7° CONGRESO IAPG
Producción y Desarrollo de Reservas

5 - 8 de Noviembre 2019
Mar del Plata, Argentina

INSTITUTO ARGENTINO DEL PETROLEO Y DEL GAS

MAXIMIZE EXTENDED REACH WITH 2 IN. COILED TUBING IN A HORIZONTAL WELL (A VACA MUERTA FORMATION)

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Key words

Extended Reach, Coiled Tubing, Shale, Vaca Muerta, Friction Reducers, String Design, Vibration Excitation Tools

Summary

This paper discusses the evolution of the steps taken to introduce new extended reach tools and techniques within the Fortín de Piedra development to increase the maximum depth that can be obtained with coiled tubing (CT) in these challenging well trajectories. The added value from this exercise resulted in being able to extend the use of smaller CT strings to perform operations traditionally associated with larger strings. By enhancing the engineering process prior to the jobs, a reduction of the overall cost of ownership and operation has been achieved associated with the reduced shipping and handling costs of smaller and lighter strings.

Resumen

En este paper se describe la evolución de las etapas desarrolladas para introducir nuevas herramientas de alcances extendidos y técnicas para el desarrollo de Fortín de Piedra que permiten alcanzar las máximas profundidades a ser obtenidas con Coiled Tubing. El valor agregado en este ejercicio es el resultado de obtener el máximo alcance con tuberías de diámetros externos menores en operaciones típicas donde se utilizan Coiled Tubing de mayores diámetros. Mejorando el proceso de ingeniería en la preparación de los trabajos, se ha logrado una reducción del costo total de operación asociado a los costos reducidos producto de utilizar tuberías de menor diámetro.

Abstract

The unconventional Vaca Muerta (VM) boom in the Fortín de Piedra field has constantly challenged engineering development. One of these challenges was to extend the drainage area in the horizontal section. The scope of work for this project was to extend the reach of 2 in. coiled tubing (CT) in each well intervention, in part to increase the use of the equipment, as well as to reduce the overall cost of ownership associated with increasing CT size. This paper documents the experience in the field, performing pre- and post-fracture intervention work. It also describes a specific case in which a new excitation tool was used as part of the bottomhole assembly (BHA), together with a customized combination of chemical products that was pumped to achieve this goal.

As part of the analysis performed, several operations were considered, both in 4-1/2 in., 13.5 lb/ft casing and 5 in., 21.4 lb/ft casing. The horizontal section lengths ranged from 2,000 to 2,500 meters. A conventional 2 7/8-in. BHA configuration was used, and a new BHA configuration was used to

evaluate its performance. This document presents a detailed summary about the well geometry, CT string configuration, the new vibration excitation tool, applied operational procedures, and a post-intervention friction matching analysis. As part of a second phase of this project, data collection is continuing for additional wells to evaluate, compare, and validate the initial observations.

The results obtained from the initial collected data were laudable, such as the longest well in the Vaca Muerta formation serviced with 2 in. CT, which followed the procedure applied in this paper.

Introduction

With intense activity in the unconventional development of Vaca Muerta, this particular operator produces more than 16 million m^3/d of gas in the Fortín de Piedra field. The Fortín de Piedra gas field covers a surface of 60,000 acres in Neuquen Province, which represents approximately only 1% of the Vaca Muerta area (Fig. 1). This development is part of an investment plan performed by the company of 2.3 billion USD in two years. The current production of Fortín de Piedra is equivalent to 12% of the total production of natural gas in Argentina (17 million m^3/d), exceeding conventional historic reservoirs producing from the same formation.

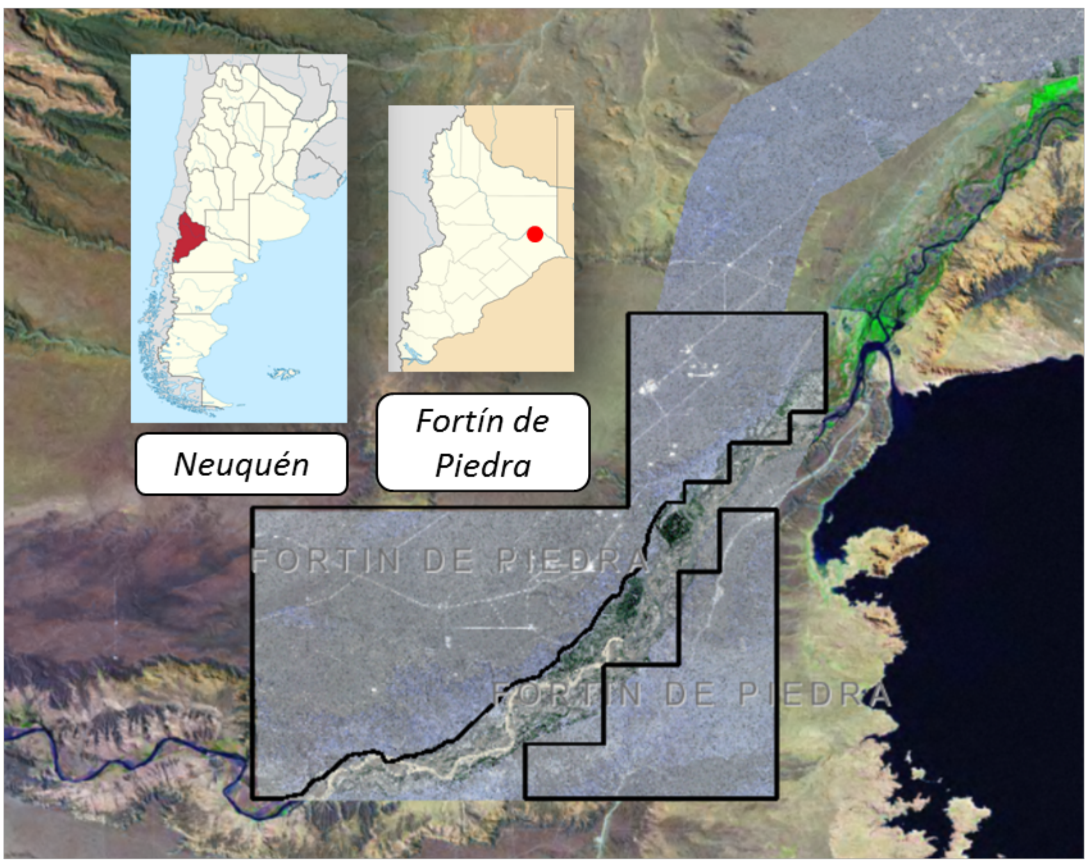


Fig. 1 – Fortín de Piedra field location.

Change in Casing Design

The development of the Fortín de Piedra field had been planned with the design of slim wells (three diameters), with 4½-in. production casing and 2,000 m of lateral length. Initially, this was considered to be the most economical option available within the operational limits. The Quintuco and Vaca Muerta formations were planned to be drilled jointly, incorporating the use of managed pressure drilling (MPD) technology to deal with narrow pressure windows. However, in seven of the first 20 wells of the field, difficulties were encountered during drilling. These difficulties were associated with a very narrow operating density window between Quintuco and Vaca Muerta formations. This issue resulted in significant non-productive time (NPT) that, in some extreme cases, led to the suspension and abandonment of the production section.

To prevent the recurrence of these events, the well architecture was changed to a four-string design (13 ⅜ in., 9 ⅝ in., 7 in., and 4 ½ in.) to isolate Quintuco and drill Vaca Muerta without the risks of severe losses and collapse as a result of formation instability (Fig. 2). Although this design is more expensive and requires more drilling days, the economic indicators are equivalent to those of the slim design because it enables the reduction of NPT and reduces the risk of losing wells and the negative production effects. In addition, the four-string design provides the added benefit of extending the lateral length, increasing the number of hydraulic fractures per well.

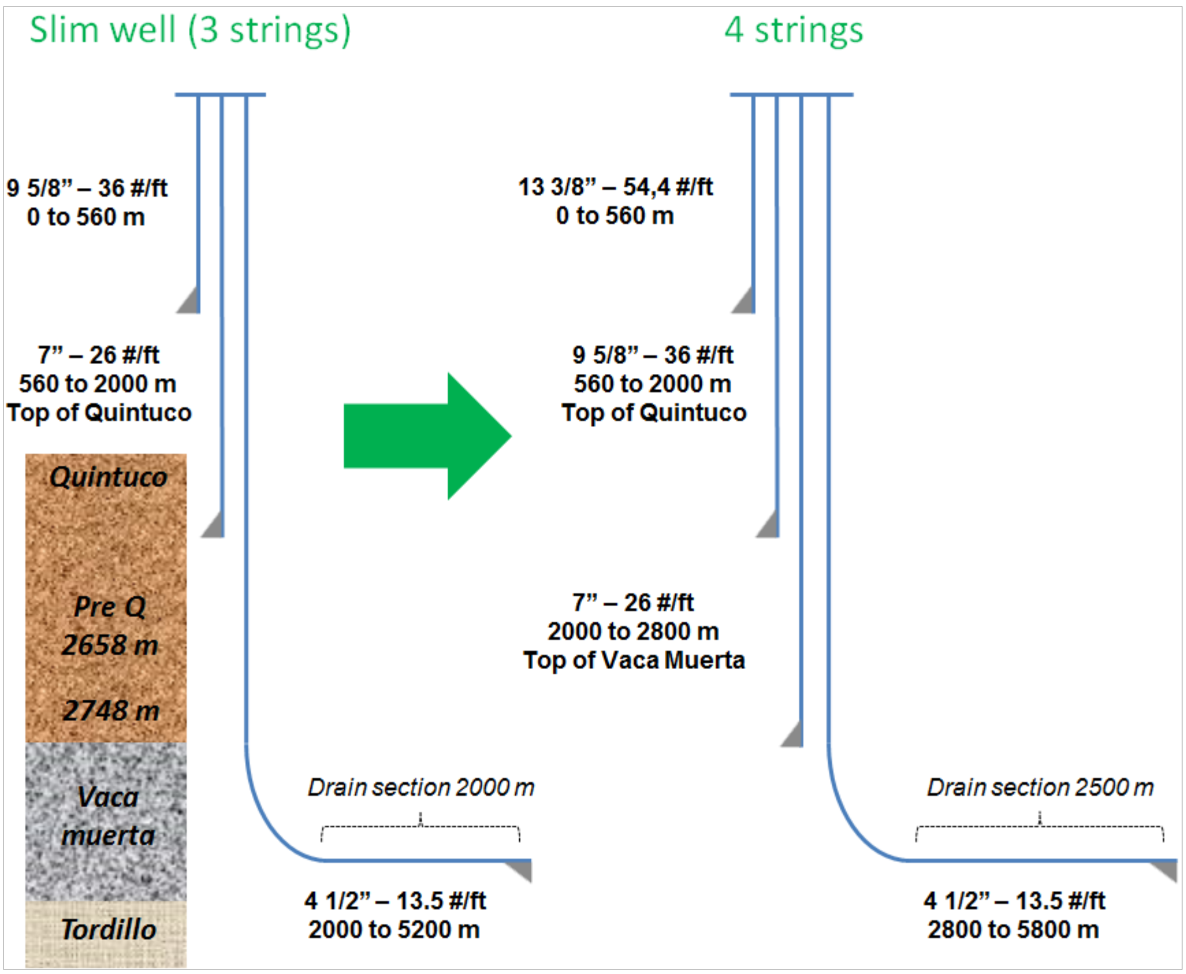


Fig. 2 – Original casing configuration vs. latest four-string design.

<u>Project Overview</u>

The operator was focusing on optimizing cost and minimizing the operating time required to finish the completion steps and begin well production. The use of larger diameter CT requires a significant increase of surface equipment capacity, resulting in more complex transport logistics, increased mobilization times, and longer rig-up times on location, as compared to 2 in. CT equipment. Because of these factors, the preference was extend the use of 2 in. CT as much as possible. Consequently, the scope of work required a focus on developing engineering procedures and redesigning the BHA and treatment fluids to enable extended reach with the smaller diameter CT. The projects included all of the steps to reach the objective, describing the chemicals, engineering process, and BHAs applied on a well-by-well basis. The operations selected as part of this particular study were part of two different operational stages: pre- and post-fracture.

Project Analysis

The pre-fracture work included calibrating the wellbore up to the casing shoe, then performing abrasive jetting perforations in the same run. The scope of this first work includes milling residual cement, mud clean-out, and hydrajetting (pumping an abrasive fluid) after the CT had reached the final depth. This process was performed to ensure that the wireline run in the first fracture step does not encounter well restrictions and to create a path through which the pumpdown fluid can flow through the perforations from the hydrajetting.

The post-fracture work is run with the CT to mill plugs and clean out sand to initiate the well production. The difference in the BHA for both jobs is the hydrajetting tool, which is only included in the pre-fracture step. In addition, the diameters of the mills are not the same; in the pre-fracture run, the BHA includes a larger mill OD. Fig. 3 provides BHA schematics for both cases; Fig. 4 shows a BHA schematic for pre-fracture operations with a shock tool.

BHA SCHEMATIC

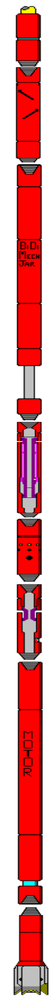
Client:	Operator
Rig/Platform:	2" Coiled Tubing Unit
Field/Well Number:	FdP - XXXh
Minimum Well Restriction:	4.126"
Top of Cement/Fill/HUD:	N/A
Bottom Hole Temperature:	285 degF
Bottom Hole Pressure:	~8,950 psi
Wellhead Pressure:	~5,650 psi
Quote Number:	1
Job Number:	1
BHA Name:	Gauge and Perforating Run
Date Drawn:	-

Item	Tool Description	Tool Connections	Tool O/D in Inches	Tool I/D in Inches	T-Length in mts	Fish neck type
1	CT Connector (for 2" CT)	2.388" PAC Pin	3.125	1.25	0.28	
2	DFCV	2.388" PAC Box 2.388" PAC Pin	2.875	0.93	0.7	
3	Single-direction Jar	2.388" PAC Box 2.388" PAC Pin	2.875	1	1.8	
4	Hydraulic Disconnect - Circ sub	2.388" PAC Box 2.388" PAC Pin	2.875	0.69	0.75	GS
5	Dual sub - abrasive perforator	2.388" PAC Box 2.388" PAC Pin	2.875	0.69	0.22	
6	Vibration Excitation ER Tool	2.388" PAC Box 2.388" PAC Pin	2.875	N/A	1.6	
7	Downhole Motor + Junk Mill	2.388" PAC Box 2.388" PAC Pin	2.875	N/A	3.94	
8	Junk Mill	2.388" PAC Box	4	N/A	0.2	

Maxiumum Tool-String OD:	4		
Minimum Tool-String ID:		0.69	
Total Length of BHA in Feet:			0.79

BHA Sheet prepared by: Coiled Tubing Engineering Team

Item	Tool Schematic
1	
2	
3	
4	
5	
6	
7	
8	



NOTE: Actual dimensions might differ from the figures included in this schematic. Review lengths and ODs on location when making up the tools. Use this schematic as a guideline

Fig. 3 – BHA schematic for pre-fracture operations.

BHA SCHEMATIC

Client:	Operator
Rig/Platform:	2" Coiled Tubing Unit
Field/Well Number:	FdP - XXXh
Minimum Well Restriction:	4.126"
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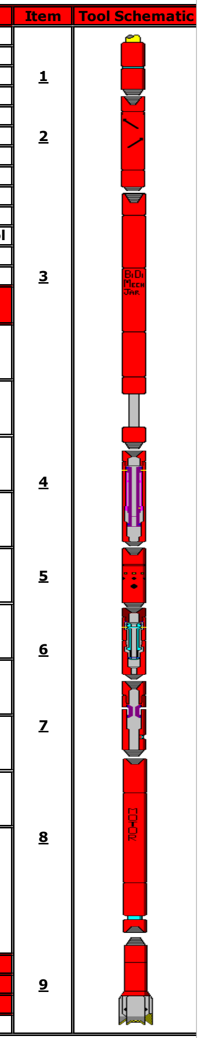
5	Dual sub - abrasive perforator	2.388" PAC Box 2.388" PAC Pin	2.875	0.69	0.22	
6	Shock Tool	2.388" PAC Box 2.388" PAC Pin	2.875	0.875	1.7	
7	Vibration Excitation ER Tool	2.388" PAC Box 2.388" PAC Pin	2.875	N/A	1.6	
8	Downhole Motor + Junk Mill	2.388" PAC Box 2.388" PAC Pin	2.875	N/A	3.94	
9	Junk Mill	2.388" PAC Box	4	N/A	0.2	

Maxiumum Tool-String OD:	4			
Minimum Tool-String ID:		0.69		
Total Length of BHA in Feet:			0.93	



BHA Sheet prepared by: Coiled Tubing Engineering Team

NOTE: Actual dimensions might differ from the figures included in this schematic. Review lengths and ODs on location when making up the tools. Use this schematic as a guideline

Fig. 4 – BHA schematic for pre-fracture operations with shock tool.

To improve the reach in both types of operations, two primary areas of focus were used: engineering process and treatment fluids pumped through CT.

The engineering process includes optimizing the string design, considering well conditions, selecting the correct pumping equipment, performing water analysis, increasing the flow rate as the well conditions allow, and maintaining low pressure needed to maintain the condition of the pumps and CT string.

In the steps performed before the CT rig up, the complete procedure must be reviewed to obtain the best results. All of the design factors are important to the overall process before running the CT in the well.

After the well data are received, the engineering team begins the design of service. The well data, CT string, and the fluid designs are entered into the CT software to run the force and hydraulic simulations. The friction coefficient is selected based on the well conditions, completion type, fluid selection, and operating parameters, or, where available, through comparisons from previous run data from similar wells through a friction matching process, which has been honed locally after years of expertise.

Well data used to run software simulations includes well schematic, deviation survey, and historical well life (drilling, fracture steps, and other previous work) data. The variables that affect the CT weight include reel tension, stripper friction, wellhead pressure, and density of well fluid and CT fluid. Fig. 5 shows the variables that affect the CT weight.

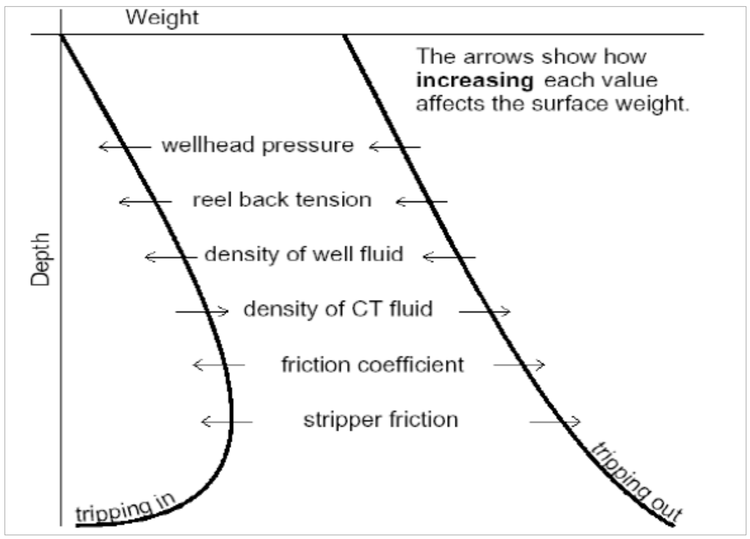


Fig. 5 – Variables that affect CT weight.

These variables can be used to obtain the final friction coefficient, which is one of the most important parameters when planning an intervention in extended reach wells. The string design is of paramount importance to extend the reach as much as possible and to increase pipe fatigue life. Wall thickness distribution has been configured such that the tip is light, the section across the heel has a high bending moment of inertia (Eq. 1), and the section in the reel and across the gooseneck has a good thickness to extend life. The string design (Fig. 6) shows the typical hour-glass configuration used in the basin.

$$E = \frac{\pi \times ({d_o}^4 - {d_i}^4)}{64} \text{ ....} (1)$$

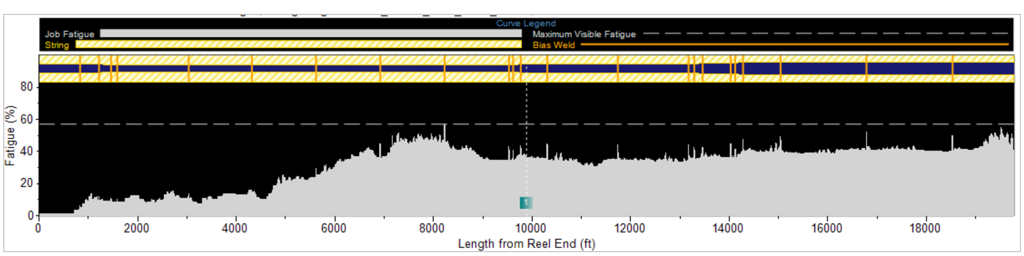


Fig. 6 – CT string design profile.

The manufacturing properties in this type of CT design also include rapid wall thickness transitions, proper section length of minimum wall thickness, and weight management of the first meters that make up the core wraps of the string, all with a 100,000-psi yield strength alloy.

The final area of focus in the engineering process is the metal-to-metal friction reducing agents, which also incorporates fluid analysis. Before beginning operations, the engineering team must select the chemical additives for the fluids to be pumped. The primary chemical products include the fluid friction reducer (FR) and the drag friction reducer (lubricant).

The FR fluid is used to reduce the pressure inside the CT during the jobs. The fluid concentration is 0.5 to 2 gal/mgal. With a reduction in pump pressure, the flow rate can be increased to obtain the best downhole motor conditions, as well as low pressures, which favor the reduction of string fatigue.

As the latest addition to the fluid system, a particulate friction reducing agent was added, which has high sphericity and specific diameter to lend additional friction reduction between strings. The particulate material functions similarly as spheres in a ball bearing, considerably reducing the friction coefficient. With the combined use of these products and the engineered concentrations of each agent, CT was able to reach TD in all cases, where previously 2-3/8 in. was required.

The first jobs were completed in eight wells, which are identified as Well A, Well B, Well C, Well D, Well E, Well F, Well G, and Well H. The types of operations completed were pre-fracture wellbore conditioning (calibration and abrasive perforating) interventions.

Results

Table 1 and Table 2 show the matching results.

Table 1 – Pilot Program Friction Coefficient Results

Well	Job	Circulating Pressure (psi)	Wellhead Pressure (psi)	Flow Rate (bpm)	Max. Extended Reach (m)	Friction Coefficient
A	Calibration + sand jetting	5,200	100	2.5	5180	0.25
B	Calibration + sand jetting	5,012	350	2.5	5140	0.27
C	Calibration + sand jetting	4,900	530	2.6	5172	0.26
D	Calibration + sand jetting	5,700	500	2.5	5223	0.28
E	Calibration + sand jetting	5,070	30	2.7	5159	0.28
F	Calibration + sand jetting	4,300	10	2.5	5084	0.27
G	Calibration + sand jetting	4,800	300	2.5	5306	0.28
H	Calibration + sand jetting	4,600	500	2.5	5179	0.20

Table 2 – Friction Coefficients After Use of Enhanced Vibration Extended Reach Tool

Well	Job	Circulating Pressure (psi)	Wellhead Pressure (psi)	Flow Rate (bpm)	Max. Extended Reach (m)	Friction Coefficient
AA - first run	Calibration + sand jetting	5,200	500	2.5	5199	0.23

AA - second run	Calibration + sand jetting	4,800	5,050	2.5	5199	0.23
BB	Calibration + sand jetting	4,800	500	2.5	5287	0.27
AB	Sand cleanout	7,600	3,600	2.8 - 3	5730	0.22
AC	Sand cleanout	3,800	3,800	2.8 - 3	5794	0.22

With the data obtained from these previous jobs, the project continues to improve the extended reach capability of CT. Using that experience, the next interventions yielded highly satisfactory results. The proven concept was successful in both focus areas: engineering processes and treatment fluids pumped through CT.

After new technologies, such as the vibration/excitation tools and the friction reducing chemical products, were selected, the design process was replicated in four additional interventions in four wells: Well AA (two runs), Well BB, Well AB, and Well AC.

Fig. 7 and Fig. 8 show the results from the trip in and trip out conditions.

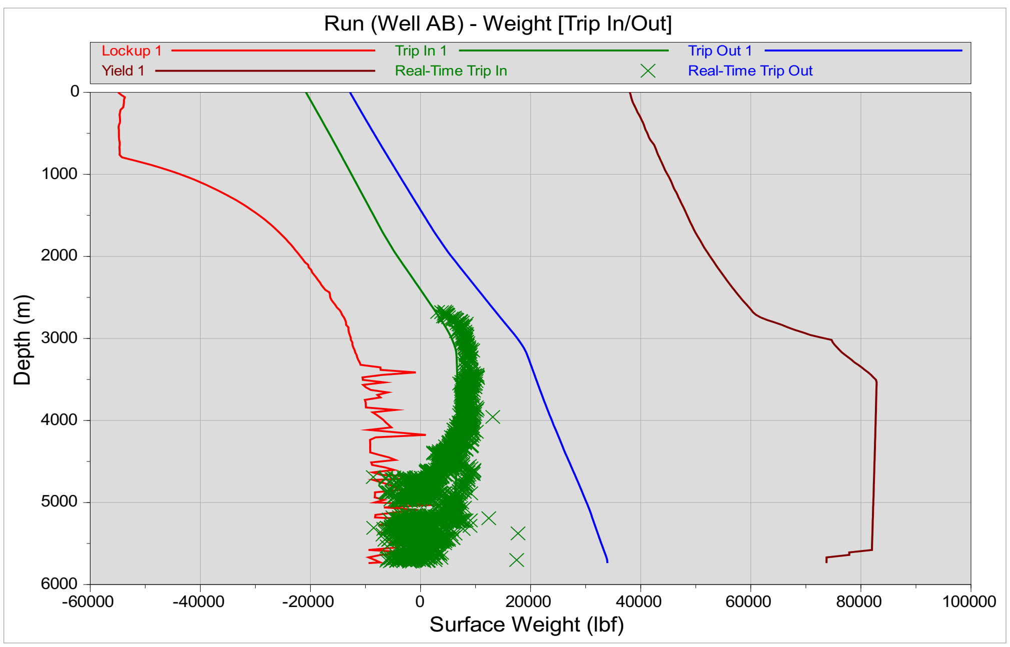


Fig. 7 – Friction matching data: Well AB.

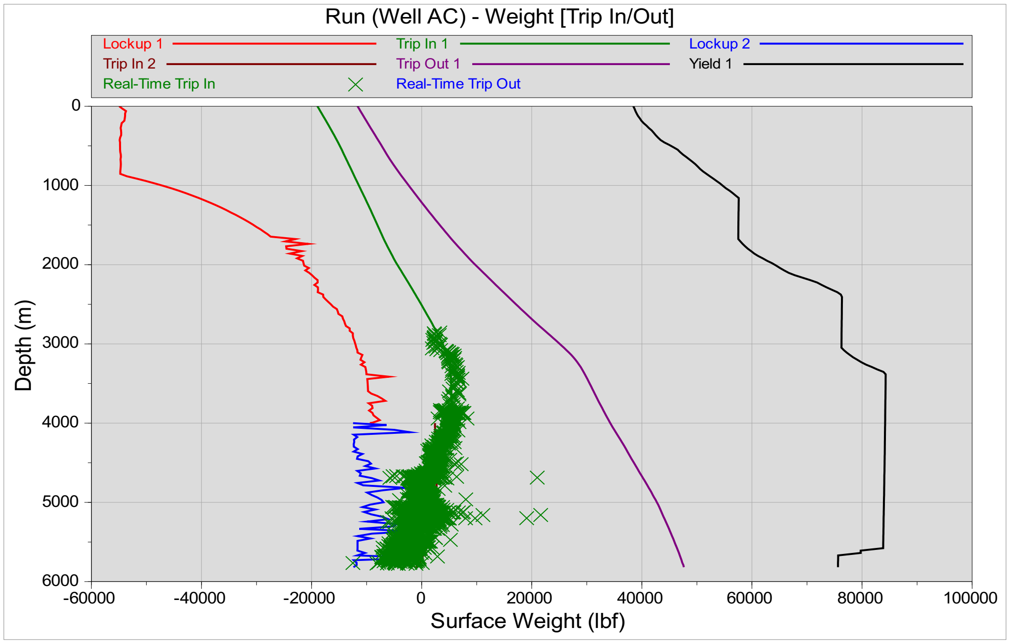


Fig. 8 – Friction matching data: Well AC.

An analysis of the results indicates an important friction coefficient difference. In the first steps of the study, the friction coefficient ranged from 0.25 to 0.28. In the second steps of the study, the friction coefficient fell below 0.23 in which the best results were observed in Well AB and Well AC. In Well AC, the friction reduction was so extensive that it became a new record of reach in the shale wells in Argentina with 2 in. CT.

All parameters of the enhanced design were applied: engineering process and treatment fluids. In Well AC, these additional parameters must be considered because they made the reach for 2 in. CT even more complex. The casing size was 5 in. with 21.4 lb/ft. The kickoff point occurred at 2930 m, with the landing point at 3303 m, and a horizontal length of 2515 m. Fig. 9 provides a 3D representation of the trajectory of Well AC.

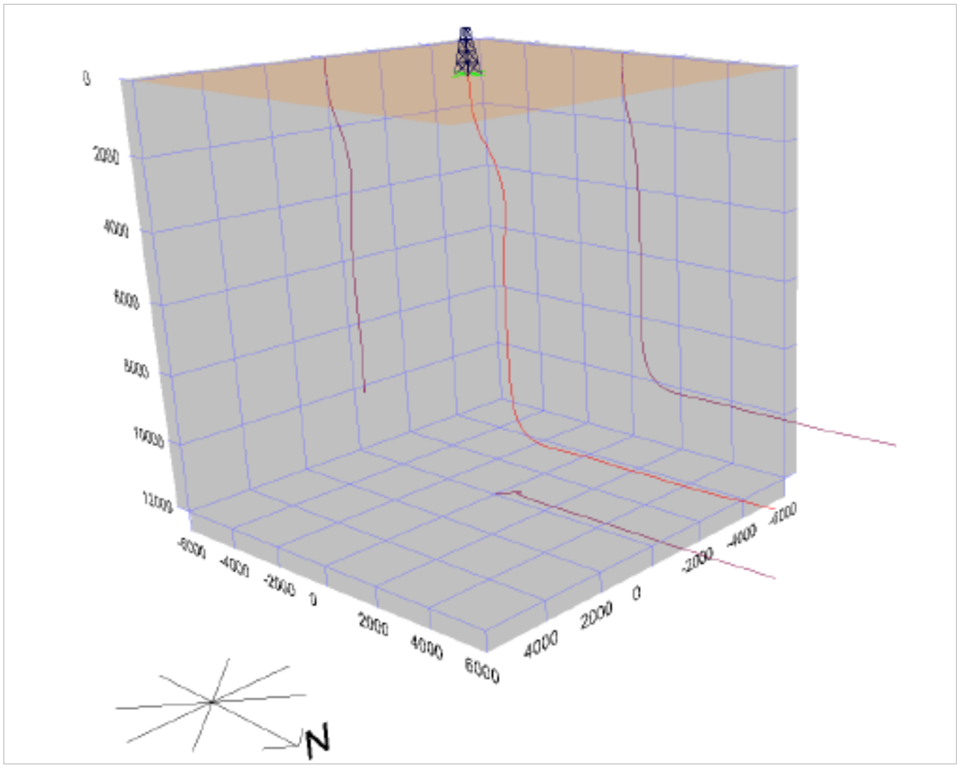


Fig. 9 – Well AC 3D survey.

Conclusion

The results obtained from the initial operations exceeded expectations; the longest well in the Vaca Muerta basin serviced with 2 in. CT was drilled with the procedure described in this paper. This concept is planned for application in all future wells. Currently, to obtain extended reach in long horizontal section wells (between 1500 and 2000 m), all concepts described in this paper are applied.

Job design optimization and abrasive perforating in the pre-fracture stage, plug milling, and post-fracture sand cleanout phases provides an efficient way to complete these extended reach wells while also reducing costs.

Combining the use of 2 in. CT with enhanced operational procedures, advanced BHA design concepts, and novel treatment fluids contributed to a successfully engineered solution that both achieved the required results and improved the economics of the project.

About the Authors

José I. Di Nardo completed a degree in mechanical engineering at Universidad Nacional de Rosario in 2010. He worked as a project engineer for three years in downstream, and in chemical plants and an oil services company for four years before joining Halliburton Production Solutions. Di Nardo has worked for Halliburton for almost two years and currently holds the position of Lead Technical Professional.

Alejandro Chacón completed a degree in mechanical engineering at Universidad de los Andes in Bogotá, Colombia in 2006. After graduation, he began his oilfield career as a field engineer, working for a top-tier oilfield services company. In 2009, Chacón accepted a position as a lead engineer at

Halliburton, performing CT services in Saudi Arabia; he later progressed to a technical sales engineer position, leading the sales efforts for the Kingdom before being promoted to technical manager. During his tenure in the Middle East, Chacón introduced several new tools and technologies, ranging from stimulation solutions to real-time fiber optic tool applications. After seven years, he was transferred to Venezuela as a technical and sales leader for the country; for the past 1.5 years, Chacón has been based in Argentina, leading the technical and sales efforts for the country and the entire Latin America region; he is currently the technical and sales manager for Argentina as well as Latin America for all well intervention services for Halliburton.

Chacón's areas of expertise include proficiency in ultra-extended reach applications, sandstone and carbonate acidizing combined with all types of divergence techniques, pinpoint hydraulic and acid fracturing operations, logging with CT, CT-TCP operations with pressure deployment, and water conformance applications.

Leandro Ponce completed a degree in electromechanical engineering at Universidad Tecnologica Nacional in 2011. He has worked as a lead engineer and technical professional at Halliburton; Ponce is currently working as a completion engineer at Tecpetrol.