Implemented stage fracturing technique to improve oil production in Nubian sandstone of North Gialo, Libya

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This paper is an investigation on North Gialo Field to enhance the oil recovery by stimulating the main reservoir, the Upper Nubian Sandstone, which is affected by pervasive diagenetic modifications of porosity and permeability. The significant increase in the production rate after hydraulic fracturing treatment shows the importance of implementing this method for this formation in Libya for optimising production. And moreover, to gain better recovery of the stored hydrocarbon in this reservoir. The sensitivity of this case that is required a critical treatment with a precaution investigation during the operation such as High Strength Proppant, type of proppant, sieve size, conductivity indication, production estimation, Net Present Value, and the comparison between treated and untreated cases. Furthermore, deeper Nubian Sandstone formation and the treatment temperature up to 149 °C. Therefore, choosing the delayed borate crosslinked fluid by using Hydroxy Propyl Guar (HPG), gelling agent and special additives designed to enhance the viscosity at a higher temperature, to break the viscosity at the end of the end of the pump time and good proppant transport. Another benefit of the additives is stable fluid rheology, low fluid loss properties, and good cleanup properties. Post-stimulation data were collected, and the evaluation was performed in order to calibrate and improve the current models and future stimulation treatment within the North Nubian Sandstones.

Keywords: *Nubian Sandstone, High Strength Proppant, Fracture Conductivity, Improve Oil Production, Hydroxy Propyl Guar (HPG), Borate Gel (HPGuar)*

Introduction

This paper evaluates the implementation of fracturing stimulation on Upper Nubian sandstone formation, which is classified as tight formation. However, the main purpose is to mitigate some formation damage issues should be operationally tested and evaluated to determine the cost-to-benefit ratio for improved well productivity.

As a general consideration at the Oil and Gas Industry, low permeability is limited to 10 mD for oil reservoir and 1 mD for the gas reservoir. For this case, fractures observed within the cores were largely closed and mineralised with quartz cementation and/or were clay-filled. On observation, open fractures appear to be localised. This investigation placed uncertainty regarding the potential effect of fracturing within the reservoir.

Nubian sandstone formation can be deep, high stress, high temperature, homogenous and can contain multiple layers. After that, the Stimulation objective is to increase the Productivity Index. Thus, this facet of the Structure process actively and positively affects the reservoir's productivity, whereas most of the other operations in this process are aimed at minimising reservoir damage, eliminating production problems, and flow paths by which hydrocarbon are efficiently extracted for low permeability rocks.

Hydraulic fracturing has experienced even more dramatic improvements since the introduction of crosslinked polymer fluids, High-Strength Proppants (HSP), and analytical techniques, such as the matching pressure plot to reduce the risk. Such techniques have enabled engineers to improve the flow from both low-permeability and high-permeability reservoirs substantially.

To evaluate the stimulation effectiveness, it is essential to estimate mechanical rock properties and hydraulic fracture properties, such as fracture half-length and fracture conductivity.

This paper discusses and presents a field case in Upper Nubian Sandstone (UNS), reservoir treated with a polymer as HPGuar with a delayed crosslinked borate and selected various proppant types, sieve sizes, and areal concentration of proppant (kg/m^2) to compare. This paper will also cover steps of the stimulation procedure for the 6J9 well, including major operational issues and present decisions made while composing the procedure.

Post-stimulation data were collected and evaluation performed in order to calibrate and improve current models and future stimulation treatment within the North Nubian Sandstones.

Finally, recommendations will be made based on the results to be applied in the future in order to obtain the maximum value of treatment for this formation.

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Fracturing Fluids and Sirte Basin Literature Overview

Fracturing fluids are technological advances in the petroleum industry proceed in incremental steps, not in the leaps and bounds associated with emerging technologies (Kevin and Norm, 2012). However, the importance of incremental advances should not be overlooked. Their impact can be measured in the production gains from wells that in the past would be shut-in because of poor economic performance or not even drilled because the technology was not present to safely complete the well. Therefore, Incremental advances have occurred in every aspect of the petroleum industry, ranging from the techniques and equipment to locate and extract hydrocarbons to the methods used to increase production and maximize recoverable reserves (Economides and Nolte, 2000).

Gray (2006) argue that Halliburton Oil Well Company as the exclusive licensee. In 1949, the process was first made available to the industry, the exclusive licensing agreement was terminated, and the fracturing process was licensed to other qualified service companies, including BJ Services since 1953 (Droegemueller and Leonhardt, 2005).

In 1955, an estimated 4,500 fracturing jobs were performed per month. In 1957, mathematical fracture models were introduced, forerunners of today's fracture simulators. Water-based fluids based on guar polymers were used by the early 1960s. Moreover, cross-linked water-based fluids had been introduced.

By the early 1970s, water-based systems replaced oil base fluids during 1970s, and 1980s water-based polymers evolved Lower residue became important with Hydroxy Propyl Guar (HPG), replacing Guar Later Carboxy Methyl Hydroxy Propyl Guar (CMHPG) replaced HPG. By the 1990s, the industry had returned to Guar for cheaper fluids, as mentioned by Abhinav et al. (2017) and Elsarawy and Naser-El-Din (2012).

Rheology testing of fracturing fluid is important in evaluating and characterising the viscosity profile Fracturing fluid in the fracture at simulated fracturing conditions. Thus the frequently, of additives may reduce the pump pressure required to move the fluid downhole (Vispy, 2004; Xu and Fu, 2012; Li et al., 2015).

The fracture fluid system has been used successfully around the globe over the last 15 years. The main reason for the global use is the HPG delayed crosslinked borate system can be prepared from nearly any type of source water. The system is used for this range of temperature 51.6° to 148.9 °C (Duenckel et al., 2016).

Thus HPG delayed crosslinked borate system fracture is used in Libya, Algeria, Egypt, Europe, Oman, Russia, and Saudi. Therefore, hydraulic fracturing history in Sirte basin started in 1993 in well C217, table 1. Since that year a total number of eight wells were fractured, these wells are C304, C217, C316, C303, C040, C313, C238, C059, and C139.

In the recent study by Mei Y. et al. (2013), an equally important function of fracturing fluids is the transport of proppant into the fracture. Various mechanisms can be responsible for the transport of the proppant that when the setting velocity of the proppant is negligible, the slurry behaves as a "perfect suspension," and the solid moves effectively with the slurry fluid velocity. Therefore, when the setting velocity of the proppant is significant, a proppant bank is created, and its top is continuously sheared off by the high- velocity slurry above the bank, and low-reservoir permeability, allowing for lower proppant-pack permeability. So the solid moves towards the fracture tip with a slower mean velocity.

The transition between the two mechanisms depends mainly on two factors the apparent viscosity of the fluid (at the settling conditions) and the density difference between the proppant material and the fluid (Aboud and Melo, 2007). In low - viscosity fluids, proppant is transported by "stationary bed saltation" flow, which is characterised by the deposition of a bed of proppant followed by saltation flow of the proppant slurry above the proppant bed. Laboratory evaluations indicate that building a proppant bank occurs in three consecutive phases.

Several authors (Gandler, 2010; Ribeiro and Sharma, 2013; Xu and Fu, 2012; Liang et al., 2016) argued that during the first phase, the bank builds up gradually as a function of time until an equilibrium height is reached near the wellbore. The bank stops growing at this point as a result of the erosion caused by the increased fluid drag forces on the proppant particles. During the second phase, that bank grows only in height until it reaches equilibrium height over its full length.

Raimbay A. et al. study (2017) shows that in the third phase, the bank grows only in length, and the injected proppant saltates over the full the length of the bank toward the bank`s front, where it settles, increasing the length of the bank in the direction of flow.

The analytical relations derived for each of these phases are to provide permeability flow paths for hydrocarbon in low sandstone formation and permanence this permeable flow path can be achieved by proppant agents that are injected with treated water.

Water frac (using slick water or water with friction reducer instead of gel to transport proppant) have been a successful fracturing technique in some tight gas reservoir.

Proppant placement is an essential factor that determines the effectiveness of such hydraulic fracture treatment and Prediction of resulting proppant distribution after the proposed preliminary main treatment. (Liu and Sharma, 2002; LaFollette and Carman, 2010).

Tab. 1. Fracture History in Sirte Basin.

Wells	**C304**	**C217**	**C316**	**C303**	**L040**	**C313**	**C238**	**L059**	**C139**
Field Name	C-North	C-Main	C-Main	C-Main	L-Field	C-Main	C-Main	L-Field	C-Main
Frac Date	3/1/1996	2/1/1993	11/1/2005	1/1/2006	11/6/2006	10/1/2007	10/1/2007	10/2/2007	10/1/2007
Fracturing Parameters									
Instantaneous Shut-In Pressure ISIP [kPa]	38004	40976	36597	36487	45188	36825	43589	33839	-
Closure pressure [kPa]	33970	33026	33474	32833	36590	33012	38025	32943	32819
Frac Gradient [kPa/m]	12.4	12.4	12.4	12.2	13.6	12.4	14.5	12	12.2
Fluid Efficiency [%]	21	30	14	12	17	20	-	29	-
Proppant In Formation [Kg]	9,072.0	5,896.7	18,143.7	17,418.0	18,279.7	15,831.0	13,607.7	128,366.6	24947.6

Instantaneous Production										
Oil [m³/day]	Before	0	23.8	28	0	31.6	46.6	73	26.5	73
	After	95.4	218.4	161	91	40.1	95.6	88	53.4	116.1
Water Cut [%]	Before	0	0	0	0	0	0	0	0	0
	After	0	4	0	0	0	24	0	16	0

Field Description

North Gialo Discovered in 2002 with the drilling of the 6J1 well exploratory well and tested the Nubian sandstone at rates up to 795 m³/day, resulting in the discovery of the field. An additional 14 appraisal wells were drilled revealing a large areal extent, low porosity (10 %), low permeability (1 mD) reservoir with a 670.56 meter hydrocarbon column of volatile oil. Initial DST rates of the appraisal wells varied widely, from 32 - 1590 m³/day. The discovery was based on the interpretation of the 3D seismic survey, data obtained by the 1970s four exploratory wells and the Farigh Field to the Northwest.

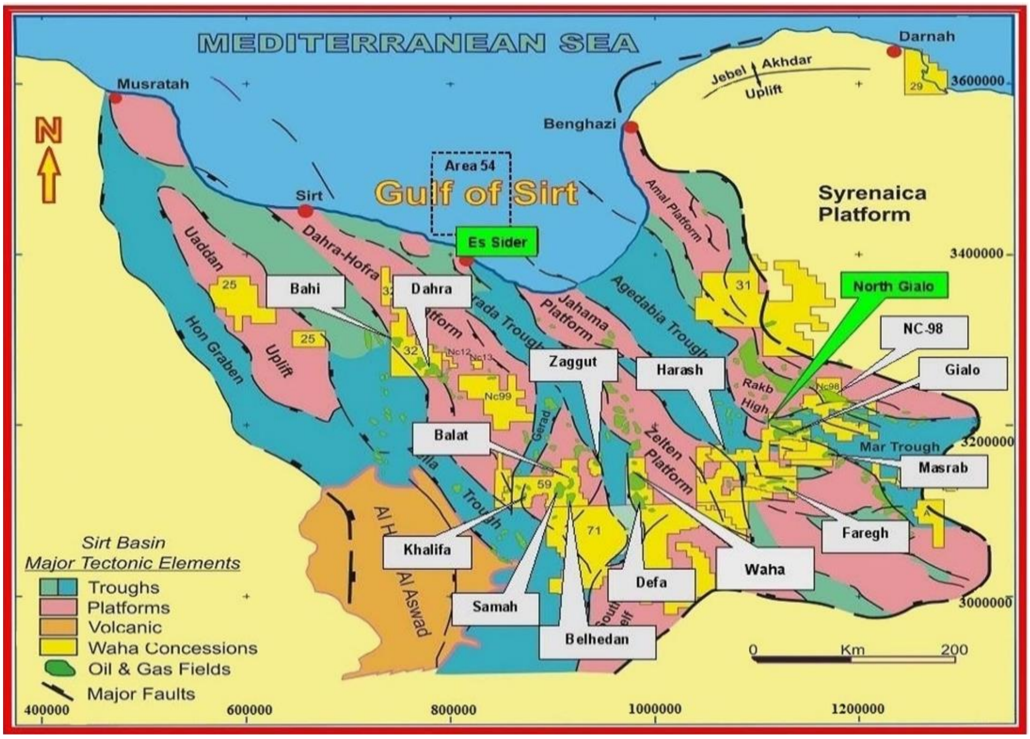

Fig. 1. Location of the North Gialo Field within the Sirt Basin Libya, (See Canales and Recep, 2002).

North Gialo is a new oil field estimated to contain 0.64 billion cubic meters of light oil and 0.187 trillion cubic meters of associated gas. The North Gialo Field is located in the SE portion of the Sirte Basin encompassing over 307,561056 m² with approximately 101,171400 productive square meters as shown in Figure 1 (see Canales and Recep, 2002).

North Gialo field lies at the intersection of the Hameimat and Ajdabaiya troughs of the Sirte Basin, southeast of the Farigh Field (Veba, Nubian, 0.191 billion cubic meter Original Oil In Place - OOIP) and north of the Gialo Field (Waha, 2.05 billion cubic meter OOIP), as argued by Liu and Sharme (2002), and Canales and Recep (2002).

Candidate Selection

The target zone for the treatment is the Upper Nubian Sandstone (UNS), for 6J9 well, located in a very heterogeneous reservoir with three multilayered producing sand. The candidate well is currently completed as an oil producer well with sets of perforations from 3743 m to 3788 m and low permeability. Thus HPGuar fluid system and High Strength Proppant fractured have been used in this study.

An average Young’s Modulus throughout the upper Nubian sandstone formation is 49.6 GPa, with Poisson ratio of 0.1672 in the competent sand. The stresses across the upper Nubian sandstone formation have some contrast between the consolidated and unconsolidated rock depending on the degree of cementation and presence of shale. The in-situ stress indicated about 57,226 kPa.

Pressure and stress analysis starts with overburden stress and pore pressure estimates provided by the ConocoPhillips Middle East-North Africa Business as argued by Philivan (2008), and Silva (2010). The Nubian section is primarily clean, quartz-rich sandstones (quartz arenites). The reservoir quality of the sands has been negatively affected by pervasive diagenetic modifications of porosity and permeability with a high degree of rock consolidation and high-temperature conditions. The treatment was done for upper Nubian sand, and the cross thickness is about 45 meter. 6J9 well Completion and reservoir data listed in table 2.

Tab. 2. 6J9 well completion and reservoir data.

Well	6J9 -59E
Formation	UNS
Interval Depth (m)	3743 – 3887.4
Frac Design (m)	3743 – 3788
Reservoir Pressure (kPa)	42058
Production Rate (m³/day)	342.6
Choke size (cm)	2.45
Reservoir Temperature (°C)	143
Permeability (mD)	4.8
Porosity (%)	10
Tubing (cm)	OD 8.89
Casing	OD 24.45
Water Saturation (%)	35
Perforation Density (shut/m)	16

Methodology and Procedures

Implementation was done by two method analyses, which were run within Production Simulator, from Stim-Lab - Baseline conductivity analysis and production analysis. Production Simulator has the capability of producing predicted production rate and net present value (NPV) curve. All inputs for these curves related to costs, however, are the only estimate and all NPV curves should be used as qualitative comparisons, not quantitative.

The simulation study is comprised of major steps completed by a different technology. Therefore, the programs used for modelling were Production Simulator and Fracture Simulator. Hence, Rheology Fluid Software Application and Fracture Simulator, these programs use known rheology, viscosity, reservoir, and mechanical rock properties along with a user-created pump schedule to produce optimised fracture geometry, conductivity, and areal concentration of proppant (kg/m²).

Hydraulically fracture was done for 6J9 well, Upper Nubian Sandstone within the perf intervals 3,743- 3,788 meter and temperature is 143°C so selected fluid system such as HPGuar delayed crosslinked Borate that this fluid system have to crosslink, the primary is water-based slurry of borate mineral, provide delayed borate crosslink fluids and the secondary is an instantaneous. HPGuar delayed crosslinked borate system is recommended for wells with bottom hole static temperatures (BHST) of 51.7° to 149 °C.

Therefore, the linear polymer solution is referred to as water frac, which is typically prepared from guar-based polymers for pre-pad and displacement. Water frac is very important and a widely - used component of the hydraulic fracture. Preparing water frac from a guar-based polymer is a two-step process. First, the gelling agent must be dispersed in water. Then, the gelling agent (polymer) must hydrate to obtain the desired increase in fluid viscosity.

6J9 Treatment Design Considerations

The stage treatment starts with filling the well with Linear Gel (water Frac) prepared with HPG to minimise friction pressures during the breakdown followed by pumping a Breakdown/Stepdown test. This test is used to evaluate bottom hole treating pressures and to determine friction pressures at the perforation and/or near wellbore area. The breakdown phase followed by a Stepdown test. The Stepdown test is used to quantify perforation and near wellbore friction (Tortuosity) which will help to determine whether fracture entrance problems are present.

Minifrac treatment is a stage to determine the fracture closure stress and the fluid leak-off parameters at in-situ conditions. Once the fractures have closed, the pumps should be brought back on as quickly as possible to try to establish one dominant fracture (the sand slug will help screen-off the other small fractures that were forming).

Larger pad volumes and fluid leak-off additives (Sand Slug), should be considered to address and negate the problem. When the treating pressure rises after a breakdown that should make run a sand slug during Pad to see how the formation would react. As the treatment will be conducted through a part of the existing perforations, included proppant slug of 120 kg/m³ depending on the formation during pumping mini-frac to verify if proppant can be placed in the formation.

Therefore, if competing multiple fractures exist, it is best to place proppant into the fracture(s) and shutdown. The mini-frac treatment provides the collection and interpretation of many valuable reservoir and stimulation characteristics which permit stimulation optimisation for each individual well. Some of these factors include average permeability, fracturing pressures, fracture extension pressure, fluid leak-off values, mechanical properties, and fracture closure pressure. The Main Treatment is designed to place 120,875 Kg of 20/40, mesh (High strength Proppant) with a proppant concentration up to 839 kg/m³.

Chemical Compositional Selection

A delayed crosslinked borate gel provides the following characteristics as shown in the tables (3 - 6)

Tab. 3. 22.7 kg Water Frac HPG composition.

Description	Additive name	Concentration
Liquid Gel Concentration	HPG	11.35 L/m³
Lower PH Buffer	A weak acid solution	0.2 L/m³
Breaker	An oxidant breaker	0.24 kg/m³

Tab. 4. 22.7 kg Water Frac HPG additional to an additive to enhancement the fluid recovery and product formation from clay swelling.

Description	Additive name	Concentration
Clay control	Clays stabiliser (Organic Polymer)	4.0 L/m³
Surfactant	A no ionic surfactant	2.0 L/m³
Breaker	A high-temperature oxidant breaker	2.0 L/m³
Biocide	A biocide (Short Action)	0.018 kg/m³

Tab. 5. Cross-Linked Gel Composition.

Description	Additive name	Concentration
Liquid Gel Concentration	HPG	11.35 L/m³
Lower PH Buffer	A weak acid solution	0.2 L/m³
Cross-linker	A primary delayed crosslinker (base oil solution)	4.2 L/m³
Cross-linker	A secondary instantaneous crosslinker (high pH, water base)	0.5 L/m³
Gel Stabilizer	A gel stabiliser for high temperature (solid)	0.48 kg/m³
High pH Buffer	A high pH control, is not strictly a buffer is pH control solution	2.72 L/m³
Breaker	A breaker activator (catalyst)	0.06 kg/m³
Breaker	an oxidant breaker	0.24 kg/m³

Tab. 6. 22.7 kg Cross-Linked Gel additional to an additive to enhancement the fluid recovery and product formation from clay swelling.

Description	Additive name	Concentration
Clay control	Clays Stabilizer (Organic Polymer)	4.0 L/m³
Surfactant	A no ionic surfactant	2.0 L/m³
Biocide	A biocide (Short Action)	0.018 kg/m³
Breaker	A high - temperature an oxidant breaker	2.0 L/m³
Breaker	An oxidant breaker	0.24 kg/m³

Frac Fluid Rheology Selection

Fluid rheology and major viscosity requirements for proppant transport at a given gel loading, and temperature based on a best-fit curve calculated values based on the software application for the rheology fracture fluid model to measured data. Almost every Halliburton stimulation field lab can generate data on fracturing fluid viscosity versus time, also called a Break Profile. The proppant in suspension and settle with the fluid an apparent viscosity up 250 mPa*s depends on the proppant laden fluid on the pump schedule and the minimum acceptable viscosity to carry the proppant is 200 mPa*s as shown in Fig. 2.

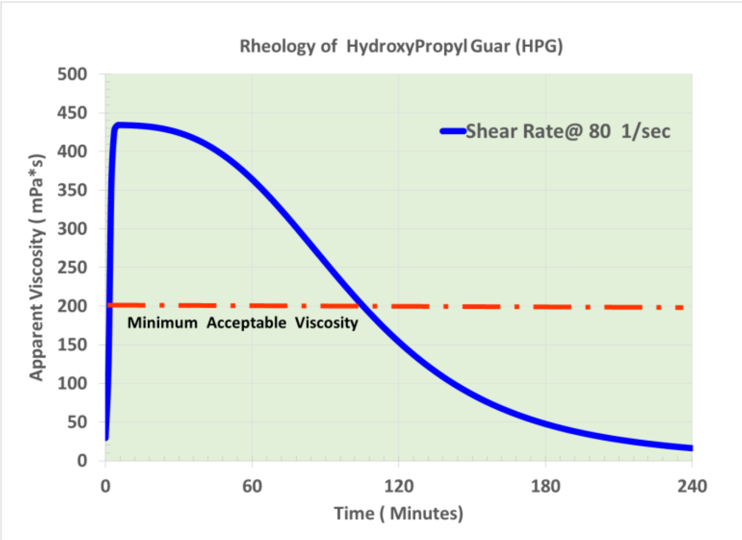

Fig. 2. Breaking Profile.

The shear rate of the fluid has been subjected for which the fluid property is desired. It is typically reported for linear gels at 300 rotation per minute (rpm) on Fann Model- 35, a viscometer equipped with a Bob size, B1 bob, this bob is the large bob. It is usually used to determine the base gel viscosity of frac fluids, which produces a shear of 511 1/sec (reciprocal seconds), as shown in Fig. 3.

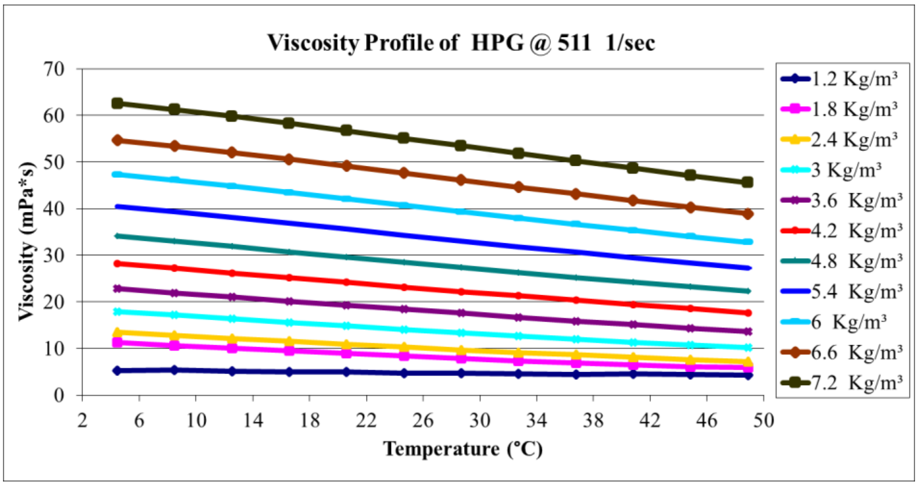

Fig. 3. Viscosity profile for several HPG concentrations Vs Temperature.

Therefore, the rheological properties of the fracturing fluid play a crucial part because they directly affect the performance of the fluid with respect to almost all the fluid functions. Thus can be directly used to calculate frictional pressure losses in the wellbore, perforations, and fracture. Several industry tests have concluded, based on laboratory proppant transport testing, that cross-linked borate fluids were perfect proppant transport fluids.

Proppant Analysis

Twelve treatments were initially compared in the Baseline Analysis. The treatment contained High Strength Proppant (HSP), and Intermediate Height Strength Proppant (IHSP), with 20/40, 16/20 and /or 16/30 sieve sizes at 5, 10 and 15 Kg/m² areal proppant concentration. The properties of these twelve treatments are listed below in table 7. Figure (4), shows the results of the Baseline Analysis, conductivity vs stress and the well has expected minimum horizontal stresses range, the 6J9-59E well has expected through the targeted perforation intervals, of 46,884 – 55,158 kilopascals, (kPa). This range is represented by the Red Vertical Lines on the plot.

At 48,263 kilopascals, (kPa) the plot shows 16/20 -HSP at 15 Kg/m² , 16/20 -HSP at 10 Kg/m², and 16/30- HSP at 15 Kg/m² having the top three conductivity values: 3,810 md*m, 2,590 md*m, and 3,000 md*m. 16/20 -HSP was chosen as the optimised proppant type and sieve size. Eliminating all other proppants, a plot was created with only 16/20-HSP at three areal proppant concentration values: 5 Kg/m², 10 Kg/m², and 15 Kg/m².

Tab. 7. 6J9 Proppant properties for Baseline Analysis.

Type	Sieve Size	Areal Concentration	Colour on Graph
HSP	20/40	5 kg/m²	
HSP	20/40	10 kg/m²	
HSP	20/40	15 kg/m²	
HSP	16/20	5 kg/m²	
HSP	16/20	10 kg/m²	
HSP	16/20	15 kg/m²	
HSP	16/30	5 kg/m²	
HSP	16/30	10 kg/m²	
HSP	16/30	15 kg/m²	
IHSP	16/30	5 kg/m²	
IHSP	16/30	10 kg/m²	
IHSP	16/30	15 kg/m²	

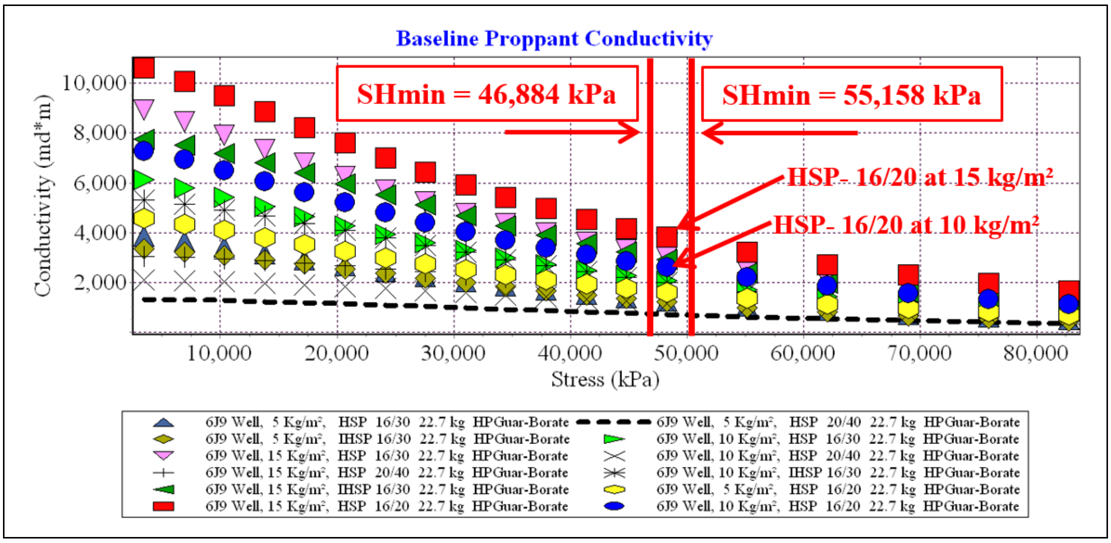

Fig. 4. 6J9 Well Baseline Analysis Results.

Production Analysis

The next analysis was Production Analysis. This analysis provides production and NPV profiles based on the well properties and costs entered by the user.

An untreated well is also analysed and compared to the treated well profiles. The production analysis incorporates damage effects caused by non-Darcy flow, multi-phase flow, and gel damage into its production calculations. It also provides corrected permeability, width, and conductivity values based on the damage effects.

Table 8 below shows the damage effect results of the production analysis run for 16/20 -HSP proppant in the 6J9 well after 2 years of production. The table shows that as proppant areal concentration increases, so do conductivity and % available width. Permeability, however, decreased as proppant areal concentration increase, but the difference is very small. The highest conductivity and % available width is seen in the 15 Kg/m² areal concentration, but the largest conductivity and % available width improvement is from 5 Kg/m² to 10 Kg/m².

Tab. 8. 6J9 Production Analysis Damage Effects.

Areal Concentration	Conductivity	Available Width	Corrected Permeability
5 Kg/m²	64.05 md*m	61.16%	42.25 darcy
15 Kg/m²	122.3 md*m	77.62%	34.40 darcy
20 Kg/m²	190.1 md*m	84.21%	32.85 darcy

The production analysis uses the above-corrected values and other reservoir and well properties to create production and NPV profiles for 6J9 well. Figures 5, 6, and 7 show estimated cumulative production, production rate, and NPV profiles, respectively, for 6J9 well. The plots contain profiles for 16/20 -HSP at 5, 10, and 15 Kg/m² proppant areal concentration as well as an untreated well.

At the end of two years, the following values in Table 9 were calculated. Again, the highest cumulative production occurs with 15 Kg/m² areal concentration, but the largest improvement is seen when going from 5 Kg/m² to 10 Kg/m² proppant areal concentration.

Tab. 9. 6J9 Estimate Cumulative Production Values after 2 years.

Areal Concentration	Cumulative Production
5 Kg/m²	270600 m³
10 Kg/m²	279500 m³
15 Kg/m²	285100 m³
Untreated Well	**165400 m³**

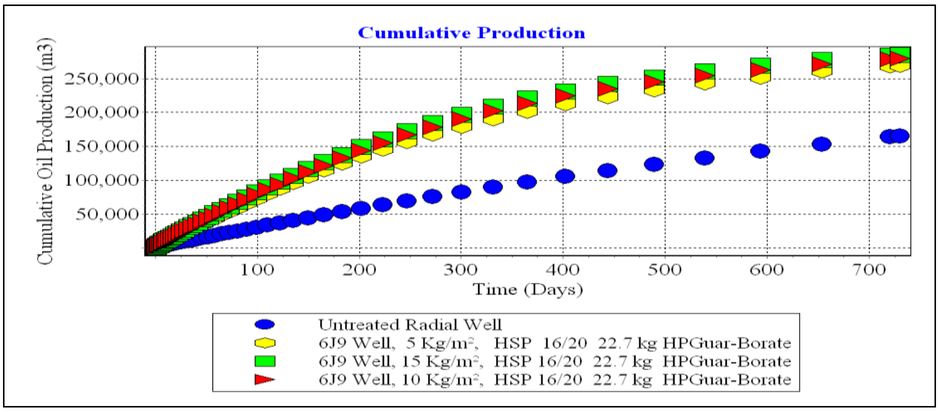

Fig. 5. 6J9 Well Estimated Cumulative Production – 2 years.

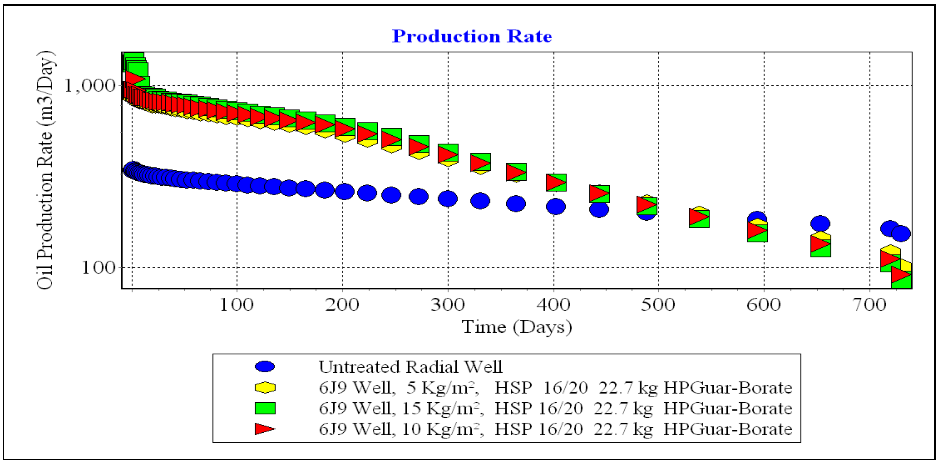

Fig. 6. 6J9 Well Estimated Production Rate – 2 years.

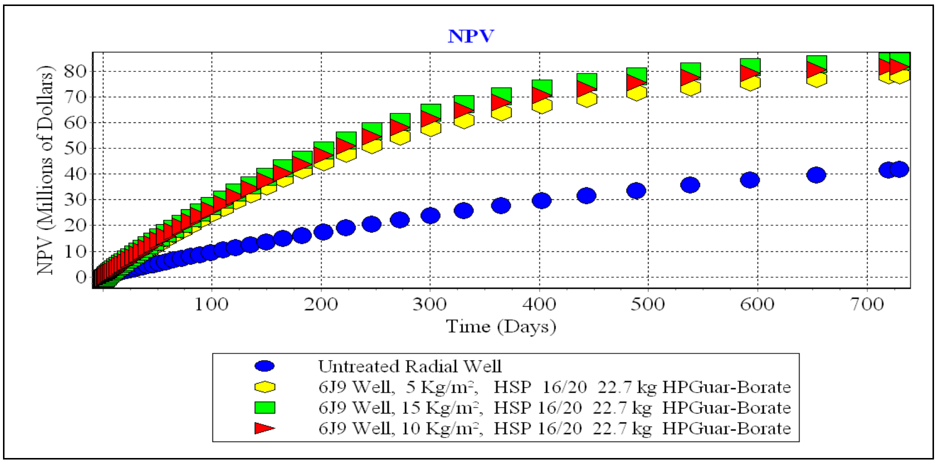

Fig. 7. 6J9 Well Estimated NVP – 2 years.

Initial and final (after 2 years) production rates are listed below in Table 10. When comparing initial production rates, 15 Kg/m² shows the highest initial production rate. Therefore, the largest improvement is seen when going from 10 Kg/m² to 15 Kg/m² proppant areal concentration. The Production rate plot also shows that after approximately one year, the production rate of the treated wells drops but the above the rate of the untreated well.

Tab. 10. 6J9 Estimated Production Rates, Initial and after 2 years production.

Areal Concentration	Initial production rate	2 years production rate
5 Kg/m²	881.7 m³/day	100.5 m³/day
10 Kg/m²	951.7 m³/day	91.88 m³/day
15 Kg/m²	1331 m³/day	85.93 m³/day
Untreated Well	**342.6 m³/day**	**153.7 m³/day**

The Net Present Value (NPV), values after two years are shown below in Table 11. Again, the highest NPV occurs at 15 Kg/m² areal concentration, but the largest improvement is seen when going from 5 Kg/m² to 10 Kg/m² proppant areal concentration.

Tab. 11. 6J9 Estimated NPV after 2 years.

Areal Concentration	NPV
5 Kg/m²	$78.34 Million
10 Kg/m²	$81.65 Million
15 Kg/m²	$83.82 Million
Untreated Well	**$41.80 Million**

6J9 Stage Fracturing Design

The design run within Fracture Simulators for 6J9 well, the target zone for treatment is 3,743 meter to 3788 meters, and the candidate well is currently completed as an oil producer well with sets of perforations through the mentioned formation. Based on the data provided, the formation characteristics and reservoir data show a very low permeability formation to cover this long interval with a hydraulic fracturing it requires fracture height controlling by pumping large quantities of slurry volume, pad volume, slurry injection rate, amount of proppants, and net pressure between the minimum in-situ stress of the formation and treating pressure.

The cross thickness was 45 meter, where the treatment contained High Strength Proppant, HSP- 16/20, 16/30 and 20/40.

One of the Fracture Simulator Module estimates the Folds-Of-Increase (FOI) which may result from various combinations of proppant volumes. It considers each proppant type independently.

The calculations interactively determine the best possible fracture. FOI Module is a very powerful tool to predict the potential of post-frac productivity in low permeability reservoirs. This would be significant in terms of total well life. This design considers proppant type and mass of proppant, where the mass of proppant varies from 100,000 kg to 150,000 kg per stage.

As shown in Fig. 8, the combination of the proppant types with an increase of proppant mass, and the acceleration of the Folds of increase values — the best result of Fold Of Increase (FOI), which would increase in HSP- 16/20. However, the type of sieve sizes and proppant will be investigated to see the effect on FOI. The following tables 12 through 13 shows - Pumping Schedule for the Fracture Simulator schedule and main treatment design results. Figures 9 through 10 show matching pressure and fracture conductivity profile. Post Fracture job might be considered to achieve better production when compared with pre-job.

This research will mostly focus on proppant section design that should be performed with several proppants and evaluated based on the predicted performance from the well and economics of the treatment. Therefore, the material selection is a key factor design. Not only proppant but the fracturing fluids have a great impact in fracture conductivity. The fluid viscosity being the most important property will dictate several conditions during the frac job (friction, fracture width, and proppant transport).

The bottom of the targeted zone for stimulation is located 17 meters above the oil-water contact. Therefore, a decision has been taken to limit the treatment zone between 3,743 to 3,788 meter. For practical considerations, and to ensure that the entire targeted zone is fractured, avoid screen out if taken place and eliminate an increase in water cut. The optimum model of Fracture Simulator is 9 to 18 meter.

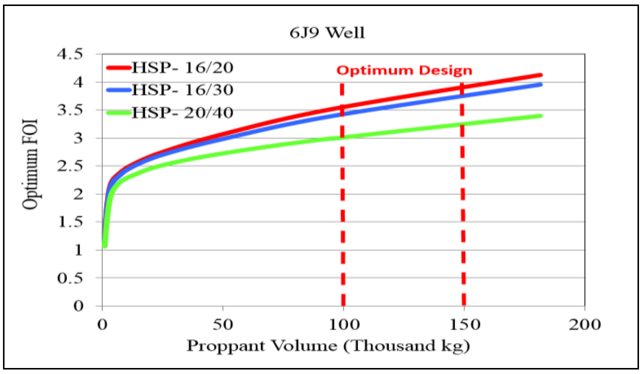

Fig. 8. Optimum FOI Results.

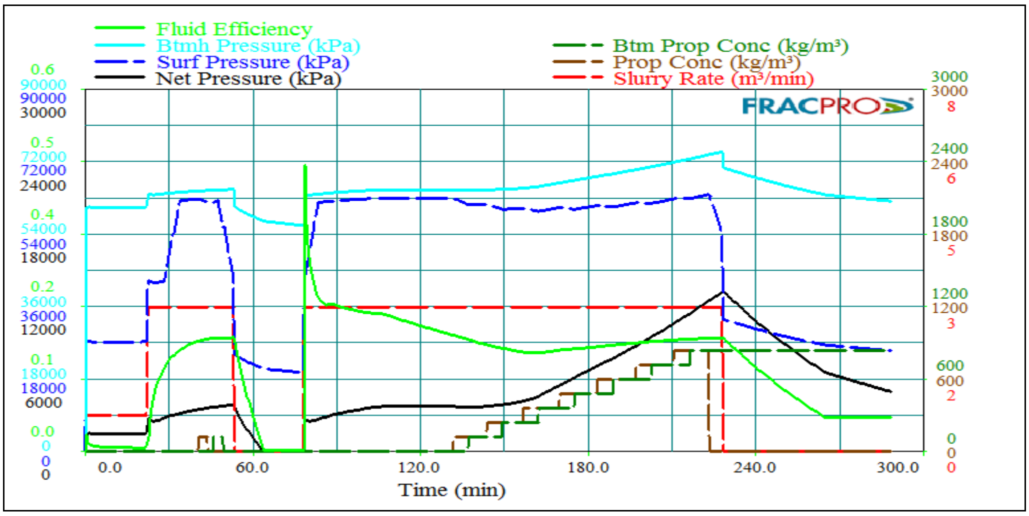

Fig. 9. Preliminary main treatment design.

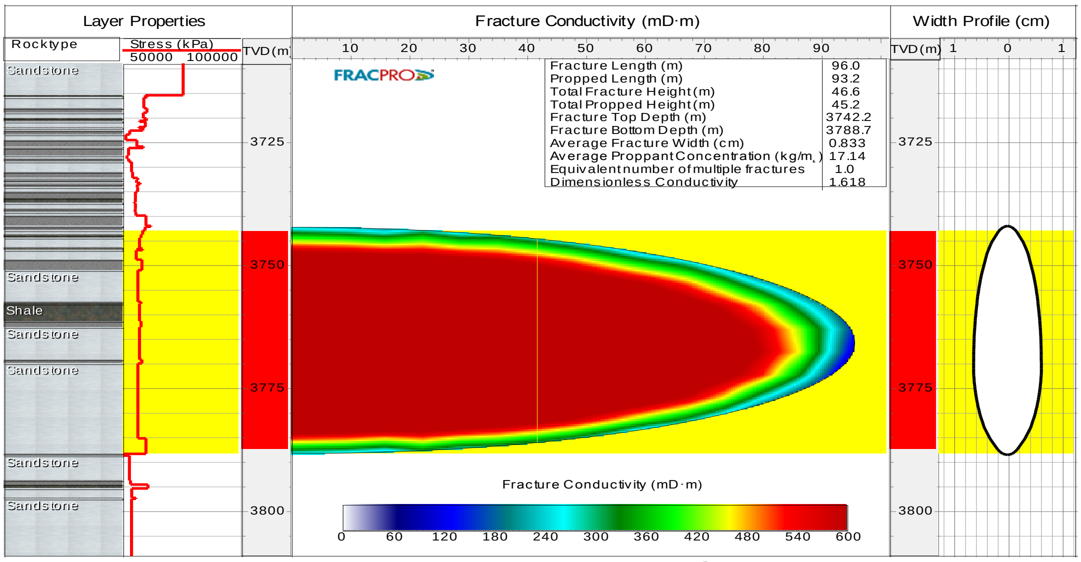

Fig. 10. Main Treatment Fracture Conductivity.

Tab. 12. Pump Schedule for MiniFrac and Main Treatment.

WELL NAME: 6J9-59E
JOB NAME: Stage 1
NO. OF PERFS: 736
MID PERF DEPTH: 3765.5 m
ESTIMATED PUMP TIME: 3.39 hrs.
BHST: 143 degC
FRAC GRADIENT: 15.2 kP/m

22.7 KG WATER FRAC (HPG): 71 m³
BORATE GEL (HPG) 22.7 KG: 488 m³
HSP 20/40: 122,238 kg

Frac the Upper Nubian interval with 428 cubic meters of Borate Gel (HPG) (45 mPa*s) carrying 120,875 Kilograms of 20/40 -HSP. Treat down 8.89 cm tubing at 3.18 m³/min with an anticipated wellhead treatment pressure of 61,301 kPa. Use following schedule:

TUBING (SURFACE)									
STAGE NO.	**STAGE DESCRIPTION**	**ELAPSED TIME MIN:SEC**	**FLUID DESCRIPTION**	**SLURRY RATE (M³/MIN)**	**CLEAN VOLUME (M³)**	**PROPPANT TYPE**	**PROP. CONC. (KG/M³)**	**PROP. MASS (KG)**	**COMMENT**
1	Load Well	22:22	22.7 Kg Water Frac (HPG)	0.79	17.791		0.0	0.0	load Hole
2	Shut-In	22:22	0.000	0.00	0.000		0.0	0.0	
3	Step Rate Test	28:20	22.7 Kg Water Frac (HPG)	3.18	18.927		0.0	0.0	Step Rate
4	Shut-In	28:20	0.000	0.00	0.000		0.0	0.0	
5	Fluid Efficiency Test	40:14	Borate Gel (HPG) 22.7 Kg	3.18	37.854		0.0	0.0	Mini Frac
6	Sand slug	43:55	Borate Gel (HPG) 22.7 Kg	3.18	11.356	HSP- 20/40	120	1362.72	Sand Slug
7	Fluid Efficiency Test	47:30	Borate Gel (HPG) 22.7 Kg	3.18	11.356		0.0	0.0	Displace
8	Fluid Efficiency Test	53:05	22.7 Kg Water Frac (HPG)	3.18	17.791		0.0	0.0	Over Displace
9	Shut-In for FET Analysis	78:05	0.000	0.00	0.000		0.0	0.0	
10	Pad	131:40	Borate Gel (HPG) 22.7 Kg	3.18	170.344		0.0	0.0	
11	Proppant Laden Fluid	143:58	Borate Gel (HPG) 22.7 Kg	3.18	37.854	HSP- 20/40	120	4542.48	
12	Proppant Laden Fluid	156:40	Borate Gel (HPG) 22.7 Kg	3.18	37.854	HSP- 20/40	240	9084.96	
13	Proppant Laden Fluid	169:46	Borate Gel (HPG) 22.7 Kg	3.18	37.854	HSP- 20/40	359	13589.586	
14	Proppant Laden Fluid	183:17	Borate Gel (HPG) 22.7 Kg	3.18	37.854	HSP- 20/40	479	18132.066	
15	Proppant Laden Fluid	197:11	Borate Gel (HPG) 22.7 Kg	3.18	37.854	HSP- 20/40	599	22674.546	
16	Proppant Laden Fluid	210:46	Borate Gel (HPG) 22.7 Kg	3.18	35.961	HSP- 20/40	719	25855.959	
17	Proppant Laden Fluid	223:16	Borate Gel (HPG) 22.7 Kg	3.18	32.176	HSP- 20/40	839	26995.664	
18	Flush	228:23	22.7 Kg Water Frac (HPG)	3.18	16.277		0.0	0.0	
Total					**559.103**			**122,237.98**	

Tab. 13. Main Treatment Design Results.

DESCRIPTION	
Propped Fracture Half Length	96 [m]
Propped Fracture Top Height	3742 [m]
Propped Fracture Bottom Height	3789 [m]
Average Fracture Width	0.83 [cm]
Fracture Average Proppant Concentration	17.13 [Kg/m²]
Dimensionless Conductivity	1.24
Fracture Average Proppant Conductivity	554.1 [mD·m]

6J9 Post Frac

The treatment has performed the Stage 1, 22.7 kilograms — a delayed cross-linked borate gel treatment on the North Gialo Field, 6J9 well. A pre-job safety meeting was held on the location, where the details of the job were discussed, and potential safety hazards were reviewed, and environmental compliance procedures were outlined. The maximum pressure for the treatment was set at 68,948 kPa. The treatment was designed at 3.18 m³/min, with 427.752 m³ of 22.7 Kg.

A delayed cross-linked borate gel is carrying 120,882.4 kg of 20/40 -HSP. The job was pumped at an average treating rate and pressure of 4.8 m³/min and 55,158 kPa respectively.

Initially, the well was loaded with 22.7 Kg Water Frac (HPG) at a rate of 0.795 - 3.18 m³/min. Once the well was loaded and the pressure stabilised, the pumps were shut down. The ISIP after Shutting down was 19,691 kPa.

Secondly, the fluid efficiency test was pumped at maximum rate and pressure of 4.83 m³/min and 53,779 kPa.

However, for more details see mini-frac job summary in table 14. Figures 11 and 12 shows a chemical job summary for all the treatments performed, and the main treating frac job summary.

Tab. 14. Mini Frac Job Summary.

Pump Time	49.28	Minute
Max Treating Pressure	53,779	kPa
Max Slurry Rate	4.8	m³/min
Max Prop Concentration	132	kg/ m³
Clean Volume	111.4	m³
Slurry Volume	111.88	m³
Prop Mass	1270	Kg
Load to Recover	111.4	m³
Perforation frictions	1813	kPa
Near wellbore (NWB) frictions	4847	kPa
BH ISIP	58,550	kPa
Frac gradient	15.6	kPa/m
Closure gradient	14	kPa/m
Fluid Efficiency	49.6	%

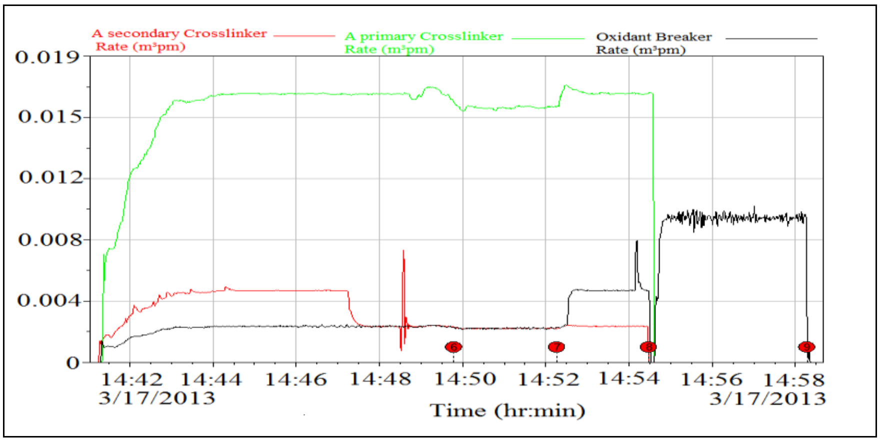

Fig. 11. Mini Frac Chemical job

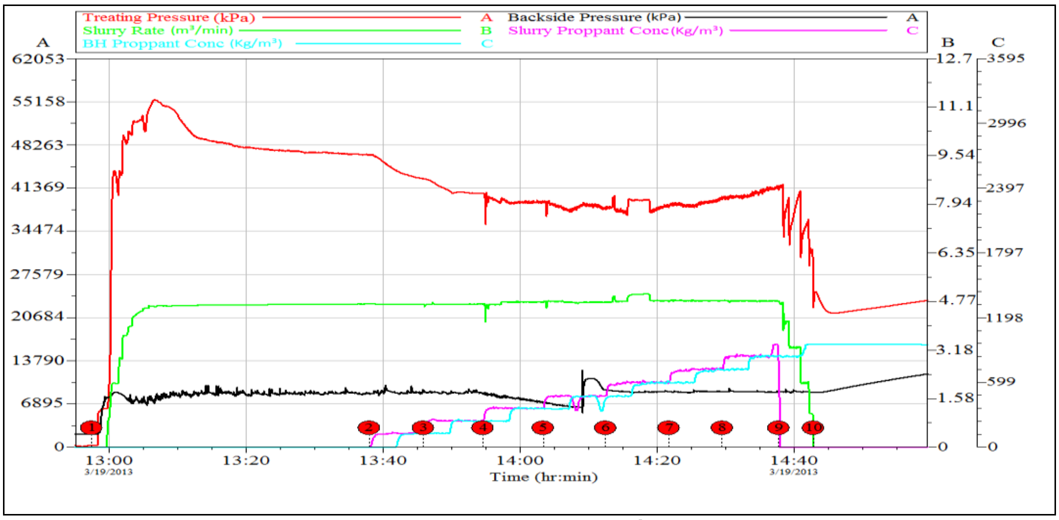

Fig. 12. Main treating Frac job Summary.

6J9 Pre and Post Stage Fracturing Treatment

The post-treatment performance provides a good indication of stimulation success, for 6J9 well and the best-applied method to determine with Production Simulator and Fracture Simulator Models. The Initial production was 342.6 m³/day when compared with the Post-stim production was 1112.4 m³/day (3.247 FOI). Therefore, this analysis is a key element for the optimisation of the hydraulic fracturing process, forecasting well performance.

Thus the treatment paid-out in 3 days and over $ 22 million in additional revenue over 60 days as shown in figure 13.

Post-stimulation data collection and evaluation will be used to calibrate and improve current models for future stimulation treatments within the North Gialo Nubian sandstone.

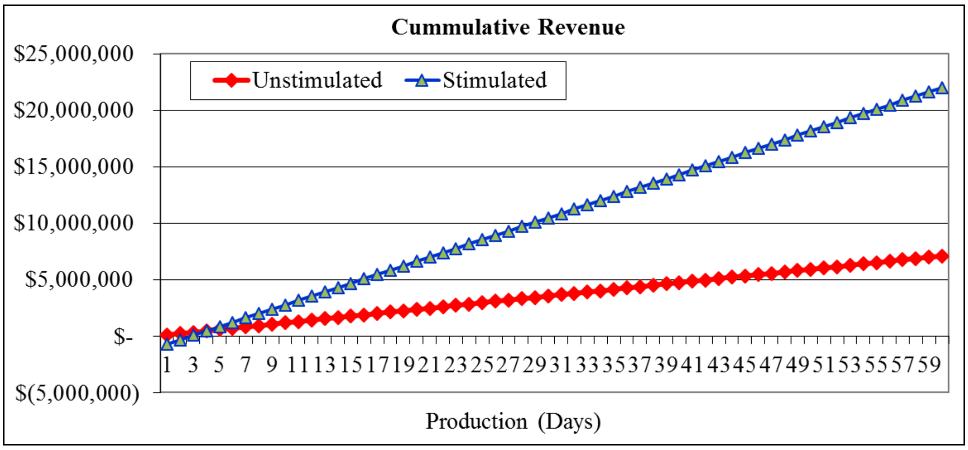

Fig. 13. 6J9 Pre and Post stage fracturing treatment.

Discussion

Fracture stimulation has been considered to enhance oil recovery for the Gialo field located in Libya. For such fracturing treatments, a reliable and combatable fracturing fluid is required to provide adequate rheological performance at a high temperature up to 146 ºC for pump during 2 hours. However, some tests were conducted on location to evaluate fluid formulations response using Services Company.

In this case, a crosslinked fluid was used in fracturing treatments to compensate the high-temperature reservoirs (bottom hole temperature > 93ºC) in order to the improved proppant transport compared to linear polymer systems.

Alternative options are available regarding fracturing fluids such as polymer and crosslinker combinations for high-temperature applications. However, it was recommended to use guar-based polymers crosslinked with either borate or zirconium compounds, which gave the best results compared to the other fluids.

An investigation of prop mesh size was performed, which showed that HSP- 16/20 had the best results with maximum performance. However, practically another size was used (HSP- 20/40) regarding two reasons: Firstly, the only prop at the stock was HSP- 20/40 at that time, and the second was no investigation was done for the size of the prop. Such analysis can lead to having a better vision for making decisions. Even though, HSP- 20/40 mesh size, which is high strength proppant, it will provide sufficient conductivity contrast between the formation matrix and the fracture.

The simulation shows that it is possible to forecast the oil production of low permeability in Upper Nubian sandstone formation. However, the results of the analysis by a combination of Production Simulator and Fracture

Simulator modelling improved an excellent accuracy to the results which is good indication comparing to deduction of actual results of the fracturing practice.

On the other hand, applied these models are not only forecasting the performance, but it also compares well performance using various proppants, fluid rheology, fracture length, fracture heights, fracture geometrics, and proppant concentration. The value of Fold of Increase (FOI) is 3.06 for the model, as shown in figure 8, where the actual stimulation result is 3.247. After that, the oil production rate was increased by a ratio of 224.7 %.

Rheology testing of fracturing fluid candidates for the Gialo field was conducted to determine the optimum fluid composition. As a result, the candidates were selected water-based, crosslinked fluid is Borate Crosslinked Guar. However, 6J9 well was responded positively to the fractured hydraulic technique by implemented HPG Fluid System. This method was applied for high temperature as well as including (HSP- 20/40).

Conclusion

The Baseline Analysis results show HSP- 16/20 proppant provides the highest conductivity, under the predicted well stress conditions, the proppant type and size was selected for the stimulation. Thus results show that the borate crosslinked fluids with HSP- 16/20 provide the highest conductivity at 15 Kg/m² proppant areal concentration.

The Production Analysis results show that stimulating the well more than doubles the cumulative production after 2 years when compared to the well unstimulated. This analysis also shows that 15 Kg/m² proppant areal concentration with borate crosslinked fluids will provide the highest cumulative production after 2 years as well as the highest initial production rate just after stimulation, 28, 5100 m³ and 1,331 m³/day, respectively.

When comparing these values to 5 and 10 Kg/m² areal concentration results as seen in table 9 the most improvement is shown when going from 5 and 10 Kg/m² rather than when going from 10 to 15 Kg/m², but table 10 the most improvement is shown when going from 10 to 15 Kg/m² rather than when going from 5 to 10 Kg/m².

The percentage increase of initial production rate with 5 to 10 Kg/m² increasing 7.94 % and 10 to 15 Kg/m² increasing only 39.85 %.

The percentage increase in cumulative production after 2 years from 5 to 10 Kg/m² is 3.29 % where from 10 to 15 Kg/m² is only 2 %.

The same increase pattern is seen when comparing the different proppant areal concentration to the final NPV after 2 years.

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