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Hydraulic fracture design optimization for Nubian sandstone formation in Libya

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HYDRAULIC FRACTURE DESIGN OPTIMIZATION FOR NUBIAN SANDSTONE

FORMATION IN LIBYA

by

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ABSTRACT

There is growing interest in developing unconventional oil and gas reserves in Libya, such as the tight portions of the Nubian sandstone.

Well-X7 is a development well drilled to a TD of 13,005' penetrating the Upper Nubain Sandstone (UNSS) at 12,122'-12,207' and the Lower Nubain Sandstone (LNSS) at 12,524'-12,880' KB. Based on open hole logs, the UNSS has 71 ft of net pay and the LNSS was found to have 295 ft of net pay. Openhole logs also showed low permeabilities of 2.5 and 3 md for the UNSS and LNSS, respectively. The well was initially perforated in both zones and tested 385 bopd. Hydraulic fracturing is to be applied to this well in the future.

This study evaluated 13 different stimulation treatments for the X-7 well. F300 frac fluid was used with varying proppant type and size, including Ottawa sand, Brady sand and Carbo Lite ceramic. 20-40 Carbo Lite ceramic was used with four different frac fluids, including slickwater. Results for all cases compared IP and 24-month cumulative recovery. Results show that a combination of F300 frac fluid and 20-40 Carbo Lite ceramic proppant give highest production rates. However, cases evaluated had low FCD suggesting conductivity should be increased, and treatment size can be reduced in a final treatment design.

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1. INTRODUCTION

There is continuing controversy over the occurrence of worldwide 'peak oil', which is the point in time marking a continuous decline in worldwide oil production. Although production for the Middle East is not always publically documented, there is speculation that the oil production from conventional reservoirs in the region has already 'peaked'. This understanding is reinforced by Kerr (2011), who indicates that OPEC's conventional oil production leveled off in 2011. Such indicators have led to a growing interest in developing 'unconventional' reservoirs worldwide.

The term 'unconventional reservoir' has become synonymous with shale play development in the United States, due to the successful production of oil and gas from reservoirs with permeability ~0.00001 mD. However, the United States actually began developing what was considered to be 'unconventional' reservoirs in the 1980s, when industry began experimenting with stimulation treatments in 'tight' sands. Tight formations were considered to be <0.1 mD for gas production and <10 mD for oil production.

King (2012) provides an illustration of formation permeability along a scale ranging from shales (0.00001 mD) to conventional reservoirs, shown in the green highlighted areas of Figure 1.1. Hydraulic fracturing is required to establish commercial production or all 'tight gas' to 'unconventional' permeability ranges shown in the figure. Hydraulic fracturing may or may not be used to enhance production or stabilize sand production tendencies in higher permeability formations.

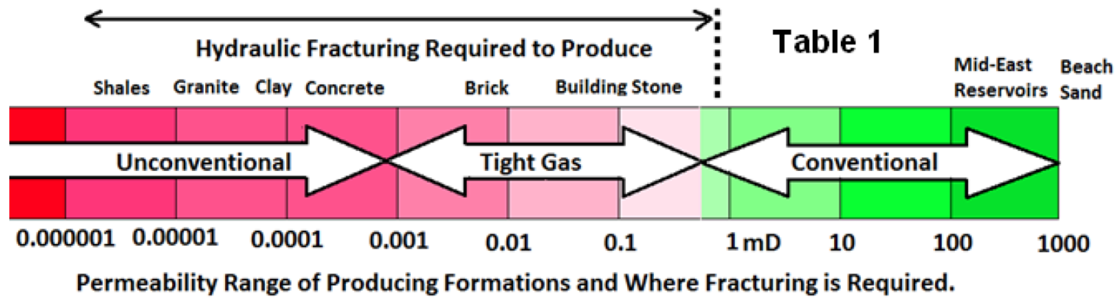

Figure 1.1. Permeability range of producing formations (King. 2012)

In the past 10 years, industry found a solution for developing the shale plays by combining horizontal well orientation with the placement of multiple fractures along the lateral section of the well. The success of this completion approach has further fueled worldwide interest in developing reservoirs considered to be 'unconventional'. China and Australia have already developed unconventional reservoirs and now count those resources as an important energy source. Recently, North Africa (particularly Libya) has increased its focus on enhancing oil and gas production from tight, unconventional, sandstone formations.

1.1. SIGNIFICANCE OF THE PROBLEM

Countries like Libya depend on oil and gas as the main source of their economy; the oil and gas sector is considered to be the main driver for the future economic growth. Production from conventional reservoirs in Libya has already started to decline. Thus, there is tremendous interest in discovering and developing new sources hydrocarbon reserves.

Figure 1.2 depicts the four major onshore basins located in Libya. The potential to produce unconventional resources such as shale oil, shale gas and tight sand oil/gas was identified in three of the basins including the Sirte Basin (center), Murzuq Basin (southwest), and Ghadames Basin (west). A lack of data for Al Kufrah Basin made it hard to identify its unconventional reserve potential. The most prospective formations include the upper Devonian Frasnian shale and lower Silurian Tannezuft basal (hot shale) which are predominant in the Ghadames Basin. The Murzuq Basin also contains hot shale throughout Tannezuft formation. The Etel and Rachmat formations are considered as the main shale resources in Sirte Basin.

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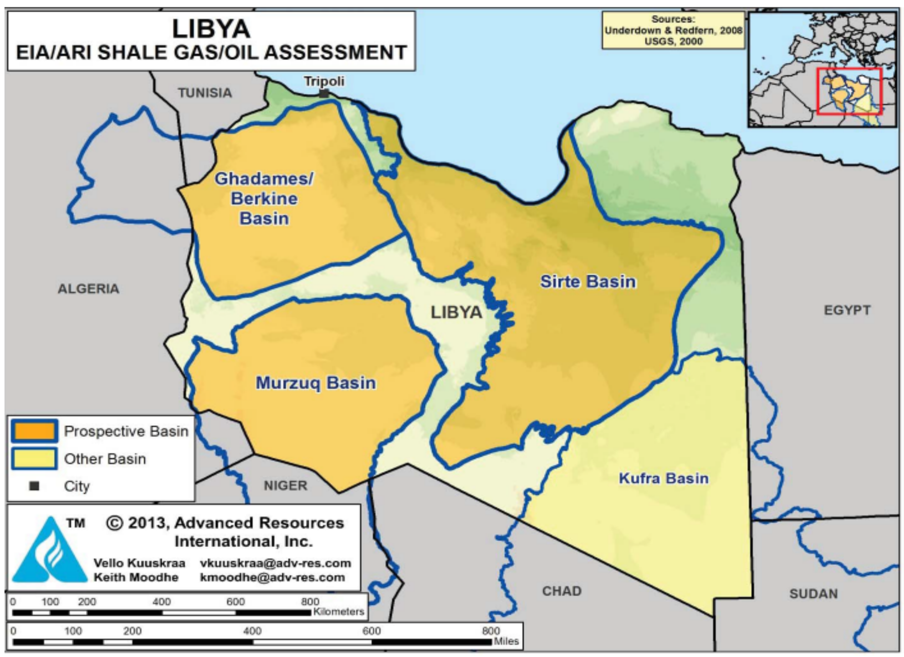

Figure 1.2. The location of the onshore basins in Libya

The National Oil Corporation (NOC) of Libya announced an estimation of unconventional hydrocarbon reserves after a study which was conducted by Advanced Resources International, Inc. (ARI) in 2013. The three basins were estimated to contain 942 TCF of shale gas in place, with 122 TCF of predicted recoverable tight and shale gas. The basins were evaluated to have a potential oil and condensate in place of 613 billion barrels, with 26.1 billion barrels of recoverable tight and shale oil. Hence Libya holds great potential for unconventional resource development in North Africa, which has been estimated to have total unconventional reserves almost as large as the United States. However, exploration and development of this resource in Libya, as well as throughout North Africa, is still very limited. (Melo et al., 2012)

Table 1.1 presents a summary of the top 10 countries with the largest projected recoverable shale oil reserves. Libya ranks 5th in this list. This reserve potential is very significant. In 2016, the National Oil Corporation (NOC) of Libya noted that the country is seeking to increase daily production rate by 3 billion cubic feet of gas per day and 3 million barrels of oil per day, to become one of the leading oil and gas producers in the region. Achieving this goal will require an increase in the application of hydraulic fracturing, horizontal well drilling and other technologies used to complete tight and unconventional reservoirs. However, there are many challenges to overcome, including the absence of a strong government, and training personnel to apply new technologies that haven't been used extensively. Libya still has a significant recoverable reserve potential of more than 60 BBO and 120 TCF if both conventional and unconventional reserves are considered.

This thesis provides an analysis of stimulating a vertical well in the Nubian sandstone, one of the unconventional (tight) oil-bearing formations of interest for future development. The work provides an evaluation of various stimulation alternatives for the Nubain sandstone and compares results of those treatments based on 24 month cumulative recovery.

Table 1.1. Technically recoverable shale oil (EIA, 2015)

Rank	Country	Unconventional oil (billion bbl)
1	Russia	75
2	U.S.	58
3	China	32
4	Argentina	27
5	**Libya**	**26**
6	Australia	18
7	Venezuela	13
8	Mexico	13
9	Pakistan	9
10	Canada	9
Total	World	345

1.2. OBJECTIVE

The main objective of this work is to use field data acquired from Well-X7, a development well in North field-X, penetrating the UNSS (Upper Nubian Sandstone) at 12,122'-12,207', NMS (Nubian Middle Sandstone) at 12,207'- 12,524' KB and the LNSS (Lower Nubian Sandstone) at 12,524'-12,880', to identify an optimum method of hydraulically fracturing this formation. Open hole logs indicate the upper Nubian and lower Nubian are productive, whereas the middle Nubian is not. Hence, the objective first required identifying the overall perforating and stimulation approach, and then evaluating changes in fracturing fluid, proppant type and size, and other treatment parameters, to identify the optimum stimulation treatment based on 24-month cumulative production.

2. HYDRAULIC FRACTURE BACKGROUND

Hydraulic fracturing has been deployed inthe oil and gas industry since 1947. The first announced application for the hydraulic fracture process for stimulation was in the Hugoton gas field in western Kansas, in 1947. The well was completed with four gas-producing intervals. The approved fluid used for the job was war-surplus napalm which is considered one of the most hazardous materials. According to the Halliburton reports, 3000 gallons were pumped in each formation. Hydraulic fracturing has become a standard treatment for stimulation of oil and gas wells. A large number of fields only produce because of the application of hydraulic fracturing technology. Figure 2.1 shows a picture from the first hydraulic fracturing treatment conducted in the Hugoton gas field in Kansas.

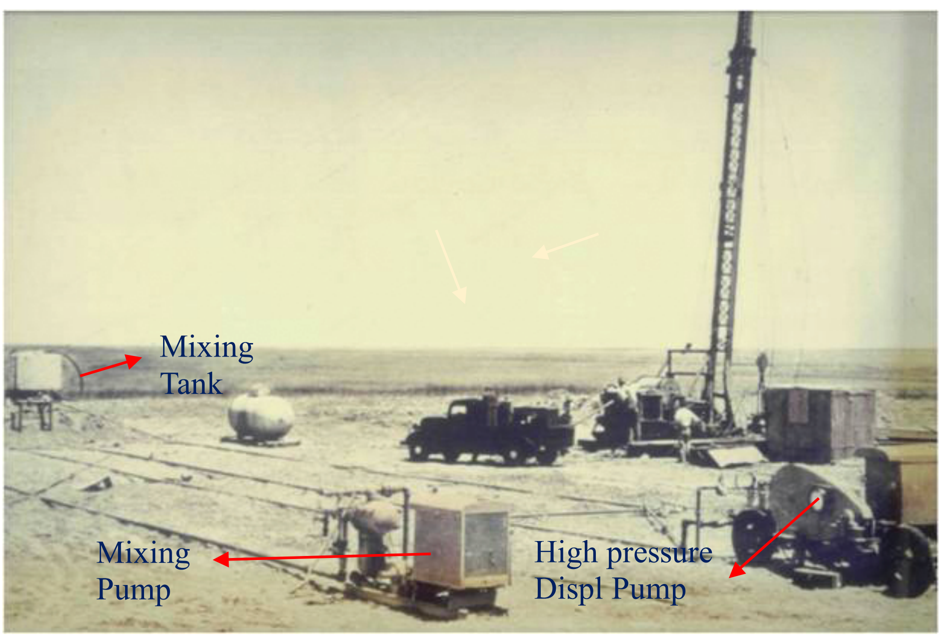

Figure 2.1. Hugoton gas field, Kansas (Michael J. Economides, T. M.2007)

In 1981 more than a million fracture treatments were performed all over the world mostly in low permeability tight formation gas (TFG) and tight oil reservoirs. In tight gas and oil formations, for example, reservoir permeability is in the micro-darcy range. In these low permeability reservoirs hydrocarbons do not flow to the wellbore without a propped and effective hydraulic fracture. In unconventional shale plays (gas and oil) where the permeability is in the nano-darcy range none of the hydrocarbons are recoverable without hydraulic fracturing. Currently, fifty five percent of the oil (6 MBOPD) and fifty three percent of the gas (50 BCFPD) being produced in the United States are produced from resources to low of permeability to produce without hydraulic fracturing. The expeditious development of unconventional sources of hydrocarbons which was donene by hydraulic fracturing had a positive effect on the oil and gas industry (Gandossi, L., 2013).Hydraulic fracturing treatments are even done in higher permeability reservoirs where hydrocarbons can be produce without fracturing. In these reservoirs, the hydraulic fracture can minimize the effects of wellbore damage, improve the production rate and rate of recovery, and extend the economic life of the well.

Throughout the world between 1993 and 2005 nearly 40% of oil wells and 70% of gas wells were completed by hydraulic fracturing. In addition in some parts of North Africa such as Algeria nearly 20 hydraulic fracturing operations were done in Hessy Masoud field between 1970 and 1980 and then 150 wells were completed between 1980 and 2005. In Libya, 9 wells in the Raguba field between 1988 and 1995 with another 134 wells completed by 2005.

2.1. HYDRAULIC FRACTURING PROCESS

Hydraulic fracturing or “fracking” is described as a technique utilized in unconventional hydrocarbon resources to access previously unaccessable hydrocarbon reserves. In the mid-1990s and early 2000s, many energy companies’ started integrating hydraulic fracturing with horizontal drilling to enhance the reserve recovery (Armstrong et al., 1995). Fracture treatments are carried out at the well site, using heavy equipment including pump trucks, blenders, proppant tanks, and fluid tanks. A fracture treatment can be divided into stages: the pad stage, the slurry stage, and the displacement or flush stage. In the pad stage a fracturing fluid (water, gel, etc...) is injected to break down the target formation, create and propagate a fracture, and to act as sacrificial fluid for leak-off during the rest of the treatment. Following the pad stage the proppant slurry is pumped which includes. Fracture fluid mixed with proppant (sand, resin coated sand, ceramic...etc.) in ever increasing concentrations depending on the desired/planned fracture conductivity. Lastly, as the proppant in the slurry nears the fracture tip and the pad fluid is nearly all leaked-off the slurry stage is displaced to the perforations to clean the wellbore and make it suitable for flow-back. As the flush reaches the perforations, to the pumps are shut down and the fracturing equipment is removed. The main purpose for injecting the proppant (slurry) is to hold the fracture open so that hydrocarbons can be produced through the fracture back to the wellbore. Figure 2.2 shows a schematic diagram of the pad and slurry stages (Boyun Guo, 2017).

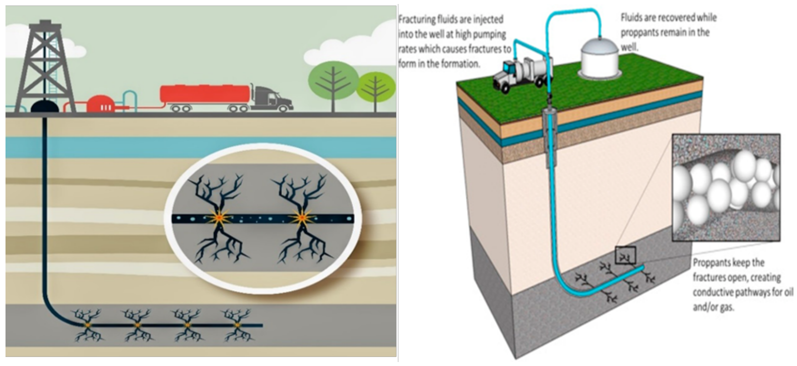

Figure 2.2. Pad stage and slurry stage process

Sand (proppant) and other chemicals have the potential to create and prop cracks in the formation and facilitate a pathways for the hydrocarbons (oil and gas) entering the wellbore (Pye and Pye, 1973). In fact, these cracks which are made by fracturing operations, can be a valuable technology for enhancing the productivity of oil and gas wells. Looking to the field of environmental engineering, hydraulic fracturing is an effective method in increasing the efficiency of the soil in-situ remediation technique. This method can illustrate the residual stress field that are widely used because its simplicity. Beside, underground disposal of waste and toxic fluids, stimulation of water wells to produce water and in mining industries as backup system specially in large scale excavation of ores. According to the U.S. Department of Energy and Ground water production Council, 99.5 percent of the fracturing operations used to develop shale formations is fresh water and sand. The other 0.5 percent are small amounts of chemical additives which are specially designed from site engineers and generally depends on the formation type and usually these additives are environmentally friendly (green).

2.2. HYDRAULIC FRACTURE TECHNOLOGIES

Many technologies are used today in the oil and gas industry for formation stimulation, hydraulic fracturing is just one of them. However, low quality fracturing operations can cause a risk to the environment. For example, a massive fracture treatment conducted on a shallow formation near the water table can cause methane infiltration in the aquifer or aquifer contamination. Further, underground disposal of drilling, completion, and fracturing fluids can cause induced local seismicity and earthquakes. Fortunately, most hydrocarbon producing formations are at much greater depths than the water table making communication unlikely and clean-up and reuse of fracturing fluids can limit the induced seismicity by minimizing the disposal. Additionally, research is being done in many universities, institutes, and companies focusing on the development of new technologies which can reduce the impact of well stimulation on the environment.

As an example, some of the research has been done on fracturing fluids over the years. As previously mentioned one of the early fluids used in fracturing was napalm but it was deemed unsafe and quit being used. Oil was used as a fracturing fluid but it didn’t make much economic sense, unless in an artic environment (Canada and Russia), to pump oil to stimulate the well when that was what you wanted to produce and sell in the first place. Water, linear gel, and cross-linked fracturing fluids have been the main fluids used by the industry but there have been variations developed and used over the years like the use of foam technology. Nitrogen and carbon dioxide foams have been used to fracture stimulate wells and though it can limit the water usage it quite expensive. Also, pre-fracture handling of the nitrogen or carbon dioxide and post fracture back production of either gas can result in some environmental concerns (leaks, excessive gas flaring, and clean-up). As a result, the use of foamed fluids in hydraulic fracturing has waned in recent years. Although, there is no universal stimulation technique that can be applied throughout the world whenever you want the stimulation technology to be used heavily depends upon the location, formation type, environmental regulations, stress regime, etc. Figure 2.3 shows the lab preparation of a foam fluid that will be used in hydraulic fracture operation.

Figure 2.3. Foam technology (Haliburton, 2013)

Different considerations should be takeninto account for more efficient hydraulic fracture operations. Some of them are major such as geologic and petrophysial considerations; others are miner considerations such as well testing, well logging and core analysis considerations. The combination of these considerations can illustrate a full picture of the reservoir behavior prior to and following the fracture treatment.

2.3. GEOLOGIC STUDY

Several parameters should be considered while doing the geologic study such as:

2.3.1. Drainage Area. Represents the area from which hydrocarbons are recovered such that the size and shape.

Which is a function of geology (formation thickness, pinchouts, faults, channels, permeability, etc.) and the fracture dimensions (the fracture length, height, and conductivity). For example, in a low permeability reservoir with a long and highly conductive fracture the shape of the drainage area will be "cigar shaped" even if the geologic considerations are benign. In permeable reservoirs, however, the size and conductivity of the propped fracture has little to do with the size and shape of the drainage area.In other words the drainage area represents the ration of the fracture length (LF) to the drainage radius (re), these have to be optimized to optimize the hydraulic fracture treatment. It is possible to determine optimum fracture length and drainage radius by constructing a relationship between flow rate and time as function of fracture length and drainage radius. In contrast, lenticular reservoir drainage radius is a fixed parameter and not a function of the fracture treatment. Most engineers can optimize the propped fracture length by optimizing (LF/re) ratio. Understanding the geologic deposition pattern is important before designing a specific fracture treatment to get the probable size of the reservoir for design and stimulation treatment.

2.3.2. Lithology. It is important to study the reservoir lithology before designing a fracture treatment. For example, in sandstone reservoirs, a water or oil based fracturing fluid will probably be selected. In shallow carbonate reservoirs, acid based fluid is probably can be applied. The lithology of a reservoir is an important factor for analysis of open-hole geophysical logs as well. Furthermore, lithology can be important depending upon certain geologic environment. For instance, cementing material might be crucial importance in cases where cement is holding together a fairly soft rock, acid should not be used then to break down the perforations or stimulate the reservoir.

2.3.3. Clay Content. Knowing the type and distribution of the materials that fills the pores is very important. Many low permeability reservoirs contain a large quantity of clay minerals in the rock fabric and pore space.

Scanning electron microscope (SEM's) and X-ray diffraction analysis can be useful to understand the type of clay and its distribution in a particular formation.Different types of clayscan affect and reduce the permeability of a sandstone reservoir. It is a fact that different types of clay can affect the permeability of a sandstone formation as shown in Figure 2.4.

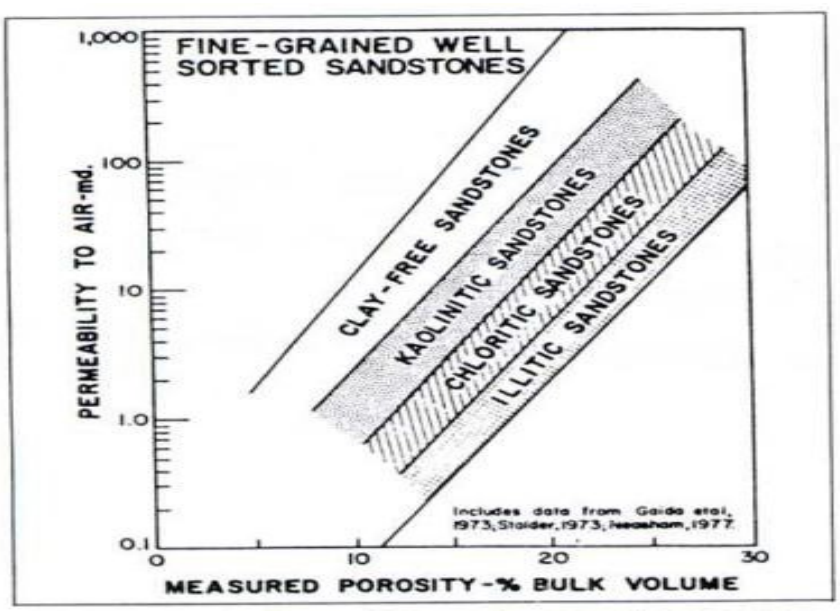

Figure 2.4. Permeability relationship of clay sandstones (John Gidley, 1990)

2.3.4. Fault Patterns. Any geological study must consider the knowledge of regional and local stress pattern in the study area. In-situ stresses are very important in the design of a hydraulic fracture treatment. Hubbert and Willis explained that localized and regional stress pattern in an area are controlling factors in determining to orientation of the hydraulic fracture and that state of stress underground is not hydrostatic but depends on tectonic conditions. (Willis, 1957).We also should consider other aspects to get better results, such as well logging, mechanical properties, and stress profile.

Well logging is used to obtain geomechanical logs of a particular formation by using well logs. A conventional log analysis usually provides values of porosity, water saturation and net thickness of the pay zone formation. These results from well logging plus PVT properties which has obtained from the laboratory measurement of the reservoir fluid, can be used to estimate oil and gas in place by the volumetric method as shown below.

$$A = \pi r^2 \tag{2.1}$$

$$OOIP = \frac{[A \times h \times \emptyset \times (1 - swi)]}{\beta_{oi}} \tag{2.2}$$

Where:

A = The drainage area of the reservoir, (acer)

h = net pay thickness, (ft)

$\emptyset$ = reservoir porosity, (friction)

S_{wi} = reservoir water saturation, (friction)

β_{oi} = oil formation volume factor, (bbl/stb)

Recognize, that a small error in porosity or water saturation can led to a difference in the estimation of reserves. So, it's important to get good quality logs and analysis results to avoid any issues determining resource size estimation.

2.4. MECHANICAL PROPERTIES

Knowledge of a hydrocarbon producing formation and its surrounding formations is very important to predict the hydraulic fracture dimensions. These mechanical properties include Young's modulus, shear modulus, Poisson's ratio, and compressibility. The best value of compressional wave velocity and shear wave velocity are obtained by recording a full wave form sonic signal from a long spaced dipole sonic log or sonic scanner as shown in the Figure 2.5.

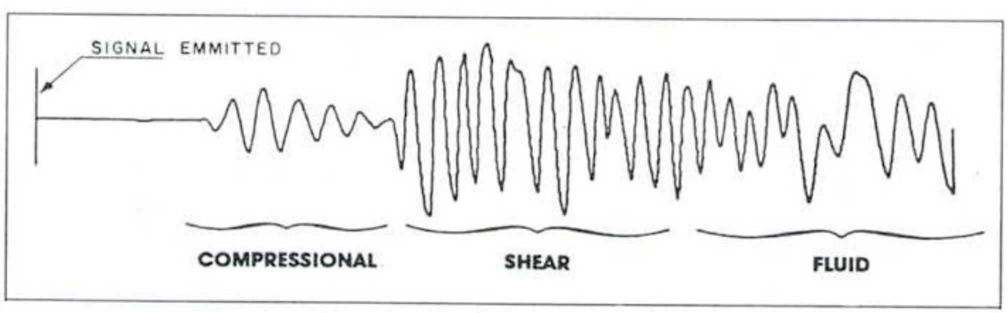

Figure 2.5. Sonic wave form in borehole (John L. Gidley, 1990)

The determination of mechanical properties requires obtaining both compressional and shear wave travel times for the formations. It was first recommended by Pickett that the ratio of shear wave travel time and compressional wave travel time was a function of lithology. With that being said, the relation between compressional wave and shear wave travel time for a number of different lithologies and fluid saturation can be demonstrate in Figure 2.6 as shown.

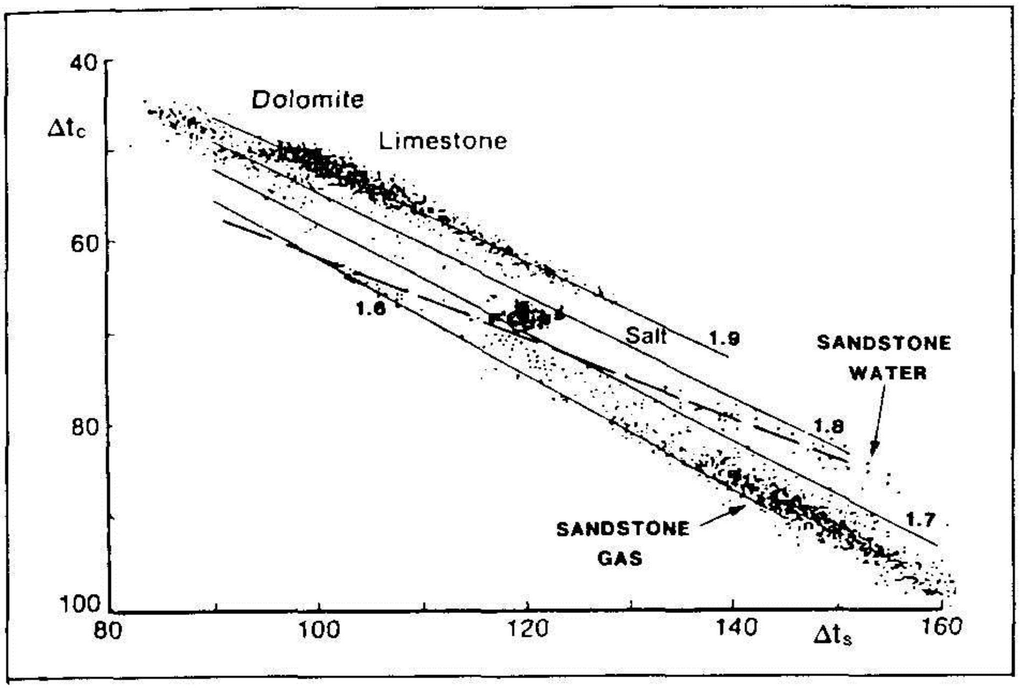

Figure 2.6. Well log example cross plot (John L. Gidley, 1990)

Where the velocity ratio has been summarized in a table as shown:

Table 2.1. Velocity ratio from cross plot

Lithology	Δts/Δtc
Sandstone/water	1.78
Sandstone/Gas	1.6
Dolomite	1.8
Limestone	1.9

Fromthe above relationship we can determine the amount of dolomite, limestone, shale and probable fluid content then an estimation of shear wave travel time. Once velocity ratio is estimated then the value of Poisson's ratio and Young's modulus can be calculated.

2.5. IN-SITU STRESSES AND STRESS PROFILE

In-situ stresses and the stress profile is decisive in designing a fracture treatment that is confined within the productive interval. Figure 2.7 shows the effect of the stress field on fracture propagation. The in-situ stresses control fracture azimuth and orientation (Vertical and horizontal), fracture height growth, fracture width, treatment pressure and fracture conductivity. Fractures grow perpendicular to the minimum in-situ stress direction, thus, stress direction can affect well-placement and spacing decisions (Willis, 1957).

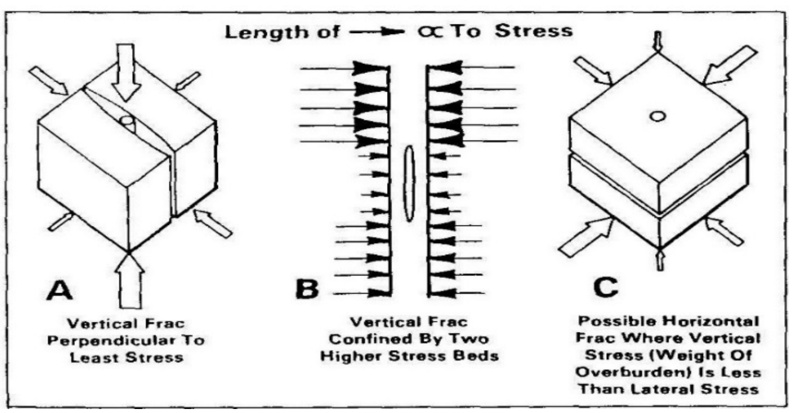

Figure 2.7. Effect of stress field on fracture propagation (John L. Gidley, 1990)

There are many techniques available today for estimating stress orientation, including tiltmeters, microseismic surveys, fracture image logs, and core-based measurements. Fracture height growth and fracture width affect the propped fracture half-length for a particular treatment size. As a result, understanding the in-situ stress is critical to fracture design. Figure 2.8 illustrates the effect of stress contrast on the hydraulic fracture propagation.

Parameters in fracture modeling include, treatment design and optimization. In addition, Conductivity of the proppant pack is greatly influenced by the in-situ stress profile. For example, under a high-stress condition (which typically is 4000 psi or greater), 20/40-mesh Ottawa sand will be crushed resulting in a loss of conductivity; consequently, higher cost resin coated or manmade proppant are needed to provide suitable conductivity to improve the stimulation as shown in Figure 2.8.

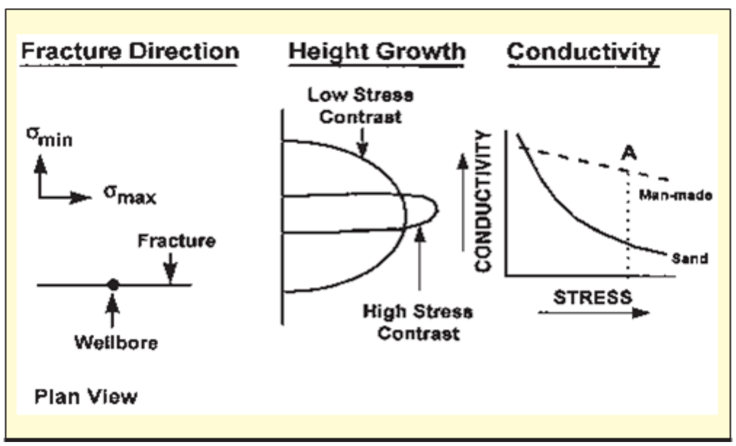

Figure 2.8. The hydraulic fracture stresses application (Michael J. Economides K. G., 2000)

Once the we know for sure that hydrocarbons are present in commercial quantities in the reservoir depending upon the analysis of geological, log and core data, a series of pre-fracture well tests should be designed, conducted, and analyzed to evaluate the formation. The purpose of a well test is to estimate the reservoir permeability, skin factor, and initial reservoir pressure along with geomechanical properties such as in-situ stress and the fluid loss coefficient. The skin factor is a quantitative measure of the formation damage. If we have damage then the value of skin is positive but if the formation is stimulated the skin value will be negative. It isn't easy to analyses post fracture well tests, optimize fracture length and to design the optimum proppant for fracture treatment if the value of in-situ permeability is not known are determined from pre-fracture well tests.

2.6. HYDRAULIC FRACTURE SOFTWARE

There are principally five commercial software packages that are available in the oil and gas industry, which utilize a 3-D (three dimensional) model of the hydraulic fracture treatment. These software systems include FracPRO, FracCADE, MFRAC, GOPHER, and STIMPLAN. While the first three of these models are pseudo-3D models GOPHER and STIMPLAN are truly fully 3D models. GOPHER is a three dimensional finite difference model while STIMPLAN is a fully three dimensional finite element model. Due to a lack of software availability a complete comparison of these software systems is beyond this study. However, the study will focus constructing a fracture model to determine the optimum fracture design. (Carter J. et al, 2000). STIMPLAN was used for this purpose.

STIMPLAN (NSI Technologies, Inc.) is a software package that contains both pseudo 3-D and true fully 3-D finite element numerical model. STIMPLAN finds implicit finite difference solutions to basic equations of mass balance, fluid flow, height growth, and elasticity. The software provides modeling capability for complex hydraulic fracture situations; for instance, fracture height growth, foam fluids, tip screen-out, and proppant settling.

STIMPLAN has the ability to allow the user to import log data, which helps in developing a geomechanical description of the reservoir. Based on an input pumping schedule, the software provides a predicted fracture height, width, and length, based on fracture fluid, pump rate and proppant concentrations. The model can run in real time to track the treatment as it is performed in the field. STIMPLAN also can provide a prediction or history match of the production data from a fractured well (using a single phase numerical simulator), and use an economic routine for determining the net present value of the particular treatments production profile. The software also generates hydraulic fracture optimization, design, and stimulation post appraisal reports for the user.

Hydrocarbon production from low permeability formations has been appealing in the last 20 years across the globe as part of the economic developments more precisely in the Middle-East. With that being said, such reservoir formations require a special technique for stimulating this kind of rock. The most commonly used technique to recover hydrocarbons from these resources economically is hydraulic fracturing. Hydraulic fracturing is considered one of the most valuable stimulation techniques for enhancing the rate of recovery of hydrocarbons (oil & gas).

Hydraulic fracturing can also extendhydrocarbon production from older fields. It is the best technique so far that challenges geologists who believed that it is impossible to produce oil and gas from a formation such as shale gas, coalbed methane, and/or tight sand. Hydraulic fracturing also has long term economic effectiveness that is too obvious to ignore. The laboratory testing and mathematical simulation of fracture geometry work effectively to mitigate any risk that might appear during the operation (Economidos et al., 2010).

Many factors have led to rapid growth of the use of hydraulic fracture technology for most of the unconventional formations. One of the most positive impacts is combining of horizontal drilling with hydraulic fracturing to extract the natural resources economically with faster return. At the starting of the rapid development of the industry, gas prices were significantly increased causing this profitable industry to associate. The industry has moreover been exempted totally or mostly from the Safe Drinking Water Act, Clean Water Act, Clean Air Act, Comprehensive Environment Response Compensation and Liability Act, Emergency Planning and Community Right to Know Act, Endangered Species Act and the Resource Conservation and Recovery Act. These exemptions mean that gas producers' openings contribute intensely in hydraulic fracturing with few regulations (Biello, 2010; Trotta, 2011. U.S. EIA 2012).

The expanding amount of the hydraulic fracture operations all over the world can give us a great indication of how helpful and useful such a technique is to perform more on tight sand formation, especially in the Middle East and North Africa. This research tries to approach with realistic fracture design at in-situ condition, fluid and proppant selection, pump rate, and pad size. The theory behind this concept has been illustrated and supported with case studies where it took place from oil and gas field in Libya with tight sandstone formation.

3. LITERATURE REVIEW

This literature review covers studies related to previous work conducted in tight sand formations and previous work of interest to hydraulic fracture design. This literature review helps provide an understanding of hydraulic fracture optimization design process.

3.1. IN-SITU STRESSES

In the past ten years, the growth of producing hydrocarbon from unconventional resources such as shale and tight sandstone formations has attracted the attention of companies across the globe. The optimum fracture treatment depends on dimensions of the hydraulic fracture; therefore, any change in the in-situ stresses will greatly impact on the fracture dimensions. Microseismic devices provide field engineers with ideas about fracture dimensions. In the field, focusing on programs including downhole arrays or surface sensors is mainly used for calibration.

Chitrala et al. (2011) performed a laboratory experiment to study different applied stresses for tight sandstone formations. In their experiment, proper fracture azimuth was determined with arrays. Furthermore, they duplicated the principle stresses, which are the main controller of the hydraulic fracture orientation, by applying horizontal stress. Their theory is that it is possible to understand the orientation and dimension of the fracture by only applying a different magnitude of horizontal stress. They used sixteen transducers with a frequency range from 50 KHz to 1.5 MHz to translate the seismic waveforms. The sample used in this experiment has been taken from the Lyons sandstone, Oklahoma. The determination of azimuth velocity was performed via circumferential velocity analysis

(CVA). The CVA is a pulse transmission technique where the velocity is a function of azimuth. The experimental results showed a very thin symmetric fracture when high external stress values reaching 4000 psi were applied and shear failure was shown to be responsible for most of the failure mechanisms in the experiment.

Hagemann and Ganzer (2012) conducted a study about the reorientation of the hydraulic fracture in tight sandstone formations. Their research claimed that hydraulic fracture orientation mainly depends on the stress state of the target formation. Hagemann and Ganzer built their model to investigate the poroelastic effect, which is a theory created by Biot in 1935. The concept of poroelasticity is when porous media allows fluid in solid rock to move freely in the pores and rock framework. These two will interact in one system and can help increase the pore pressure in case the fluid is still inside the rock. By generating a model, this investigation showed the physics of the interface's poroelasticity. Hagemann and Ganzer also provided input to this study that included an isothermal formation, constant wellbore flowing pressure, no flow boundary, single-phase Darcy's law flow behavior, and uniform initial stress state. The model was performed in two dimensions, emulating a reservoir with infinite thickness. These dimensions were 1600 m in x-direction and 1200 m in y-direction. The reservoir was saturated 100% with gas, and the temperature was constant at 110 °F. The conclusion of their study showed that if there is a small difference between the minimum and maximum horizontal stress, then the reservoir characteristics will be influenced and the propagation and the direction of the fracture will have a significant height growth.

Ohati and Mikada (2017) examined the differential stresses and anisotropy of different kinds of formations. They claimed that it is common knowledge that hydraulic fractures propagate in the direction of maximum stress. However, some types of rocks have strength anisotropy that can form a failure plane over the weak plane. In their experiment, they used a numerical model called DEM (discrete element method) to show the brittle condition of rock. At the beginning, they performed a calibration process to avoid any error when measuring the anisotropic properties via DEM. Following the calibration, the propagating direction of the hydraulic fracture was illustrated based on both the anisotropic properties and differential stress magnitude. The results showed that when the anisotropy is in medium range, the propagation of the hydraulic fracture will be in the direction of maximum principal stress. In contrast, the strong anisotropy will show a failure along a weak plane and the fracture will propagate in the direction of the minimum horizontal stress.

Baig and Urbancic (2015) made an evaluation regarding stress and strain during the fracture operation. The evaluation was based on multiple well records of microseismic reading in order to observe the strain and stress in the reservoir. Geomechanical models were also used in the evaluation to assign the dynamic stress regime, which controls the propagation of the hydraulic fracture. The authors started by examining the mechanism that activates several fracture sets in the reservoir, which can create a damage zone. They then analyzed and measured the clustering methodology around the wellbore. The evaluation showed how directly the dynamic strain is important during the treatment because it affects deformation. This information is especially important in calibrations of the geomechanical models because it shows that propagation and fracture geometry are controlled by stress and strain.

3.2. TREATMENT AND CHARACTERIZATION DESIGN OF FRACTURING FLUID

The selection of hydraulic fracture fluid is very important for better proppant transport in the fracture. Many companies these days have put a lot of effort into developing different kinds of hydraulic fracture fluid that are cheaper and not harmful to the environment. Fracture fluid relies on reservoir properties such as reservoir fluid properties, bottomhole static temperature, rock mechanical properties, and formation permeability. The development of hydraulic fracture fluid over the years has encouraged many operation companies to use fluids that are more viscous in order to carry higher concentrations of proppant to create conductive fractures in higher permeability formations. In the early 1960s, the main fracture fluid was water, which carried a low proppant concentration. This was called slickwater fracture treatment. By the 1970s, viscous fluids such as cross-linked polymer fluids had been introduced to the industry,. The new fluids had the ability to carry more proppant than water (Sharma et al., 2004). In recent years, as the fracturing activity in the low permeability unconventional shale market has dramatically increased the need for higher proppant concentrations has been reduced and slickwater fracturing has had a resurgence.

Holditch and Ely (1973) performed a comparison between wells stimulated with high viscous fluid and high proppant concentrations and wells with low viscosity fluid and low proppant concentrations. The study was applied to compare the long-term productivity of gas wells and the fluid carrying the proppant with different concentrations in a sandstone formation in South Texas. The average depth for the wells was 11,000 ft, and the average bottomhole temperature was 275 °F. All the wells had low permeability and porosity. The authors noticed that the change in the productivity index before and after the treatment in high viscous fluid carrying a higher proppant concentration was 5.2, while the productivity index for the low viscous fluid carrying a low proppant concentration was 10. However, most wells stimulated with high viscous fluid sustained higher productivity over time than the wells stimulated with lower viscous fluid. The study was performed again for the same wells after two years, where the average productivity index for high viscous fluid wells was three times higher than the wells with low viscosity fluid. The conclusion of their study was that the reservoir temperature enhanced the gel fluid, which allowed it to break and clean-up the fracture fluid in the fracture. In summary, when the temperature of the formation is high and there is low permeability covering the whole formation, it is better to pump higher proppant concentration and use a highly viscous fluid in order to increase the productivity index of the well.

Wenjun (2010) conducted a laboratory study of a new type of fracturing fluid that is suitable for a low-pressure and low temperature formation. The study was performed for eight wells in Daqing oil field in China. Dealing with a shallow reservoir with low temperature made Wenjun choose organic titanium and organic zirconium as cross-linked base fluids in the hydraulic fracture application for all the wells. The fluids had strong intermolecular bonding force that is recommended in low temperature formation, and it is easy to flow back. According to the laboratory study, the cross-linked fluid was broken and the viscosity of the fracture fluid remained almost constant after four hours from first pumping. The ratio of flow-back fluid improved by 35% more than any other fluid before.ohnson and Wright (1993) performed on-site analysis of hydraulic fracture fluid injection by using a foam technology. They tried to study the responses of the reservoir toward foam that would be used as carrying fluid for the proppant. Around 75 gal of foam was pumped into the well. Fortunately, the leakoff was below 2%, and net pressure showed no reaction of stresses that might resist the fracture growth. However, initial pressure rapidly declined, and closure pressure occurred after 20 minutes, which reduced the convection. By the end of pumping the foam, the researchers concluded that installing the foam technology in the sandstone formation made it very difficult to gain the fracture pack due to the high value of fluid efficiency and lower proppant concentration that would be pumped with such technology.

Smith (1965) conducted a study to determine the most stable treatment fluid that should be used in hydraulic fracture applications. Smith explained in his paper that hydraulic fracture treatments depend on factors such as orientation of induced fracture because it dictates that the suitable procedure should be employed in designing the fracture fluid. He classified the fracture fluid to two categories: The first is Newtonian fluids, which are defined as fluids with constant viscosities, such as crude oil, fresh water, salt water, and some acids. The second is non-Newtonian fluids, which are defined as the fluids with viscosities that are not constant, normally a Newtonian fluid converted to a non-Newtonian fluid when additives are introduced to the fluid, such as gelling agents, emulsifiers, friction reducers, water-based gel, and hydrocarbon gel. In the study, he applied a vertical fracture treatment design in laboratory to detect the best fluid that can be used in the fracture application. After he tried thirteen types of fluids, he concluded that gel has the ability to adopt a higher proppant concentration than any other fluid he used in the experiment (i.e., a large amount of viscous gel can create a vertical fracture very easily).

Friehauf and Sharma (2005) performed an evaluation study for different designs to add more energy to the fracture fluid. Enhancing or energizing the fracture fluid creates a high gas saturation around the wellbore, more precisely, in the invaded zone, which makes the gas more functional for flow back. One third of the fracture operations in North America perform by energized gaseous phase. Most of the energized fluid is used in reservoirs with very low pore pressure, low permeability, and water-sensitive formation (Gabris, 1986; Mazza, 2001). Friehauf and Sharma presented a sensitivity analysis study to address the effective parameter that can be modified for optimum fracture design without any field trails. Their model showed that gases with high solubility perform better than gases that are not soluble. For example, co_2 has higher solubility range than n_2, so they eliminated n_2 from the study and focused more on co_2, where they started with adding methanol in liquid phase in order to increase the solubility of CO2 which will reduce swelling of the clay in the formation.

They concluded that before energizing the fracture fluid, the phase behavior must first be used to control leakoff of the fluid. If the drawdown pressure is more than capillary pressure, we can remove the damage in the fracture face generated by loss of water-based fracturing fluid. The energized technique is most likely applied to formations in case the drawdown pressure is not enough to remove the liquid. High solubility will promote the fluid's ability to avoid any damage near the wellbore.

3.3. PROPPANT SELECTION

The first hydraulic fracture treatment was performed without proppant in 1946, but the fracture did not remain open for long. In 1947, sand from the Arkansas River was introduced to the industry and used to prop the first fracture. The development of the proppedt fracture expanded in the early 1960s with the use of resin-coated sands and bauxite, which can keep the fracture open for long time. The main role of the proppant is to keep the hydraulic fracture open in order to preserve the well conductivity, which can make the well operate in an economical way. Nowadays, choosing the proper proppant for the specific hydraulic fracture application has become very important for cost-effective reservoir conditions and long term well stability.

Leshchyshyn (2003) performed a field study about the effect of proppant selection on well productivity for a sandstone formation in Alberta, Canada. He used nine fractured wells with ceramic proppant and compared with three wells fractured with sand proppant. Leshchyshyn additionally examined the hydraulic fracture productivity. The wells in this study were stimulated with 185 tons of proppant for each well from one to five stages. After the first year, the production of fracture sand wells was 302 MMscf of gas, while the production of the fracture ceramic wells was 402 MMscf. He noticed that the returned cost of ceramic proppant was recovered after 31 days, which is considered a profitable increase. He recommended using ceramic proppant, which is rounder and more spherical with afiner size distribution to improve the fracture conductivity over sand. The higher the fracture conductivity is, the higher the production rate is during transient flow.

Rixe et al. (1963) presented a procedure to estimate the embedment pressure of the target formation, which can give a great indication of the rock resistance to embedment throughout a proppant agent life. Rixe and his colleagues performed an experiment to obtain the hydraulic fracture capacity in order to select the best propping agent. They built correlations based on the long-term and short-term hydraulic fracture capacity just to eliminate the nonfunctional proppant agent. The types of samples used in the experiment were taken from formations in different zones starting with carbonate from Louisiana, sand from Oklahoma, sand from Canada, lime from Texas, and sand from Wyoming. To estimate the embedment pressure of the formation, they used a steel ball with 0.05 in. diameter located on the top part of the platen of the hydraulic compression machine. The samples were placed on the lower part of the platen of the machine. The purpose of the steel ball was to embed to a certain depth; for instance, the ball in the experiment was embedded to a depth of 0.00625 in. The load required to reach this depth was recorded. The results showed that the diameter of pore space increased as the embedment pressure decreased. The form of pore space was normally made by the mechanical properties of the formation. The formation embedment-pressure test can measure the resistance of the rock inside the formation to embedment by using proppant agent. The correlation of Rixe can be used to aid in the selection of the proppant_agent for the desirable hydraulic fracture capacity.

Anderson and Seccombe (1982) applied a study to evaluate the performance of bauxite as a proppant agent in hydraulic fracture application for a tight sandstone formation in Wyoming. Generally, bauxite proppant is used when the fracture pressure or closure pressure is above 8000 psi. When the pressure exceeds 8000 psi, sand tolerates considerable crushing, generating a large reduction in permeability. On the other hand, the areas where the closure pressure ranges between 6000 to 8000 psi, it is difficult to assume which kind of proppant to use: either sand or bauxite, depending on the reservoir condition. In addition, an economical model and simulation study were used for the optimization of the proppant fracture and fracture length. These two models can help to ensure that bauxite is the best choice for this reservoir in Wyoming. At the end of the evaluation, Anderson and Seccombe recommended that bauxite should be assigned as fracture proppant in this reservoir because economically it is greater than sand as a proppant agent at high reservoir permeability. The fracture half-length increases with decrease in the permeability.

David (1985) performed an experiment to evaluate the optimum proppant that can be used in deep wells with high closure pressure. Different kinds of proppants were used in the experiment, such as sintered bauxite, ceramic, and resin-coated sand. David used 15 lbs. of 20/40 mesh sand after it was heated in the oven to reach 450 °F. The sand was steamed inside the muller and the temperature was monitored as it declined. These procedures were performed for the resin-coated sand because the phenol-formaldehyde in resin-coated sand is a function of temperature and time. Based on his results, David concluded that resin-coated sand can provide a high conductivity fracture in deep wells at closure pressures less than 6000 psi.

In the last twenty years, many companies have started to perform site tests for the proppant that will be used in fracture treatments. The idea of verifying proppant capability before and after the hydraulic fracture treatment can add an important value to the fracture stimulation. For instance, Freeman et al. (2009) developed a field test protocol for use by an operating company to ensure that a proppant can meet the job expectation. The company established new technology that created quality-control data at the wellsite to use for comparison with public domain data. These data give the site engineers insight into how the chosen proppant will perform, and help to avoid running an expensive conductivity test on every job. This technology can easily sample the proppant at a well site before the fracture treatment. However, this technology requires that the proppant follow the American Petroleum Institute (API) and the International Organization for Standardization (ISO) regulations. In 2005, Freeman and his team introduced their technology in Zapata

County of south Texas, USA, in order to apply it to a multi-stage fracture job for tight sandstone formation. Twenty fracture treatments were sampled, and the proppants that were used are listed below:

1. Premium-resin-coated curable sand
2. Resin-coated economy ceramic
3. Resin-coated lightweight ceramic
4. Intermediate-strength ceramic

The results showed that resin-coated sand had a negative effect on conductivity when it was compared to the public domain database. Resin-coated economy ceramic has a high chance to be crushed in about 10 months compared with the public domain database. Resin-coated lightweight ceramic and intermediate-strength ceramic showed great conductivity and resistance to crushing inside the fracture compared with the public domain data.

3.4. GEOLOGY

Reservoir characteristics are very important to understand the geological description which can reduce the time spent on history matching with a reservoir model. A few studies were conducted of the Nubain Sandstone Formation. Patrick and Noreddin (2010) studied the geology and petrophysical approach in regard to the Nubain Sandstone Formation. The study was based on the laboratory measurement of different cores that had been taken from six oil wells in the Sirte Basin, Libya. They used the petrophysical element approach in order to improve the reservoir description and identify geological and petrophysical rock types for the formation. Based on the cores in the experiment and petrophysical element analysis, a significant distinct trend in texture contrast where the finger grained in the middle of the core samples were associated with low porosity and permeability. in addition Nuban sandstone is considered as one of the worst quality rock formations in the Sirte Basin. Figure 3.1 shows the lack of porosity and permeability in Nubain Sandstone formation.

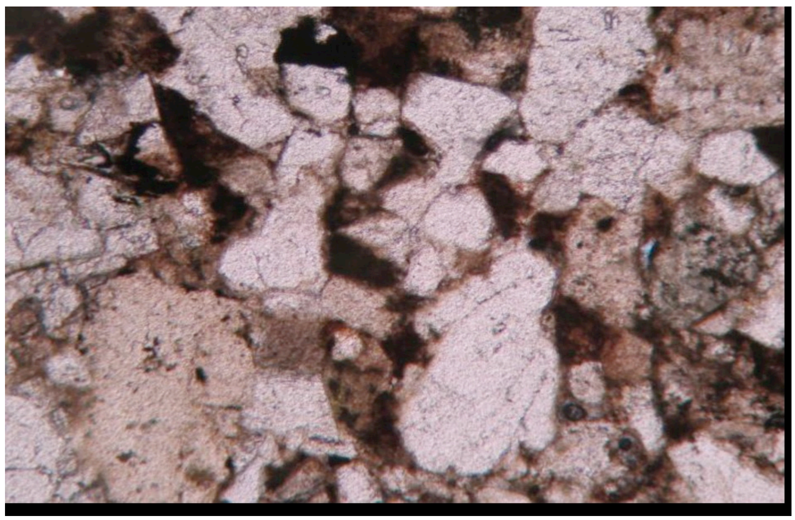

Figure 3.1. Nubain sandstone Sirte Basin

Le Calvez et al. (2016) discussed the important role of the geological consideration in unconventional and conventional formations, predicting the production performance, as well as developing and evaluating stimulation design. This may simplify the study of rock properties of the reservoir and surrounding formations. The observation of the natural fracture network and structure history of a region of interest is the key to performing an optimum fracture model (Miller et al., 2013) Le Calvez's study was based on micro-seismic monitoring, 3D seismic surveys, acoustic impedance (AI), and calculated properties such as Young's modulus and Poisson's ratio, as well as sonic log burial history, micro-seismic surveys, and petrophysical measurements from well logging. He concluded that it is not possible to build a hydraulic fracture model without integration of the fracturing model with a geologic and structure model to estimate the different completion strategies and the optimum stimulation plan.

Van Dam (2000) performed a laboratory experiment on artificial soft rock, which has properties more than 90% similar to sandstone, to study the behavior of closure and fracture propagation. In addition, he developed a simulation model that can help in interpreting and extrapolating the measurement results to field scale. He focused more on rock plasticity regarding the hydraulic fracture. He claimed that such plastic behavior may persuade high tip pressure and will consequently increase wellbore pressure and make the fracture wider and shorter. Then, he used the simulation model for comparison with the experimental results, where he concluded that rock behavior at the fracture tip can be obtained with a consistent zone over which the rock loses its bearing capacity. The experiment results showed that interpreting fracture geometry by relying only on pressure measurement is insufficient. Closure pressure in the experimental rock showed a stress section lower than field stress on the fracture plane.

Zhang and Jeffrey (2007) applied a study about the effect of frictional geological discontinuities. The study was based on sedimentary rock and the affects that fluid flow and frictional slippages will have on the interaction of elastic deformation. This kind of interaction can be generated in fracture blunting crossing the stress contrasts, and sometimes shear strength of discontinuity. Zhang and Jeffrey made a comparison between the results obtained from the simulation study and field observations. They noticed that when the fracture interacts with long geological discontinuities, the fracture growth can be eliminated by the process, while treating pressure increases significantly by high-pressure gradient, which has been made at offsets in fracture channels. The study also revealed that proppant transport may be encumbered due to association with this offset, narrowing fracture width. At the end of the study, they concluded that the increase of vertical stress might lead to decent widths across the interface of different layers.

The importance of hydraulic toughness in hydraulic fracturing is not easy to understand because of the effect of some factors, such as in-situ stress, containment, and the dominate fracture geometry. After his laboratory experiment on sandstone core taken from different wells in Colorado, Rubian (1983) found that fracture toughness has to be included in any design and numerical model for hydraulic fracturing. However, some researchers claimed that stress intensity at the front the tip of the fracture is more likely to be greater than fracture toughness of the rock. Therefore, toughness may not be important in fracture design. Barker (1977) performed an experiment to measure the fracture toughness of sandstone, shale, and siltstones. From the experiment, Barker was able to find the toughness of each type of rock; for example, fracture toughness for sandstone had an average of 1.27 MPa.m^1/2, while shale had an average of 1.46 MPa.m^1/2. He concluded that the toughness of sandstone is 15% less than shale, which can provide great understanding of fracture toughness in the determination of fracture containment and geometry.

3.5. SIMULATIONS OF HYDRAULIC FRACTURE

As hydraulic fracturing has become a significant stimulation technique for development of the tightest formations and low permeability reservoirs, the use of computing models has also become very important. Simulators have the ability to predict treatment designs, additives, pump schedule, injection rate, proppant selection, and fracture propagation. Hydraulic fracture simulators are performed based on realistic values in order to investigate fracture width and geometry, volumetric injection rate of the proppant, optimum pump rate, and the number of stages that can be assigned. Most hydraulic fracture simulators contain three physical processes: fluid flow in the porous media, fracture propagation for both existing fractures and the new fracture, and the deformity of the matrix throughout the formation (Shlyapobersky, 1985; Adachi et al., 2007).

Producing hydrocarbon from tight sandstone formations is growing rapidly, and the use of hydraulic fracturing is the optimum application for that. Sarmadivaleh and Ramses (2012) performed a numerical simulation model by using PFC2D (Particle Flow Code) software to examine the differences and their effectiveness on the interaction mechanism. The model results were conducted from a lab experiment of a sample of sandstone to determine bond strength and friction, which are inputs of the PFC. They initiated the fracture in the center of the sample, and the magnitude and direction of all the stresses were calculated as follows:

σv =2500 psi, σH =2000 psi, and σh =500 psi, where

σv = overburden pressure, psi

σH = Maximum horizontal stress, psi

σh = Minimum horizontal stress, psi

The sample was tested in lab by using the PFC simulator. The results that appeared on the PFC showed that fracture propagation is a function of rock properties in which the fracture starts its direction. Friction coefficient was also a very important property that can play a big role in changing interaction mechanisms.

In the past ten years, many offshore fields in southern Asia have been producing with a high rate; but recently, their production has been decreasing. Nguyen and Bae (2013) applied a simulation study on one of the Vietnamese fields. They used real reservoir data to approach the optimum fracture design technically and economically. The MFrac simulator was used in this study for estimating the best fracture design.

The type of the formation is tight sandstone with a permeability range of 0.1 md to 2 md and porosity from 12% to 16% with natural fracture all over the field. They built a strategy based on the optimum fracture procedure that guarantees actual results based on perforation design, fracture fluid, optimum proppant type, and the reservoir parameters. Based on the software results, the fracture half-length should be between 90-200 m to maximize the net pressure value, and 150,000 lbs of intermediate strength proppant is needed to create this fracture length. The MFrac software used the steady-state fracture model for primary prediction of production rate from the well. Tables 1a and 1b show the input data of the software and an estimation of the production rate.

In some cases, a hydraulic fracture may propagate into different layers. This is a common scenario that occurs in multiple layered formations depending on the magnitude of the fracture stimulation net pressure and the in-situ stress profile and formation thickness. Therefore, it is important to know whether one treatment design or multiple treatment designs should be used. Desroches and Elbel (2000) applied a simulation model for a multi-layer hydraulic fracture design for field X.

Table 1.3 and 3.2 shows all the inputs for Mfrac software for this model and the predict flow rate for this design. It showed how dramatically the flow will increase as the fracture length increase as the researchers expected.

Table 3.1. M-Frac hydraulic fracture inputs

property	Value	Unit
Fluid Type	LN 35	
Proppant Type	C003	
Fracture Length	300	m
Pump Rate	18	bpm
Initial and Incremental Proppant Concentration	1	lbm/gal
Final Proppant Concentration	10	lbm/gal
Maximum Proppant Concentration (at tip)	10	lbm/gal
Target Dimensional Conductivity	30	
Proppant Damage Factor	0.65	

Table 3.2. Flow rate versus fracture length

Solution Point Flow Rates	
Fracture half length (m)	Flow (bbl/d)
Inflow (1) 50	1329
Inflow (2) 75	1501
Inflow (3) 100	1593
Inflow (4) 125	1640

The computer simulator calculates the flow rate through multiple layers and multiple fractures based on the material balance equation (mass conservation and pressure continuity). The simulator treats the fracture in each layer as a pseudo-three-dimensional (P3D) fracture model, which can allow fracture height growth into the closet layer. In addition, the simulator consists of two parts, the rate distribution through multiple layers, and a model for a single fracture layer. The inputs of the simulator are pay zone gross height, in-situ stress pay zone, in-situ stress above, in-situ stress below, Poisson's ratio, Young's modulus, and leak-off fluid coefficient. Desroches and Elbel (2000) showed in their results that near-wellbore screen-out will turn the flow rate into other fractures. Furthermore, due to the increase of the pressure during the screen-out, it will be difficult to carry out the fracture fluid from the wellbore. They recommended a "limited entry treatment technique" to achieve an optimum design for higher flow rate.

Nowadays, simulation engineers have the ability to use a different kind of grid technique, but they have to choose which grid is capable of solving the problem they have. Bhore (2017) conducted a simulation study of hydraulic fracture performance and production rate of tight sand and shale formation. The idea of his study is basically built on two types of grid techniques under the dynamic model of the reservoir: locally orthogonal gridding (PeBi) and hybrid Cartesian gridding. Saphir software was utilized to build a 2D PEBi model in order to perform a horizontal fracture with an optimum rate of 100 bbl/D for 100 hr. Bhore (2017) started with a three-layered homogenous tight reservoir model with multiple thicknesses. In addition, a single horizontal well was multi-fractured in the model to estimate the rate profile and pressure transient for 11 months. The materials used in this model were sandstone, shale, and carbonate. The horizontal well had a length of 1000 ft and total vertical depth of 6114 ft with infinite fracture conductivity. After running the simulator, the results showed that the PeBi grid has detailed information about the near-wellbore geometry, and this grid technique becomes accurate in early time transient pressure models. Bhore compared the numerical results and analytical results that had been made prior to the simulation model, which were almost identical. The Pebi grid helped to perform an evaluation of the transverse fracture for the horizontal wells. PeBi has more of an advantage to offer a solution for inflow performance than the analytical solution, which can save more time.

Chen et al. (2015) discussed the effect of hydraulic fracture interaction with natural fractures that already existed on the pay zone formation via a finite element model. They investigated fluid flow inside the hydraulic fracture, elastic deformation, and fracture propagation. They focused in their study on reservoir conditions such as geomechanical and geometrical properties, intersection angle, in-situ stresses, and treatment parameters which include fracture fluid viscosity and injection rate. The finite element software allowed them to study the effect of the leak-off fluid and height growth in nonhomogeneous formation. The study was built based on tight sandstone, with constant injection rate through a homogenous formation. The distance between the injection point (wellbore) and the natural fracture is 10.3 m. The left side of the injection point is 1.7 m long. Other properties were also determined in the study, such as fracture energy (G_c) = 100J/m^2, tensile strength (T_O) = 1 MPa, and the natural fracture, which has a 10 m height in the Y direction. The authors concluded that the hydraulic fracture tends to intersect with the natural fracture faster when injected with high fluid viscosity and rate. In low stress, the initial conductivity of the natural fracture may affect the intersection between the hydraulic fracture and natural fracture. Figure 3.2 shows the estimated angle that will reach the natural fracture.

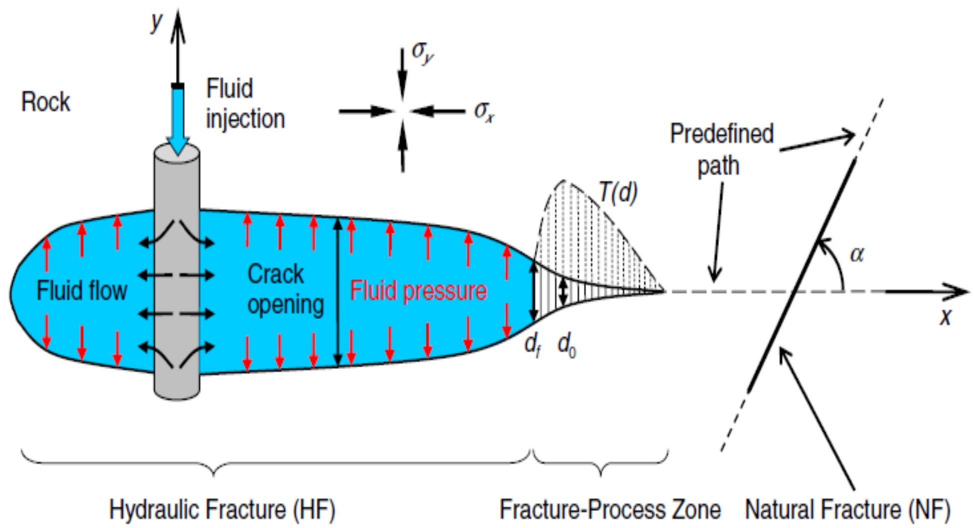

Figure 3.2. The hydraulic fracture propagation toward the natural fracture

4. HYDRAULIC FRACTURE OPTIMIZATION DESIGN

This section discusses the methods used to determine the optimum fracture design for the Nubain sandstone formation in vertical well X-7, field-H, in Libya. This section also details how all available data were used in the study. The calibration data needed for the software were provided from an operating company, which will be called Company-M for confidential purposes. STIMPLAN software was used to build an optimum hydraulic fracture model.

In order to investigate fracturing alternatives for any well in field-H, it is necessary for the model to first match known performance of a vertical fractured well. Well X-7 was selected for this purpose and calibrated using STIMPLAN. The average permeability values for the reservoir were lower than expected for the sandstone formation in the area. Well X-7 was selected mainly because it was noticed that the production rate declined suddenly even though the reservoir properties did not change. Also it was one of the wells recently planned to be fractured, and data were available in a digital format. Due to the political situation in the country, the company could not yet perform a fracturing stimulation on this well.

4.1. WELL BACKGROUND AND FIELD HISTORY

The producing reservoirs in Sirte Basin mostly start from Precambrian basement (igneous rocks) to Olgocene sand, which are considered the main precursor to form fracture porosity in Sirte Basin. Amal, Messlah, Bu Attifel, Masrab, and Gialo fields are the most famous fields in Sirte Basin. Many studies were performed to address the types of the formation in Sirte Basin. However, to date there are some areas still undeveloped. A recent study by Rusk (2017) indicates a presence of outstanding source rock called (Cretaceous Sirte Rachmat Shale).

Field-H was discovered in 1974 with the drilling of the X-1 well. The discovery was appraised in 1982 with the X-2 well, and finally put on production in July 1996 during the drilling of X-3 deviated well. Wells X-4, X-5, X-6 were drilled in the west during 1996, followed by X-7 which was temporarily abandoned despite showing oil due to some mechanical problems after encountering a fault zone. Activity level changed significantly in late 2000, when it was decided to drill the X-8 deviated well. The X-9 and X-10 wells were both vertical and drilled in 2002 to test the easternmost portion of the field and results of the first seismic reservoir characterization study, which were incorporated with positive results. The X-11 well was drilled in late 2002 in the far south of the field. Seismic results of this well showed thick sand in the area, and it was presumed to have undepleted pressure.

Well X-7 is a development well drilled to a TD of 13,005 ft., penetrating the UNSS (Upper Nubian Sand-Stone) at 12,122'-12,207' KB, NMS (Nubian Middle Shale) at 12,207- 12,524 ft and the LNSS (Lower Nubian Sand-Stone) at 12,524-12,880 ft. Based on open hole logs conducted in July-2013. The UNSS and LNSS are the targeted reservoirs with pay zones of 61 ft and 286 ft, respectively, whereas the NMS is considered non-reservoir. Open hole (OH) logs showed low porosities of 7.4% and 7.9% and poor (tight) permeabilities of 2.5 md and 3 md for the UNSS and LNSS, respectively. The operator initially planned to perforate, fracture and test these two formations separately. Figure 4.1 shows the location of the well X-7.

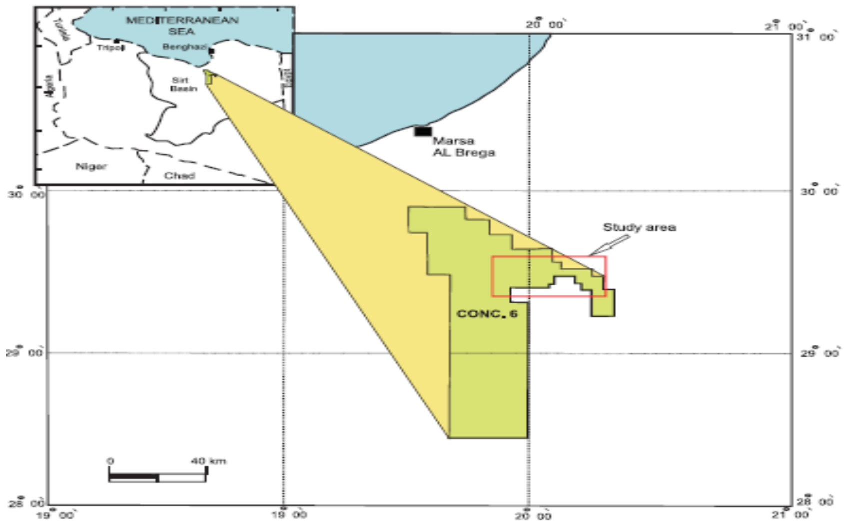

Figure 4.1 Location map of the study area in Sirte Basin, Libya

4.2. X-7 WELL CONFIGURATION AND HISTORY

There are three productive interval sections in well X-7, two layers in the Lower Nubian Sandstone and one in the Upper Nubian Sandstone. The Upper Nubian Sandstone is found from 12,132 ft to 12,208 ft, and the Lower Nubian Sandstone layers occur from 12,562 ft to 12,670 ft, and from 12,700 ft to 12,810 ft. Figure 4.2 provides the wellbore schematic for well X-7. Data from well X-7 was used to create a STIMPLAN fracture simulation model that would match aspects of the fracture treatment of this well and be able to match results from STIMPLAN fracture simulation production forecase with actual post-frac production found in well X-7. This match is important because it allows for a calibration of STIMPLAN prior to evaluating fracture optimum design for future wells.

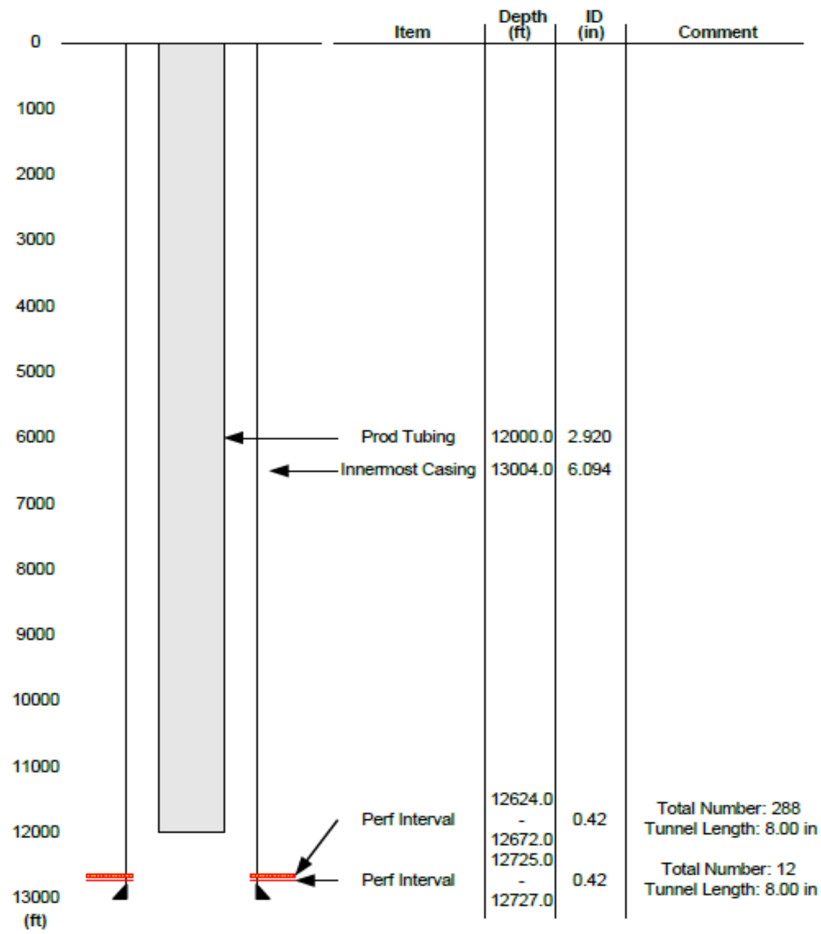

Figure 4.2. Well X-7 schematic

4.3. LOG ANALYSIS

This section discusses log analysis, and how logs are used to determine formation lithology, layering, geomechanical profile, and ultimately define a stress profile for the formations the stress profile determines stress contrasts, which can control fracture height growth.

The most common types of logs include gamma-ray, resistivity, caliper, neutron porosity, and density porosity. The gamma-ray has the ability to read natural gamma-ray radiation emitted by fluid-filled rocks. Some types of shale can release significant natural gamma-rays, and consequently read high on a gamma-ray log, while sandstone and carbonate rock do not release many gamma-rays, so they produce low gamma responses.

The resistivity curve measures the resistance or inversely the conductance of the fluid-filled rock when an electric impulse is measured across the formation. Normally, there will be three curves in the resistivity log record, each providing information on the electric response at increasing penetration depths into the formation. The reading is made in ohm, a measurement of the rock formation resistance to the flow of the electricity. Typically, deep resistivity is of greatest significance for calculating formation saturation and potential hydrocarbon reserve.

There are two types of porosity measurements: density porosity and neutron porosity. Density log consist of a highly radioactive gamma-ray source emitted to the formation. The neutron log refers to a log of porosity based on the effect of the formation on fast neutrons emitted by a source. The Neutron porosity log responds principally to porosity and it is strongly affected by clay and gas. Therefore, the gas zones have a very low apparent porosity.

The sonic log can be identified as measurement of the interval transit time of a compressional sound wave, which is traveling through the rock along the axis of the well borehole. The transit time calculated from the sonic log is a function of lithology and porosity. It is usually displayed in track 2 or 3 of a log, and the units are μsec/m and μsec/ft.

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4.3.1. X-7 Log Data. A digital LAS file contains gamma-ray log, neutron porosity log, density porosity log, sonic compression log, and resistivity log. These files were imported to the STIMPLAN for the analysis. Figure 4.3, 4.4 and 4.5 show combined log responses for the X-7 well. In Figure 4.4, the upper Nubain sandstone formation is identified from 12,122 ft to 12208 ft. The reservoir is comprised of mainly sandstone with some shale beds in different formations. Figure 4.5 shows the log section through the lower Nubian sandstone from 12,550 ft to 12,880 ft. These log data were provided by Company-M.

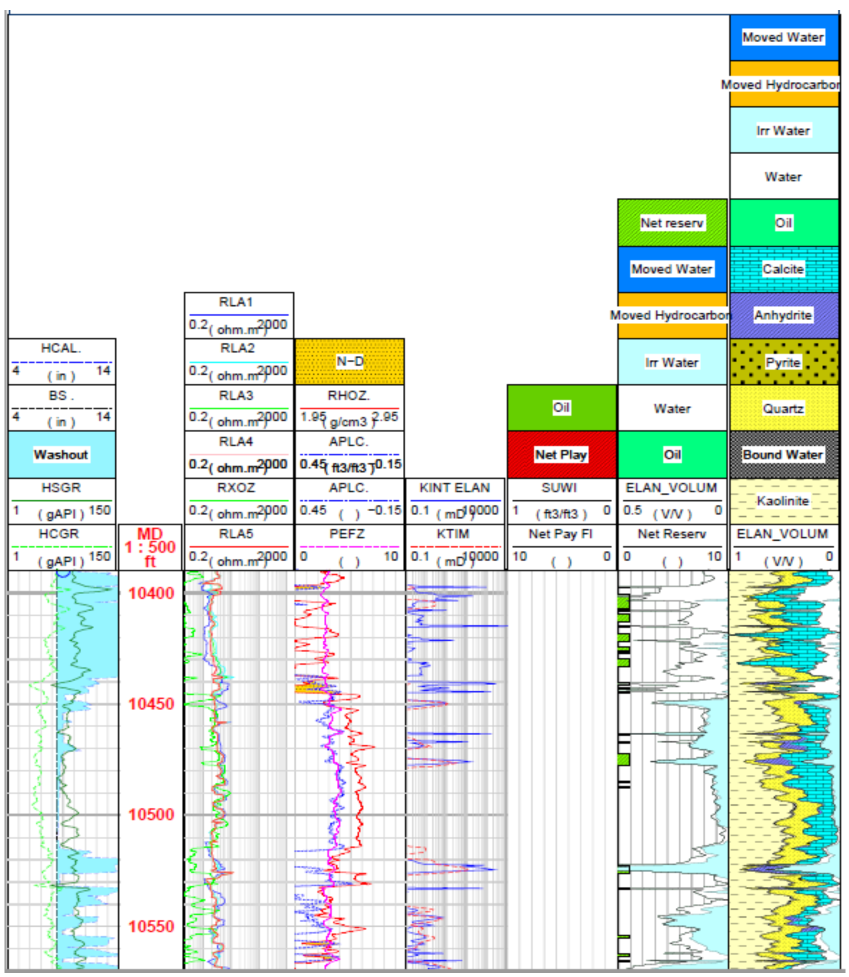

Figure 4.3. X-7 Well log response to 10,700 ft

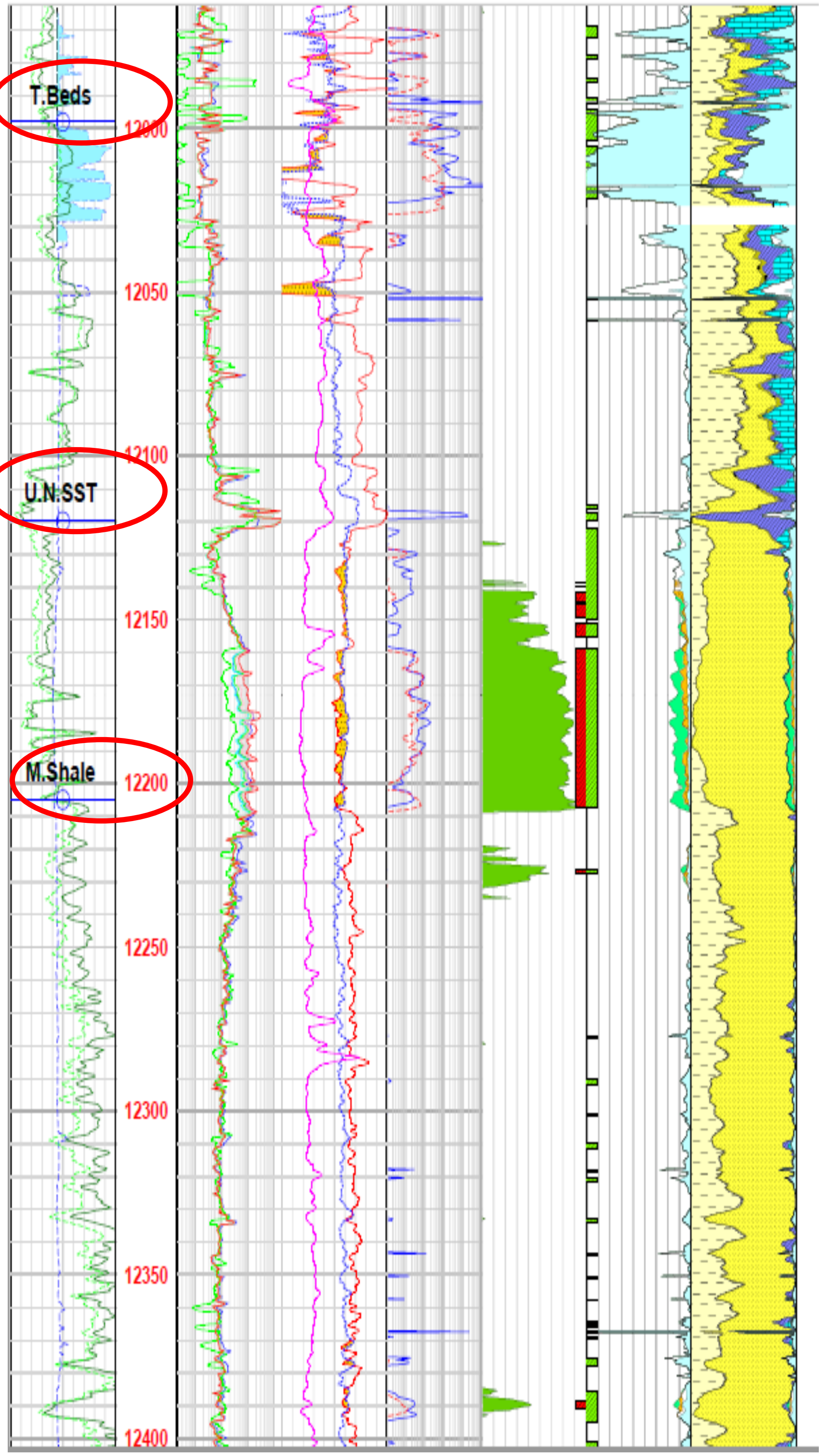

Figure 4.4. X-7 Well log response Middle and Upper Nubain sandstone

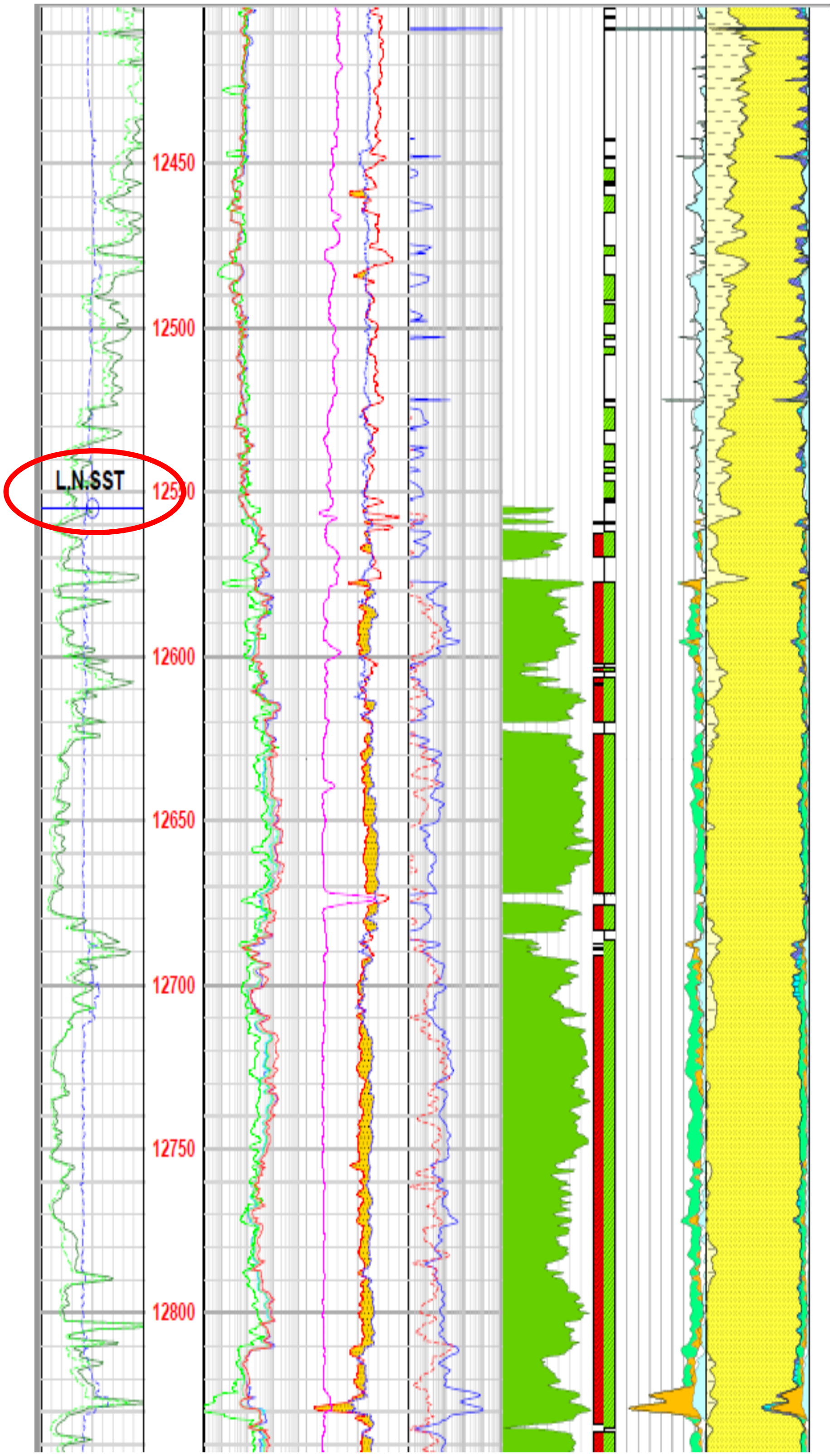

Figure 4.5. X-7 Well log response through Lower Nubain sandstone

Techlog software was used to analyze the well log data. Table 4.1 summarizes the formation top and bottom depths, net pay, average porosity, average permeability, and average water saturation for each zone.

Table 4.1. Reservoir summary of the well X-7

Zone	Top ft	Bottom ft	Net ft	Avg Phi	Avg K md	Avg SW	Phi* H ft
Upper Nubian ss	12,122	12,207	70.75	0.087	2.5	0.183	6.13
Middle Shale	12,207	12,524	22.25	0.073	0.38	0.475	2.96
Lower Nubian ss	12,524	13,000	295.25	0.87	3.1	0.204	25.65
All Zones	12,122	13,000	371.5	0.087	2.6	0.194	32.41

As shown in Table 4.1, the Lower Nubian sandstone has a reservoir pay section much thicker than the upper Nubian sandstone. Therefore, the Lower Nubian sandstone was the focus for determining an optimum hydraulic fracturing treatment.

4.3.2. Identification of Lithology and Layers. It is important to create a stress profile and geomechanical model for the formation and surrounding lithology, to determine fracture height growth or containment for the stimulation treatment. The available data of the LAS file were imported to STIMPLAN to identify geological layers.

Figure 4.6 shows the results of importing gamma-ray, density, resistivity, and sonic files, and the resultant layering. Three distinct layers were identified within the Lower

Nubian sandstone as shown in Figure 4.6. Layers were first selected according to the gamma-ray response. If the gamma-ray is below 60 GAPI, then the formation will be considered sand. If the gamma-ray reading is above 100 GAPI, the formation will be considered shale. Between the 65-100 GAPI will be considered silt.

The layers selected were highlighted within STIMPLAN as shown in Figure 4.6. Different colors shown on the far left side of Figure 4.6 represent each formation; green denotes sand layers, yellow denotes silt layers, and the light purple denotes shale. There were 66 layers identified in total for the X-7 well. All results from this analysis were transferred to the geological layering module to create a stress profile in STIMPLAN.

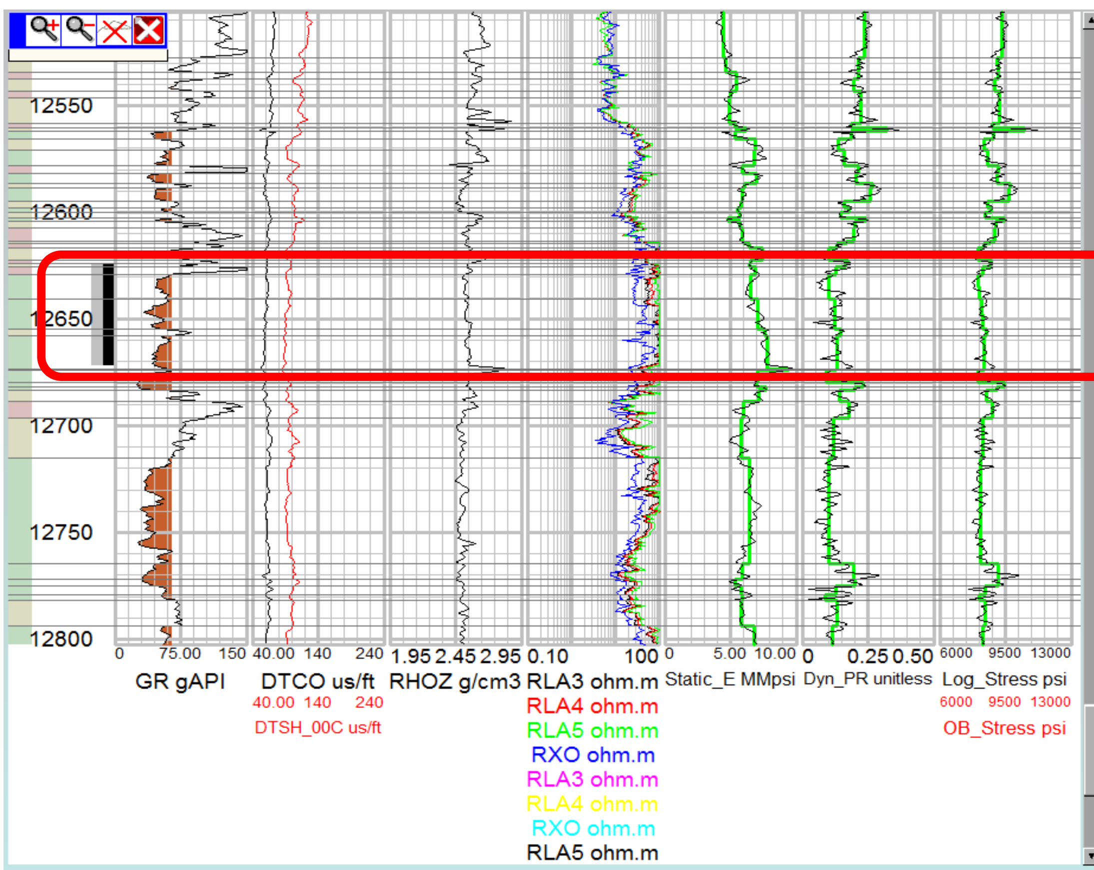

Figure 4.6. STIMPLAN layering identified based on LAS file

After transferring all the log data, a geomechnical profile was developed by adding Young's modulus (dynamic and static), Poisson's ratio, log stress, and the overburden stress. The stress profile is generated by importing bulk density readings from the density log (RHOZ g/cc), compression travel time (DTCO us/ft), and shear travel time (DTSH us/ft) from the acoustic sonic log. These values were entered in STIMPLAN as shown in Figure 4.7.

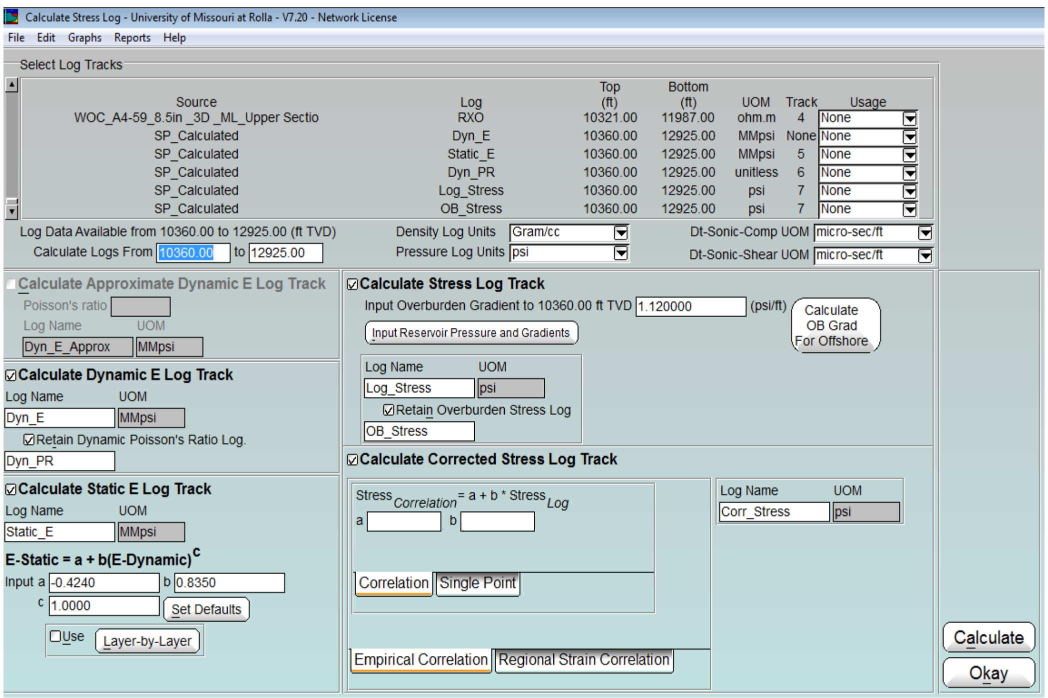

Figure 4.7. STIMPLAN input for determining log stresses

A single value of overburden is required in the calculation of stress. This value must be entered as a gradient. For sandstone, the common value was determined to be 1.12 psi/ft. For the calculation of stress profile, it is necessary to define reservoir pressure and overburden for the type of formation (sand, shale, silt). In the analysis, an initial reservoir pressure of 6000 psi was used, and the gradient was calculated using this pressure and divided by the depth of the target layer.

A stress profile was determined from 10360 ft to 12925 ft, as shown in the right hand track of Figure 4.6. This geomechanical profile is used in the fracture design.

It was assumed that a single hydraulic fracturing treatment, stimulating the most net pay, would provide the greatest economic benefit. Given three distinct layers (one layer in UNSS, two layers in LNSS), the question was how to effectively perforate and stimulate three layers in one treatment. To investigate this, STIMPLAN was used to simulate perforating the UNSS only, the bottom layer of LNSS only, and then the middle LNSS layer only (using existing LNSS perforation depths in well X-7), to model the fracture growth in each case. This analysis showed that perforating the middle layer through existing well X-7 perforations resulted in the greatest amount of stimulated net pay. These perforations are 75 ft above the original oil water contact. The perforations and layer selected for injection are highlighted in red in Figure 4.6 and Figure 4.8 shows fracture height growth through these perforations.

In all cases the fracture initiation from the lower Nubian sandstone formation grew beyond the oil-water contact regardless of whether water, linear gel, or cross-linked fluid was used. The implication of perforating the upper Nubian sandstone is that whether a vertical well completion or horizontal well completion the Upper Nubian sandstone is landing interval. If the upper Nubian sandstone was perforated the fracture growth could be limited to above the oil-water contact.

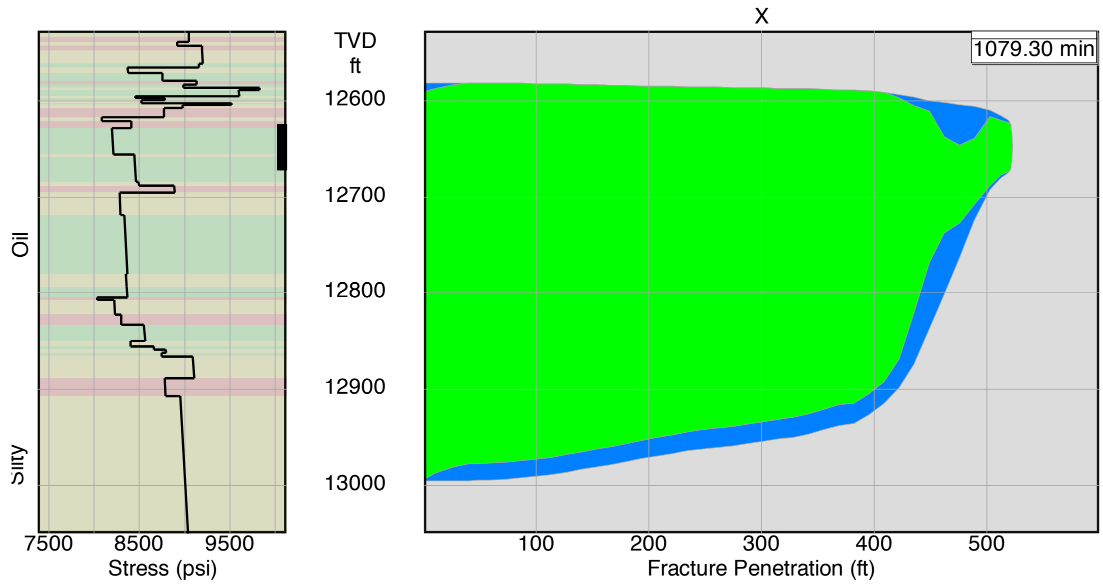

Figure 4.8. Fracture height growth in Middle Nubian sandstone

4.3.3. Pressure and Production Rate Analysis. STIMPLAN'S pressure analysis allows fracture pressure and post-production appraisal from fall off and buildup pressure data provided by the operating company. The pressure decline analysis function allows the user to interpret mini-frac pressure decline data using fracture diagnostics to determine fluid efficiency and leak-off coefficient. In addition, STIMPLAN has the ability to support production history matching with a 3-D numerical reservoir simulator to appraise effects of simulation and provide insights for any upcoming design. Production type curve analysis also provides for quick user-friendly post. (http://www.nsitech.com/software/index.htm)

At the outset of the study, it was expected that full well performance data from well X-7 would be available to match and to calibrate the STIMPLAN model. However, only production data and injection data from the main fracture treatment were available for analysis. The step-rate test and pressure fall off were not available for this study. This is somewhat limiting because without fall off data, it is difficult to completely verify the well performance match.

Production data analysis for Well X-7 were used to match predicted well performance with the fracture design parameters. Five months of production data were available for analysis. The data were provided in an excel spreadsheet which included flowing time (min), bottomhole pressure (psi), and oil production rate (BOPD). Due to confidentiality, a complete copy of the excel spreadsheet of production data is not included in this report.

Since the GOR and the water cut are at acceptable range with 1200 scf/bbl and 11% respectively, only the production rate was used to match well performance with predicted fracture performance. Figure 4.9 shows a screenshot of how the wellbore pressure and rate are imported to STIMPLAN. A production data plot of rate (BOPD) versus time (min) is shown in Figure 4.10. The production test was performed on fixed choke size 32/64" to control the water production from the formation. The production test continued for 28 hrs and was monitored by the service company and the other parties.

This step was made to get a prediction about the efficiency, fluid coefficient, and closure pressure. Due to the lack of data on the lAS file we could not make a full performance of mini frac, but the research instead used the two days production test to study to efficiency of the treatment that will be use on this research.

This study utilized reservoir, fluid, pressure and production data to build a STIMPLAN model for well X-7 in the Nubian sandstone, from which various hydraulic fracturing alternatives are evaluated. Production rate data for two days, (January 4-5, 2014) were used for analysis. The highest flowing rate period, shown in Figure 4.10, is used for the match within STIMPLAN.

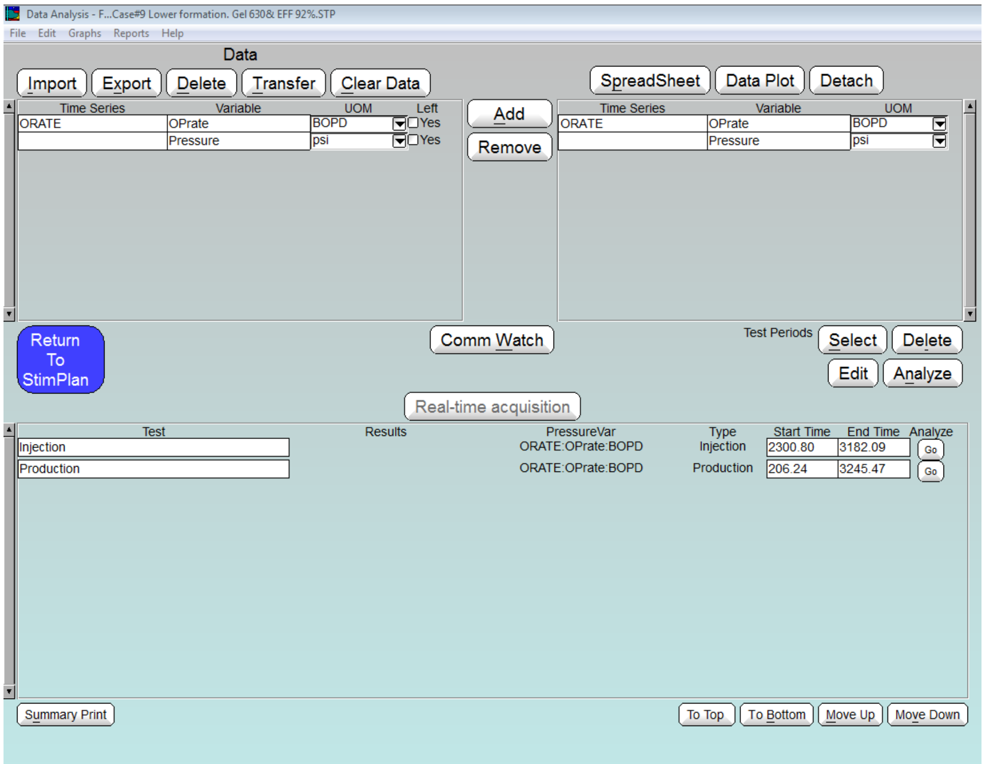

Figure 4.9. Import of production and injection data to STIMPLAN

4.3.4. Hydraulic Fracture Design. Well X-7, which is currently temporarily abandoned is expected to ultimately be hydraulically fractured, or an offset well drilled and stimulated as a replacement for well X-7. In either case, the purpose of this study is to determine and optimum stimulation treatment using the data provided by the operator.

Figure 4.10. Production test data for Well X-7

Figure 4.11 summarizes reservoir data used in this study and Figure 4.12 summarizes reservoir fluid data. Data shown in Figure 4.11 represent the average reservoir properties for the perforated interval, and are similar to the upper and lower layers of the Lowers Nubian sandstone. The values were verified with Sapphire software using the pressure data for well X-7. Reservoir and fluid data were inserted into STIMPLAN as shown in Figures 4.11 and 4.12, in order to predict future production rate and fracture geometry for each simulation case. All the data was provided from company in excel file and they were also verified by Sapphire software. All reservoir data provided matched the values from Sapphire and were deemed correct for use.

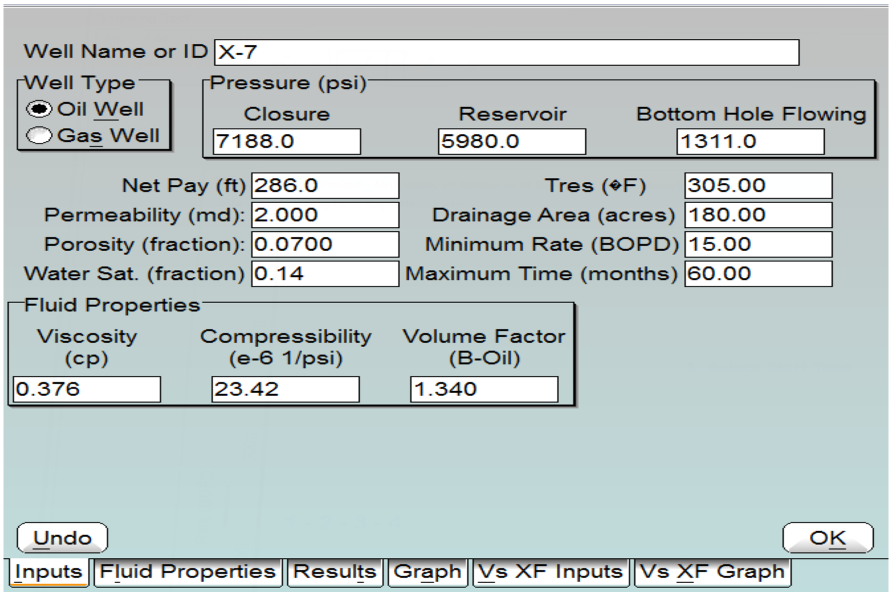

Figure 4.11. Reservoir data

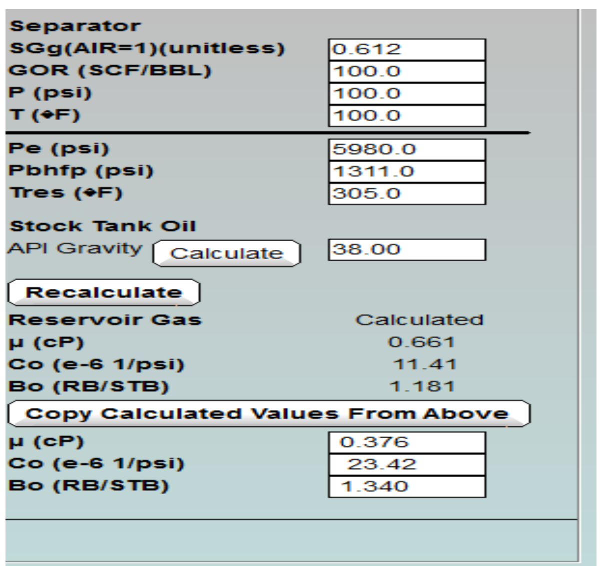

Figure 4.12. Fluid data

STIMPLAN software was used to evaluate thirteen different hydraulic fracturing cases, varying frac fluid type, proppant type, or proppant size. Most cases use an injection rate of 25 bbl/min, although some cases vary this injection rate, as well as the end of job proppant concentration or number of stages pumped. In all but one case (case 12) proppant concentration starts from 1 ppg and increases at a constant rate until the end of job concentration. Case 12 is slickwater which starts with a proppant concentration of 0.5 ppg. Table 4.2 presents a summary of the cases evaluated in this study. These data are combined with all previous information to predict the future production rate, cumulative recover and fracture geometry for each fracturing alternative.

Table 4.2. Summary of cases evaluation in this study

Case#	Fluid type	Proppant type	Proppant size	Inj. Rate	EOJ
1	F-300 Linear gel	Ottawa Sand	20-40	25	7
2	F-300 Linear gel	Ottawa Sand	16-30	25	7
3	F-300 Linear gel	Ottawa Sand	12-20	25	7
4	F-300 Linear gel	Brady Sand	20-40	25	7
5	F-300 Linear gel	Brady Sand	16-30	25	7
6	F-300 Linear gel	Brady Sand	12-20	25	7
7	F-300 Linear gel	Carbo Ceramic	20-40	25	7
8	F-300 Linear gel	Carbo Ceramic	16-20	25	7
9	F-300 Linear gel	Carbo Ceramic	12-18	25	7
10	XL-#30 Gaure	Carbo Ceramic	20-40	25	7
11	F-160 Linear gel	Carbo Ceramic	20-40	20	6
12	Slickwater	Carbo Ceramic	20-40	40	4
13	F-300 Linear gel	Carbo Ceramic	20-40	25	8

4.3.5. Linear Gel (F300) Cases 1-9. The first nine cases use a constant frac fluid type. In all of these cases it was decided to apply a linear gel, noted as F300 in STIMPLAN. The injection rate and end of job proppant concentrations are also held constant for each case, but the type of proppant and proppant size are varied. Three types of proppant were investigated.

4.3.5.1. Ottawa sand cases 1-3. The first case study for hydraulic fracture design will be with Ottawa sand, where the different sizes will be performed to examine the fracture conductivity. Table 4.3 shows three proppant sizes (20-40, 16-30, and 12-20) with fixed pump rate of 25 BPM, which is considered an efficient rate to carry the proppant in a linear gel fluid. Eight stages were assigned for this case and proppant concentration will end at 7 ppg. Total pump time are also given for each case. Figure 4.13 illustrates the STIMPLAN prediction of fracture conductivity versus fracture penetration for each case.

Figure 4.13 Proppants conductivity and fracture penetration for the Ottawa sand.

Table 4.3. Fracture design with different sizes of Ottawa sand

Case#	Proppant Name	Fluid Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
1	Ottawa 20-40	F300 Gel	25	1354.7	8	7	54.2
2	Ottawa 16-30	F300 Gel	25	1352	8	7	52.6
3	Ottawa 12-20	F300 Gel	25	2046	9	7	81.8

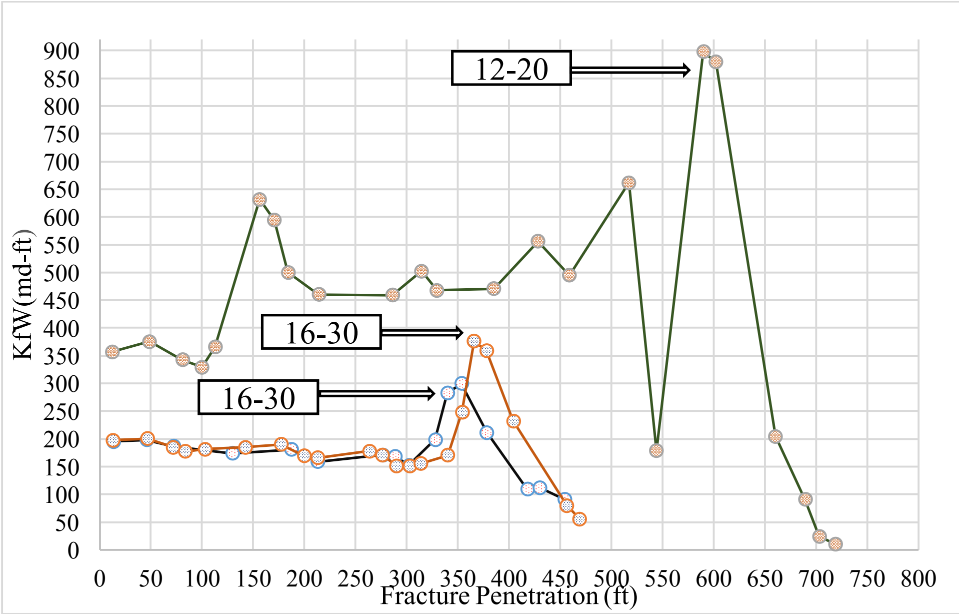

Figure 4.13. Proppant conductivity of Ottawa sand

4.3.5.2. Brady sand cases 4-6. Brady sand is considered one of the best proppants in the industry that can handle stress up to 8500 psi. Brady sand will be used in the fracture design of this study to see its effect on the fracture propagation and to test the proppant conductivity in different sizes. Table 4.4 summarizes these cases and provides the total pump time for each case. End of job proppant concentration remains the same, although pump stages vary slightly.

Table 4.4. Hydraulic fracture design with Brady sand

Cases#	Proppant Name	Fluid Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
4	Brady 20-40	F300 Gel	25	1466	7	7	58.7
5	Brady 16-30	F300 Gel	25	1220	9	7	48.8
6	Brady 12-20	F300 Gel	25	992	7	7	39.7

Figure 4.14 illustrates the STIMPLAN prediction of fracture conductivity versus fracture penetration for each case.

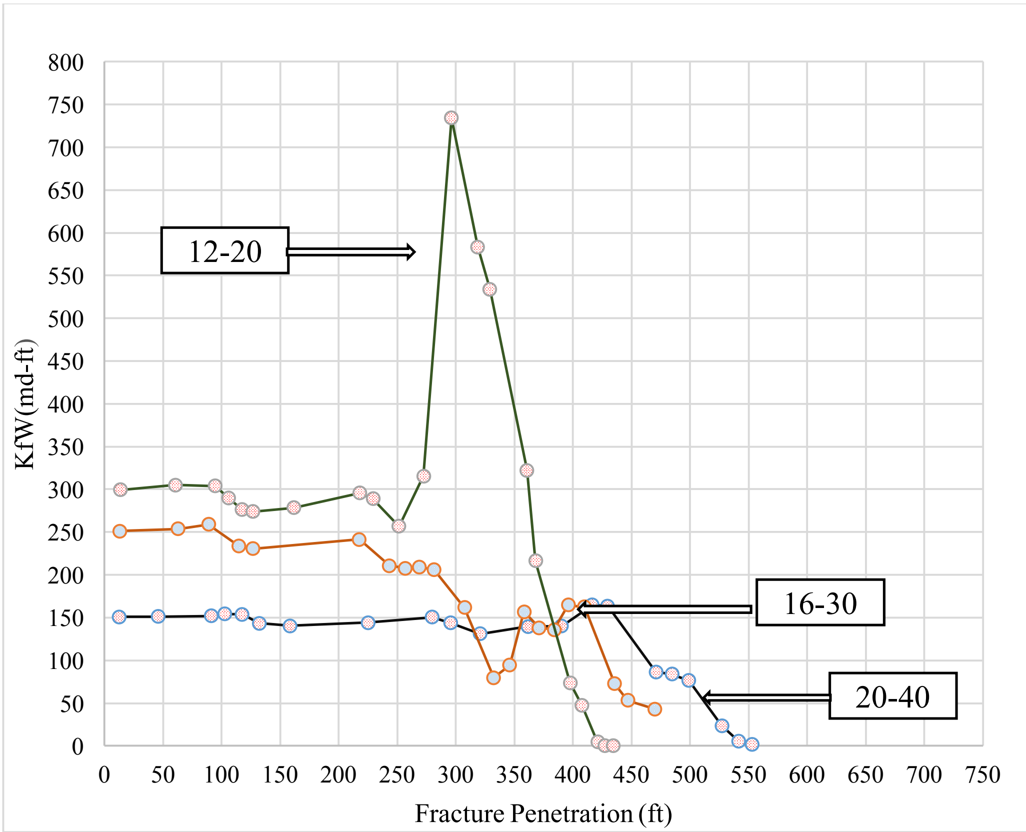

Figure 4.14 Proppants conductivity of Brady sand

4.3.5.3. Carbo lite ceramic cases 7-9. Ceramic proppant is a man-made, commonly using a bauxite material. It is the most expensive type of proppant. However, because it is manufactured (not mined), companies have the ability control to control it's physical properties such as roundness and sphericity, thus increasing fracture conductivity.

In addition, ceramic proppant has high strength, which provides the ability to handle the high stress encountered at deeper depths (> 6000 ft). Presently, many companies in the Middle East recommend using ceramic in deep sandstone formations with permeability below 10 md. Therefore, the research examined one type of ceramic called carbo lite in different sizes. Table 4.5 shows the different cases, estimated slurry volume and pump time. The fluid type and pump rate remain the same as in previous cases.

Table 4.5. Hydraulic fracture design of Carbo Lite ceramic

Cases #	Proppant Name	Fluid Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
7	Carbo L 20-40	F300 Gel	25	1357	11	7	55
8	Carbo L 16-20	F300 Gel	25	1350	8	7	54
9	Carbo L 12-18	F300 Gel	25	2046	10	7	82

Figure 4.15 illustrates the STIMPLAN prediction of fracture conductivity versus fracture penetration for each case using Caro Lite ceramic proppant.

Comparing Figure 4.15 fracture conductivity with that shown for sand (Figures 4.13 and 4.14) it is evident the Carbo Lite ceramic provides far greater fracture conductivity. The Nubian sandstone is found at depths exceeding 12,000 ft, and the ceramic proppant is preferred in this high stress situation. Based on these considerations three hydraulic fracture design cases were evaluated for ceramic proppant as a constant, but varying types of frac fluids.

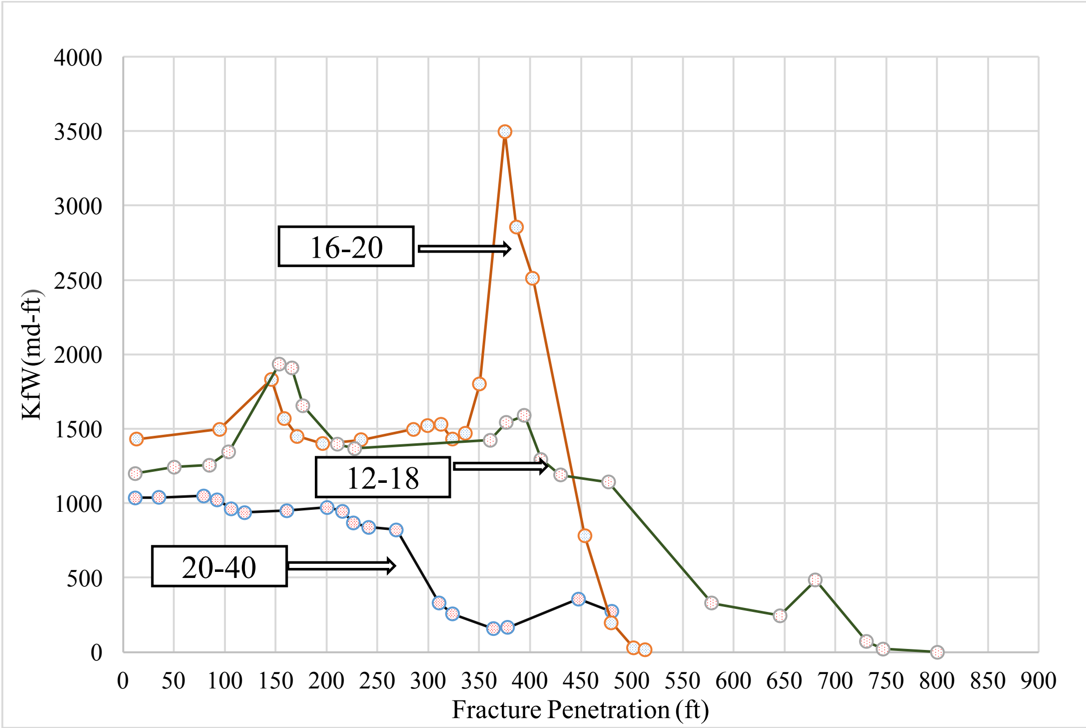

Figure 4.15. Proppant conductivity of Carbo Lite ceramic

4.3.6. Carbo Lite Ceramic Cases 10-13. Cases 10-13 all use 20-40 Carbo Lite ceramic proppant, but vary the type of frac fluid. Four fracture fluids types were selected for this evaluation based on formation properties and cost. Each frac fluid type has a different pump rate because the fluid viscosity and proppant carrying capacity are significantly different.

In considering these different frac fluids it was important to evaluate fluid loss and fluid efficiency. Fluid loss and fluid efficiency have a significant impact on fracture morphology, even in tight sandstones such as the Nubian.

4.3.6.1. X-Link#30, case 10. In this design, a crosslinked 30 lb/gal gel frac fluid is used (noted X-link#30) and 20-40 Carbo Lite ceramic is the fixed proppant. Pump rate of 25 bbl/min was used, as X-link fluids functionally can be applied in pump rates between 25 and 35 BPM. Slurry volume was estimated, and the number of stages in this design was assigned. Table 4.6 shows the X-link#30 design schedule.

Table 4.6. X-Link#30 Fracture design

Case #	Fluid Name	Proppant Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
10	X-Link #30	Carbo L 20-40	25	1357	11	7	55

4.3.6.2. Gel F160, case 11. Case 11 evaluated a liner gel, noted as F160 in STIMPLAN. This linear which is well known with its ability to hold a high concentration of the proppant and low fluid loss inside the formation. The model was run with pump rate 20 BPM, slurry volume below 1600 bbl and proppant concentration of 6 ppg. Carbo lite ceramic will remain as hydraulic fracture proppant. Table 4.7 shows the estimated fracture design for gel F160.

Table 4.7. Gel F160 hydraulic fracture design

Case #	Fluid Name	Proppant Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
11	Gel F160	Carbo L 20-40	20	1500	10	6	75

4.3.6.3. Slickwater, case 12. Slickwater is a frac fluid commonly used in unconventional formations such as shale. Most companies in North America use slickwater in their hydraulic fracture application due to its low cost, quick recovery, and simplicity in the operation.

Despite slickwater having low proppant transport capability, it was decided to examine this fluid to see its effect in the Nubian sandstone formation. Table 4.8 shows the schedule design for slickwater fluid with different stages, higher pump rate, and slurry volume.

Table 4.8. Slickwater hydraulic fracture design

Case #	Fluid Name	Proppant Name	Pump Rate(BPM)	Slurry Volume (BBl)	Pump Stages	Proppant Conc (PPg)	Total time (min)
12	Slickwater	Carbo L 20-40	40	1369	9	4	39

4.3.6.4. Gel F300, case 13. Gel F300 fluid can handle high formation temperature, especially in deep onshore reservoirs. Also, F300 has high proppant transport properties that can help reduce the fluid loss. In this design, gel F300 is used to test the fluid loss with a different slurry volume and number of stages. Previously, Case 7 evaluated the same proppant fluid combination, but at different end of job concentration, stages and slurry volume. Table 4.9 illustrates the predicted hydraulic fracture design for Well X-7.

The fluid loss for the four types of fluids and the duration time will take to reach the stabilization condition were estimated via STIMPLAN. Figure 4.16 shows a plot of fluid loss versus time for the four frac fluids evaluated in cases 10-13. As shown, slickwater has high fluid loss compared to the gel frac fluids.

Table 4.9. Gel 300F hydraulic fracture design

Case #	Fluid Name	Proppant Name	Pump Rate(BPM)	Slurry Volume (BBl)	stages	Proppant Conc (PPg)	Total time (min)
13	Gel F300	Carbo L 20-40	25	2116	13	8	124.7

The erratic pressure response of slickwater shown in Figure 4.16 is of an indication that the fracture was refusing higher proppant concentration. This might have been due to near wellbore tortuosity. Spontaneous pressure drops were interpreted to correlate to sudden height growth that occurs when the fracture breaks another stress barrier such as shale beds.

In the slickwater case, proppant concentration during pumping was kept between 5 to 8 lb/gal in order to place the maximum amount of proppant in the fracture. There was some indication of tip screenout action, which might occur late during in the pumping schedule.

Most of the pressure data provided were also imported to STIMPLAN for analysis. During the treatment, there were no bottomhole gauges in the well and bottomhole pressure can only be estimated with approximated friction losses. Friction losses may be significant as the treatment is pumped down the casing.

Closure stress was estimated by company-M from their software analysis of the pressure fall off data. Their estimation of closure stress was approximately 7,188 psi. A mathematical estimation of the closure stress was performed for comparison, using Eaton's equation, which was 7,095 psi:

$$\sigma_{h\min} = \left(\frac{\nu}{1-\nu}\right)(\sigma_v - p_{res}) + p_{res} + P_{tectonic} \tag{3}$$

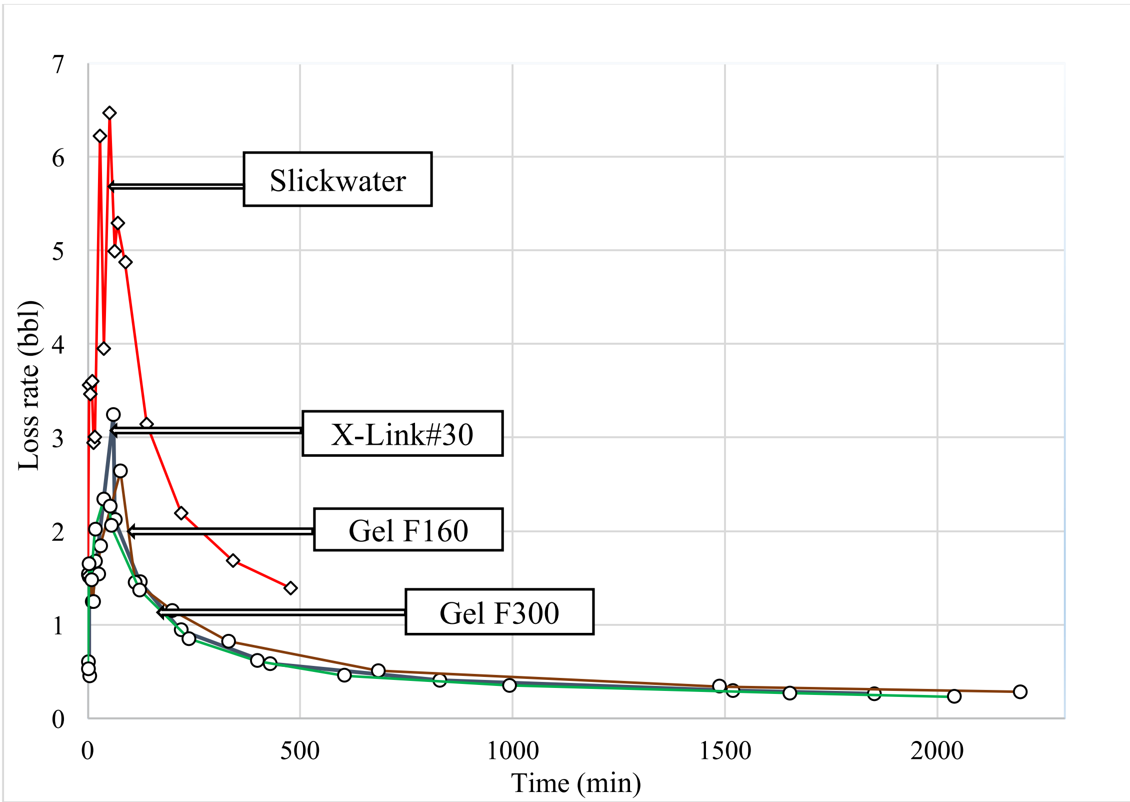

Figure 4.16. Fluid loss for different kinds of fracture fluid

where,

$\sigma_{h,min}$ = minimum horizontal stress

ν = Poisson's ratio

P_{res} = Reservoir pressure

$P_{tectonic}$ = Strain component of the stress

According to net pressure theory (Nolte- Smith Log- Log Interpretation), the slope of the net pressure plot will be 1 when a screenout occurs. Using the closure stress 7,188 psi and drawing a best-fit line through the late-time data, the slope found was 1.72. To match the net pressure plot with a slope 1 requires a closure pressure of 6,043 psi which is essentially equal to the reservoir pressure value. Since closure pressure should be higher than static reservoir pressure, it is doubtful that a tip screenout was achieved. Figure 4.17 shows a net pressure plot from the treatment. As shown, there is significant scatter in the data and only late time trend is evident.

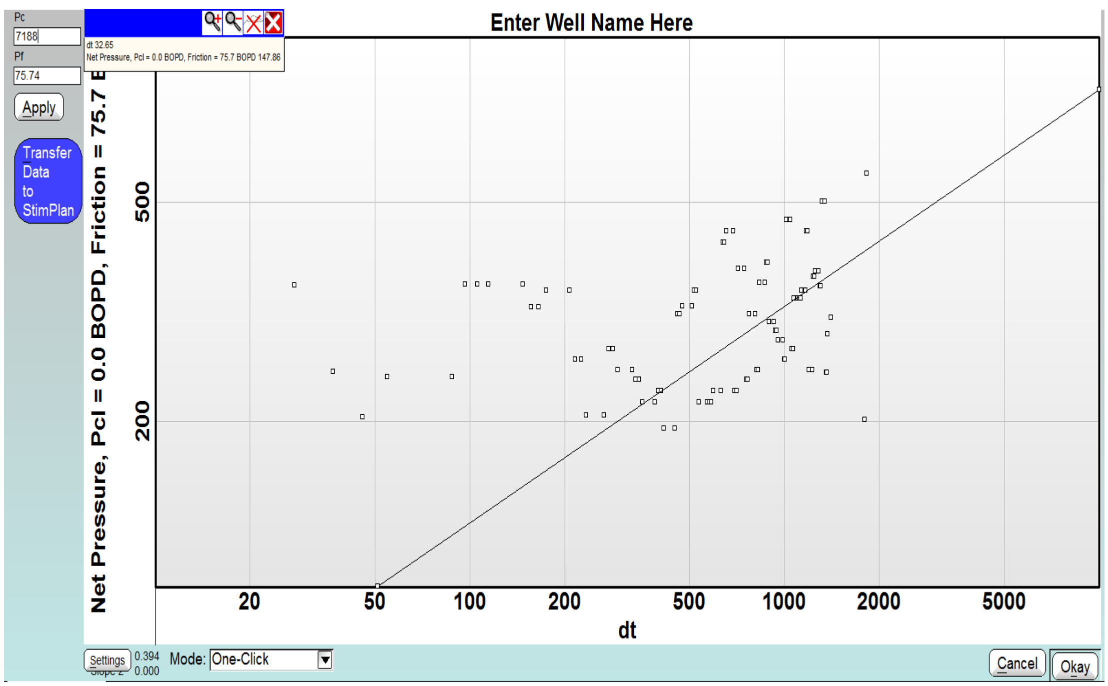

Figure 4.17. The net pressure plot for treatment

5. RESULTS

The following section presents results of the STIMPLAN simulations for all hydraulic fracturing cases described in section 4.0. Results for 30-day flowrate (IP) and 24-month cumulative recovery are given for each case. In addition, flowrate as a function of time is examined.

5.1. RESULTS FOR PROPPANT CASES

Results for cases with a constant fluid type, but varying proppant type and size are summarized in the following sections. F300 linear gel was used for all of the proppant cases.

5.1.1. Ottawa Sand Cases 1-3. Cases 1-3 are simulations using Ottawa sand, with the same injection rate, similar end of job concentrations, the same frac fluid (F300) and slightly different pump schedules. Proppant sizes vary between each case. The fracture design require additional conductivity and less fracture length to achieve an optimal FCD of 2 (Prats 1960).

Table 5.1. Presents a summary of the resulting fracture geometry for these cases

Proppant #	Case #	Proppant Size	Proppant length (ft)	Fracture length (ft)	Fracture Height (ft)	Fracture width (ft)	Net Pressure	FCD
Ottawa sand	1	20-40	475.1	476.4	457	0.017	633.2	0.18
	2	16-30	474.7	476.2	455	0.0174	635.6	0.21
	3	12-20	696.9	730.3	419.3	0.0165	606.3	0.34

Table 5.1 STIMPLAN fracture dimensions created for Cases 1-3 Figure 5.1 presents plots of flowrate versus time and Figure 5.2 presents a summary of 24-month cumulative production for the Cases 1-3.

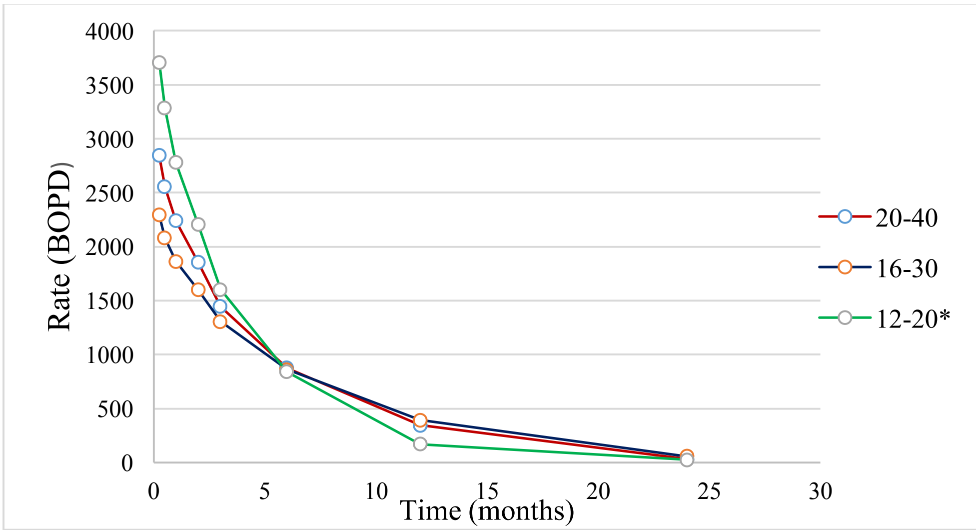

Figure 5.1. Cases 1-3 production rate versus time for 24 months

The IP for the three proppant sizes were 2844 BOPD for Ottawa 20-40, 2292 BOPD for Ottawa 16-30 and 3705 BOPD for Ottawa 12-20.

The 24 month cumulative production was found to be 478.2 MBO for Ottawa 20-40, 457.3 MBO for Ottawa 16-30 and 474.3 MBO for Ottawa 12-20.

5.1.2. F300 Fluid, Brady Sand Cases 4-6. Cases 4-6 are simulations using Brady sand, with the same injection rate, similar end of job concentrations, the same frac fluid (F300) and slightly different pump schedules. Proppant sizes vary between each case. The fracture design require additional conductivity and less fracture length to achieve an optimal FCD of 2 (Prats 1960).

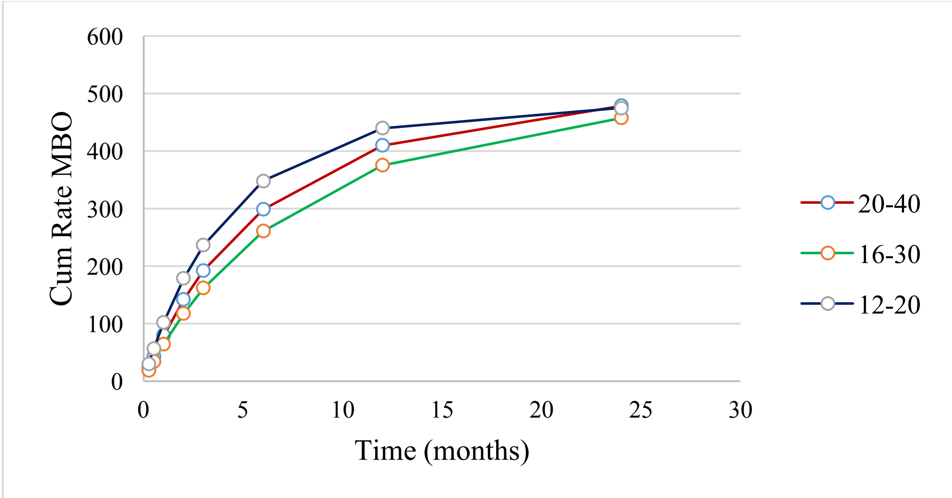

Figure 5.2. Cases 1-3 cumulative production versus time for 24 months

Table 5.2. Presents a summary of the resulting fracture geometry for these cases

Proppant #	Case #	Proppant Size	Proppant length (ft)	Fracture length (ft)	Fracture Height (ft)	Fracture width (ft)	Net Pressure	FCD
Brady sand	4	20-40	531	555.8	476.1	0.0157	623.5	0.13
	5	16-30	473.6	475.8	448.2	0.0165	623.8	0.24
	6	12-20	413	436.5	456.8	0.0141	629.7	0.39

Table 5.2 STIMPLAN fracture dimensions created for Cases 4-6 Figure 5.3 presents plots of flowrate versus time and Figure 5.4 presents a summary of 24-month cumulative production for the Cases 4-6.

The IP for the three proppant sizes were 3,705 BOPD for Ottawa 20-40, 3,706 BOPD for Ottawa 16-30 and 3,455 BOPD for Ottawa 12-20

The 24 month cumulative production was found to be 474.41 MBO for Ottawa 20-40, 474.79 MBO for Ottawa 16-30 and 471.59 MBO for Ottawa 12-20

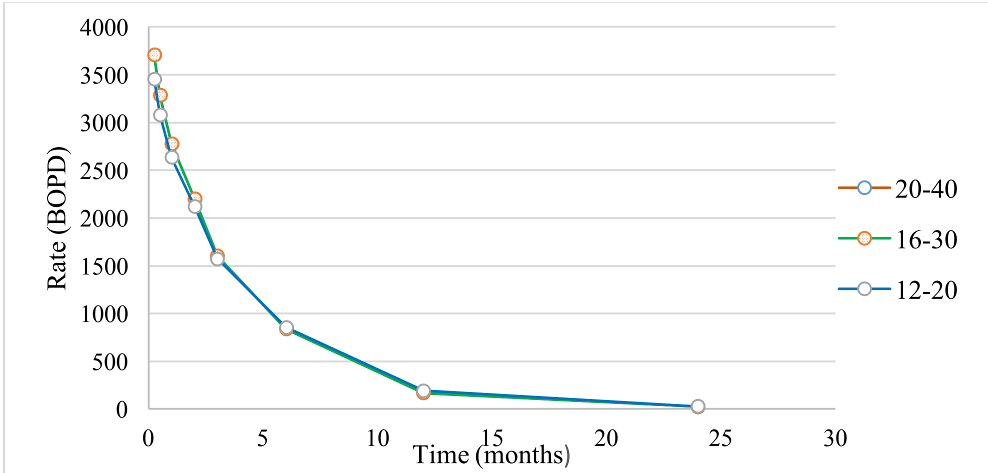

Figure 5.3. Cases 4-6 production rate versus time for 24 months

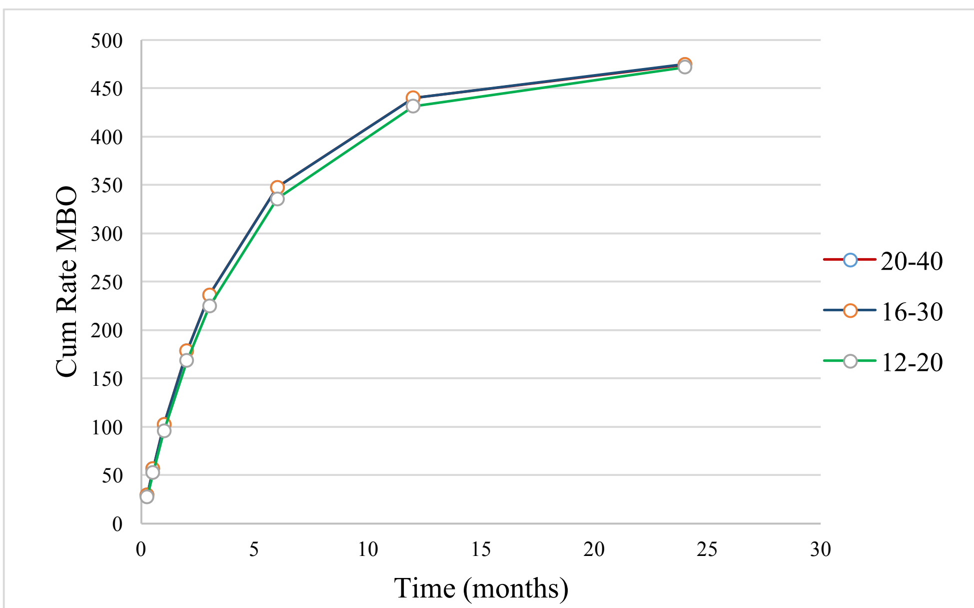

Figure 5.4. Cases 4-6 cumulative production versus time for 24 months

5.1.3. F300 Fluid, Carbo Lite Ceramic Cases 7-9. Cases 7-9 are simulations using Carbo lite ceramic, with the same injection rate, similar end of job concentrations, the same frac fluid (F300) and slightly different pump schedules. Proppant sizes vary between each case. The fracture design require additional conductivity and less fracture length to achieve an optimal FCD of 2 (Prats 1960).

Table 5.3. Presents a summary of the resulting fracture geometry for these cases

Proppant #	Case #	Proppant Size	Proppant length (ft)	Fracture length (ft)	Fracture Height (ft)	Fracture width (ft)	Net Pressure	FCD
Carbo L ceramic	7	20-40	487.3	487.3	453.6	0.0177	645.8	0.7
	8	16-20	498	519.9	480.7	0.016	635.1	1.55
	9	12-18	722	808.8	473.4	0.0164	563.6	0.75

Table 5.3 STIMPLAN fracture dimensions created for Cases 4-6 Figure 5.5 presents plots of flowrate versus time and Figure 5.6 presents a summary of 24-month cumulative production for the Cases 7-9.

The IP for the three proppant sizes were 4,268 BOPD for Ottawa 20-40, 5,050 BOPD for Ottawa 16-20 and 4,914 BOPD for Ottawa 12-18.

The 24 month cumulative production was found to be 494.2MBO for Ottawa 20-40, 479.29 MBO for Ottawa 16-20 and 478.41 MBO for Ottawa 12-18.

5.2. RESULTS FOR FLUID CASES

Results for cases with a constant proppant type and size, but varying fluid types are summarized in the following sections. Carbo lite ceramic 20-40 proppant have been used in all cases.

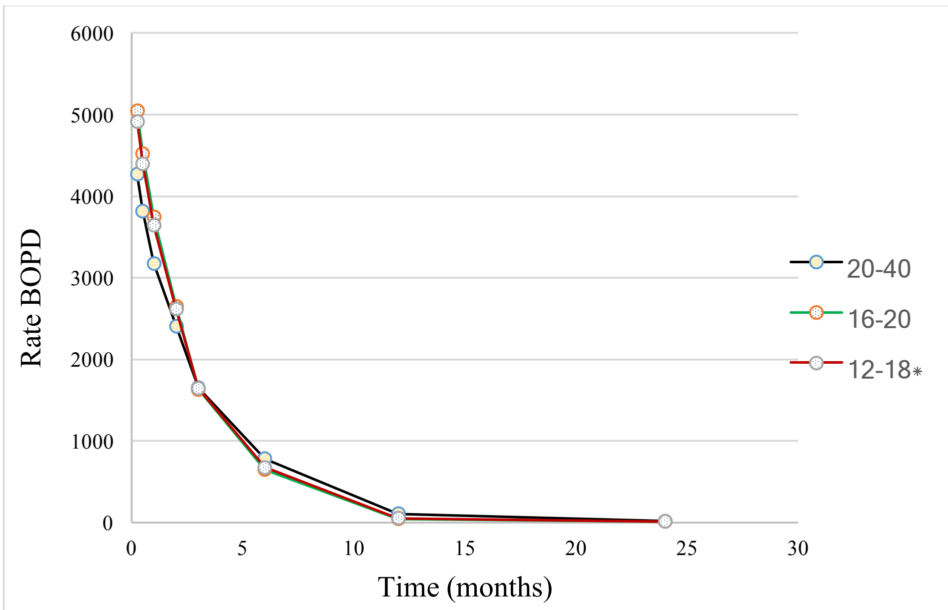

Figure 5.5. Cases 7-9 production rate versus time for 24 months

5.2.1. Carbo L Ceramic, XL-30#, Case 10. Figure 5.7 shows a 2-D prediction of fracture growth if cross linked 30 lb/gal frac fluid and carbo lite ceramic 20-40. The injection rate is 25 bpm, end of job concentration is 7 lb/gal and 11 pump stages were used. Cross linked frac fluids provide high viscosity and the capacity to carry higher proppant concentrations

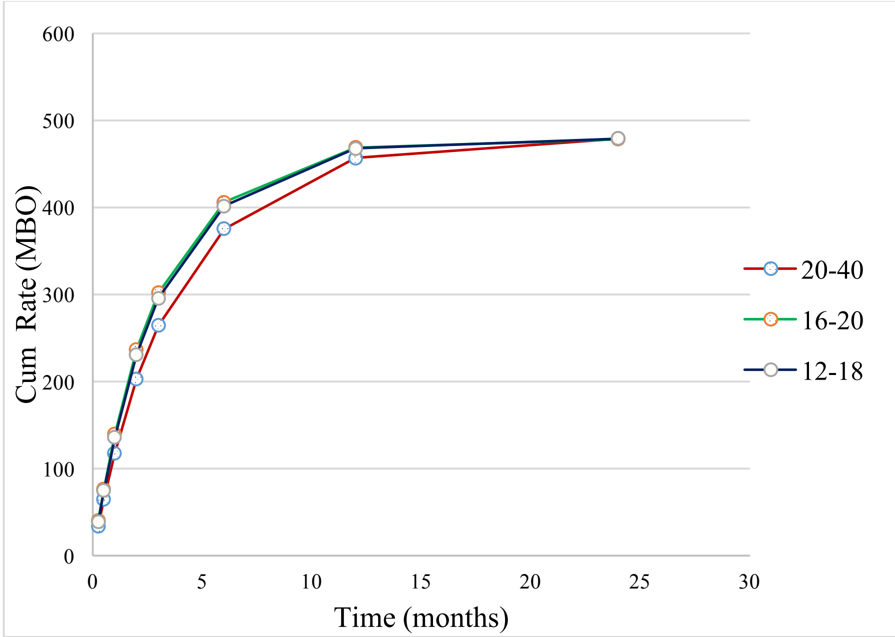

Figure 5.6. Cases 7-9 cumulative production versus time for 24 months

. This results in a high portion of propped fracture area, which can be seen in the green shaded area of Figure 5.7. Using a cross linked fluid, the total fracture length is 523 ft with a fracture height of 413 ft

At the time the flow rate was maintained at constant rate, the bottomhole injection pressure started to increase over time till it reaches a breakdown pressure.

5.2.2. Carbo L Ceramic, F160 Linear Gel, Case 11. Figure 5.9 shows a 2-D prediction of fracture growth if F160 linear gel fluid and carbo lite ceramic 20-40 proppant is pumped. The injection rate is 20 bpm, end of job concentration is 6 lb/gal and 10 pump stages were used.

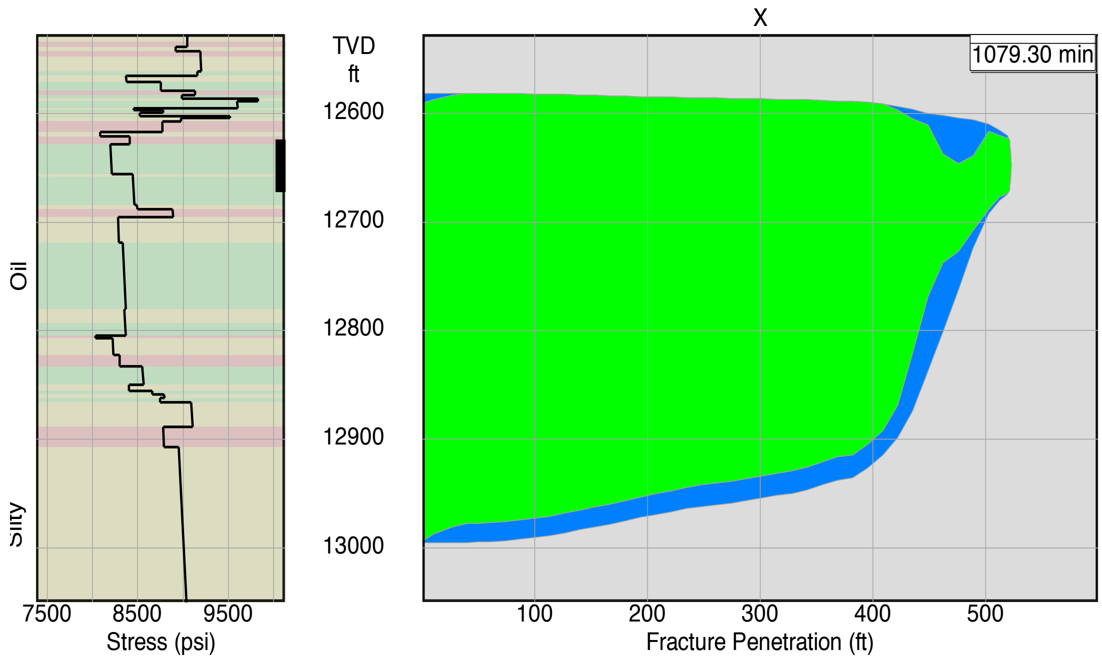

Figure 5.7. 2-D fracture morphology summary plot of the X-link #30 design

Linear gels have less viscosity than cross linked fluids, and less capacity to carry higher proppant concentrations. Despite this, there is a high portion of propped fracture area over a majority of the total fracture area, which can be seen in the green shaded area of Figure 5.7. Using a F160 linear gel fluid, the total fracture length is 596 ft with a fracture height of 500 ft.

5.2.3. Carbo L Ceramic, Slickwater, Case 12. Figure 5.11 shows a 2-D prediction of fracture growth if slickwater frac fluid pumped with carbo lite ceramic 20-40 proppant.

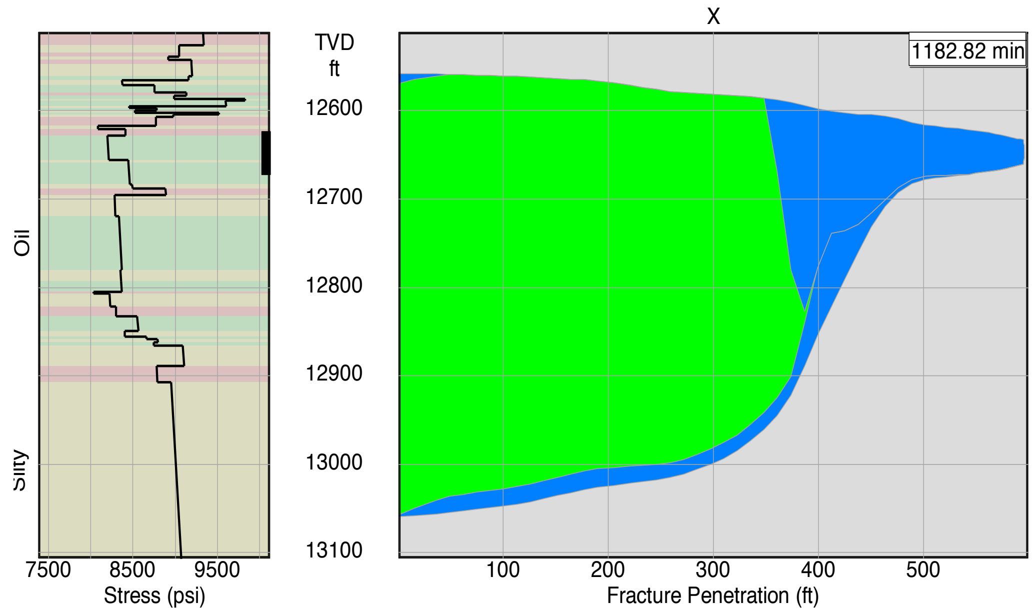

Figure 5.8. 2-D fracture morphology summary plot of the F160 gel design

The injection rate is 40 bpm, end of job concentration is 4 lb/gal and 9 pump stages were used. Slickwater frac fluids has low viscosity and the low capacity to carry higher proppant concentrations. This results in a very low propped fracture area, which can be seen in the green shaded area of Figure 5.11. Using a cross linked fluid, the total fracture length is 771 ft with a fracture height of 250 ft.

5.2.4. Carbo L Ceramic, F300 Linear Gel, Case 12. Figure 5.13 shows a 2-D prediction of fracture growth if F300 linear gel fluid and carbo lite ceramic 20-40 proppant is pumped. The injection rate is 25 bpm, end of job concentration is 8 lb/gal and 13 pump stages were used.

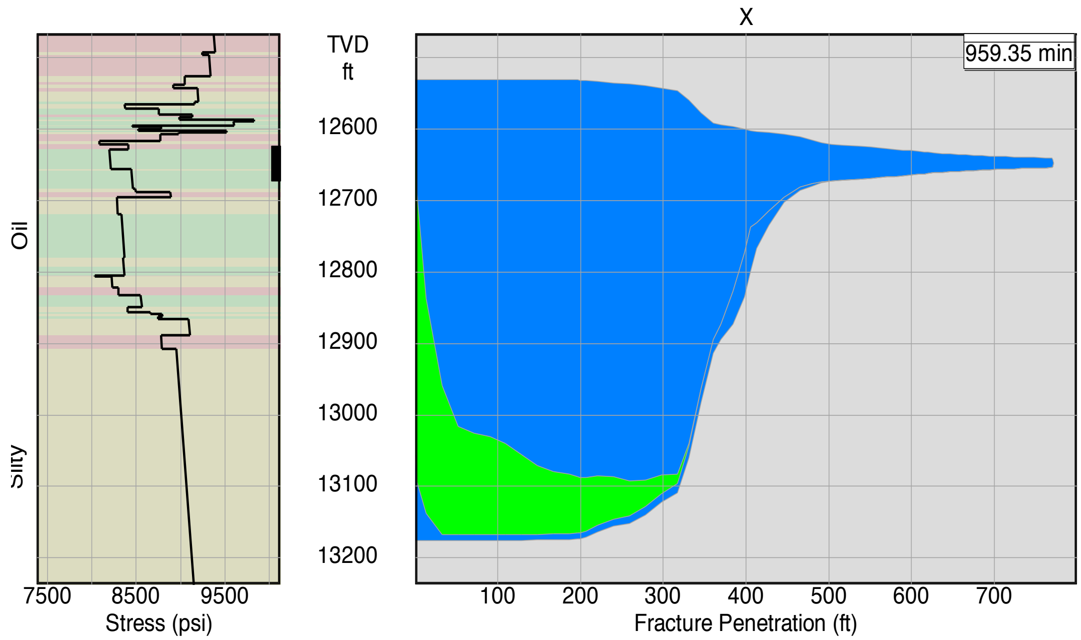

Figure 5.9. 2-D fracture morphology summary plot of the slickwater

F300 gel is expected to have high performance in deeper, hotter formations with a good proppant carrying capacity. This results in a high portion of propped fracture area, which can be seen in the green shaded area of Figure 5.13. Using a F300 linear gel fluid, the total fracture length is 478 ft with a fracture height of 478 ft.

The IP for the four fluids types were 28443,038 BOPD for slickwater 3,739 BOPD for linear gel F160, 4,438 BOPD for X-link#30, and 5,004 for linear gel which match with same value of case 11.

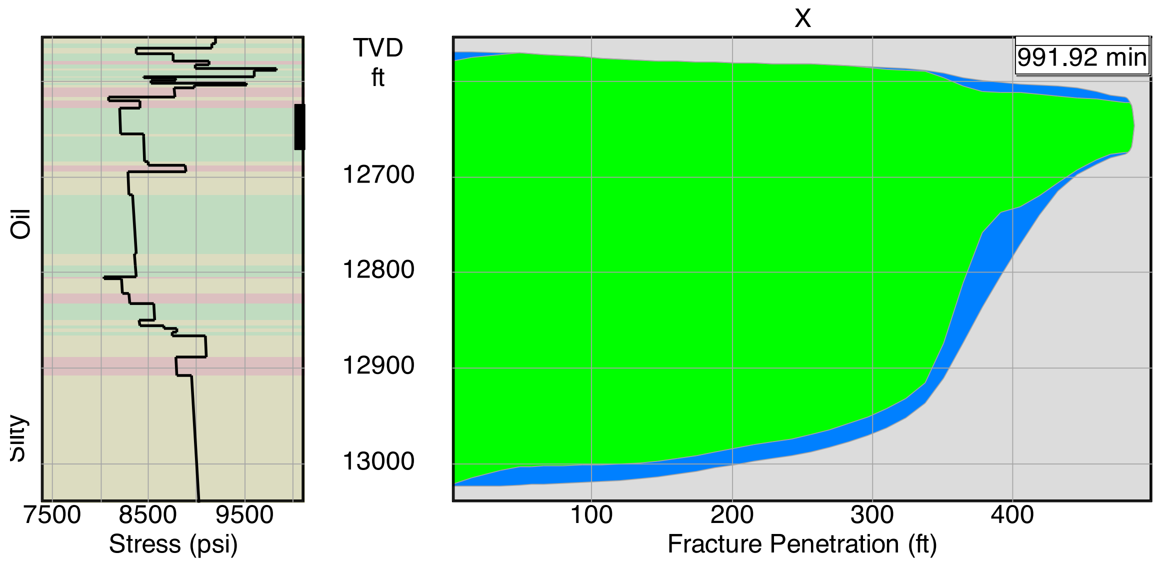

Figure 5.10. 2-D fracture morphology summary plot of the F300 linear gel design

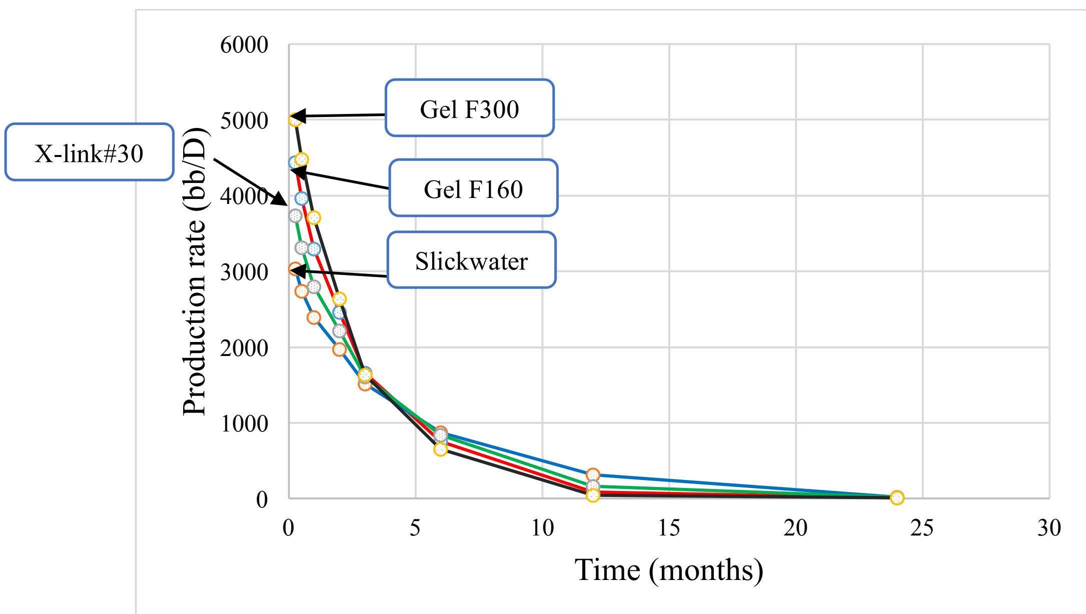

Figure 5.11. Cases 10-12 production rate versus time for 24 months

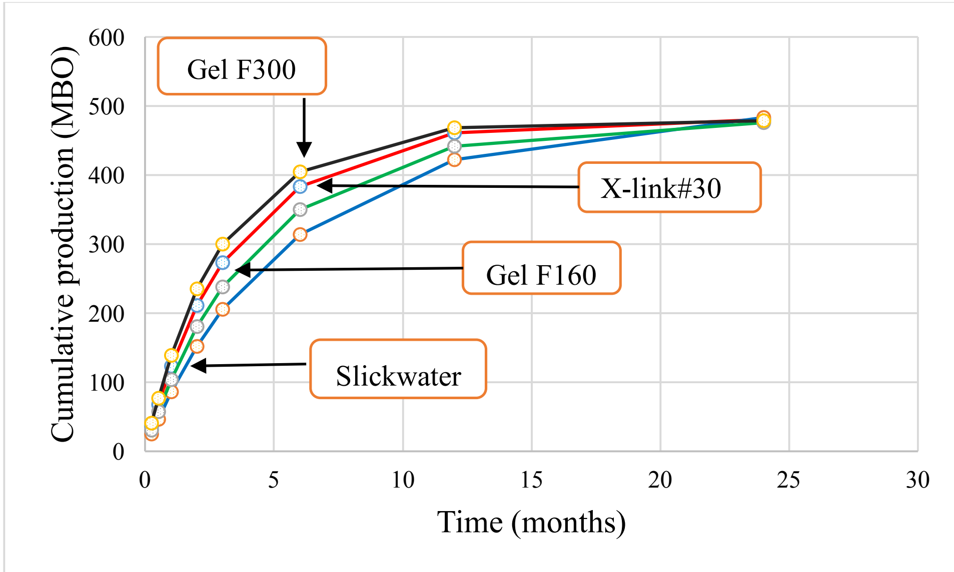

Figure 5.12. Cases 10-12 cumulative production versus time for 24 months

The 24 month cumulative production was found to be 24.25 MBO for slickwater, 30.07 MBO for linear gel F160, 35.58 MBO for X-link#30, and 40.07 MBO for linear gel F300.

6. DISCUSSION

Thirteen different cases were evaluated in this study to determine an optimum hydraulic fracture design for the Nubian sandstone in Libya. These cases focused on stimulating only the Lower Nubian sandstone in a single treatment. Results of these cases compare IP and 24 month cumulative recovery for these cases.

This analysis indicates that while many fracturing alternatives produce similar fracture geometry, the combination of F300 gel with 20-40 Carbo Lite proppant suggests the highest fracture conductivity and production performance. All cases evaluated have low values of FCD suggesting that conductivity could be increased.

It should be noted that economics have not been considered in this study. Ideally the highest production at lowest cost will produce the greatest economic benefit. However, in this study, only cumulative production has been considered.

The Nubian sandstone is found at significant depths of greater than 12,000 ft. It should be noted that regardless of the fluid selected for treatment, ceramic proppant will provide a greater strength and resistance to crushing than sand. Given the fracture conductivity of ceramic proppant is three times that of all cases using sand, it is likely this will be of greatest benefit even if economic analysis is included.

7. CONCLUSIONS AND FUTURE WORK

The following conclusions can be made from this research and evaluation:

1. Libya contains significant ‘unconventional’ oil and gas reserves found in mid-range permeability such as the Nubian sandstone, to ultra-tight shale formations.
2. The H-field demonstrated potential for development of the Nubian sandstone, although well stimulation has been delayed for various reasons
3. Log analysis indicates 71 feet of pay in the Upper Nubian sandstone and 295 feet in the Lower Nubian. This mean lower Nubian formation is almost four times thicker than upper Nubian formation and was selected as the focus of the stimulation design.
4. This study utilized reservoir, fluid, pressure and production data to build a STIMPLAN model for well X-7 in the Nubian sandstone, from which various hydraulic fracturing alternatives are evaluated.
5. Thirteen cases evaluated hydraulic fracturing alternatives for different frac fluids, proppant type and proppant sizes. All cases evaluated had low FCD and could benefit from increased conductivity.
6. Ceramic proppant provides the best fracture conductivity regardless of the type of fracturing fluid used. However, slickwater showed a poor propped fracture area with slickwater.
7. F300 linear gel and 20-40 Carbo Lite proppant provide an excellent recovery for the perforations assumed in the middle layer of the Lower Nubian sandstone.
8. This study has evaluated fracturing alternatives based on well production and 24-month cumulative recovery. Economics have not been considered.

- **FUTURE WORK**

The following additional work is suggested to further advance the current study of hydraulic fracturing in the Nubian sandstone in Libya:

- It is suggested that an economic analysis be performed in addition to the hydraulic fracture modeling. This would provide a more complete comparison of the cases.
- This study includes 13 cases which combine different types of fracture fluids, proppant type and size. Future work could consider a wider range of choices in the many variables of hydraulic fracture design, and particularly investigate higher conductivity with resulting FCD closer to 2.0.
- Future designs should consider an approach for stimulating both the Upper and Nubian sandstone formations, even if in separate treatments.
- Other fields in Libya which have unconventional reservoirs should be considered for analysis in the future.

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