First Successful Openhole Lateral Multistage Acid Frac in a Complex Unconventional Carbonate Reservoir North Kuwait-SPE-188710-MS

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First Successful Openhole Lateral Multistage Acid Frac in a Complex Unconventional Carbonate Reservoir North Kuwait

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Abstract

Openhole (OH) multistage fracturing (MSF) is increasingly used to stimulate and maximize production within low-permeability reservoirs in unconventional plays globally, extending its use from tight sands, shales, and carbonate reservoirs. Technological breakthroughs in hydraulic fracturing have helped enable OH MSF within lateral sections.

The target reservoir is a tight heterogeneous carbonate with unsustainable productivity. The hydrocarbon produced is oil of relatively low API and gas/oil ratio (GOR). Given the challenging nature of the unconventional Mauddud reservoir of the Bahrah field, a sophisticated design of both the well completion and fracturing treatment is necessary to achieve the North Kuwait strategic production targets by maximizing reservoir contact and enhancing well performance.

A long horizontal well was drilled within the Mauddud reservoir. Completion technology was based on distributing swellable packers along the lateral section to develop MSF acidizing.

The multistage packer and port designs were based on the reservoir mechanical and formation properties, to achieve the best fracture extension. Fracture acidizing was performed on each stage, the well was flowed clean, and an electrical submersible pump (ESP) was run to produce the well. A production logging tool (PLT) survey was run immediately after fracture acidizing and six months after production. The recorded data indicated different contribution profiles of the stages, which indicated the fractures and production within such reservoirs take time to stabilize.

This paper describes and addresses the effectiveness of MSF. Additionally, MSF performance in horizontal vs. vertical wells is assessed. Well performance analysis, exploitation approaches, and successful implementation are discussed, highlighting the advanced completion technology applied. The PLT results at different stages of the well life (post-acidizing and after ESP installation) are discussed. A comparison between the multifracture within the lateral section and vertical fractured well showed the benefit of the technology used to boost and sustain production. Effective horizontal drilling and MSF have helped enable the development of unconventional resources, which were considered economically unfeasible previously.

Introduction/Background

Approximately 69% of the oil reserves are stored within carbonate reservoirs (Salah et al. 2016). Tight carbonate reservoirs present additional challenges during development. Maintained and sustained production is the primary challenge in tight carbonate reservoirs. Horizontal drilling increases reservoir contact and improves productivity.

Horizontal drilling applications in the oil industry first began in the 1950s. The first horizontal well was drilled in the Gulf of Mexico (GOM) in 1955, with a short radius of less than 500 ft long because of directional technology limitations. This short radius well showed substantially improved well production potential compared to vertical wells and encouraged the move towards horizontal drilling. With further development of directional drilling techniques, tools, and equipment, horizontal drilling technology emerged, and more complicated horizontal wells were drilled to take advantage of the state-of-the-art horizontal drilling technology. Matrix acidizing aims to create conductive channels to connect the pores together and form a flow path. Accurate acidizing is the primary challenge to operation success because of acid’s tendency to treat the more permeable intervals, which can leave large portions of the reservoir untreated.

The well is located in the Bahrah oil field, onshore Kuwait **(Fig. 1)**, with an area of approximately 170 km^2. The field falls on the prominent structural feature of the Kuwait arch. From south to north, a string of major oil fields dots the Burgan arch. The first exploration began in the 1920s.

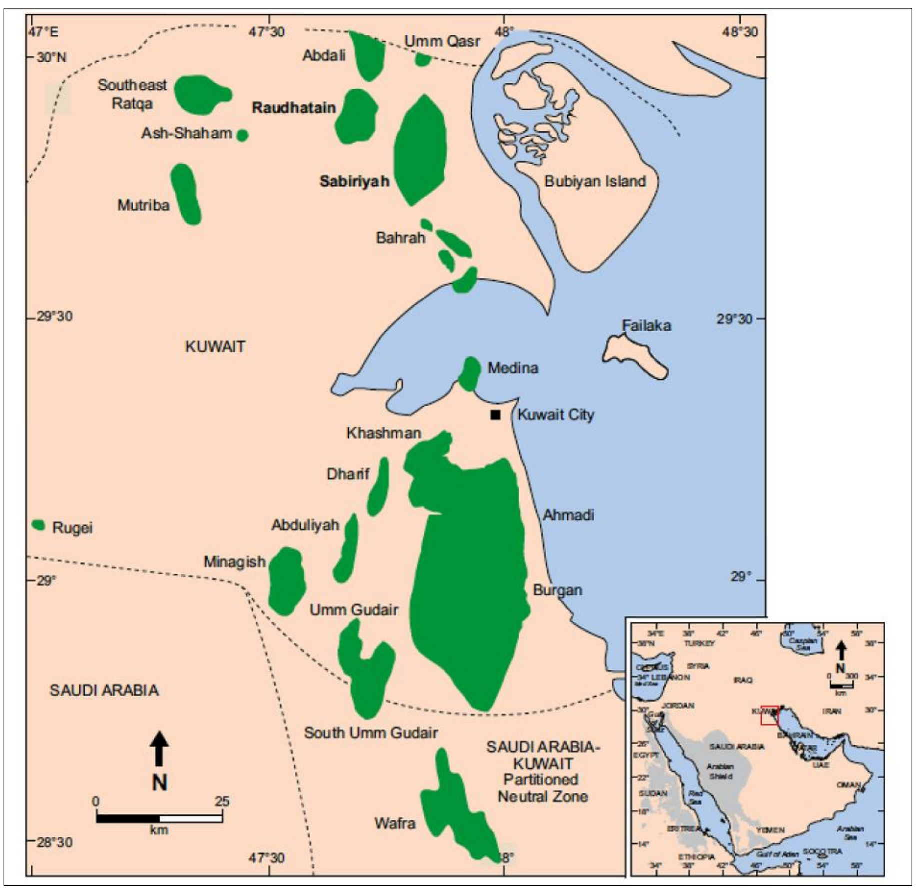


Fig. 1—Location of Bahrah field.

The Bahrah-1 well was the first exploration well drilled in Kuwait in 1936 and was primarily based on oil seeps along the northern shoreline of Kuwait Bay (Al-Anzi 1998). Field development was overshadowed by the subsequent discovery in 1938 of the super-giant Greater Burgan field immediately to the south of Bahrah. Appraisal drilling of the Mauddud reservoir in the Bahrah field commenced in 1956 by drilling vertical wells.

In 2015, the development of the Bahrah field advanced with the drilling of seven additional wells, which included six vertical and one horizontal well. In addition to a full suite of log data (including image logs), five of the vertical wells were fully cored through the Mauddud reservoir and these data were used for petrophysical calibration and sedimentological purposes. Moreover, a petrographical [including scanning electron microscopy (SEM) and X-ray diffraction (XRD) analysis] and microfacies characterization of the reservoir was conducted using a large thin-section database. The static characterization of the Mauddud reservoir was integrated with a database of dynamic production data to understand the controls on flow and facilitate further field development. In 2016, the latest phase of development planning culminated in the drilling of horizontal production wells, with each well completed using multistage acid fracturing.

Geological and Development Description

The Mauddud formation is an Upper Cretaceous carbonate-dominated succession that resulted from the transgression of the delta-related clastic-dominated sediments of the Burgan and Nahr Umr formations. Above, retrogradation of the Wara formation delta-related depositional systems introduced the clastic-dominated sediments that overlie the Mauddud formation in the northern-central parts of the gulf. The formation comprises a range of skeletal and peloidal wackestones to grainstones representing deposition in a shallow marine carbonate ramp environment. Towards the base of the Mauddud formation are a number of shoreface/pro-delta incursions representative of a waning in clastic supply. The formation is a porous limestone-dominated reservoir characterized by low transmissibility and heterogeneous properties. It is divided into 10 units characterized by different properties. The MaD layer is the targeted reservoir (Ashqar et al. 2017). Strohmenger et al. (2006) define the boundary between the underlying Burgan and the Mauddud formation as a supposedly chronostratigraphically significant regional flooding surface. The upper boundary of the Mauddud formation was also defined as a chronostratigraphically significant flooding surface overlain by the Wara shale of the Cenomanian age.

The Mauddud-D subzone has extremely low permeability compared to a typical carbonate oil reservoir, with productivity considerably lower than that experienced in the same reservoir of nearby fields. Matrix permeability ranges between 0.5 to 10 md. This raises the issue of poor matrix transmissibility (KH/cp). This low transmissibility will not provide good and sustainable well flowability.

Initially, vertical wells were drilled across the reservoir, and a single fracture was initiated. An ESP was installed to sustain the production. However, such wells showed varying success with low-rate and irregular production. This was caused by the low drainage radius from the single fracture and fast production depletion, as a function of the small stimulated volume observed in this completion type. An additional risk during drilling of vertical wells and fracturing the reservoir is the possibility of connecting to the water-bearing intervals, which can cause water breakthrough. In addition, the extremely low permeability of the oil-bearing reservoir necessitates a different completion technique.

Vertical vs. Horizontal Well Design

Horizontal wells are drilled to increase productivity. However, horizontal wells are more costly to drill and complete compared to vertical wells. Hence, productivity plays a primary role in helping ensure economic feasibility.

Mathematical models are used to describe the flow in the porous media and compare the vertical and horizontal cases.

Assessing productivity in horizontal wells is more difficult than vertical wells because of the simplified assumptions and data necessary during assessment. Models, such as the Babu and Odeh (1989) model, are used in the steady-state case.

The steady state assumes the outer boundary pressure remains constant. It can be written for a single-phase flow as follows:

Vertical well

$$q = \frac{Kh(p_e - p_{wf})}{141.2B\mu\left(ln\frac{r_e}{r_w} - \frac{1}{2} + s\right)} \quad (1)$$

Horizontal well

$$q = \frac{K_h h(p_e - p_{wf})}{141.2B\mu\left\{ln\left[\frac{a+\sqrt{a^2-(L/_2)^2}}{L/_2}\right] + \frac{h\,I_{ani}}{L} ln\frac{h\,I_{ani}}{r_{w(}\,I_{ani+1)}}\right\}} \quad (2)$$

where

B = formation volume factor, dimensionless, RB/STB

H = formation thickness, L, ft

I = anisotropy factor : $I = \sqrt{\frac{k_h}{k_v}}$

k = permeability, L^2, md

p_p = gas pseudopressure, m/Lt^3, $psia^2/cp$

$\bar{p}_R$ = average reservoir pressure, m/Lt^2, psia

p_{wf} = bottomhole pressure (BHP), m/Lt^2, psia

r_e = external drainage radius, L, ft

r_w = wellbore radius, L, ft

s = skin factor, dimensionless

T = temperature, T, °R

z = gas compressibility factor, dimensionless

μ = viscosity, m/Lt, cp

The horizontal wells produce 3.4 times more than the vertical wells within the studied reservoirs and have 3.5 times more productivity. This is represented in **Fig. 2,** based on a sensitivity analysis using a reservoir simulator. This forecast shows the cases as a vertical fractured well, horizontal well with no fractures, and a horizontal well with three, seven, and 15 transversal fractures.

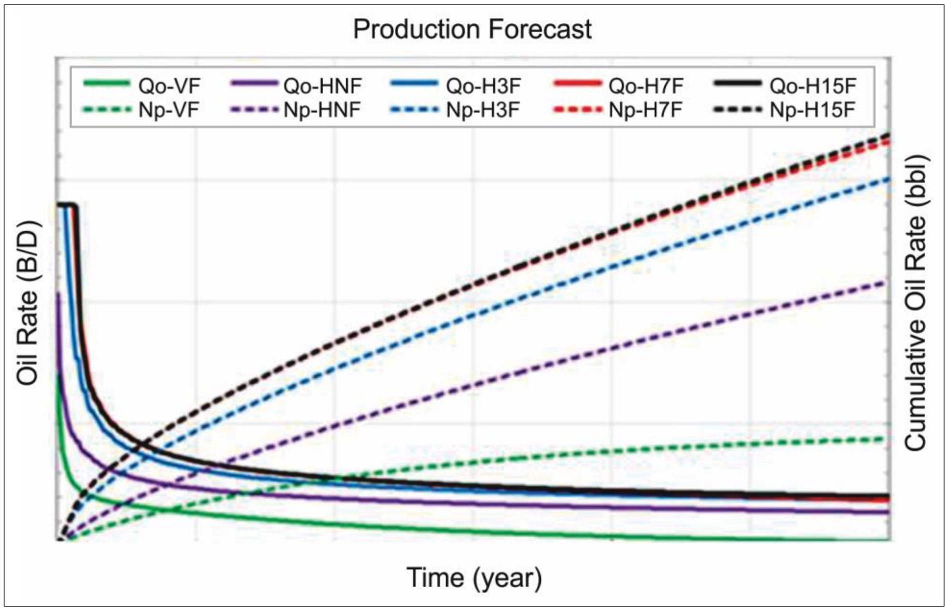


Fig. 2—Comparison among the different simulated well cases.

Multistage Horizontal Wells Strategy

Unconventional reservoirs necessitate a holistic approach **(Fig. 3)** to stimulation and completion as follows:

- A keen understanding of the reservoir, geology, petrophysics, geomechanics, geochemistry, tectonics, etc. is necessary.
- Wells should be drilled and constructed to accommodate the proposed stimulation condition. Pressure drops at high-stimulation rates should be predicted and the completion designed accordingly.
- Completions should be designed to maximize the stimulated reservoir volume and extend the production life of the treatment.
- Preplanning, interdisciplinary teamwork, and close, open collaboration among the involved professionals is essential.
- Production analysis is important to evaluate further changes in the design.

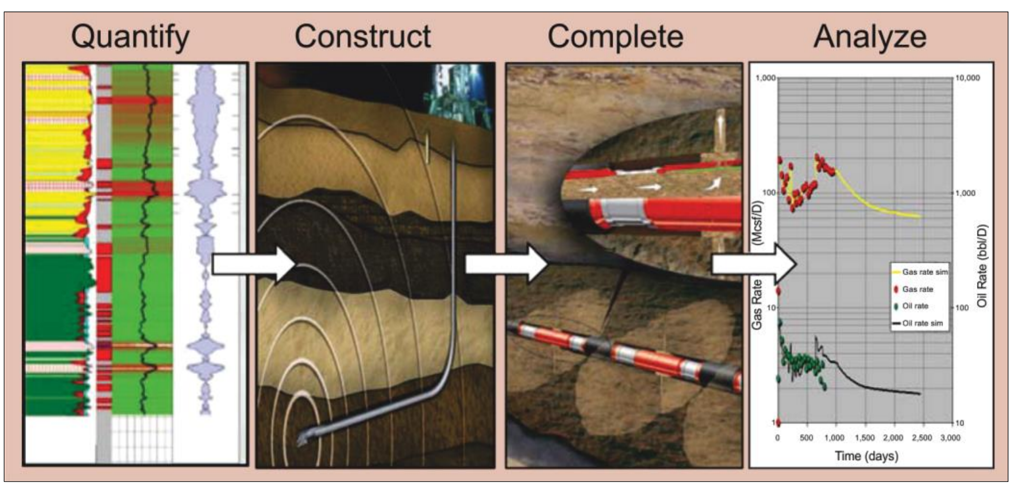


Fig. 3—Unconventional reservoirs development strategy.

The development of this reservoir was planned to drill lateral wells in the direction of minimum horizontal stress (Sh) with an OH (6 1/8 in.) sliding sleeve completion (4 1/2 in.) to maximize formation exposure. The horizontal well lateral length was designed to have 3,000-ft length in the direction of the Sh.

Fig. 4 shows a structural three-dimensional (3D) model of the drilling area with the planned trajectory and offset wells. **Fig. 5** shows the geosteering design of the horizontal section.

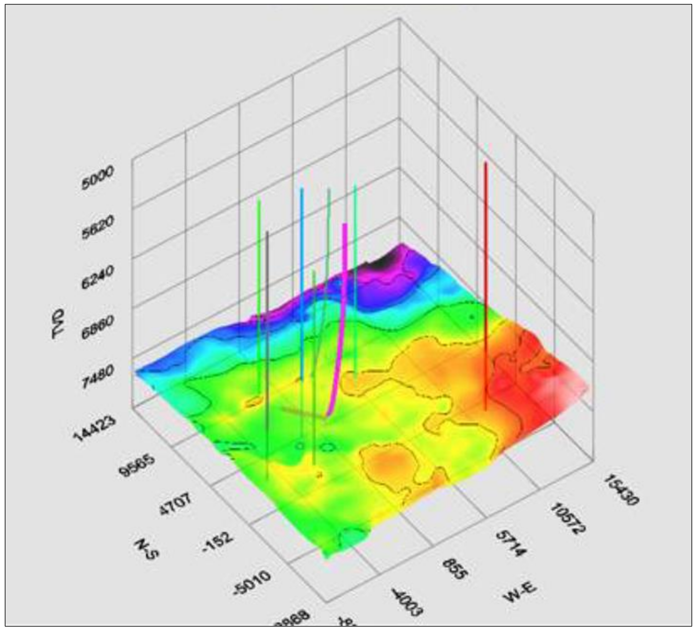


Fig. 4—Well design schematic.

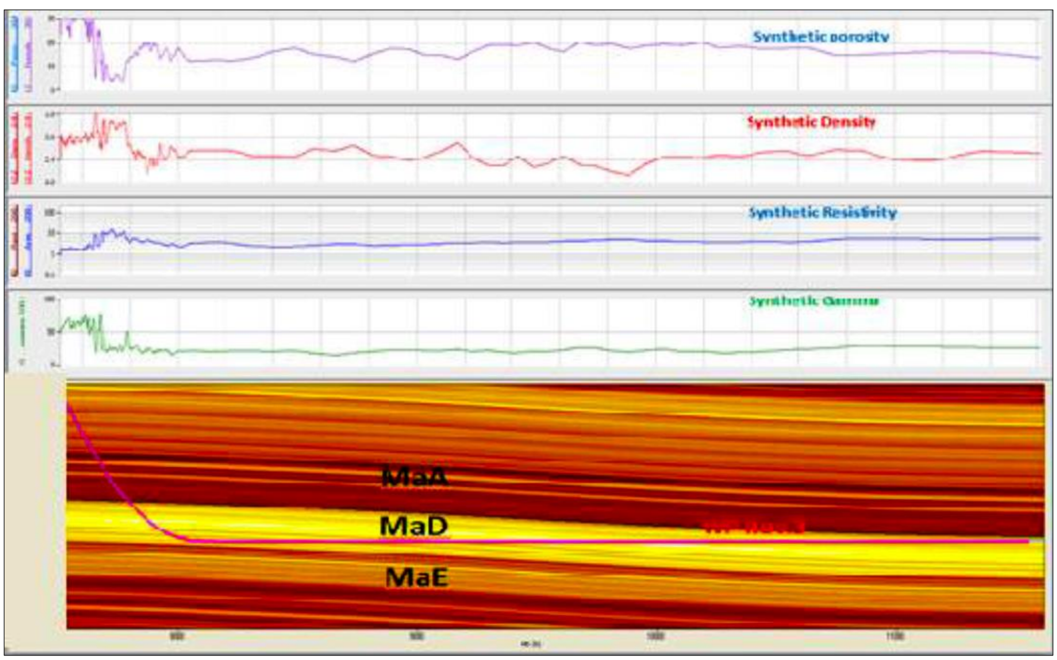


Fig. 5—Proposed horizontal section of the reservoir.

Completion Design

The formation of transverse fractures is expected as a result of the acid fracturing treatment **(Fig. 6).** The Sh was estimated using a poro-elastic equation and calibrated to fracture closure pressures interpreted from the acid fracturing results. The orientation of the horizontal in-situ stresses was determined from oriented 6-arm caliper data and image logs.

Acid fracturing is performed to propagate the channels necessary to allow the hydrocarbon to flow to the surface. These fractures form the reservoir fluid pathways to flow to the borehole. The infinite conductive channel is created by etching the fractured rock with acid. The etching aims to provide a high-flow capacity channel.

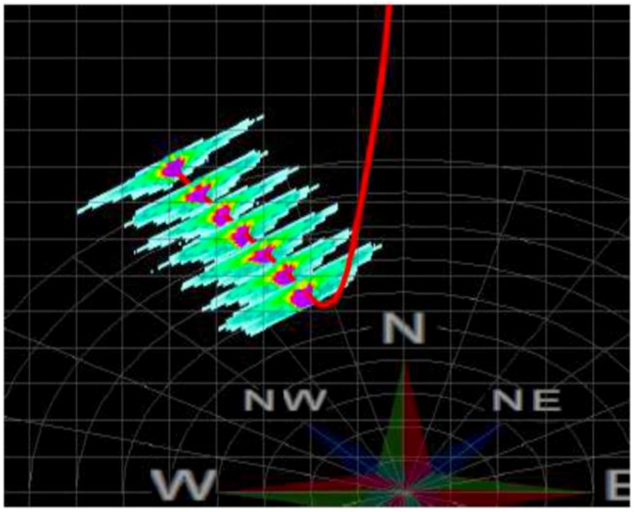


Fig. 6—Fracture propagation in horizontal wells drilled parallel to the Sh.

The proposed method to achieve this objective was using a completion that was capable of allowing for treatment while managing production properly. The completion was designed to use swellable packers to isolate the OH segments **(Fig. 7).** Each OH completion consisted of swellable packer zonal isolation systems, completion sleeves, and initiator sleeves. The completion was divided into two sections [upper and lower (permanent) completion] **(Fig. 8).**

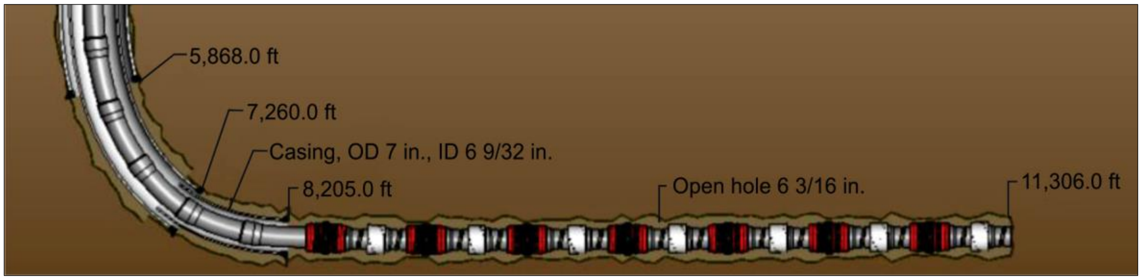


Fig. 7—Swellable packers isolating OH segments.

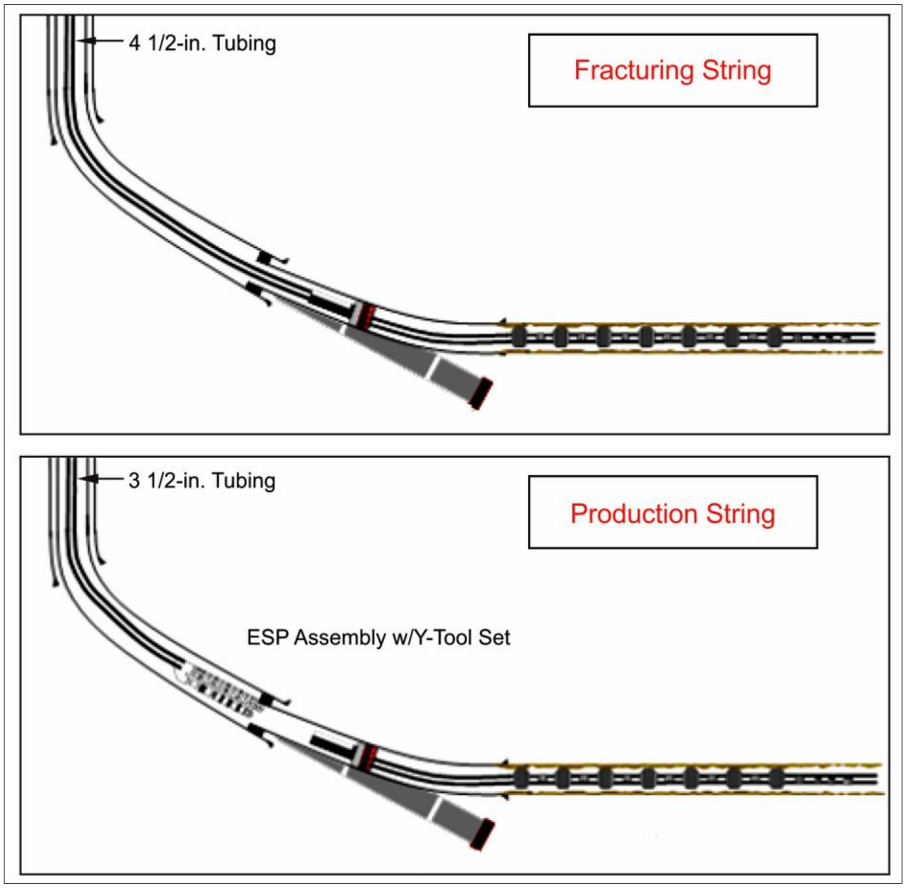


Fig. 8—Completion design (upper and lower completion).

The reactive elastomer is designed to react to the oil phase. Consequently, when these packers are exposed to oil or diesel, they begin swelling. Additionally, these packers are longer and adapt easily to the borehole shape, which helps improve the success rate of stage isolation and induces low stress to the borehole **(Fig. 9).** The acquired caliper data are used to adjust the OH sections to the optimal location for continuous isolation **(Fig. 10).** This is a crucial measurement to help ensure packers placement in an interval that allows them to hold the necessary differential pressure, which is related to the maximum hole diameter across the packers length. Holding the necessary pressure is subject to the hole size (i.e., the larger the hole, the lower the differential pressure). **Fig. 11** shows the relationship between the hole size and differential pressure.

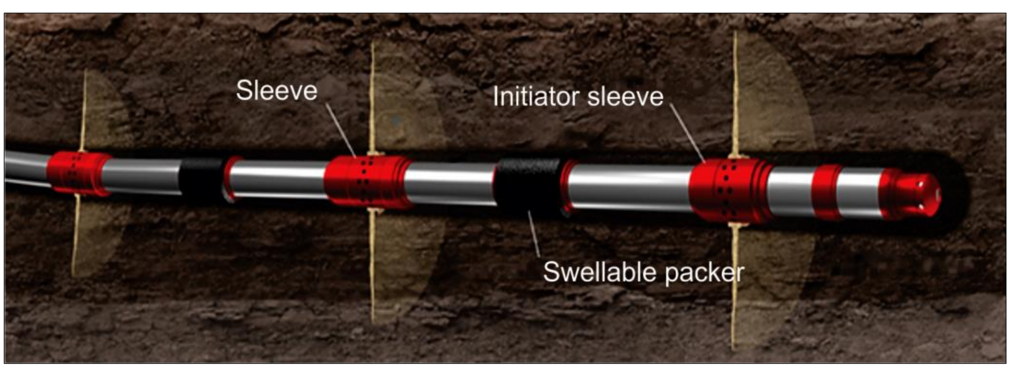


Fig. 9—Lower completion with swellable packers.

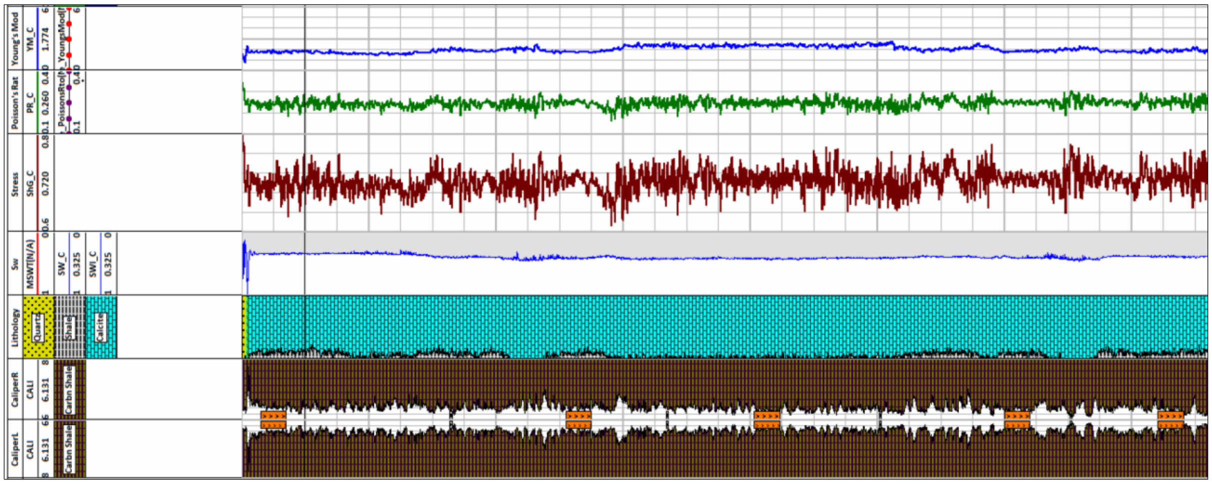


Fig. 10—Layout showing packers placed across the borehole. A caliper is used to identify suitable positions (Track 1). Track 2 shows lithology, Track 3 water saturation, Track 4 stresses, Track 5 Poisson's ratio, and Track 5 Young's modulus.

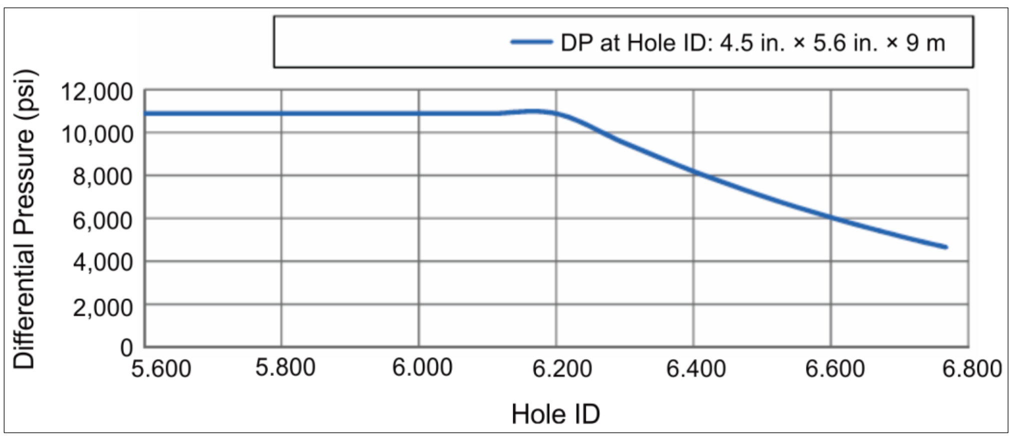


Fig. 11—Differential pressure profile.

Packers swelling time is related primarily to the hole size. However, reservoir temperature and hydrocarbon viscosity affect the total swelling time. **Fig. 12** shows the time necessary for the packers to swell in relation to the hole inner diameter (ID).

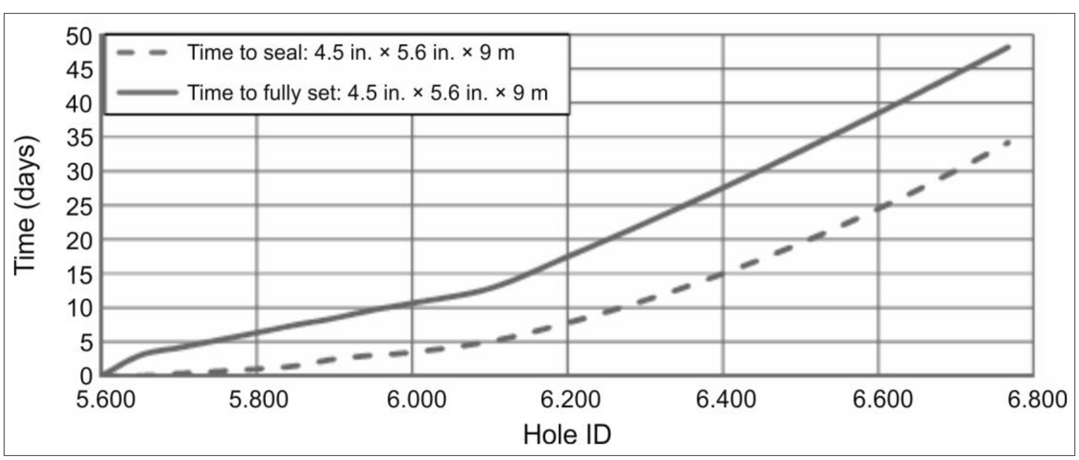


Fig. 12—Swellable packers profile.

MSF and Acidizing Design

Production in fractured wells is controlled by the formation properties (porosity, permeability, and saturation), fracture conductivity, half-length, and number of fracture stages.

A large contact area between the reservoir and fractures is important to help ensure production enhancement. Stress is a dominating factor in creating fractures. Teufel and Clark (1984) determined that the elastic properties of either side of the interface could influence the propagation of the vertical growth by affecting the vertical distribution of the Sh state. This is because the increase in the minimum horizontal in-situ stress in the bounding layers and a weak interfacial shear strength of the layers could contain the vertical growth of the hydraulic fractures. For composite rock, differences in Young's moduli and the fluid volume within the fracture, the conductivity, and productivity in adjacent layers can influence the hydraulic fracture width, if it expands across the interface.

Buller et al. (2010) highlight the relationship between brittleness and production, with production expected to increase in a brittle formation because more brittle rocks develop more complexity around the induced fractures planes. This increases the surface area of these fractures **(Fig. 13).** As a result, fracture operation success can increase if intervals with similar brittleness are grouped together in the same stage.

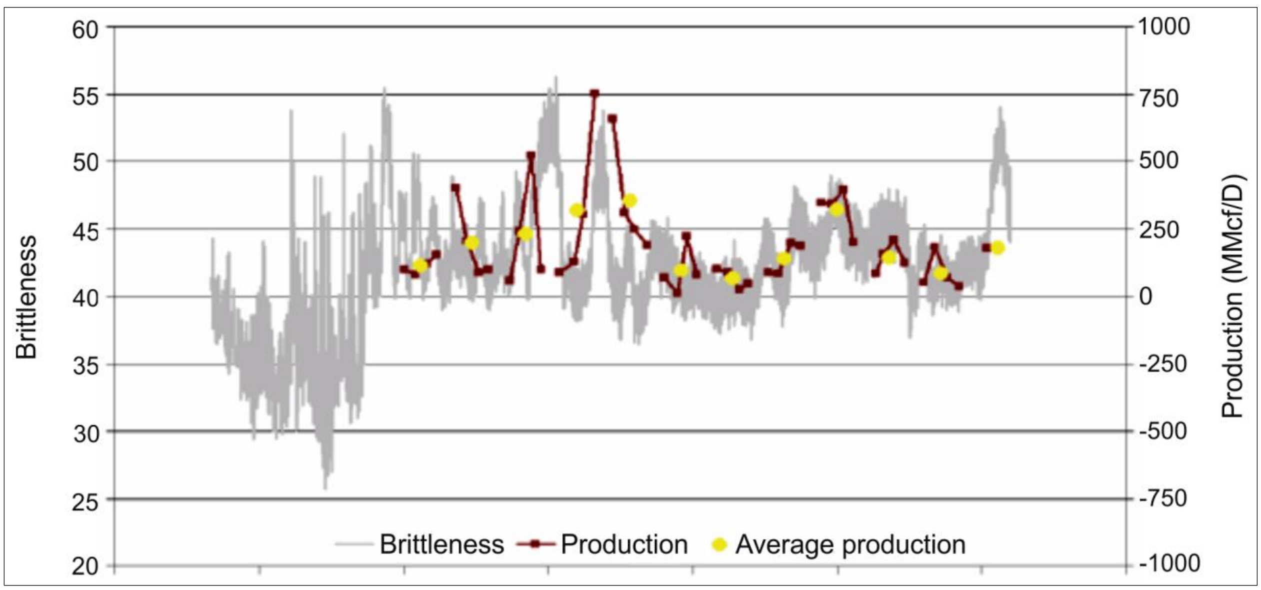


Fig. 13—Brittleness vs. production (after Buller et al. 2010).

Acidizing is performed to increase productivity by initiating a fracture through the reservoir. Formations with 80% acid-solubility and low permeability are considered good candidates for acidizing.

To achieve successful acidizing, the treatment should be designed to fit the formation and should address the following issues:

- Conductivity initiation
- Fracture flow capacity numbers
- Reactivity control
- Fluid-loss control
- Rock quality and its mineralogy

Fracture flow capacity numbers are a crucial property necessary to design fracture acidizing recipes. These values are determined from special laboratory tests performed on cores in which different acid types are injected into the core, and the differential etching and flow capacity values generated from the acid reaction are documented. Hydrochloric (HCl) acid is generally used to create an etched fracture, which is the primary mechanism for maintaining an open fracture during the life of a well. **Fig. 14** shows the results of the etching test, which are used as the base of the acid treatment.

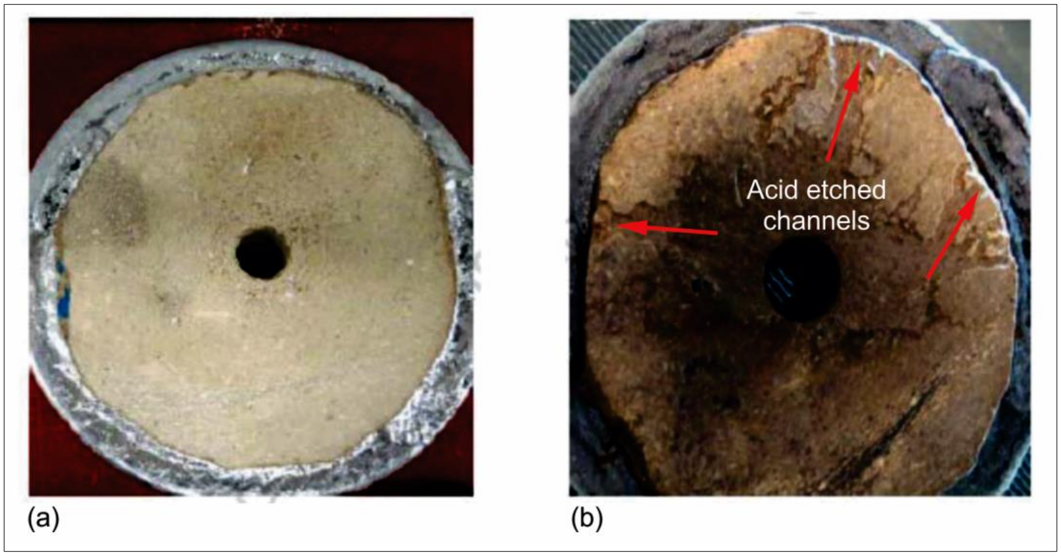


Fig. 14—Etching test results: (a) core face before acid reaction; (b) core face after acid reaction channels are evident.

The acidizing sequence is designed to generate conductivity, control fluid leakoff, and formation reactivity as follows:

- Pad stage (preflush) to create the fracture geometry before pumping the acid
- Primary fracture acidizing system to maximize the effectiveness of fracture acidizing in carbonate formations
- Leakoff control and acid diverting system to immediately crosslink as it contacts the carbonate formation, thus providing viscosity and slow spending near-wellbore (NWB) to help control the effective etched fracture length and reduce the increased fluid loss caused by the primary acid system
- Closed-fracture acidizing (CFA) to continue the primary treatment

The primary acid systems used for this field are carbonate stimulation acid (CSA) gel at 28% HCl acid and zonal coverage acid (ZCA) crosslinked gel at 15% HCl acid. Laboratory tests were conducted to determine the best acid treatment for the Mauddud formation. **Table 1** shows the acid fracturing sequence.

Operation Step	Objective
1) Breakdown	Pump at maximum rate to initiate a single fracture
2) Step-up test	Determine fracture extension pressure and rate
3) Mini frac and analysis	Determine the actual formation and fluid-loss characteristics of the fluid system
4) Main frac	Achieve longer effective etching length
5) Displacement	Overdisplace acid
6) CFA	Pump below fracture gradient pressure
7) Displacement	Underbalance to help recover acid

Table 1—Sequence of the acid fracturing operation.

The 28% CSA fluid system acid, 15% ZCA diverting system, fracturing fluid crosslinked gel, and relative permeability modifier (RPM) are alternated as necessary. The difference in acid strength (28% CSA fluid system acid and 15% ZCA diverting system) with alternated stages of fracturing fluid crosslinked gel and RPM during the operation helps improve the viscous fingering and enhances fracture conductivity.

The acid is overdisplaced to push live acid further into the formation, therefore allowing the most favorable treatment outcome.

After the primary treatment, a continued low-rate, low-pressure (below fracture gradient) treatment is performed with 28% HCl acid to help further enhance fracture acid etching and conductivity in the NWB region. **Table 2** illustrates the pumping schedule.

No.	System	Fluid	Rate (bbl/min)	Volume (gal)	Volume (bbl)
1	Main frac pad	Fracturing fluid, 30 lbm	35	8,000	190
2	Main frac acid	15% ZCA	35	6,000	143
3	Main frac pad	Fracturing fluid, 30 lbm	35	5,000	119
4	Main frac acid	28% CSA	35	8,000	190
5	Diverting system	Treatment fluid	35	2,000	48

Table 2—Sequence of the acid fracturing operation pumping schedule.

Three cycles were considered with two stages of the diverting system between cycles. After these cycles were pumped and injected into the formation, the well was shut down to obtain the closure pressure. Injection continued below this pressure gradient at matrix flow to help enable application of the CFA technique. **Fig. 15** shows the cycles distribution.

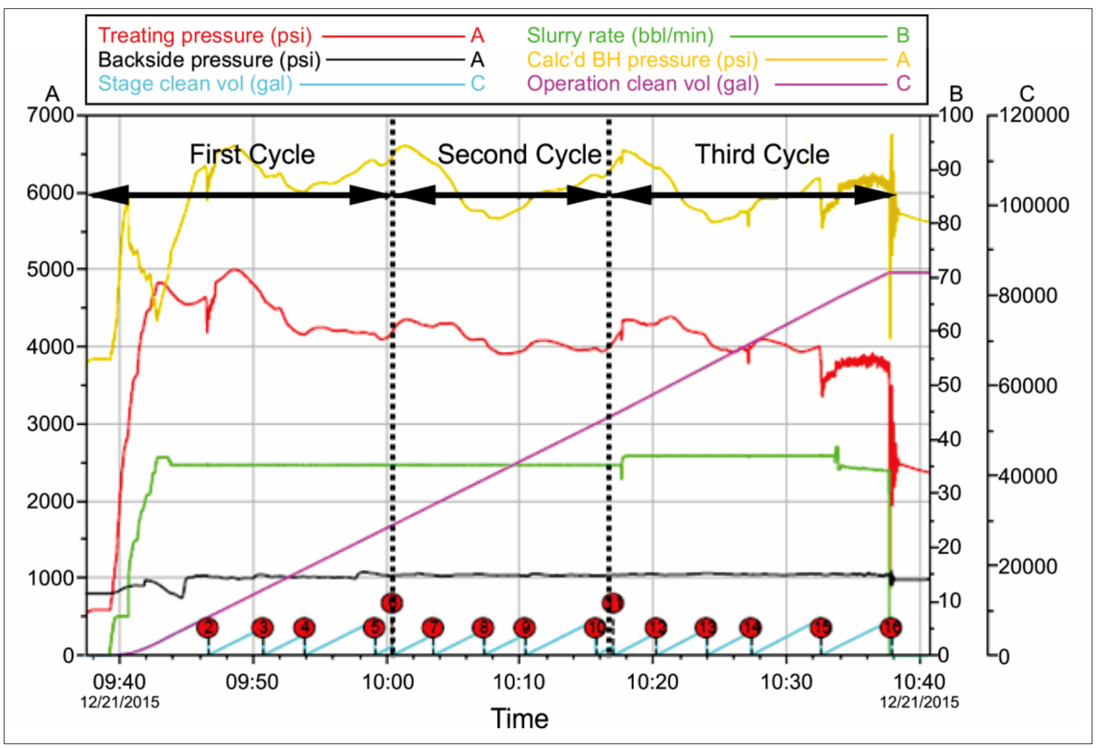


Fig. 15—Acid fracturing cycles distribution.

MSF Acidizing for BH00XX

BH00XX was drilled to cover 3,000 ft within the Mauddud-D reservoir. **Fig. 16** shows a 3D snapshot of the lateral section across the reservoir. The well was completed with seven stages, based on an optimized number of stages vs. cumulative oil production over 30 years. Seven stages were determined to be the optimum strategy for this well. A total of 19,600 bbl of acid and chemicals were pumped during treatment.

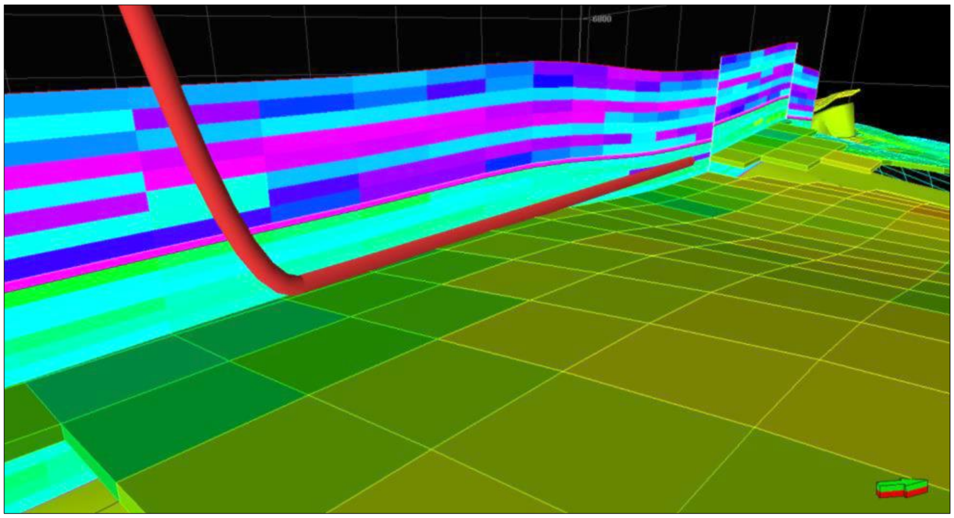


Fig. 16—3D snapshot of the horizontal drain in BH00XX.

The production potential of BH00XX was estimated using a single-well model to determine the production capacity of the fractured horizontal well and compare it to the vertical wells. Several scenarios were developed as sensitivity cases and compared to the vertical well scenario. **Fig. 17** shows one of these cases with specific well spacing and a bottomhole flowing pressure (BHFP). An ESP was considered in all scenarios.

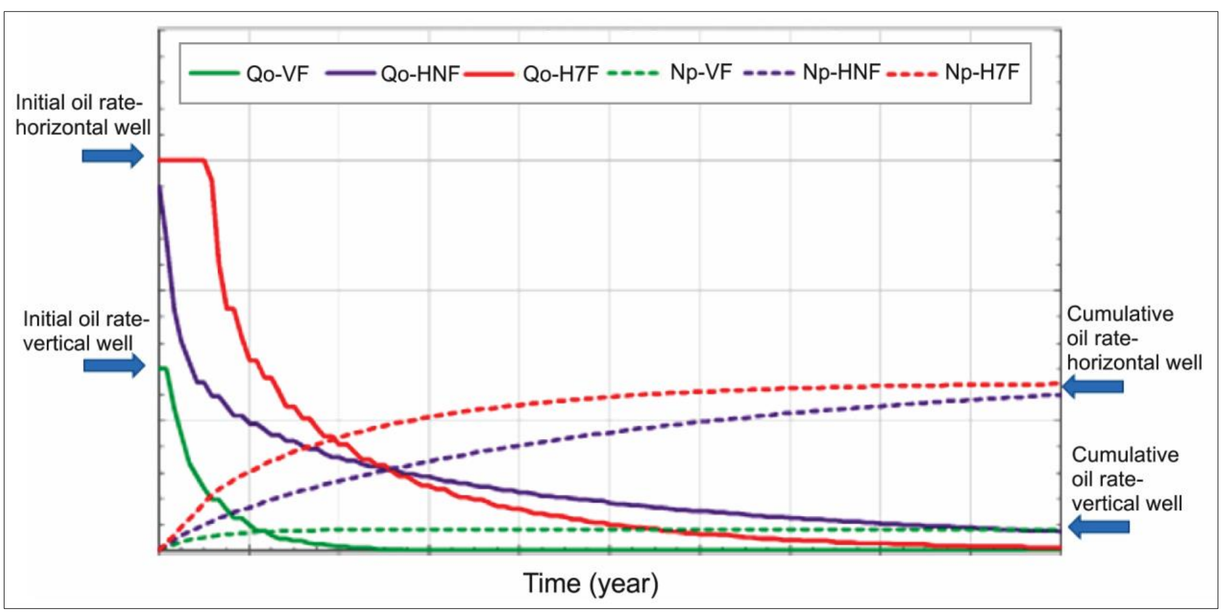


Fig. 17—Production profile of BH00XX. Red indicates the horizontal completion, and green indicates the vertical completion.

Post-Fracture Acidizing Evaluation

The well was opened to flare pit post-MSF. Test results using the portable test separator showed the average horizontal well production was between three and four times greater than the vertical well production.

Two PLT surveys were acquired. The first survey was conducted while the well was flowing naturally, and the second survey was conducted after the artificial lift installation to achieve the following:

- Determine the flow contribution of the different stages and determine water entry points
- Help ensure no leaks in the swellable packers
- Measure downhole pressure and temperature
- Maintain a pressure buildup for approximately 800 hours

PLT Results

The first PLT survey determined the following:

- Three sections were not contributing to well production.
- Four other stages were contributing to production.
- The majority of oil production originated from two intervals.

The results were caused by the low differential pressure across the lateral section, which necessitates artificial lift.

Fig. 18 shows the production profile across the lateral section combined with the borehole profile.

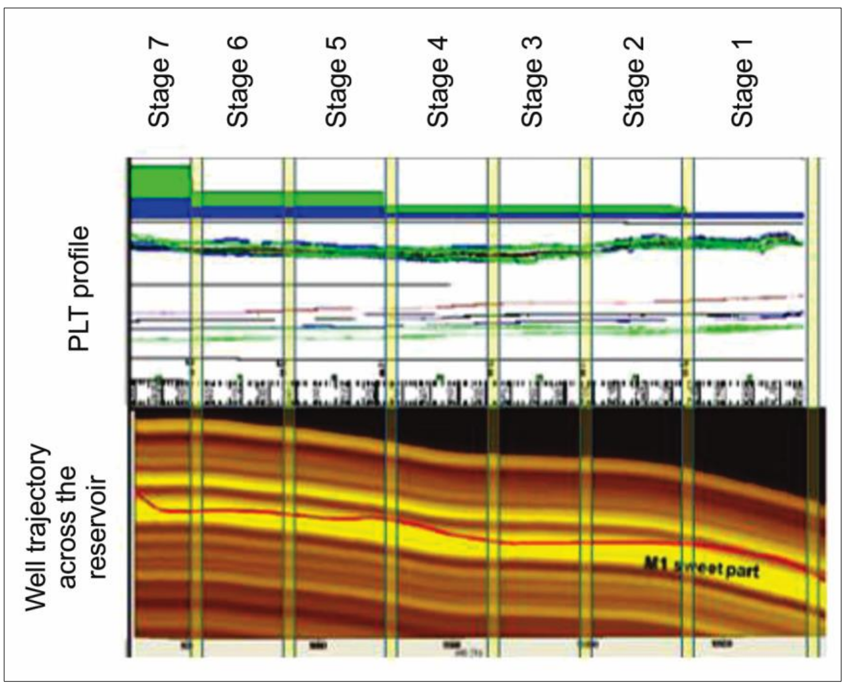
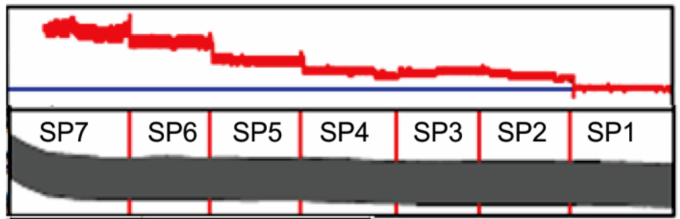


Fig. 18—PLT survey results with the well trajectory.

The second PLT survey was performed after the artificial lift completion and showed that all intervals contributed to well production, except SP4 **(Fig. 19).**



Stage	Contribution (%)
SP7	43
SP6	10
SP5	12
SP4	0
SP3	10
SP1+2	25

Fig. 19—PLT results after installing the artificial lift.

Pressure Transient Analysis (PTA) Results

PTA was performed **(Fig. 20).** However, it was determined to be an impractical method for a horizontal MSF well in a low-permeability reservoir because the model is quite complex and needs extensive time to provide a representative interpretation.

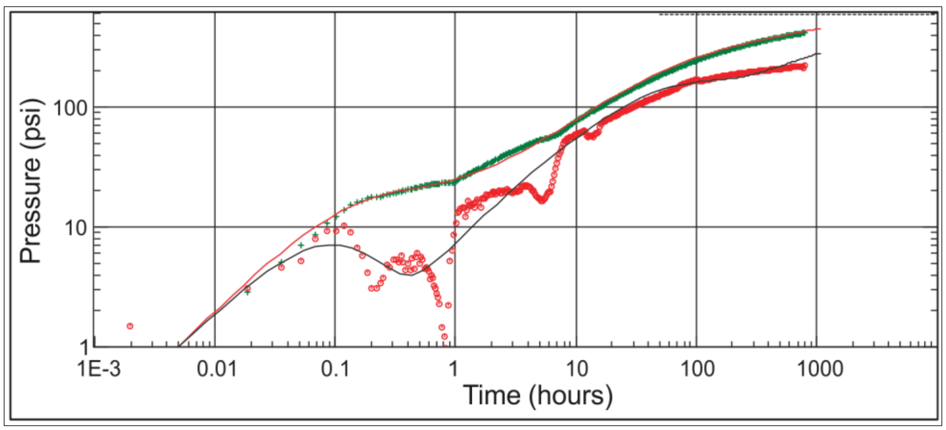


Fig. 20—PTA results.

PLT results were matched with a reservoir simulator, together with a nearby well and completion hydraulic simulator, to create accurate production forecasts, evaluate the completion delivery, and make adjustments, if necessary. **Fig. 21** shows the results.

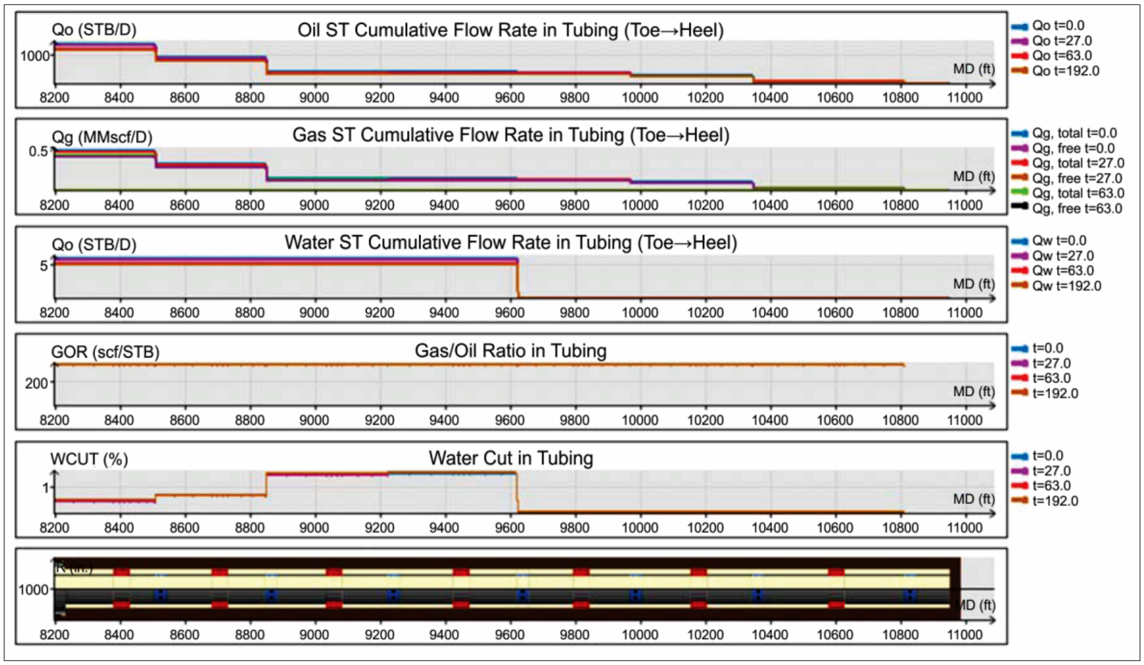


Fig. 21—Production forecast using PLT data.

Conclusions

The following conclusions are a result of this work:

- Understanding of the field geology, offset wells, and proper drilling technology that allows for accurate navigation and well path into the target interval is essential to achieve stimulation and production as planned.
- Completion designs should comply with the expected stimulation rates and production targets. Additionally, all the mechanical components should be reliable to achieve the well objectives.
- Artificial lift designs should consider the transient behavior of horizontal hydraulically fractured wells, offering a wide range of oil rates.
- A definition of post-fracturing evaluation methods using reservoir simulation or production analysis is necessary to determine whether the completion/stimulation method should be modified to obtain better production deliverability.

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