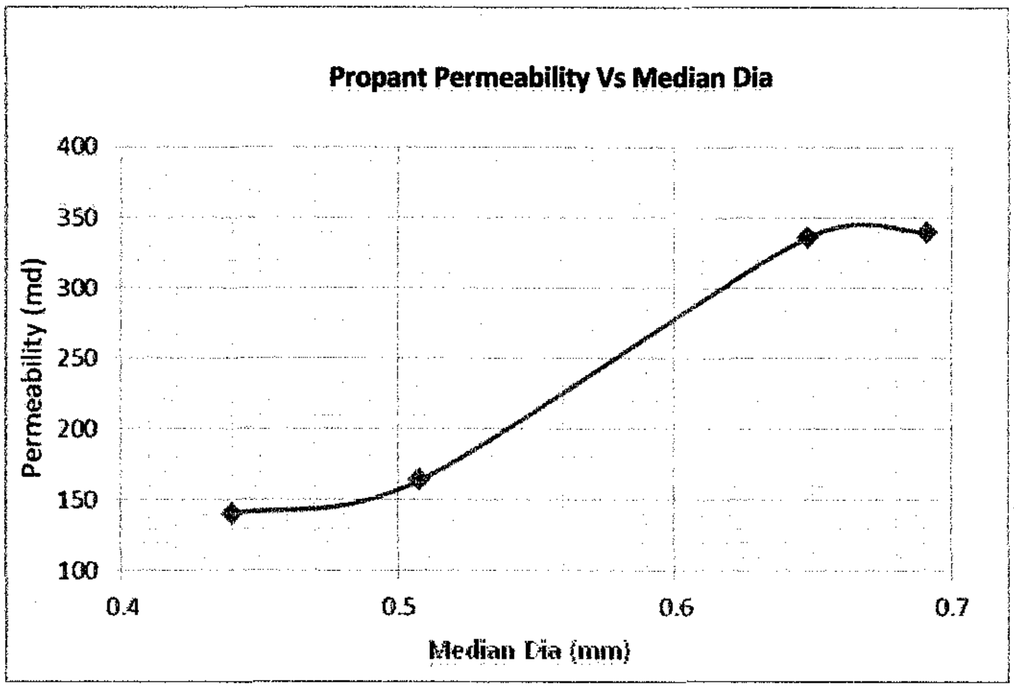


Figure 4.12: Proppant Permeability Vs Median Diameter

VII. Determination on FCD based on its Half-length

Analysis is done with 4 dimensionless fracture conductivity which are 1, 10, 100, 1000.

Permeability (md)	Xf (ft) at Fcd			
	1	10	100	1000
140	23.33333	2.333333	0.233333	0.023333
164	27.33333	2.733333	0.273333	0.027333
336	56	5.6	0.56	0.056
340	56.66667	5.666667	0.566667	0.056667

Table 4.9: Fracture half-length with respect to dimensionless fracture conductivity

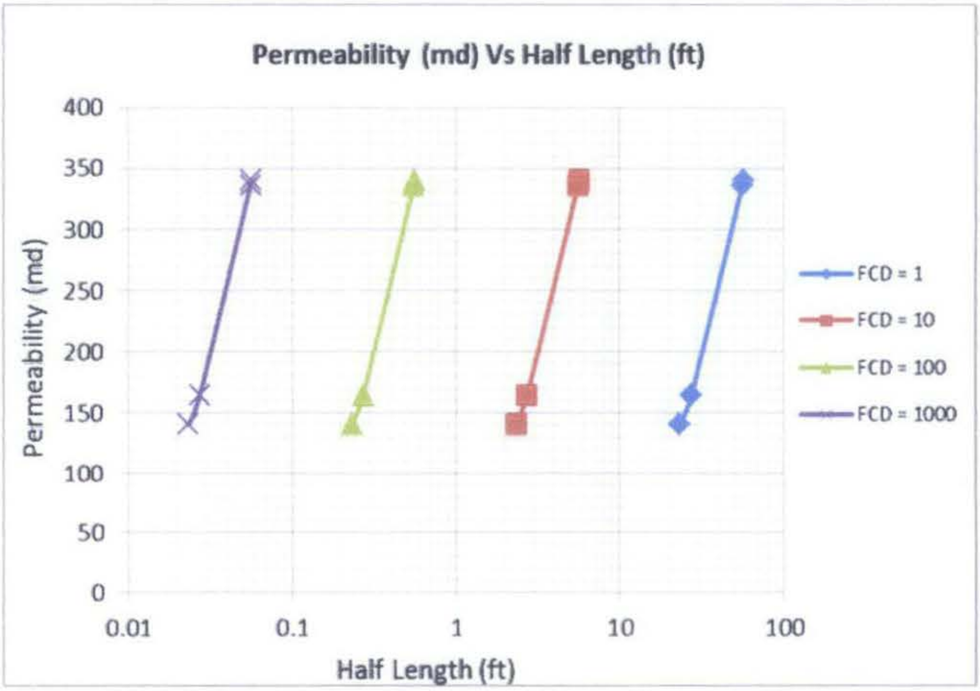


Figure 4.13: Permeability Vs Half length Graph

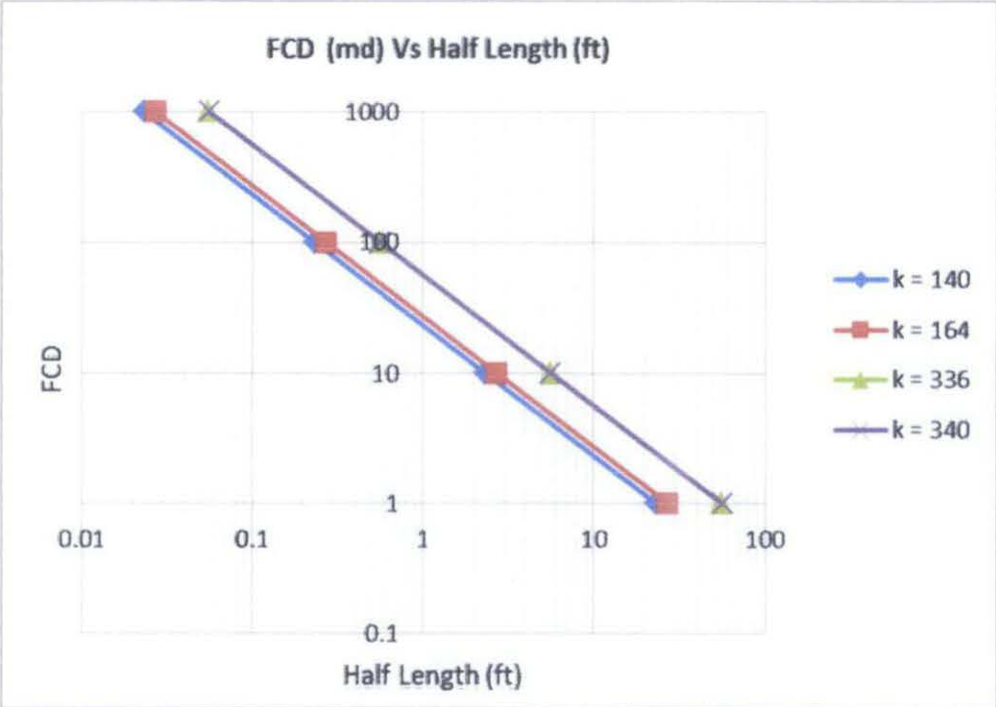


Figure 4.14: FCD Vs Half Length.

From figure 4.13 to 4.14 and table 4.9, we can see that as we decrease the dimensionless fracture conductivity, the fracture half-length will increase for each permeability. Thus, we chose **FCD = 1** to be used in our fracture simulation using WellFlo as it will generate the highest fracture half-length.

VIII. AOF after fracture.

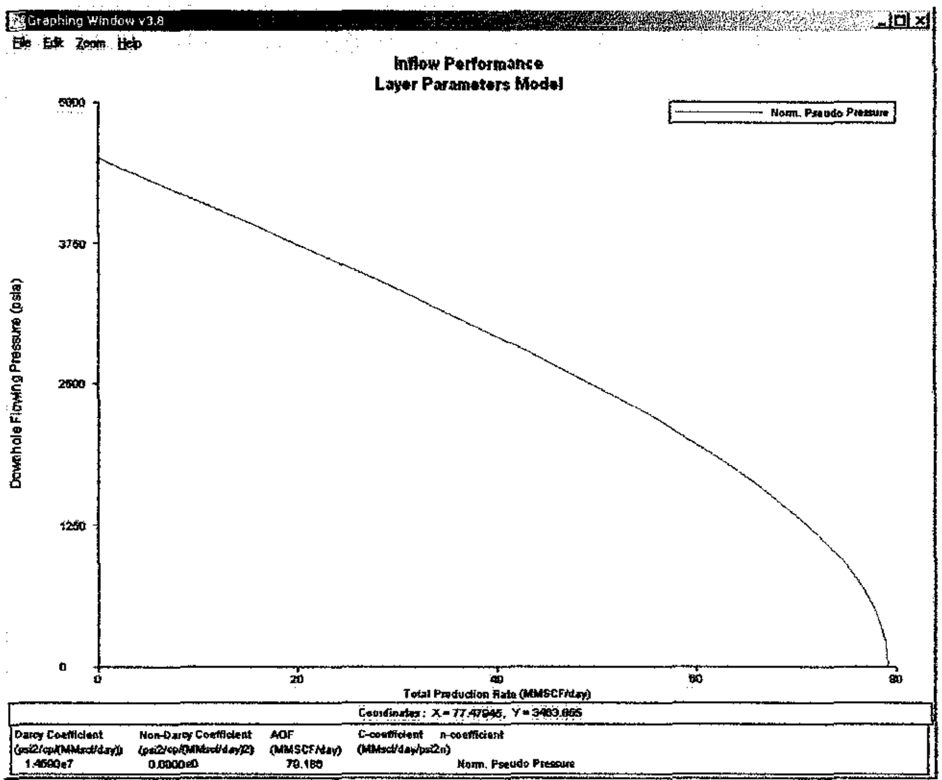


Figure 4.15: IPR curve for median diameter 0.440mm.

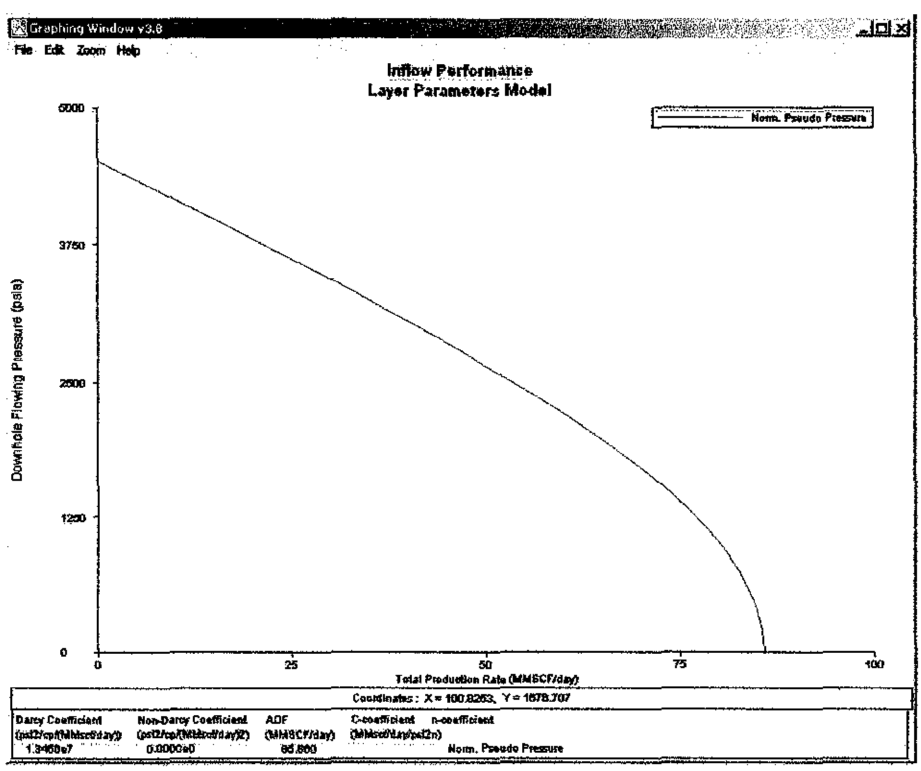


Figure 4.16: IPR curve for median diameter 0.508mm.

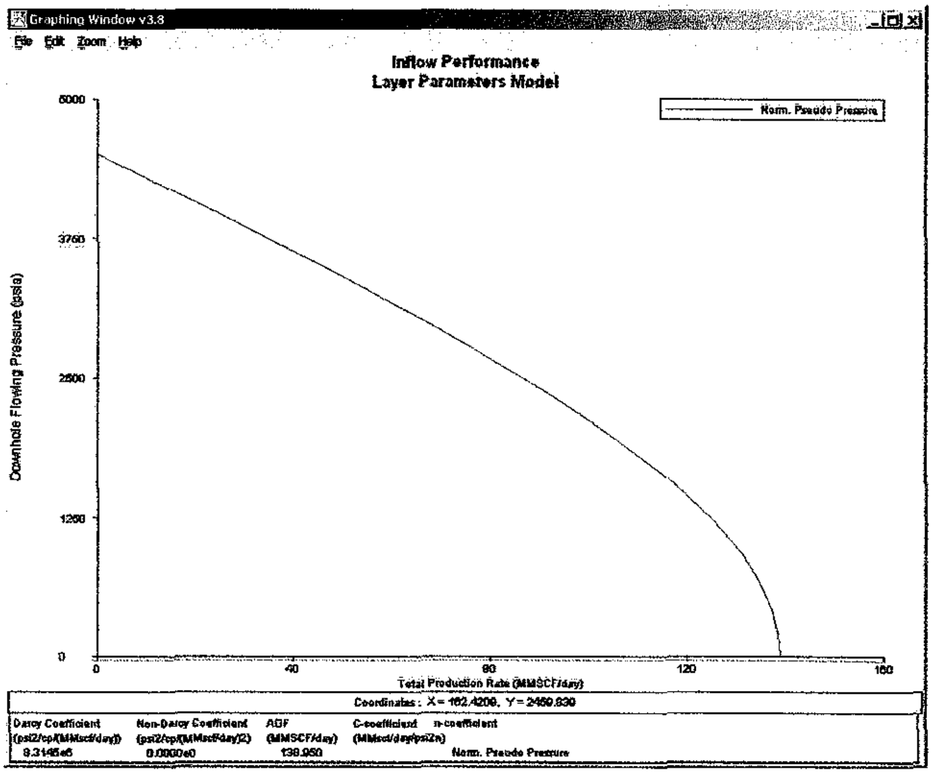


Figure 4.17: IPR curve for median diameter 0.648mm.

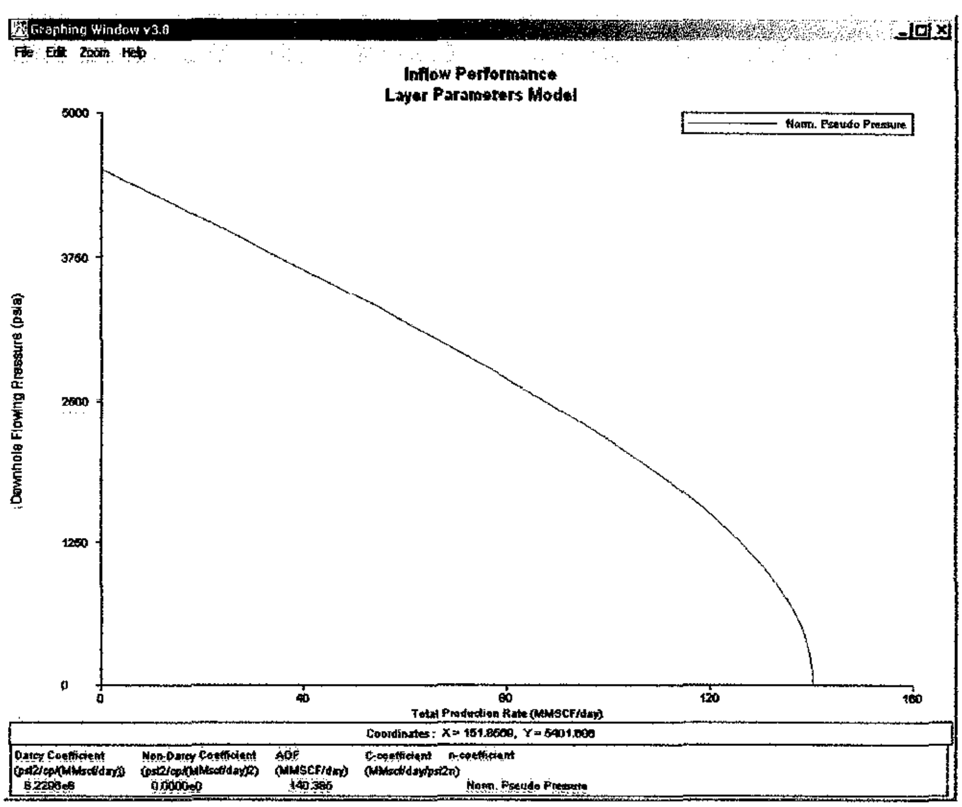


Figure 4.18: IPR curve for median diameter 0.691mm.

Median Dia (mm)	Proppant Perm. (md)	AOF after Frac (MMscf/d)
0.440	140	79.186
0.508	164	85.860
0.648	336	138.950
0.691	340	140.385

Table 4.10: Proppant Permeability and AOF with respect to Median Diameter.

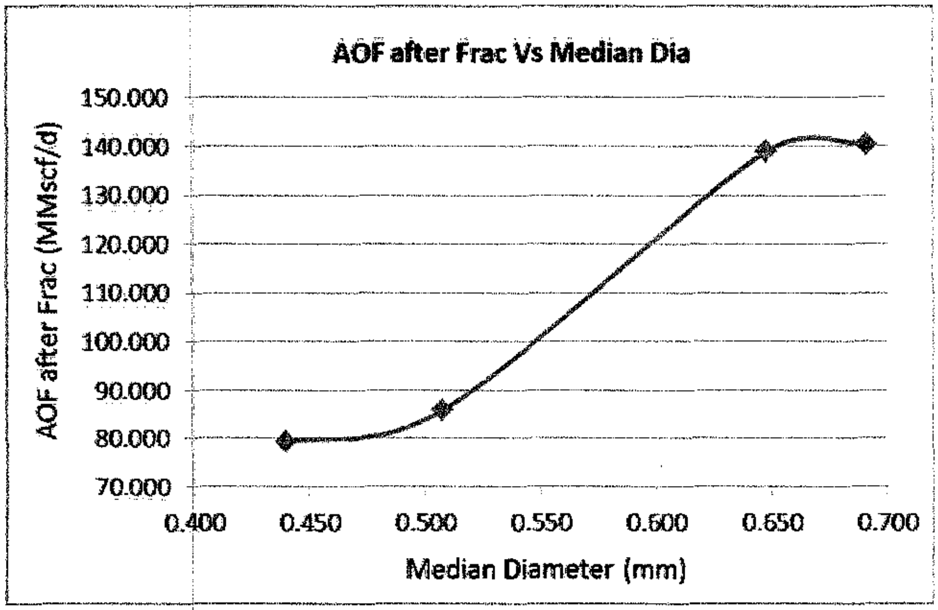


Figure 4.19: AOF Vs Median Diameter

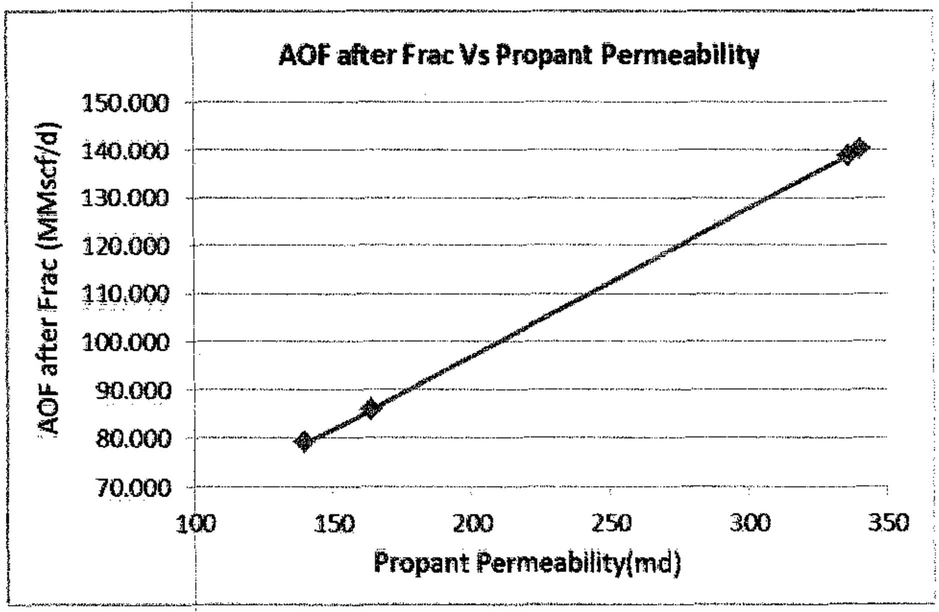


Figure 4.20: AOF Vs Proppant permeability.

From the figure 4.15 to figure 4.20 and table 4.10, we can see the AOF trend as we increase the median diameter. The Proppant Permeability will increase as we increase the median diameter of the proppant and the highest proppant permeability is when we use proppant with median diameter 0.691mm which give use proppant permeability of 340md. This will thus **increase our AOF** by **297%** where it **increases from 50.299MMscf/d before fracture to 140.385MMscf/d after fracture**. Because of that, **we chose proppant with median diameter 0.691mm** to be used for fracture job.

Chapter 5

Conclusion and Recommendation

5.1 Conclusion

From this project, we can enhance the productivity of the tight gas reservoir by fracturing stimulation and focusing on the proppant median diameter. After calculation and simulation had be done, it is decided that the FCD to be used for doing simulation is 1 which can generate a high fracture half-length and meanwhile the proppant median diameter chosen is 0.691mm which give us a permeability of 340md. This has increase the AOF from 50.299MMscf/d before fracture to 140.385MMscf/d after fracture.

5.2 Recommendation

Further studies can be made in order to further improve the productivity of tight gas reservoir as for this project; the time frame given wouldn't be enough to achieve the best result which requires further research and development. Some other parameters must also be taken into consideration when doing the research such as the fracture skin damage and etc.

We can also extend our research on the proppant median diameter to see the trend of the proppant permeability after a certain value of median diameter. Thus able to decide the optimum median diameter that will give us the higher proppant permeability.

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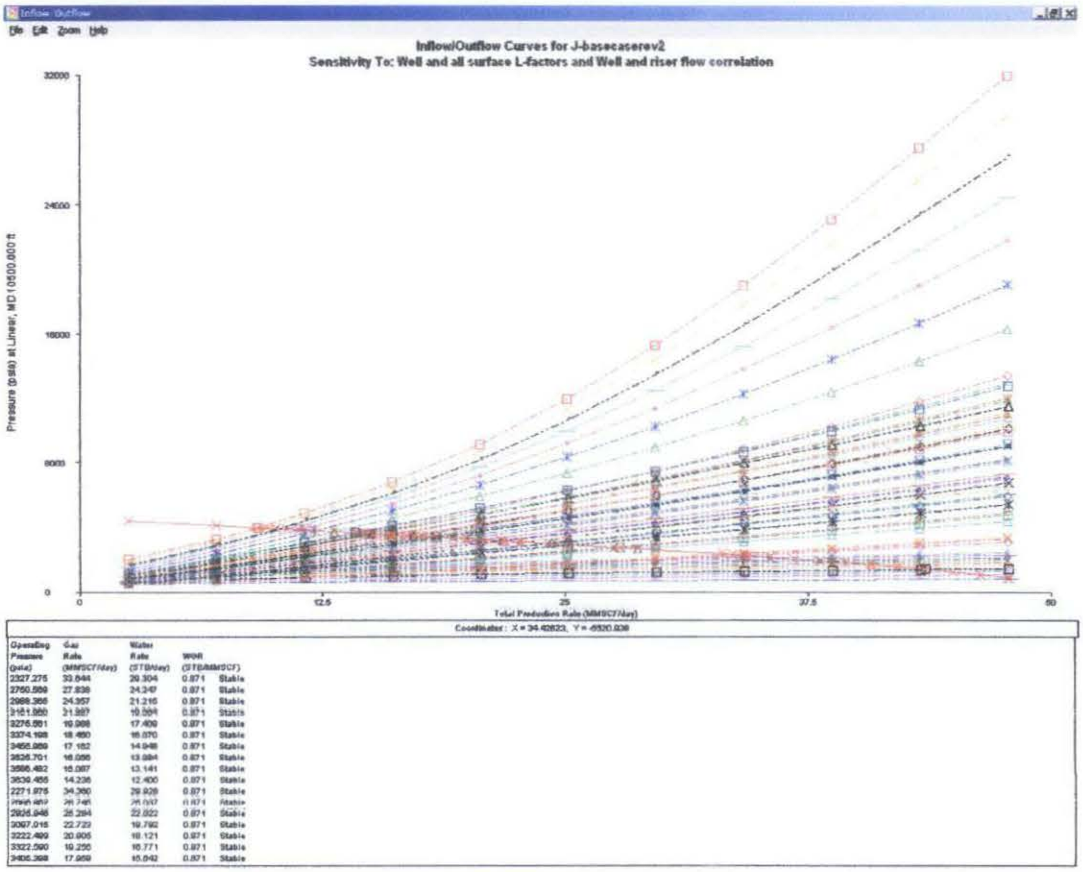
Appendices

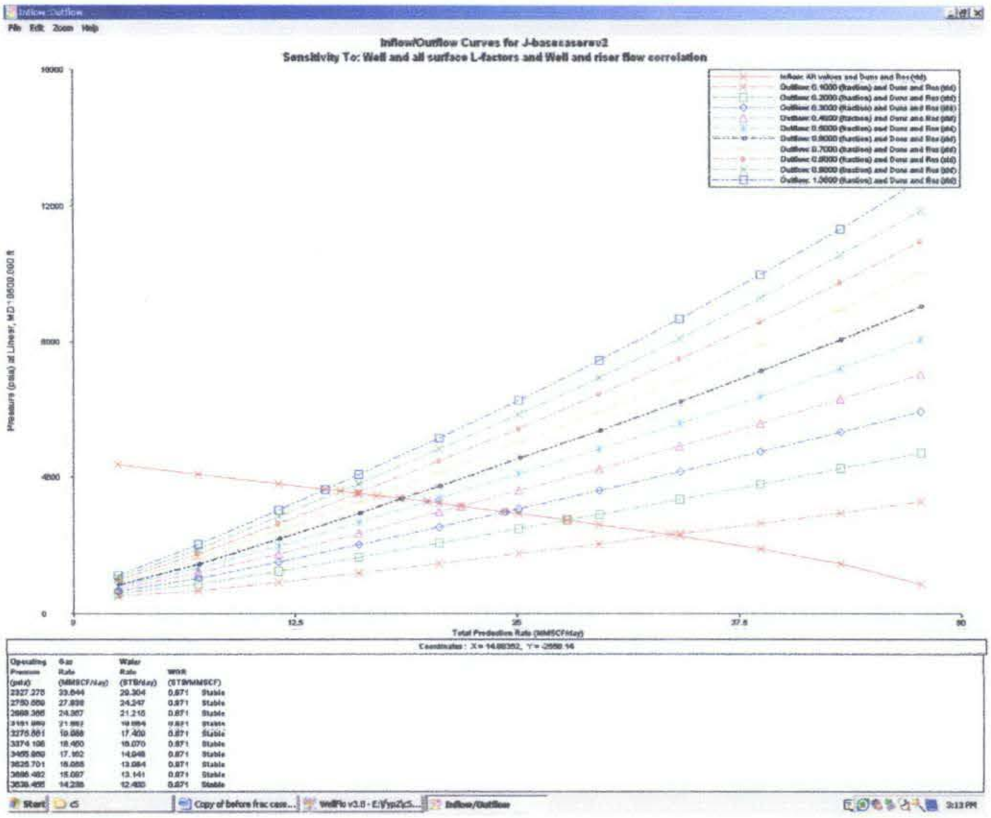
1) Correlation used for analysis using WellFlo

Assume that we are looking for 70% of our AOF (AOF before fracture)

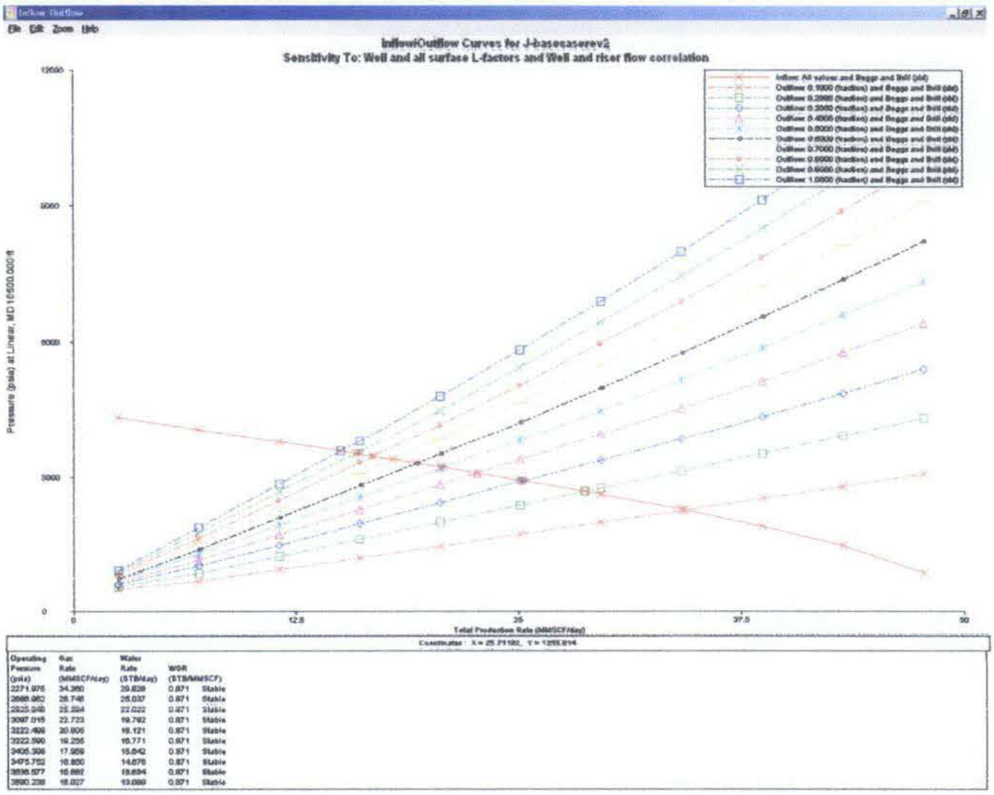


Operating Pressure (psia)	Gas Rate (MMSCF/day)	Water Rate (STB/day)	WGR (STB/MMSCF)	
2327.275	33.644	29.304	0.871	Stable
2760.569	27.836	24.247	0.871	Stable
2989.366	24.357	21.216	0.871	Stable
3161.880	21.887	19.064	0.871	Stable
3276.661	19.988	17.409	0.871	Stable
3374.198	18.450	16.070	0.871	Stable
3456.989	17.162	14.948	0.871	Stable
3526.701	16.096	13.984	0.871	Stable
3586.482	15.087	13.141	0.871	Stable
3639.456	14.236	12.400	0.871	Stable
2271.976	34.360	29.928	0.871	Stable
[illegible]	[illegible]	[illegible]	0.871	Stable
2926.946	25.284	22.022	0.871	Stable
3097.016	22.723	19.792	0.871	Stable
3222.499	20.905	18.121	0.871	Stable
3322.590	19.256	16.771	0.871	Stable
3406.398	17.969	15.642	0.871	Stable

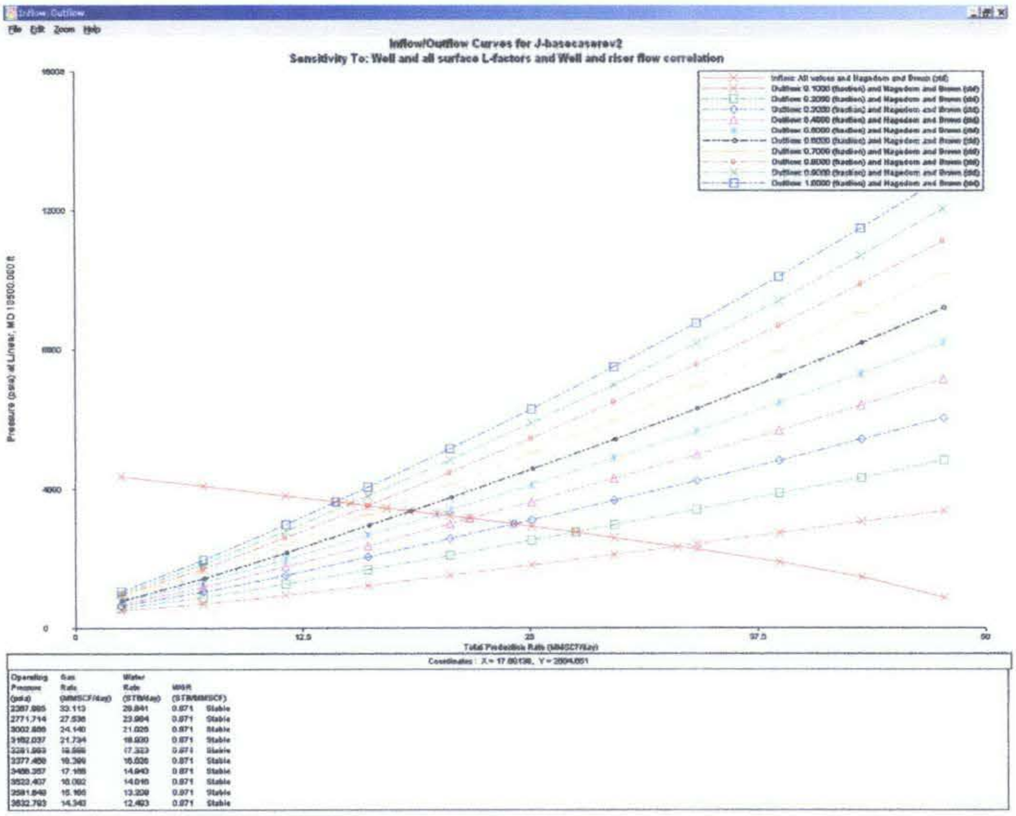
All correlation



Dun & ros

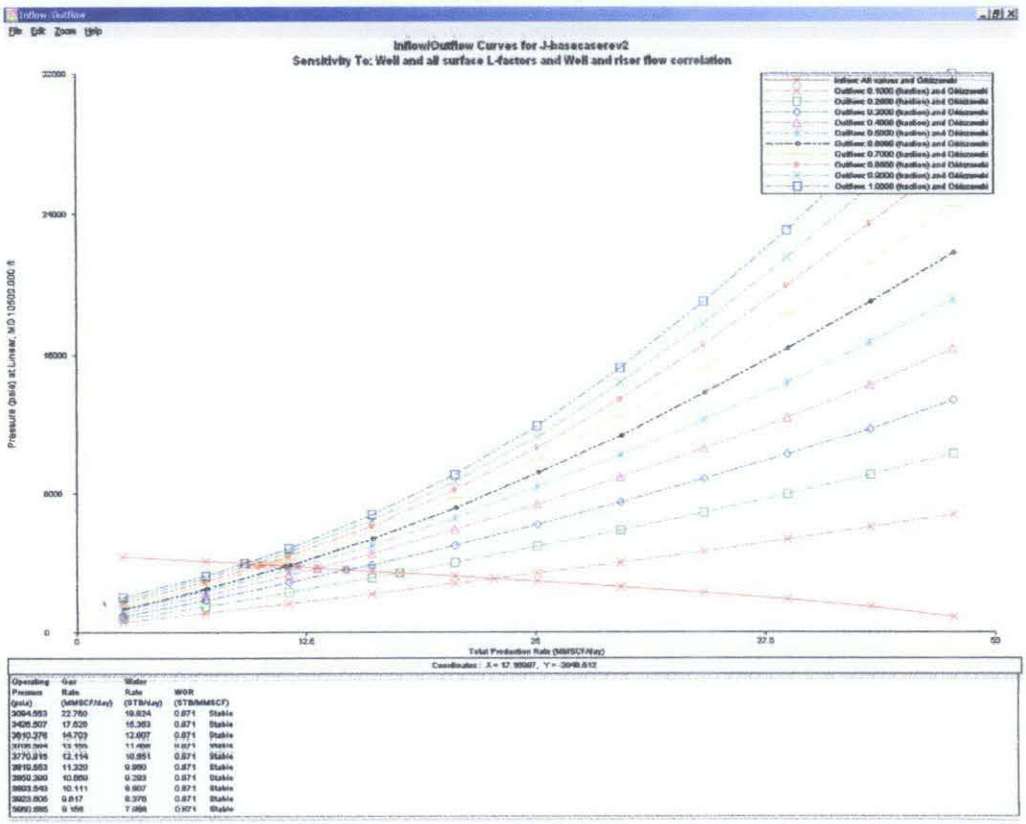


Beggs & bills



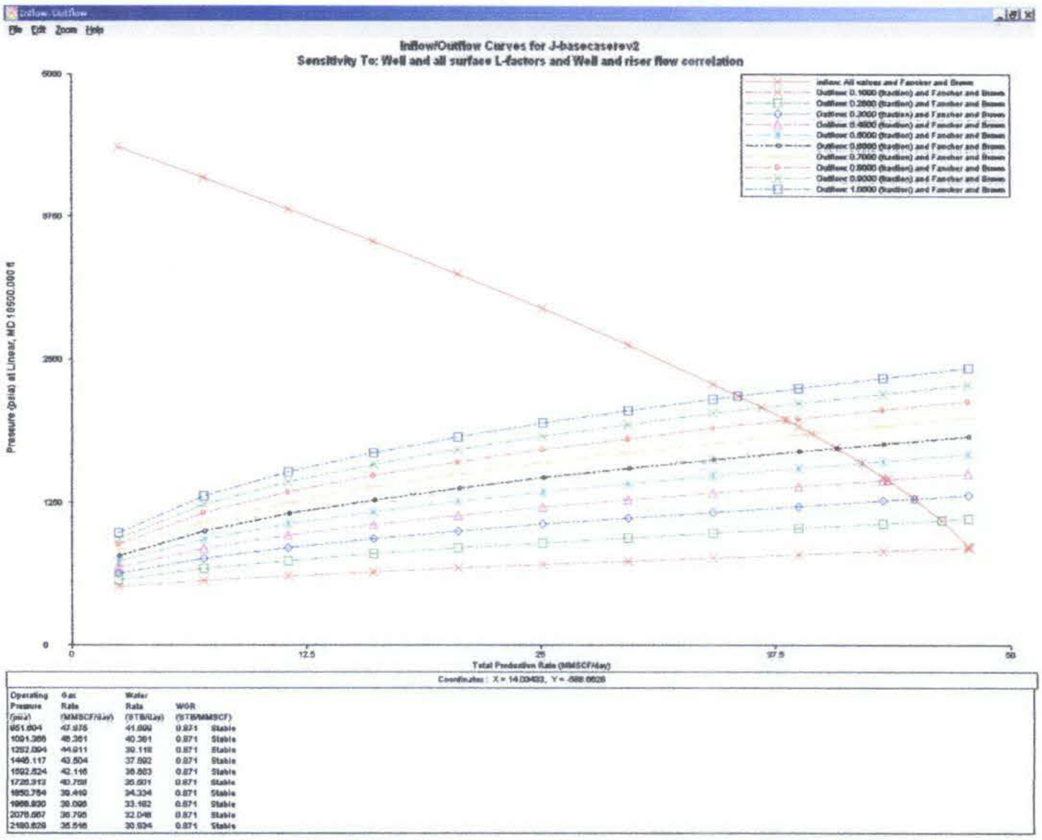
Operating Pressure (psia)	Gas Rate (MMSCF/day)	Water Rate (STB/day)	WGR (STB/MMSCF)	
2387.985	33.113	29.841	0.871	Stable
2771.714	27.536	23.984	0.871	Stable
3002.806	24.140	21.026	0.871	Stable
3182.037	21.734	18.930	0.871	Stable
3281.993	[illegible]	17.333	0.871	Stable
3377.450	18.399	16.026	0.871	Stable
3488.357	17.165	14.940	0.871	Stable
3522.407	16.092	14.016	0.871	Stable
3581.849	15.166	13.209	0.871	Stable
3632.793	14.340	12.493	0.871	Stable

Hagedom & brown

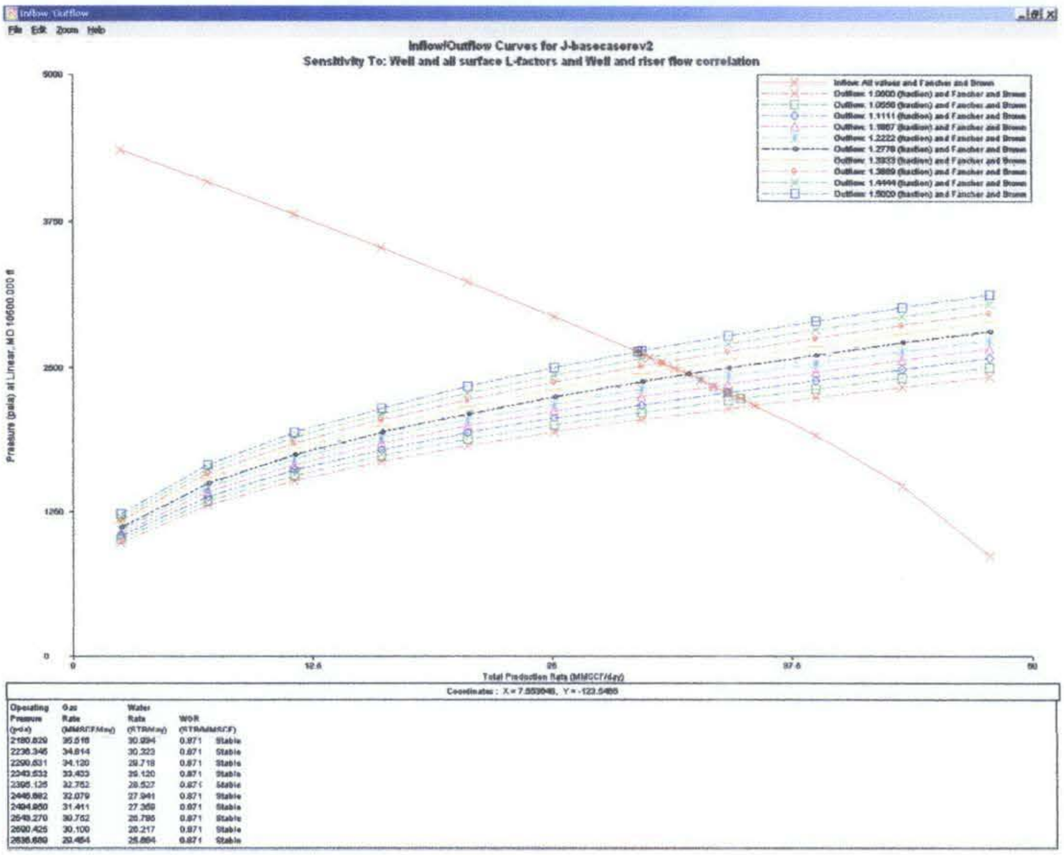


Operating Pressure (psia)	Gas Rate (MMSCF/day)	Water Rate (STB/day)	WGR (STB/MMSCF)	
3094.553	22.760	19.824	0.871	Stable
3426.507	17.620	15.353	0.871	Stable
3610.376	14.703	12.807	0.871	Stable
[illegible]	[illegible]	[illegible]	0.871	Stable
3770.815	12.114	10.551	0.871	Stable
3819.553	11.320	9.860	0.871	Stable
3859.399	10.659	9.283	0.871	Stable
3893.549	10.111	8.807	0.871	Stable
3923.606	9.617	8.376	0.871	Stable
[illegible]	[illegible]	7.986	0.871	Stable

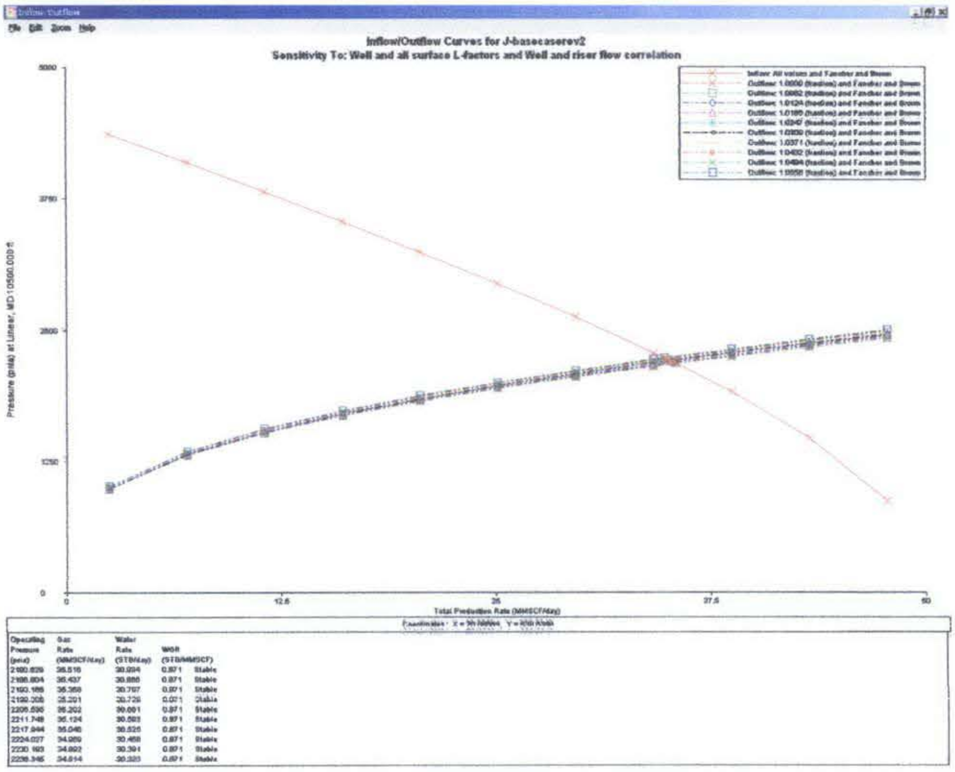
Orkiszweski



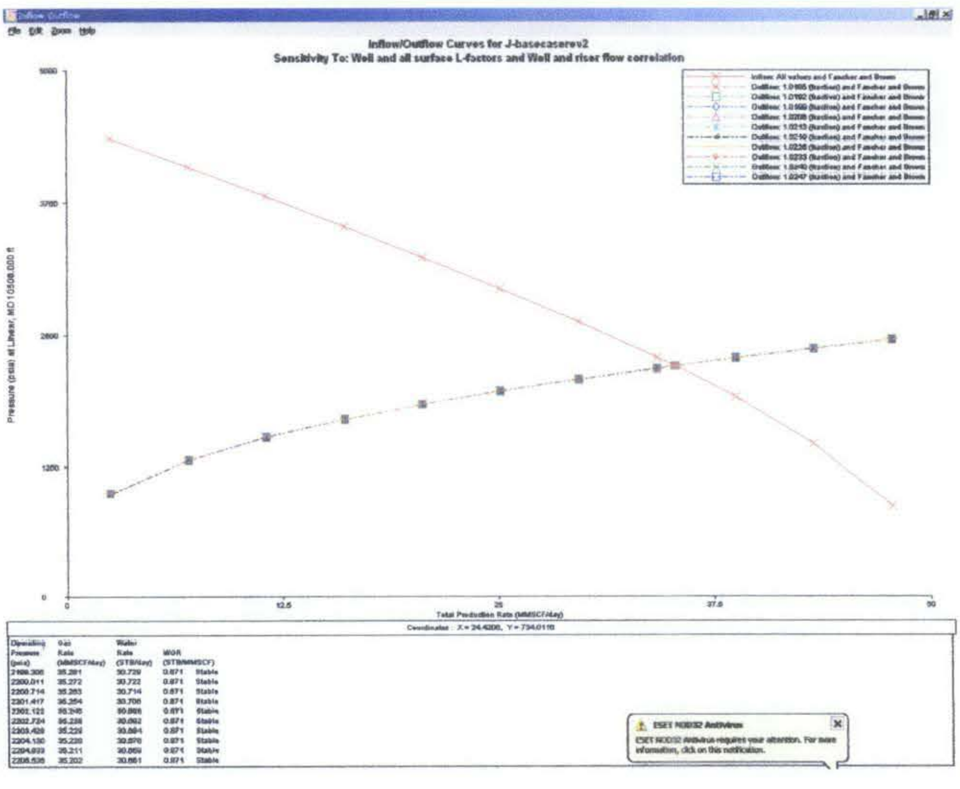
Fancher and brown (L-factor 0-1)



Fancher & brown (L-factor 1-1.5)



Fancher & brown (L-factor 1-1.0556)



Fencher & brown (L-factor 1.0185-1.0247)

The correlation used for doing analysis in WellFlo are Fencher & Brown with L-factor = 1.0247