SPE 93071

Optimizing Stimulation Treatments in Straddled Completions

M.I. Willemse, O. Mostafa, M. El-Ashry, I. Abdallah, and A.A. Sattar, Bapetco, and A. Waheed and B. Conrad, Halliburton

This paper was prepared for presentation at the 14th SPE Middle East Oil & Gas Show and Conference held in Bahrain International Exhibition Centre, Bahrain, 12–15 March 2005.

Abstract

Completing a producing zone(s) behind straddle packers is a common occurrence; hundreds of wells have been completed in this manner. Should such wells produce trouble-free and meet expectations, there is not much to ponder over; but if not, the options for executing an enhanced stimulation treatment have been limited. Generally, treatment has consisted of pumping and squeezing away the treatment into the perforations via the sliding side door (SSD) and hoping for the best. The preferred technique is to improve the injectivity into the perforations by "spotting" reactive fluids at the perforations or using some type of mechanical action such as "perforation jetting" to break up blockages in the perforation tunnels. This is only possible when perforations are accessible through the wellbore.

These problems become more complicated if the zones of interest are sandstone reservoirs. A study[1] in the late-1990s revealed a success ratio in the 30–40% range when treating such formations.

This paper addresses such a scenario in which a dirty sandstone reservoir, not previously matrix-acidized, was producing at sub-par rates (declining to the point of being negligible). The zones were completed between straddle packers and were only accessible through SSD, 100 ft above the perforations.

The prudent decision was to stimulate, but make all efforts to maximize the chances of success. Apart from applying the best practices in sandstone acidizing technology, a true fluidic oscillator (TFO) was included as a stimulation tool. This tool provides a continuous pressure pulse in the fluid system that allows solids buildup within the perforations to fatigue and break up while the acid system works on the rock matrix.

The results from the treatment of this well were exceptional and will be detailed in this paper. The production improvement was 10-fold over its prestimulation performance.

Background

Well X was an exploration well drilled in the Badr El Din field of the Western Desert of Egypt **(Fig. 1)**. Original plans were to target a deep formation (lower Cretaceous) in addition to evaluating the upper Cretaceous reservoirs **(Fig. 2)**. The openhole logs contained a few surprises; the deep zone was found to be water-bearing and therefore was plugged back, while Sands A and B were found to be oil-bearing and at virgin pressure (5,350 psi), while Sand C was gas-bearing with a depleted reservoir pressure (2,500 psi).

The well therefore required a selective completion to isolate Sands A and B oil zones from the Sand C gas. A straddle packer with an SSD allowed separation of the oil-producing zones (to be commingled) from the gas zone that would be produced through the main production tubing **(Fig. 3)**.

The oil zones were perforated first, producing at an initial rate of 450 BOPD. The production rate declined fast, reaching 200 BOPD and finally ceased to flow within a period of 3 months **(Fig. 4)**.

Well Performance Analysis

The quality of Sands A and B and the mobility ratios determined from petrophysical evaluations and formation testers suggested that the zones were producing considerably less than their potential rates (before ceasing to flow). The formation permeability was estimated to be in the 15–30 md range (minimum value estimates), and based on nodal analysis simulations (assuming no skin factor), predicted the production rates in the order of 850–1,300 BOPD **(Fig. 5)**.

This led to the belief that the formations were either damaged or the permeabilities were much lower than calculated. Incidentally, the pressure buildup test run on this well was inconclusive because most of the data was obscured by wellbore storage.

Assuming that the well was damaged, the logical source for this damage was a cement plug that was placed across this zone while temporarily abandoning the well. The well was re-entered 2 ½ months later; the cement plug was drilled out and a liner was set across the open hole. The zones were perforated in a slightly overbalanced condition with 4 $^{5}/_{8}$-in. tubing-conveyed perforating.

Normally TCP guns would provide adequate charge penetration in such sandstones to go past the cement damage and leave the formation in a stimulated state, but since the well was overbalanced during perforating, the benefits were probably lost. In fact, it appears that the well was potentially more damaged during workover (i.e. well re-entry) due to wellbore fluid losses and fines migration. Under these assumptions, a hydrofluoric (HF) acidizing job seemed a logical way to remove the damage and clean the debris from the perforation tunnels to enhance production from the oil zones.

Stimulation Challenges

There were several challenges in the stimulation design for Well X. There was minimal past history in acid stimulation of these formations, and what was available was not encouraging. In most cases, the reasons for failure could be attributed to poor candidate selection and a lack of understanding of the rock mineralogy, rather than failure of the acidizing job.

Additionally, there were no specific case histories on the stimulation of A and B reservoirs, considering that sandstone formations are much more difficult to stimulate than carbonates. The acid chemistry for sandstone rocks is complex, and if not applied properly, it can cause more harm than good. This aspect of acidization needed close attention.

The completion design (as noted) had the zones of interest behind an SSD valve and the perforations 100 ft below the SSD. Not having direct access to the parts limited the use of proven jetting technology in stimulation. No injectivity tests had been conducted earlier on the formation, which could have helped determine suitable injection fluids (e.g.., would nitrified fluids be easy to inject?) that could easily penetrate the perforation barriers. The lifting of the well after stimulation was also important. The reservoir pressure at 5,350 psi may have been sufficient to lift the well but at minimal drawdown. It was therefore necessary to consider nitrogen lifting to assist in fluid recovery after the acid job.

Meeting the Challenges

Mineralogical Issues

It was imperative to have rock mineralogy data, but no cores were available from the A and B formations. The alternative was to perform X-ray diffraction (XRD) studies on drill-cutting samples from the formation to determine the mineral content of the reservoir. Results **(Table 1)** indicated that the rocks were primarily composed of quartz with large quantities (>12%) of sodium feldspars and kaolinite clays in addition to small quantities of illite clays.

The carbonate content was significant at 6–8%. The acid-soluble part was approximately 5.5–6%, obtained from solubility tests performed on the drill cuttings samples. The carbonate within the reservoir posed a threat to proper stimulation because many complex secondary and tertiary reactions with HF can cause severe damage deep within the matrix.[2] Fortunately, this carbonate content was within the treatable bounds of an acid preflush in preparation for a subsequent HF acid stage. However, clay content and bottomhole temperature (BHT) should be taken into account when choosing the type of acid. Clays are known to be unstable in HCl acid, depending on their composition and the temperature. Pumping strong HCl into a sandstone formation above the stability temperature of the clays can lead to damage of the matrix permeability during pumping.[3] During this process, metal ions such as Fe, Al, Ca, and Mg, are dissolved from the mineral, leaving an insoluble silica gel mass that can be extremely damaging. With a BHT of 250°F on Well X, this was the case (**Fig. 6**).

Fig. 6 plots the clay content of Well X against its instability rating to HCl acid. The clay instability rating (CIR) is primarily a function of bottomhole temperature and the nature of clays, based on data available from research studies on various minerals.[4] The results provided a CIR of 86, which is considered severe. Fortunately, most clays are very stable in organic acids (acetic, formic), even to elevated temperatures.[5] But acetic acid can cause clay swelling if used alone.[6] The presence of illite-smectite indicated that clay swelling could be an issue, and therefore, a mixture of organic acids and ammonium chloride was preferred. The modified acid system could (1) remove matrix carbonate and thereby remove drilling damage, (2) dissolve carbonate scale without destroying formation clays, and (3) contact smectite clays without causing swelling.

Compatibility between acid and oil was an important issue because previous work history was not available. Acids (i.e., HCl), in general, can create sludges and emulsions when contacting oils in the reservoir. Organic acids, however, are mild and are less likely to cause sludging problems when contacting black oils. Nevertheless, the crude oil samples from the wellhead were tested for compatibility with the proposed acid systems. Acid additives were incorporated to reduce emulsion tendencies, improve water-wetting upon contact with the damage, and prevent corrosion of the tubulars. (See **Table 3** for details on compatibility testing.)

Another factor is that fines-migration damage cannot be removed by organic acids. An HF acid system is the answer in such cases. Past experience in other areas of the world with retarded HF acid treatments provided excellent results.[7-9] The retarded HF acid system is essentially 15% HCl, 1.1% HF, retarded with aluminum chloride. Recent research[7,8] has also shown this fluid to be particularly compatible with feldspars and illite. The reason for its success is that conventional matrix acidizing with hydrofluoric acid is only effective for removing shallow clay damage 1 or 2 in. from the wellbore, while retarded hydrofluoric acid systems can treat up to 2 to 6 in. from the wellbore, in addition to stabilizing fines migration.

Because there were two formations to be treated (A and B), the overall length of the perforated interval was 26 m. It was believed necessary to divert the acid to get a better distribution throughout the zones of interest. A single diverting stage of foamed slug was included to achieve this diversion.

It was planned to nitrify the entire fluid system to assist in flowing back the well. Nitrogen lifting was also made available to assist in well recovery.

Completion Issues

The benefits of using high-pressure jetting to loosen up debris across the damaged perforations could not be used on Well X (as explained). However, a new tool known as a true fluidic oscillator (TFO) was recommended **(Fig. 7)**.

This tool has been used by several operators around the world to reap stimulation benefits. It has successfully helped in removing damage (scale buildup) behind gravel pack screens[10,11] in horizontal wells[12] that have had poor communications and in general acidizing cases.[10] The TFO system is built around a patented fluidic oscillator. This oscillator creates pulsating pressure waves within the wellbore and formation fluids. These pressure waves help break up any type of near-wellbore damage and restore the permeability by carrying the fluid past the wellbore into the formation **(Fig. 8)**.

The TFO is run into the well on coiled tubing (CT) (see **Fig. 9** for BHA details) and the desired treatment fluid is pumped through it.

The oscillating pressure waves are not affected by standoff, as with conventional jetting or velocity tools. The kinetic energy of the pressure pulse travels through the wellbore fluid with no appreciable energy loss. When the pressure wave contacts the formation, the energy is dumped, and the process of removing damage is initiated. As the damage is removed and the permeability restored, these pressure waves penetrate deeper into the formation. The pressure waves expand in a spherical fashion from the point of origin providing 360° coverage while moving the tool across the interval. The acoustic streaming induced by the oscillator focuses the treatment and tool energy to the immediate area of the tool. The TFOs are true fluidic oscillators based on the Coanda effect. There are no moving parts, and the tool does not rely on cavitation to create pressure waves. There are no packer elements to fail, and the TFO efficiently transfers the kinetic energy of the fluid pumped to the damaged zone. TFOs work according to the following process:

1. Treatment fluid enters the switch body and is accelerated into the fluidic oscillator.
2. The fluid stream enters the oscillator and preferentially attaches to the outer wall of one of the fluid passageways.
3. The flow continues down the selected passageway to the outlet.
4. As the flow passes a cross channel, a low-pressure area is created that causes the main fluid stream to be interrupted and the flow to switch and attach to the other fluid passageway.
5. The switch begins to oscillate, which causes alternating “bursts” of fluid to be ejected into the wellbore.
6. As each “burst” is ejected, it forms a compression wave within the wellbore fluid.
7. Compressive loading occurs when the wave contacts the formation face.

Job Execution

Precautions

The acid treatment was designed by assuming that the formation would not have much difficulty accepting fluid (i.e. injectivity would exceed 1.5 bbl/min at 2.000 psi annulus pressure with a formation permeability of 30 md and +5 skin factor). A surface pressure limit of 2,500 psi was assumed to avoid fracturing the formation. This was a conservative value because actual breakdown tests had never been performed on this formation. However, there was a possibility that the formation would be tight (more than forecasted); in which case, the nitrogen commingling that was planned for the job would be avoided to reduce the injection pressure. Furthermore, if injectivity was excessively reduced, the foamed diverter would also be eliminated. With the perforations behind an SSD valve, it was not possible to circulate out fluids and spot fluids of choice across the perforations to improve injectivity during the job.

No fresh water was used during the job for peripheral activities such as pressure testing of pumping lines or CT. Fresh water could remain in the lines and be pumped inadvertently into the formation and hurt the sandstone reservoir by causing clays to swell, leading to plugging of pore throats.

The complete acid job plot during the execution phase is presented in **Figs. 10** through **12**. It was difficult to analyze the “live” pressure in the CT/tubing annulus due to the presence of natural gas that masked some of the injection sequences; injection of nitrified fluids also caused formation pressures to rise. The main concern was monitoring the pressure response as the different stages of the stimulation treatment entered the formation. Because this was the first job, it was important to learn the effect of different acids on the formation.

Summarized Operations

The CT was pickled with acid and a gauge run was made by pumping a 1.2-in. ball through the tubing. The CT volume was marked with a dye. The TFO was function-tested on surface. The CT was filled with 7% ammonium chloride water (brine) before running in hole to avoid loss of fresh water to the formation. Approximately 4 bbl of brine was circulated through the CT string when it reached its setting depth (close to SSD 2, Fig. 3) to record a circulating pressure of 2,690-psi tubing pressure and 37-psi annulus pressure at a pumping rate of 1.8 bbl/min. The wing valve was closed and an injectivity test was performed with 2.5 bbl of brine to get 1.74 bbl/min at 2,490-psi tubing pressure and 53-psi annulus pressure. This test revealed an acceptable injectivity value, but because the test was short, there was a possibility the result was not representative. Therefore, the following stages of aromatic fluid and the next 1,000 gal of preflush acid were pumped without commingling with nitrogen to further assess the injectivity of the fluids. The pressure responses can be seen in **Figs. 10** and **11**.

Analyzing the Injection Scheme

Throughout the early stages of the acid job, an increasing pressure trend occurred. This trend was determined (later) to be a consequence of injecting energized fluids and not due to the damaging effect. However, since this was not known at the time, a few changes to the program had to be made during the job to counter the suspected negative effects. First, the nitrogen injection was terminated early (at the conclusion of the first-stage overflush). The diverter stage also was eliminated because the surface pressure had crossed its limit even without pumping any diverting (temporarily plugging) material. The consequence of these changes and the true reflection of formation response to acidizing is evident in the latter part of Figs. 11 and 12. During the second stage of acidizing, the annulus pressure progressively decreased in all the reactive fluid stages (i.e. preflush, main acid, and overflush). The pumping rate was maximized thereafter because the surface pressure was within prescribed limits (**Fig. 13**).

At the end of the acid job, the annulus pressure dropped to approximately 450 psi. The well was opened up and the flowing pressure recorded was in the range of 450–330 psi. The CT was picked up to a shallow depth and nitrogen lifting was started at a rate of 700 scfm. The well was flowed back for more than 11 hours.

Results

After the acid job, the well was producing 1,350 BOPD with 0% watercut and 0.5 MMscf/D gas. Production has shown a gradual decline as the reservoir is on depletion drive, but even after 6 months of production, the rate is above 600 BOPD (**Fig. 4**).

Conclusions and Recommendations

Based on the job results, several conclusions can be drawn from the experience:

1. Integrated teamwork was a key to success.
2. Acid jobs should be considered on a case-by-case basis.
3. The response of the well depends on correctly analyzing the damage mechanism and choosing an appropriate stimulation technique.
4. Rock mineralogy information is essential if sandstone acid stimulation is planned.
5. The completion design, if possible, should be optimized to allow direct access to the perforations.
6. The organic acid and retarded HF acid systems worked very well with the formation types treated.
7. Pressure responses from the job plots verified this, as did the production results. In future jobs, acid volumes can be optimized.
8. Though nitrified acid is one of the better systems for stimulating low-pressure reservoirs, it should be carefully re-evaluated if chosen again for tight formations such as those seen in this well.
9. The TFO provided a new and better way to treat zones that are not directly accessible.
10. Artificial lift is necessary for lifting the spent acid and putting the well on production.
11. The formation was competent enough to resist sand production after the acid job.

Acknowledgements

The authors would like to thank the management at Bapetco and Halliburton for allowing us to present this paper.

References

1. Nitters, G. et al.: “Structured Approach to Advanced Candidate Selection and Treatment Design of Stimulation Treatments,” paper SPE 63179, presented at the 2000 Annual SPE Tech. Conf., Dallas, Texas, 1–4 October.
2. Gdanski, R. and Shuchart, C.: “Advanced Sandstone Acidizing Designs Using Improved Radial Models,” paper SPE 38597 presented at the 1997 Annual Technical Conference and Exhibition, San Antonio, Texas, 5–8 October.
3. Gdanski, R.: “A Model of HF Reactivity and Damage Removal,” paper presented at the 1999 NIF 10th International Oil Field Chemicals Symposium, Fagernes, Norway, February 28–March 3.
4. Gdanski, R.: “Formation Mineral Content Key to Successful Sandstone Acidizing,” *Oil and Gas J*. (30 August 1999) 90.
5. Underdown, D.R., Hickey, J.J., and Kalra, S.K.: “Acidization of Analcime-Cemented Sandstone, Gulf of Mexico,” paper SPE 20624 presented at the 1990 Technical Conference and Exhibition, New Orleans, Louisiana, 23–26 September.
6. Gdanski, R.: “Fractional Pore Volume Acidizing Flow Experiments,” paper SPE 30100 presented at the 1995 European Formation Damage Symposium, The Hague, The Netherlands, 15–16 May.
7. Hall, B.E.: “Methods and Compositions for Dissolving Silicates in Subterranean Formations,” U.S. Patent 4,304,676 (Dec. 8, 1981).
8. Gdanski, R.: “$AlCl_3$ Retards Acid for More Effective Stimulations,” *Oil and Gas J*. (October 1985) 111-115.
9. Guichard III, J., et al.: “An Overview of HF Acid as Applied to the Wilcox Sand in Redell Field, Southwest Louisiana,” paper SPE 31139 presented at the 1996 International Symposium on Formation Damage Control, Lafayette, Louisiana, 14–15 February.
10. Harthy, A., et al.: “Screen and Near-Wellbore Cleaning and Stimulation Tools Evaluation: Recent Experience in Well Operation,” paper SPE 89653 presented at the 2004 SPE/ICoTA Coiled Tubing Conference and Exhibition, Houston, Texas, 23–24 March.
11. McCulloch, D. et al.: “Damage Removal in Screened Horizontal Wells,” paper SPE 81732 presented at the 2003 SPE/ICoTA Coiled Tubing Conference and Exhibition, Houston, Texas, 8–9 April.
12. Gunarto, R., et al.: “Production Improvement for Horizontal Wells in Sumatra,” paper SPE 86545 presented at the 2004 International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, 18–20 February.

Table 1—X-Ray Diffraction of Drill Cutting Samples from Sands A and B Approximate Depths

Sample No.	**1**	**2**	**3**	**4**	**5**
Depth (m)	Sand A	Sand A	Sand B	Sand B	Sand B
Quartz (%)	28	59	54	40	45
K-Feldspar (%)	2	0	0	0	Trace
Na-Feldspar (%)	14	15	13	24	15
Calcite (%)	2	6	4	4	3
Dolomite (%)	6	2	1	3	0
Kaolinite (%)	26	8	12	16	17
Illite/Mica (%)	2	1	3	4	2
Smectite (%)	8	0	0	0	5
Apatite (%)	8	7	11	7	12
Barite (%)	3	2	3	2	2

*Not available

Table 2—Planned Fluid Stages

Fluid Stage	Volume (gal)	Purpose
Aromatic solvent preflush	250	Remove heavy oil deposits and other organic material
Organic acid preflush (first stage)	2,000	Remove carbonate material
Retarded acid stage (first stage)	1,000	Main treatment for fines migration, rock damage
Overflush (first stage)	500	Assist in inhibiting secondary precipitation
Foam diverter	300	Diversion for 32 m of perforations
Organic acid preflush (second stage)	2,000	Remove carbonate material
Retarded acid stage (second stage)	1,000	Main treatment for fines migration, rock damage
Overflush (second stage)	500	Assist in inhibiting secondary precipitation
Post flush	3,000	Clear the near wellbore area and provide deep acid penetration
Displacement	1,260	Displace fluids to perforations

Table 3—Acid-Oil Compatibility Testing

Fluid Type	Separation %	Separation Time min:sec	Acid Phase Cond	Interface		Sludge	Comments
Preflush: Organic acids (Acetic, Organic with surfactant, corrosion inhib, mutual solvent, clay stabilizer	98	2:00	Dirty	L	R	none	Oil/Acid Emulsion Test
"	100	4:00	Dirty	L	D	none	Oil/Acid Emulsion Test
"	100	10:00	Dirty	L	S	none	Oil/Acid Emulsion Test
Main Acid: 13.5% Hcl + 1.5% HF(AluminumChloride with surfactant, corrosion inhib, mutual solvent, antilsudge, clay stabilizer)	80	2:00	Dirty	L	D	none	Oil/Acid Emulsion Test
"	100	4:00	Dirty	L	S	none	Oil/Acid Emulsion Test
"	100	10:00	Dirty	L	S	none	Oil/Acid Emulsion Test

ACID	ACID PHASE	INTERFACE		SLUDGE	TYPE SLUDGE
L = LIVE	C = CLEAN	L = LOOSE	S = SHARP	T = TRACE	E - EMULSION
S = SPENT	CL= CLOUDY	T = TIGHT	D = DIFFUSED	M = MODERATE	A - ASPHALTENE
	D = DIRTY		R = RAGGED	H = HEAVY	P - PARAFFIN

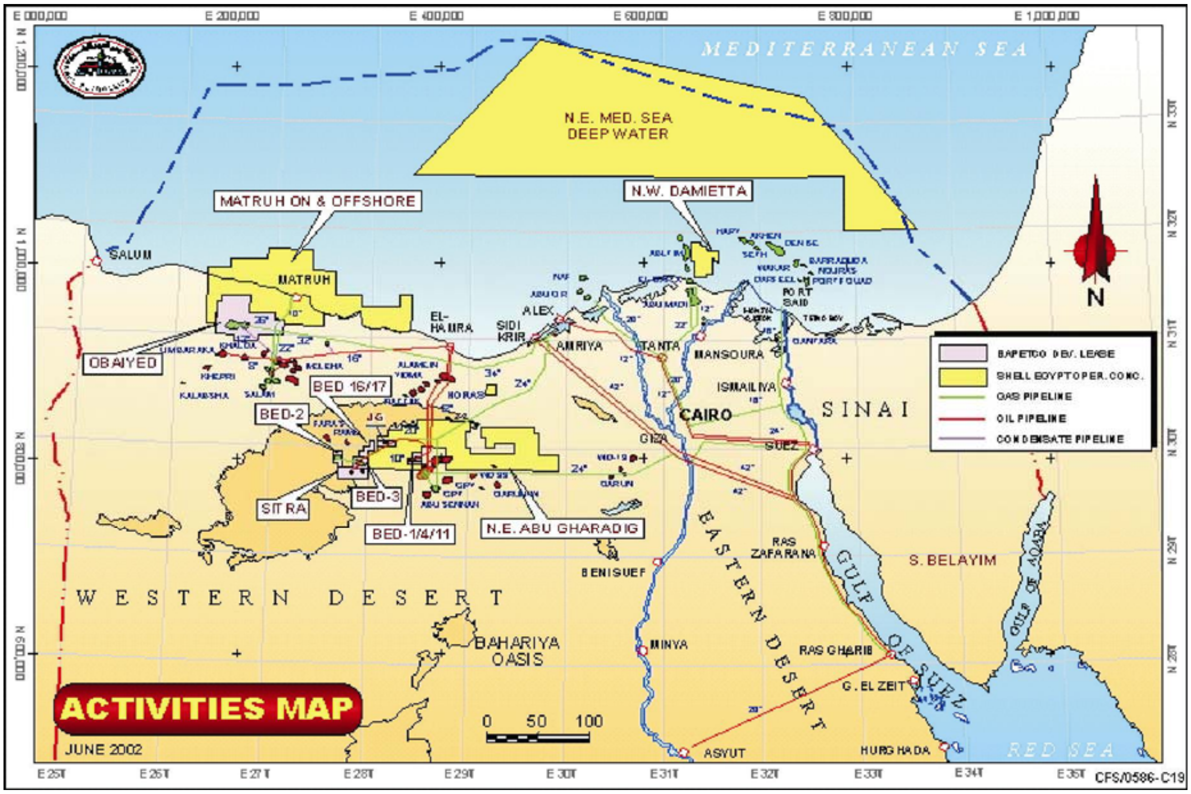

Fig. 1—Location map.

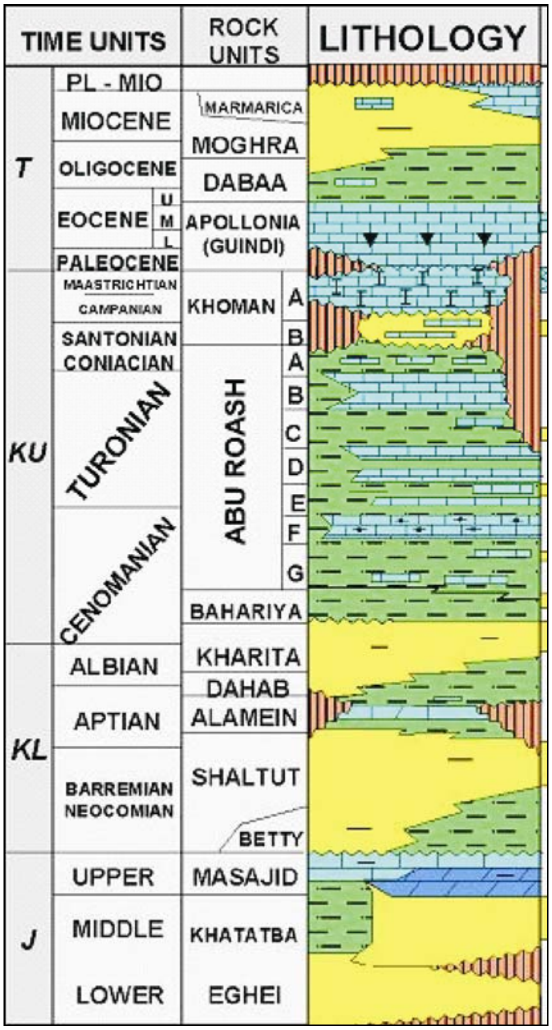

Fig. 2—Stratigraphic column.

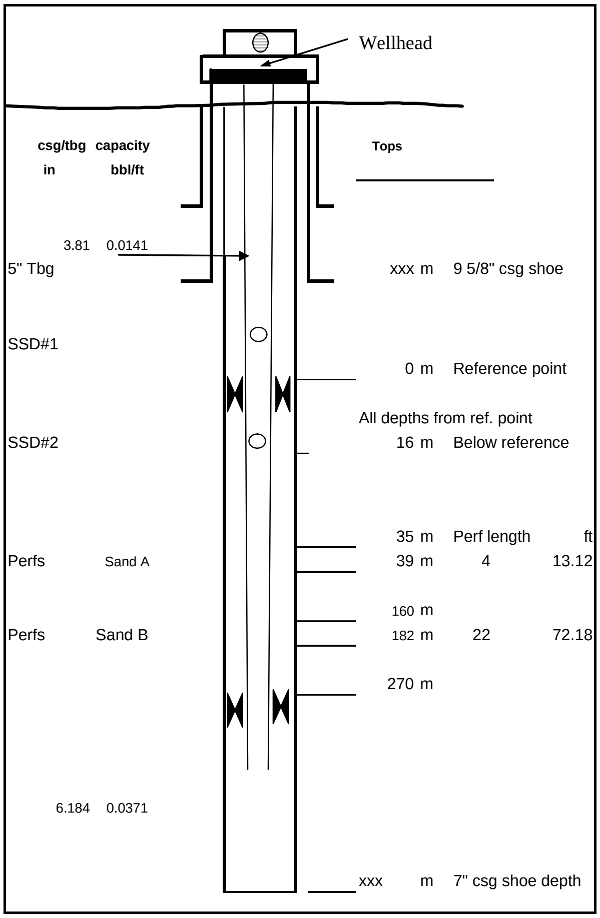

Fig. 3—Wellbore Schematic.

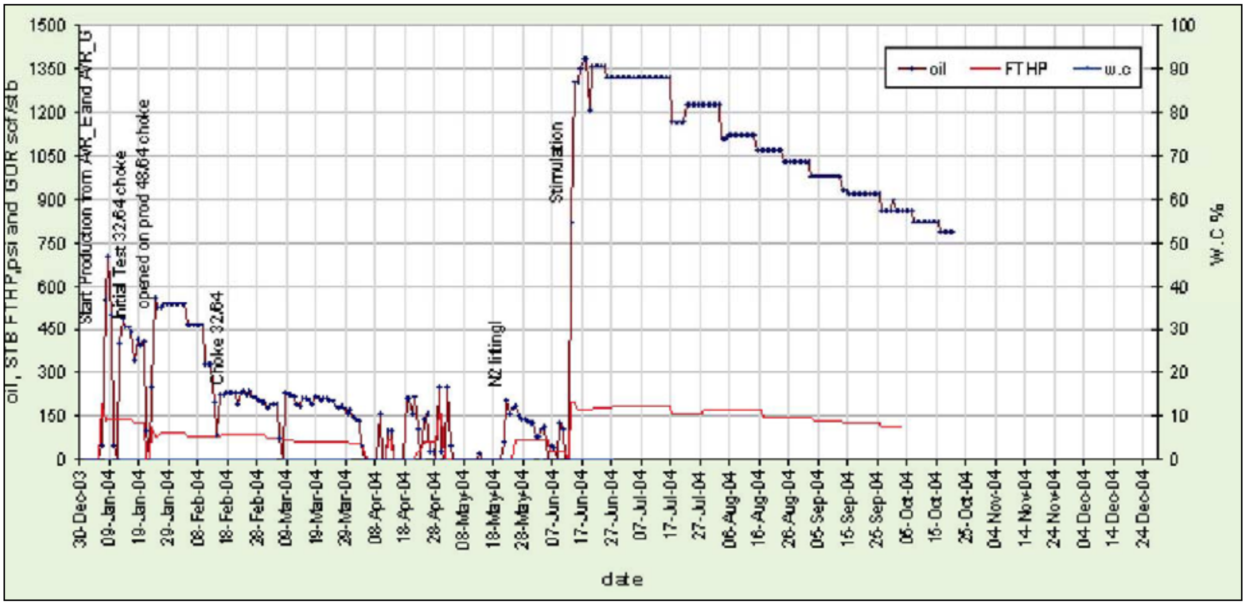

Fig. 4—Production data.

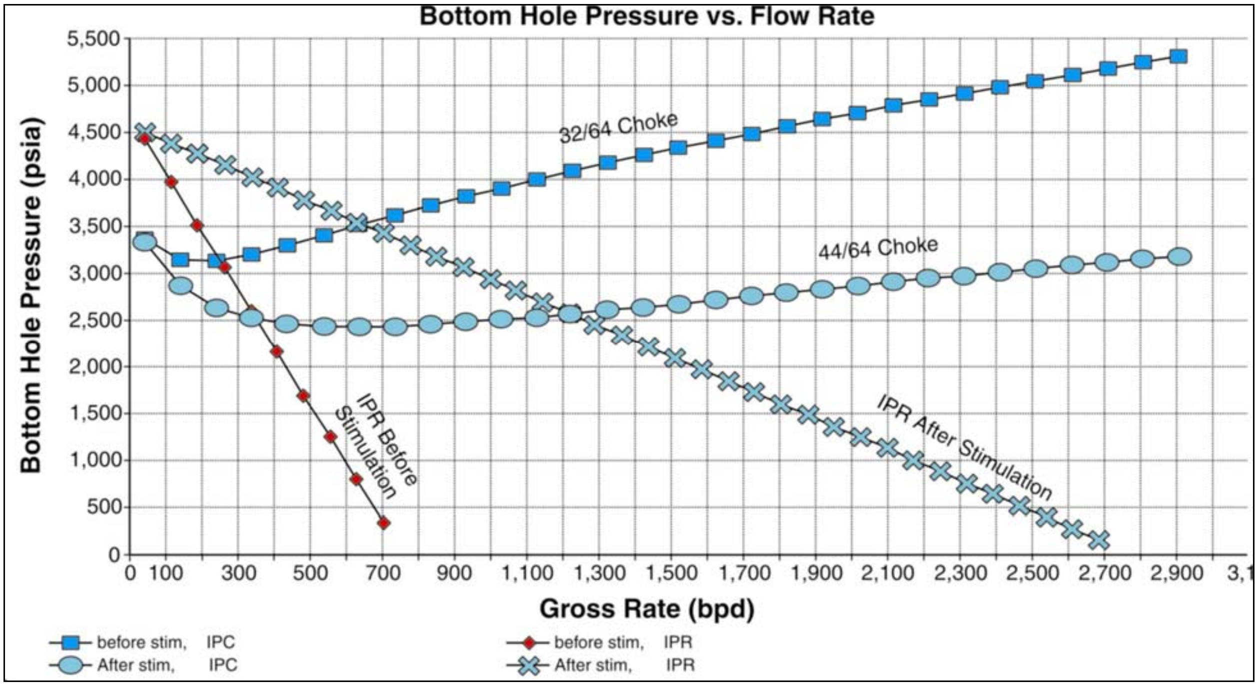

Fig. 5— Production stimulation.

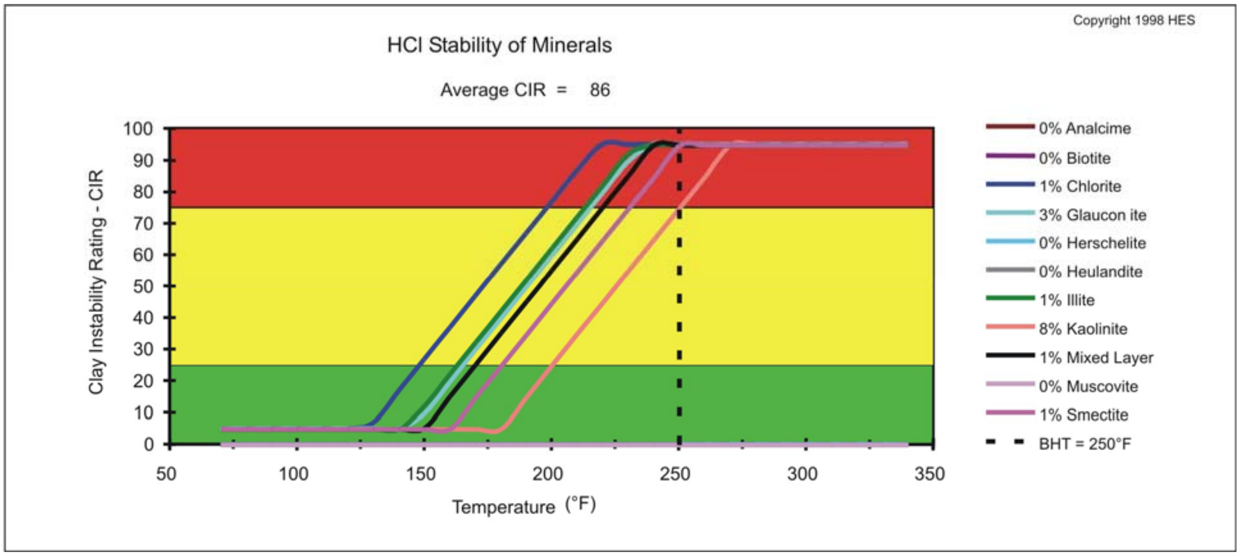

Fig. 6—Clay instability in HCl acid.

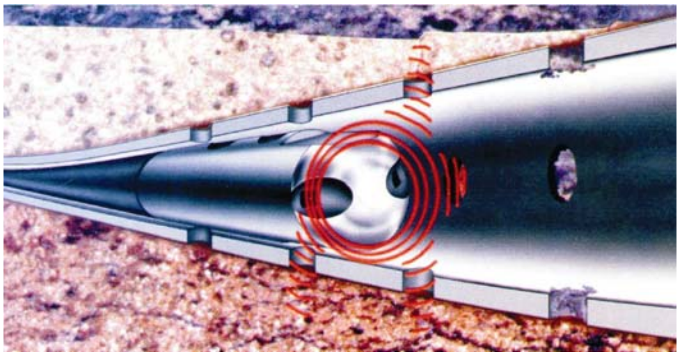

Fig. 7—TFO in action.

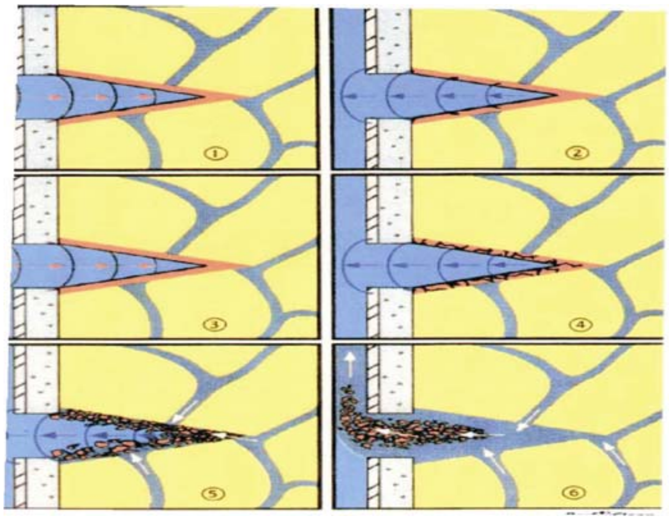

Fig. 8—TFO removing debris.

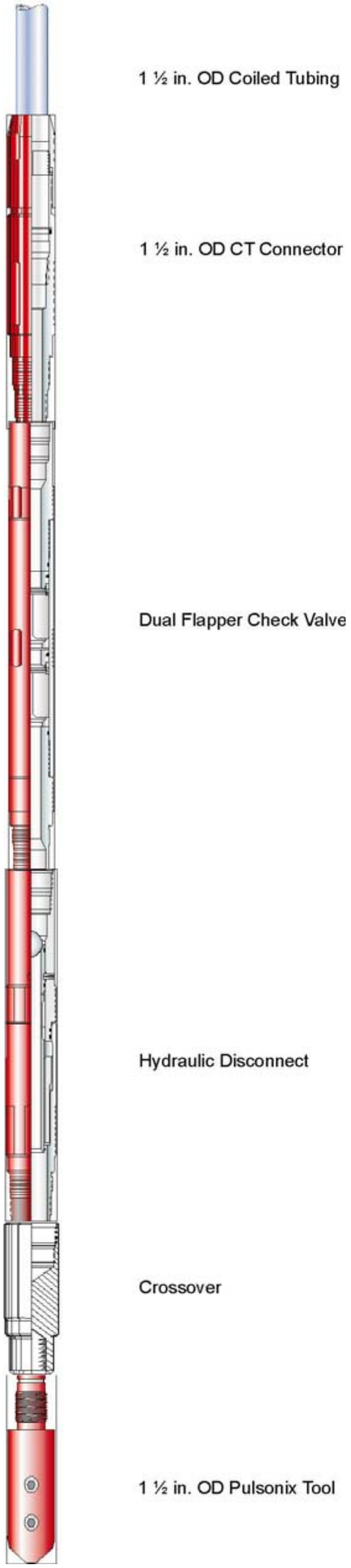

Fig. 9—Coiled-tubing BHA, TFO installed at end.

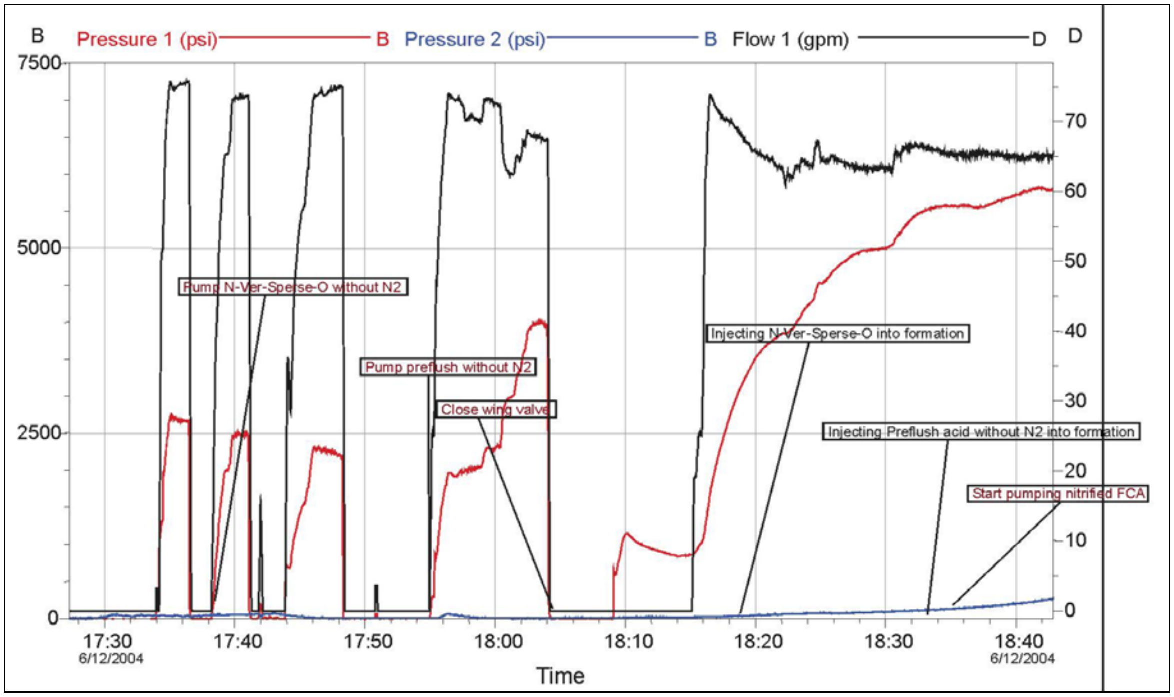

Fig. 10—Job Plot 1 (Pressure1-CT Pressure; Pressure2-Annulus Pressure).

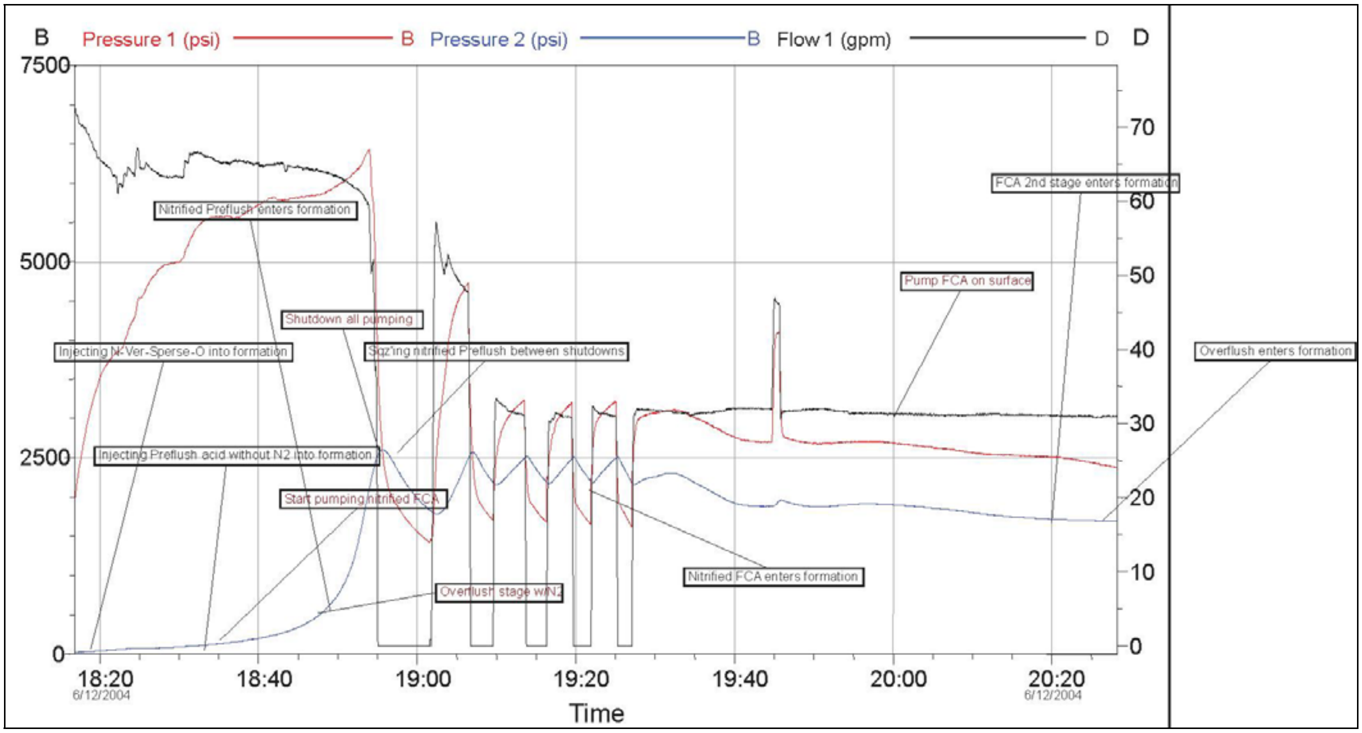

Fig. 11—Job Plot 2 (Pressure1-CT Pressure; Pressure2-Annulus Pressure).

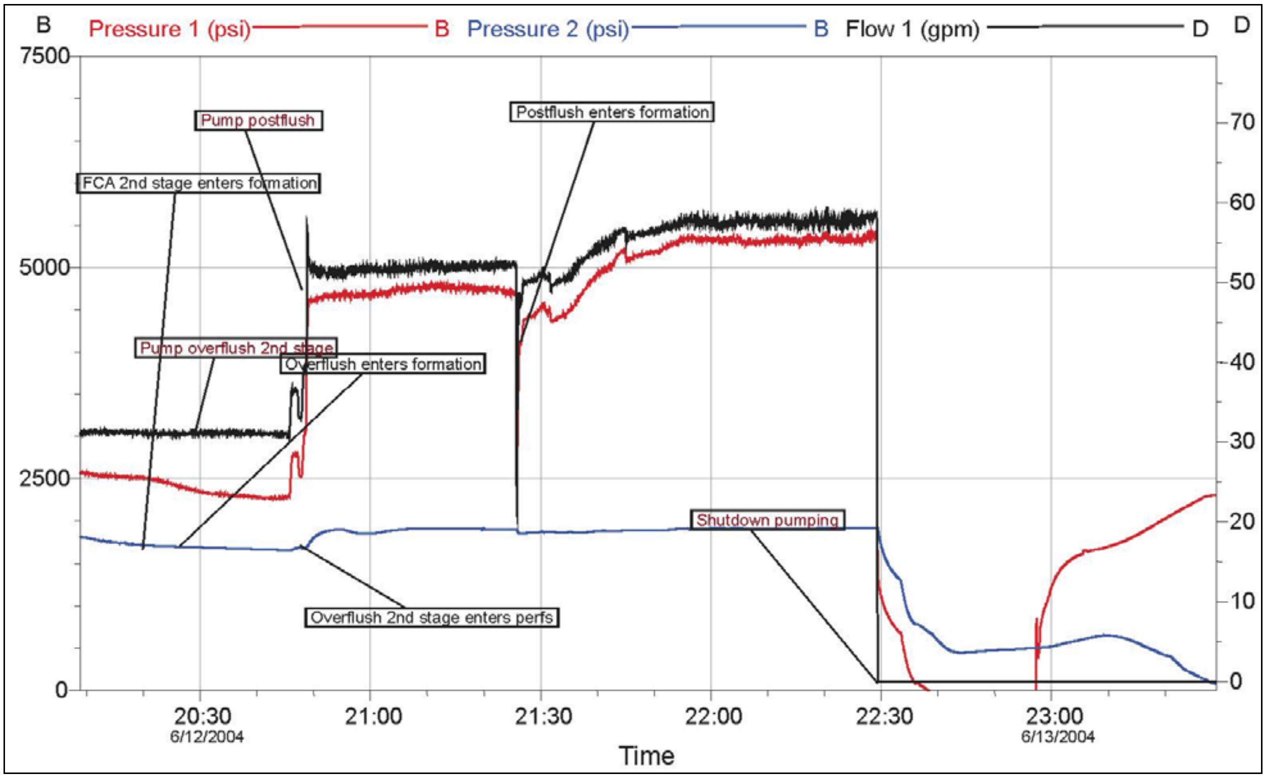

Fig. 12—Job Plot 3 (Pressure1-CT Pressure; Pressure2-Annulus Pressure).

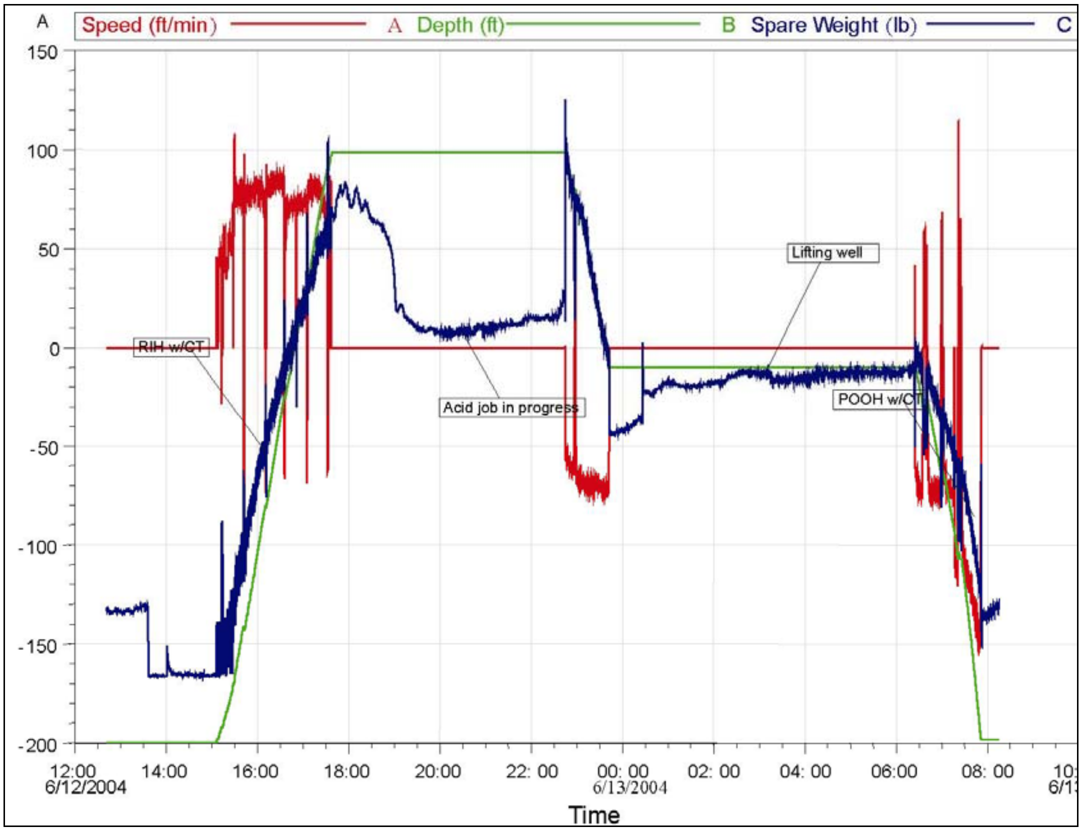

Fig. 13—Coiled-tubing job plot.