Usage and Performance
of
Ener-Core Lined Tubing
by
Fletcher Challenge Energy Canada Inc.
in the
Consort / Provost Area

Prepared By

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Performance of Ener-Core Tubing in Fletcher Challenge Energy Canada Inc.'s Wells in the Consort / Provost Area

INTRODUCTION

Fletcher Challenge Energy Canada Inc. operates a large number of heavy oil wells in the Consort / Provost area. Typically these are Dina (Basal Quartz / Ellerslie equivalent) sand wells. Initial production had high oil cuts but water breakthrough has occurred and water cuts of 95 to 99% are common. Wells are produced using progressive cavity pumps. Wells pump from 50 to 250 m3 fluid per day with pump speeds up to 350 RPM. A number of the wells are deviated or horizontal. The produced brine is quite corrosive and this tendency is exacerbated by up to 8% CO_2 in the well gas. Chemical inhibition of the corrosion was ineffective due to the high volumes of fluid produced and / or too expensive to implement.

Producing challenges in this area include the need to control operating costs on low oil production wells and the need to lift large volumes of fluid to produce economic oil volumes. Internal tubing corrosion has resulted in a high number of failures. Additional failures have occurred as a result of rod corrosion and rod wear on PC pumped wells. At high RPM, in some wells, mechanical stresses have resulted in failures of the tubing couplings. On one well, which was equipped with a packer, the tubing was broke into four lengths before the rods finally failed.

A number of remedies have been attempted including rod centralizers, various vibration dampers, packers and alternative tubing anchors without a great deal of success.

In 1998, Enerline Restorations Inc. approached Fletcher Challenge to try several strings of high-density polyethylene lined Ener-Core tubing in some of the worst wells. To date, there have been no "in-service"** tubing failures and rod failures have been significantly reduced. No corrosion failures of the tubing string have occurred; even in wells that previously had corroded tubing strings to junk in twelve months. Fletcher Challenge currently has approximately 45 wells currently using Ener-Core tubing. More wells are being equipped with Ener-Core tubing each month including some new completions.

**Two separate Ener-Core tubing failures have occurred. In each case, used tubing was internally lined. Inspection failed to discover deep rod box cuts where the internal wall of the tubing was worn to less than 1 mm thickness. The tubing blew out when pressure testing the pump. These tubing failures can be attributed to failures of the inspection process since this tubing had greater than 50% wall thickness loss and should never have been coated.

SUMMARY OF THE RESULTS

The data shows that Ener-Core tubing has been successful in stopping tubing corrosion related failures in the Provost Area for Fletcher Challenge. There has not been an "in-service" failure of Ener-Core tubing since installation.

Mean installation time for the 23 wells studied is nine (9) months. The oldest string in service is on the Hayter 11B-26 well. This well has run for 22 months without problems. The next oldest string, at the Veteran 5C-36 well, has been in service for 20 months on a well equipped with an ESP. The pump failed after 17 months and the tubing was visually inspected and rerun with a new pump. The third oldest string is in the Sounding Lake 9D-27 well. In 19 months service the polished rod was replaced once and there have been two rod breaks. The first rod break occurred after one year's service. The tubing was pulled, visually inspected, and the stator and tubing rerun. At Consort, the 12D-21 well had been suspended as too expensive to run due to aggressive corrosion. The well had been reactivated with Ener-Core tubing and an ESP and has run for five months trouble free producing an average 3.5 m3/day oil.

Tubing and rod related failures have decreased four-fold (4 x). Prior to the installation of Ener-Core tubing the rod/tubing failure rate was 0.15 jobs/month versus 0.04 jobs/month after. For the twenty-three (23) wells studied, repairs costs have declined an estimated $29,000 per month.

Downtime from all causes declined from 2.96 days/month prior to 1.8 days/month resulting in decreased operating costs and increased production. Production increases amount to increased net revenue of $26,950 per month

Average installation costs for Ener-Core tubing are $27,000. This includes service rig charges, tubing, rods (replacement typically required due to wear/corrosion), and a new pump. The incremental cost of the Ener-Core tubing is less than half of the total cost.
Payout of the total cost of the average installation cost is 10 months. The installations studied have paid out their installation cost and continue to reduce operating costs and increase production compared to their prior history.

The Fletcher Challenge engineering and operating staff were unanimous in their support for the product. An additional 21 wells, including some newly drilled wells, have been equipped with Ener-Core tubing.

It was not possible to determine if the internal coating reduced energy costs through reduced friction in the pumping system. Data for energy consumption before and after Ener-Core installation was not available. Similarly, it was not possible to determine the effect of the smooth internal surface on pressure drop of flowing fluid in these wells.

STUDY OBJECTIVES

Enerline Restorations Ltd. requested Kooyman Engineering to conduct an independent assessment of the performance of its Ener-Core lined tubing in service in various wells for Fletcher Challenge Energy Canada Inc in the Consort / Provost area.

The study objectives were to attempt to determine:

a) How successful is the Ener-Core tubing in preventing internal corrosion?
b) How successful is the Ener-Core tubing in preventing tubing/rod wear?
c) Does the smooth internal surface of the Ener-Core tubing enhance fluid flow?
d) Does the internal coating reducing rod wear and energy costs?
d) Does the Ener-Core tubing reduce overall operating costs? By how much? What are the economics for installation of Ener-Core tubing?

Initially it was planned to conduct the study on a few selected "worst case" wells, but Fletcher Challenge generously offered summary workover histories on all wells within four fields it operates in the Consort / Provost area. In consultation with Enerline, it was decided to broaden the scope of the study to include all wells with Ener-Core tubing installations for which Accumap production histories existed and where more than three (3) months post installation production had occurred. Twenty-three (23) of the approximately forty-five (45) wells met these criteria. No attempt was made to exclude or include wells on the basis of workover history or other criteria.

STUDY DISCUSSION

The Study began with a visit to the Consort area office of Fletcher Challenge Energy Canada Inc. (FCEC). The two production engineers in the office had each selected two fields for discussion. The four fields selected for review were:

a) Veteran – 36-34-8 W4M
b) Sounding Lake 27-37-4 W4M
c) Hayter – 26-40-1 W4M
d) Consort – 21-35-6 W4M

Summary workover histories had been prepared on all wells in the four fields. Two of the field summaries (Sounding Lake and Hayter) included field estimated workover cost totals. Workover data for Consort and Veteran commences in April 1997 and does not include cost data.

Some time was spent discussing the operating problems in the fields with the two engineers and with the workover supervisor.

Typical wells in this area produce low gravity (20 – 25 deg API), high viscosity oil from the high permeability Dina Sand (Basal Quartz / Ellerslie equivalent). Initial production had good rates and high oil cuts but once the low viscosity water breakthrough occurred, water cuts jumped to 95 to 99% and oil volumes fell. Currently wells are produced using progressive cavity pumps. Wells produce from 50 to 250 m3 fluid per day at pump speeds up to 350 RPM (or more). A number of the wells are deviated or horizontal causing additional problems with rod wear. The produced brine is quite corrosive and this corrosion is accelerated by up to 8% CO_2 in the well gas. Chemical inhibition of the corrosion was ineffective due to the high volumes of fluid produced and / or too expensive to implement.

Producing challenges in this area include the need to control operating costs on low oil production wells and the need to lift large volumes of fluid to produce economic oil volumes. Internal tubing corrosion has resulted in a large number of failures. Additional failures have occurred as a result of rod corrosion and rod wear on progressive cavity pumped wells. At high RPM, in some wells, mechanical stresses, plus corrosion and dynamic loading caused by imbalances in the rod string, have resulted in failures of the tubing near the couplings. On one well, which was equipped with a packer, the tubing was broken into four lengths before the rods finally failed and the well stopped pumping.

A number of remedies have been attempted including rod centralizers, various vibration dampers, packers and alternative tubing anchors without a great deal of success.

Ener-Core tubing was first installed in 1998 on several FCEC wells that had histories of pumping problems. Following initial success in field trials, Fletcher Challenge has continued to install the tubing into a variety of wells and is currently has approximately 45 installations. Other than two instances, when improperly inspected tubing failed during the pressure tests, there has not been an "in-service" tubing failure and rod failures have also been significantly reduced

STUDY PROCEDURE

The workover summaries for all wells equipped with Ener-Core tubing were examined. The EUB public database was examined and production histories pulled for all wells where the data existed. Twenty-three wells were selected for further study based up their production history (more than three (3) months post installation production history available). No other screening criteria were applied to limit selection. Production data is current through February 2000.

The production histories for the wells were imported into a spreadsheet and grouped by field. Downtime was calculated by subtracting the hours in a month from the reported production hours.

The field production engineers maintain summary workover histories on all wells in the four fields. Two of the field summaries (Sounding Lake and Hayter) included field estimated workover cost totals. Workover data for Consort and Veteran commences in April 1997 and does not include cost data. In this study, production and downtime data prior to April 1997 was ignored for Consort and Veteran.

The production histories were combined with the reports for the workover events. Workovers were grouped into three classifications, 1) tubing and rod failures, 2) pump failures, and 3) other, which included initial completions, workovers to plug back the wells, reactivations, drive head failures, etc.

For each well, a series of calculations was made to attempt to determine the number and cost of workovers, downtime attributed to the workover, and downtime from all causes. For each well, we summarized the number of workovers in each category, downtime for each category, costs and downtime from all causes before and after installation of Ener-Core tubing. The “before” and “after” data for each well was then compared to determine changes in workover frequency and determine if the Ener-Core tubing was effective in reducing downtime due to all causes. This data was then “rolled up” by field and for the project.

DISCUSSION OF RESULTS

The study was based solely on the production and workover history of the twenty-three wells. In all cases, well performance was compared before and after installation of Ener-Core tubing. It was felt that well performance prior to Ener-Core tubing installation was a good predictor of expected long-term performance and that a comparison by well was valid.

A comparison of the Ener-Core equipped wells against all wells was not conducted for several reasons. To date, Ener-Core tubing has been installed in “problem” wells and a comparison against “good” wells might bias results. Also the volume of data for all wells is huge and beyond the scope that the client wanted to conduct.

Twenty-three of the forty-five Ener-Core equipped wells were selected for the study. The balance were excluded principally because they were only recently equipped with Ener-Core tubing and had little or no production history or, in one case, because the well’s Accumap production history could not be located.

Tubing and rod failures were grouped. Often, although either the tubing or the rods were the cause for a well to go down, during the repair extensive replacement of both tubing and rods occurred. The tubing and rods interact in the wellbore. The tubing and rods both must function in order for the pumping system to work. It was decided to treat tubing and rod related failures as a system and to see what effect replacement of one component of the system, the tubing, had on overall system reliability.

Corrosion and corrosion related failures of the tubing and rod strings have been a majour problem in the area. Corrosion damage is primarily internal pitting corrosion of the tubing with large diameter pits consistent with CO_2 attack. A high fluid velocity on large volume pumped wells also likely contributes to corrosion damage. Mechanical abrasion (rod box cuts/wear) is a second major cause of failure. High rod stresses associated with operation of high volume progressive cavity pumps means that rod failures are also common. The data shows that <u>Ener-Core tubing has been successful in stopping tubing corrosion</u> related failures in the Provost Area for Fletcher Challenge. There has not been an "in-service" failure of Ener-Core tubing since installation. Rod failures have also been substantially reduced.

To date, there has not been an "in-service" Ener-Core tubing failure. Prior workover history suggests that several tubing failures should have been expected. Overall, pumping system failures have been reduced four fold from 0.15 jobs/month to 0.04 jobs/month. This suggests that rod failures have also decreased and overall system performance has improved. When preparing the data for this study, one notices in well after well, how a litany of rod breaks and tubing failures stops abruptly after installation of Ener-Core tubing.

Several tubing failures on wells in this study were caused by mechanical vibration downhole. Typically, a fatigue failure occurred at the last engaged thread in the tubing box. This failure mode has not reoccurred.

Overall workover costs have decreased in another area. Pumps which were pulled and replaced before their run life had expired are now remaining in the hole longer and the Fletcher Challenge engineers foresee wells requiring workovers due to pump run life failures which seldom happened before. An example of this is the Veteran 5C-36 well, where the Ener-Core tubing has been in service for 20 months on a well equipped with an ESP. The pump failed after 17 months. The tubing was pulled to replace the pump, visually inspected and rerun with a new pump.

A second indication of the effective of the Ener-Core tubing on the pumping system is the comparison of downtime from all causes before and after Ener-Core installation. Downtime was calculated by subtracting producing hours from total hours in a month. Average downtime for all wells in the study dropped from 2.96 days/month before installation to 1.8 days/month after installation indicating increased reliability in the pumping system. This additional production time also increased monthly production volumes increasing the operator's revenue. Theoretically, increased system reliability should have decreased the field operator's time and costs, but no attempt was made to quantify this item.

The decreased workover costs and improved production have quantifiable values. For the wells in the study, average workover costs decreased $1,262/month and the increased production time resulted in additional revenue of $1,172/month for a total of $2,434/month. The average Ener-Core tubing installation cost was approximately $25,000. This included the tubing, rods as required, pump as required, and service rig time. Payout of this cost occurs in 10.3 months. The incremental cost of the Ener-Core tubing is approximately ¼ of this total and thus, payout of the incremental cost of the Ener-Core tubing installation is much less.

Fletcher Challenge does not have records in its Consort office of energy consumption on a monthly basis for the individual wells. It was not possible to determine if the Ener-Core tubing reduced overall power consumption and/or reduced rod loads and torque. A separate study should be conducted with Fletcher Challenge's assistance on a couple of wells due for installation of Ener-Core tubing to determine this.

Likewise, it was not possible in this operating configuration to determine the effective pressure drop and compare it to wells with bare steel tubing. A good candidate well has been located in another field and a separate study will be conducted.

Two "infant mortality" tubing failures have occurred. In each case, a joint of used tubing containing a deep rod box cut in the tubing wall was internally coated and sent into the field. It is uncertain how or if the tubing was inspected prior to coating. When pressure tested in the field, the tubing had insufficient wall thickness to hold the pressure test and blew out. Currently, tubing inspection is a third party process, often conducted by the well operator. It is common practice to internally coat used tubing with inspection as conducted or directed by the tubing owner. Enerline Restorations is looking into alternatives for tubing inspection and the possibility of bringing the inspection process "in-house" to improve overall process quality.

Over the next 24 months, failures of the Ener-Core coated tubing can be expected to occur. Careful tracking and documentation of these failures should be conducted to determine the nature of the failure mechanism and to assist in determining the expected life of the Ener-Core tubing and its true economics. An effective inspection mechanism needs to be developed to assess coating damage and remaining life on mature Ener-Core tubing strings. Consideration should be given to inspecting a couple of mature tubing strings in the field now to predict potential failures. A new multi-finger internal caliper tubing inspection tool from Lonkar Wireline may prove useful (and cost effective) for this purpose.

It should be noted that in cases where the internal coating is worn but where extensive corrosion damage of the steel tubing has not occurred, it is possible to remove the existing coating and salvage the steel tubing for recoating. Depending on inspection and removal costs, this may prove to be cost effective.

CONCLUSIONS

The Ener-Core tubing product has proven to be effective in stopping internal tubing corrosion and reducing overall workover costs. Pumping system reliability has improved and oil production increased.

The product is cost effective. Incremental and overall payout times are short.

The product quality is excellent. There have been no "in-service" tubing failures to date.

The product can be handled using existing equipment and methods and is compatible with existing field equipment.

Both the engineering and field staff of Fletcher Challenge accept the product and its use is increasing.

A procedure needs to be developed to inspect and assess mature tubing strings in field service.

APPENDICES

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