Chair of Drilling and Completion Engineering

Master's Thesis

Tight Gas Reservoir Production - Evaluation of Hydraulic Fracturing Enhancement

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Fran Sikonja, 02 December 2019

Abstract

Although hydraulic fracturing has been used for many decades, in recent years it is taking a much bigger interest of companies around the world. With hydrocarbon reserves depleting every year the need for production from unconventional reservoirs increases. Therefore, the application of the hydraulic fracturing simulation method has enabled production from such reservoir types and thus provided a new momentum in the oil and gas industry.

With the huge contribution that hydraulic fracturing provides to the production of hydrocarbons from unconventional reservoirs, there is no need to neglect either the great added value that this technology provides in numerous projects run on conventional oil and gas reservoirs. This thesis will follow an onshore exploration well which was a project from a Croatian oil company. The well confirmed existence of gas and gas condensate in projected volumes but due to low permeability of reservoir it was not possible to produce economically. The decision was made to improve production by implementing hydraulic fracturing stimulation. Which allowed a successful resumption of exploration project, whose initial unsatisfactory results did not provide sufficient basis for putting the well in production.

Every part of the project will be analysed with possibility of revealing and improving any aspect. The main focus will be on hydraulic fracturing part of the project and evaluation of production performance which was expected with the one attained from hydraulic testing.

Zusammenfassung

Obwohl hydraulischen Frakturierung seit vielen Jahrzehnten eingesetzt wird, hat es in den letzten Jahren ein viel größeres Interesse von Unternehmen auf der ganzen Welt gefunden. Da die Kohlenwasserstoffreserven jedes Jahr erschöpft sind, steigt der Bedarf an Produktion aus unkonventionellen Reserven. Die Anwendung des hydraulischen Fraktursimulationsverfahrens hat daher die Produktion aus solchen Reservoirtypen ermöglicht und damit der Öl- und Gasindustrie einen neuen Impuls verliehen.

Angesichts des enormen Beitrags, den das Hydrofracking zur Gewinnung von Kohlenwasserstoffen aus unkonventionellen Lagerstätten leistet, muss auch der große Mehrwert, den diese Technologie in zahlreichen Projekten mit konventionellen Öl- und Gaslagerstätten bietet, nicht vernachlässigt werden. Diese These wird einer Onshore-Explorationsbohrung folgen, die ein Projekt eines kroatischen Ölkonzerns war. Das gut bestätigte Vorhandensein von Gas und Gaskondensat in projizierten Mengen, aber aufgrund der geringen Durchlässigkeit des Speichers war es nicht möglich, wirtschaftlich zu produzieren. Es wurde beschlossen, die Produktion durch die Implementierung einer hydraulischen Frakturierungsstimulation zu verbessern. Dies ermöglichte eine erfolgreiche Wiederaufnahme des Explorationsprojekts, dessen anfänglich unbefriedigende Ergebnisse keine ausreichende Grundlage für die Inbetriebnahme des Bohrlochs darstellten.

Jeder Teil des Projekts wird mit der Möglichkeit analysiert, jeden Aspekt aufzudecken und zu verbessern. Das Hauptaugenmerk wird auf dem Teil des Projekts zum hydraulischen Frakturierung und der Bewertung der Produktionsleistung liegen, die mit der aus den hydraulischen Tests erzielten Leistung erwartet wurde.

Acknowledgements

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Contents

Chapter 1 Introduction

Being used for many decades, hydraulic fracturing, just recently started getting a lot of attention from companies around the world. With a number of suitable candidate reservoirs decreasing the industry is looking for new ways to increase production and keep up with the demand. Hydraulic fracturing or fracing, through the world, is becoming one of the most important processes in completing a well.

It involves the injection of proppant, water and specific chemicals at a very high rate and pressure into the formation. As the flow rate increases, so does the pressure differential. Pressure and stress are mostly the same things, which means that fluid flow generating a pressure differential also creates stress in the formation. If the rate keeps increasing, eventually a point will be reached where the stress becomes higher than the maximum stress that formation can sustain, and the rock will physically split apart, and a fracture will form. Proppant, which travels with fracture fluid into the fracture, keeps it open after the pumps shut down and fluid leeks out. (Economides and Martin 2007).

Hydraulic fracturing stimulation is generally used to increase the permeability and reduce the skin damage caused by drilling. Unconventional reservoirs with extremely low permeability would never produce at an economically feasible rate without hydraulic fracturing. With the appearance of slick water frac and production from low permeability reservoirs made possible, the industry started to move from conventional resources with high permeability, to tight (low permeability) resources. Conventional resources are hard to find, but once found it is easier to produce from them without using hydraulic fracturing, as seen in Figure 1. On the other hand, unconventional resources would hardly produce economically without hydraulic fracturing.

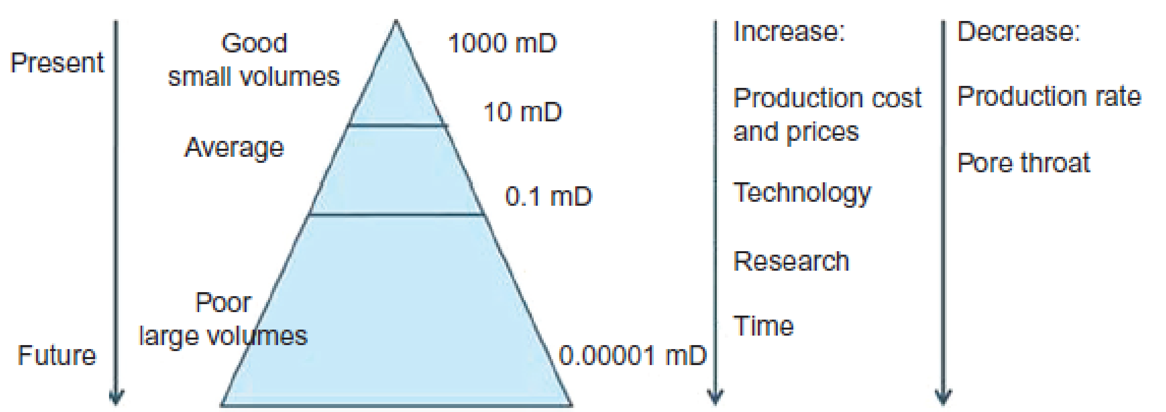

Figure 1: Gas resource pyramid (Belyadi, Fathi and Belyadi 2017)

Here are some of the main applications of hydraulic fracturing used in the oil and gas industry:

1. Increase the flow rate of low permeability reservoirs.
2. Increase the flow rates of damaged wells (near wellbore skin damage) caused by drilling.
3. Connect hydraulic fractures with existing natural fracture
4. Reduction in sand production by decreasing the pressure drop around the well.
5. Reduce the number of infill wells with an application of horizontal hydraulic fracturing stimulation.
6. Increase the amount of formation contact or surface area with the wellbore.

The most important application listed above and the main reason behind hydraulic fracturing is to increase the permeability of the reservoir. In the naturally fractured formations with low permeability, hydraulic fracturing not only increases the productivity of the wells but also allows better connection and communication between the well and formation. Additionally, the new crated fractures increase the connectivity with the existing network of natural fractures.

Porous and permeable reservoir rocks are any company's desire but even then, problems can occur. When producing from high permeability sandstone formation, sand grains can restrict the flow and eventually lead to a reduction in production. Hydraulic fracturing can then be used together with conventional gravel-packing and crate an excellent conduit for the flow of hydrocarbons in a process called frac packing. Accordingly, hydraulic fracturing can also have a positive effect in conventional high permeability formations.

1.1 Brief History of Fracturing

Hydraulic fracturing or fracing is becoming one of the most important processes in completing a well. Although it took much time to get there, it would not have been possible if not for the countless efforts of early petroleum engineers. Since its first introduction in 1947, nearly 2,5 million treatment have been conducted worldwide. It is believed that roughly 60% of all wells drilled today are fractured (Montgomery and Smith, Hydraulic Fracturing: History of an Enduring Technology 2010).

The first endeavours at fracing formations for the purpose of improving production took place as early as 1890. It is documented that they were not even hydraulic in nature but involved usage of high explosive to break the formation apart and provide "flow channels" from the reservoir to the wellbore. As technology advanced, during the 1930s, acidizing became an accepted well development technique. During its application it was observed that above a certain "breakdown" pressure, injectivity would increase dramatically and unknowingly that were some of the first acid fractures. They weren't recognized up until the 1940s when Torrey, Grebe, Yuster and Calhound, first in cement squeezing operations and later water injection wells, recognized that pressure generated during these operations could break the rock along bedding planes or other lines of "sedimentary weakness" (Economides and Martin 2007).

Figure 2: The very first frac job, 1947 (Montgomery and Smith, Hydraulic Fracturing: History of an Enduring Technology 2010)

The first experiment ever conducted to stimulate a well using hydraulic fracturing, "Hydrafrac”, was completed in the Hugoton gas field in Grant County, Kansas, in 1947 by Stanolind Oil (Figure 2). Napalm (naphthenic acid and palm oil) and sand from the Arkansas River were used and injected, followed by a gel breaker, to improve gas production from a limestone formation. Although the deliverability of the well didn't change substantially, it was a valuable lesson for the industry. Two years later, a patent was issued, which licensed Halliburton Oil Well Cementing Company (Howco) to operate with the new Hydrafrac process. They completed the first two commercial fracturing treatments, costing them around 900 USD each. In the first year alone, 332 well were treated, with an average production increasing 75%. Half a century later, in 2008, over 50000 frac stages were finished worldwide with costs ranging from 10000 USD to 6 million USD (Montgomery and Smith, Hydraulic Fracturing: History of an Enduring Technology 2010).

1.2 Frac Steps

Each hydraulic fracture design is different from each other. It can vary from the layer, fracture fluid, proppant, pump rate too many other things which are essential to consider when designing. But the process itself generally consists of the same main steps which will be described.

1.2.1 Pad Stage

In order to initiate fracture creation, a fluid stage is known as the pad (which is a combination of only water and chemicals) is pumped first. The pad will create fracture length, height and width before going with the proppant stage. It is strongly believed that if not enough pad volume is pumped, then when the proppant reaches the fracture tip, the fractures will be filled and a sand-off (screen-out) will occur. Nevertheless, if too much pad volume is pumped, after pumping the proppant, a vast unpropped region will remain. Since propped fracture regions can move towards the unpropped one, a result will be a poor distribution of proppant inside the main fracture. That why calculating the pad volume is extremely important and related to fluid efficiency which will be explained later.

1.2.2 Proppant Stage

When the pad volume is pumped, the proppant stage starts. In this stage a combination of water, chemicals and proppant (slurry) is pumped downhole. Depending on the fluid system used for fracturing, the primary mechanism for placing proppant in the formations is either pump rate or viscosity of the fluid. Either way, the proppant stage starts with small concentrations of proppant and gradually increases to higher ones as shown in Figure 3. The reason for it is to try to have a uniform concentration of proppant through the entire fracture length. This will not only result in a uniform fracture conductivity but will also keep the density of the slurry homogeneous through the job and prevent gravity segregation of the proppant and minimize viscous fingering.

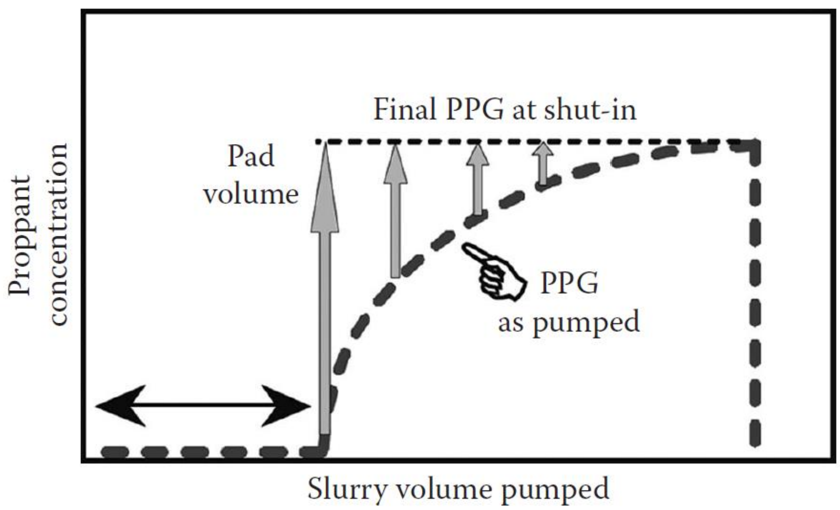

Figure 3: Proppant schedule for a typical frac design (Montgomery and Smith, Hydraulic Fracturing 2015)

1.2.3 Flush Stage

After pumping the designed proppant stage, the proppant is cut, and the well is flushed. The purpose of flushing is to clear the inside of tubing of sand and to move/flush all the remaining proppant into the formation. For flushing only water and chemicals are used. The casing grade, weight, and bottom perforation depth are needed to calculate the desired flush volume. As a rule of thumb, at least one casing volume is pumped to the bottom of perforations after all the surface line is clear of sand. To be sure that surface lines are clear of sand, the densometer is placed close to the wellhead.

Chapter 2 Hydraulic Fracturing Fluid System Types

Above other things, the main functions of fracturing fluid are to create and extend the fracture, transport proppant through the mixing and pumping equipment and place it at the preferred location in the fracture. If any of these actions fail, the whole treatment may be compromised. Here, types of fluid systems will be examined, and their main characteristics explained.

2.1 Slick Water Fluid System

A well-known type of fluid system used mainly in U.S. shales and many other low permeability reservoirs around the world. This system uses water, sand and certain chemicals which are pumped downhole to create a complex fracture system within the reservoir and to maximize the surface area. In this technique a huge amount of water is used to create the maximum surface area and the high rate is the force needed to create the complex fracture system within the formation. By using a higher rate, better surface area with a result of better production is obtained. Consequently, to acquire higher rates more pumps are needed and occasionally the size of the pad (well site) and many other factors limit the operator’s number of pumps necessary for the job.

The pressure is another critical factor that limits the usage of the required rate. Various surface equipment and casing burst pressure ratings put limitations on the maximum allowable treating pressure. This pressure is obtained from the surface, casing and wellhead pressure rating used for the job. Only by decreasing pressure bellow maximum allowable treating pressure can the rate increase.

By using a chemical additive called friction reducer (FR), the friction of water is reduced which enables the water to be pumped at high rates. Also, by using formation water instead of freshwater, better productivity will be obtained. Formation water reduces the chance of filer cake along the created fractures to appear and helps water to move along natural fractures which increases surface area contacted by hydraulic fracturing stimulation.

Best candidates for slick water frac are formation with high brittleness. Having a brittle formation will help keep the fractures open after the rock was fractured. Best indicators for brittleness are high Young´s modulus (30-70 GPa) and low Poisson´s ratio (<0.3). Figure 4 shows a typical hydraulic fracture and complex network system in slick water frac.

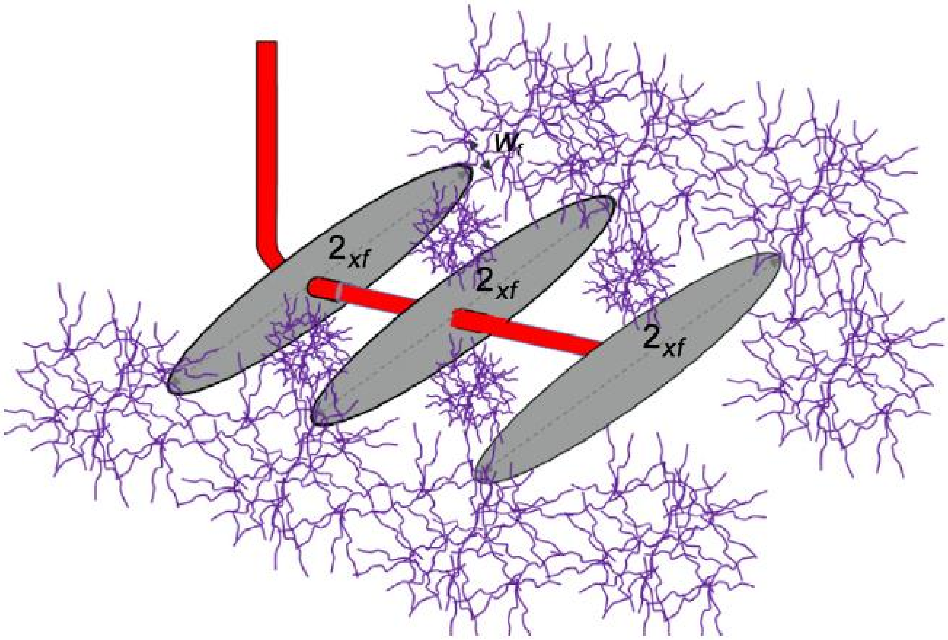

Figure 4: Complex fracture system (Belyadi, Fathi and Belyadi 2017)

2.2 Cross-linked Gel Fluid System

In comparison to slick water, a cross-linked gel is a heavy viscous fluid. It is used in both conventional and unconventional reservoirs with the objective of obtaining the so-called biwing fracture system, shown in Figure 5. If cross linked gel fluid system is applied, the viscosity of the fluid system is of the primary importance. The velocity of the proppant placement is not critical. The purpose is to achieve maximum sand concentration near the wellbore (higher conductivity) through the use of a viscus fluid. The cross-linked gel uses heavy viscous liquid to place the proppant, in comparison to slick water that uses a high rate (velocity) and water.

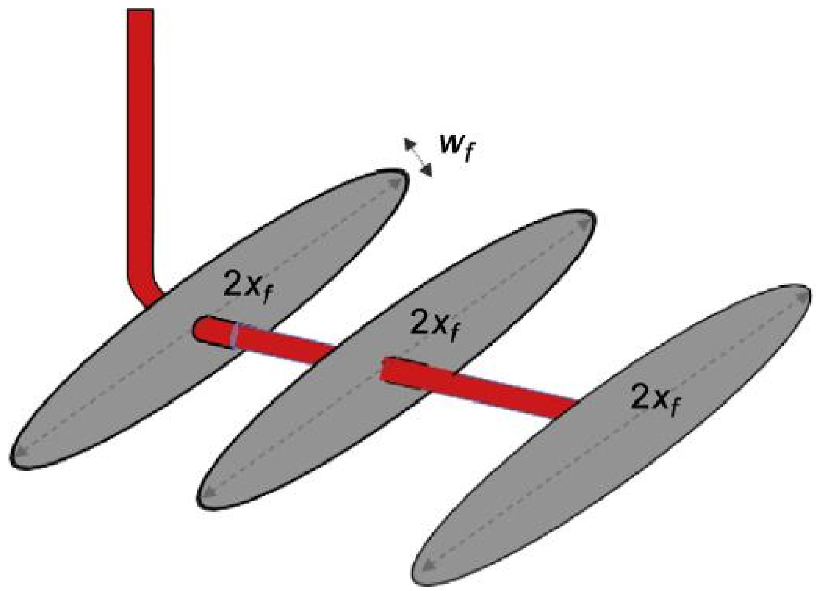

Figure 5: Biwing fracture system illustration (Belyadi, Fathi and Belyadi 2017)

High Poisson´s ration and low Young´s modulus formations that have high permeability are the best candidates for cross-linked frac. High permeability reservoirs usually have significant fluid leak-off and the cross-linked fluid system is known to reduce it and keep the proppant suspended until closure. But gel residue that cross-linked fluid system leaves in the formation is also the biggest concern. If it is not broken properly at reservoir conditions, it can cause severe damage to the created fractures by reducing fracture conductivity and permeability. In some cases even after taking all the necessary parameter into account, specific type of frac does not give the best production results. That's why, using production data is the main element when deciding on the frac fluid system.

2.3 Hybrid Fluid System

Often used in unconventional reservoirs when there are serious issues with placing higher sand concentrations into the formation. First slick water is used to pump at a lower sand concentration which is followed by a cross-linked gel to pump at a higher sand concentration in order to maximize near wellbore conductivity. The reason for this is that some formations are not compatible with higher sand concentrations and the only solution to place all the designed sand is to use linear gel (less viscous than cross-linked gel) or cross-linked gel at higher sand concentrations.

Chapter 3 Rock Mechanical Properties

In order to understand the principles of hydraulic fracturing, it is essential that the various parameters of rock mechanics are entirely understood. Generally, rock mechanics focus is on rock deformation and possible failure of rock as a result of natural or manmade forces.

For the field of hydraulic fracturing, the interaction between the rock and fluid, in which fracture initiation, propagation and geometry occur because of applied hydraulic force are main points of interest. To understand this a deep understanding of formation in-situ stress conditions and stress behaviours around the fracture is needed. The essential parameters for the characterization of rock mechanical properties are stress, strain and deformation (Belyadi, Fathi and Belyadi 2017).

3.1 Young´s Modulus (E)

When a body's motion is constrained in space while a force is applied to it a deformation will occur. Young´s modulus is defined as a measurement of stress over the stain or only as a slope of a line on a stress versus strain plot. In hydraulic fracturing it can also be referred to as the amount of pressure needed to deform the rock. Young´s modulus measures rock stiffness, and greater it is, harder the rock. For having a successful frac job a higher Young´s modulus is required since it will help keep the fractures open for better production after the frac job. Having a Young´s modulus with a bigger value, also indicates that the rock is brittle and that will determine the type of frac fluid which will be used (Belyadi, Fathi and Belyadi 2017).

3.2 Poisson´s ratio (v)

Poisson´s ratio measures how much a material will deform in a direction perpendicular to the direction of the applied force. It is another measure of rock strength that is crucial rock property related to closure stress. The typical values of the dimensionless Poisson´s ratio are in the range between 0.1 and 0.45, where low values indicate that rock will fracture easier and high Poisson´s ratio means rocks are harder to break. The core sample is the best way to measure Poisson´s ratio even though the sonic log is also used (Belyadi, Fathi and Belyadi 2017).

3.3 Fracture Toughness

Fracture toughness in hydraulic fracturing represents the amount of energy necessary to split the rock apart in the presence of a fracture tip. Together with Young´s modulus it specifies how energy is used to create fracture width and how much of it will be used to create fracture height and length. High fracture toughness values are a sign of ductility while low value points out that materials are experiencing brittle fractures (Economides and Martin 2007).

3.4 In-Situ Stress

There are three principal stresses that characterize in-situ stress. They are the stresses within the formation, which serve as a load on the formation and are oriented perpendicular to each other. They impose the size and orientation of a fracture, and the magnitude of the pressure needed to crate it. However, many factors including tectonics, depth and also wellbore can considerably impact the stresses in a specific area and determine how stress is transmitted and spread among formations (Nolen-Hoeksema, R. 2013).

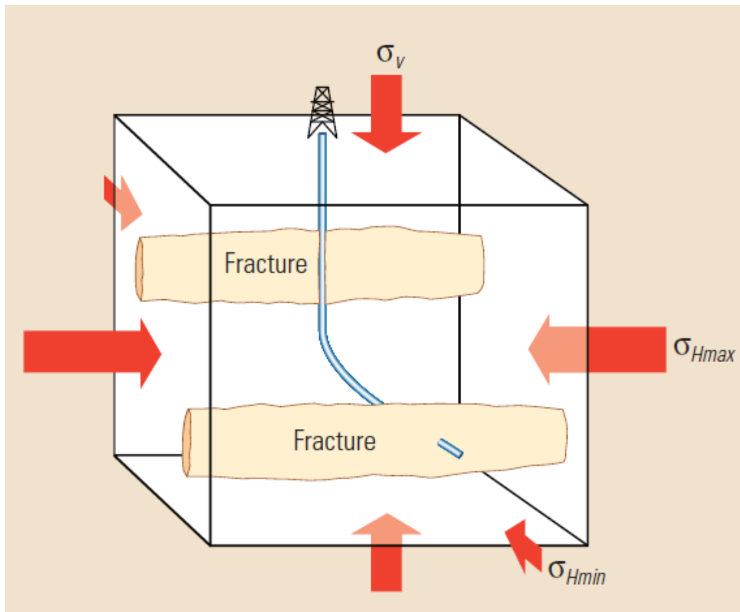

Figure 6: In-situ stresses and hydraulic fracture propagation (Nolen-Hoeksema, R. 2013)

3.4.1 Vertical Stress

Vertical stress (σ_V), also called overburden stress, is simply the sum of all the pressures induced by all of the different rock layers. Since every formation contains rock and fluid each one must be accounted for separately. Considering that that it is very demanding to obtain rock and fluid densities from various depths, a density-logging tool is used for accurate measurements.

3.4.2 Minimum and Maximum Horizontal Stress

Both horizontal stresses are a consequence of stresses accumulated from combining tectonic and fluid forces. Since a hydraulic fracture is a tensile fracture, it will always propagate in the direction of least resistance. Which means that a fracture will generate parallel to the greatest principal stress (usually maximum horizontal stress, σ_{Hmax}) and perpendicular to the plane of the least principal stress. The minimum horizontal stress is usually the lowest principal stress ,a created fracture will almost always propagate on a vertical plane. The direction of stresses can be determined from calliper log, since borehole breakout aligns with maximum horizontal stress, and from Minifrac tests which will be discussed later (Economides and Martin 2007).

Minimum horizontal stress (σ_{Hmin}) is estimated as fracture closure pressure. Stress and pressure are essentially related, but the main difference is that pressure acts in all directions equally, whereas stress only acts in the direction of the force. Being a direct result of overburden stress, Poisson´s ratio will determine the magnitude of stress that can be transmitted horizontally (Belyadi, Fathi and Belyadi 2017).

3.5 Fluid Leakoff and Fluid Efficiency

During hydraulic fracturing, while the fracturing fluid is pumped into the formation, a certain amount of this fluid is lost in the formation. This is called fluid leakoff and it is inversely related to fluid efficiency. Fluid efficiency is the ratio of the volume stored within the fracture and the total volume injected into the fracture. When a fluid system is described as "efficient" it means it has low fluid-loss characteristics (low leakoff). Generally, unconventional reservoirs with low permeability have low fluid leakoff and will create fractures more effectively, hence needing less pad volume to be pumped. Fluid efficiency is used in many fracturing applications and is calculated using Minifrac, which will be shown later.

3.6 Fracture Geometry

Having a detailed knowledge of the distribution of petrophysical properties is vital to pinpoint the initiation of hydraulic fractures and to figure out the progression of fracture-geometry configuration. Hydraulic fracture geometry is very complex and is influenced by initial reservoir stress conditions, rock mechanical properties (Young's modulus and Poisson's ratio), permeability, porosity, natural fracture system, and operational requirements such as injection rate, pressure, and volume. Specific assumptions have been made to simplify modelling of this process, while keeping the most essential characteristics of hydraulic fracture geometry. Thus, it is assumed that the hydraulic fracturing process would occur in an isotropic and homogeneous formation that would lead to a symmetric, bi-wing fracture from the point of the line source of the injecting fluid. Three fracturing modelling methods, which are based on these assumptions, are most commonly used: the radial fracture model, the Khristianovic-Geertsma de Klerk (KGD) model, and the Perkins and Kern (PKN) model (Abe, Mura and Keer 1976).

3.6.1 Radial Fracture Model

There are various radial models that have been developed, but in all of them it is assumed that the height of fracture (h_f) is directly related to fracture length (x_f). It is used in shallow formations where overburden stress is equal to minimum horizontal stress. In this model, a fluid pressure within the fracture and the injection rate are assumed to be constant. Also, the fracture width (w_f) is proportional to fracture radius (r_f) as shown in Figure 7.

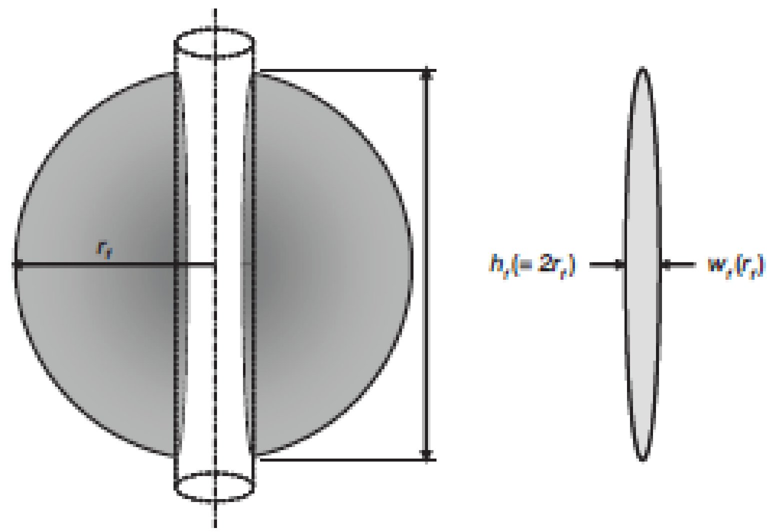

Figure 7: Radial fracture geometry (Economides and Martin 2007)

3.6.2 KGD Model

The KGD model assumes a fixed fracture height and width is proportional to fracture length. Also, it is assumed that width is constant in the vertical direction and rock stiffness is only considered in horizontal plane. Figure 8 show the fracture geometry in the KGD model.

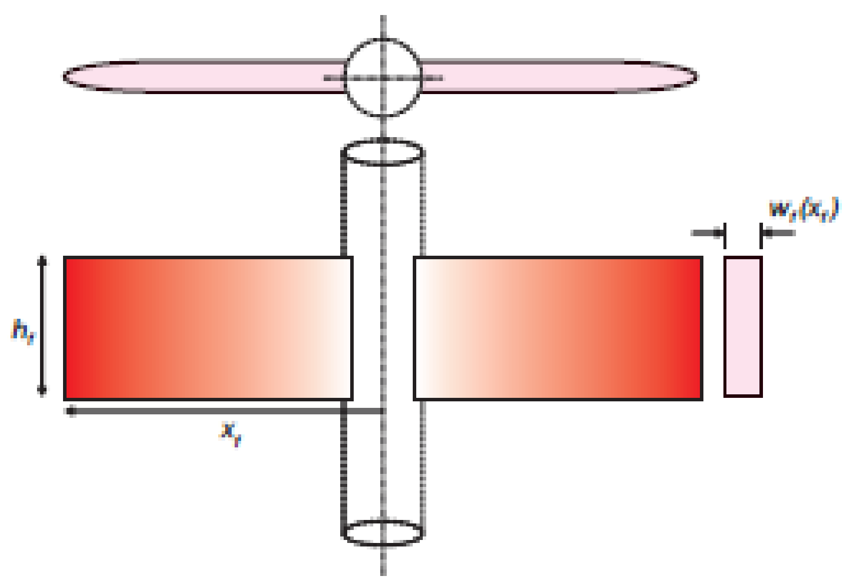

Figure 8: KGD fracture geometry (Economides and Martin 2007)

3.6.3 PKN Model

Like the previous model, height is again assumed to be constant. However, unlike the previous one, the width is proportional to fracture height. Also, here we have an elliptical cross-section in a vertical direction. The PKN model assumes a fracture height that is much smaller than the fracture length (opposite of KGD model) which is shown in Figure 9.

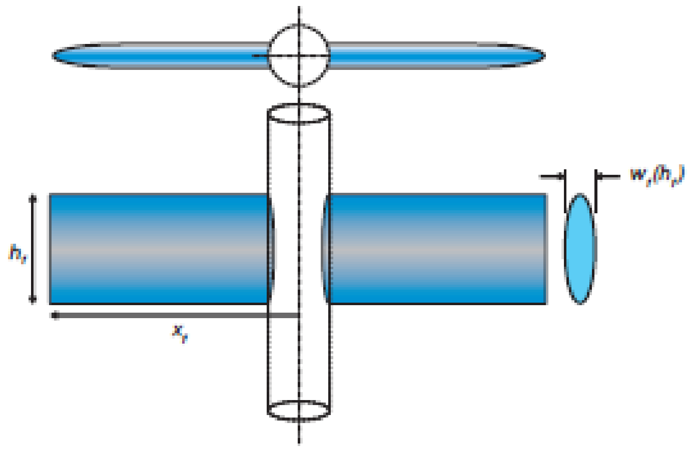

Figure 9: PKN fracture geometry (Economides and Martin 2007)

Chapter 4 Proppants

Having a created fracture permeability higher than the reservoir matrix permeability is the essence of successful well productivity enhancement. Proppants, or propping agents, prevents the fractures from closing due to overburden pressure after the frac job is completed and the treating pressure is relieved. Therefore, the proppant is an essential part of the completion system because it provides connection for hydrocarbons to flow between the reservoir and the producing wellbore. Theoretically, the proppant will provide flow conductivity large enough to minimize pressure losses in fracture during production but in practice, that is not always achievable because proppant selection includes compromises enforced by economic and practical considerations. One of the main points of selection is that it should withstand the forces which are trying to close the fracture. There are numerous types of proppants available for hydraulic fracturing and they are going to be examined in the following sections, together with their effect on fracture.

The increase of oil/gas production after hydraulic fracturing can be achieved only if the fracture is adequately filled with proppant and has a designed conductivity which is strongly influenced by the following proppant properties:

- High Strength,
- Size, sphericity and roundness,
- Corrosion Resistant,
- Low Specific Gravity,

The most frequent proppant types used for fracturing operation are:

- Quartz Sand,
- Sintered Bauxite,
- Ceramic Material, and
- Resin Coated Sand, Bauxite or Ceramics.

Fracture permeability is a function of proppant type, proppant concentration, reservoir temperature, fracture closure stress and the amount of fines, gel residue, etc. that are in the proppant pack. The key criteria for selecting the proper proppant size is to get high conductive fracture.

4.1 Sands

Sand is the lowest - strength proppant which is highly available worldwide and is also the cheapest. They can typically handle closure pressure of up to 400 bar which mostly occurs at depths of less than 2500 m. Although they can originate from many geographical locations around the world, the most famous and best quality ones are Ottawa and Brady sands (commonly called “white” and “brown”), both found in the USA. Sands can be subdivided into groups of excellent, good and substandard grades (API RP 56, 1983; and ISO 13503 – 2,

2006) depending on their physical properties and overall balance. Specific gravity for sands is usually around 2,65 (Economides and Martin 2007).

4.2 Resin–Coated Proppants

Brittle failure of sands led to the development of resin–coated proppants (RCP) in which for the purpose of improving grain strength each grain is encapsulated with resin coating. The coating is often at least partially cured during manufacturing to produce a non-melting, chemically inert surface film. It is considered intermediate–strength proppant and is more expensive than regular ones. They are usually used in a formation with closure stress ranging from 400 bar to 550 bars. The main reason they are not utilized very often is because of their price. So using them should be economically justified.

The first type is precured resin–coated proppant. It has a hard coating around the grains, causing it to have higher conductivity compared to uncoated grains. Precured proppant will encapsulate crushed fines and prevent their migration but will not bond in fractures. Fines are formed after the closure pressure is applied to the sand.

The other type is curable resin–coated proppant whose properties are very similar to precured ones. The primary application for this type of proppant is to control the flowback. Since it´s only partially cured when manufactured, the additional curing should occur in the fractures (under closure pressure) so that the coatings of proppants bond together and prevent flowback, as seen in Figure 10 (Belyadi, Fathi and Belyadi 2017).

Figure 10: Curable resin-coated proppant under reservoir conditions (Belyadi, Fathi and Belyadi 2017)

4.3 Ceramic proppants

Ceramic type proppants are considered the best quality ones. They have uniform shape and size and are thermally resistant., manufactured from high–aluminium ores. Depending on the closure pressure which will be encountered there are various types of ceramic proppant.

The most reliable type of proppant is high–strength sintered bauxite shown in Figure 11. It contains corundum, which is one of the hardest materials know and is used in deep wells with high–stress and high–temperature environment. Due to its high price it is only used when closure pressure exceeds 700 bar but can handle a closure pressure of up to 1400 bar. Its specific gravity is around 3,4 or greater (Economides and Martin 2007).

Figure 11: Sintered bauxite proppant (Economides and Martin 2007)

Another type of ceramic proppant is intermediate–strength proppant (ISP). The specific gravity of it ranges between 2,9 and 3,3, depending on the raw material used for manufacturing. Compared to sintered bauxite it has lower strength and is used in closure stresses between 550 bar and 800 bar. ISP displays perfect roundness and sphericity, just like sintered bauxite (Belyadi, Fathi and Belyadi 2017).

Lightweight ceramic proppant (LWC) can withstand closure pressure of 400 bar to 700 bar. Although it is weaker than ISP or bauxite its specific gravity is approximately 2,72. Its fracture conductivity is much better than sand or resin–coated proppants, making is highly usable, even in high–permeable formations (Economides and Martin 2007).

4.4 Proppant Size

Depending on frac design there are different proppant sizes that can be used for successful production enhancement. After discussing different proppant types, the following are the most commonly used sizes of proppants.

100 mesh is designed to be placed in hairline cracks of the formation and is similar to baby powder since the mesh size is minimal. When starting a frack job 100 mesh is used to seal off microfractures and also to decrease leak–off through cracks. It provides a conduit for the upcoming bigger proppant by covering small microscopic cracks in the formation and erosion of perforation hence is highly recommended in naturally fractured formations. By traveling further into the formation its goal is to obtain as much surface area as possible since it is not designed for conductivity.

40/70 mesh is typically pumped after 100 mesh. Using them together creates the required fracture length for maximum surface area and some conductivity in fractures. Majority of the unconventional sand reservoirs use this combination of sizes.

Since 30/50 mesh is larger than 40/70 it has better conductivity providing more flow paths. 30/50 mesh is recommended in liquid–rich areas for better fracture conductivity near the wellbore. Generally smaller particles (40/70 mesh) penetrate deeper into the formation compared to bigger ones so using a combination of sizes is the best option for getting optimal conductivity and surface area.

20/40 mesh is usually the largest size used in fracking. Often used at the end of the pumping process to maximize near-wellbore conductivity. As mentioned before, to get the best production performance design has to be based on theory and simulation, each being different for a specific job and circumstance.

4.5 Proppant Characteristics

Having a knowledge of essential proppant characteristics is a must when designing the frac job. It also helps to understand why some proppant types are more expensive than others. Here are some that are important to know and monitor when possible.

Both roundness and sphericity are important proppant properties. While roundness is the measure of relative sharpness of the grain corners, sphericity is the measure of how round an object is or how closely the grain approaches the shape of the sphere. Improving them results in more even stress distribution and potentially increasing proppant pack porosity. In both roundness and sphericity, the American Petroleum Institute (API) recommends values of 0.6 or higher. The standard method for determining roundness and sphericity is the use of the chart as shown in Figure 4 (Belyadi, Fathi and Belyadi 2017).

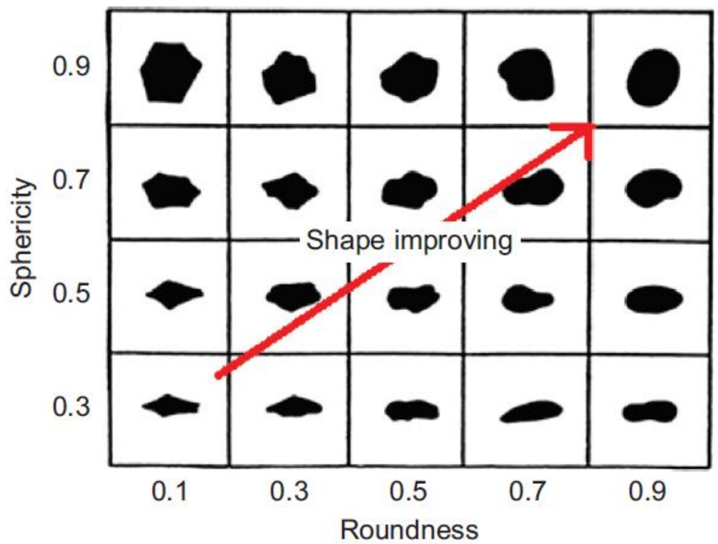

Figure 12: Visual estimation of roundness and sphericity (Belyadi, Fathi and Belyadi 2017)

Crush resistance measures the fines created under a given load (exposure to stress). Proppant can be tested in the lab by applying different stresses. By doing these tests (K–value testing) the percentage of fines produced under each specific stress is acquired. K–value is the closure stress (rounded down) under which 10% of the proppant will crush and become fines or out of the standard mesh size (Belyadi, Fathi and Belyadi 2017).

Bulk density describes a unit volume occupied by a given mass of proppant, including both the proppant and the void volume. It is used when determining the mass of a proppant needed to fill a fracture. Specific gravity represents the absolute density of individual proppant pellets divided by the absolute density of water. Generally, specific gravity is used to estimate proppant settling time, while bulk density is used to calculate transportation volumes and the actual volume of the fracture (Economides and Martin 2007).

Acid solubility is the solubility of proppant when used with 12% HCl or 3% HF acids. It determined the suitability of proppant which may come in contact with acids but can also indicate the amount of soluble content present in the proppant (Belyadi, Fathi and Belyadi 2017).

4.6 Proppant Transport and Distribution in Hydraulic Fracture

Proppant transport is an essential factor, when doing a frac design, to effectively place proppant in the pay zone. In the design, multiple sizes and concentrations of proppants are pumped down to the formation and are moving in both horizontal and vertical directions. While in horizontal direction proppant follows the fracture tip with the same velocity as fracturing fluid, in the vertical direction the proppant velocity is different than fluid velocity due to gravitational forces and slippage between fluid and proppant particles, i.e. settling velocity. Due to proppant particles settling, fracture width is filled and, consequently, the proppant concentration is increasing in the vertical cross section. If the critical proppant concentration is reached, beyond it screening out (sanding off) will occur. Screening out or rate of proppant bank growth is a function of proppant settling velocity (Belyadi, Fathi and Belyadi 2017).

Taking a more realistic proppant distribution prediction into account in hydraulic fracturing can help to optimize the design and maximize the efficiency of the frac job. Effect of proppant settling velocity on proppant distribution and fracture conductivity can, if ignored, lead to overestimation in dimensionless productivity index. So using the right proppant size can lead to highest hydraulic fracturing efficiency, especially in low permeability formations, as shown in Figure 13 (Kong, B., Fathi, E. and Ameri, S. 2015).

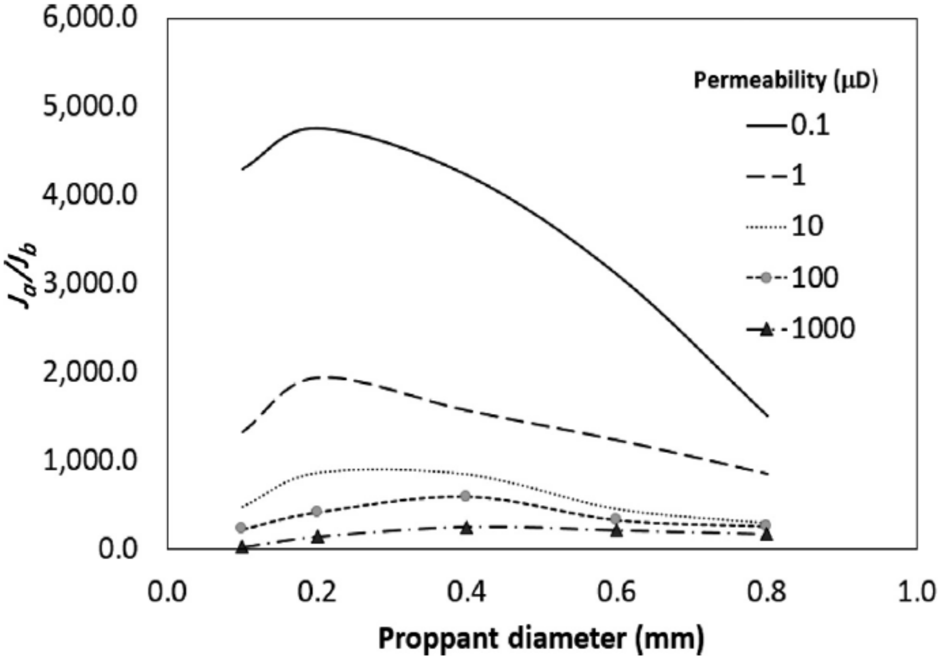

Figure 13: Effect of proppant size in dimensionless productivity index for different reservoir permeability (Belyadi, Fathi and Belyadi 2017)

4.7 Fracture Conductivity

Being considered in every aspect of hydraulic fracturing makes fracture conductivity one of the most critical elements of design. It is defined as a fracture width (w_f) times proppant permeability inside the fracture (k_f) and is basically a measure of how easily fluids flow through a fracture to the wellbore. Therefore, it is also referred to as flowback capacity. Since permeability and conductivity change with different stresses, as closure pressure increases, conductivity decreases.

Factors that affect fracture permeability are usually proppant size, sphericity, fines, strength and gel damage. Also, factors that affect fracture width are proppant density, proppant loading, gel filter cake, and embedment. Usually for each type of proppant, the manufacturer provides a chart that shows fracture conductivity vs. closure pressure (Belyadi, Fathi and Belyadi 2017).

4.8 Dimensionless Fracture Conductivity

Dimensionless fracture conductivity, F_{CD}, is a measure of how conductive the fracture is compared to the formation. It is defined in Equation. 1 as the ability of fracture to transmit reservoir fluid to wellbore divided by the ability of the formation to transmit fluid to the fractures.

Equation 1: Dimensionless Fracture Conductivity

$$F_{CD} = \frac{k_f w_f}{k x_f} \tag{1}$$

Where k_f= fracture permeability, mD, w_f= fracture width, m, k= formation permeability, mD, and x_f= fracture half-length, m.

The recommended proppant selection workflow is shown in Figure 15.

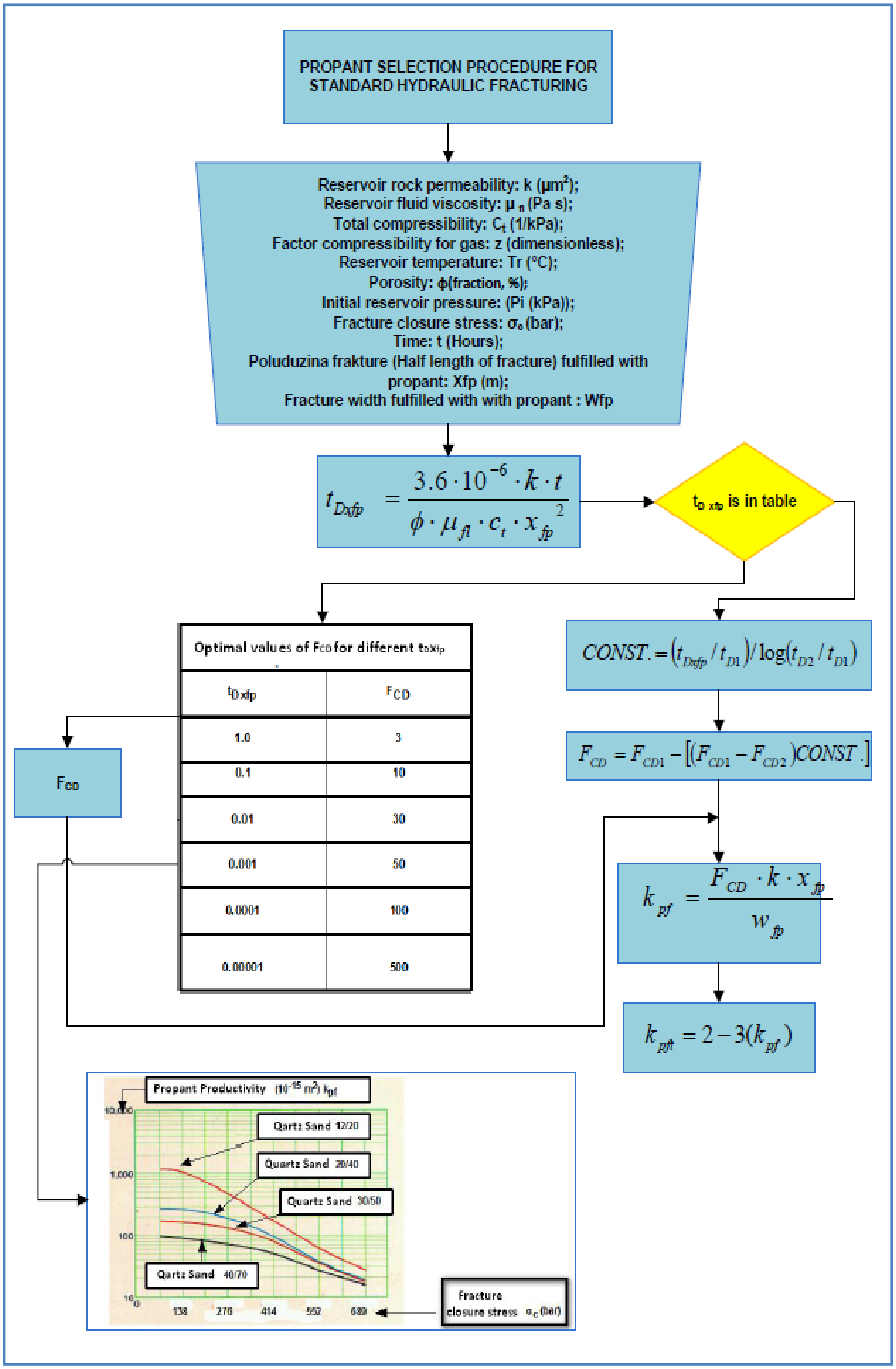

Figure 14: Proppant selection workflow

Chapter 5 Frac Fluid Chemicals

Selecting the right chemicals for a hydraulic fracturing job is jet another vital aspect of its design. Getting the right type and concentration of chemicals makes the frac successful and profitable. Chemicals that are used are highly priced, that's why companies have invested a lot to find the optimal chemical design and make sure they are environmentally friendly to not harm the public health, safety and environment. The amount of chemicals used in hydraulic fracturing is not vast, and here the most common ones will be discussed.

The purpose of fracturing fluids is basically:

- To transmit the pressure from the surface to the bottom of a well, to initiate a fracture,
- To hydraulically extend (or propagate) the fracture into the formation,
- To transport and distribute the proppant along the fracture, and
- In acid fracturing, to create unevenly etched flow channels.

The fluids selected for a fracturing treatment can have a significant influence on the resulting propped fracture length and fracture conductivity. Fluids that leak-off rapidly into the formation will not extend the fracture to the desired length and may result in a premature screen-out. Moreover, if a significant amount of residue of the gelled fracturing fluid remains either in the proppant pack, and/or as a filter cake at the fracture face, the fracture conductivity and production performance of the fracture may be considerably less than the design value.

When choosing a fluid, it is important to take into consideration the well bottomhole static temperature and formation properties. Some conditions to consider are: water sensitivity, low reservoir pressure, extra viscosity required, high proppant pack conductivity, short length (< 90 m /300 feet), and low conductivity. These should not be the only factors used in making a decision.

5.1 Friction Reducer

Friction reducer (FR) is the most essential chemical used in fracturing with water-based fluids. It is a type of polymer that reduces friction between fracturing fluids and tubular. But it will not only reduce the friction and horsepower needed for the pumping operation, but also preserve the equipment from wear and tear resulting from high rates of this operation. Most typical FR is polyacrylamide, with cationic, anionic and nonionic types. When selecting FR there are few things to consider: quality of FR (different supplier, different quality), the salinity of used water (fresh water needs less FR, while high salinity one needs higher concentrations) and chemistry of the water (Belyadi, Fathi and Belyadi 2017).

5.2 Gelling Agents

Fracturing fluids main job is to place proppant in the formation. When gelling agent is used, a linear gel is created, the viscosity of frac fluid increases, friction reduces and proppant transport into the formation is improved (Figure 15). With higher viscosity the fracture width increases, and proppant can be placed more easily into the formation, which is especially important for higher sand concentrations. Further, fluid-loss control is increased with the use of gelling agents. The most common polymer types used as gelling agents are guar (raw guar contains 10-13% insoluble residue), hydroxypropyl guar (1-3% insoluble residue), carboxymethyl hydroxypropyl guar (1-2% insoluble residue), hydroxyethyl cellulose (minimum residue), and polyacrylamide (FR, minimum residue). Generally, having less residue means a more refined gelling agent, correspondingly being more expensive (Belyadi, Fathi and Belyadi 2017).

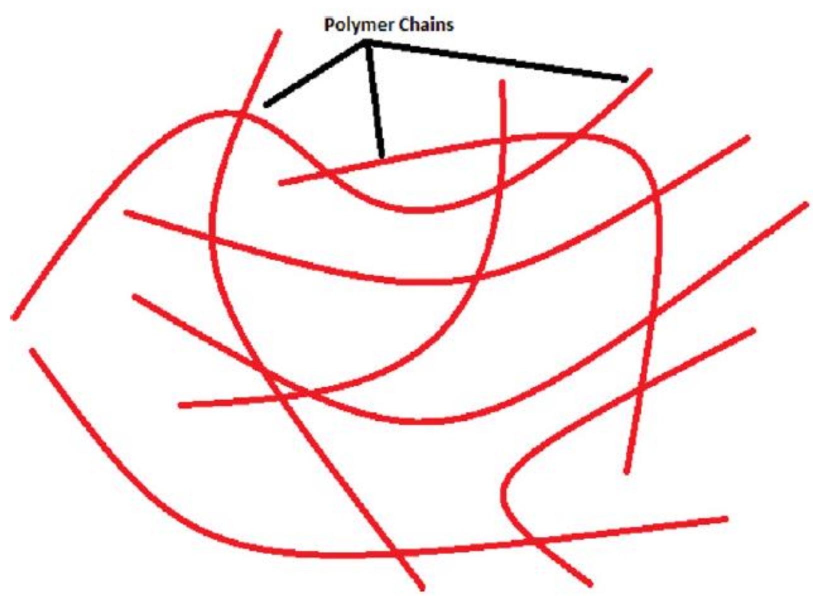

Figure 15: Linear base gel (Belyadi, Fathi and Belyadi 2017)

5.3 Biocides

With the use of natural polymers there is a high a chance for bacteria to form. Since they are a food source for them, they degrade the polymers, and cause instability in viscosity and even turn reservoir fluids sour. Biocide is added to the water in the tanks to kill or prevent the growth of the bacteria. The most common and cost-effective biocide used in hydraulic fracturing is glutaraldehyde. The best way to use biocide is to sterilize treatment water before adding the polymer rather than removing the already existing one (usually too late to save the tank of gel) (Economides and Martin 2007).

5.4 Buffers

Buffers have various uses in fracturing fluids. Their primary use is to control the pH of the gel, but they also help polymers to disperse in the water and in gel hydration properly. Having a consistent pH is crucial for cross-linking of polymers and its stability. Depending on the pH needed for the base fluid, there are two types of buffer solution, acidic buffer (acetic acid) and basic buffer (potassium carbonate) (Belyadi, Fathi and Belyadi 2017).

5.5 Cross-linker

Using a cross-linker chemical is the most economical way to increase the viscosity of fracturing fluid without using a more gelling agent. It increases fluid viscosity by connecting separate gel polymers together and increasing their molecular weight. The biggest disadvantage of cross-linkers is that they also increase friction pressure, nevertheless they improve proppant carrying ability and wider fracture geometry. Most popular cross-linkers are borate (used in high pH and moderated temperatures) and zirconium (used in low pH and high temperatures). Figure 16 shows how cross-linkers link polymer molecules together (Economides and Martin 2007).

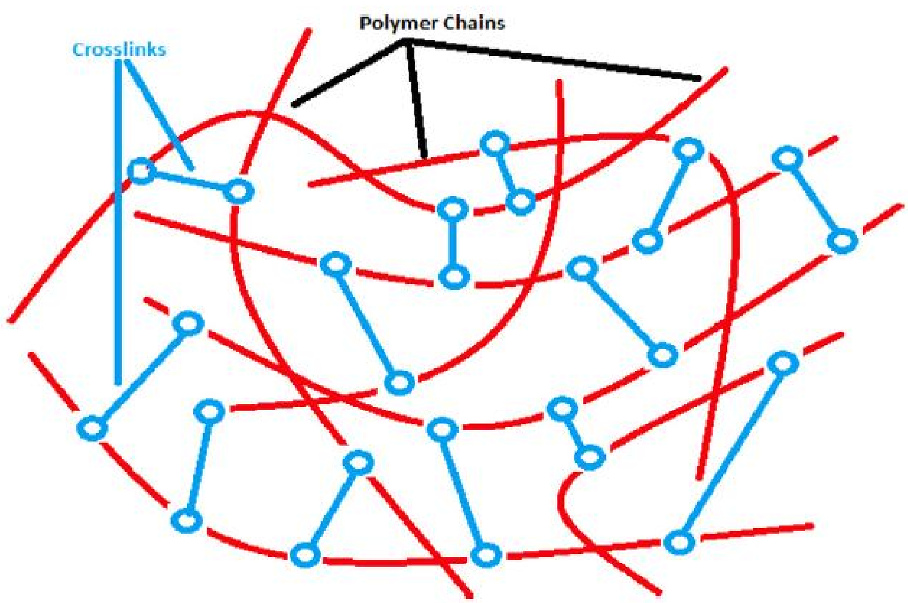

Figure 16: Cross-linked gel (Belyadi, Fathi and Belyadi 2017)

5.6 Gel Breaker

Pumping gel breaker along with the rest of the agents will cause the gel to break once it has been placed into the formation. It will "break" (reduce) the viscosity of the fracturing fluid and help in cleaning the proppant pack and the filter cake. The quality of gel reduction will depend on gel breaker type, temperature, time, pH and gel and breaker concentration. If the gel doesn't break properly in the formation it can seriously reduce conductivity. That's why the test is done prior to the pumping stage to ensure they will reduce viscosity after reaching reservoir conditions (Belyadi, Fathi and Belyadi 2017).

5.7 Surfactants

Surfactants have many different applications when used in fracturing fluids. The primary application is to reduce the surface tension of the liquid. A microemulsion is a type of surfactant that is used to change the contact angle of the leak-off fluid. By also changing the wettability of the fluid to the formation rock, it reduces surface tension, which results in more fluid recovery during flowback, especially in tight gas. Another important one is nonemulsifier, that reduces the interfacial tension between formation and treatment fluid, thus preventing forming of emulsions. It is mostly used in oil or condensate formations where it separates oil or condensate from an aqueous emulsion (Belyadi, Fathi and Belyadi 2017).

5.8 Clay Stabilizers

By injecting low-salinity water and acid solutions, hydration of clay can be expected. Also, even though there are many non-swelling clays in formations, they tend to migrate in sandstone formations and stick to narrow pore throats, leading to a considerable reduction of permeability. With the use of clay stabilizers like, ammonium chloride or zirconium chloride, hydrate polymers are formed in water that adsorb on the clays and binds the particles to the sand-grain surface, thus preventing swelling (Donaldson, E. C., Alam, W. and Begum, N. 2013).

5.9 Temperature Stabilizers

As mentioned before, all the polymers that are used to "thicken" frac-fluids are sensitive to pH, especially at high bottomhole temperatures. Therefore, by maintaining the pH values between 8 and 10 stability is enhanced by removing the presence of hydrogen ions. Oxygen (from mixing and storage operations at the surface) is also harmful to polymers as the temperature of the fluid rises. By using sodium thiosulfate and methyl alcohol fluid is more stable when fracturing deep formations (Donaldson, E. C., Alam, W. and Begum, N. 2013).

5.10 Fluid selection

The fluid selection chart in Figure 17 is used to see from where to start the process of selecting the most appropriate fracture fluid. Choose a fluid that will give large conductivity and the lowest polymer damage. Optimize according to the leak-off coefficient, retained factor, whether or not flowback is in the design, good clean-up, Bottomhole Static Pressure (BHSP), Bottomhole Pressure (BHP), formation sensitivity, friction data, and formation permeability (k).

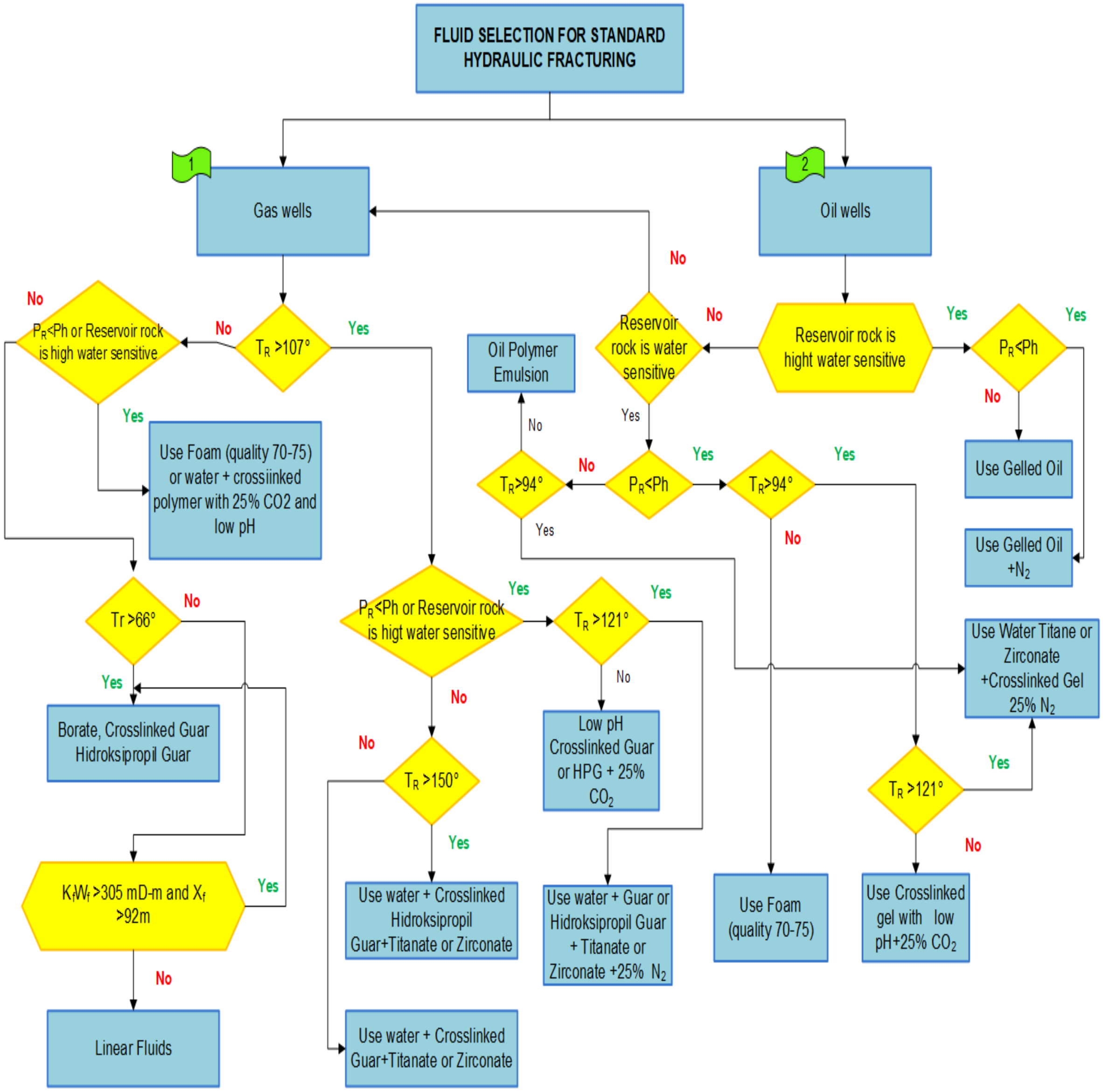

Figure 17: Fluid selection workflow

Chapter 6 Fracture Pressure Analysis

Like many other drilling, completion, and reservoir behaviour problems, hydraulic fracturing cannot be observed directly. That is why understanding pressure is one of the most critical aspects of the successful frac operation. Similar to describing reservoir behaviour, analysis based on wellhead pressure and flow rate, are used to understand what is happening in the wellbore and more importantly in the formations. Here, along with types of pressure, the procedures for testing and analysing will be described.

6.1 Types of Pressure

Since pressure is encountered in almost every step of hydraulic fracturing it is important to distinguish different types of it. Here we will introduce most of them and explain the idea behind their names, how they are measured or what the pressure is doing:

Hydrostatic Pressure, p_h. Also referred to as hydrostatic head or fluid head. This pressure is the pressure of the liquid column exerted in static condition due to its density, depth and gravity.

Wellhead Pressure, p_{inj}. Also referred to as WHP, injection pressure or surface treating pressure. It is the pressure at the top of the well, at its wellhead, during a hydraulic fracturing treatment. It is measured by pressure gauges of the wellhead fittings. It is also pressure against which the frac pumps must act.

Pipe Friction Pressure, $p_{pipe\ friction}$. Also referred to as wellbore friction pressure or tubing friction pressure. This pressure loss occurs as a result of friction effects in the wellbore while fluids are injected. It is greatly influenced by fluid density and is proportional to the pumping rate.

Bottomhole Treating Pressure, p_{bhtp}. Also referred to as BHTP or bottomhole injection pressure. This pressure is located downhole, in the wellbore, along the fracture face that keeps the fractures open. It can be calculated from surface data using Equation. 2.

Equation 2: Bottomhole Treating Pressure

$$p_{bhtp} = p_{inj} + p_h - p_{pipe\ friction} \tag{2}$$

Perforation Friction Pressure, Δp_{pf}. This pressure loss is due to fracturing fluid passing through the restricted flow area of the perforations.

Tortuosity Pressure, Δp_{tort}. Also know tortuosity, is a pressure lost by fracturing fluid between the perforations and main fracture(s) due to region of restricted pathways.

Near-Wellbore Friction, Δp_{nwb}. This is equal to total pressure loss due to near-wellbore effects and is equal to the sum of tortuosity pressure plus perforation fracture pressure.

Instantaneous Shut-In Pressure, p_{isip}. Also known as ISIP. Immediately after pumps come offline following a hydraulic fracturing stage or usually after doing a Minifrac, the ISIP is obtained, so that effects of all fluid friction-based pressure losses have gone to zero. The best way to get it is by using a surface treating pressure graph which will be shown later.

Closure Pressure, p_c. It is the minimum pressure required inside fractures to keep them open. It is also the pressure exerted by the formation on the proppant. For a single layer, p_c is usually assumed to be equal as the minimum horizontal stress. It can also be determined from a step-rate test and minifrac.

Fracture Extension Pressure, p_{ext}. This pressure is inside of the fracture(s) and is required to make the fracture grow. It is always higher than p_c in order to keep the fracture open so it can gain its length, height and width. Extension pressure will vary with fracture geometry and it can also be determined from the step-rate test.

Fracturing Fluid Pressure, p_f. This is a pressure of the fracturing fluid after it has progressed through the perforations and tortuosity. Due to friction effects it is not constant over the entire fracture.

6.1.1 Net Pressure

Considered one of the most essential pressures to look out for when doing a hydraulic fracturing job. Net pressure (p_{net}) is the energy in the fracturing fluid needed for propagating the fracture and increasing its width. It refers to excess pressure in the fracturing fluid inside the fracture, above the need to just keep the fracture open. When used in analysing fracture geometry, it is just inside the fracture and immediately beyond the wellbore. Essentially it is the difference between the fracturing fluid pressure and closing pressure but can also be defined as seen in Equation 3.

Equation 3: Net pressure

$$p_{net} = p_{bhtp} - \Delta p_{pf} - \Delta p_{tort} - p_c \tag{3}$$

Propagation of the fracture to produce length and height is also defined by it. The condition $p_{net} > p_{ext}$ must be satisfied in order to propagate the fracture, which means that net pressure has to be high enough to induce stress in formation to split the rock.

6.2 Nolte-Smith Analysis

Nolte and Smith (1979) proposed a method for analysing the pressure response of a formation during pumping, so that fracture geometry which is being produced can be interpreted from it. During a live frac stage treatment, if net pressure (y-axis) versus time (x-axis) is drafted on the log-log plot, a net pressure chart is obtained. With it, different fracture propagation behaviours can be estimated by observing pressure trends. Figure 18 shows possible net pressure during the treatment and Table 1 explains the modes.

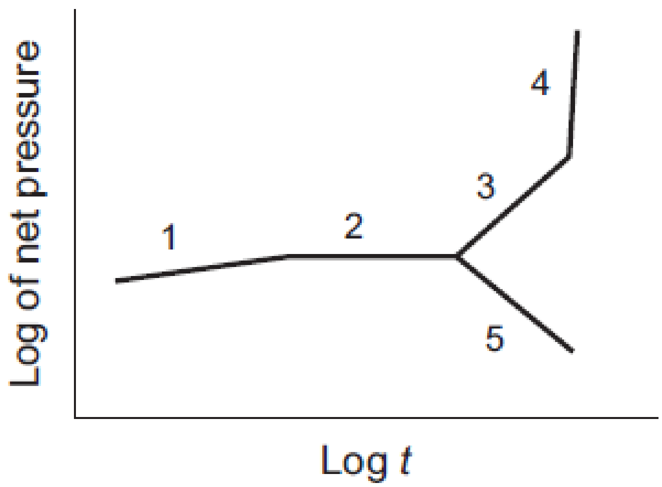

Figure 18: Nolte-Smith analysis pressure response (Belyadi, Fathi and Belyadi 2017)

Mode	Behaviour
1	If the pressure response is similar to mode #1, it indicates confined height and unrestricted length extension during the treatment (slope is slightly positive).
2	If the net pressure is constant (mode #2), it means that height is contained and length extension is less effective, or possible opening up more fractures with fluid loss, or both.
3	In mode #3 p_{net} is directly proportional to time. This indicated that formation is giving up and it is highly likely a sand-off (tip screen-out) will occur if sand is not cut on time.
4	Mode #4 is a full sand-off, indicated by a rapid rise in pressure. Pumps should be turned off so that increased pressure does not damage equipment and casing.
5	Mode #5 shows a negative slope. It indicates rapid growth of fracture height.

Table 1: Nolte-Smith Analysis pressure response modes (Economides and Martin 2007)

6.3 Formation Breakdown Test

The formation breakdown test is one of the easiest injection type tests to do. It is performed by pumping the fluid until the formation breaks. Once it breaks, the pumping is stopped and ISIP is taken from the pressure chart. Additionally, formation fracture pressure can be taken roughly. This test is not really reliable and is not usually done with frac fluid but with treated or normal water.

6.4 Step Rate Test

Step rate test (SRT), together with minifrac, is a type of calibration test. The tests are performed by fluid injection before the actual frac, and their purpose is to collect data that will improve fracture simulation and thus provide a more accurate prediction of fracture geometry. There are two types of step rate test, step-up test and step-down test, usually done one after the other.

The step-up test (SUT) is used to determine the fracture extension pressure (p_{ext}). Fracture extension pressure is also an upper boundary of closure pressure. The test is performed with the fracture initially closed, by starting with the lowest possible flow rate a pump can handle. Once the desired pump rate has been reached, pressure needs to stabilize and then the exact rate and pressure are recorded. After the rate and pressure are recorded, the pump rate has to be increased, the stabilized pressure is recorded, and the procedure has to be repeated at each increased pump rate stage. It is more important to get stabilized pressure then exact rates. Recorded BHTP against slurry rate is plotted to determine the fracture extension pressure, as shown in Figure 19.

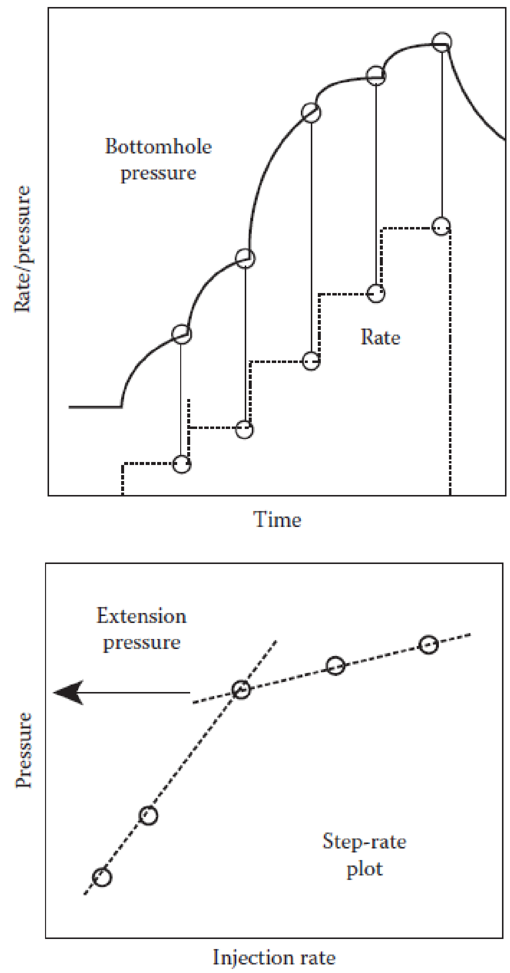

Figure 19: Typical pressure versus rate cross-plot from a step-up test (Montgomery and Smith, Hydraulic Fracturing 2015)

Step-down test (SDT) is usually performed right after SUT. It is conducted in order to quantify perforation and tortuosity near-wellbore losses and provide information for the execution of the main frac. Opposite to the step-up test, SDT starts with the fracture open and is conducted quickly in order to keep the fracture open through the whole test. The injection rate is then reduced in a stair-step pattern, with each step lasting equally. By analysing the pressure losses at different pump rates, we can distinguish between losses due to tortuosity and due to perforations, and with that acquire information related to perforations (Economides and Martin 2007).

6.5 Minifrac

The Minifrac is also called Diagnostic Fracture Injection Test (DFIT), Pump-in/Decline test exc., depending on the operator, service company or injected volume. It is a type of calibration test, which is designed to be as close as possible to the actual fracing treatment, but without using any proppant. Thus, Minifrac should be pumped with the treatment fluid, at the rate expected for the main treatment, and it should have enough volume to contact all the formations that the expected main frac design is anticipated to contact. If the Minifrac is conducted appropriately, it will provide data on rock mechanical properties, fracture geometry and fluid leak off, which are crucial for conducting the main treatment.

6.5.1 Minifrac Procedure

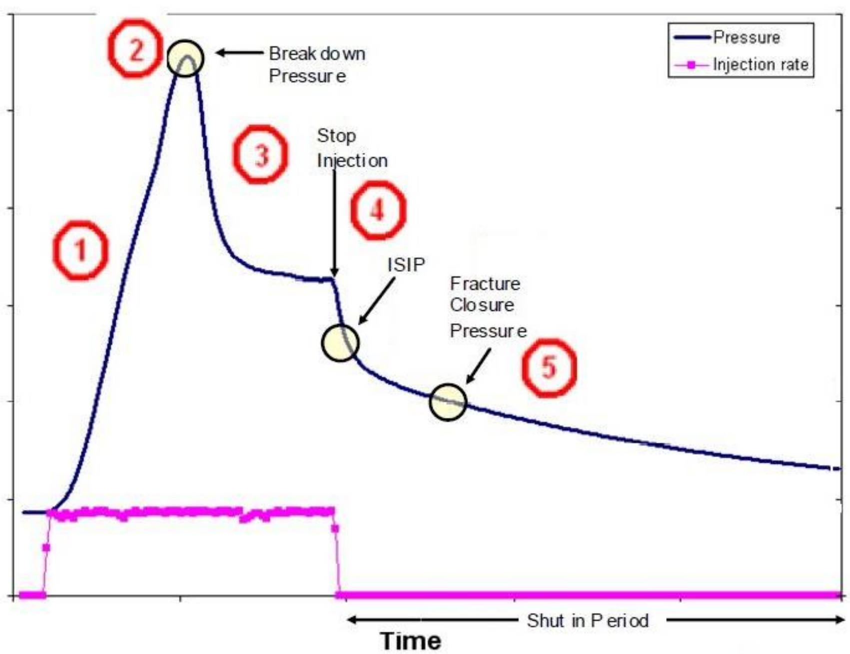

Figure 20: Typical Minifrac job plot, showing pressure response and rate (Nguyen and Cramer 2013)

First, the well needs to be filled with water, with special care to remove any remaining gas and air.

Then, a typical Minifrac sequence follows as shown in Figure 20:

1. A surface pump establishes a constant injection rate during which pressure on formation rises.
2. After some time, formation breakdown pressure is reached, indicating that a hydraulic fracture is being propagated into the formation.

3. Injection of treatment fluid continues, and wellhead pressure is stabilized or changes slightly.
4. After reaching desired volume, surface injection is stopped, which results in instantaneous shut-in pressure (ISIP).
5. The pressure decline is then monitored for signs of fracture closure pressure.

6.6 Pressure Data Analysis

As previously mentioned, using the shape of pressure versus time plot during pumping gives a lot of information about fracture geometry. Using Nolte-Smith analysis gives an idea of how the fracture propagates in terms of height, length and even width. However, this analysis is not very accurate. The best way to obtain better information about fracture geometry is to perform a pressure match which will be discussed later.

Another important part of pressure analysis comes after the end of pumping. The analysis of data from pressure decline up to fracture closure provides the following information:

- Near-wellbore friction assessment-difference between, p_{bhtp} (BHTP) and, p_{isip} (ISIP).
- ISIP. When the pumps shut down, and all friction goes to zero; p_{isip}=p_{f} − the pressure of the fluid inside the fracture.
- Fracture closure pressure (p_{c}). It can be seen as a change in the pressure gradient on the decline plot. Usually it is hard to spot so there are different methods that help with this.
- Net pressure (p_{net}). Is the difference between p_{isip} and p_{c}.
- Fluid leakoff (efficiency). When the closure pressure is recognized, closure time, together with fractur area gives the leakoff rate, an, thus, the leakoff coefficient.

Workflow shown in Figure 21 gives detailed sequences of HF data preparation and required test for planning, designing and execution of HF operation.

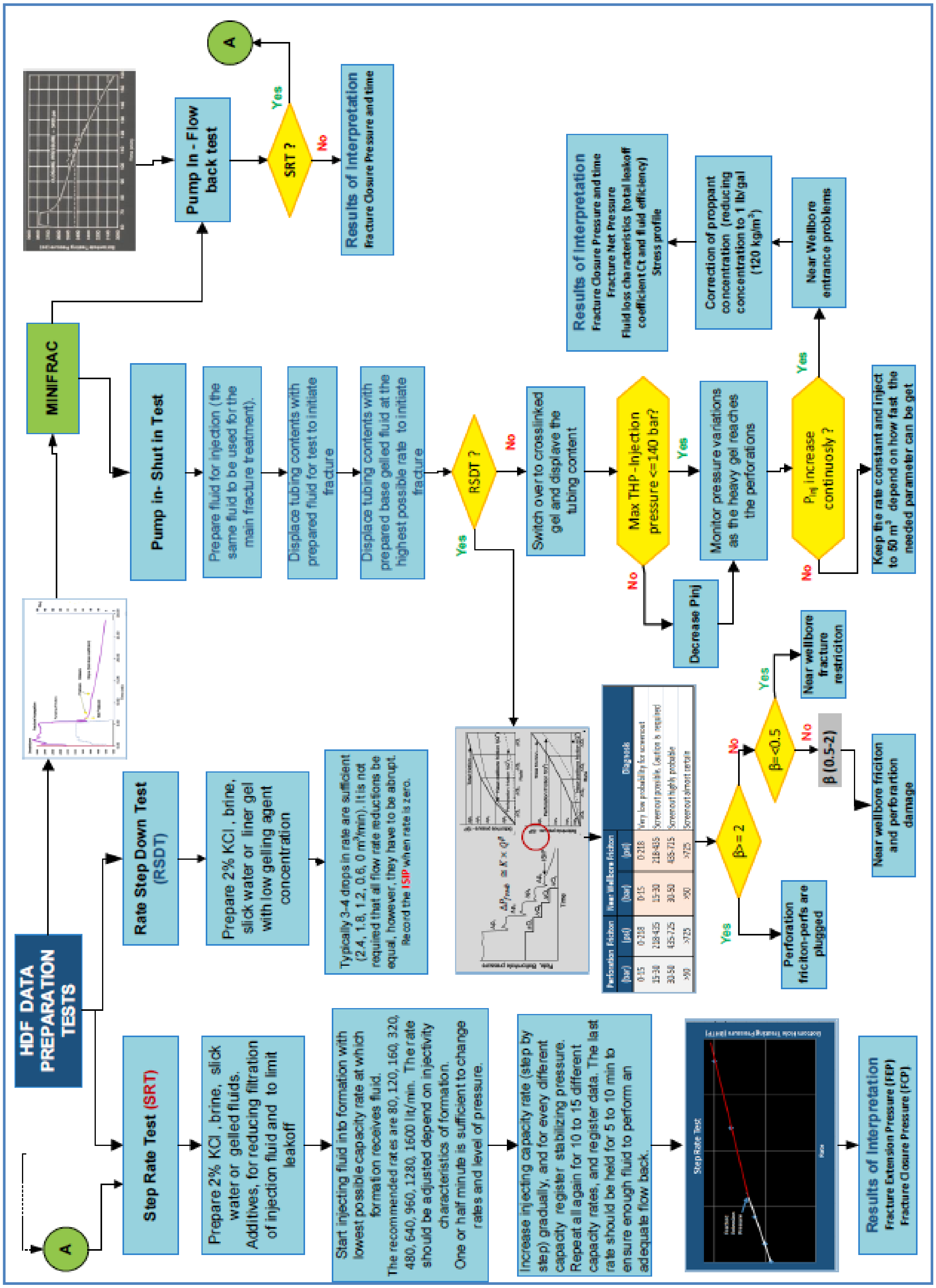

Figure 21: HF data preparation workflow

6.6.1 G-Function Analysis

Nolte (1979, 1986) introduced a method for analysing pressure decline that is used with three models (PKN, KGD and radial). It uses the G function, $G_c(\Delta t_D)$. G-function is a function related to dimensionless time. When plotted against pressure it is used to identify fracture closure, fracture geometry, fluid leak-off and leak-off mechanism.

G-function at shut-in (ISIP) is equal to zero, therefore, every plot starts from then. Using the derivative of pressure decline helps in finding the closure pressure. Ideally, the closure occurs when the pressure decline (or derivative) curve deviates from a straight line. At this point $G_c(\Delta t_{D)} = G_c$. Using G_c with different equations allows assessment of various parameters, like fluid efficiency, fracture length and fracture width. But today, with use of fracture simulators, most of the plots can be plotted on the computer and calculated with minimum effort (Martin 2005).

In Figure 22 a normal leak-off type mechanism of G-function can be seen. There are three other leak-off types: pressure-dependent leak-off, height recession leak-off, and fracture tip extension. They depend on the type of rock, reservoir conditions and behaviour of the fluid. The easiest way to differentiate them is by G function plot shape but that will not be discussed here (IHS Markit 2014).

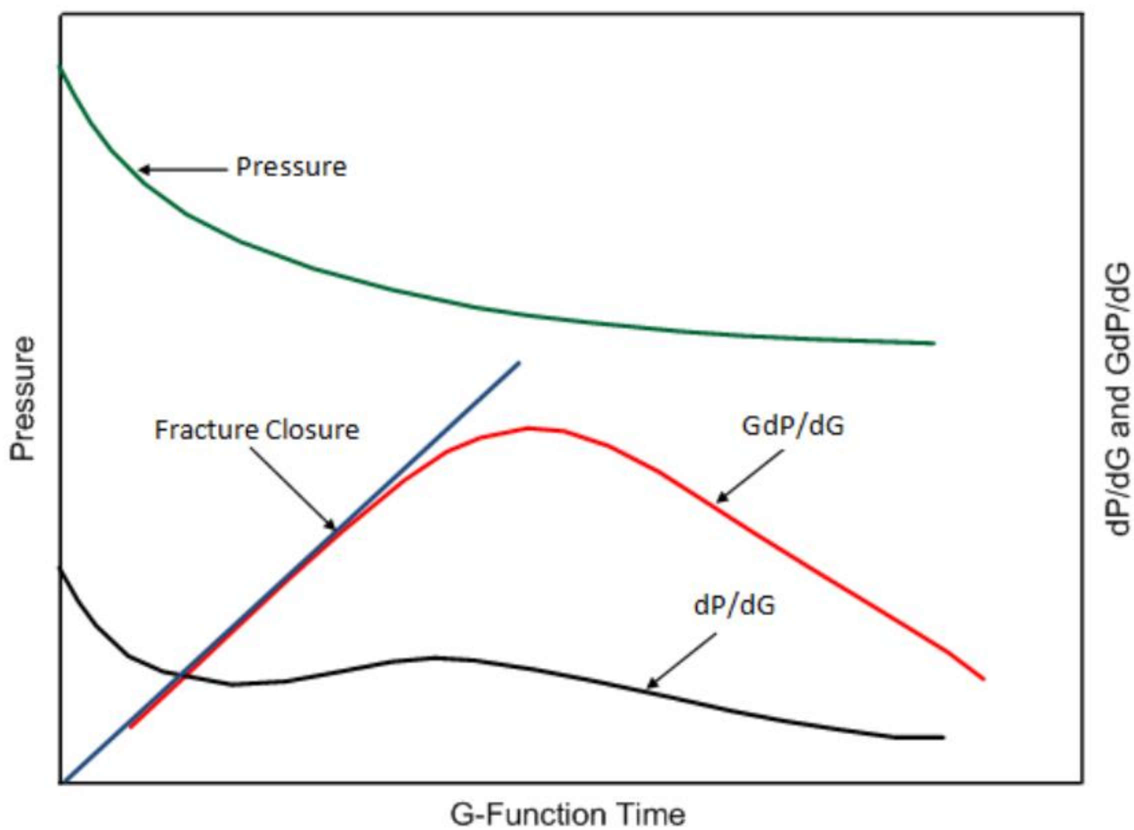

Figure 22: Normal leak-off - pressure versus G-function time plot (IHS Markit 2014)

6.6.2 Pressure Matching

Another known method for analysing pressure data is known as pressure matching. The simulated results of HF, the engineer will use to reproduce the same pressure response as the reaction which is produced by the formation. For better understanding of rock mechanisms properties and fracture mechanisms, the good knowledge of fracturing process is vital in order to perform a quick and efficient pressure match.

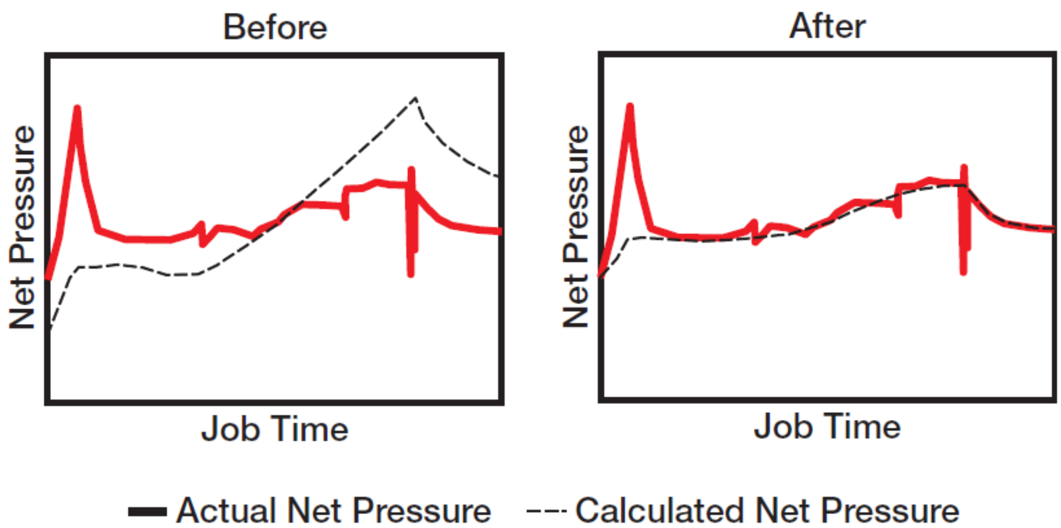

Figure 23: Pressure matching (Economides and Martin 2007)

In Figure 23, it can be seen before pressure match net pressure (left), where the simulator does not match the actual net pressure, and after pressure match has been performed (right). After a matching is done, the simulator is adjusted to the formation. This will allow putting any desired treatment schedule, and the simulator will predict the fracture geometry with a justifiable degree of precision.

The pressure match process involves the fine-tuning of four primary variables in each formation affected by the fracture. These variables are stress, Young´s modulus, fracture toughness and fluid leak-off. Including them, there are many other minor variables that help match the pressure. This means that there are more similar solutions to one pressure match (Economides and Martin 2007).

Chapter 7 Case Study

In this chapter an exploration well, which was drilled in the exploration field of Drava basin in north part of Croatia by INA company, is analysed. The well has discovered hydrocarbon potential but due to low production, it did not meet the economic criteria for declaring a commercial discovery and commissioning a well for production. Therefore, the decision was made to do a hydraulic fracturing enhancement on one of the perforated intervals and improve its production parameters and thus commission it for production. Furthermore, hydraulic fracturing will be the main focus. The procedure of hydraulic fracture modelling with the use of hydraulic fracture simulators (MFrac and FracCAT) will be explained. Finally, before the case study conclusion, the evaluation of hydraulic fracturing enhancement results will be carried out to show potential production increase and its effectiveness.

Because of the non-disclosure agreement signed between INA and the author, the name of the actual well and the name of the field will be assigned with new names.

7.1 Introduction

Exploration prospect S is located in exploration area DR-02 on the north part of continental Croatia, Figure 24, and was distinguished on the basis of structural-geological interpretation of a wider area, on 3D seismic data. The observed structural trap – S has been interpreted in detail, with analogous data of nearby exploitation fields (EF) M, K and F. Based on the borehole data of the surrounding exploitation fields, a gas/water contact at a depth of 3220 m was assumed, resources were evaluated, and production profile and an economic evaluation of the prospect were made.

Based on the analysis, an exploration well S-1 was located, which aimed to determine the gas reservoir in the Miocene biocalcanites and dolomite breccias, which are assumed to form a single hydrodynamic unit, analogous to the deposits of the surrounding exploitation fields (M and K). Contact gas/water was supposed to be at 3220 m. The estimated final depth of well S-1 was decided to be 3400 m +/- 100 m.

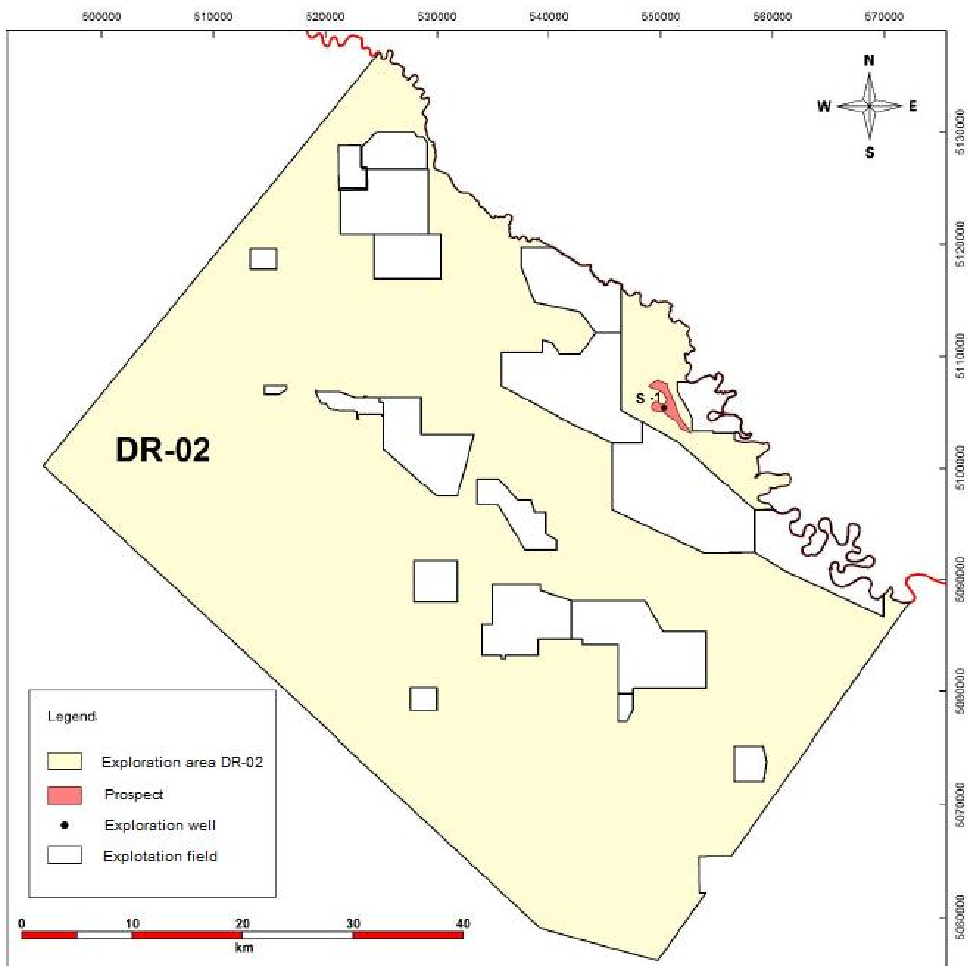

Figure 24: Location map of exploration prospect S in exploration area DR-02 (INA ltd. Source 2019)

Exploration well S-1 was made according to the geological project at the site defined by the results of the structural and geological interpretation of the 3D seismic measurements and analogy of nearby fields. The exploration well has drilled the planned deposits to the bottom of limestone and marl layers, up to a final depth of 3410 m. After geological monitoring and analysis of well logging measurements, hydrocarbon potential was discovered. One core was extracted from the potential hydrocarbon zone and four intervals of interest were perforated and tested. The test results provided insight into the initial pressure and temperature of the reservoir, fluid composition, and hydrodynamic characteristics of well and reservoir. Due to poor permeable nature of the reservoir, the shallowest tested interval was subjected to stimulation.

7.2 Interpretation of Geological and Petrophysical Data

The main task of the borehole was to drill and test the gas and condensate reservoir in the DR-2 exploration area of the Drava basin.

The well met the target and confirmed hydrocarbon potential at 3288 m, in limestones of poor reservoir properties.

The basic petrophysical analysis and measurement of the core from the S-1 well showed low porosity values of 2,16 to 9,31%, exceptionally 15,56% and with absolute permeability 0,04 to 0,59 mD, with a maximum of 3,14 mD measured.

The petrophysical parameters of the prospect were estimated on well logging analysis over the entire interval of the drilled reservoir. Also, a core was retrieved (J-1) in the interval of lithofacies III at 3293-3302 m. Which, together with the analogy of neighboring EF M, helped further improve the accuracy of parameters.

The petrophysical characteristics of each interval from the analysis are shown in Table 2.

Interval 4				
Cut Off Por.	None	1	2	3
Thickness (m)	39,976	17,48	9,652	5,472
Net/Gross (m)	1	0,437	0,241	0,137
Avr. Por	1,291	2,589	3,54	4,433
Avr. S_w	82,347	79,866	74,001	66,338
Interval 3				
Cut Off Por.	None	1	2	3
Thickness (m)	7,98	7,98	7,98	7,752
Net/Gross (m)	1	1	1	0,971
Avr. Por	4,993	4,993	4,993	5,054
Avr. S_w	57,458	57,458	57,458	56,829
Interval 2				
Cut Off Por.	None	1	2	3
Thickness (m)	3,04	3,002	2,508	1,444
Net/Gross (m)	1	0,988	0,825	0,475
Avr. Por	2,739	2,762	2,972	3,411
Avr. S_w	2,697	62,515	59,884	56,117
Interval 1				
Cut Off Por.	None	1	2	3
Thickness (m)	4	3,572	2,204	0,722
Net/Gross (m)	1	1	0,617	0,202
Avr. Por	2,444	2,444	2,926	3,855
Avr. S_w	83,059	83,059	80,646	78,131

Table 2: Analysis of tested intervals of well S-1 (INA ltd. Source 2019)

7.3 Well Testing Results of S-1 Well

Based on the results of the petrophysical interpretation, well testing was conducted (Int. 4 initially agreed from 3298 to 3305 m but subsequently expanded to 3288-3328 m). The goal was to determine the initial pressure and temperature of the reservoir, and productive and hydrodynamic characteristics of the well and reservoir. Figure 25 shows chosen intervals.

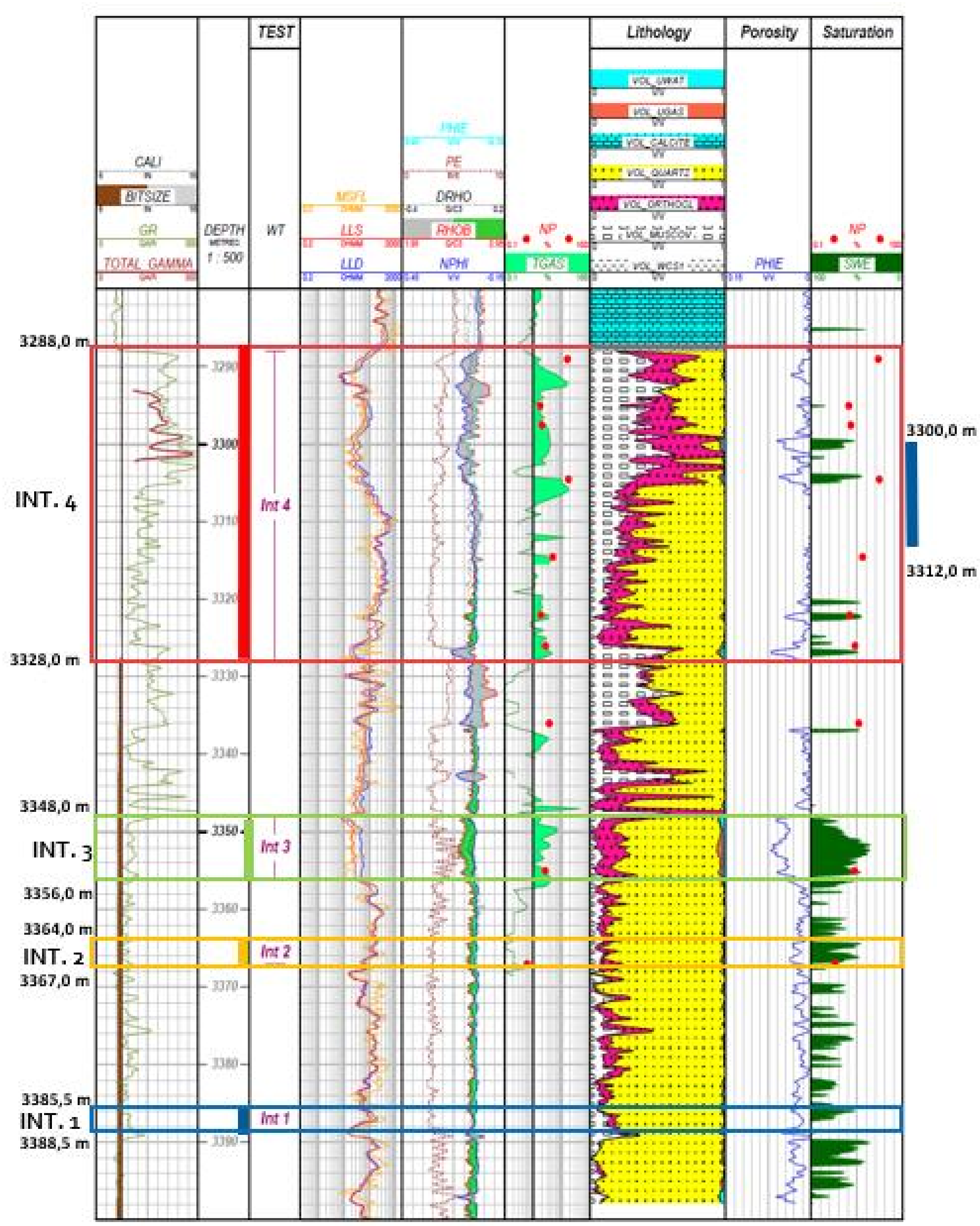

Figure 25: Well logging data with four intervals (INA ltd. Source 2019)

<u>The first tested interval</u> is located from 3385,5-3388,5 m. The pressure at the depth of 3388 m was 399,46 bar and the temperature 182,9 °C. At the length of 3387 m the gradient was 0,95 bar/10 m, and the pressure was 401 bar. At 77% of the depression on the layer, the well

was producing 4325 m^3/d of gas and 20,3 m^3/d of water. The interval is located in the transition zone of gas/water contact. The pressure increase was not completed. The results (permeability and skin) were adjusted to increase the pressure of the third interval. The first interval was isolated by installing a mechanical plug at a depth of 3380,5 m.

The second interval (3364-3367 m) did not produce any gas and the pressure at the wellhead was 0 bar during the test. The interval is impermeable, so it is an insulator. The second interval was isolated by installing a mechanical plug at a depth of 3362 m.

The third interval (3348-3356 m) is in gas saturation. 20 000 m^3 of gas/d, condensate and water vapor were obtained. The condensation was 80 cm^3/m^3 while the water content in gas is 85 cm^3/m^3. The well has produced with a high drawdown of as much as 93%. The third interval was also isolated by installing a mechanical plug at a depth of 3340 m.

After perforation, the fourth interval (3288-3328 m) has been tested and no increase in pressure at the wellhead was observed. The pressure was dropped from 100 bar to 0 bar. Gas was burned at the torch but the pressure at the inlet was 0 bar. The estimated gas quantity was about 1000 m^3/d.

The dynamic gradient in the well was measured. The interval is almost impermeable or has major damage at the near wellbore zone. The pressure buildup has not stabilized. It was interrupted in the area of subsequent inflow. At the mechanical plugs 3340 m peak, a cement plug was installed up to 3336 m. Within the perforated fourth interval, only 12 m is reperforated from 3300 to 3312 m.

Interval 4				
Top int. (m)	Bott. Int. (m)	Int. (m)	Type fluid	Production
3288	3328	40	gas	Q_{gas}= cca. 1150 m^3/d
Interval 3				
Top int. (m)	Bott. Int. (m)	Int. (m)	Type fluid	Production
3348	3356	8	gas/con.	Q_{gas}= cca 20 000 m^3/d Q_{con}=1,6 m^3/d
Interval 2				
Top int. (m)	Bott. Int. (m)	Int. (m)	Type fluid	Production
3364	3367	3	gas	very low permeability
Interval 1				
Top int. (m)	Bott. Int. (m)	Int. (m)	Type fluid	Production
3385,5	3388,5	3	gas/water	Q_{gas}= 4000 m^3/d Q_{water}=20 m^3/d

Table 3: Well testing results (INA Itd. Source 2019)

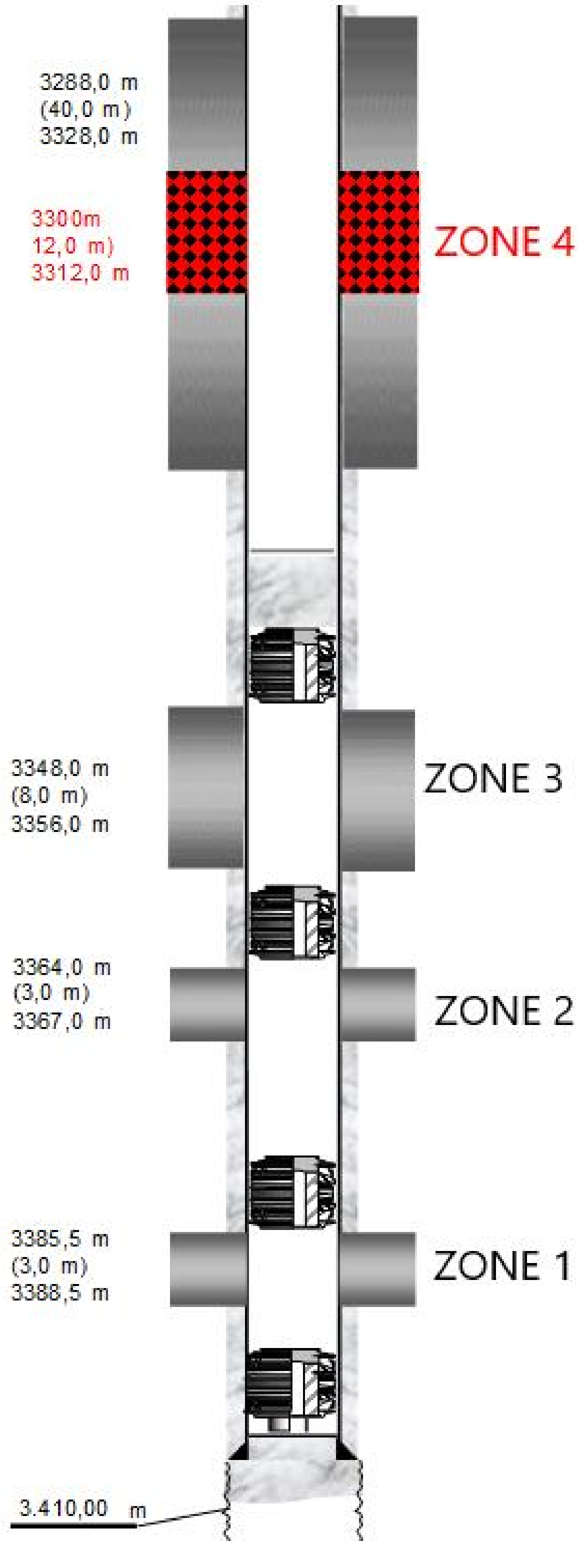

Figure 26: S-1 well schematics of four tested intervals (INA Itd. Source 2019)

During drilling of well S-1 the pressure gradient was estimated at 1,4 bar/10 m, while with hydrodynamic testing it was 1,22 bar/10 m. In comparison to other reservoirs of Drava basin, in well S-1, the lowest initial pressure gradient was measured, as shown in Figure 27.

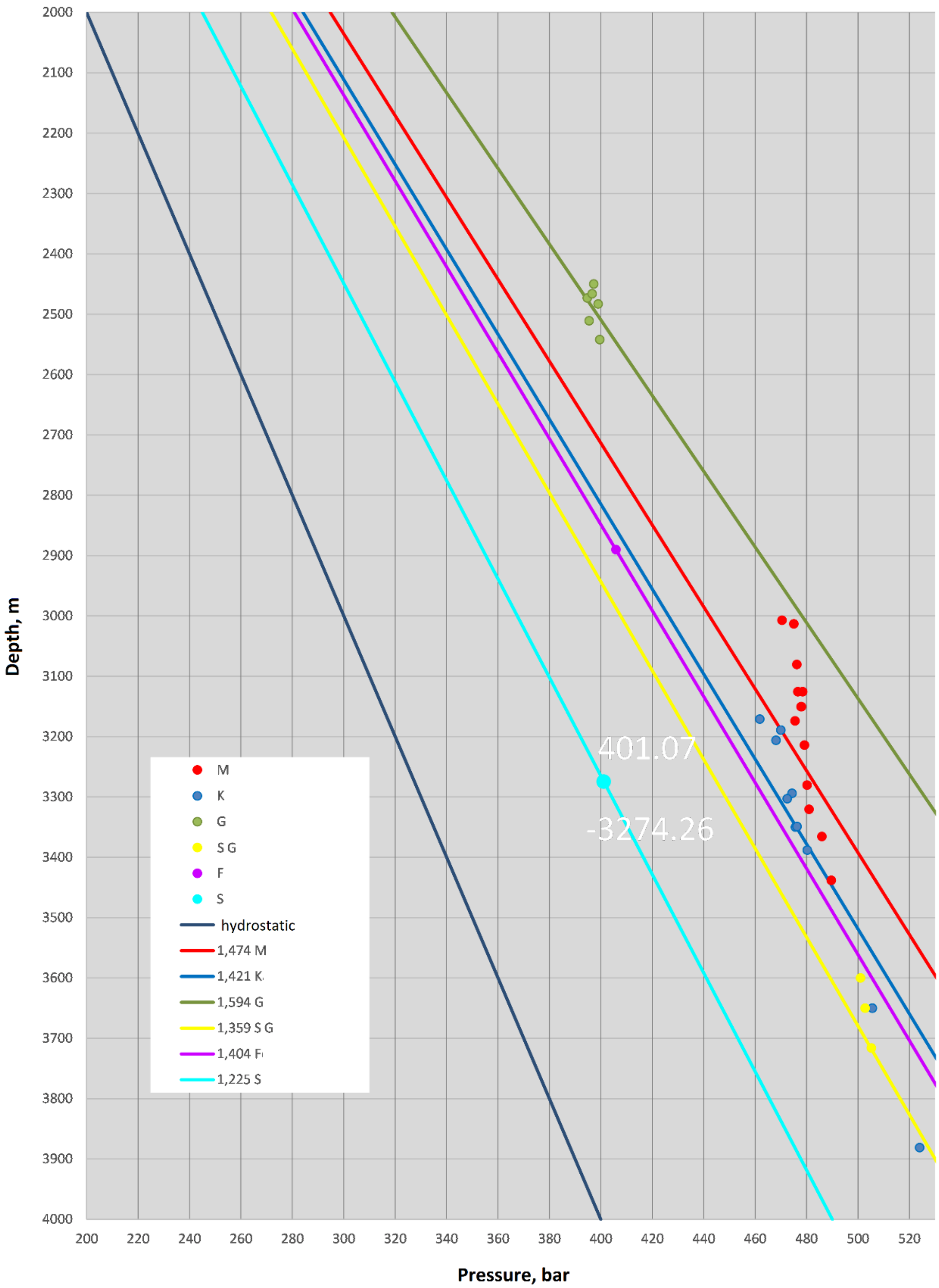

Figure 27: Initial pressure gradient of well S-1 and other reservoirs of Drava basin (INA ltd. Source 2019)

7.4 Hydraulic Fracturing Stimulation

After acquiring all the necessary data, obtained through the drilling of the well as well as with the well testing, an extensive analysis of the works performed was made, Although the well confirmed the existence of hydrocarbons, the production quantities did not meet the designed parameters and did not allow the well to produce economically. Thus, the decision was made to go with hydraulic fracturing enhancement and to improve the properties of the low permeable formation (3288-3328 m).

The fracturing treatment was designed and executed by the Schlumberger service company. In order to maximize the results in the given reservoir conditions before the operation itself, a detailed work program was made. It included all stages from: analysis of well completion, zonation and formation properties selection, job design, fluid characteristics and job execution design. Before the main fracturing treatment was carried out, DataFRAC was executed in order to collect more information about the formation and pumping fluid properties. The main job design was adjusted and confirmed based on DataFRAC, which included few calibration injection tests, and further recommendations were made as a result of the analysis.

7.4.1 Well Completion Information

S-1 is a vertical well. Pumping was done through tubing with an installed packer. The frac string was designed with a 3,5″ tubing. The detailed completion specification can be seen in the Table 4.

Tubing Specification				
Depth (m)	OD (mm)	ID (mm)	Weight (kg/m)	
3240	88,9	69,8	19,3	
Casing Specification				
Depth (m)	OD (mm)	ID (mm)	Weight (kg/m)	
3336	177,8	154,8	47,6	
Perforations				
Top (m)	Bottom (m)	Shot density (shots/m)	Number	Diameter (mm)
3288	3328	19,7	787	10,67

Table 4: Completion specification of well S-1 (INA Itd. Source 2019)

As previously mentioned, the interval 3300-3312 m was reperforated shortly before the fracturing treatment. Also, lower perforation intervals were isolated with mechanical and cement plugs up to 3336 m.

7.4.2 Job Design and Fluid Characteristics

The acquired data allows to prepare detailed design for treatment fluid and proppant.

To deliver the required rheological properties at the bottom-hole temperature of 178 °C, SAPPHIRE XF50 and SAPHPHIRE XF45 were selected for the treatment.

The design included a Pad stage, followed by 9 proppant stages with 100 kg concentration step increments up to 800 kg. 2 proppant sizes were selected for the treatment: 30/50 and 20/40. The breaker schedule was proposed according to the temperature predictions based on simulation, fluid properties and breaking time from lab testing.

Linear polymer gel SAPPHIRE LF was used for tubing fill-up and flushing.

The composition of the SAPHIRE XF treatment fluid is provided in Table 5. Laboratory tests were conducted to confirm the efficiency of the composition according to the forecasted reservoir and pumping properties.

Crosslinked Fluid Composition		
Concertation	Unit	Description
18-20	l/m^3	SAPHHIRE Gelling Agent
3,5	l/m^3	SAPHHIRE Crosslinker
5	l/m^3	Acetic Acid (10%)
1	l/m^3	pH Buffer
2	l/m^3	Crosslinker
0,12-0,96	kg/m^3	HT breaker
0,12-0,3	kg/m^3	HT Encapsulated breaker
0,0-1,2	kg/m^3	HT Stabilizer
3,5-3,8	kg/m^3	HT Fiber

Table 5: SAPPHIRE XF fluid composition (Schlumberger ltd. Source 2018)

The composition of linear gel is seen in Table 6.

Linear Gel Composition		
Concertation	Unit	Description
5	l/m^3	SAPHHIRE Gelling Agent
1	l/m^3	Surfactant
2	l/m^3	Clay Stabilizer

Table 6: SAPPHIRE LF fluid composition (Schlumberger ltd. Source 2018)

7.4.3 Calibration Injection Tests (DataFRAC)

The calibration tests (DataFRAC) schedule included 3 main stages: breakdown test, a SUT/SDT and a Minifrac. After hard shutdown on each of the stages the decline pressure was observed to identify closure pressure and fluid efficiency. Breakdown test was followed by SRT to identify near-wellbore restrictions and friction losses. Minifrac was performed to analyze the reservoir mechanical model and calibrated pumping fluid properties before the main fracture treatment. The pump schedule can be seen in Table 7 and the actual pressure and rate over time plot of all calibration test can be seen in Figure 28.

					Clean Fluid		Slurry		Proppant				
STG #	Stage Name	Slurry Rate (m3/min)	Fluid Type	Time (min)	Stg Vol (m3)	Cum Vol (m3)	Stg Vol (m3)	Cum Vol (m3)	Prop Type	Prop Description	Conc (KgPA)	Stage Qty (Kg)	Cum (Kg)
1	Fillup	2.0	Treated	00:02:30	5.0	5.0	5.0	5.0	0	0	0	0	0
2	BreakDown	3.9	Treated	00:02:34	10.0	15.0	10.0	15.0	0	0	0	0	0
3	Fillup	2.0	Treated	00:02:30	5.0	20.0	5.0	20.0	0	0	0	0	0
4	SRT/SDT	3.9	Treated	00:02:34	10.0	30.0	10.0	30.0	0	0	0	0	0
5	Fillup	2.0	SAPPHIRE LF	00:02:30	5.0	35.0	5.0	35.0	0	0	0	0	0
6	Calibration	3.9	SAPPHIRE XF	00:20:31	80.0	115.0	80.0	115.0	0	0	0	0	0
7	Flush	3.9	SAPPHIRE LF	00:03:56	15.3	130.3	15.3	130.3	0	0	0	0	0
				00:37:06		130.3		130.3					0

Total Fluid	SAPPHIRE XF 50	80.0	m3
	SAPPHIRE LF 20	20.3	m3
	Treated water	30.0	m3
	-	-	m3
	-	-	m3
	Total	130.3	m3

		Qty (kg)
1	30/60 HSP Ceramic	-
2	20/40 S600 ISP	-
3	-	-
4	-	-
	Total	0

Table 7: Calibration test pump schedule (Schlumberger ltd. Source 2018)

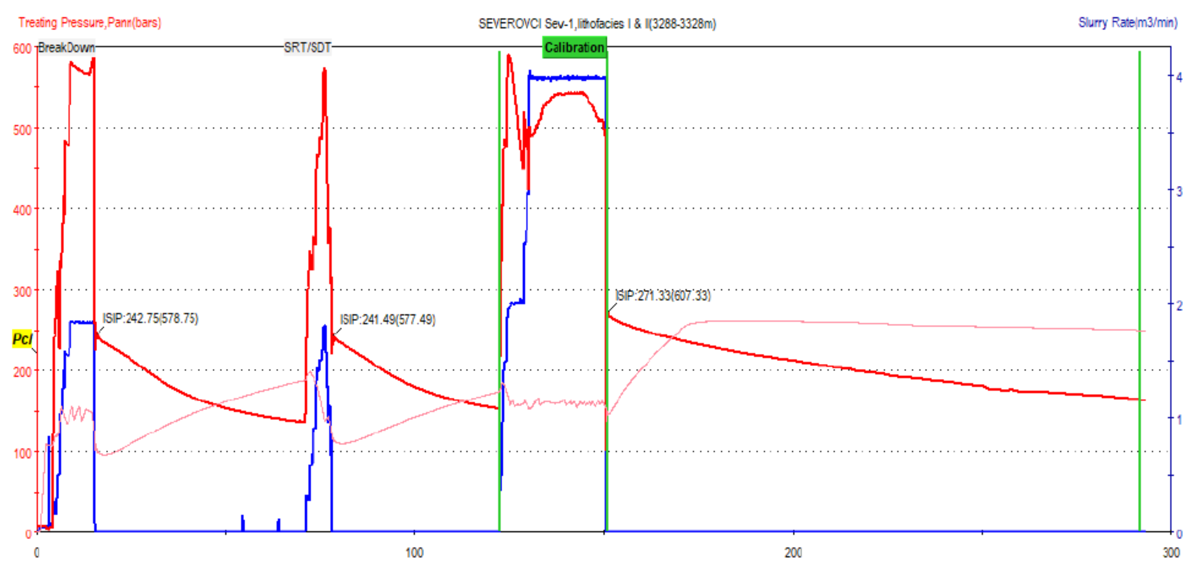

Figure 28:: Breakdown, SRT and Minifrac tests execution plot (INA ltd. Source 2019)

7.4.3.1 Breakdown Test

The first calibration test that was executed was the breakdown test. The breakdown stage was pumped at 1,8 m^3/min rate. The well was filled-up with 0,2 m^3. The rate was gradually increased from 0,3 to 1,8 m^3/min and a total of 16,2 m^3 of treated water was injected for breakdown in order to displace the brine in the wellbore.

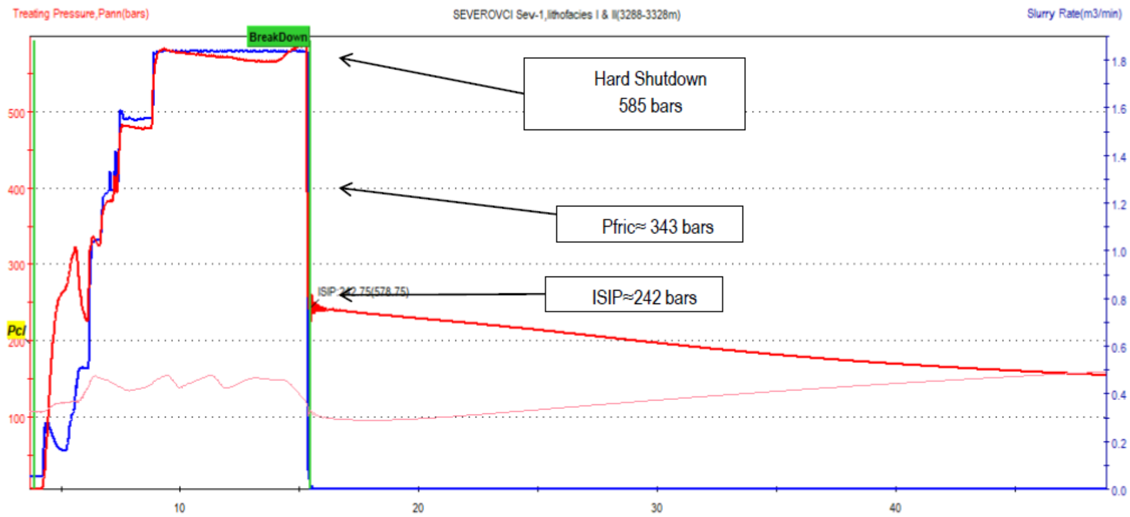

Figure 29: Breakdown execution plot (INA Itd. Source 2019)

After inspecting the plot, the shutdown of 585 bar and ISIP of 242 bar (surface) was decided. As a result, the fluid efficiency of 41% for treated water was acquired. Also, the estimated closure pressure of 531 bar, and the generated net pressure of 50 bar was achieved.

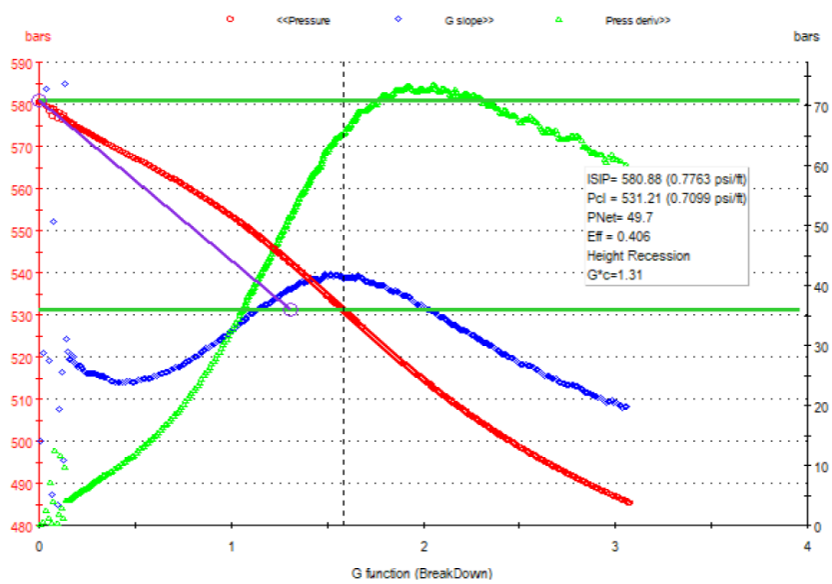

Figure 30: Breakdown G function analysis (INA Itd. Source 2019)

7.4.3.2. Step Rate Test

After the breakdown test, SRT was carried out. Using treated water, with 6 steps for SUT, rates from 0,3 m³/min up to 1,8 m³/min were achieved. After the step-up test, the step-down test was performed. The total volume of the fluid used for SRT was 7,4 m³.

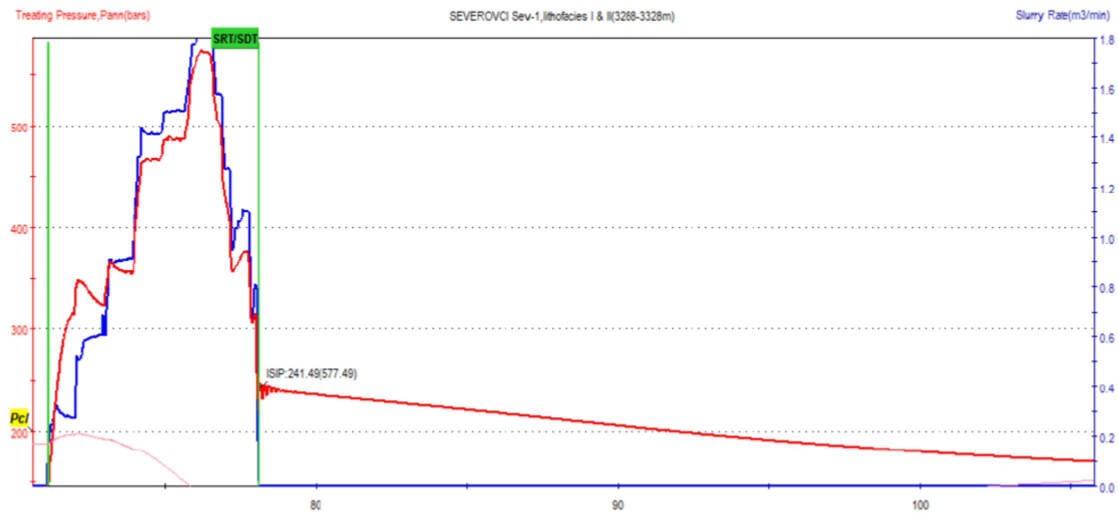

Figure 31: SRT execution plot (INA ltd. Source 2019)

Plotting the test indicated an early fracture initiation in the second step. Thus, the only approximate analysis was available. The SUT estimated an upper boundary closure pressure of 610 bar.

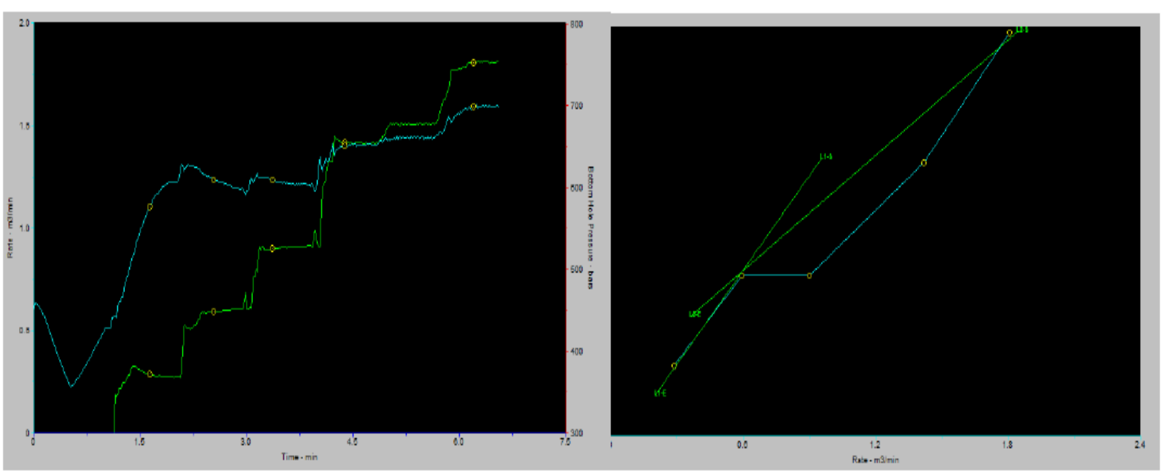

Figure 32: SUT points selection and data analysis plots (Schlumberger ltd. Source 2018)

With the use of hydraulic fracturing software, SDT analysis indicated that 4 perforation can be considered to be active. Also, the analysis indicated that the friction losses due to perforations at 1,8 m³/min were dominant.

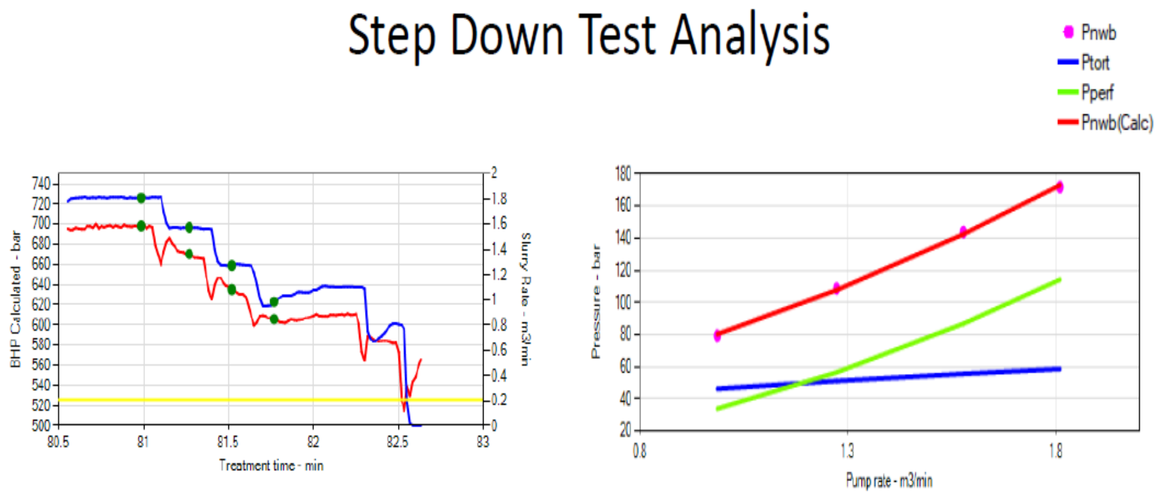

Figure 33: SDT points selection and data analysis plots (INA ltd. Source 2019)

G function analysis of the SDT indicated a slight height recession signature. ISIP of 242 surface bars (576 BH bar) with an efficiency of 47% with treated water was acquired. The estimated closure pressure was 534 bar and net pressure 42 bar.

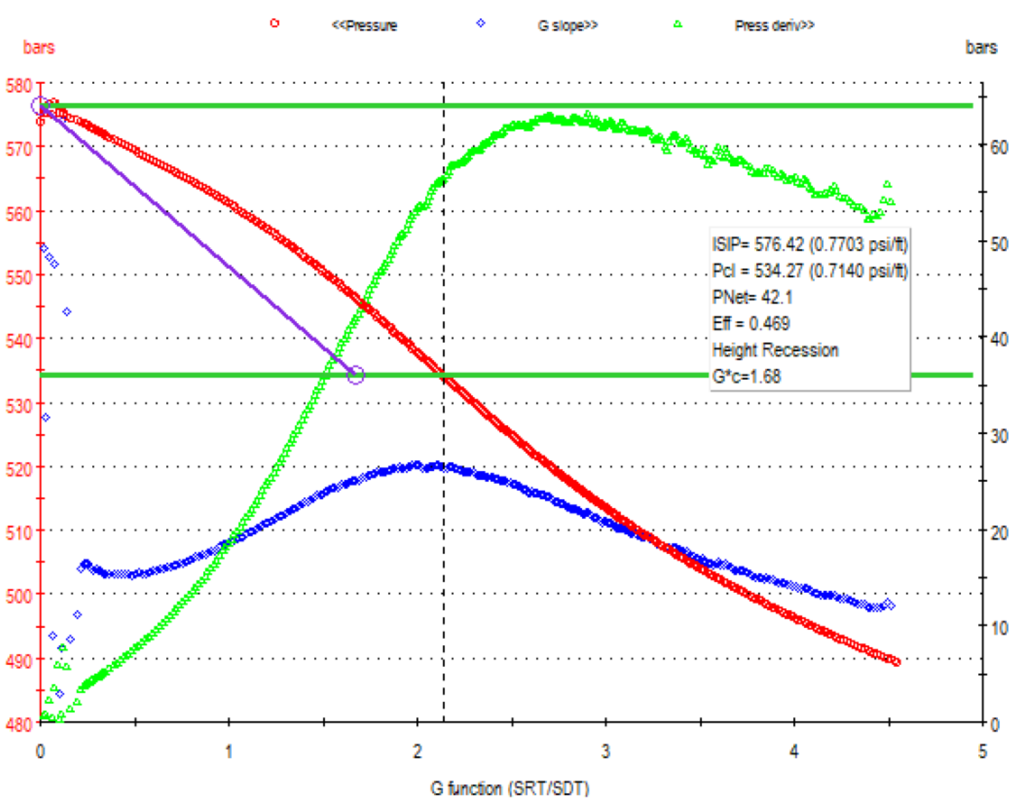

Figure 34: SDT G function analysis (INA ltd. Source 2019)

7.4.3.3 Minifrac

The Minifrac was pumped after SUT/SDT were completed. The rate of 4 m^3/min was used. In total 80 m^3 of SAPPHIRE XF 50 fluid was injected for Minifrac analysis. The ISIP was found to be 271 bar, which showed an increase of 29 bar in comparison to breakdown test. As a result. 219 bars of total friction was estimated at 4 m^3/min pump rate.

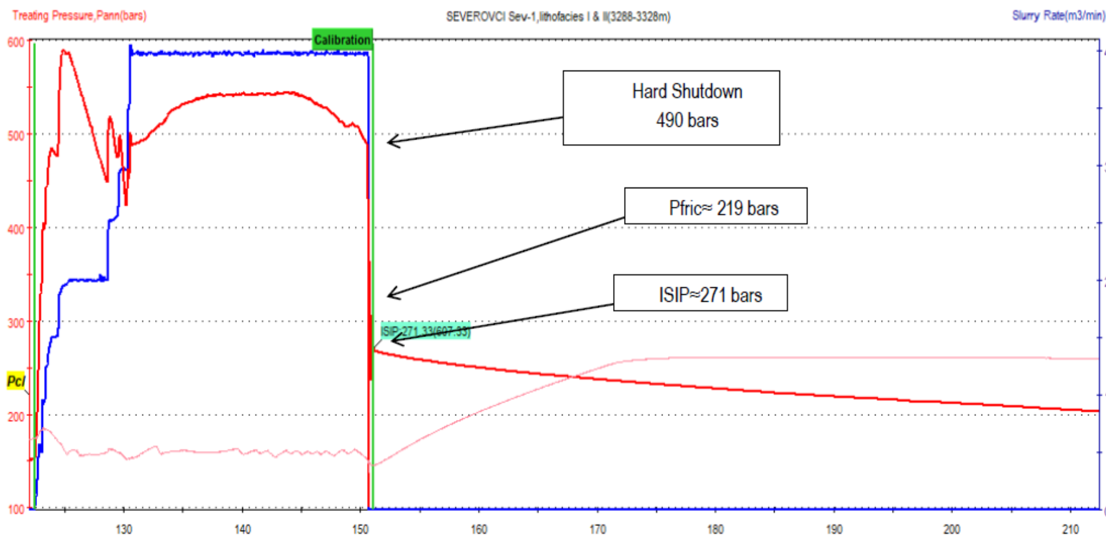

Figure 35: Minifrac execution plot (INA ltd. Source 2019)

From the plot, a slight length recession can be seen at the early decline. Unfortunately, data was corrupted due to PRV on the annulus leaking during decline. However, the pressure closure was selected from the breakdown and SUT/SDT closure, and efficiency on the crosslinked gel was estimated at 47%.

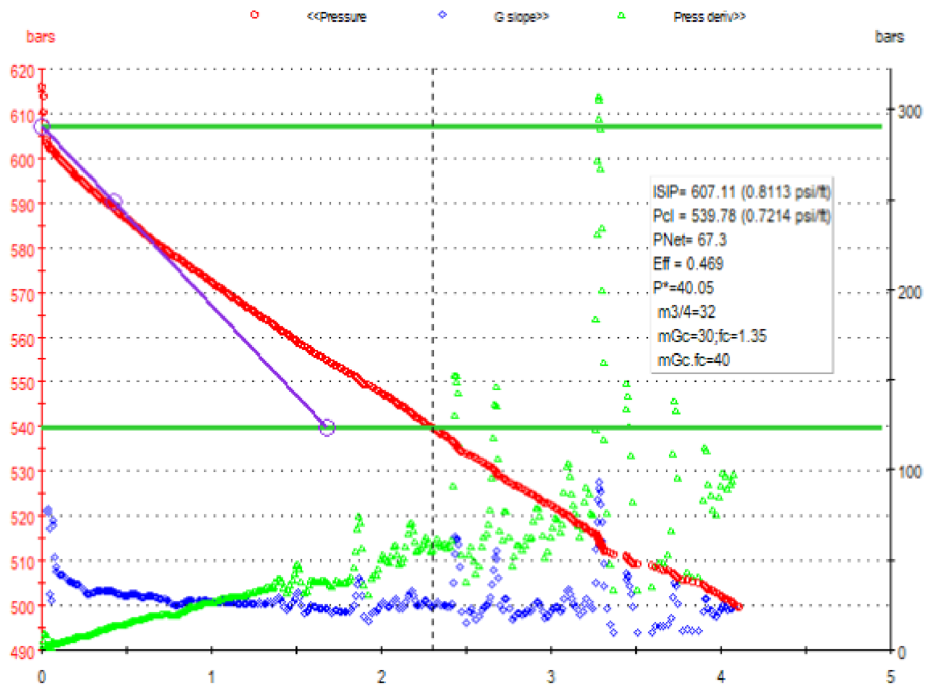

Figure 36: Minifrac G function analysis (INA ltd. Source 2019)

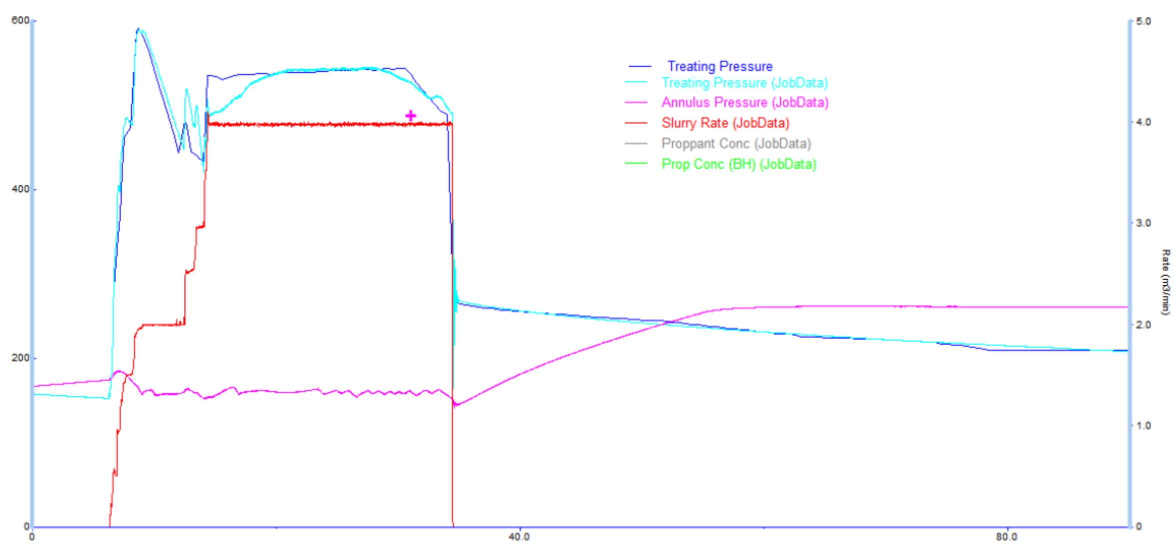

Figure 37: Minifrac pressure matching (INA ltd. Source 2019)

After pressure matching in the FracCAT software, certain fracture characteristics were obtained, as shown if Table 8.

Max Hyd Frac Half-Length	208.8 m	EOJ Net Pressure	63 bars
Propped Frac Half-Length	0.0 m	Efficiency	0.464
EOJ Hyd Frac Half-Length	208.8 m	Effective Conductivity	0 md.m
EOJ Hyd Height at Well	41.2 m	Average Gel Concentration	0.0 kg/m3
EOJ Hyd Width at Well	6.2 mm	Effective Fcd	0.0
Propped Width at Well	0.0 mm	Max Surface Pressure	590 bars
Average Propped Width	0.0 mm	Estimated Closure Time	60.1 min

Table 8: Fracture characteristics obtained from FracCAT after Minifrac (INA ltd. Source 2019)

7.4.3.4 Temperature Log

After calibration tests, temperature logs were made to get better understanding of fracture propagation (by height). From Figure 38 it can be seen that the fracture was relatively contained in the perforated area. Main injection point was at 3300-3325 m and small injection point at the top of perforation.

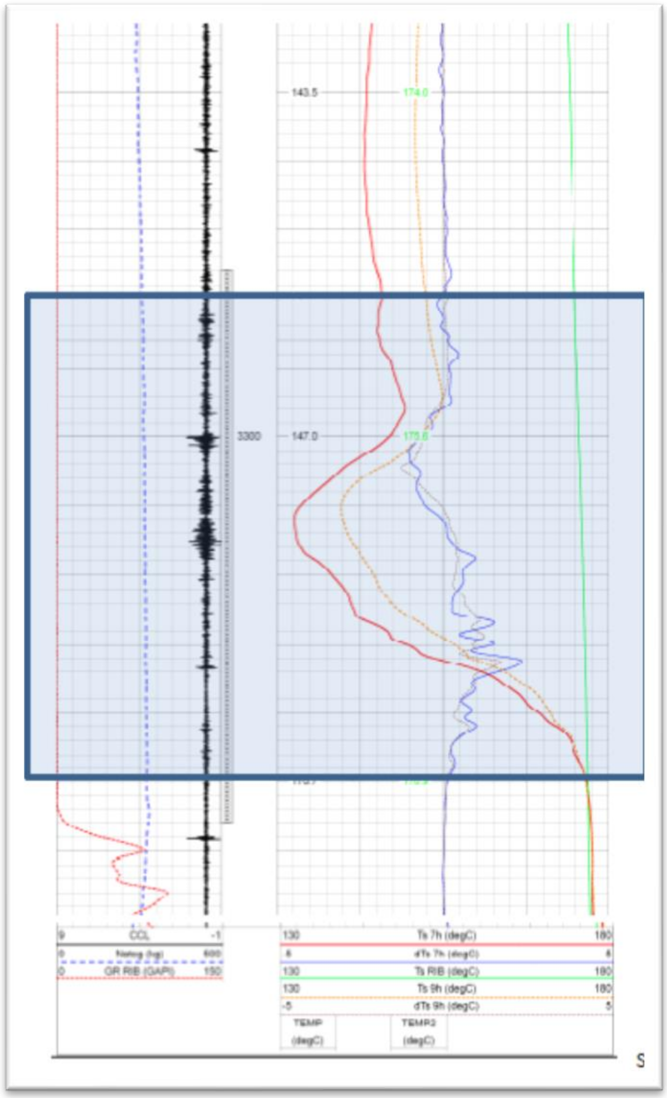

Figure 38: Temperature log of S-1 well after Minifrac (INA ltd. Source 2019)

The interpretation of calibration tests and temperature logs suggests that the hydraulic fracture remained contained within the barriers. No non-ideal behavior e.g. natural fissures or fracs could be identified in the pressure decline analysis.

7.4.4 Main Frac

The main fracturing treatment was redesigned based on calibration tests analysis results and previously collected information. The main redesign considerations were the following:

- The fracture closure pressure corresponds to around 530 bar based on 2 estimations: breakdown and SUT/SDT
- The actual in-situ stress is slightly lower than the preliminary design (based on pressure match analysis)

- Height grow calibration suggest a lower static Young´s modulus

The Main frac recommendations are the following:

- No significant changes to the main proppant schedule because of the good match of a geomechanical model and preliminary design
- Schedule should be adjusted on the fly, based on pressure response

The designed pump schedule, fracture profile and proppant concertation are provided in Table 9 and Figure 39.

					Clean Fluid		Slurry		Proppant				
STG #	Stage Name	Slurry Rate (m3/min)	Fluid Type	Time (min)	Stg Vol (m3)	Cum Vol (m3)	Stg Vol (m3)	Cum Vol (m3)	Prop Type	Prop Description	Conc (KgPA)	Stage Qty (Kg)	Cum (Kg)
1	Pad	3.9	SAPPHIRE XF 50	00:44:52	175.0	175.0	175.0	175.0	0	0	0	0	0
2	100.0 KgPA	3.9	SAPPHIRE XF 45	00:13:11	50.0	225.0	51.4	226.4	1	30/50 S602 HSP	100	5000	5000
3	200.0 KgPA	3.9	SAPPHIRE XF 45	00:13:32	50.0	275.0	52.8	279.2	1	30/50 S602 HSP	200	10000	15000
4	300.0 KgPA	3.9	SAPPHIRE XF 45	00:13:54	50.0	325.0	54.2	333.4	1	30/50 S602 HSP	300	15000	30000
5	400.0 KgPA	3.9	SAPPHIRE XF 45	00:14:16	50.0	375.0	55.6	389.0	1	30/50 S602 HSP	400	20000	50000
6	500.0 KgPA	3.9	SAPPHIRE XF 45	00:14:37	50.0	425.0	57.0	446.0	1	30/50 S602 HSP	500	25000	75000
7	500.0 KgPA	3.9	SAPPHIRE XF 45	00:14:50	50.0	475.0	57.8	503.8	2	20/40 S600 ISP	500	25000	100000
8	600.0 KgPA	3.9	SAPPHIRE XF 45	00:12:11	40.0	515.0	47.5	551.3	2	20/40 S600 ISP	600	24000	124000
9	700.0 KgPA	3.9	SAPPHIRE XF 45	00:06:15	20.0	535.0	24.4	575.7	2	20/40 S600 ISP	700	14000	138000
10	800.0 KgPA	3.9	SAPPHIRE XF 45	00:04:49	15.0	550.0	18.8	594.5	2	20/40 S600 ISP	800	12000	150000
11	Flush	3.9	SAPPHIRE LF 20	00:03:25	13.3	563.3	13.3	607.8	0	0	0	0	150000
				02:35:54		563.3		607.9					150,000

Total Fluid	SAPPHIRE XF 50	175.0	m3
	SAPPHIRE XF 45	375.0	m3
	SAPPHIRE LF 20	13.3	m3
	-	-	m3
	-	-	m3
	Total	563.3	m3

		Qty (kg)
1	30/50 S602 HSP	75,000
2	20/40 S600 ISP	75,000
3	-	-
4	-	-
	Total	150,000

Table 9: Main Frac pump schedule as designed (Schlumberger ltd. Source 2018)

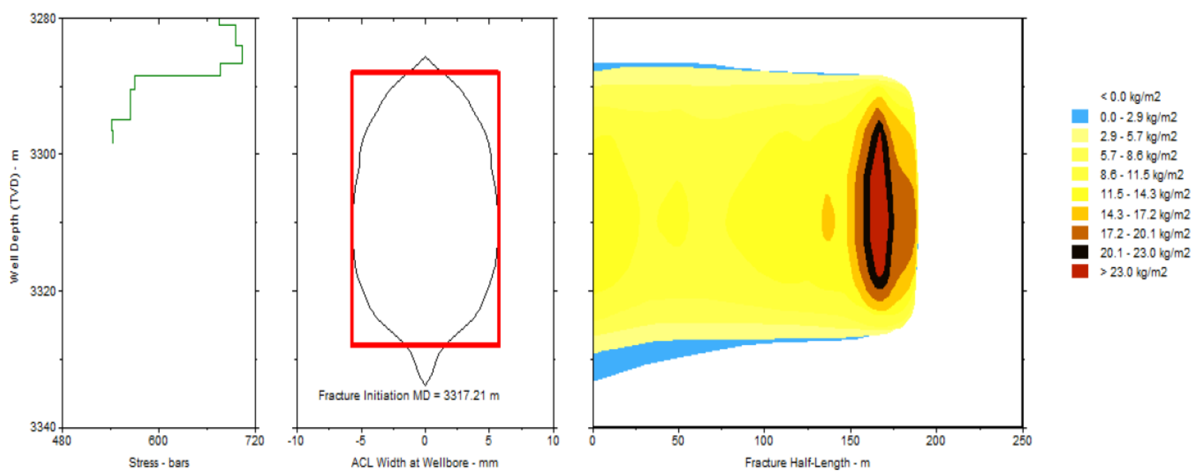

Figure 39: Main Frac fracture profile and proppant concentration as designed (INA ltd. Source 2019)

7.4.4.1 Execution

For the main treatment, a pump rate of 4 m^3/min was used. The average treating pressure was 519 bar, while the maximum pressure was 588 bar. During the job, the annulus pressure was kept at 140-160 bar.

The whole treatment was pumped as initially designed, without encountering any setback. Treating fluid samples were taken regularly during the job and checked by lab technician, to ensure the frac fluid properties were in the design limits. Overall, 100% (150 tons) of design proppant volume was pumped into the well.

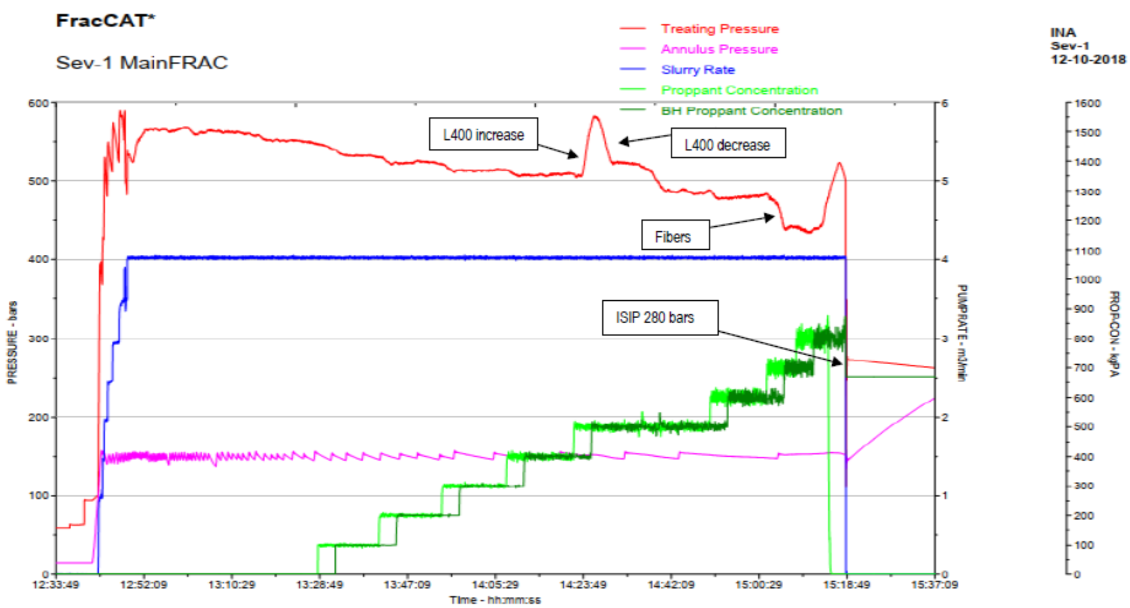

Figure 40: Main frac execution plot (INA ltd. Source 2019)

7.4.4.2 Analysis (Treated Fracture Evaluation)

The results of the Main frac analysis, indicate that during the injection of the mixture of gel and proppant, the pressure on the perforations was constant and the pressure drop at the wellhead was a consequence of increasing the specific weight of the mixture (by adding a larger proppant mass to m^3 of gel). There is no indication that the fracture, during the HF, entered a substantially higher permeable zone or discontinuity zone of the natural fracture system, which would cause increased filtration of the gel, resulting in a drop of pressure and eventually a sand-out.

The fracture geometry was evaluated after the treatment execution, based on pumping data. The simulation model represented a reasonable match of the simulated and actual treating pressure. The final simulation results of the pressure matched model, seen in Figure 41, were considered to reflect the actual treatment results.

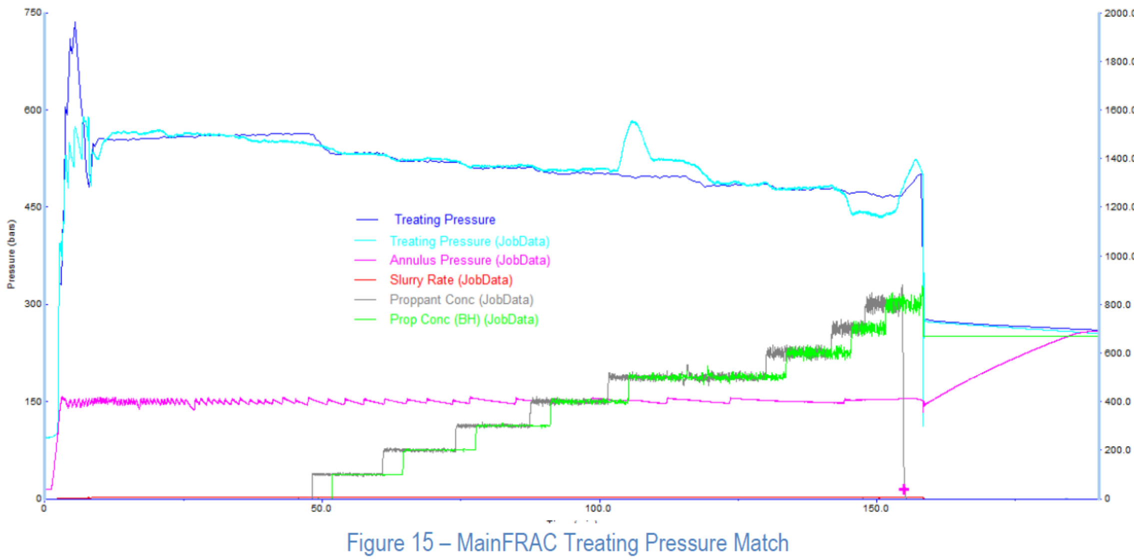

Figure 41: Main frac pressure matching (INA ltd. Source 2019)

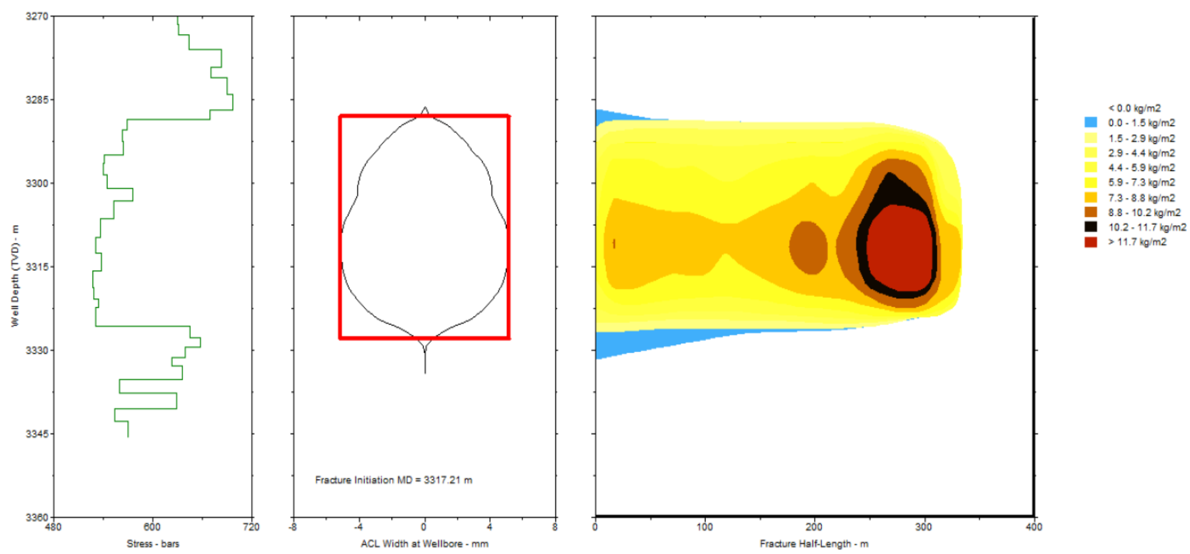

Figure 42: Main Frac fracture profile and proppant concentration as executed (INA ltd. Source 2019)

Based on the stimulation results, the geometry of the induced fracture of a maximum half-length of 340,9 m, an average width of 2,5 mm and an average conductivity of 579 mD per m were estimated.

Max Hyd Frac Half-Length	340.9 m	EOJ Net Pressure	76 bars
Propped Frac Half-Length	340.3 m	Efficiency	0.339
EOJ Hyd Frac Half-Length	278.9 m	Effective Conductivity	579 md.m
EOJ Hyd Height at Well	47.8 m	Average Gel Concentration	100.9 kg/m3
EOJ Hyd Width at Well	10.6 mm	Effective Fcd	17.2
Propped Width at Well	1.8 mm	Max Surface Pressure	736 bars
Average Propped Width	2.5 mm	Estimated Closure Time	33.0 min

Table 10: Fracture characteristics obtained from FracCAT after Mainfrac (INA ltd. Source 2019)

7.5 Production Results and Evaluation of Hydraulic Fracturing Stimulation

After the fracing treatment, the well was producing on the torch for 15 days along with the cleaning. From this, it produced on the separator for 7 days: 5 days on the nozzle d=4,76 mm and for 2 days on the nozzle d=5,55 mm. The results are shown in Table 11.

Day	Q_{gas} (m^3/d)	Q_{con} (m^3/d)	Q_w (m^3/d)	P_t (bar)	WGR (cm^3/m^3)	CGR (cm^3/m^3)
1	31,426	2,46	41,88	164-164	1332,65	78,28
2	31,286	2,50	40,10	165,8-163	1281,72	79,91
3	31,064	2,35	39,20	162,8-162	1583,83	75,65
4	30,324	2,19	52,32	160,1-158,1	1725,37	72,22
5	29,584	2,07	51,46	158-155,5	1739,45	69,67
6	33,922	2,25	55,85	155,5-145,8	1646,42	66,33
7	32,725	2,13	58,51	145,5-142,2	1787,93	65,09

Table 11: Production result after hydraulic fracturing stimulation (INA ltd. Source 2019)

After connecting to the separator, the well produced 348,2 m^3 of water. During the cleaning period, it is estimated that it produced 300 m^3 of water. It is a total of 648 m^3 of water. A bit more was pumped in the layer during stimulation.

After fracturing the interval, high pressure of p_t = 160 bar was obtained, but large amounts of water were obtained. WGR was 1800 cm^3 of water/m^3 of gas.

Since it was assumed to be a massive type of reservoir, the appearance, as well as the origin of the water in the shallow zone above the gas-saturation interval without water in the test (Int.3) is confusing.

A multidisciplinary analysis of all collected data was made in order to decide on possible additional testing to define the origin of water and the possibility of predicting production parameters in case of commissioning.

The possibility of communicating with the natural fracture system was analyzed, either by the flow of water from the aquifer or laterally by the sedimentary bodies or lithofacies with expressed fracture porosity. It is not possible to exclude the possibility of establishing communication with the aquifer through such discontinuity after the layer stimulation.

By comparing the chromatographic analysis of the separation gases, it can be concluded that the share of non-hydrocarbon components (N_2 and CO_2) as well as the share of hydrocarbons (C_1-C_{12+}), of the gases obtained from the S-1 well have components and the properties most similar to the gases from the EF M. Liquid phase comparisons showed the highest relation with condensate from EF K. According to the comparative values of the salinity of the formation water, it is noticeable that the formation water is the most similar to the formation of water samples from M field.

The theoretical possibility of releasing initially bound water and its stimulation-induced flow has been considered. The ratio of bound water in low porosity and permeability reservoirs, which is the case here, because of the high hydrophilic porous space is very high (S_{wi} 65-70%). As a result of stimulation, the contact angle is increased and the bound water within the induced fracture system becomes mobile.

However, the estimation of the amount of released bound water in this case, taking into account only the size of the fracture from the results of the Main frac analysis, gives little value (several cubic meters) but in nature it is probably not just a fracture but an induced fracture zone.

7.6 Case Study Conclusion

Even though the borehole achieved the goal and determined the hydrocarbon potential at 3288 m it did not achieve all the objectives set out in the geological project or enable economically viable production.

Analysis of reservoir fluids: produced gas (including nonhydrocarbon components), gas condensate and reservoir water indicate similarity with surrounding exploitation fields.

The lowest initial pressure gradient (1,225 bar/ 10m) has been recorded in the S-1 well, compared to the other reservoirs of the region, which opens up the possibility that the initial reservoir has not been recorded but that there is communication with neighbouring fields.

The hydraulic fracturing operation was performed satisfactorily in accordance with the project. After the stimulation the interval gave good production results, high dynamic pressure of p_t =160 bar was achieved, but unfortunately large quantities of water were also obtained.

Further analyses of the origin of the water are needed to make a final decision on the well status and the possibility of commissioning the well.

Based on the conclusions of post-evaluation, it is proposed that:

1. Continue with Interval 4 testing with pressure measurement at interval 3 for the determination of S-1 wells production potential and analysis of mutual communication between the two interrupted intervals within the borehole.

2. Creation of deep seismic volume, seismic inversion in depth and detailed interpretation of the lateral distribution of lithofacies based on the boreholes data of exploitation fields M and K and well S-1 to confirm OGIP and estimate potential reserves.

3. Putting together a 3D geomechanical model The 3D geomechanical model results can be used to analyze the impact of stress on the cap and reservoir rocks and for the adequate design and performance of wells in various scenarios of stimulation and production by linking the results of the 3D geomechanical model and dynamic modeling. The purpose of the model is to estimate the effect of stress change during the pumping phase.

Chapter 8 Conclusion

The objectives of the thesis were:

- To consider all aspects of hydraulic fracture job for the selected well and to explain complete hydraulic fracturing process, which includes most essential fracturing characteristics, rock mechanical properties, as well as to explain the pressure data, how it is collected and analysed.
- Analyse the well in terms of characteristics known before the stimulation decision, why the decision was made and how the production behaved after the stimulation.
- Explain how hydraulic fracture stimulation was performed and evaluate with the acquired data and obtained fracture characteristics the stimulation.
- Evaluate the production potential and propose further actions

Although hydraulic fracturing has been used for many decades, just recently it started getting a lot of attention from companies around the world. With a number of good candidate reservoirs, the industry is looking for new ways to increase production and keep up with the demand. That is why hydraulic fracturing is becoming one of the most important processes in completing a well.

An unconventional reservoir with extremely low permeability would never produce at an economically feasible rate without hydraulic fracturing. It also made it possible for the industry to move from conventional resources with high permeability, to tight (low permeability) resources.

There are several applications of hydraulic fracturing used in the oil and gas industry but the most essential application and the main reason behind hydraulic fracturing is to increase the permeability of the reservoir.

Hydraulic fracturing can also be a useful tool in exploration in cases where sufficient hydrocarbons have been discovered that cannot be economically produced by convention well completion methods.

To ensure good results of hydraulic fracturing operation, a detailed plan of all activities should be made, from the collection and analysis of borehole and reservoir to the data obtained from calibration injection tests needed for treatment adjustment and design of treatment itself. Proper selection of the fluid systems, chemicals and proppants is crucial to the ultimate success of the operation.

The multidisciplinary approach and teamwork of reservoir geologists, geochemists, geophysicists, reservoir and production engineers and contractors themselves is a necessary prerequisite for maximum results.

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Acronyms

API RP	American Petroleum Institute Recommended Practice
BHP	Bottomhole Pressure
BHSP	Bottomhole Static Pressure
BHTP	Bottomhole Treating Pressure
CGR	Condensate/Gas Ratio
DFIT	Diagnostic Fracture Injection Test
EF	Exploitation Field
FR	Friction Reducer
HF	Hydraulic Fracturing
ISIP	Instantaneous shut-in Pressure
ISO	International Organization for Standardization
KGD	Khristianovic-Geertsma de Klerk model
OGIP	Original Gas In-Place
PKN	Perkins and Kern model
SDT	Step-down Test
SRT	Step Rate Test
SUT	Step-up Test
USD	United States Dollar
WGR	Water/Gas Ratio
WHP	Wellhead Pressure

Symbols

d	diameter	[m]
E	Young´s Modulus	[Pa]
F_{CD}	dimensionless fracture conductivity	[-]
G_{c}	G-function	[-]
h_f	height of fracture	[m]
k	permeability	[mD]
k_f	fracture permeability	[mD]
p_{bhtp}	bottomhole treating pressure	[Pa]
p_c	closure pressure	[Pa]
p_{ext}	fracture extension pressure	[Pa]
p_f	fracturing fluid pressure	[Pa]
p_h	hydrostatic pressure	[Pa]
p_{inj}	injection pressure	[Pa]
p_{isip}	instantaneous shut-in pressure	[Pa]
p_{net}	net pressure	[Pa]
$p_{pipe\ friction}$	pipe friction pressure	[Pa]
p_t	tubing pressure	[Pa]
$\Delta p_{nwb}.$	near-wellbore friction	[Pa]
Δp_{pf}	perforation friction pressure	[Pa]
Δp_{pf}	perforation friction pressure	[Pa]
Δp_{tort}	tortuosity pressure	[Pa]
Q_{con}	condensate flow rate	[m^3/s]
Q_{gas}	gas flow rate	[m^3/s]
Q_w	water flow rate	[m^3/s]
r_f	fracture radius	[m]
S_{wi}	initial water saturation	[%]
Δt_D	dimensionless time	[-]
w_f	fracture width	[m]
x_f	fracture half-length	[m]
σ_{Hmax}	minimum horizontal stress	[Pa]
σ_{Hmax}	maximum horizontal stress	[Pa]
σ_V	vertical stress	[Pa]

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