ICCPGE 2016, 1, 25 - 30

Hydraulic Fracturing Technique to Improve Well Productivity and Oil Recovery in Deep Libyan Sandstone Reservoir

Saleh Arwini*
Department of Petroleum Engineering, University of Tripoli, Tripoli, Libya
*Corresponding Author: s.arwini@uot.edu.ly

Abstract

Hydraulic fracturing has become an important technique to improve well production and the recovery of low-permeability reservoirs in the oil and gas field development. Worldwide there are vast reserves of hydrocarbons trapped in tight sandstone formation. To produce this huge amount of reserve from low permeability formation economically, hydraulic fracturing can be applied. This paper discusses the analysis of pressure and production data from successful hydraulic fractured vertical well in low permeability Nubian reservoir. Based on several screening criteria, the vertical oil well from Nubian sandstone reservoir was selected for stimulation job by hydraulic fracturing. Several hydraulic fracture models have developed to optimize hydraulic fracture in order to increase the productivity index of the subject wells. All Pressure and production from the pre and post-hydraulic fracturing treatment data were collected and analyzed to assess the job success in terms of effective fracture parameters, fracture conductivity and reservoir parameters. Based upon the results of these results, the oil production rate of the subject wells is improved dramatically by 10 times with a significant decrease in the formation damage near the wellbore. Therefore, the success of the fracture treatment is largely due to efficient candidate selection, project management, fully integrated project team and systematic application of existing hydraulic fracturing techniques.

Keywords: Hydraulic fracturing; low permeability reservoir; Nubian sandstone reservoir; well productivity and oil recovery; formation damage.

1. Introduction

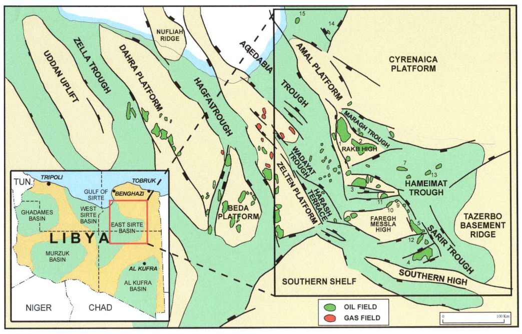
Many fields would not exist today without hydraulic fracturing. Hydraulic fracturing is a well stimulation treatment routinely performed on oil and gas wells in low-permeability layers to increase productivity. The technique of hydraulic fracturing has been widely used in the oil industry during the last 60 years. The first hydraulic fracturing treatment was pumped in 1947 on a gas well operated by Pan American Petroleum Corporation in the Hugoton field. The Kelpper Well No.1, located in Grant County, Kansas was a low productivity well, even though it had been acidized. The well was chosen for the first hydraulic fracture stimulation treatment so that hydraulic fracturing could be compared directly to acidizing .Since that first treatment in 1947, hydraulic fracturing has become a standard treatment for stimulating the productivity of oil and gas wells [1, 2]. Hydraulic fracturing operation is complicated as it involves fluid and solid mechanics, fluid flow in fracture and diffusion processes (fluid and thermal), and fracture propagation. Furthermore, all of the responses are coupled and depend on each other. Special fracturing fluids are pumped at high pressure into the reservoir intervals to be treated, causing a vertical fracture to open. The wings of the fracture extend away from the wellbore in opposite directions according to the original stresses within the formation. Proppant, such as sands of a particular size, is mixed and pumped together with treatment fluid into the fracture to keep it open after the treatment is complete. Hydraulic fracturing creates high-conductivity channel within a large

area of formation and bypasses any damage that may exist in the near-wellbore area. Complexity arises from two directions: geologic reality and the inherent multidisciplinary nature of the fracturing process [3, 4]. To assess the stimulation efficiency, we need to estimate reservoir and hydraulic fracture properties, such as effective permeability, fracture half length and fracture conductivity. The knowledge of these parameters are not only important for predicting future production performance of fractured wells, but also have significant impact on determining development strategies in exploitation of tight reservoirs, which has increased in recent years [5]. This paper presents and discusses a successful hydraulically fractured vertical tight oil well in deep Libyan sandstone reservoir. All Pressure and production from the pre and post-hydraulic fracturing treatment data were collected and analyzed to assess the job success. It is well-known that the purpose of fracture treatment is to remove reservoir damage near the wellbore, reduce total skin factor, increase reservoir permeability near the wellbore and increase well production.

2. Field Description

The North Gialo Field is situated in the eastern portion of the Sirte Basin at the intersection of the Hameimat and Ajdabaiya troughs on the northern flank of the Gialo structural high as shown in Figure 1. The prospective area of the Sirte Basin occupies about 230,000 km^2. A new structural-stratigraphic play concept was developed by Waha in 1995 that led to the acquisition of a 3D seismic survey. Based on the interpretation of the 3D seismic data, an exploration well was proposed and drilled in early 2002. North Gialo Field was discovered with the drilling and testing of the 6J-1 well in early 2002. During 2002-2004, the well intermittently produced for a total of 129 days with cumulative production of 338 MBO, representing an average rate of 2620 bbl/day. The discovery was based on interpretation of the 3D seismic survey, data obtained by the 1970's four exploratory wells and the Farigh Field to the Northwest. An additional 17 appraisal wells were subsequently drilled to define the limits of the field, fluid contacts and define the characteristics of the reservoirs. Waha estimates, given the present data, that the field covers more than 108 square kilometers. The eastern and southern extensions of the field are still to be defined by recently acquired 3D seismic data. Currently, the estimated $STOOIP$ is over five billion barrels of OIP of 43°API gravity. North Gialo is expected to produce 100,000 bpd of crude and 5.7 million cubic feet per day of gas [6, 7].

Figure 2.1: Eastern Sirte Basin Structural Features Map.



Structurally, the field is bisected by numerous faults, the western side of the field is dominated by NNW-SSE-trending faults, while the eastern side is dominated by faults trending WNW-ESE. The NW part of the field is further bisected by several major faults with throw from 300' to 1000', separating the field into major fault blocks. This major NNW trending fault (Figure 2.2 and 2.3) separates the X1 from the Farigh field continues southeast just west of the 4C-159 well and trends along the up dip limit of the UNS sub-crop. Moreover, the reservoir is considered a tight sandstone reservoir, which belong to the lower part of Lidam Nubian Sandstone formation (Late Cretaceous age), and the reservoir found at depth 12,555 ft [6, 7].

Figure 2.2: Schematic North Gialo Structural/Stratigraphic Model.

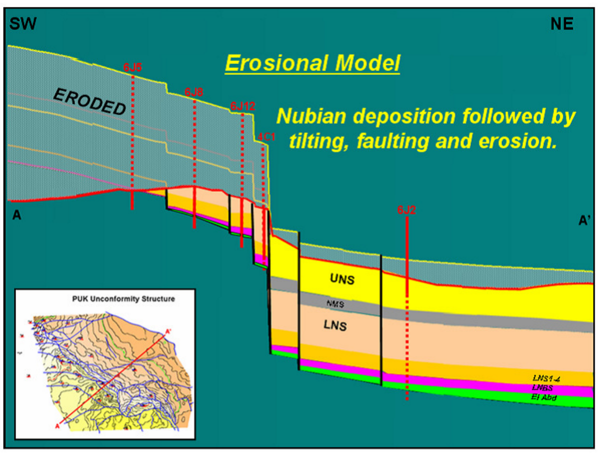
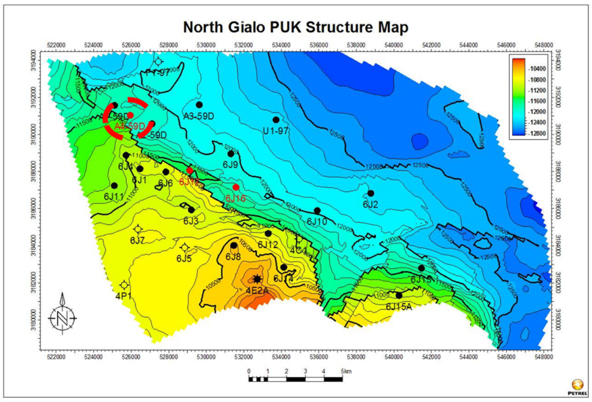


Figure 2.3: North Gailo, field structure map.



3. Candidate screening and selection

It is a complicated problem to determine which well to hydraulic fracture because the conditions of every well are different and there is no exact answer. But it is certain that the best candidate wells for hydraulic fracturing are the wells which are in need of production increase due to the near wellbore damage and which is capable of production increase by having substantial volume of oil and gas in place. The candidate well-X1 was selected based on several factors: Formation thickness, Volume of OIP, OWC & GOC and Formation Damage analysis. Formation damage is the big challenges for the Nubian reservoirs at North Gialo field. Two formation damage studies were performed by Corelab & Hycal and completed in 2008. Two main topics were studied, namely mechanical and chemical mechanisms, the laboratory work showed the Nubian reservoirs intervals are susceptible to a variety of mechanical and chemical formation damage mechanism. Because of the limited in-situ permeability initially available, drilling, completion and production practices will need to use a proper stimulation technique to preserve the productivity of wells. Table 3.1 presents information on the candidate well-X1. In 2009 the comprehensive reservoir simulation study conducted by ConcoPhillips company concluded that the hydraulic fracture stimulation is the best completion option to remedy near wellbore damage created by any of the damage mechanisms. The selected candidate exhibited low permeability and low porosity in the entire sandstone formation section. Core and open hole logs analysis indicated about 284 ft of net pay with an average porosity of 8.20 % [6].

Table 3.1: General information for selected candidate well.

Company	Waha Oil Company
Field Name	North Gialo
Well No	X1
Well Orientation	Vertical
Well Completion	Cased hole
Perforated Interval	(12624-12672 & 12725-12730), ft
Reservoir Temperature (T)	305 ^oF
Reservoir Pressure (Pr)	3950 psig
Reservoir Bubble Point Pressure (Pb)	4350 psig
Reservoir Porosity (Φ)	8.2 %
Reservoir Permeability (K)	0.5 mD
Net Pay Thickness (h)	284 ft

Table 3.2: Pre and Post frac PTA results.

Parameter	Before Frac	After Frac	Unit
Formation	LNSS		
Perforations	12624-12672 & 12725-12730		ft
Net pay thickness (h)	284		ft
Reservoir temperature (T)	305		^oF
Static reservoir pressure at gauge depth	5926	5893	psig
Reservoir Permeability (K)	5.37	4.80	md
Permeability-thickness product (Kh)	1525	1363	md.ft
Skin Factor (S)	+55.8	+2.9	Unitless

4. Results and Discussion

Schlumberger executed intensively 2D and 3D models to accomplish fracture-treatment design for the candidate well-X1. The main relevant well completion, formation, and treatment input data used in the fracture design are listed in Appendix A, Table A.1.

The location of the perforations in the section is seen in Appendix AppendixA, Figure ??. Schlumberger DataFRAC treatment of lower Nubian Sandstone formation (LNSS) in the candidate well-X1 utilized 16/30 HSP (ceramic) Proppant. Analysis results from the DataFRAC module in FracCADE software automatically update the fracture geometry simulator. Because of understanding the stress regime is critical to fracture growth, geometry, and treating pressures, Schlumberger recommend to run DSI log on this well and analyse the stress profile to optimise the frac treatment.

Therefore, stress profiles and other elastic rock properties estimated in the geomechanical analysis were used as input for the design. Injection Test Evaluation, Sand Slug and Crosslinked Fluid Treatment Evaluation and Temperature Log Evaluation were conducted successfully on the candidate well. Injection decline analysis was performed after treatment to verify closure pressure, fluid efficiency, identification of fracture and fissures, transmissibility and reservoir pressure analysis [6].

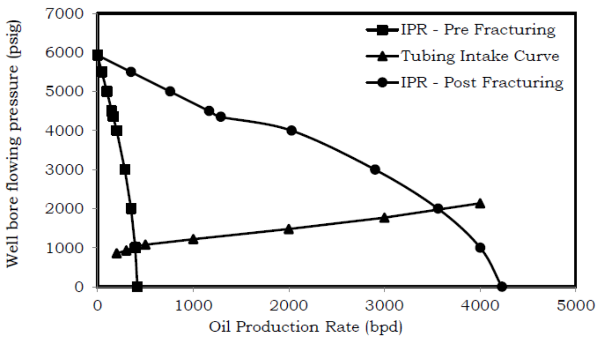
The results of these tests are not available to publish in this paper. Based on simulator history matching, the optimum hydraulic fracture half-length and fracture width are 270 ft and 0.166 in respectively. Bottom hole pressure data was interpreted to estimate reservoir parameters and to identify the reservoir model using semi log and log-log plots and type curve matching. We found that the skin factor decreased from +55.8 to +2.9 (decrease rate $\approx$ 95%) as seen in Table 3.2. The value of permeability obtained from the analysis result seems to be reliable and consistent with previous result. At the same time, when the skin factor reduces almost 20 times, the corresponding Absolute Open Flow Potential ($AOFP$) increases by a factor of 10 from 417 *bpd* to 4229 *bpd* as shown in Figure 4.1. The well productivity Index (PI) increased by factor of 10 as well as seen in Table 4.1. The main result of PTA and IPR analysis are tabulated in Table 3.2 and Table 4.1.

Table 4.1: Pre and Post frac IPR's Analysis.

Data	Pre-frac	Post-frac	Unit
Shut-in bottomhole pressure (Pws)	5930*	5930*	psig
Bubble-Point Pressure (Pb)	4350**	4350**	psig
Optimum Flow Rate (Qopt)	400	3560	bpd
PI below Pb	0.104	1.03	bbl/d/psi
AOFP	417	4229	bpd

* Static pressure at mid-perforations.
** Bubble point pressure for well-X1 crude from PVT.

Figure 4.1: Pre and Post frac IPR plot.



5. Conclusion

The following main conclusions can be drawn from this work:

1. For the candidate well-X1, the well PI increased by factor of 10 and the corresponding AOFP increases over 900%. Based upon these results, this project was a tremendous success from both an operational and engineering standpoint.
2. The post treatment performance provide s a good indication of stimulation success, whereas, PTA and production data analysis for hydraulically fractured vertical well in tight reservoir remains the most applied method to determine the reservoir and fracture parameters.
3. In addition to involving all necessary disciplines (Completions, Drilling, Reservoir, Geology and

Geophysics), it was essential that each team member fully bought into the project and took ownership of their individual responsibilities. Therefore, fully integrated project team was totally critical to the overall success of the frac project.

Abbreviations

API	American Petroleum Institute
AOFP	Absolute Open Flow Potential
DST	Drill Stem Test
GOC	Gas-Oil-Contact
HSP	High Strength Proppant
IPR	Inflow Performance Relationship
LNSS	lower Nubian Sandstones
MBO	Thousand Barrels of Oil (M = 1000 and MM = 1 million)
OIP	Oil Initial in Place
OWC	Oil-Water-Contact
PI	Productivity Index
PTA	Pressure Transient Analysis

Acknowledgment

The authors express thanks to faculty members, engineers and BSc project students at Petroleum Engineering Department, Faculty of Engineering, University of Tripoli for their support. Also, I thank Waha oil company for providing the data used in the present research.

References

[1] Gidley, J.L.; Holditch, S.A.; Nierode, D.E. et al. An Overview of Hydraulic Fracturing. In Recent Advances in Hydraulic Fracturing, Monograph Series, SPE, Richardson, Texas:, 1989, 12. Chapter 1, pp. 1-38.

[2] Montgomery, C. T.; Smith, M. B. Hydraulic Fracturing: History of An Enduring Technology. Journal of Petroleum Technology, 62(12), December 2010, pp 26-32.

[3] Liang, F.; Sayed, M.; Al-Muntasheri, G.; Chang, F.; Li, L. A comprehensive review on proppant technologies. Petroleum, KeAi, 2016, 2, pp 26–39.

[4] Mattax, C. C.; Dalton, R. L. Reservoir simulation: Richardson, Society of Petroleum Engineers. Texas, 1990.

[5] Dmour, H. N.; Shokir, E. M. Pre-Post Frac Test Data Analysis For Hydraulically Fractured Vertical Tight Gas Well- Field Case Study. Oil and Gas Business Journal, Russia, 2008, ISSN 1813-503X.

[6] Anon. Evaluation Report for Candidate Well X1. Waha oil Company Tripoli, 2015.

[7] Zanatı, M.; Sarı, R.; Canales, H. New Giant Hydrocarbon Dıscovery in Sirte Basin, Libya. EAGE-EarthDoc, 18th International Petroleum and Natural Gas Congress and Exhibition of Turkey, May 2011.

AppendixA.

Table A.1: Data required for hydraulic fracturing design.

Parameter	Value	Unit
Depth	12677	ft
Producing interval	12555-12884	ft
Perforated interval	12624-12672 & 12725-12730	ft
Formation thickness	284	ft
Average reservoir pressure (BHSP)	5930	psi
Reservoir oil compressibility	2.93E-05	psi^{-1}
Reservoir water compressibility	3.00E-06	psi^{-1}
Oil formation volume factor	2.939	res.bbl/STB
Oil saturation	67	%
Water saturation	33	%
Gas saturation	0	%
Formation porosity	8.2	%
Original formation permeability	0.5	md
Fracturing fluid viscosity	25	cp
Fracturing fluid density (Linear Gel).	8.34	ppg
Reservoir oil viscosity	0.13	cp
Area of filter medium	22.8	cm^2
Slope of fluid loss curve at lab.	0.24384	$cm/min^{\frac{1}{2}}$
Filtration pressure at lab.	500	psi
Casing outer diameter	7	in
Wellbore diameter	8.5	in
Drainage diameter	1400	ft
Proppant size and type	16/30 HSP (ceramic)	mesh
Porosity of packed proppant	30	%
Specific gravity of proppant	3.6	unitless
Fracturing fluid spurt loss	0.2	gal/ft^2
Tubing inner diameter	3.5	in
Tubing depth	11860	ft
Gas oil ratio	3129	scf/bbl
Bubble point pressure	4350	psi
Reservoir temperature (BHST)	305	°F
Frictional pressure gradient inside tubing	0.25	psi/ft
Perforation diameter	0.42	in
Perforation discharge coefficient	0.8	unitless
Number of perforations	265	shoot

Figure A.1: wellbore diagram.