SPE 38770

Design and Implementation of a 22,600 ft Underbalanced Coiled Tubing Scale Cleanout in the Gomez Field, Pecos County, Texas

L.S. Adams, SPE, Chevron USA Production Company and C.C. Overstreet, SPE, Cudd Pressure Control, Inc.

This paper was prepared for presentation at the 1997 SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 5–8 October 1997.

Abstract

This paper reviews the design, implementation, and results of a 22, 611 ft underbalanced coiled tubing scale cleanout project for the wellbore of the Fort Stockton Gas Unit 5-1. The Fort Stockton Gas Unit 5-1 is a deep, low pressure, high temperature, Gomez (Ellenburger) Field gas well.

Introduction

The recent development of reliable 100,000 psi minimum yield strength coiled tubing has provided an economic avenue for performing deep underbalanced workover operations.[1] Coiled tubing technology can provide significant economic and technical enabling qualities versus conventional workover methodology.[2-5] Major areas of impact are, lower transportation cost, reduced rigup & teardown expense, less logistical coordination, reduced trip time of tubulars, elimination of kill fluids, reduction/elimination of reservoir damage, and elimination/reduction of safety hazards.

The Fort Stockton Gas Unit No. 5-1 (FSGU 5-1) produces from the Gomez (Ellenburger) Field located in the Delaware Basin on the southwest flank of the Central Basin platform (Figure 1). Development of the Gomez (Ellenburger) Field was initiated in 1963. The Ellenburger formation is a fractured dolomite of Ordovician age having an average gross thickness of 1,600 ft with an average reservoir temperature is 335 ^{o}F.

No remedial operations have been performed on the FSGU 5-1 since its completion in March 1970 (Figure 2). In July 1993, during bottomhole pressure data acquisition, an obstruction was tagged at 21,164 ft from surface. An attempt using a 1.5 in. bailer deployed on slickline was unsuccessful in obtaining any type of sample. However, on the basis of offset well data, an assumption was made that scale with major physical characteristics of calcium carbonate and iron oxide was causing the restriction. In August 1993, the well was acidized for the first time since initial completion with no effect to its production characteristics. Because the FSGU 5-1 was considered a prolific producer relative to offset production, it was determined to remain risk adverse and not attempt any further remedial activity.

Average daily production from the FSGU 5-1 was 4.7 MMcf/D during the first quarter of 1996 with 900 psig wellhead backpressure. Based on a detailed nodal analysis simulation study performed in August 1996 on the well, wellhead compression was installed reducing wellhead backpressure from 900 psig to 500 psig. Although a 1.6 MMcf/D production increase was realized from this compression project, the nodal analysis simulation study indicated the well's production could still be optimized by approximately 2.0 MMcf/D.

Based on offset well information, a 94% soluble scale interval beginning at 21,164 ft from surface existed and was restricting the well's inflow performance. From historic data, the probability that a surface acid treatment contacting enough scale surface area to dissolve it was minimal. Since a surface acid treatment was unsuccessful, the concept of drilling through the scale section and using a wash tool along with acid to remove any remaining scale rings was developed.

Design

The potential for cash flow enhancement indicated from the nodal analysis simulation study and risk of total production loss sometime in the future initiated a wellbore cleanout feasibility study. The study evaluated the technical and economic risk for performing cleanout operations in the Fort Stockton Gas Unit 5 No. 1 wellbore. The feasibility study compared cost and risk of a through-tubing underbalanced coiled tubing scale cleanout to a conventional methodology wellbore scale cleanout performed in February, 1995. The comparable conventional methodology wellbore scale cleanout required the removal of the existing production tubing and the use of a rotary drilling rig.

The actual cost of the conventional methodology scale cleanout was $866,000. Although this work successfully restored 82% of the well's prior production, only 80% of the perforated interval was cleaned out due to differential sticking. Also, 4,910 bbls of fluid were lost to the formation. As an alternative, the through-tubing underbalanced scale cleanout technique was estimated to cost a maximum of $110,000 with potential of no fluid lost to the formation. Therefore, coiled tubing technology to clean out the FSGU 5 No. 1 wellbore was chosen because an 87% cost savings could be realized.

A risk analysis was made based solely on mechanical failures and fishing operations during tubing changeouts versus coiled tubing installations into existing tubing strings and through-tubing workovers performed on Chevron operated wells in the Gomez (Ellenburger) Field. This study indicated that using coiled tubing technology for the scale cleanout eliminated an 89% risk of fishing operations and an 11% risk of losing the wellbore.

Major areas of project design focused on coiled tubing, cutting removal combined with minimized formation damage and the bottom hole assembly (BHA). Although each of these design considerations are discussed separately, it should be understood that they interrelate and should not be designed independently.

A 1.5 in. OD, 100,000 psi minimum yield strength coiled tubing string having seven inside wall diameter tapers was designed and manufactured.[6] The tapers ranged from 0.095 to 0.156 in. wall thickness. The overall length of the coiled tubing string was 23,000 ft with a consistent overpull design of 9,060 lbs. This overpull design was based on 72% of the coiled tubing's minimum yield value.

Using the well's average shut-in bottomhole pressure of 2,100 psia an evaluation of the annular velocity for carrying cuttings to surface was performed. This study indicated that no particles greater than 0.1 in. could be brought to surface without maintaining a full stabilized column of 65 or greater foam quality. Further analysis indicated that during actual operations the prolonged development and maintenance of a full wellbore column of 65 or greater foam quality would be difficult to accomplish. Conceptually the use of acid to dissolve particles was highly desirable.

A 15% by volume hydrochloric acid (HCL) package was selected due to the amount of iron content in the scale and need for high solubility under short contact time. The appropriate corrosion inhibitor package resulted by testing coupon samples from the 1.5 in. OD coiled tubing string manufactured for the project. The coupons were exposed at 350 ^{o}F for an 8 hour period to six various inhibitor packages blended in an acid system consisting of 15% HCL + acetic anhydride + foaming agent + friction reducer. The weight of each coupon after exposure to the acid system was recorded and compared to its initial weight. A corrosion rate was then calculated in lb/ft^2 per test time.

A 1.688 in. OD impact drill was selected for deployment on the coiled tubing due to its tolerance for high temperatures and flexibility for being powered with gas, fluid, or both combined.[7] The impact drill was manufactured of Inconel 725 material. A 2.25 in. OD button-bottom bit was selected due to its historic success in removing tubing scale. The bit body was built of Inconel 725 material with tungsten buttons. A 1.687 in. OD wash tool was placed directly above the impact drill and was actuated by pumping a 0.5 in Teflon ball down the 1.5 in. OD coiled tubing. The total length of the bottomhole assembly (BHA) was 8.07 ft and was manufactured of Inconel material (Figure 3).

A generic project procedure is provided in Table 1.

Implementation

Equipment logistics and the surface injection & flow line configuration are displayed in Figure 4. Total on-site operation with coiled tubing equipment was approximately 50 hours.

Although water separation was being routed through an existing on-site two-phase separator and dumped into an existing water tank, a flare pit with approximately 200 bbls fluid capacity was excavated.

Continuos reservoir inflow was maintained throughout the coiled tubing operation phase of the project.

The BHA was installed on the coiled tubing and tested using nitrogen as the power media. Overpull checks were taken at various depths to ensure coiled tubing design limitations were not exceeded (Figure 5).

While running in the hole, excessive drag was encountered at 11,800 ft. This was believed to be caused from scale buildup in the area of the tailpipe assembly at 10,000 to 10,200 ft.

After encountering the excessive drag, the BHA was pulled uphole to 9,500 ft and pumping of fresh water combined with foamer and nitrogen for generating a 65 quality foam system was initiated. After making a wiper run through the tailpipe assembly containing the profile nipples and taking various overpull checks to 13,700 ft, water injection was stopped and the nitrogen rate was increased. Good foam continued to be returned to surface until a depth of 18,700 ft was reached.

A restriction was tagged at 21,167 ft which was three feet deeper than the depth restriction tagged by slickline operations in July 1993. Upon contact of the restriction, actuation of the impact drill was initiated with 400 lbs of weight being applied and the tool allowed to drill off to 200 lbs based on surface weight indicator readings.

Nitrogen was being pumped at 1,100 scf/min with a 1 bbl acid sweep pumped every 15 minutes. The acid sweep was to aid in scale restriction removal and to dissolve particles that might be present in the coiled tubing annulus. This process removed six scale intervals that ranged from 1 to 58 ft in thickness (Figure 6). Upon reaching PBTD at 22, 611 ft, a 0.5 in. Teflon ball was pumped downhole to close the impact drill and actuate the wash tool.

The perforated interval from 22,602 to 21,098 ft was acid washed with 2,000 gallons of a 65 quality foam acid system using the wash tool. Injection rates were .5 bbl/min of acid and 1100 scf/min of nitrogen. The BHA was pulled uphole to 10,200 ft while continually pumping nitrogen. From 10,200 to 10,000 ft, 1500 gals of acid with 500 scf/min nitrogen were pumped through the wash tool to remove any possible scale buildup across the tailpipe assembly. After completing this process, the BHA was pulled out of the wellbore while pumping a neutralizing solution. This solution consisted of 500 gals of potassium carbonate. Then the coiled tubing was displaced with 20,000 scf of nitrogen.

After removal of the coiled tubing from the wellbore, a stabilized flow rate of 9.3 MMcf/D against a backpressure of 80 psig was recorded prior to pumping a 160 bbl nitrified acid treatment down the production tubing. This treatment was performed to ensure near wellbore reservoir cleanup. The well was shut in for one-half hour and flowback of acid load was initiated. Within a 48 hour flowback period, full fluid recovery was accomplished and the well placed on production at a flow rate of 8.3 MMcf/D unloading 12-15 BWPD against a line pressure of 550 psig.

Results And Conclusions

1. The success of this project showed the technical capability and cost effectiveness of coiled tubing technology for deep gas well through-tubing underbalanced scale cleanout operations.

2. The development of reliable 100,000 psi minimal yield strength coiled tubing was a major factor that allowed this work to be accomplished.

3. An eighty-five percent (85%) cost savings which correlates to $736,000 was realized versus a comparable conventional methodology cleanout in the Gomez (Ellenburger) Field.

4. The overall methodology developed through this project is becoming a standard for deep well cleanouts in the Gomez (Ellenburger) Field.

Acknowledgments

The authors wish to thank Chevron U.S.A. Production Company and Cudd Pressure Control, Inc. for permission to publish this paper. We also thank BJ Services Company, U.S.A., "Hipp-Tripper" a subsidiary of Sonoma Corporation, and Quality Tubing, Inc. A special thank you is extended to Ed Lujan, Chevron U.S.A. Production Company, for his expertise and dedication to this project.

References

1. Tipton, S.M., "Surface Characteristics of Coiled Tubing and Effects on Fatigue Behavior," ICoTA/SPE2nd North American Roundtable, Apr 1-3, 1997.

2. Teel, M.E.: :Coiled tubing 1994: Enhanced value through innovation," World Oil (January 1994) 35-43.

3. Adams, L. and Marsilli, D.: "Design and Installation of a 20,500 ft Coiled Tubing Velocity String in the Gomez Field, Pecos County, Texas," paper SPE 24792 presented at the 1992 SPE Annual Technical Conference and Exhibition, Washington, DC, Oct. 4-7.

4. Adams, L. and Smith, L.: "An evaluation of Large Diameter Coiled Tubing for Subsurface Production Tubulars," Paper SPE 29456 presented at the 1995 SPE Production Operations Symposium, Oklahoma City, OK, Apr. 2-4.

5. Crouse, P.: "Economic and Risk Considerations for

Coiled Tubing Technology," presented at the 1995 3rd Annual International Management Conference on Coiled Tubing Technology and Applicaitons, Dallas, TX, Feb. 6-8.

6. *Coiled Tubing String Design*, Cudd Pressure Control, Inc. Engineering Documentation Manual.

7. Beynon, D. and Thompson, D., "Performance Comparisons of "HIPP-TRIPPER" Impact Drill-Jars with Convention Down-Hole Motors," 5th International World Oil Conference On: Coiled Tubing and Well Intervention, Houston, Texas, Feb. 4-6 1997.