Coiled Tubing Applications

Viewed from the wide perspective of the exploration and production industry, the coiled-tubing (CT) fraternity might be regarded as a relatively small group of fringe players who plastically deform pipe for a living. However, the truth is that CT has grown into a business generating USD 3 billion in revenue and has become an indispensable tool in many operating locations.

Like many emerging technologies, the first decade of CT's existence was mostly a struggle to stay alive; but having survived the challenges of the early years where pipe failure was a regular occurrence (Who doesn't remember a CT string inexplicably parting in a well and the subsequent fishing operation?), the industry changed gears and began to expand outside niche areas. In more than 3 decades of continuous development, we have seen CT materials reach an unprecedented level of manufacturing reliability such that premature pinholes have been virtually eliminated. As a result, pipe sizes have increased and strings have become longer, which in turn has propelled the technology in ever-increasing directions. Thirty years ago, a typical string weighed approximately 12,000 lbm, while today we routinely use strings weighing in excess of 60,000 lbm, with some of the larger strings tipping the scales at 120,000 lbm or more.

The technology has evolved from its traditional role of gas lifting and sand cleanouts to embrace such diverse applications as re-entry directional drilling, CT fracturing, multilateral stimulation, and grass-roots drilling to name just a few. The papers selected for this feature are designed to highlight just how far the technology has come and hopefully stimulate the reader along some new avenue of investigation.

Interestingly, many of the early adopters of this technology are still active in the field, having dedicated much of their working lives to both the advancement of the technology and the exploitation of such technology in new applications. I never cease to be amazed at their ingenuity, and I am confident that the next generation will continue the legacy of the pioneers. JPT

Coiled Tubing Applications additional reading available at the SPE eLibrary: www.spe.org

SPE 110382 • *"Case History: Application of Coiled-Tubing Tractor to Acid Stimulate Openhole Extended-Reach Power-Water-Injector Well" by Ayedh M. Al Shehri, SPE, Saudi Aramco, et al.*

SPE 106639 • *"16Cr Coiled-Tubing Field Trial at Prudhoe Bay, Alaska" by J.Y. Julian, SPE, BP plc, et al.*

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Coiled-Tubing Underbalanced Drilling in the Lisburne Field, Alaska

In 2005, BP Alaska began evaluating the application of underbalanced-drilling (UBD) technology as a method for drilling multilateral wells in the Lisburne field. The evaluation process was enacted as a response to slow rate of penetration (ROP) through the hard carbonate Wahoo formation; frequent total losses of drilling fluid when drilling conventionally; and poor understanding of the orientation, frequency, and effect of fractures on production.

Introduction

The Lisburne carbonate reservoir has approximately 2 billion bbl of original oil in place. The Wahoo formation, at a depth of approximately 8,900 ft true vertical depth (TVD), is tight, fairly thick (400 ft), and highly consolidated, with thin interbedded mudstone layers. Reservoir fluid is mainly oil with a gas cap covering a portion of the field. The gas contains approximately 60 ppm H_2S and 12% CO_2.

Previous drilling in the reservoir was overbalanced. Lisburne is a hard-rock carbonate with unconfined compressive strengths from 15,000 to 25,000 psi. Drilling problems include low ROP when drilling overbalanced and instability of the mudstone layers when exposed to water-based muds (WBMs). Production performance of the reservoir in general has been disappointing, with an oil recovery to date of only 8% because of low matrix permeability and excessive gas production. It is apparent that the formation is fractured and that intersection of effective fractures is critical to well performance. Wells that have intersected significant fractures have been among the better performers.

In a bid to intersect more of the fractures, BP Alaska had attempted through-tubing coiled-tubing (CT)

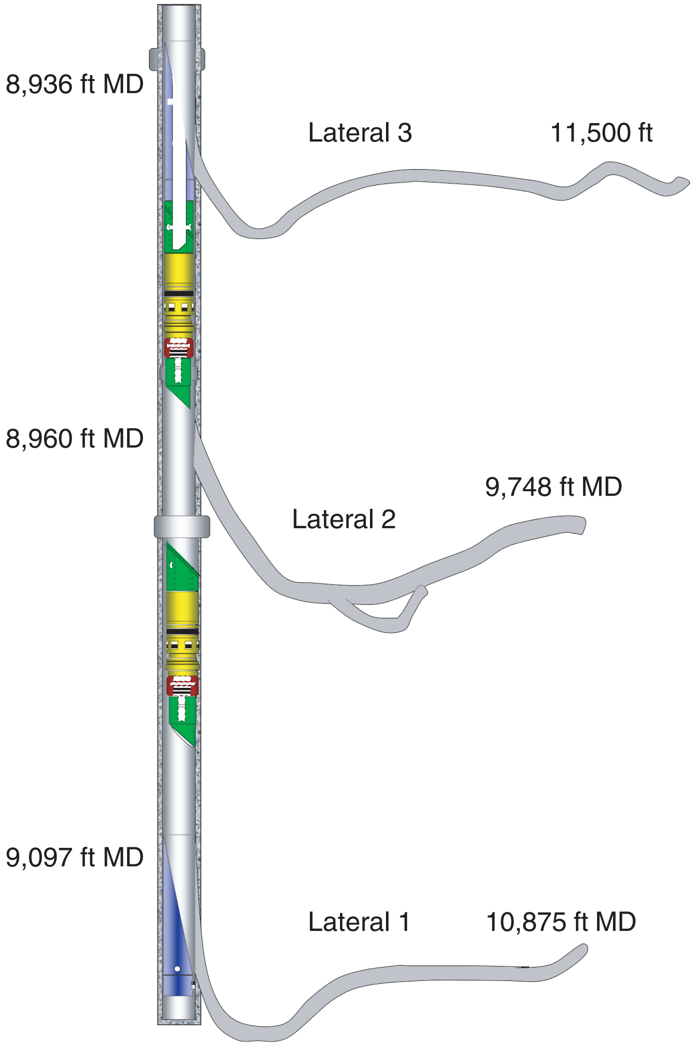

Fig. 1—Second UBD sidetrack well.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 108337, "Coiled-Tubing Underbalanced-Drilling Applications in the Lisburne Field, Alaska," by ***Mark Johnson,*** *SPE, BP;* ***Patrick Brand,*** *SPE, Blade;* ***Sam French,*** *SPE and* ***Greg Sarber,*** *SPE, BP;* ***Dave Hildreth,*** *SPE, Orbis;* ***Bob Harris,*** *SPE, Baker Oil Tool;* ***Pedro Rangel,*** *SPE, Schlumberger;* ***Udo Cassee,*** *SPE, Nordic; and* ***Jimmy Clark,*** *ASRC, prepared for the 2007 IADC/SPE Managed Pressure Drilling and Underbalanced Operations Conference and Exhibition, Galveston, Texas, 28–29 March. The paper has not been peer reviewed.*

sidetracking, placing single horizontal laterals in the carbonate sections. Production-performance delivery of these wells has been 50% successful, prompting consideration of other alternatives. One of the main alternatives considered was through-tubing CT-UBD sidetracks. The idea was to place multiple laterals from a single main wellbore within the carbonate sections, thus increasing exposure and avoiding the potentially unstable mudstones. The main motivation for UBD was to improve ROP and eliminate drilling problems associated with overbalanced operations.

Engineering and Design

The preliminary well planning and basis of design was started in February 2005. Typical well information was used to determine if UBD was feasible. The main design constraint was a surface pressure of 600 psi (later increased to 650 psi), so that production could be sent directly from the separator to the pipeline to eliminate flaring.

Either brine or diesel could be used for the power fluid with 2-in.-outside-diameter (OD) CT, but only diesel gave an acceptable window for $2^3/8$-in.-OD CT.

Multiphase-Flow Modeling. A commercially available UBD hydraulics-modeling program was used to perform multiphase modeling on the generic well. The preliminary modeling showed that underbalanced conditions with no flow were not a problem with 2-in.-OD CT and diesel as the drilling fluid. With inflow, UBD also would not be a problem, but could be limited by the number of fractures that are encountered.

The modeling also showed that hole cleaning would be a problem in the 7-in. casing, below the tubing and above the window. To mitigate this potential problem, the decision was made to install a $4^1/2$-in. scab liner across the 7-in. casing to eliminate low-velocity sections in the wellbore and provide additional isolation from high gas production from main-wellbore perforations.

The most UBD operational flexibility existed when 3-in. bicenter hole was drilled with a $2^3/8$-in.-OD drilling bottomhole assembly (BHA) on 2-in.-OD CT. This hole and CT size enabled the practical use of diesel as a drilling fluid, recognizing supply constraints, and also provided a greater margin of underbalance capability should water have to be substituted as the drilling fluid.

Weight-on-Bit (WOB) Modeling. To evaluate the drillability of the proposed directional plans, drag modeling was performed to estimate available WOB vs. measured depth. However, historical friction coefficients based on overbalanced drilling with a WBM probably would not be accurate when compared to the diesel drilling fluid planned for Lisburne. After some research, two cases were presented for each directional-well plan: a worst-case scenario using 0.3 and 0.4 friction coefficients for tubing and open hole, respectively, and a best-case scenario using 0.2 and 0.3. The latter case was based on previous experience with service CT operations where diesel with a drag-reducing additive (DRA) and gas lift assist was used in fill cleanouts. It was determined that the UBD program needed to achieve the lower friction coefficients to reach the targeted total depths.

Whipstock Development. One of the objectives of the project was to be able to re-enter each lateral selectively. To meet this objective, a whipstock was developed for the project that consisted of a packer and tail pipe and a replaceable tray.

The packer and tail pipe allowed a plug to be set to isolate the laterals after they were drilled. This ensured that the formation was protected from any accidental overbalance incident while drilling subsequent laterals. It also eliminated the frictional pressure loss caused by producing previously drilled laterals.

Fluid Selection. The liquid phase for an underbalanced project may be either an oil-based or water-based system. Oil-based systems have the advantage of having a lower density, which requires less gas to achieve a lower density. Oil-based systems have the disadvantage of toxicity and flammability.

Diesel was selected as the power fluid primarily because of the lower density, allowing a larger operating margin for underbalanced operations. Another major advantage with diesel was the mitigation of mudstone-instability problems. These mudstones tend to disperse into WBMs, causing significant ledging and lost-hole problems. Diesel also eliminated concerns with emulsions that could cause upsets at the Lisburne plant, and mitigated corrosion, emulsions, and hydrates concerns. The biggest disadvantage with diesel is availability. There is a limited availability of diesel on the North Slope, and the only excess capacity occurs in the summer months. This limited the trial to June through the middle of August.

Lift Gas. To lighten the fluid head and achieve underbalanced conditions, field-gas lift gas was injected down the inner annulus and entered the $4^1/2$-in. production tubing through a deep gas lift mandrel. This source of gas was readily available on the North Slope and a purpose-built control skid provided desired gas rate and pressure to the well. The presence of H_2S in gas lift gas and produced fluids required a significant amount of hazard-risk mitigation, identified early in the planning of the program.

Fluid Additives. To facilitate separation at surface, UBD fluids normally are clear fluids, with low viscosity. The only additives required for the project were corrosion inhibitors and friction reducers.

For the diesel drilling-fluid system, it was felt that the diesel would provide sufficient protection from corrosion. A DRA was added to reduce pump pressure, and lubricants were added to reduce hole friction. Mineral-oil sweeps were used to clean the hole as required.

Equipment Selection. To minimize surface-kit size in the harsh cold-weather environment of the North Slope, a locally available portable test separator was used for the Lisburne CT-UBD project. Additional equipment included diesel-storage tanks and a heater, to mitigate potential problems with hydrates and emulsions.

Equipment Layout. The equipment layout was controlled by the hazardous-areas constraints adopted for the project. A Zone-2 area, defined as a 60-ft radius around each of the wells, had restricted access. An additional 150-ft zone was defined around the

well that was being drilled. This area was to be clear of any potential ignition sources.

Training

There were three levels of training given for the Lisburne project. All critical decision makers, both office- and field-based, were given 2 days of CT-UBD scenario training. This included both classroom training and simulator exercises depicting problem scenarios that could develop during the trial. All field personnel underwent a project-orientation course. This highlighted the key risks of the project, discussed roles and responsibilities, introduced the crews to the standard and emergency procedures, described the equipment being used, and highlighted the importance of communication. The orientation was followed with a tour of the equipment.

Implementation

Workover Phase. Two wells were worked over in batch mode. The production tubing was pulled, and the original perforations were cemented. Numerous cement squeezes were required to isolate the old perforations. The new monobore completion consisted of a $4^1/2$-in. scab liner and $4^1/2$-in. production tubing. The production tubing included a tubing-retrievable surface-controled subsurface safety valve at 2,000 ft and gas lift mandrels. During the workover phase, the UBD equipment was spotted and commissioning began. Final inspections and audits were performed before the authorization to proceed was given.

Drilling Phase. *First Well.* Before sidetracking, static reservoir pressure was measured to be 3,512 psi at 8,900 ft TVD in the first well.

Lateral 1. Final live gas-rig training was conducted for all crews before milling the casing for the first lateral. Once crew competency was assured, the first window was milled at 10,732 ft measured depth (MD) to a 3.80-in. inside diameter (ID) and UBD of the 3-in. open hole commenced. As planned, drilling started with a 2% potassium chloride (KCl) fluid to mitigate risk until the crews gained comfort in the operations. Similarly, the well was killed for the first trip (all subsequent trips were performed live using pressure-deployment/-undeployment techniques).

The preliminary drilling with the 2% KCl was disappointing because the target ROP improvement was not met. Injection rates ranged from 1.5 to 1.6 bbl/min of liquid, with gas-injection rates from 3.0 to 4.5 MMscf/D for a bottomhole pressure (BHP) between 2,487 and 3,350 psi.

After the crews gained confidence, the fluid system was switched to diesel. Problems with weight transfer to the bit were overcome by experimenting with additions of DRAs and use of an agitator. Drilling parameters ranged from 1.5 to 1.7 bbl/min, with gas-injection rates ranging from 3 to 4 MMscf/D for a BHP between 3,000 and 3,300 psi. Production rates between 0.3 and 0.5 bbl/min were noted while drilling.

The lateral reached a planned total depth (TD) of 12,800 ft. The well was tested before setting the whipstock for drilling the next leg. Following the flow test, significant paraffin was noted on the pipe. Several runs were required to clear the wellbore of paraffin before proceeding.

Lateral 2. The second lateral was drilled from 10,707 ft to a TD of 12,532 ft. Initial conditions were 1.7 bbl/min of diesel, with 3 MMscf/D of lift gas for a BHP of 2,900 psi. Lift gas was turned off on this lateral when production was sufficient to achieve underbalanced conditions without the aid of lift gas. The well was tested at TD. Paraffin problems occurred again following the flow test, causing additional lost time.

***Second Well.* (Fig. 1)** Before sidetracking, static reservoir pressure was measured to be 3,177 psi at 8,900 ft TVD in the second well.

Lateral 1. During the rig move, the annular element was found to have degraded during drilling of the first well. The element was changed during the move.

The whipstock was set and the window milled. The lateral was drilled from 9,907 ft to a planned depth of 10,875 ft. Diesel pump rates were between 1.5 and 1.7 bbl/min, with gas-injection rates between 3.5 and 4.5 MMscf/D for a BHP between 2,800 and 3,300 psi. The lateral was flow tested, and the well was prepared for the next lateral.

Lateral 2. Because of problems not associated with this project, the source of diesel was lost. The decision was made to continue with the project using a 2% KCl brine as the drilling fluid. The second lateral was drilled from 8,960 to 9,748 ft. Brine pump rates ranged from 1.6 to 1.7 bbl/min, with gas-injection rates from 4.0 to 4.5 MMscf/D for a BHP between 2,850 and 3,350 psi. Following a trip for a BHA change, it was not possible to pass a mudstone at 9,408 ft. Multiple attempts to pass the mudstone failed. The decision was made to abandon this lateral and sidetrack to avoid the problem zone.

Openhole Sidetrack. An openhole sidetrack was performed at 9,260 ft. The lateral was drilled to a depth of 9,370 ft. After a wiper trip to the window, it was found that the bit would not pass a mudstone previously drilled at 9,122 ft. The decision was made to abandon the lateral and move up the hole.

Lateral 3. A new window was cut higher in the well to avoid the troublesome mudstone. The final lateral was drilled from 8,936 to 11,500 ft. Pump rates ranged from 1.5 to 1.7 bbl/min, with gas-injection rates from 4.0 to 4.5 MMscf/D for a BHP between 2,850 psi and 3,350 psi. Gas injection was stopped when contribution from a fracture at 10,300 ft allowed underbalanced conditions to be maintained without injection. The lateral was tested. The whipstock trays and packer plugs were pulled, and the guidestock tray was set.

Conclusions

The Lisburne CT-UBD trial demonstrated that UBD could be implemented successfully while meeting the strict environmental and safety standards of the North Slope. No safety incidents occurred during the complex high-pressure operations. More than 14,000 bbl of oil was produced from the wells while drilling. Reservoir characterization based on production while drilling pointed out the faults, fractures, and fluid-entry points along the laterals. The drilling ROP more than doubled, and a record Lisburne CT drilling horizontal length of 2,564 ft was achieved. A novel completion design with retrievable whipstock trays and custom packers allows complete near-wellbore control of all five laterals drilled in the two wells. The UBD pilot proved a technology that may help deliver additional oil resources from the Lisburne field. **JPT**

CT-Failure Causes: A Decade of Experience

The full-length paper reviews a decade of tracking coiled-tubing (CT) failures and their causes and sets the results against the perspective of the changing nature of the business over the same time period. Critical factors for reliable CT service-life performance are identified, and whether reliability is higher today than a decade ago is examined.

Introduction

Since the beginning of 1996, all early CT-string failures experienced in company operations have been examined to identify cause of failure. The results of these examinations are recorded in a database to enable historical tracking, so trends can be observed and appropriate policy or procedural changes made. The full-length paper presents data captured from 1997 through 2007. Early failures are those that are experienced before the safe working life of a CT string has been fully consumed. Very few strings are used until they reach their maximum-allowable safe working life, and, therefore, this database basically captures all string-failure data.

The database contains information on more than 250 failure investigations. During the same period, more than 2,200 CT strings were in service, performing approximately 60,000 jobs, using an average of 138 CT units, with both land and offshore operating locations.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 113676, "CT-Failure Monitoring: A Decade of Experience," by ***A.R. Crabtree,*** *SPE, BJ Services, prepared for the 2008 SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Texas, 1–2 April. The paper has not been peer reviewed.*

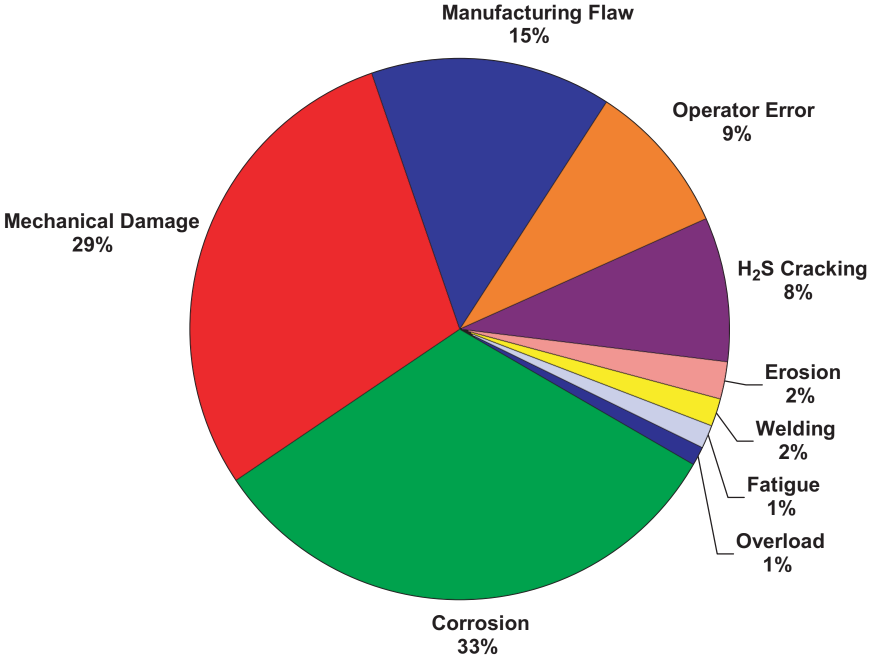

Fig. 1—Failure by cause, 1997–2007.

Research into the low-cycle fatigue performance of CT conducted since the early 1990s has resulted in predictive algorithms and fatigue-management software. This, combined with improved string-manufacturing techniques, has all but eliminated most pure cyclic-strain-induced fatigue failures (i.e., fatigue not associated with secondary mechanisms such as corrosion).

Data Overview

Examination of all the data **(Fig. 1)** shows that the leading reasons for early failure are dominated by five main classifications: corrosion, mechanical damage, manufacturing flaws (or defects), operator error, and hydrogen sulfide (H_2S) cracking. These groups account for approximately 94% of all failures.

Reviewing the overall data and superimposing the number of jobs per year **(Fig. 2),** it can be seen that the number of failures appears to be proportional to jobs performed. This would seem to indicate that the failure rate (jobs performed/number of failures) has not improved. However, this is not the case because the chart belies the underlying numbers. In fact, the failure rate from 2000 through 2007 improved 47%. The year 2003 was anomalous and is a result, in part, of an increase in the CT fleet in the later portion of 2002, leading to the addition of several new CT strings being used in 2003.

From 1997 through 2007, the job count increased by 30%, but the unit count increased by 65%. Use, in terms of days/year the equipment is deployed

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

in operations, has remained almost constant. This implies that individual jobs are of a longer duration and more difficult than previously. This also is borne out by examining the mix of strings used. While the most prevalent CT size used is still 1^1/2 in., there has been a shift to the larger-diameter strings, with 1^3/4- and 2-in. strings becoming commonplace. Similarly, over the decade, there has been a move to the higher-strength grades. The 80,000-psi specified-minimum-yield-strength (SMYS) grade is still the most frequently purchased, but a much higher proportion of the mix today is composed of the 90,000 and 100,000+ psi SMYS grades.

Another indicator of the changes in strings being used today is that the average string length has increased from 12,700 ft in 1997 to 16,960 ft in 2007.

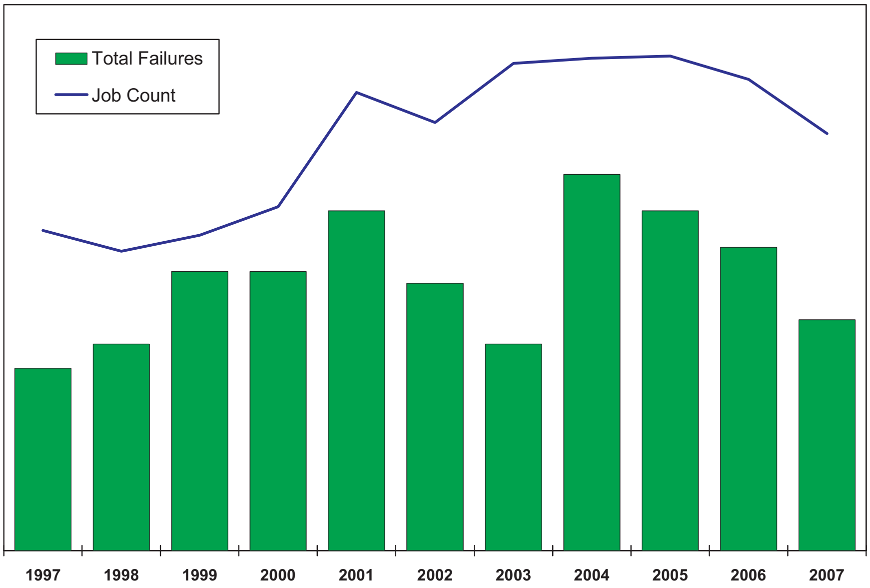

Fig. 2—Failures and jobs per year.

Failure Classification

Corrosion Failures. Corrosion failures can be subdivided into those resulting from corrosion occurring during storage of the string and those as the result of acidizing work performed with the string. Storage corrosion has been a consistent issue in failure prevention. As would be expected, the locations that have suffered most with this issue are offshore operations. In one major operating location where brines and seawater are not routinely pumped through operational CT strings, there has been only one storage corrosion failure in the previous 11 years. However, since the introduction of preventative procedures at these locations, the incidence rate has fallen.

Acid-based corrosion is influenced by the nature of the operation and the duration of exposure to the acid. Throughout the period under consideration, the same standard for determination of inhibitor schedules has been used. However, the type of work has changed in that the CT string often is left in the well during acid displacement into the formation, soak period, and flowback. In earlier years, the CT often was used only to spot the acid at the desired location within the wellbore and then was extracted. The increased exposure time, and the change in operational sequences, means that the criteria used to determine an appropriate acid-corrosion-inhibitor loading have been modified. Additionally, the job procedures were modified to help limit the tubing exposure to acid, spent and unspent, during the job. These changes have occurred in the last few years and seem to be resulting in a reduction in failures of this nature.

Mechanical Damage. Damage to the CT accounts for approximately 30% of failures and originates from many sources. These failures can stem from the CT surface equipment or from damage caused while running into and out of the well. Damage from CT equipment can occur at the reel, gooseneck, or injector. Sometimes this is from equipment misuse or from mechanical-equipment failures, such as when loose, broken items find their way onto the pipe and are pressed into the surface of the CT by the injector chains. Mechanical damage of this latter type can cause a CT fatigue-life reduction of approximately 75%. Mechanical damage is approximately evenly divided between that caused by surface equipment and that caused in the well.

The fundamental CT-unit design has not changed over the last 10 years, but the tubing deployed has increased in diameter and strength grade. This imposes greater equipment loads. Mechanical-damage failures have occurred on 57% of strings with a diameter greater than 1^1/2 in. Since 2000, this frequency has increased to 70%. There was no other discernible trend in this particular data set.

Manufacturing Flaws. Manufacturing flaws, or defects, are a result of a problem with either the steel-manufacturing or the tube-manufacturing process. The former usually takes the form of undissolved inclusions in the steel, and the latter is usually a problem with welds performed to form the tube, either the seam weld or the bias weld.

Since 2001, there have been no failures recorded that were the result of steel-manufacturing issues. This may be a result of tighter quality controls, imposed both by the steel manufacturers and by the tube mills.

The predominant failure mechanism in tube manufacturing has been with seam-welding problems. These can be divided into two broad subcategories: inclusions in the weld and lack of fusion. Inclusions in the seam weld usually are a result of the slitting process wherein the master coil is cut into the widths required for the strips that will be formed into the tubing.

Inclusions also can be a result of the edge preparation or dirt in the tube plant. Lack of fusion is a failure of the seam-welding process, usually at discrete points, to weld the two edges of the strip together fully. Both of these failure mechanisms do not tend to become apparent until a CT string has

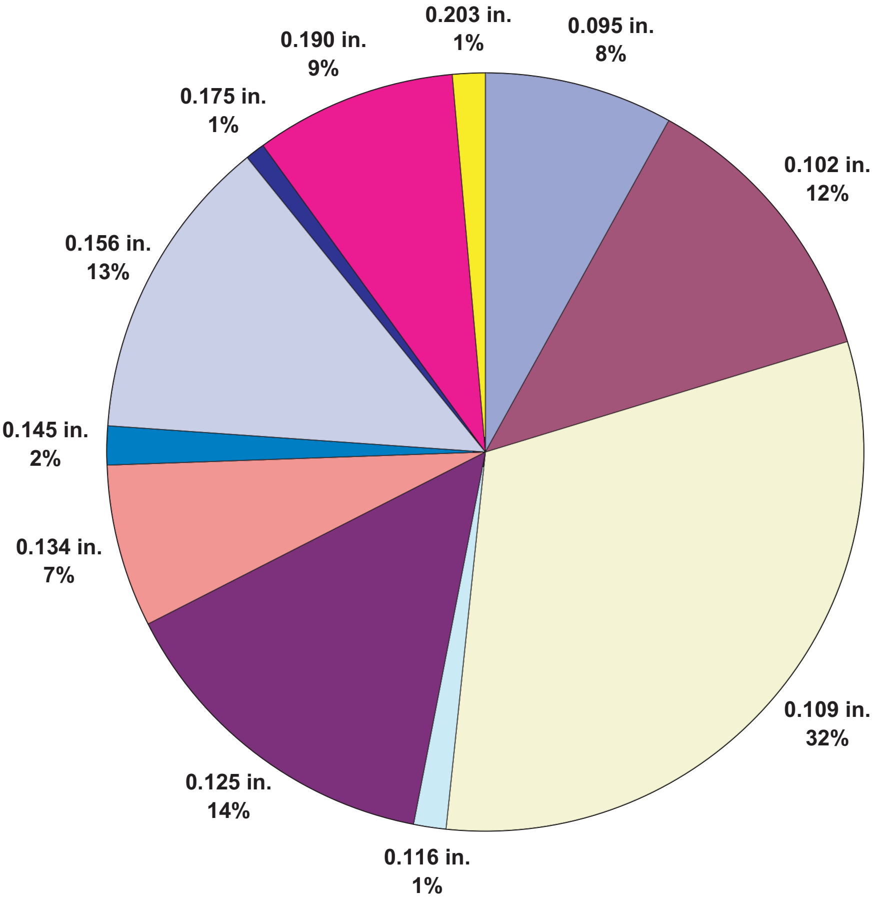

Fig. 3—Wall thickness as a proportion of total failures.

been in service for sometime because it takes a finite time for the weakness in the weld to initiate and propagate a crack through the weld.

What is readily apparent is that there was a marked increase in 2007 after 5 years of consistent occurrences. In 2006 and 2007, the demand for CT strings was very high, forcing delivery times to increase to as much as 9 to 10 months. All of the manufacturing flaws experienced in 2005, 2006, and 2007 were a result of a lack of fusion in the seam weld. This reflects the efforts that the tubing manufacturers have made with their suppliers to improve the quality of the slitting and edge-preparation processes.

Operator Error. Generally, operator error results in the CT being overloaded in some manner, resulting in buckling and/or parting of the tubing. During 2003–06, there was a demographic shift in experienced CT personnel, with operators and supervisors in short supply. This caused the annual turnover rates of these staff to shift from 15% to 100% in some locations. This reduction in field experience is reflected in the failure statistics.

H_2S Cracking. Sour cracking was a major issue in the early part of the 2000s and has since declined. This is a direct result of intensive sour-service studies conducted throughout this period. These studies have led to changes in job procedures and programming.

Fatigue. While the full-length paper does not provide an in-depth analysis of fatigue failures, it is worth noting that there has been an unusual fatigue-failure recorded. This fatigue failure was unique in that the failure mechanism was one that had not been observed previously and, therefore, was not captured in existing modeling software. Failure occurred at approximately 30% of the predicted safe working life. Fatigue studies were performed to examine and delineate this phenomenon more fully, and it has since been added to the software models.

Other Influences

Aside from examining the direct causes of failures, it is worth examining if there are any other underlying factors. There has been a trend toward the use of larger-diameter, heavier-wall, higher-grade, longer tubing strings over the last decade. CT strings not only are more expensive, but the average cost of a CT string in 2007 increased by 85% compared to one of the same specification in 1997. Before 1998, CT prices had remained reasonably stable.

CT Pricing. Fig. 9 in the full-length paper illustrates the cost of a typical tapered $1^3/4$-in. CT string. During this time, the manufacturing cost has increased similarly, but not to the same extent. During the period, steel prices increased by 68%, Texas industrial-electricity supply by 41%, and Houston labor cost by 26%. Weighing these factors accordingly would indicate that the effective cost of materials has increased by 54%. Therefore, the gross margin would appear to have increased in the intervening decade. Steel prices over the decade have been volatile, and CT steel commands a higher price. However, it would appear not to be subjected to the same volatility and has fluctuated only by approximately ±6% around a median price for the eight quarters between third quarter 2004 and second quarter 2006.

CT Wall Thickness. No clear evidence was found that any wall thickness has any greater susceptibility to early failure. Clearly, some wall thicknesses are more common in the data **(Fig. 3),** but their frequency is only consistent with the mix of strings being purchased. This also held true when inspecting the data for individual years.

CT Strength Grade. The proportion of failures by CT grade also appears to be in agreement with the mix of grades purchased over the period. However, a closer examination of the failure rate, in this instance defined as the ratio of strings in service to those that failed demonstrates that there has been an improvement in the performance of CT strings rated to 100,000+ psi and a significant improvement in 90,000-psi-grade CT strings. Conversely, there is a considerable decline in the performance of 80,000-psi strings. Interestingly, a large proportion of these failures resulted from a lack of fusion in the seam weld.

The decrease in performance of the 70,000-psi grade could not be evaluated because the sample is statistically insignificant for 2007. The 2005 ratio (2006 was also statistically insignificant) for 70,000-psi grade evaluates to a failure rate of 10 and is indicative of a slight decline in performance.

CT Diameter. There has been a general shift toward larger-diameter strings, and more of these larger-diameter strings are subject to failure. Again, appearances can be deceptive. It transpires that $1\frac{3}{4}$-in.-outside-diameter strings have a failure rate 2.5 times that of $1\frac{1}{2}$-in. strings. Similarly, 2-in. strings are four times and $2\frac{3}{8}$-in. strings are two times that of $1\frac{1}{2}$-in. strings. These ratios have fluctuated during the period under review, but there always has been a greater failure rate among the larger string diameters.

Land and Offshore. There are considerably more jobs per unit performed by land-based CT units compared to offshore units; a ratio of 10:1 is typical. It is not surprising, therefore, that the greater proportion of string failures occurs on land-based equipment. However, the failure rate for land-based strings is far less than for those working offshore. This ratio has a high variability, but the trend is consistent. One aspect that is not captured easily with the fatigue database is the turnover ratio of string inventory in the various operating locations. But with the lower job count per unit offshore, it is reasonable to surmise that strings in these locations have a lower turnover rate. This influences how likely a string is to undergo degradation.

Fatigue. The majority of strings fail before 75% of the safe working life has been consumed. While the amount of fatigue life consumed by a string before failure tends to be a function of the nature of the final failure mode, it is nonetheless an overall indicator of the stewardship the string has received. This proportion has not changed during the decade. **JPT**

Resources

State-of-the-Art Coiled-Tubing Operations at Prudhoe Bay, Alaska

The full-length paper details a field trial of coiled tubing (CT) with an installed fiber-optic line. More than 150 fiber-optic CT (FOCT) operations have been performed successfully at Prudhoe Bay and Kuparuk, Alaska. Cementing, perforating, fishing, milling, and other operations were conducted successfully during the 2-year field trial.

Introduction

Prudhoe Bay, with its long history of innovative CT intervention, continues to push the limits of CT technology as its wells become increasingly complex. Daily operations with three 24-hour/day CT units allow a quick pace for technology development. Multilateral and ultraextended-reach well-intervention capability is the primary push for developing new CT technology. Wells are being drilled that are deeper, farther, and harder to work on than at any other time. Although many of these are designed to be “interventionless,” history suggests that at some point in the life of the well, intervention will be required.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 11533, “State-of-the-Art Coiled-Tubing Operations at Prudhoe Bay, Alaska,” by ***J.Y. Julian,*** *SPE,* ***T.L. West,*** *SPE,* ***K.E. Yeager, R.L. Mielke, J.N. Allely,*** *SPE, and* ***C.N. Jenkins,*** *SPE, BP plc;* ***P.D. Perius, R.L. Bucher,*** *and* ***C.I. Foinquinos,*** *Schlumberger;* ***K.C. Forcade,*** *SPE,* ***J.A. Fagnant,*** *and* ***D.B. Montgomery,*** *Orbis Engineering;* ***J.G. McInnis,*** *ASRC Energy; and* ***J.K. Sack,*** *SPE, Petrotechnical Resources of Alaska, prepared for the 2007 International Petroleum Technology Conference, Dubai, UAE, 4–6 December. The paper has not been peer reviewed.*

FOCT

One of the most exciting technology developments in recent years is intelligent CT with fiber optics. The fiber-optic line is encapsulated inside a 0.071-in.-outside-diameter (OD) inconel tube that is pumped through a standard CT reel.

The FOCT and a downhole sensor package convey real-time depth, temperature, and pressure at the downhole end of the CT. These measurements can be used to make informed decisions with actual data, rather than inferring downhole conditions on the basis of surface data such as CT pump pressure and wellhead pressure. The system consists of surface electronics, modular tool strings, and software.

The system provides real-time accurate depth correlation using a casing-collar locator (CCL) and downhole temperature and pressure monitoring (both inside and outside the CT). Distributed temperature sensing (DTS) also can be obtained, allowing temperature readings at 3-ft intervals along the entire length of the CT.

Data are transmitted from the tool string up the fiber-optic line to an electronics package that converts the fiber-optic signal to a wireless signal, allowing communication to the control cab. The data are displayed by a command-and-acquisition software program and can be viewed remotely.

FOCT Tool String. The FOCT tool string obtains CCL data and measures CT downhole pressure, downhole production-tubing pressure, and downhole temperature. The fiber-optic connection can be blanked off during CT operations that do not require its use.

The tool string is 2^1/8-in. OD with a 0.688-in. minimum restriction. Field data show that the restriction has no effect at typical CT pump rates. Ball-operated tools can be run below the tool string, which can pass a ball as large as ^{5}/8 in.

The tool string is approximately 7 ft long and is rated for 12,500 psi differential pressure and 60,000 lbf tensile load.

North Slope Field Trials

A recirculation loop was set up for the fiber-optic tube installation. Once the tube is injected into the CT, the reel is installed on a standard CT unit and drifted with a ^{5}/8-in. ball. To date, four 1^3/4-in.-OD reels have been deployed on the North Slope. More than 150 operations have been performed in the 2-year field trial, which continues at present. Not all of these operations have used the fiber-optic capability. The four reels have had 400,000; 542,000; 582,000; and 548,000 running footage (RF) with 130 operational days. RF is defined as the distance run into a well, not the round-trip footage. The FOCT unit typically performs an average of six to seven operations per week.

Operations were performed in vertical, horizontal, and multilateral wells. Interventions included CT cleanouts (with and without nitrogen), sand plugs, acidizing (with wax bead diversion), ice-plug removal, fishing, perforating, cementing (with aggregate), milling, and DTS surveys.

Fluid Compatibility. During the field trial, fluids pumped included water, gels, diesel, methanol, cement with lost-circulation material, sand and calcium carbonate ($CaCO_3$) slurries in gel, and hydrochloric and hydrofluoric acids.

Field-Trial Highlights. The first FOCT reel deployed in Alaska performed an average of six operations per week. It had 32 continuous operational days and performed a variety of CT opera-

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tions, including pumping acid stimulations, performing drift runs, fishing, making junk-basket runs, logging, perforating, milling, performing cleanouts (with and without nitrogen), removing ice plugs, and performing multilateral-well interventions.

The second reel continued to exploit the benefits of the real-time CCL and was used for lateral recognition in a multilateral well. The CCL also was used to create a jewelry and correlation log in a multilateral well and set a whipstock for a CT-drilling sidetrack. As confidence with the robustness of the system increased, the string was used to place a sand plug and perforate a deviated well.

The third reel performed 40 days of continuous operations, averaging seven operations per week. The tools passed the 1-million-RF mark. The string was used to place a sand plug, followed by a cement squeeze. The cement included aggregate, a type of particulate lost-circulation material. Perforating success continued, with operations in a horizontal well and six continuous runs to add 125 ft of perforations. The CCL was used to create a depth-correlation log for a lateral into the multilateral mainbore.

Additionally, FOCT was used for diagnostics, and a temperature log identified water breakthrough in a multilateral well. In the same trip, a water-shutoff operation was performed using $CaCO_3$ to shut off the water breakthrough zone. Although the operation was unsuccessful, it demonstrated the ability of the system to diagnose and remediate in a single trip.

Depth Control and Perforating. To date, the primary benefit of FOCT has been its accurate depth control. Depth correlation is easily accomplished "on the fly" and can improve operational efficiency for extended perforating intervals. It also reduces CT RF because extra tie-in runs with a memory CCL or tubing-end locator are not required. This is particularly important in Alaska where high-angle and horizontal wells are common, and wireline and slickline often cannot reach target depth because of deviation. Depth control often is critical, and conventional CT must make additional trips with a memory CCL tool string for depth correlation. At Prudhoe Bay, memory CCLs are rerun every three to four perforating runs to ensure accurate depth correlation. This results in additional RF and time, which can be significant for long horizontal wells.

Typical gun lengths at Prudhoe Bay are 30 ft. The use of the FOCT tool string decreases the maximum gun length to 25 ft.

Additionally, average CT life has been severely shortened as a result of the abrasive chrome tubulars that have replaced half of Prudhoe Bayís completions. Minimizing RF in chrome tubulars by eliminating extra runs can have significant cost and efficiency benefits. Correlation logs are available electronically or as hard copy and can be viewed remotely in real time.

Generally, collar identification is more difficult in chrome completions, especially for large-diameter tubulars. FOCT CCL has proved to be as sensitive as a same-size wireline CCL, and there has been no significant CCL signal difference in carbon-steel or 13Cr completions. The CCL is so sensitive it has detected perforation holes. The FOCT software allows the CCL sensitivity to be changed during operations.

It has been observed that the CT does not always enter the wellbore consistently every trip. Depth correction ranges from 0 to ±4 ft on subsequent runs after initial depth correction has been made. This underscores the fact that real-time CT depth correlation is beneficial on depth-critical operations.

The FOCT CCL also has been used to observe the difference in CT stretch between an empty CT string and a fluid-packed string. Stretch calculation predicted 6 to 7 ft, and the CCL log indicated 7 ft of actual stretch.

CT Cleanouts. In addition to the benefits of accurate depth control, real-time downhole temperature and pressure (inside and outside the CT) data can also assist with optimizing cleanouts, particularly in low-bottomhole-pressure (BHP) wells. Downhole data measurements can allow accurate modeling for cleanouts.

During a cleanout, small "bites" of fill are taken and swept up the tubing. As additional fill is circulated up the tubing, it is important to monitor hydrostatic head to avoid lifting too many solids. This can lead to excessive overpull or, in the worst case, stuck CT. Real-time downhole pressure data can help determine the optimal penetration rate into fill.

Downhole pressure data can be used to calculate friction loss to monitor cleanout-fluid rheology performance and consistency between batches. Real-time BHP eliminates the need for accurate friction calculation.

For low-BHP wells, real-time downhole pressure data can be used to determine if nitrogen is required and the optimum amount. During foam cleanouts, foam quality can be calculated and controlled with actual downhole temperature and pressure data to ensure optimum liquid-/nitrogen-rate combinations.

Cement Operations. Cement-squeeze operations are one of the costliest and most complicated procedures performed by CT at Prudhoe Bay. There have been no problems pumping 15.8-lbm/gal Class G cement systems (with and without aggregate lost-circulation material) through FOCT.

Temperature is a critical parameter in ensuring that the cement blend is designed with the correct fluid loss and filter-cake thickness. This is particularly true for wells with higher bottomhole temperatures. An incorrectly estimated temperature used in the laboratory to qualify a cement blend can result in substandard cement quality, which can compromise the operation. In the worst case, if actual temperature is higher than the predicted temperature, the cement may set up prematurely in the wellbore. Real-time temperature can verify downhole conditions.

In addition to temperature, real-time CCL data also are often beneficial during cementing operations. Often, a sand plug or composite plug is set to protect lower perforation intervals from cement contamination. Accurate depth correlation is critical if the acceptable depth window is small.

Conclusions

FOCT technology is one of the most promising and exciting developments in CT-technology development, particularly for multilateral intervention. The field trial proved many applications of the current FOCT tool string. As proved in the multilateral-intervention example, tool string configuration alone is not always sufficient to ensure passage through the lateral junctions, even with extensive shop testing. The real-time CCL can confirm where the tool string is in the wellbore, making FOCT particularly beneficial for multilateral interventions. JPT