OPTIMIZATION AND ANALYSIS OF HYDRAULIC FRACTURING METHODS FOR CBM WELLS

A Project Report

submitted by

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in partial fulfilment of the requirements
for the award of the degree of

BACHELOR OF TECHNOLOGY
in
APPLIED PETROLEUM ENGINEERING
with specialization in
UPSTREAM

Under the guidance of

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April 2016

DECLARATION BY THE SCHOLAR

I hereby declare that this submission is my own and that, to the best of my knowledge and belief, it contains no material previously published or written by another person nor material which has been accepted for the award of any other Degree or Diploma of the University or other Institute of Higher learning, except where due acknowledgement has been made in text.

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CERTIFICATE

This is to certify that the thesis titled **"OPTIMIZATION AND ANALYSIS OF HYDRAULIC FRACTURING METHODS FOR CBM WELLS"** submitted by **Mr. Rupal Ranjan | R870212029** , University of Petroleum and Energy Studies, for the award of the degree of **BACHELOR OF TECHNOLOGY** in APPLIED PETROLEUM ENGINEERING with specialization in UPSTREAM is the bonafied record of project work carried out by him under my supervision and guidance. The content of the thesis, in full or parts have not been submitted to any other Institute or University for the award of any other degree or diploma.

Dr. Pushpa Sharma
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ACKNOWLEDGEMENT

I would like to express gratitude to my mentor Dr. Pushpa Sharma | Professor Department of Petroleum Engineering and Earth Sciences, UPES who gave me the opportunity to work on the project “OPTIMIZATION AND ANALYSIS OF HYDRAULIC FRACTURING METHODS FOR CBM WELLS” and for her constant guidance, monitoring and encouragement throughout the course of the project. I would like to thank Dr.D.K.Gupta for his constant support and guidance.

I would like to thank Mr. Anjani Kumar | Manager Hydraulic Fracturing Department, Essar Oil Limited for his guidance throughout the project and providing the data required to carry out the study.

I would also like to thank my parents for their constant support and encouragement through all the good and tough times without which this couldn't be achieved.

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1. Introduction and summary

With increasing demands of energy every day the need is exploiting unconventional sources of energy. One of such sources is CBM or coal bed methane. The largest CBM resources lay in former Soviet Union, Canada, China, Australia and United States. Approximate reserve in India is about 4.6 TCM. CBM reserves produce methane which is a clean fuel and is thus environment friendly as compared to usual conventional fuels.

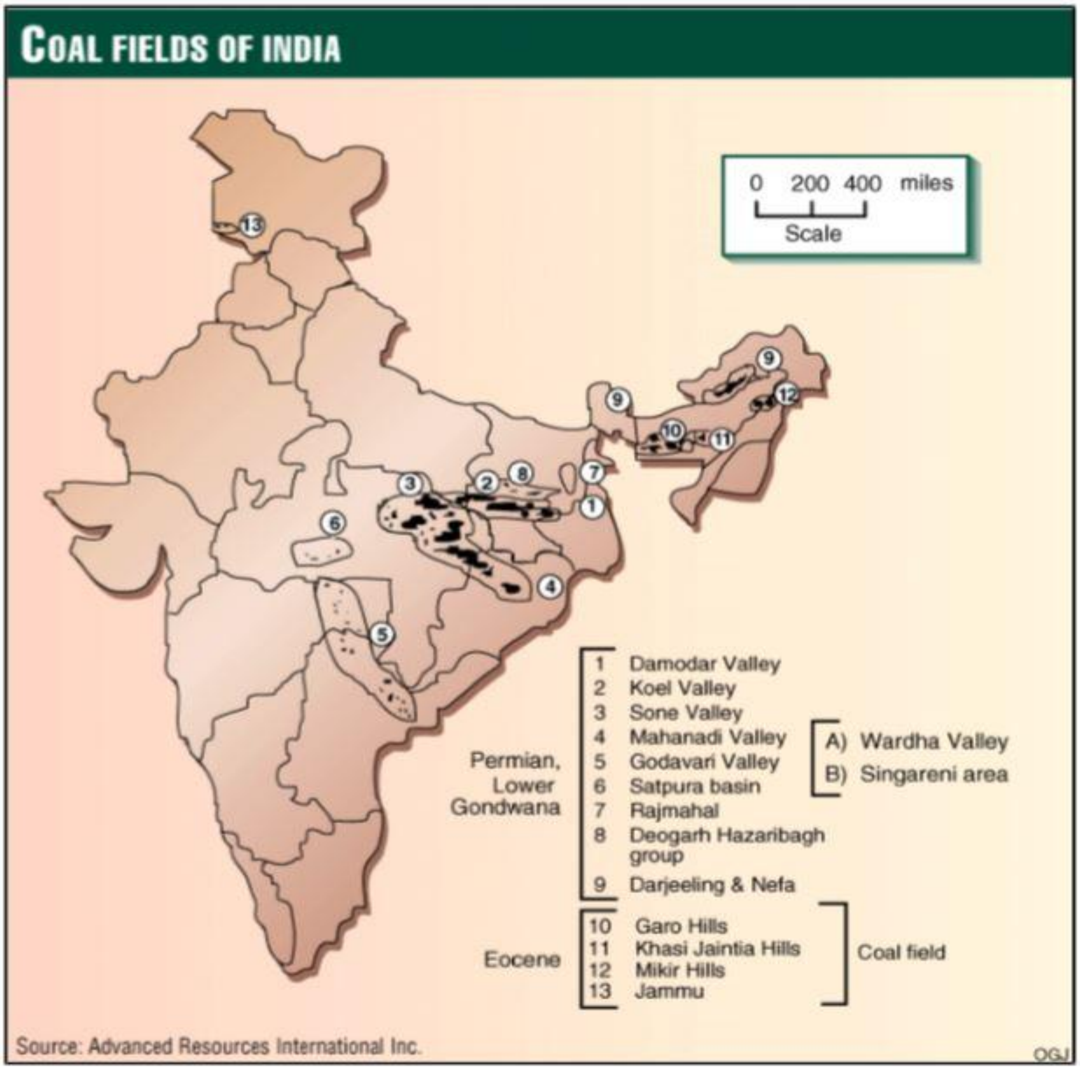


Figure 1 Coal Fields of India

1.1 COAL

Coal, which is a combustible black or brownish-black sedimentary rock usually occurs in layers or veins. These layers or beds are called coal beads or coal seams. As organic matter gets buried, compressed and dewatered inside the earth's surface, peat is formed. Peat, which is a dark brown residue is produced by partial decomposition of the plant that grows in the marshes and swamp. As peat gets buried deeper, heat and pressure simultaneously drive off water and volatile content present in it and it is then transformed into coal as the carbon content increases through devolatilization.

The quality of each coal deposit is determined by:

- Types of vegetation in the region where the coal originated
- Depths of the burial
- Temperatures and pressures at the burial depths
- Time for which the coal has been forming in the deposit

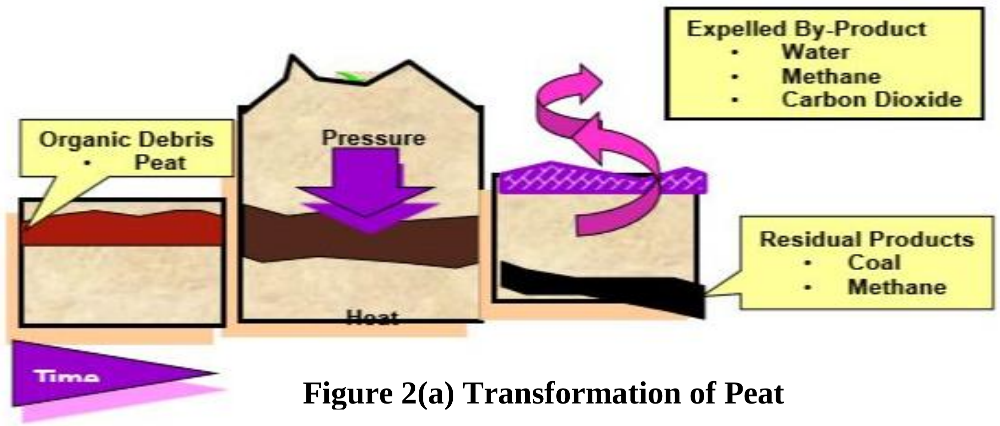


Figure 2(a) Transformation of Peat

The degree of change that coal undergoes maturing from peat to anthracite is known as coalification. Coal is solid in appearance but it contains gas and oil like substance which are formed during coalification. Most of the physical and chemical properties of coal are determined by Coal Rank and Relative Abundance of various components.

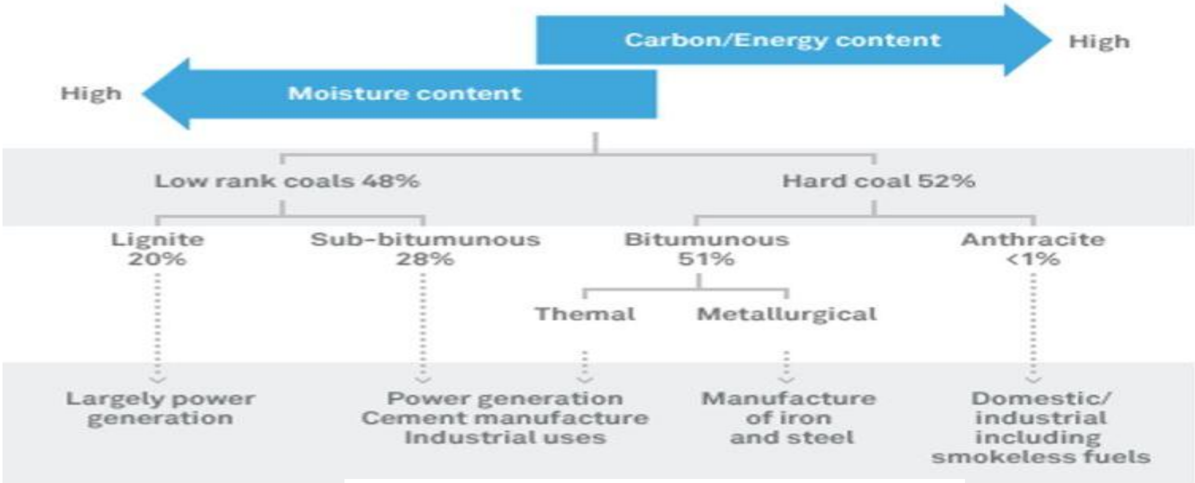


Figure 2(b) Transformation of Peat

The total gas in-place and the gas deliverability of the reservoir are the two most important parameters in evaluating a coal bed methane prospects. These parameters are largely determined by the physical properties of the coal. Density, porosity, strength, permeability and rank parameter are the physical properties that are useful in evaluating coal for CBM productions. Several physical and mechanical properties of the coal are significantly different from most reservoir rocks Coal resources can be more accurately estimated if the coal density is known.

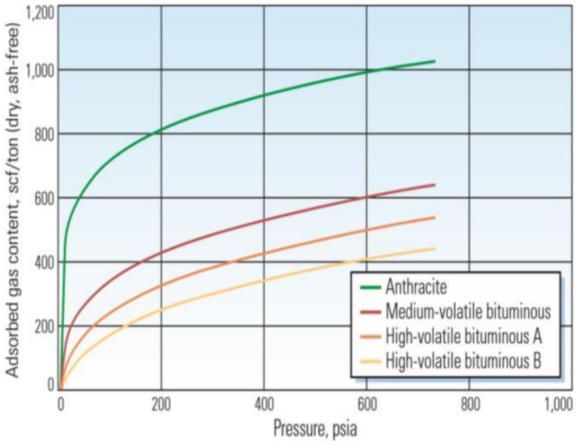


Figure 3 Adsorbed Gas Vs Pressure

It can be difficult to accurately determine the volume of coal and its density because of the porous nature of the coal. Usually, apparent density of coal reaches a minimum at about 85 percent carbon in the low volatile bituminous range.

Coals of medium volatile bituminous through anthracite rank typically display porosity value of which doesn't exceed five percent. Cleating is most developed in the low volatile bituminous range where compressive strength of coal reaches a minimum. Hardgrove Grindability Index(HGI) determines coal strength. High HGI indicates weak coal and vice-versa. If HGI value is available in existing data, you may be able to use it as an indicator of relative cleat intensity. However some coal have a high HGI value, but display little or no cleating.

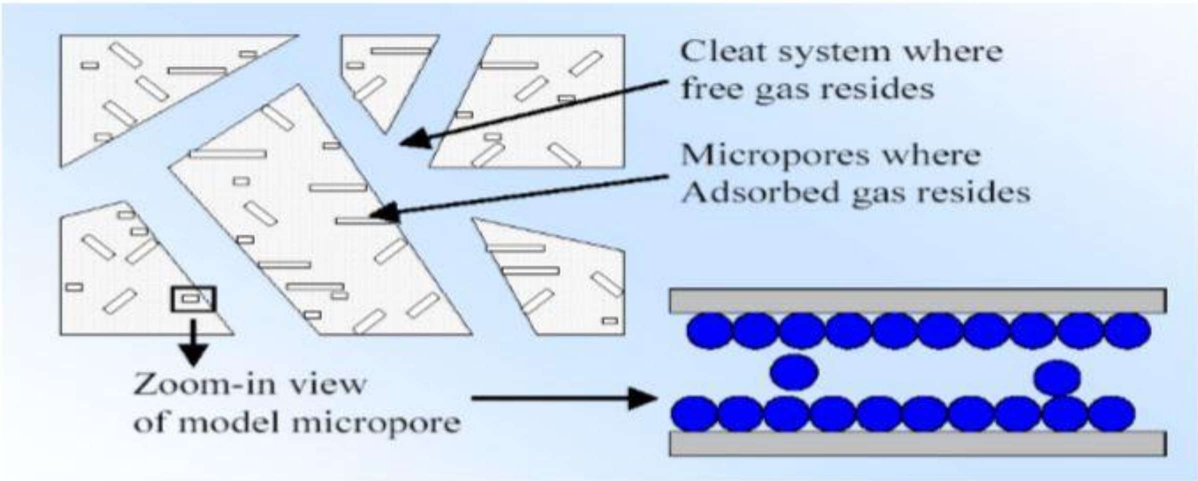


Figure 4 Cleat System

Cleat refers to the natural system of vertical fractures which is a result of coalification process. Typically, the cleat system in coal consists of two or more sets of sub parallel fractures the orientation of which is nearly perpendicular to bedding. Coal bed permeability influences cleat spacing. Cleat spacing is closely related to rank, petrographic composition, mineral matter content, bed thickness and tectonic history. Low permeability can be a result of mineral fillings in cleat, as per which in case a large proportions of the cleat are filled, absolute permeability may be extremely low.

1.2 CBM Reservoir

Natural gas stored in coal seams and generated during the process of coalification is called Coal Bed Methane (CBM). The term refers to methane adsorbed into the solid matrix of the coal. Lack of hydrogen sulfide gives it the name of 'sweet gas'. Presence of this gas presents a serious safety risk and is well known from its occurrence in underground coal mining.

Coal Bed Methane differs from typical sandstone or other conventional gas reservoir, as methane is stored within the coal by a process called adsorption. Lining the inside of pores within the coal (called the matrix), the methane is in a near-liquid state. The open fractures in the coal are called cleats, can also contain free gas or may be saturated with water. Unlike much of the natural gas from conventional reservoirs, coal bed methane contains very little heavier hydrocarbons like propane or butane, and contains no natural gas condensate. It often contains up to a few percent carbon dioxide.

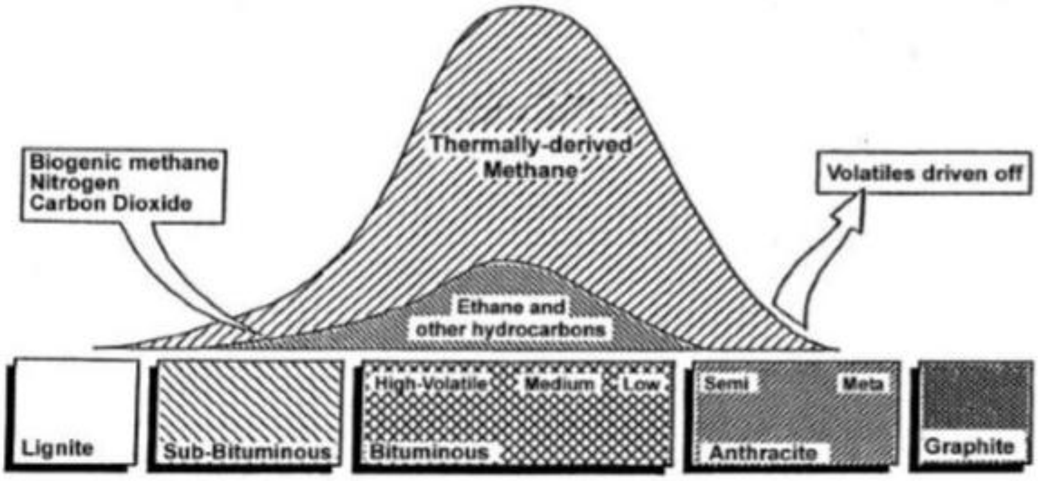


Figure 5 Methane Generation

Former Soviet Union, Canada, China, Australia and United States have the largest CBM resources. Much of the world's CBM recovery potential remains untapped. As of the data in 2006 it was estimated that of global resources summing up to 143 trillion cubic meters, only 1 trillion cubic meters was actually recovered from reserves due to a lack of incentive in some countries to fully exploit the resource base, particularly in parts of the former Soviet Union where conventional natural gas is abundant. In case of India, it lacked the infrastructure to commercially exploit the associated CBM gas, which resulted in delay in its economical production in the subcontinent. Depleting conventional resources and increasing demand for clean energy, forced India to explore alternatives to conventional energy resources. CBM is considered to be one of the most viable alternatives to combat the situation. With the growing demand and rising oil and gas prices, CBM is definitely a feasible alternative source.

India's coal reserve has been estimated at around 4.6 TCM which makes it the fourth-largest proven coal reserves in the world and therefore considerable prospects exist for exploration and exploitation of CBM in the country. Eastern and North-eastern parts of the country contain most of India's coal deposits. India is one of the select countries which has undertaken steps through transparent policies to harness domestic CBM resources.

Resource	The amount of coal that may be present in a deposit or coalfield. This does not take into account the feasibility of mining the coal economically. Not all resources are recoverable using current technology.
Reserves	Reserves can be defined in terms of proved (or measured) reserves and probable (or indicated) reserves. Probable results have been estimated with a lower degree of confidence than proved reserves.
Proved Reserves	Reserves that are not only considered to be recoverable but can also be recovered economically. This means they take into account what current mining technology can achieve and the economics of recovery. Proved reserves will therefore change according to the price of coal; if the price of coal is low proved reserves will decrease.

CBM has become a popular fuel of choice globally due to the environmental, technical, and economical advantages associated with it. With the energy demand/supply bridge predicted to further go apart, India has intensified its efforts in exploration of unconventional hydrocarbon sources, especially those related to CBM. India possesses significant prospects for commercial recovery of CBM having the fourth largest proven coal reserves and being the third largest coal producer in the world.

CBM reservoirs differ from conventional reservoirs in many ways, the porosity in coal is much lower than conventional reservoirs yet they can store up to six times more gas then sandstone under same pressure conditions. Storage capacity in coals is related to pressure and adsorption capacity usually described by Langmuir isotherm. Due to the lesser permeability of CBM the method of producing CBM also differs from conventional methods. To contact the maximum drainage area, wells are stimulated by hydraulic fracturing to connect cleats and natural fractures within the wellbore. Then the wells are dewatered. Once the pressure is sufficiently low so as to produce gas, gas production is observed from the annulus and water is simultaneously produced from the tubing.

A fracturing job is designed keeping in mind all the parameters that have an effect on fracture generation, propagation and closure. The actual treatment schedule might somewhat differ from the designed, depending upon pressure responses of the formation. The pre frac job design varies with type of formation and its properties. This reports aims at optimization of pre-frac job design for CBM wells considering all the important parameters such as proppant type, size, concentration, volumes of different stages and fluid properties. The dependency of a good job on such parameters is illustrated through a number of examples.

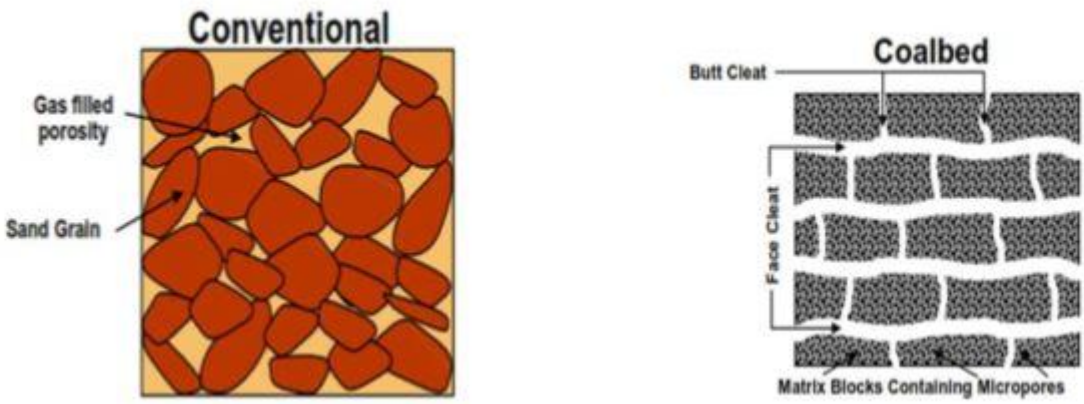


Figure 6 Conventional Vs Coalbed

Conventional Gas	Coalbed
Darcy flow of gas to wellbore.	Diffusion through micropores by Fick's Law.
Darcy flow of gas to wellbore.	Darcy flow through fractures.
Gas storage in macropores; real gas law.	Gas storage by adsorption on micropore surfaces.
Production schedule according to set decline curves.	Initial negative decline.
Gas content from logs.	Gas content from cores. Cannot get gas content from logs.
Gas to water ratio decreases with time.	Gas to water ratio increases with time in latter stages.
Inorganic reservoir rock.	Organic reservoir rock.
Hydraulic fracturing may be needed to enhance flow.	Hydraulic fracturing required in most of the basins except the eastern part of the Powder River basin where the permeability is very high. Permeability dependent on fractures.
Macropore size:[3] 1μ to 1 mm	Micropore size:[3] <5A° to 50A°
Reservoir and source rock independent.	Reservoir and source rock same.
Permeability not stress dependent.	Permeability highly stress dependent.
Well interference detrimental to production.	Well interference helps production. Must drill multiple wells to develop.

1.3 Description of the Block

Raniganj coalfield, West Bengal is the largest coalfield in India, belonging to the Gondwana Super Group. Alanson, situated about 210 km NW of Kolkata, is the main town in this coalfield. Mining in this region dates back to the British period.

The Basin is divided into three Blocks:

1. Raniganj North Block – Operated by ONGC

2. Raniganj South Block – Operated by GEECL

3. Raniganj East Block – Operated by Essar Oil

The Block RG (East)-CBM-2001/1 covers an area of 500sq.km. (approx.) and is located eastern most part of the Raniganj coalfield area. It falls largely in Barddhaman district, West Bengal. The block is bounded by Latitude: 23°21’45’’ and 23°41’12’’N and Longitude: 87°14’40’’ and 87°28’46’’E.

CBM blocks in India

State	No. of Blocks	Area (Sq. Km)
West Bengal	4	1308
Jharkhand	6	1326
Madhya Pradesh	5	2648
Rajasthan	4	3972
Chattishgarh	3	1917
Andhra Pradesh	2	1136
Maharashtra	1	503
Gujarat	1	790
Total	**26**	**13600**

Essar oil has total 5 secured CBM blocks in India having more than 10 TCF of reserves.

Block	Area (Sq. Km)
Sohagpur	339
IB velly	209
Raniganj	500
Rajmahal	1128
Talchir	557

2. Hydraulic Fracturing

The process of pumping fluid into a wellbore at an injection rate that is too high for the formation to accept without breaking is called Hydraulic Fracturing. During injection the resistance to flow in the formation increases, which results in increasing the pressure in the wellbore to a value called the breakdown pressure, which is the sum of the in-situ compressive stress and the strength of the formation. Once the formation "breaks down," a fracture is formed, and then the injected fluid flows through it. From a limited group of active perforations, which is ideally a single, vertical fracture is created that propagates in two "wings" being 180° apart and identical in shape and size. In naturally fractured or cleated formations, it is possible that multiple fractures are formed and/or the two wings evolve in a tree-like pattern with increasing number of branches away from the injection point.

Fluid not containing any solid (called the "pad") is injected first, until the fracture is wide enough to accept a propping agent. The purpose of the propping agent is to keep apart the fracture surfaces once the pumping operation ceases, the pressure in the fracture decreases bellow the compressive in-situ stress trying to close the fracture. In deep reservoirs, man-made ceramic beads are used to hold open or "prop" the fracture. In shallow reservoirs, sand is normally used as the propping agent.

Hydraulic fracturing is a type of well stimulation treatment designed to improve the fluid flow path from the formation to the well by bypassing near-wellbore damage. In CBM, Hydraulic fracturing is done to create a conductive flow path from formation to the wellbore and to thereby increase the productivity index. The rate at which oil or gas can be produced at a given pressure differential between the reservoir and the wellbore is defined by the productivity index, while the injectivity index refers to the rate at which fluid can be injected into an injection well at a given pressure differential.

There are many applications for hydraulic fracturing. Hydraulic fracturing can:

- Increase the flow rate of oil and/or gas from low-permeability reservoirs
- Increase the flow rate of oil and/or gas from wells that have been damaged
- Connect the natural fractures and/or cleats in a formation to the wellbore
- Decrease the pressure drop around the well to minimize sand production
- Enhance gravel-packing sand placement
- Decrease the pressure drop around the well to minimize problems with asphaltine and/or paraffin deposition
- Increase the area of drainage or the amount of formation in contact with the wellbore

2.1 Types of hydraulic fracturing :

- acid fracturing
- propped fracturing

Both types of fracturing treatments create highly conductive paths from reservoir to the wellbore.

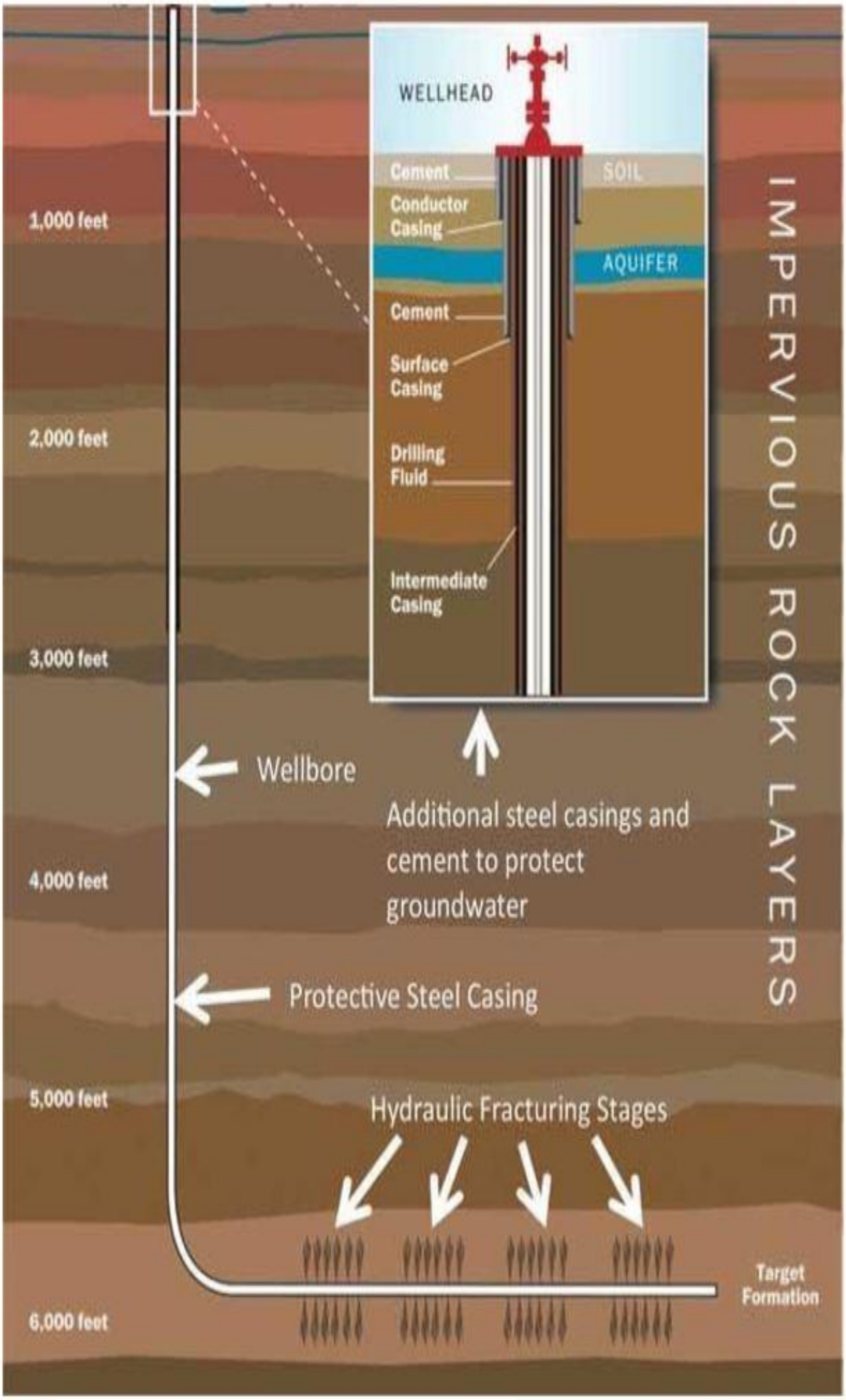


Figure 7 Hydraulic Fracturing Stages

In acid fracturing, a low pH fluid is used which dissolves some portion of rock on the fracture surface. Then the two etched surfaces are unable to close and seal properly, thus a highly conductive conduit is created in the formation. Injection rate should be high enough and formation permeability should be low enough so as to prevent excessive fluid loss.

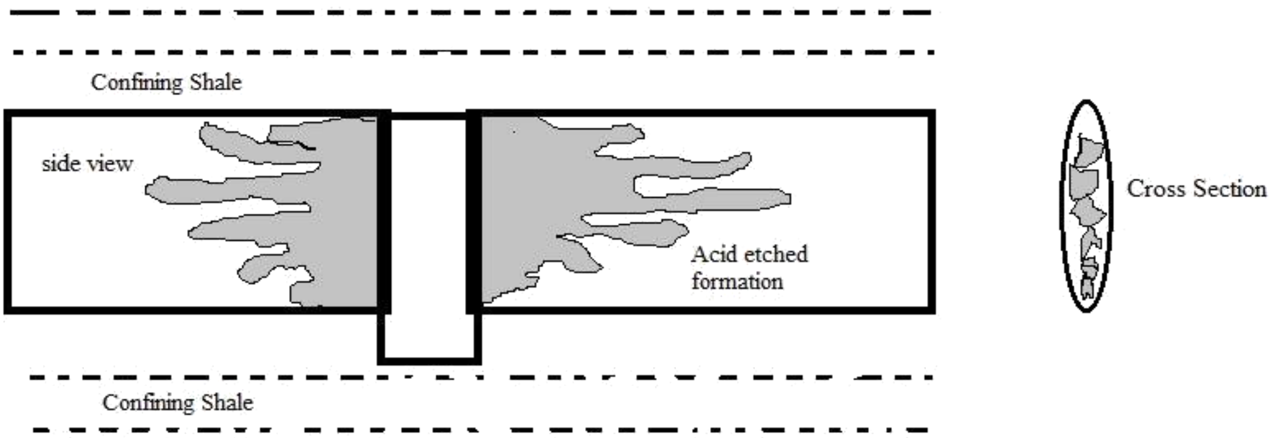


Figure 8 Acid fracture

In Proppant Fracturing, a viscous fluid is pumped at sufficiently high pressure in completion interval so that a two winged, hydraulic fracture is formed. To hold this fracture open, conductive proppant is pumped in this fracture. Depending upon type and size of treatment employed fracture of varied dimensions is created.

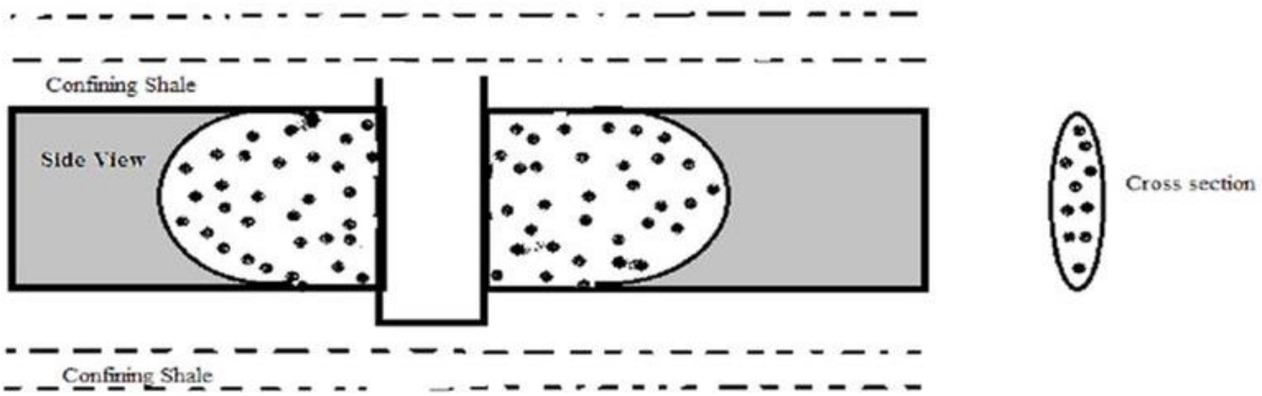


Figure 9 Propped Hydraulic fracture

Propped Hydraulic fracture aims at improving productivity index by increasing effective wellbore radius of wells completed in low permeability formations such as coal, carbonates etc.

2.1.1. Why proppant hydraulic fracturing is done in CBM?

Acid fracturing is generally preferred for carbonates (limestone and dolomites) and it involves consideration of following factors:

- Low reservoir permeability
- compatibility with formation fluids
- fluid loss prevention
- reaction rate and time
- rock solubility (temperature)
- cost of fluid

Relative formation solubility in acid is first considered in deciding between an acid fracturing treatment and a propped fracture treatment. Wells having fair permeability or deep and extensive wellbore damage are the most appropriate candidates for acid fracturing. A propped fracture is less expensive than an acid frac that achieves the same lateral fracture penetration. The next step is to determine if we can realistically achieve the required conductivity by using high proppant concentrations to give exceptional propped fracture width.

We should examine well records to determine if there is a significant or historical problem (e.g., lack of long-term response, many screenouts) resulting from the use of conventional propped fracture treatments. Logistical concerns such as location accessibility and the availability of sufficient fracturing equipment must be addressed first and then we should perform comparative studies to predict the theoretical results from several different treatments. Propped hydraulic fracturing is preferred because of the so many considerations and difficulties in predicting the formation response to acid fracturing.

2.2. Fracture propagation

The stresses existing in the formation and usually act as a compressive load on the formation are called In situ stresses. A three dimensional complex stress regime exist in most formations which can be resolved in three mutually perpendicular stress components, the vertical stress σ_v and the horizontal components σ_h,min and σ_h,max and associated with these stresses are strains in three mutually perpendicular directions. Relationship between these stresses and strains is governed by Hooke's law.

$$\epsilon_x = [\sigma_x - v\,(\sigma_y + \sigma_z)]/E$$

This equation means that strain in any direction can be found in a three dimensional stress regime given that stress in that direction and two mutually perpendicular directions are known.

In case of elastic deformation with no influence of outside forces such as tectonics, in an isotropic and homogeneous formation, stresses will be symmetrical on horizontal plane.

$\sigma_{h,min} = \sigma_{h,max}$ and since each individual rock is pushing other there is no deformation in horizontal direction i.e. $\epsilon_{h,min} = \epsilon_{h,max} = 0$
Therefore Hooke's law reduces to $\sigma_h = \sigma_v$
Thus unless there are some extreme outside influence, horizontal stress will always be less then vertical stress.

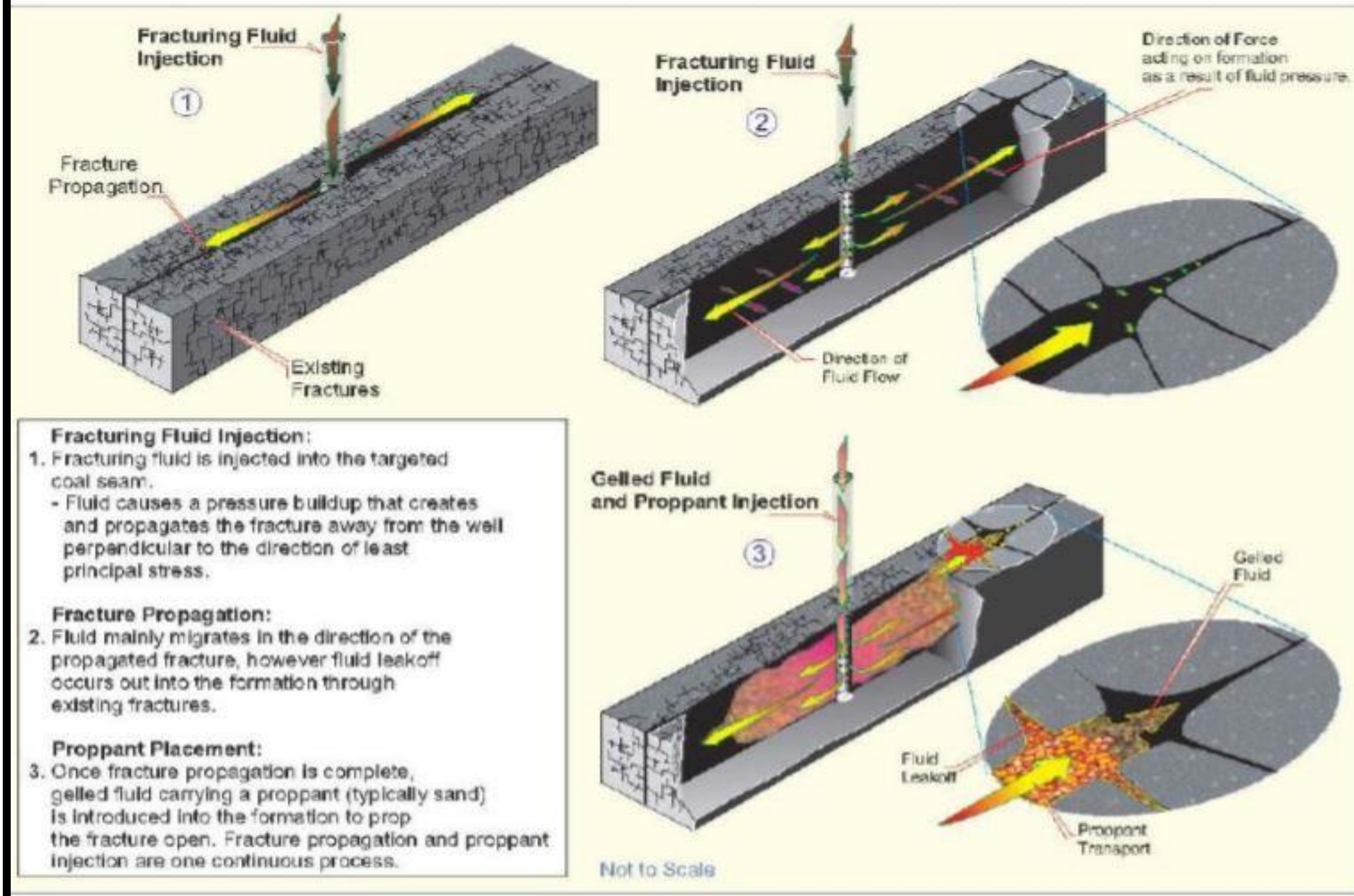


Figure 10 Fracture Propagation

2.3 Fracture orientation

Fracture propagates along the path of least resistance. In a three dimensional stress regime a fracture will create width in a direction that requires least force and will propagate so as to avoid the greatest stress which means that a fracture will propagate parallel to the greatest principle stress and perpendicular to the plane of least principle stress. Thus fracture will almost always propagate on a vertical plane and if formation is lost due to erosion, overburden stresses are reduced but since horizontal stresses have been locked in they are not reduced. Thus there is a region where horizontal stresses are greater than vertical stresses. This means that the fracture will propagate horizontally.

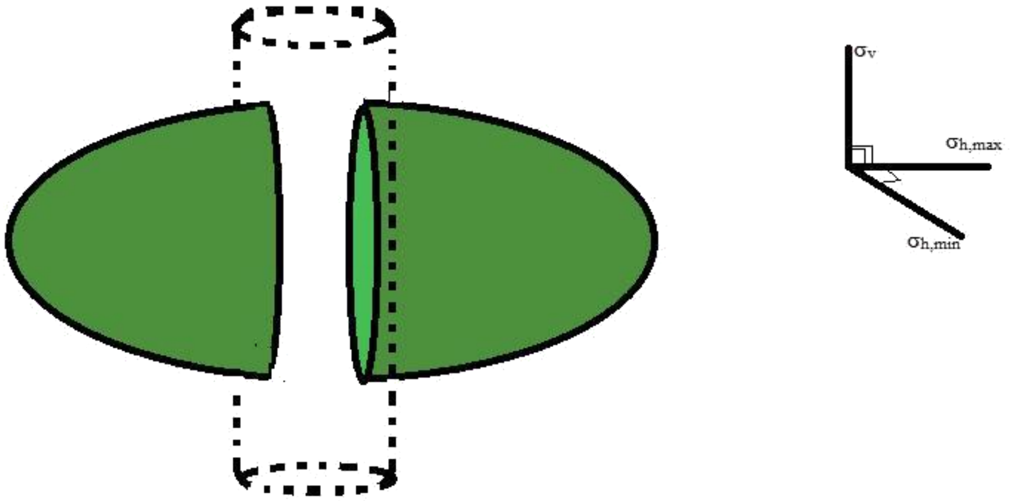


Figure 11 Fracture propagation perpendicular to minimum horizontal stress

In shallow formations with sufficient consolidation and strength to lock in the horizontal stresses, horizontal fractures are more likely.

In the formations where $\sigma_v = \sigma_h$, it becomes very difficult to calculate the fracture orientation. Also due to action of tectonics and volcanic forces, there are significant effects on fracture orientation, the forces imposed by movement of earth crust can alter the horizontal stresses but do not affect overburden stresses. Some formations can also undergo bending and buckling. If under extreme bending formation runs vertically, horizontal stresses are locked in place, so now original vertical stress is horizontal thus fracture propagates horizontally.

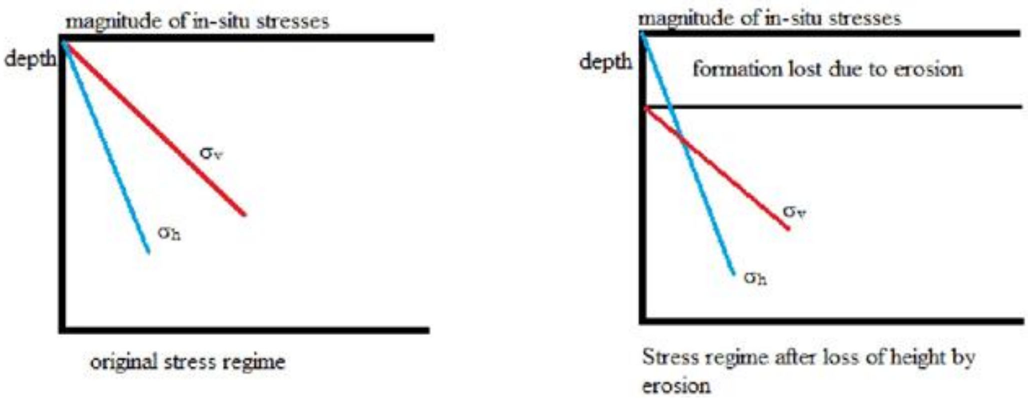


Figure 12 Changes in stress regime due to erosion or glaciation

Other than the effects of stresses, Fracture propagation also depends upon no of other factors such as:

- type of formation
- Rate of pumping
- Perforation

Type of Formation

The stresses in the formation will depend upon the type of formation. If the formation is unconsolidated, the overburden stresses will be less as compared to overburden stresses in more consolidated formation.

Rate of Pumping

If Rate of Pumping Frac fluid in the formation is more, same propagation will be achieved in less time. Thus rate of pumping affects the total job time and through minifrac analysis required rate is decided by carrying out no of step up and step down tests.

Perforation

A fracture tends to propagate through path offering least resistance. Fractures may not propagate through each perforation. For fracturing the required zone, it is important that the orientation of well is along maximum principle stress. The drilling of well is done on the basis of stress analysis which is done through seismic survey of coal seam. Perforations should be done along the maximum principle stress so that fracture propagates perpendicular to minimum principle stress.

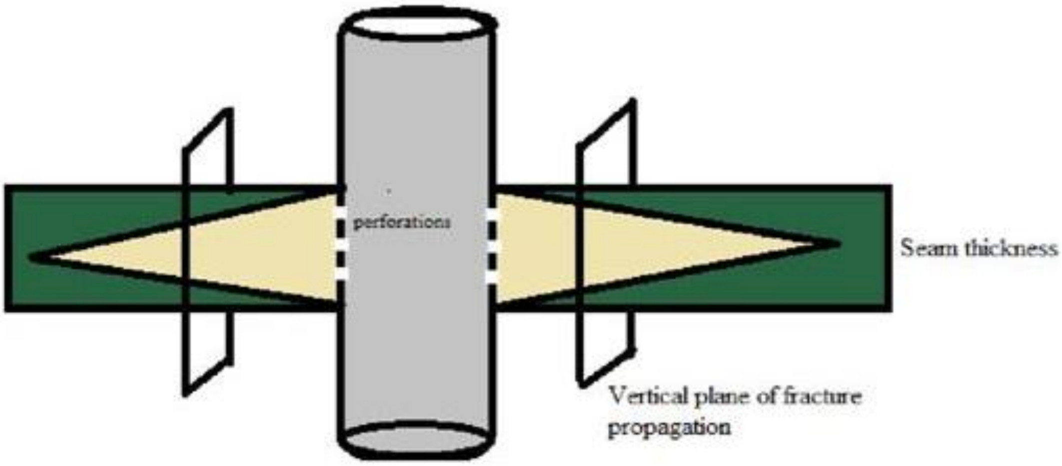


Figure 13 Perforations can be done either through CT or by wireline

3. Frac Fluid

Fracturing fluids are those fluids whose injection at desired rates initiates a fracture. When a fracture is initiated, it needs to propagate through formation to create a conductive path. Due to overburden and in-situ stresses, fracture have a tendency to close, to prevent it, proppants are pumped along with frac fluids. Thus frac fluid should be viscous enough to carry the proppant and once the proppant are placed inside the fracture, frac fluid is recovered by adding breakers which reduce its viscosity. Depending upon requirement, different types of frac fluids are used for different formations.

Frac fluid functions :

- Initiation of fracture
- Propagation of fracture
- Carrying proppant
- Return to wellbore after treatment

Frac fluids properties :

- Low cost
- Ease of use
- High viscosity for proppant transport
- Low viscosity after treatment for fluid recovery
- Highly efficient i.e. fluid leak off should be less
- Compatibility with formation fluids and proppant
- Environment friendly
- Should be safe to use

Types of Frac Fluid

There are many different types of fluids used in fracture stimulation. Early fracture treatments almost exclusively used crude oils or special refined oils to ensure complete compatibility with the reservoir. They are categorized as:

- **Water- based systems**
- **Oil based systems**
- **Emulsion**
- **Visco-elastic surfactant**
- **Gas/Foam fluids**

4. Proppant

The most important material used in hydraulic fracturing is the one that remains in the well the propping agent, or *proppant.* They are basically used to keep the fractures open during or following a fracture treatment and create a conductive path to the wellbore.

4.1 Types of proppants

Proppants are classified as:

- Naturally occurring sand
- Man-made Proppants:
  1. Sintered bauxite
  2. Intermediate strength proppant
  3. High strength proppant
  4. Resin coated proppant
  5. Ultra-Lightweight proppants

4.2 Fracture conductivity and permeability

To optimize a treatment's impact on the reservoir's long-term productivity, it is essential to attain both deep fracture penetration and adequate fracture conductivity. It is also essential to achieve a proper balance between these two parameters in order to maximize their respective benefits. In reservoirs of very low permeability, we must create very long fractures; at the same time, we must provide sufficient conductivity to effectively utilize most of the created fracture length. In higher permeability reservoirs, it is equally important to adequately prop the short fracture in order to realize the maximum benefit from the created fracture width.

The factors that determine the extent of productivity improvement are:

- the extent of the fracture area contacting the pay layer
- the fracture conductivity (the product of the fracture width and the proppant permeability)

4.2.1 Proppant Pack Permeability and Fracture Conductivity

The purpose of the propping agent is to prop open the fracture after it has been created. The proppant must be capable of holding the fracture faces apart so that formation fluids can flow through the fracture with a minimal loss of energy, and it must be long lasting. From a practical standpoint, it should be capable of being placed using pumping equipment and a fluid system that are currently available, also it should also be readily available, safe to handle, and relatively inexpensive. The most important property of the created proppant pack is fracture conductivity.

Fracture conductivity is the product of the packed fracture's in-situ permeability and its effective propped width. Both permeability and width may vary along the fracture. Proppant permeability is determined in the laboratory by measuring the flow rate through a proppant-filled test cell of finite dimensions at several flowing pressure differentials until steady state flow is achieved. The test cell is configured such that elevated temperature and uniaxial loading to simulate closure stress may be applied and the cross-sectional area of the test cell is then used in Darcy's linear flow equation to determine the proppant permeability.

4.3 Properties Affecting Proppant Performance

Mechanical and Geometric Properties

The propping agent qualities that are effective in achieving proppant packs of high permeability and good integrity are:

- uniform size (narrow mesh distribution)
- high degree of sphericity
- high compressive strength
- high degree of roundness
- consistent density
- insolubility in reservoir fluids
- stability at reservoir temperature

4.4 Quality Check of Proppant Sand

- Sieve Analysis Test
- Acid Solubility Test
- Spehericity and Roundness Test
- Crush Resistance Test

4.5 Proppant Selection

Generally, it is advised to pump as large a proppant grain size as possible. Larger the grain size, the higher the permeability the less susceptible the proppant is to embedment in the cleat faces and also the larger proppant grains allow the coal fines to pass through, rather than collect and gradually plug up the conductivity. The recommended proppant size is 20/40 instead of the earlier used 16/30 Sand. Proppant volume ranges from 3,000 to 10,000 lbs per vertical ft of net height. Here 4000 lbs per ft is placed inside the fracture.

5. Additives

Breakers

These are Chemicals, usually enzymes, oxidizing agents or reducing agents. They attack the viscosifiers in the fracturing fluid, breaking the molecular chains and reducing the fluid viscosity. This reduced viscosity eases the return of the fluid trapped in the reservoir pores after the treatment and allows faster and more complete recovery of the treatment fluids and the effectiveness of chemical breakers depends on their concentration and temperature. Breakers may start acting at the moment of addition, or they may be delayed in action or triggered by another factor such as temperature. The two types of breaker systems currently used are enzymes and oxidative breakers.

Biocides

Biocides, also known as Bactericides, are designed to kill bacteria. Any bacteria, especially sulphate reducing bacteria, will eat the polymer used in frac fluids. Biocides eliminate surface degradation of the polymers in the fluid tanks and stop the growth of anaerobic bacteria in the formation. They are added in the water tanks.

Buffers

Buffers control the pH of the fracturing fluid and breaker systems and also accelerate or slow down the hydration of certain polymers. Typical products are sodium bicarbonate, fumaric acid (a weak organic acid), combinations of mono and disodium-phosphate, sodium acetate and their combinations.

Corrosion Inhibitors

To avoid corrosion of steel tubing, well casings, tools and tanks, acid corrosion inhibitors are used. The solvent acetone is a common additive in corrosion inhibitors and the concentration of acid inhibitors in fracturing fluid is very less, in CBM wells it is 1gallon per 1000 gallon of slurry.

Foam Stabilizers

Foam stabilizers help maintain the properties of foam fluids, mostly they are polymers. Foams without stabilizers generally have a half-life of 3-4 minutes and by adding stabilizers, you can increase the half-life of foam to 20-30 minutes.

Friction reducers

Friction reducers suppress fluid turbulence and thus reduce the frictional pressure associated with high injection rates. Friction reducers may prove especially useful for improving injectivity in through-tubing fracture treatments.

Surfactants

Surfactants lower the surface tension of the fracturing fluid. A surfactant is always composed of two parts: a long hydrocarbon tail, hydrophobic part, that is practically insoluble in water and a strongly water-soluble head, hydrophilic part. Due to partial solubility in oil and water, the surfactant will tend to accumulate at the interface of these fluids. Surfactants provide water wetting, prevent emulsions and lower surface tension. Reduction of surface tension allows improved fluid recovery. Surfactants are available in cationic (positive), anionic (negative) or non-ionic forms.

6. Pressure

Energy Gain	Energy Use
Conversion of mechanical energy into pressure and rate by frac pumps Hydrostatic head	Wellbore friction Perforation friction Tortuosity Fluid friction in fracture Overcoming in-situ stresses Fluid leakoff Producing fracture width Splitting rock at the fracture tip

Different types of pressures encountered during operations and analysis:

Injection Pressure , P_{inj}
Also referred to as wellhead pressure(WHP) , surface treating pressure(STP). It is the pressure at the wellhead, against which the frac pumps must act.

Hydrostatic Head , P_{head}
Also referred to as hydrostatic pressure(P_h) or fluid head. This is the pressure exerted by the wellbore fluid due to its depth and density

Pipe Friction Pressure , $P_{pipe\ friction}$
Also referred to as tubing friction pressure or wellbore friction pressure. This is the pressure loss due to friction effects in the wellbore as fluids are injected.

Bottomhole Injection Pressure , P_{iw}
Also referred to as bottomhole treating pressure(BHTP). This is the downhole pressure, in the wellbore, in the centre of the interval being treated.

$$P_{iw} = P_{inj} + P_{head} - P_{pipe\ friction}$$

Perforation Friction Pressure , $\triangle P_{pf}$
This is the pressure lost as the fracturing fluid passes through the restricted flow area of the perforations.

$$\Delta p_{pf} = 0.2369 \frac{q^2 \rho_s}{N_{perf}^2 D_p^2 C_d^2}$$

Where
ρ is the slurry density(ppg)
q is the total flow rate(bpm)
N_{perf} is the number of perforation(so that q/ N_{perf} is the rate per perforation)
D_p is the perforations diameter(inches)
C_d is discharge coefficient

Tortuosity Pressure , ΔP_{tort}

This is the pressure lost by the fracturing fluid as it passes through a region of restricted flow between the perforations and the main fracture or fractures.

Near-Wellbore Friction , $\Delta P_{near\ wellbore}$

This is the total pressure loss due to near-wellbore effects and is equal to sum of perforation friction plus tortuosity pressure.

Instantaneous Shut-In Pressure , P_{ISI}

Also known as ISIP or instantaneous shut-down presure(ISDP). This is the bottomhole injection pressure immediately after the pumps have been shut down, so that effects of all the fluid friction-based pressure losses($P_{pipe\ friction}$, ΔP_{pf} and ΔP_{tort}) have gone to zero.

Closure Pressure , P_c

This is the pressure exerted by the formation on the proppant. It is also the minimum pressure required inside the fracture in order to keep it open. For a single layer, P_c is usually equal to the minimum horizontal stress, allowing for the effects of pore pressure. Otherwise , P_c is the result of some natural averaging process involving all the layers. For distinctly multilayered formations, it is possible to observe more than one closure pressure.

Extension Pressure , P_{ext}

This is the pressure required inside the fracture in order to make the fracture grow. $P_{ext} > P_c$ as the fracture has to be held open before it can gain length, height and width. It is not constant and varies with fracture geometry.

Fracturing Fluid Pressure , P_f

This is the pressure of the fracturing fluid inside the main body of fracture, after it has passed through the perforations and any tortuosity. It may not be constant over the entire fracture due to friction effects.

Net Pressure , P_{net}

It is the excess pressure in the fracturing fluid inside the fracture, above that required to simply keep the fracture open(i.e. P_c). It is the energy in the fracturing fluid available for propagating the fracture and for producing width.

$$P_{net} = P_f - P_c$$

$$P_{net} = P_{iw} - \Delta P_{pf} - \Delta P_{tort} - P_c$$

All analysis involving fracture geometry uses net pressure as the common variable linking all parts of mathematical model. The net pressure , multiplied by the volume of the fracture, gives us total quantity of energy available at any given time to make the fracture grow.

7. The Minifrac

A minifracture, or injection-leakoff test, is a series of pump-in tests performed before designing a fracture treatment. These tests can help in obtaining important data for planning fracture stimulation and the purpose of the minifrac is to provide the best possible information on the formation, prior to pumping the actual treatment. Any time that the quality of information available for a frac candidate is poor, a minifrac should be planned which is designed to be as close as possible to the actual treatment, without pumping any significant volumes of proppant. The minifrac should be pumped using the anticipated treatment fluid, at the anticipated rate and it should also be of sufficient volume to contact all the formations that the estimated main treatment design is anticipated to contact.

The minifracture test can improve the design and implementation of a hydraulic fracturing treatment by:

- Estimate fluid leakoff
- Estimate fracture gradient
- Estimate fracture closure pressure
- Recognize high fracture pressures

7.1 A typical job plot

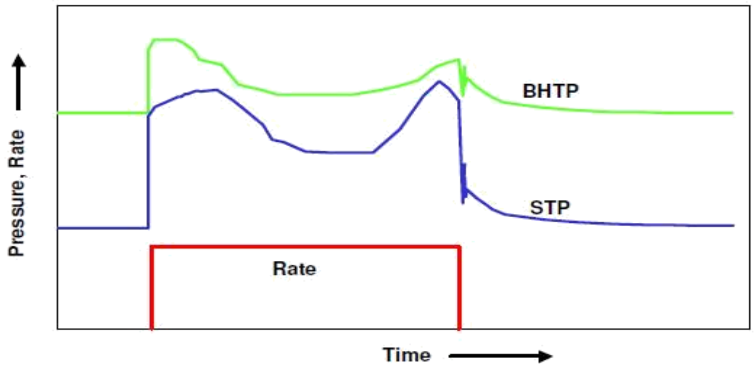


Figure 14 Typical Job Plot

The above figure shows a typical job plot between bottom hole treating pressure, surface treating pressure and Rate versus time. The BHTP tells the way the fracture is behaving and the amount of work being performed on the formation by the fluid and vice versa. The rate is important for determining the fracture geometry, as the volume of fluid pumped into the formation, less the volume of fluid which has leaked off, is equal to the volume of the fracture. If proppant slugs have been pumped the proppant concentration can also be important.

7.2 Nolte-Smith Analysis

It is a method for analyzing the pressure response of a formation during pumping, in order to interpret the fracture geometry being produced. The method analyzes the expected pressure response from the formation during fracture propagation and then predicts the pressure response when certain type of behaviour takes place.

PKN fracture geometry assumes constant height, with length considerably longer than height and also that net pressure is a function of time such that $P_{net}(t)\,\alpha\,t^{e}$, where 1/8<e<1/5 for a Newtonian Fluid. Taking log of this relationship : **log P_{net} = e log$t$ + constant**

For power law fluids the gradient e is defined with upper and lower boundaries as :

$$\left(\frac{1}{4n'+4}\right) < e < \left(\frac{1}{2n'+3}\right)$$

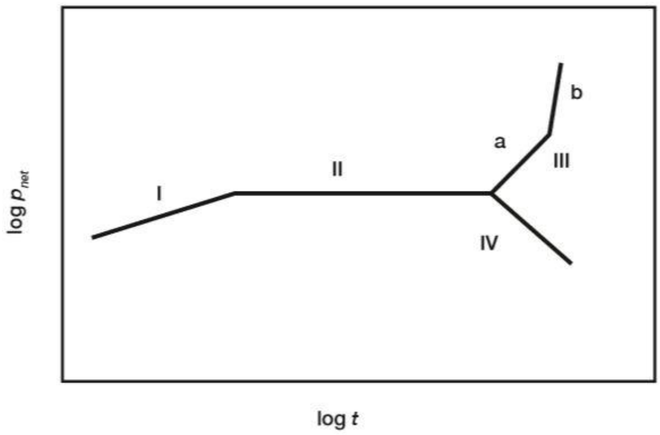


Figure 20 log P_{net} Vs log$t$

Mode	Behavior
I	Propagation with PKN fracture geometry. Gradient is equal to e (see Eq. 4-16) for constant frac fluid rheology.
II	Constant gradient = 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 p_{net} and w_f (see Eq. 4-5 – this implies a change in rock mechanical characteristics).
IIIa	Unit slope. This means that p_{net} is now directly proportional to time (and also to rate, as this is usually constant with respect to time). This behavior is usually associated with additional growth in w_f such as during a tip screenout (see Section 4-7.3.2).
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.

The upper and lower boundaries are the result of solving a polynomial equation. This means that for practical values of n', the lower boundary of e will be between 0.25 and 0.125, while the upper boundary will be between 0.3333 and 0.2. So any straight line on Nolte-Smith Plot with gradient between 0.3333 and 0.125 probably indicates that there is very good height containment.

Radial or penny shaped

In this model the height is a function of the radius or half-length of the fracture, R such that H=2R and fracture width is proportional to fracture radius.

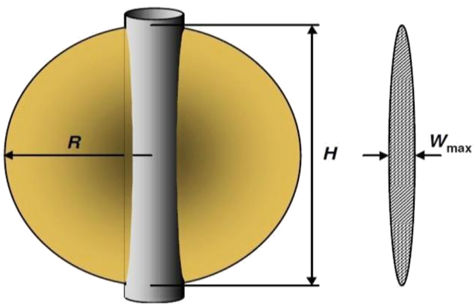


Figure 15 Radial Geometry

KGD

In this model fracture height is fixed and width is proportional to fracture length and it is assumed constant width against height and slippage at the formation boundaries.

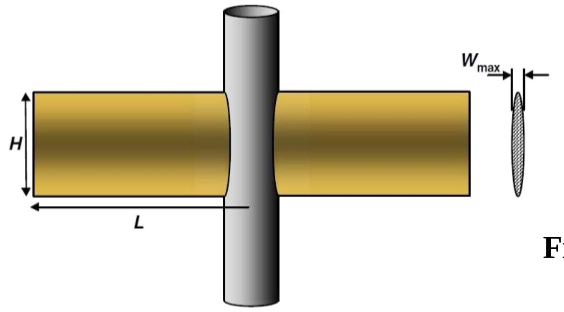


Figure 16 KGD Geometry

PKN

In this model fracture height is assumed to be constant. There is no slippage between formation boundaries and width is proportional to fracture height.

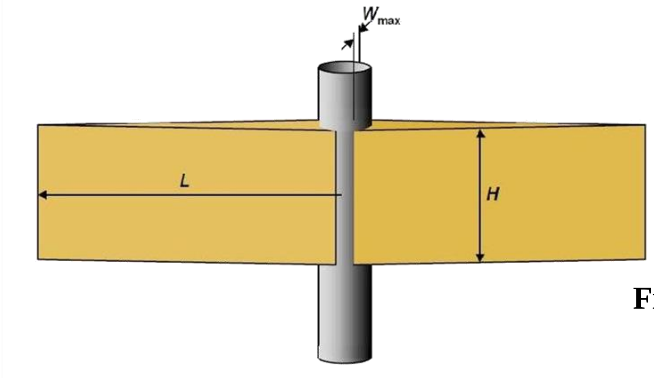


Figure 17 PKN Geometry

7.3 Fracture Height

Fracture height affects fracture volume in two ways: directly and through its effect on the width. The methods which are used to determine the height:

- Temperature and Gamma-Ray logs: The most common approach for determining fracture height uses temperature and gamma ray logs. These logs are usually run during pre and post job to detect the radioactive material and temperature differences a few inches away from the wellbore. Temperature logs made before and after the stimulation can be compared to an define interval cooled by injection of the fracturing fluid and thus provide the estimate of the fractured zone. The temperature behaviour strongly depends on the pattern and the magnitude of the displacement. When the fracture is perfectly connected with the wellbore, the cool region on the log indicates the top and bottom of the fracture clearly. If radioactively marked fluid or proppant is used, post frac gamma ray logs will show higher levels of activity opposite where the tracer was deposited. These areas can then be equated with the fractured interval.
- Softwares: Software's and fracture simulators such as Fracture Geometry Simulator (FGS) are used to estimate the fracture height.

8. Software's

Various software's are used while carrying out the minifrac job and its analysis. Meyer and Associates is highly respected, global leader in hydraulic fracturing simulation software. It aims to develop user friendly software's guided by industry leading innovation. It helps customers to maximize well production and return on investment.

The Meyer Software is a powerful suite of engineering programs for the design, analysis and monitoring of hydraulic fractures. Some of the software's developed by the company are as follows:

MFrac

Mfrac is a 3D Hydraulic Fracturing simulator. It is a comprehensive design and evaluation simulator containing a variety of options including three-dimensional fracture geometry, design features, and integrated acid fracturing solutions. **MFrac** also has options for 2-D type fracture models.

MView

MView is a data handling system and display module for the real-time and replay analysis of hydraulic fracture treatments and minifrac analysis. It is generally used along with MFrac and MinFrac. **MView** can accommodate up to two hundred (200) data channels and simultaneously allows selection of up to two hundred (200) parameters for processing. A channel can also be specified for Multi-parameters (e.g., channel C can be assigned to more than one parameter.). This data can include the parameters: pump rate, bottomhole and surface pressure, proppant concentration, and nitrogen or CO2 injection rate.

MinFrac

MinFrac is developed to analyze the data recorded during a minifrac treatment. The evolution of this technology has resulted in procedures that permit the interpretation of injection and fall-off pressures in order to characterize the basic fracturability of a reservoir. This process results in the ability to approach an optimum treatment design. **MinFrac** is a comprehensive tool that implements the latest fracture injection and pressure decline theory. With the many types of analyses and superposition derivatives available, MinFrac is considered a “state of the art” simulator by the petroleum industry.

MProd

MProd is a single phase analytical production simulator developed by Meyer & Associates, Inc. Although the program was designed primarily for hydraulic fracturing applications, it can also be used to explore the production potential of unfractured reservoirs. **MProd** has options for Production Simulation, History Match Production Simulation, and Fracture Design Optimization. Production Simulation, allows the user to input typical production data to simulate well performance for fractured and unfractured wells. The capability to compare the output (numerical simulated results) with measured data is also provided.

MNpv

MNpv is a fracturing design optimization simulator, based on the concept of Net Present Value developed by Meyer & Associates, Inc.It is designed to be used with **MProd** to automatically determine and compare the NPV of various fracture scenarios in order to identify an optimal design. Using **MNpv**, treatment advantages or disadvantages can be ascertained by evaluating predicted cash flow and future return on investment.

MFrac-Lite

MFrac-Lite is a three-dimensional hydraulic fracturing simulator similar to **MFrac** but with a limited number of **MFrac** features and capabilities (i.e., a lite version).This simplified three dimensional simulator provides ease of use with less input data and fewer options to choose from for applications which do not require some of the advanced features in **MFrac.**

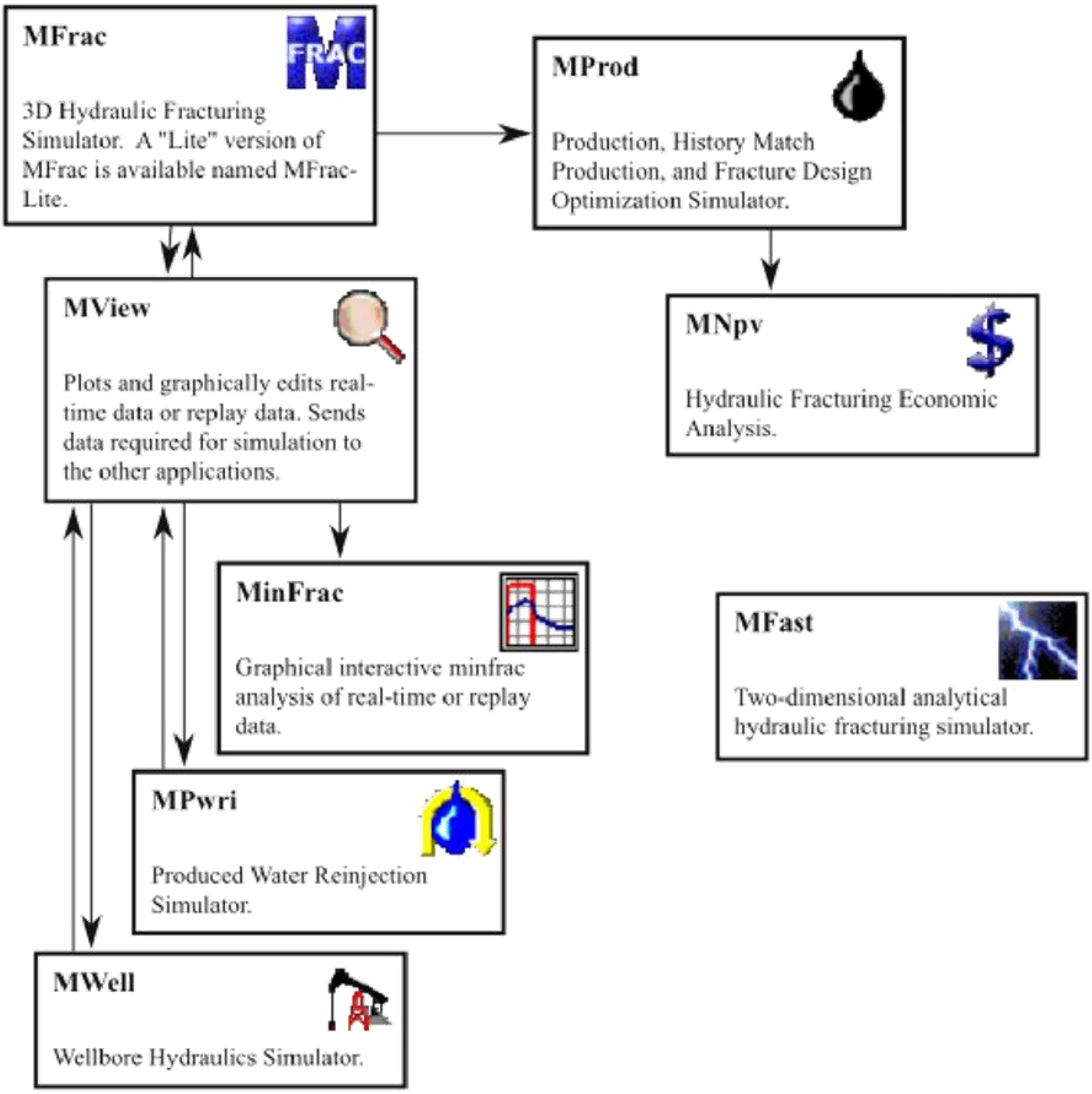


Figure 18 Software's

9. STANDARD OPERATING PROCEDURE

SOP FOR MAIN FRAC OPERATIONS

PROCEDURE :

1. Get the pull test, operation test and pressure test done for CT. After completion of the rig up, get the pressure test done for Frac as well as CT lines. The pumps are always primed before starting any pumping to remove any air in the lines. Ensure that the flowback line is installed above the master valve.
2. Check the over pressure on the pumps and on the pop off valve to be within the 80% of the burst pressure of the production casing.
3. After completion of the pressure test, Injectivity test with either water or gel is to be performed in the bottom most zones which is already perforated by wireline.
4. If the injectivity is good, coordinate with the service engineer and plan the pumping schedule for the main frac operations. Cross check the flush volumes and surface volumes used in calculations. Plan if there is a requirement for sand plug setting by under-flushing the last stage. Get the gel of proper viscosity mixed and pump the job according to the pumping schedule with minimum on the fly changes if required. Coordinate with the service engineer for the same.
5. If injectivity is not good, decide whether to mix 15% HCl + 10% Acetic Acid or Only 20% Acetic Acid. Get Mixed Acid - 12 bbl / 24 bbl depending on the thickness of the coal seam. Also decide based on injectivity whether to pump acid with coil or through the annulus. Whether to spot and squeeze or directly bullhead acid. Whether to give soaking time for the acid, if yes how much time to be given for acid soak.
6. After giving soaking time, check injectivity again. If it is still bad, decide whether to re-perforate the coal seam or pump acid once again. Try getting some sand inside the formation. Check response in the slug stages; if possible pump the job at low proppant concentrations.
7. Once the frac job is completed, monitor the pressures for at least 15-20 minutes to observe frac closure. Even if the closure cannot be identified in the plot, keep the well shut in for at least 45 - 60 min. to allow the frac to close and let the pressure bleed off. Pumping Lines are flushed after completion of frac job.
8. Start running in the coil if the coil is not already in hole. Check the location of short collar/long collar and apply correction factor. Consider distance between Nozzle and MCCL keys while applying corrections. Before starting the cut always correlate at least two collars below the zone and apply corrections. Meanwhile get the slurry for hydra-jetting mixed.
9. Plan whether for Sand plug setting if there is a need dumping the sand from cuts.
10. Once the nozzles are at the desired depth, start the cuts by maintaining the desired back pressure with the adjustable chokes at surface in order to prevent any flow back from the previous job.
11. Once the cuts are completed, bottoms up to be performed from an appropriate depth (usually 10-15 m below the target coal seam) to remove any unnecessary sand plug.
12. Once the bottoms up is done tag the sand with coil tubing to confirm the sand plug depth. If it is at the expected depth repeat the procedure from Step 2.

13. During the operations, keep a track of chemicals, acid, sand, water inventory at location. Check for the water level in pits. Coordinate with water haulers and Production Well head team for arrangement of tankers for Pit Evacuation.
14. After the last job of the well is completed, start flowing back the well after sufficient waiting time. Once the flow-back is completed, Master valve will be rig down so rig up Casing Cross-over to avoid any water spillage. Install pressure gauge and needle valve on the crossover.
15. Follow up with the service company engineers for Post Job reports and Job logs.

STANDARD OPERATING PROCEDURE FOR SQUEEZING ACID THROUGH COIL TUBING

WRITE UP :

Hydraulic fracturing is the most common technique of stimulation in unconventional gas reservoirs. Initiation of fractures in coal seams is found to be difficult whereas the propagation is quite easy. Acid treatment can prove helpful in easing the initiation of fracture in the coal seams in such cases. Difficulties in initiation of fracture might be a result of mud/filtrate, cement loss during drilling operations and near well-bore debris or metal junk from wire-line perforation. Another probable reason might be impure native state of coal having mineral deposition across cleats. Acid job can help in overcoming these initiation issues by reacting with minerals/cement/mud present in the cleats, removing them and hence, increasing the cleat aperture.

Acid solution generally used in CBM reservoir used is a mixture of 15% HCl and 10% Acetic Acid. 15% HCl is used because of its lower cost and easy availability, easy inhibition and lower hazardous levels. 10% Acetic Acid acts as iron control additive and retarded acid.

Various techniques of carrying out acid jobs before stimulation mainly include squeezing through Coil Tubing (CT), spotting and squeezing through CT, spotting through frac pumps, and bull-heading acid during frac jobs through frac pumps. Injectivity test pressures, number of seams clubbed in the job and thickness of the job would decide which of the above mentioned technique to use. This document includes the squeezing acid through coil tubing. This is to be done in case of multiple seams in a single job or in case very high pressures are encountered at lower rates during injectivity test.

PROCEDURE :

1. Decide the volume of acid to be pumped:
    a. 12 bbl or 500 gal, for general cases;
    b. 24 bbl or 1000 gal, for thicker seams; or
    c. 6 bbl or 250 gal, for extremely thin seams.

   Consider additional volume for the hoses from the acid tank to the pump and from the pump to the coil tubing.
2. Check if the acid drums which are to be used are properly sealed and labeled with hazard ratings.
3. Get 4 drums of HCl and 1 drum of Acetic Acid mixed in the acid tank for 12 bbl of acid job (or accordingly for other volumes).
4. Get 2 gal of Corrosion Inhibitor mixed to the acid mixture in the acid tank.
5. Get ½ sack of Iron Control mixed in the solution.
6. Get the remaining volume in the acid tank filled in with water (up to the marked level) to obtain the required volume of acid solution.
7. Ensure the personnel involved in handling acid drums are equipped with proper PPE and the drums are handled safely and with proper tools and equipments.
8. Get 5 bbl of Corrosion Inhibitor mixed in the batch mixer.
9. Keep the choke open so as to maintain WHP same as the previous operation.

10. Run-in the coil tubing below the bottom-most perforation depth of the job.
11. Correlate the depth and pull out the coil to the bottom-most perforation depth of the job.
12. Pump 3 gal of Corrosion Inhibitor through coil tubing at 2 bpm.
13. Pump acid from the acid tank at 2 bpm through coil tubing.
14. Close the choke completely after the stage bbl count becomes equal to the amount of acid to be pumped plus the volume required for covering the whole zone.
    a. 1 bbl covers 12 m in 5-1/2" casing.
    b. 1 bbl covers 15 m in 4-1/2" casing.
    c. 1 bbl covers 7 m in 7" casing.
15. Decide whether to displace the acid by gel or water depending on the next step after acid job. If overnight soak or a prolonged soak is to be done, water is preferred for displacement.
16. If a single seam with perforations is present, pumping is continued without stopping the pump and acid is displaced till whole of the volume of coil is pumped.
17. If there are multiple seams with perforations in a single job then divide the mixed volume of acid and pump few bbl in front of each set of perforation and keep pulling out the coil placing in front of each perforation depth.
18. Pull out the coil above the depth covered by acid in the casing while pumping gel and maintain the pressure last seen during acid job.
19. While operation is going on, observe the well head pressure trend.
    a. If a good breakdown or reactivity is observed, give a soak of 10-15 min.
    b. If very less reactivity is observed then a longer soak of around 30 min is to be given.
    c. If surface pressure seems to cross (or reach) the safety limit, call off the job and wait for some time and then try again.
    d. If after Step 19c, it is not possible to pump the acid further, open the choke slowly and dump the acid in the pit. Dump 2-3 sacks of Buffer for neutralization of the acid.
20. Get 1 sack of Buffer mixed in the batch mixer.
21. After completion of the soak,
    a. If the coil tubing is to be pulled out of the hole then pump the buffer there.
    b. If coil is in the hole, then open the choke slightly and pump the buffer solution.
22. If the coil is pulled out, then pump gel/buffer solution and manipulate choke to maintain the pressure last seen during acid job.
23. Make sure Corrosion Inhibitor is compatible with the acid solution used.

STANDARD OPERATING PROCEDURE FOR SAND WASH BY REVERSE CIRCULATION THROUGH CT UNIT

WRITE UP :

After sand jetting or main frac pumping job, cleaning of sand through the wellbore has become an important job as this process is time consuming. Sand wash with forward circulation is not effective if annulus area between Coil and casing is large (like in 7" production casing), it will take more time to wash the sand and become non-productive time for HF. But Sand wash by reverse circulation through coil could be very helpful as in this circulation sand slurry have to flow through coil (less area) which create more velocity and turbulence in flow and helps to lift sand from wellbore in minimum time of span.

PROCEDURE :

1. Make surface line up arrangement for both forward and reverse circulation, line up all check valves, gate valves and high pressure lines according to both circulations.
2. After sand cutting for one job (max 2 cut), pulled out Coil minimum 50m or maximum 100m (from cut depth) for safe side. During pull out continue pumping gel through coil at 3 bpm.
3. Switch line up to reverse circulation and start pumping 15cp gel through annulus maximum at 1.75 bpm to 2 bpm. During pumping maintain differential well head pressure and annulus pressure maximum to 1000psi.
4. Pump at least 2 cycle coil tubing volume, maintaining the differential pressure. Observe return regularly, after 2 cycles, will get sand in return.
5. Now start running in, continuing reverse circulation. Monitor coil tubing weight and return through coil tubing.
6. Run in up to the depth till sand plug is needed to isolate the last hydraulic fractured seam.
7. After reaching at this point, continue reverse circulation at 1.75 bpm to 2 bpm.
8. Observe return at this point, pump 15cp gel till get clear return (clean gel without sand).
9. After getting clear return, pump one more cycle volume of coil tubing for safe side.
10. Then switch to forward circulation and carry out further operation.

Note:- If we have 3 cut or more in a single job then cut first 2 then switch to reverse circulation, sand wash till 10m below to bottom cut, then switch to forward circulation, sand cut the remaining, then again switch to reverse circulation and go up to sand plug required.

10. Job Designing

Designing of a frac job is most important step of performing fracturing. Depending upon the designed job, volumes of frac fluid with or without proppant as per requirement is pumped in the formation. By observing the pressure responses of formation, the appropriate changes are made in the job design, the actual treatment may vary from the designed job. From data obtained from minifrac, the nature of formation is known and depending upon various factors different parameters are considered and optimized for an optimized job design. For example if leakoff coefficient is high, total volume of fluid leaked will be more and thus fracture created will receive less fluid then excepted and overall fracture volume will be less.

Volume fluid Pumped - Volume of fluid leak of = Volume of fracture

In such formations a more efficient fluid is pumped and this fluid should have more viscosity to reduce fluid loss. Crosslink gel are preferred over linear gels in more permeable formations and then the most suitable job design is selected and implemented. Various factors which can be altered in a job design for obtaining enhanced fracture conductivity are :

- Type of frac fluid used
- Volume of each stage
- Proppant concentration of each stage
- Proppant concentration and volume of slug stage
- Proppant size
- Variation in concentration of enzymes added depending upon the formation

Type of Frac Fluid

Viscous fluid is used depending upon the value of leak off coefficient. Depending upon the requirement and type of formation different fluids such as linear, crosslink gel, Visco-elastic surfactant, foam etc can be used. Economics of whole operation is also one important factor considered while deciding for type of frac fluid and in the fracturing operations performed at Essar, Raniganj 30pounds of linear gaur gel is generally used for fracturing.

Volume of each stage

The fracturing job is carried out in no of stages. Volume of each stage is decided by observing the pressure response of formation to the previous stage.

Proppant concentration of each stage

The total proppant to be pumped in the formation is calculated. Total proppant to be pumped is decided from proppant per foot of formation. From experiments, a figure of 4000lbm/ft is used as standard amount of proppant concentration. It is observed that a job with sand 3000-6000lbm/ft gives better conductivity. Thus proppant concentration of each stage is adjusted so as to nearly meet the total proppant. Concentration of proppant in the frac fluid should be gradually increased if the formation is accepting lower concentrations. More is the volume of stages in which concentration is increasing, more properly and uniformly proppants will distribute and settle in the fracture. The pad volume pumped is the gel without proppant. The more concentrated slurry near wellbore creates proper and more efficient packing.

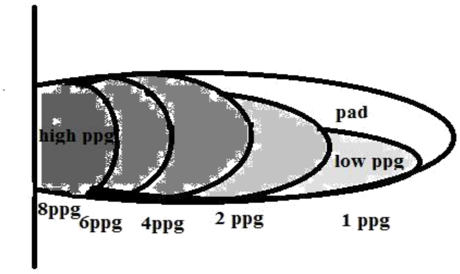


Figure 19 Ideal distribution of proppant in the fracture

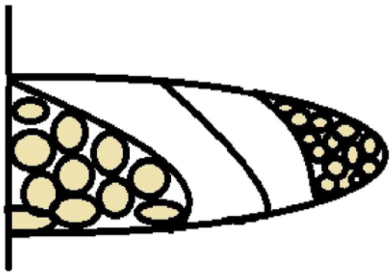


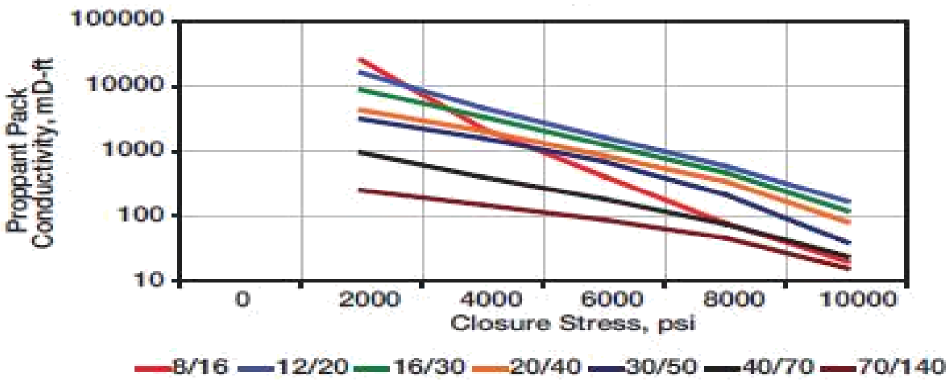
Figure 20 Sand Placement

Proppant concentration and volume of slug stage-To relieve tortuosity and create fracture width for further higher concentration the slug stage is pumped. The proppant concentration in slug stage should be small and the volume should be sufficient to create the desired fracture geometry.

Generally a low proppant concentration, small volume is pumped in the slug stage. In the stage following slug stage, at least one complete annular volume of clean gel should be pumped so as to observe the pressure response of slug stage. Depending upon tortuosity, fluid leak off tendency and thickness of seam to be fractured, one or more slug stages are pumped.

Proppant size – Proppant size is one of the most important factors responsible for generating fracture conductivity. Proppant size is characterized by the medium diameter of the discrete grains. Proppants with larger grain sizes provide a more permeable path. However as grain size increases, grain strength decreases, the larger grain sizes are more susceptible to crushing in deeper wells due to higher value of overburden. The figure below shows effect of grain size on permeability of higher quality sand at increasing closure pressure.

Figure 21 Conductivity Vs Stress For Various Ottawa Sand Proppant Sizes



Thus in deeper formations, smaller sized particles are more suitable and generate lesser fines as compared to lager sized fines. Also it is not necessary to pump same sized sand through the fracture. Smaller sized sand can be pumped in the initial stages and larger sand in the later stages of job. This will provide better fracture conductivity and more effective packing near the wellbore. Ideally in lead slurry very small sized proppant is pumped followed by higher concentration in tail slurry.

However there are some complications associated with this practice:

- Care and attention is required because the type of sand pumped will be changed during the job
- At the time of flowback proppants have a tendency of flowing back to the wellbore. The smaller proppants might plug the pore spaces between the larger proppants, reducing permeability.

10.1 Factors considered while designing a CBM frac job

Various factors are considered while designing a frac job for CBM. Some of them are:

- **Thickness of coal seam (True Vertical Depth, TVD)**
  Total sand to be pumped in the formation is calculated depending upon thickness of the seam in which fracturing job is to be carried out. The proppant concentration of each stage is decided accordingly.

- **Permeability of formation**
  Permeability of formation is an important factor considered while deciding the pad percentage to be pumped. The pad stage creates fracture geometry. If permeability is low, less pad volume is required. However if the permeability of the formation is high more volume of pad will be required to create the required fracture geometry.

- **Young's modulus of formation**
  Young's modulus of formation gives an idea of how much tough the formation is. i.e. how easy or difficult it will be to fracture the formation. It gives the rate of injection of fluid required to fracture. Volume of each stage is decided keeping in mind the total time span of a job.

- **Efficiency of frac fluid**
  Efficiency of the frac fluid gives the leak off tendency of the fluid when it is pumped into the formation. If the fluid leak off is less then the fluid is more efficient and if the fluid leak off is more, the fluid is less efficient. Viscosity should be increased to increase efficiency of fluid. Spurt loss will be less and thus fluid efficiency will be high if the wall building ability of fluid is more. Thus depending upon the type of formation and leak off chances in it, type of fluid to be pumped and its viscosity is decided, the viscosity being altered by gel loading.

- **Tortuosity**
  More restrictions are faced by fluid while it travels through the formation when the tortuosity is more and thus the fluid instead of creating fractures, is spent in relieving the tortuosity. Thus more volume of slug stage should be pumped in such cases.

- **Available volume of water**
  Given by the environment considerations, it is advisable to reuse the produced water. All the slurries i.e. cutting slurry used for perforation or frac fluid slurry used for fracturing are prepared with water and so a very large volume of water is required on the site for carrying out the job. Also water supply at the time of job should be continuous. Thus sometimes volume of water available is also to be considered while deciding the stage volumes of the job.

10.2 Calculations Involved

Basic Calculations required before coming to the location

HHP = Pump Pressure (psi) * Designed Job Rate (bpm) /40.8 = P (psi) * Rate (gpm)/1713.6

This power will tell the least number of hydraulic pumps required for the job. But to be on safer side considering 1.5 times the required HHP needed on the job.

Maximum Allowable WTP (psi) = Internal Yield Pressure * 0.80 (Safety Factor)

Blender Sheet Calculations

Absolute Volume (gal/lb) = 1/(sp.gravity*8.33)

Volume Factor (V.F) = 1 + (sand conc (ppg) x (abs. Vol (gal/lb))

Dirty vol (Vs) (bbl) = Clean vol (bbl) x V.F

Slurry density (ppg) = (Base fluid density (ppg) + sand concentration (ppg)) / V.F

Water required (gal) = Clean vol (gal) - Gel Required

Volume of the pit (m^3) = L (m)*W (m)* H (m)

Cylindrical Volume (m^3) = 0.7854 **d* (m)**d* (m)**Height* (m)

Hydrostatic Pressure (psi) = 0.05195 * ρ (ppg) * H (ft)

Volume to Perf (bbl/m) = Capacity Factor (bbl/m) * Length (m)

Vol of additive = (Concentration * Vol. of Mixing Fluid for that Stage) / 1000

Additive Rate = Clean Rate * Conc.

Total Additive Volume (gal) = Sum Stage Volumes (gal)

Total Proppant Volume (gal) = Sum Stage Volumes (gal)

%Pad Volume (gal) = Pad volume (gal) / (Total job volume including sand slug pumped after pad (gal) – Flush (gal))
*Generally we take 30-40% of Total job volume pumped

Or

Pad volume = (fluid volume*%pad) / (1-%pad)
This formula is used when pad percentage is calculated from Mini Frac to optimize the pad volume pre-calculated.

N.B – Always consider clean rate/volume while calculating the additive rate/volume, proppant vol.

<u>To calculate the sand volume:</u>

Find **clean volume** using casing fill factor in the casing
Total amount of sand in the casing (wt of sand W) = Clean volume* Sand conc (ppg at any stage)
No. of sacks in the casing = W (lb) / bulk density (lb/sack)
E.g. – Bulk density of 102 lb/ft^3 will contain 102 lb of sand in 1 sack
1 ft^3= 1 sack
Density of proppant = 13.36 lb/gal = 561.12 lb/bbl

<u>To calculate the height of sand settled:</u>
For 4.5”
Height of sand in the casing (m) = 0.035047 (m/lb)* W (lb)
Height filled for 1MT sand = 77.24 m

For 5.5”
Height of sand in the casing (m) = 0.022825 (m/lb) * W (lb)
Height filled for 1MT sand = 50.30 m

For 7”
Height of sand in the casing (m) = 0.013783 (m/lb)* W (lb)
Height filled for 1MT sand = 30.38 m

This is very helpful to find the amount of sand during screen outs

Calculation for the flush volume

Casing/Tubing capacity (bbl/m) = $I.D^2$ *3.281/ 1029.4
Annular capacity (bbl/m) = $(I.D^2 – O.D^2)$ *3.281/ 1029.4
where I.D is in **inches**

For 4.5” O.D & I.D = 4”
Flush volume (annular) (bbl) = Tub Volume + Surface line volume + (0.05085 (bbl/m)*Flush depth (m) – 0.0097 (bbl/m)*Coil depth)

For 5.5” O.D & I.D = 4.95”
Flush volume (annular) (bbl) = Tub Volume + Surface line volume + (0.07808 (bbl/m)*Flush depth (m) – 0.0097 (bbl/m)*Coil depth)

For 7” O.D & I.D = 6.366”
Flush volume (annular) (bbl) = Tub Volume + Surface line volume + (0.1293 (bbl/m)*Flush depth (m) – 0.0097 (bbl/m)*Coil depth)

Calculation for Pressure

BHTP(psi) (dynamic) = $P_w + P_h - P_{perf} - P_{pipe} - P_{tort}$

$P_{perf} = 0.237 * \rho * [Q / (N*D_p^2*C_d)]^2$

ρ – Slurry density (ppg)
Q – rate (bpm)
N – no. of perforations
D_p – Entry Hole Diameter (inch)
C_d – Coeff. of Discharge (0.6 for new nozzle, 0.8-0.95 for wear out nozzle)

BHTP (static) = $P_w + P_h$ = ISIP

P_{net} = BHTP (static) – $P_{closure}$

Frac Gradient = ISIP / Mid perf

Closure gradient = $P_{closure}$ / Mid perf

10.3 Examples of Job Design

CASE STUDY #1 : TIP SCREEN OUT

The Tip Screen Out is a technique used to artificially increase the width of the fracture, without increasing the length. For any given fracture, there exists a fixed relationship between width and length. If we can artificially overcome this, then we can dramatically increase the productivity. Figure illustrates this:

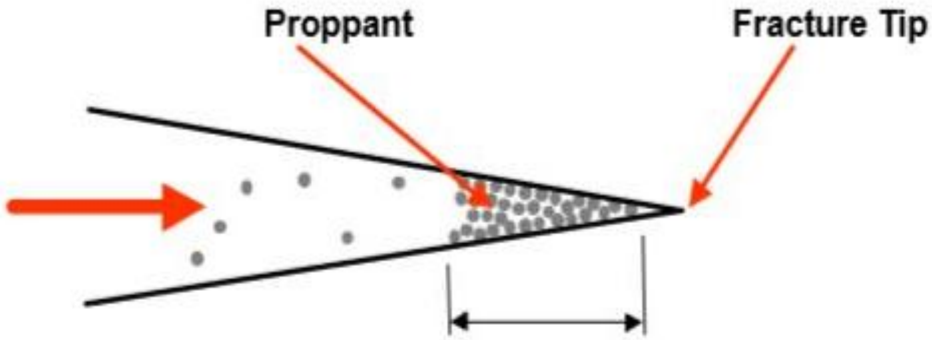


Figure 22 Tip Screen Out

In reservoirs of moderate to Low permeability, where fracturing treatments are aimed to remove near wellbore damage, relatively long, highly conductive fractures are required. Fracture length does not affect the outcome of the treatment as dramatically as in low permeability reservoirs. Thus, the objective of a fracturing treatment here is to maximize the fracture conductivity (propped fracture width). This can be achieved with a so-called tip Screenout design. The TSO occurs when sufficient proppant has concentrated at the leading edge of the fracture to prevent further fracture extension. Once fracture growth has been arrested (and assuming the pump rate is larger than the rate of leak off to the formation), continued pumping will inflate the fracture (increase fracture width). This TSO and fracture inflation is generally accompanied by an increase in net fracture pressure. Thus, the treatment can be conceptualized in two distinct stages: fracture creation (equivalent to conventional designs) and fracture inflation/packing (after tip screen out). Variation of different types of parameters like surface injection pressure, bottom- hole tubing pressure and proppant concentration with respect to time is as shown in analysis sheet.

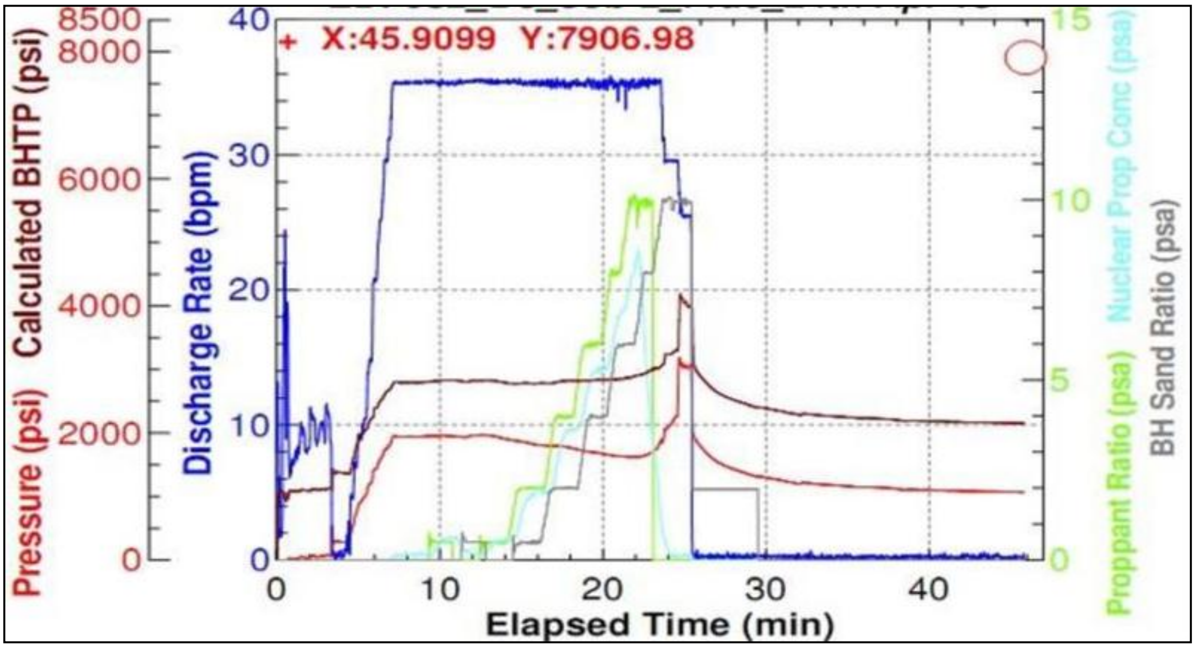


Figure 23 Actual Treatment Plot of Main

The BHTP trend was stable initially and after the hitting of first slug stage there was slight increase in the pressure which signifies that micro-fractures were blocked. On entry of 1ppa sand in the formation, pressure decreased slightly showing that some near wellbore restriction was cleared and then BHTP had a positive slope over the entire job after 6ppa, showing that all the sand introduced was efficiently packed in the fracture and hence there was a sudden rise in the pressure during the flush stage.

The STP trend was initially similar to BHTP but it deflected downwards upon the entry of proppant stages because the 'hydrostatic head inside the wellbore was increasing with increasing stages of sand, when flush stage started or the displacement of 10ppa sand, the surface pressure increased. This increase in surface pressure can be attributed to efficient packing till the tip of the fracture (dominated) as well as to the decreasing hydrostatic head in the wellbore. Proppant Concentration inside the formation after the end of the job was 5540 pounds per foot.

NOTE:
If the coil tubing is in bore hole then as zone screens out, the CT should be pulled out with pumping, because the sand in the well bore will settle upon the BHA of coil tubing and it may get stuck.

CASE STUDY #2 : EZ Clean Job

EZ Clean G Enzyme treatment is a patented, polymer-specific fluid custom formulated to degrade and help remove polymer damage, polymer residue and filter cake on formation faces or in proppant packs. Treatment candidates include well damaged by polymeric fluids in stimulation, completion and workover operations.

Breakers are used, they reduce the molecular weight of polymer and help in cleaning. They are oxidisers or enzymes. The most common oxidisers are persulphates and typically produce peroxygen, which is a very reactive free radical species that attacks the polymer or any specie prone to oxidation and degrades it. At low temp(<120^{o}F), reaction rate is too slow and catalysts are required. Since the half-life is short and reaction rate is fast encapsulation technology is used. The use of enzymes at low temperatures and nearly neutral or low pH condition has been prevalent since 1960s. Oxidisers not only degrade the polymer but also reduce the pH of the fluid thus activating the enzymes. Enzymes are catalysts and so can continue degradation process for a long time. Since they are very specific, they do not interact with other additives and are very compatible with resin-coated proppants. oxidisers produce more residue. Enzyme breakers may cost more on a weight basis but they become cost-effective when used in proper concentrations as they are catalysts.

The productivity of the three bottom seams i.e. **RN-3 , RN-3 and RN-4L,** productivity of these seams were suspected to be damaged by polymer residues in the proppant pack. Henceforth, a polymer damage removal treatment was pumped using BHI EZ-Clean system to improve the overall productivity from these seams.

JOB NO.	Coal Seams	Coal seam interval (MD), M			Job Span	Avg. Density	Perf Interval		GAP B/W JOBS
		From	To	Thickness			CTU	WIRELINE	
1	RN-3	1290.7	1293.5	2.8	2.8	1.43	NA	1291.20-1293.20	NA
2	RN-3	1219.1	1221.4	2.3	2.3	1.47	1220.7	NA	70.5
							1219.6		
3	RN-4(L)	1199.3	1201	1.7	35.8	1.44	1200.1		19.5
		1165.2	1165.7	0.5		1.6	1165.4		
	Total Thickness (MD)			7.3					

To remove the polymer damage we prepare a treatment having :

- Bactericide (0.3ppt) eliminate surface degradation of the polymers & stop the growth of anaerobic bacteria in the formation
- Enzyme Breaker (2gpt)
- Flo Back Surfactant (3gpt)
- Organic Acid (3gpt) Acetic Acid to be added till the ph is in the range 4-5.
- Corrosion Inhibitor (2gpt)

Job 1 : RN-3

Total Thickness	**2.8 m**
Total Proppant Mass Pumped	**38903 lbs**
Proppant Type	**16/30 Natural Sand**
Bulk Density of Sand	**1.62 g/cc (13.51 lb/gal)**
Porosity of the Proppant Pack	**40%** (considering embedment, crush and damage)

Step 1 : Determine Bulk Proppant Volume in Gallons
So, **38903 lbs/ 13.51 lbs/gal = 2879.57 gals**

Step 2 : Determine Pore Volume of Proppant Pack
Pore Volume = 2879.57 gals * 0.4 = 1151.83 gals

Step 3 : Recommend at least 2 pore volumes for EZ Clean
Final Treatment Volume = 2303.65 gal (approx 55 bbl)

Job 2 : RN-3

Total Thickness	**2.3 m**
Total Proppant Mass Pumped	**31724 lbs**
Proppant Type	**16/30 Natural Sand**
Bulk Density of Sand	**1.62 g/cc (13.51 lb/gal)**
Porosity of the Proppant Pack	**40%** (considering embedment, crush and damage)

Step 1 : Determine Bulk Proppant Volume in Gallons
So, **31724 lbs/ 13.51 lbs/gal = 2348.18 gals**

Step 2 : Determine Pore Volume of Proppant Pack
Pore Volume = 2348.18 gals * 0.4 = 939.27 gals

Step 3 : Recommend at least 2 pore volumes for EZ Clean
Final Treatment Volume = 1878.55 gal (approx 45 bbl)

Job 3 : RN-4L

Total Thickness	**2.2 m**
Total Proppant Mass Pumped	**33080 lbs**
Proppant Type	**16/30 Natural Sand**
Bulk Density of Sand	**1.62 g/cc (13.51 lb/gal)**
Porosity of the Proppant Pack	**40%** (considering embedment, crush and damage)

Step 1 : Determine Bulk Proppant Volume in Gallons
So, **33080 lbs/ 13.51 lbs/gal = 2448.55 gals**

Step 2 : Determine Pore Volume of Proppant Pack
Pore Volume = 2448.55 gals * 0.4 = 979.42 gals

Step 3 : Recommend at least 2 pore volumes for EZ Clean
Final Treatment Volume = 1960 gal (approx 47 bbl)

PROCEDURE :

1. Rig up wellhead and CT.
2. Line up CT pump from blender to CT, in order to pump EZ-Clean slurry through coil.
3. Line up, transfer pump from frac tanks to the frac pump, to facilitate water pumping through annulus.
4. Pressure Test surface lines to 5000psi for 5min, using water.
5. RIH CT till bottom of RN-3 (zone1) i.e. 1295m.
6. Add acetic acid to water(pH 8.5) in hydration unit to decrease its pH to 4.
7. Enzyme G, Gasflo is then added in blender.
8. Pump 10bbl of EZ-Clean against RN-3 at 1295m at 2.9bpm.
9. Close the return lines on surface and start pumping through annulus from the lined up frac pump at 3bpm.
10. Pump another 45bbl across RN-3 at 1295m from CT.
11. While picking up CT from 1295m to 1165m pump 47bbl across RN-3 and RN-4L at 2.1bpm.
12. Pump remaining 28bbl at 2.9bpm from coil.
13. Flush the coil with water(17bbl).
14. Stop pumping from CT.
15. Continue pumping from annulus via frac pump for another 3min.
16. Shut down pump and close the annulus.
17. Pull CT to the surface.

PERFORATION PLAN

** COAL MARKER LOCATED AT DEPTH 828.95M - 837.95M									
JOB NO.	Coal Seams	Coal seam interval (MD), M			Job Span	Avg. Density	Perf Interval		GAP B/W JOBS
		From	To	Thickness			CTU	WIRELINE	
1	RN-4(L)	1111.5	1113.9	2.4	2.4	1.56	1113.3		51.3
							1112.3		
2	Local	1072.8	1073.4	0.6	12.8	1.57	1073.1		38.1
	RN-4(U)	1060.6	1062.1	1.5		1.5	1061.4		
3	RN-4(U)	1041.1	1041.8	0.7	15.9	1.64	1041.4		18.8
		1032.5	1033.6	1.1		1.53	1033.0		
		1025.9	1026.6	0.7		1.57	1026.3	NA	
4	RN-5	973.7	974.8	1.1	1.1	1.45	974.3		51.1
5	RN-5	945.8	946.4	0.6	12.7	1.62	946.1		27.3
		933.7	934.3	0.6		1.67	934.0		
6	Local	892.3	893.6	1.3	1.3	1.49	893.0		40.1
7	RN-6	847.7	850.3	2.6	2.6	1.54	849.7		42
							848.6		
	Total Thickness (MD)			13.2					

Figure 24 Perforation Plan

Job - 1

	Stage	Pumping Rate	Slurry Stage Volume	Time	Type of fluid	Cumulative Volume	Proppant Conc Stage		Stage proppant	Stage proppant	Proppant Type	Cumulative proppant
		bpm	bbl	min.		bbls	ppg		lbs	lbs/min		lbs
							From	To				
Pre Pad	1	30	140	4.7	30# Linear Gel	140	0	0	0	0		0
Sand Stage	2	30	90	3.0	30# Linear Gel	230	0.5	0.5	1848	616	20-40 sand	1848
	3	30	20	0.7	30# Linear Gel	250	0.5	2	993	1490	20-40 sand	2841
	4	30	90	3.0	30# Linear Gel	340	2	2	6928	2309	20-40 sand	9769
	5	30	20	0.7	30# Linear Gel	360	2	4	2217	3325	20-40 sand	11986
	6	30	80	2.7	30# Linear Gel	440	4	4	11367	4263	20-40 sand	23353
	7	30	20	0.7	30# Linear Gel	460	4	6	3420	5130	20-40 sand	26773
	8	30	25	0.8	30# Linear Gel	485	6	6	4947	5936	20-40 sand	31720
Sand Plug	9	30	2	0.1	30# Linear Gel	487	6	6	396	5936	20-40 sand	32115
FLUSH	10	30	82	2.7	30# Linear Gel	569	0	0	0	0		32115

Figure 25 Actual Treatment Schedule

In the above case, the seam thickness is 2.4m. Cumulative proppant to be pumped should be thus nearly 31500 lbs (4000lbs/ft ideally). Keeping this figure in mind the job is designed. RN-4L seam is at around 1112m depth.

SIGNIFICANCE OF VARIOUS JOB STAGES

Practically no of stages in which the job is to be completed depends upon total proppant to be pumped and volume of water available for making desired volume of slurry.

1st stage- 140bbls of 30#linear gel at 35bpm is pumped without proppant. Pad stage creates fracture geometry. Volume to be pumped is chosen as 30%-40% based on the details obtained from mini-frac analysis. Generally one annular volume of clean fluid is sufficient for first stage to create the proper geometry.

2nd stage- 90bbls of 0.5 ppg stage is pumped to reduce tortuosity. This low proppant concentration stage further creates fracture geometry and creates width for higher concentration stages. For greater seam thickness and depths, large volume of it is pumped. Volume to be pumped is chosen as a little extra volume than one annular volume, this will tell us about the pressure response from the fractures and based on its quick analysis during the job the modification in design can be done.

Further stages are decided upon the basis of total sand (proppant) to be pumped in the formation. There are two types of stages, ramp stage and hold stage. The stage in which proppant concentration is gradually increased is called ramp stage and the stage in which proppant concentration is hold at a particular value is called hold stage.

3rd stage- 20bbls of 0.5-2 Ramp stage is pumped. For seams with less thickness 20-40 bbl is observed to be a sufficient volume for pumping ramp stage. With increasing concentration, volume of slurry should be gradually decreased for a uniform packing.

4th stage- 90bbls of 2 Hold stage is pumped. The pressure response of each stage will be observed during job and accordingly next stage will be pumped.

Thus in the similar fashion rest stages are designed.

5th stage- 20bbls of 2-4 Ramp stage is pumped.

6th stage- 80bbls of 4 Hold stage is pumped.

7th stage- 20bbls of 4-6 Ramp stage is pumped.

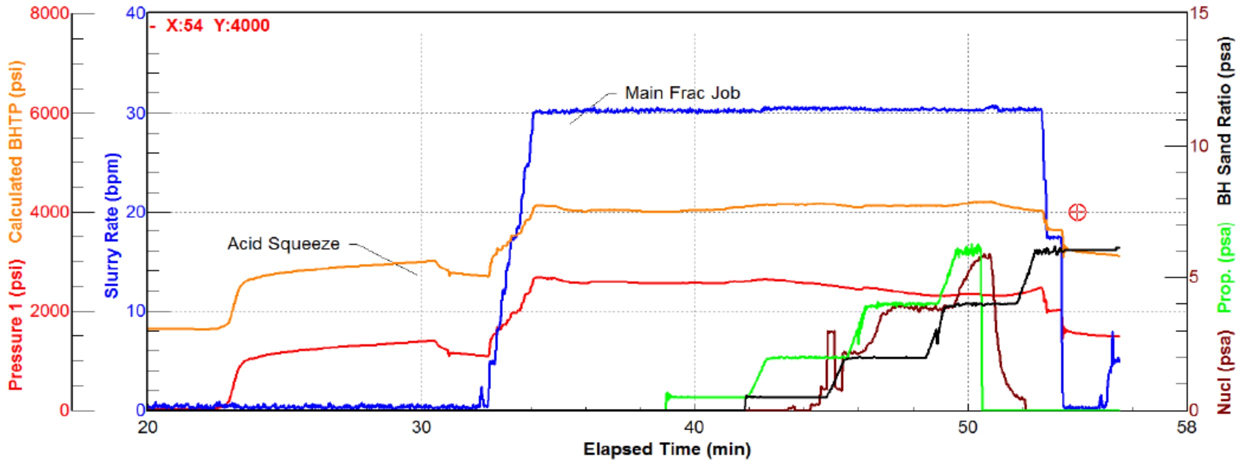
8th stage- 25bbls of 6 Hold stage is pumped.

9th stage- 2bbls of 6ppg Sand Plug stage is pumped.

10th stage- 82bbls of 0ppg Flush Volume is pumped.

The last stage is designed on the basis of calculations of underflush volume. Here two seams are separated by sand plug. Thus depending upon height of sand plug to be formed, clean volume to be pumped is calculated. These calculations should be done with extreme care because overflush is an undesirable effect. Due to overflush the sand left in the casing for making sand plug flows into the formation. The proppant placed near wellbore is displaced and thus pinch out may occur.

Figure 26 Actual Treatment Plot of Main Fracture



The BHTP trend shows a slight increase in the pressure upon the hitting of slug stage which signifies reduction in tortuosity. On reaction of 2ppa sand with the formation, pressure decreased slightly and then BHTP had a slightly positive slope over the entire job till 6ppa. No screenout was observed. A slight decrease in pressure was observed during the flush stage. The pressure trend shows that more sand could have been pumped(more than 4000ppf) as the formation had the capacity to accept more sand. The STP trend was initially similar to BHTP but it deflected downwards upon the entry of proppant stages because the hydrostatic head inside the wellbore was increasing with increasing stages of sand, when flush stage started or the displacement of 6ppa sand, the surface pressure increased. This increase in surface pressure can be attributed to the decreasing hydrostatic head in the wellbore. Proppant Concentration inside the formation after the end of the job was 4078.40 pounds per foot.

Job - 2

	Stage	Pumping Rate	Slurry Stage Volume	Time	Type of fluid	Cumulative Volume	Proppant Conc Stage		Stage proppant	Stage proppant	Proppant Type	Cumulative proppant
		bpm	bbl	min.		bbls	ppg		lbs	lbs/min		lbs
							From	To				
Pre Pad	1	33	120	3.6	30# Linear Gel	120	0	0	0	0		0
Sand Stage	2	30	90	3.0	30# Linear Gel	210	0.5	0.5	1848	616	20-40 sand	1848
	3	30	20	0.7	30# Linear Gel	230	0.5	2	993	1490	20-40 sand	2841
	4	30	90	3.0	30# Linear Gel	320	2	2	6928	2309	20-40 sand	9769
	5	30	20	0.7	30# Linear Gel	340	2	4	2217	3325	20-40 sand	11986
	6	30	50	1.7	30# Linear Gel	390	4	4	7104	4263	20-40 sand	19090
	7	30	20	0.7	30# Linear Gel	410	4	6	3420	5130	20-40 sand	22511
	8	30	30	1.0	30# Linear Gel	440	6	6	5936	5936	20-40 sand	28446
Sand Plug	9	30	18	0.6	30# Linear Gel	458	6	6	3562	5936	20-40 sand	32008
FLUSH	10	30	69	2.3	30# Linear Gel	527	0	0	0	0		32008

Figure 27 Actual Treatment Schedule

In the above case, the seam thickness is 2.1m. Cumulative proppant to be pumped should be thus nearly 28000 lbs (4000lbs/ft ideally). Keeping this figure in mind the job is designed. RN-4(U) seam is at around 1070m depth.

SIGNIFICANCE OF VARIOUS JOB STAGES

1st stage- 120bbls of 30#linear gel at 35bpm is pumped without proppant. Pad stage creates fracture geometry. Volume to be pumped is chosen as 30%-40% based on the details obtained from mini-frac analysis.

2nd stage- 90bbls of 0.5 ppg stage is pumped to reduce tortuosity. This low proppant concentration stage further creates fracture geometry and creates width for higher concentration stages.

3rd stage- 20bbls of 0.5-2 Ramp stage is pumped. For seams with less thickness 20-40 bbl is observed to be a sufficient volume for pumping ramp stage. With increasing concentration, volume of slurry should be gradually decreased for a uniform packing.

4th stage- 90bbls of 2 Hold stage is pumped. The pressure response of each stage will be observed during job and accordingly next stage will be pumped.

Thus in the similar fashion rest stages are designed.

5th stage- 20bbls of 2-4 Ramp stage is pumped.

6th stage- 50bbls of 4 Hold stage is pumped.

7th stage- 20bbls of 4-6 Ramp stage is pumped.

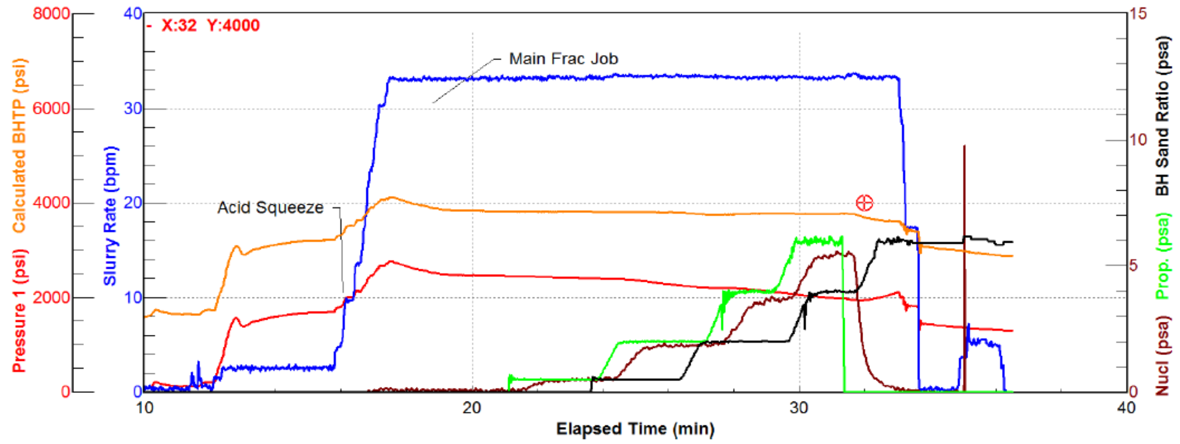
8th stage- 30bbls of 6 Hold stage is pumped.

9th stage- 18bbls of 6ppg Sand Plug stage is pumped.

10th stage- 69bbls of 0ppg Flush Volume is pumped.

The last stage is designed on the basis of calculations of underflush volume. Here as well two seams are separated by sand plug. Thus depending upon height of sand plug to be formed, clean volume to be pumped is calculated. These calculations should be done with extreme care because overflush is an undesirable effect. Due to overflush the sand left in the casing for making sand plug flows into the formation. The proppant placed near wellbore is displaced and thus pinch out may occur.

Figure 28 Actual Treatment Plot of Main Fracture



The BHTP trend shows no increase in the pressure upon the hitting of slug stage which signifies no significant reduction in tortuosity or that tortuosity was already very less in the zone. On reaction of 4ppa sand in the formation, pressure decreased slightly and then BHTP had a constant almost zero slope over the entire job till 6ppa, showing that all the sand introduced was sent into the fracture and there may have occurred extension of the zone or the zone already had enough capability to accept more sand. A decrease in pressure was observed during the flush stage. The pressure trend shows that more sand could have been pumped(more than 4600ppf). The STP trend was initially similar to BHTP but it deflected downwards upon the entry of proppant stages because the hydrostatic head inside the wellbore was increasing with increasing stages of sand, when flush stage started or the displacement of 6ppa sand, the surface pressure increased. This increase in surface pressure can be attributed to the decreasing hydrostatic head in the wellbore. Proppant Concentration inside the formation after the end of the job was 4645.50 pounds per foot.

CASE STUDY #3 : Sand Plug Designing

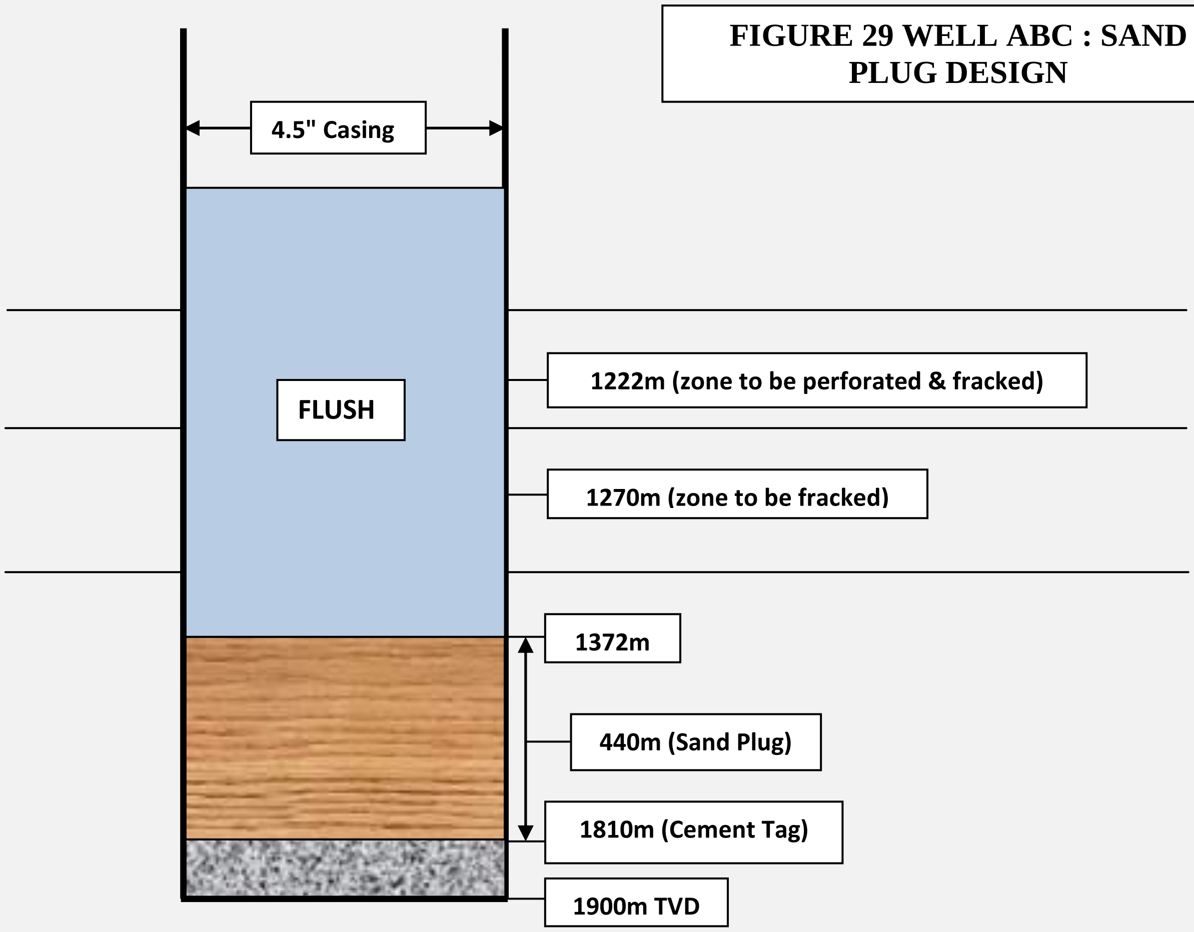
Consider a well with TVD 1900m. The cement tag is at 1810m. The casing is 4.5" and ID 4". At 1270m there is a zone that is to be fracked and at 1222m there is a zone that has to be perforated and then fracked.

1 Metric Tonne of sand acquires 74m in 4.5" casing. For perforation of 1222m zone we will be doing two cuts and doing sand dump. Thus we will require space for this sand so that it doesn't plug the hole created. Hence we leave space for two cuts i.e. 150m.

Ht. of Sand Plug Required = Depth of Cement Tag - Depth of Bottom Zone + Sump
= 440m

Since the well is inclined it may lead to formation of bridges if we send such large amount together. We will send the sand plug in two stages, each of 220m ht. We can't use 8ppa sand because it would lead to plugging of Blenders Discharge because the screws would suck less at less rate sand plug job, so we will use 6ppa sand.

FIGURE 29 WELL ABC : SAND PLUG DESIGN



Assuming casing to be a cylinder, volume at a given depth will be given by **$V = 3.14 * r^2 * h$**
In 4.5" casing well , Annular Vol. = 0.051 bbl/m or 29.44 lb/m
i.e. 1m requires 29.44 lbs so
2204 m - 6476.8 lbs

6ppa sand means 6 lbs in 1 gal of clean fluid

Dirty Vol(bl) = Clean Vol(bl) * (1+(ppa/(2.65*8.33)))

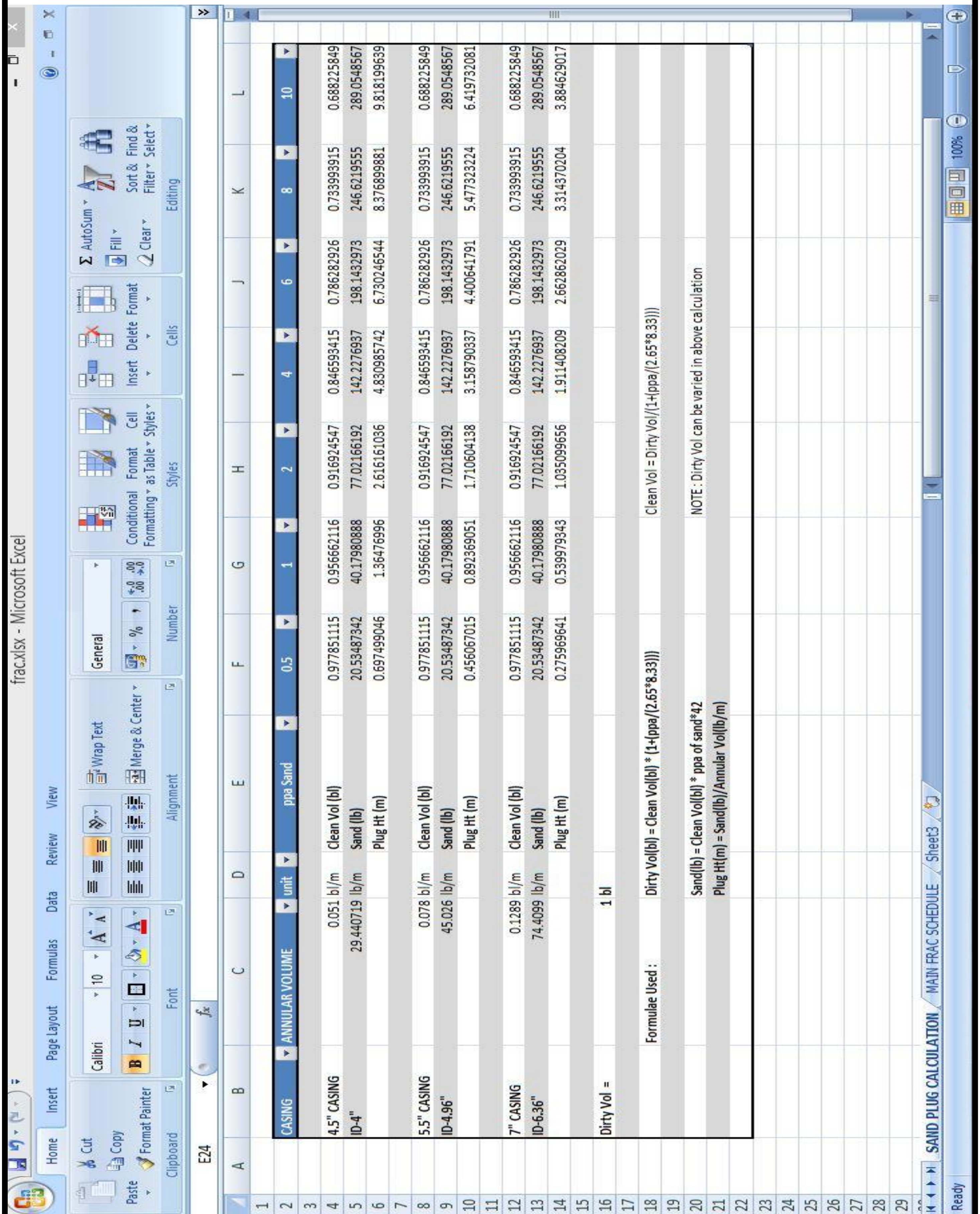
From above we can calculate Dirty Volume, which comes out to be 1.2718 gal
Thus 6476.8 lbs means 1372.8657 gal or 32.6872 bbl is required for 220m of sand plug.
Dividing 32.6872 bbl by annular volume 0.051bbl/m we get 640.92m of slurry ht.

Now the sand volume calculation in the control monitor is shown by the top of slurry and not its bottom, so we need to keep in consideration the slurry ht. of 640m. We will drop the sand plug from 20m above the 1270m zone keeping it as safe margin. So we perform the drop from 1250m i.e. still 610m (or 31.11bbl) space is left in the well that has to flushed.

Flush Volume = Tub Volume + Line Volume + Annular Volume
= 2 bbl + 8 bbl + 31.11 bbl
= 41.11 bbl

After this we allow the sand to settle by giving settling time of 1 hr. Now the sand is filled up to the depth of 1590m. Now we again pump 32.6872 bbl of 6ppa sand and drop from the same ht. 1250m. Flush Volume again remains the same 41.11 bbl. Allow a settling time of 1 hr.

Figure 30 Sand Plug Calculation



CASING	ANNULAR VOLUME	unit	ppa Sand	0.5	1	2	4	6	8	10
4.5" CASING	0.051	bl/m	Clean Vol (bl)	0.977851115	0.956662116	0.916924547	0.846593415	0.786282926	0.733993915	0.688225849
ID-4"	29.440719	lb/m	Sand (lb)	20.53487342	40.17980888	77.02166192	142.2276937	198.1432973	246.6219555	289.0548567
			Plug Ht (m)	0.697499046	1.36476996	2.616161036	4.830985742	6.730246544	8.376899881	9.818199639
5.5" CASING	0.078	bl/m	Clean Vol (bl)	0.977851115	0.956662116	0.916924547	0.846593415	0.786282926	0.733993915	0.688225849
ID-4.96"	45.026	lb/m	Sand (lb)	20.53487342	40.17980888	77.02166192	142.2276937	198.1432973	246.6219555	289.0548567
			Plug Ht (m)	0.456067015	0.892369051	1.710604138	3.158790337	4.400641791	5.477323224	6.419732081
7" CASING	0.1289	bl/m	Clean Vol (bl)	0.977851115	0.956662116	0.916924547	0.846593415	0.786282926	0.733993915	0.688225849
ID-6.36"	74.4099	lb/m	Sand (lb)	20.53487342	40.17980888	77.02166192	142.2276937	198.1432973	246.6219555	289.0548567
			Plug Ht (m)	0.275969641	0.539979343	1.035099656	1.911408209	2.662862029	3.314370204	3.884629017

Dirty Vol = 1 bl

Formulae Used :

Dirty Vol(bl) = Clean Vol(bl) * (1+(ppa/(2.65*8.33)))

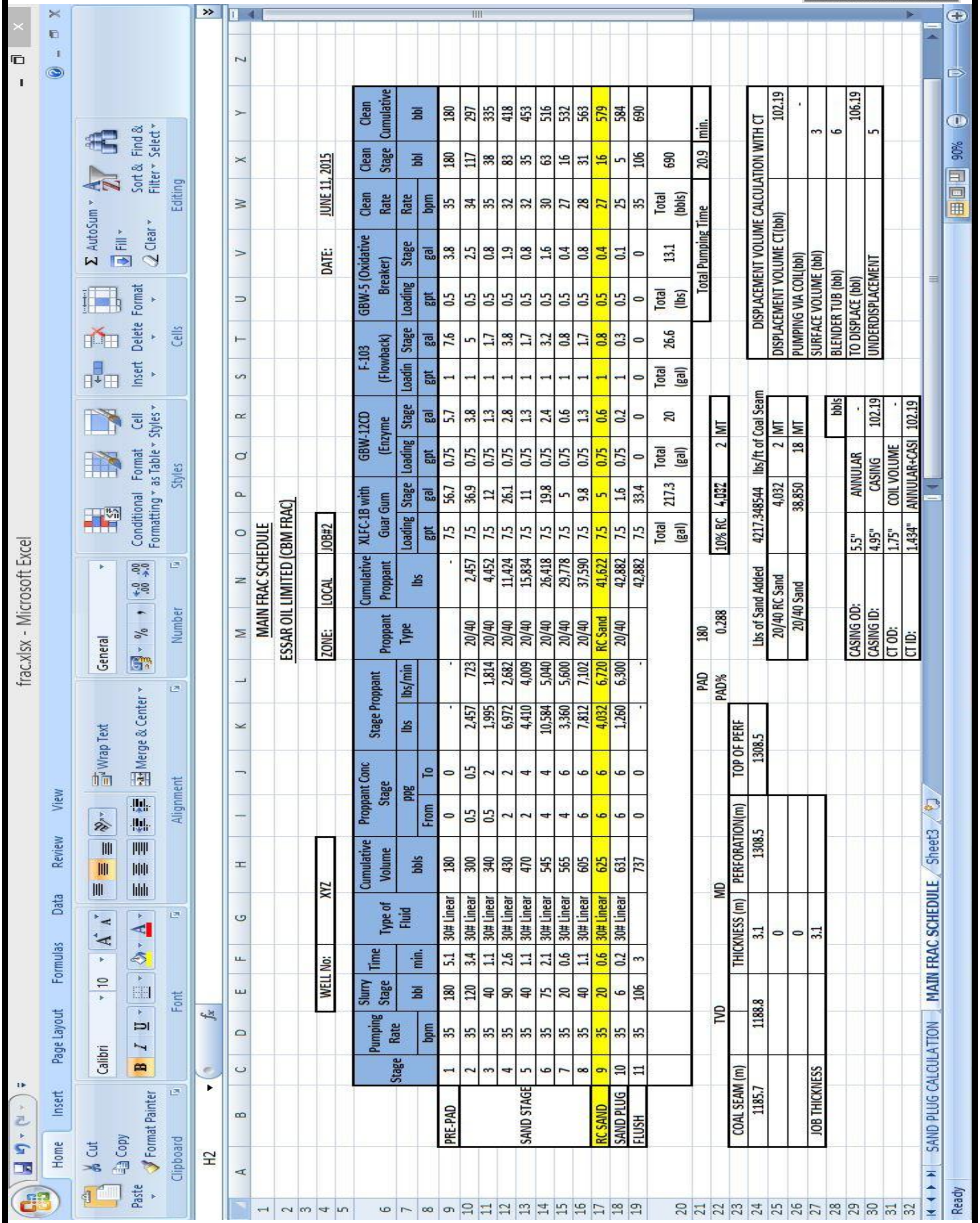
Clean Vol = Dirty Vol/(1+(ppa/(2.65*8.33)))

Sand(lb) = Clean Vol(bl) * ppa of sand*42

NOTE : Dirty Vol can be varied in above calculation

Plug Ht(m) = Sand(lb)/Annular Vol(lb/m)

Figure 31 Main Frac Schedule



frac.xlsx - Microsoft Excel

MAIN FRAC SCHEDULE

ESSAR OIL LIMITED (CBM FRAC)

WELL No: XYZ | ZONE: LOCAL | JOB#2 | DATE: JUNE 11, 2015

	Stage	Pumping Rate (bpm)	Slurry Stage (bbl)	Time (min.)	Type of Fluid	Cumulative Volume (bbls)	Proppant Conc Stage ppg From	Proppant Conc Stage ppg To	Stage Proppant (lbs)	Stage Proppant (lbs/min)	Proppant Type	Cumulative Proppant (lbs)	XLFC-1B with Guar Gum Loading (gpt)	XLFC-1B with Guar Gum Stage (gal)	GBW-12CD (Enzyme Loading (gpt)	GBW-12CD (Enzyme Stage (gal)	F-103 (Flowback) Loadin (gpt)	F-103 (Flowback) Stage (gal)	GBW-5 (Oxidative Breaker) Loading (gpt)	GBW-5 (Oxidative Breaker) Stage (gal)	Clean Rate (bpm)	Clean Stage (bbl)	Clean Cumulative (bbl)
PRE-PAD	1	35	180	5.1	30# Linear	180	0	0	-	-		-	7.5	56.7	0.75	5.7	1	7.6	0.5	3.8	35	180	180
SAND STAGE	2	35	120	3.4	30# Linear	300	0.5	0.5	2,457	723	20/40	2,457	7.5	36.9	0.75	3.8	1	5	0.5	2.5	34	117	297
	3	35	40	1.1	30# Linear	340	0.5	2	1,995	1,814	20/40	4,452	7.5	12	0.75	1.3	1	1.7	0.5	0.8	35	38	335
	4	35	90	2.6	30# Linear	430	2	2	6,972	2,682	20/40	11,424	7.5	26.1	0.75	2.8	1	3.8	0.5	1.9	32	83	418
	5	35	40	1.1	30# Linear	470	2	4	4,410	4,009	20/40	15,834	7.5	11	0.75	1.3	1	1.7	0.5	0.8	32	35	453
	6	35	75	2.1	30# Linear	545	4	4	10,584	5,040	20/40	26,418	7.5	19.8	0.75	2.4	1	3.2	0.5	1.6	30	63	516
	7	35	20	0.6	30# Linear	565	4	6	3,360	5,600	20/40	29,778	7.5	5	0.75	0.6	1	0.8	0.5	0.4	27	16	532
	8	35	40	1.1	30# Linear	605	6	6	7,812	7,102	20/40	37,590	7.5	9.8	0.75	1.3	1	1.7	0.5	0.8	28	31	563
RC SAND	9	35	20	0.6	30# Linear	625	6	6	4,032	6,720	RC Sand	41,622	7.5	5	0.75	0.6	1	0.8	0.5	0.4	27	16	579
SAND PLUG	10	35	6	0.2	30# Linear	631	6	6	1,260	6,300	20/40	42,882	7.5	1.6	0.75	0.2	1	0.3	0.5	0.1	25	5	584
FLUSH	11	35	106	3		737	0	0	-	-		42,882	7.5	33.4	0	0	0	0	0	0	35	106	690
													Total (gal)	217.3	Total (gal)	20	Total (gal)	26.6	Total (lbs)	13.1	Total (bbls)	690	

Total Pumping Time 20.9 min.

PAD 180

PAD% 0.288

10% RC	4,032	2	MT

	TVD		MD		
COAL SEAM (m)			THICKNESS (m)	PERFORATION(m)	TOP OF PERF
1185.7	1188.8		3.1	1308.5	1308.5
			0		
			0		
JOB THICKNESS			3.1		

Lbs of Sand Added 4217.348544 lbs/ft of Coal Seam

20/40 RC Sand	4,032	2	MT
20/40 Sand	38,850	18	MT

			bbls
CASING OD:	5.5"	ANNULAR	-
CASING ID:	4.95"	CASING	102.19
CT OD:	1.75"	COIL VOLUME	-
CT ID:	1.434"	ANNULAR+CASI	102.19

DISPLACEMENT VOLUME CALCULATION WITH CT	
DISPLACEMENT VOLUME CT(bbl)	102.19
PUMPING VIA COIL(bbl)	-
SURFACE VOLUME (bbl)	3
BLENDER TUB (bbl)	6
TO DISPLACE (bbl)	106.19
UNDERDISPLACEMENT	5

SAND PLUG CALCULATION | MAIN FRAC SCHEDULE | Sheet3

11. Recommendations

Advantages of Large Grain Size :

- Larger the grain size, higher the permeability & less susceptible the proppant is to embedment in cleat faces.
- Large grain allow coal fines to pass through, rather than collect and gradually plug up the conductivity.

Advantages of Small Grain Size :

- Travels faster than average fluid velocity at that location because the proppant tends to be confined to the centre of the flow channel where the fluid velocity is higher.
- As size increases the fracture walls retard the proppant.
- Retardation of particle relative to fluid greater for larger particles due to hydrodynamic stress exerted on sphere by walls in a narrow gap.
- Viscosity tends to be higher with smaller particles because particle-particle interaction and resistance to flow is present even at low shear rates
- Larger gains are more susceptible to producing permeability reducing fines than smaller grain size distribution. This is because large grain size distribute the closure pressure across fewer grain to grain point of contact and so the point of contact loads tend to be greater.

In 20/40 Mesh, particles larger than 100 Mesh Size don't migrate through the pack because they are too large to travel through pore throats.

Thus for an Ideal Job :

- Sand pumped first should be smaller in size and gradually size should be increased
- 100 Mesh size sand should be used for leak off control
- This would lead to an increase in fluid efficiency at the tip
- 20/40 Mesh size sand should be used for 0.5 stage , 0.5-2 ramp stage , 2 hold stage , 2-4 ramp stage.
- 16/30 Mesh size sand should be used for 4 hold stage , 4-6 ramp stage and so on.
- This would lead to an increase in near wellbore conductivity

Frac Recommendations :

- All Sand calculations should be based on thickness of coal seams only.
- The Pad Stage volume can be chosen in the range of 25% to 30%. This would give the same result in wells having low leakoff coefficient and also save the extra money spent on gel.
- If tortuosity is more, more volume of slug stage should be pumped.
- If the well depth value is not very large, then the volume pumped initially can be 1.2 times the annular volume for 0.5 slug stage and 2 hold stage and slowly decreasing for further sand stages. For deeper wells we have to go blind and hence we will get same result with 1 annular volume being used in initial stages instead of 1.2 times.
- Wells with higher leakoff coefficient(>0.0008 ft/ $min^{0.5}$) do not deviate much from the predicted simulation data because permeability is likely high enough to allow any increase in pressure to equilibrate with the reservoir prior to pumping a frac job.
- Wells with less than 0.0006 ft/ $min^{0.5}$ require a reduction of approx 35% to match frac job net pressure behaviour.
- Data from post frac analysis show that the leakoff characteristics of formation actually change between pumping minifrac and main frac job. This is due to increase in pore pressure as a consequence of pumping the minifrac.
- The vertical distance between two successive combined zones should not exceed more than 20 m or 60 ft.
- In such a case it is possible that either of the two zones will not achieve adequate fracture dimensions.
- It is also highly possible, that either of the two fractures will screen out near wellbore.
- One seam can screen out while the other will take on all the fluid, hence giving a false appearance of a successful job. Even if the job is run at very low sand concentrations, such a scenario is likely.
- Pressure increase or spikes were observed in certain cases before the complete volume of sand had been pumped in, this could be due to the fact that the gel didn't have enough viscosity to carry the sand or proppant with it inside the fracture.
- Thus instead of currently in use Linear Gel, it is recommended to switch to Delayed Cross linking Gel and it would prove to be more efficient as it would significantly reduce the problem of early screen out.

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