COILED TUBING FOR ARTIFICIAL LIFT

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The advent of coiled tubing makes possible new CT applications to improve artificial lift techniques.
To understand why we think that CT represent a new alternative to produce fluids from a well, lets first review some basic characteristics of CT.

Throughout the years and even nowadays, CT is used to ***service wells***, meaning continuous ***in and out of the hole*** to perform clean outs, to pump fluids, to set down hole tools and even to drill.
Reviewing the sequence of going in hole or coming out of hole, we can see that the full cycle demands **(6)** ***bendings***, as follows: going in hole or ***unspooling*** takes the straightening (1) of the pipe coming out the spool on its way to the gooseneck, takes another bending (2) around the gooseneck, and goes back to straightening (3) through the injection head. The reverse motion of coming out of hole, or ***spooling***, demands 3 more bendings.
That itself tells how this noble product is capable to withstand bending, before reaching unacceptable fatigue damage.

Not only bendings affects CT. Also is affected by internal pressure and corrosion caused either by exposure to air, or by certain types of circulation fluids. Basically what we want to remark is that CT *for service* is subjected to severe stresses that requires quality and integrity of the product. Computer modeling based on experience and empirical calculations allows CT service companies to monitor the life of a work string to determine when is time to remove it from service, to avoid failures down hole.
Knowing the ability of this product to withstand severe stresses when used to *service wells*, the question was, ***why not to use it for permanent installations were requirements are less stressful??...***

Before going into further considerations lets review basic OCTG concepts:
Two main groups can be identified:

A) Service strings
B) Permanent strings

The first group, includes drill pipe, drill collars, *for drilling*, and jointed tubing and coiled tubing when used for *workovers*
The second group, includes casing, production tubing and CT as velocity strings.
It can be observed that jointed tbg and CT has something in common; can be used either as ***service string*** or as ***permanent production string***.
The main difference between this two products are the connections. While CT has no connections, jointed tbg has 3 per hundred feet.

The only known application of CT as permanent string is for velocity strings in gas wells.

Trying to identify new applications, fluid displacement was the first issue to consider if we were to use it to convey fluids from bottom to surface.
Reviewing hydraulic concepts, it was found that in most of the cases of artificial lift we use large diameter jointed production tubing because we have to accommodate sucker rods inside. *Not because of hydraulics*.!!!
After basic calculations, it was a surprise to discover that most of production on rod pumping wells can be brought to the surface through a pipe not larger that 1.5" diameter !!
This simple conclusion lead to the idea of using CT to convey fluids to surface.

Knowing that hydraulics was not an issue, if we plan to use it as "hollow sucker rod string", the next thing to consider was the grade of the material and the cross sectional area to withstand tensile loads, Taking in consideration that the ultimate pull was going to be its own weight in air plus the weight of fluid inside, we found the first parameter to establish limitations.

Another thing to consider was the need to have a straight CT. The standard type of injection head of a CT unit does not guaranty a straight CT. When performing services in and out of hole this perhaps is not so important, but if we plan to use CT as sucker rod string is better to straiten the CT. A crooked or corkscrewed CT not only will produce drag against casing, but also can induce premature fatigue due to buckling on the down stroke

If compression forces were an issue, *what about elongation due to tensile loads ??*.
Based on experiences of CT used as *service string*, elongation is something that needs special attention since in many instances the CT not only has to withstand his own weight plus the fluid inside, but also is subjected to internal pressure when pumping fluids through nozzles, down hole motors, etc.

Reviewing this particular issue, we discover than when CT is used as *hollow sucker rod*, elongation is not major a concern. The weight of the pipe plus fluid inside is constant, and the pressure exerted on the surface in most of the cases is no more that 100 psi (flow line pressure from well head to a gathering station). Calculations showed CT elongation similar to sucker rod string.

Since the CT was to be reciprocated, we envision that fatigue eventually was going to develop, but we consider this less severe than the fatigue caused in normal service by continuous bending.

Following the first test, which was a simple "try and error" type of test, a computer program was developed to predict fatigue for CT used as pumping string. This computer model proved to be successful, and further experience with this pumping system will lead to improvements of this program.

<u>HISTORY OF TESTS CONDUCTED WITH CT AS HOLLOW SUCKER ROD STRING</u>

The first test: Oil well (Argentina)

5.1/2" csg with 2.7/8" tbg @ 2,300 ft.
Trying to find a new alternative to produce from slim hole wells, the first test on a " try and error basis" was conducted in 1998 in a regular production well in Argentina.In this well we try to reciprocate 1.1/2" CT inside 2.7/8" tbg to simulate a slim hole, and the test proved to be successful after 18 months of continuous pumping. See SPE paper 56671

The second test: gas well East Texas, USA

2.7/8" slim hole @ 6,000 ft
This test was the first test aiming to de-water a Slim Hole gas well with CT. We use 1.1/2" CT inside 2.7/8" csg an instead of using a hollow polished rod, we run a polished rod liner on the upper part of the string, does eliminating a high stress connector and a hollow polished rod.

The third test: Oil well on secondary recovery, by water injection.

West Texas, USA
4.1/2" csg @ 4,000 ft
This test was perfomed to find an alternative to ESP pumping, using a long stroke pumping (Rotaflex) unit with CT as hollow sucker rod string. In this case we use 1.3/4" CT to reciprocate a rod pump inside 4.1/2" csg..
In my opinion this is the most aggressive test ever conducted using CT as pumping string, and the lesson that we learn is that we need to maintain the CT confined to avoid buckling due to compressive forces in the down stroke. For future applications we need to consider the use of jointed production tubing (even used and with holes) just to keep the CT confined.
Also, H_2S took its toll in the CT string. See SPE paper 74832

The fourth test: Oil well, East Texas, USA

2.7/8" Slim Hole @ 6,000 ft
This test was to prove the ability to produce oil from a slim hole well, using 1.1/2" CT.
Tested a retrievable anchor, and eliminated the use of either hollow polished rod, or polished rod liner. The same CT acts as hollow polished rod through the stuffing box.

Fifth test: Gas well, North Louisiana, USA
2.7/8 Slim Hole @ 6.000 ft
To de-water a gas well. Bad well selection. This well had high gas pressure and displaced more than 1mmcf/day, therefore the rod pump had a tendency to gas lock.

Sixth test: Gas/Oil well, East Texas, USA
2.7/8 slim hole @ 6,000 ft.
In this successful test, we try Quinn retrievable pump anchor

Seventh test: Oil well, West Texas, USA
Re-cased a well with 2.7/8" regular tbg as new csg @ 7.000 ft
This test was to recover an ABD well with corroded csg. by running 2.7/8" tbg as new csg and pumping it as a slim hole well with 1.1/2" CT. In this well a Quinn anchor was used to set the pump, and a Baker CT external connector to link the CT with the hollow pull rod of the pump. Pump successfully for about four month, but CT experience some leaks, reason why CT was pulled out of hole. We found two problems: a) when the new casing was set and cemented (2.7/8" tbg) was left on compression, does leaving a "crooked hole", and the recommended 6 spm was increased to almost 10. We think that the combination of those two things lead to premature CT failure.

This Is the only CT failure observed in all the CT test with the exception of the string subjected to H_2S mentioned previously. Paper was presented in the Artificial Lift Forum., Midland, Tx in 2002

Eight test: gas well, East Texas, USA
2.7/8" Slim Hole @ 6,000
In this test we include all previous improvements, plus a new type of pump anchor to improve the flow area around the anchor, and also used a small pumping unit to show that CT can be run with small capacity pumping unit. Regardless of less polished rod and torque capacity, we learn that we still need the stroke length.
Paper was presented in Denver De-Watering Gas Conference in March 2003

Ninth test: Gas well, North Louisiana, USA
2.7/8" slim hole @ 5,000 ft. Trash in the pump created problems .We learn that is necessary to clean the well before installing CTRS in a gas well. Either bail the trash accumulated throughout the years or circulate with the same CT before installing a rod pump

Tenth test, Gas well, New Mexico, USA
2.7/8" slim hole @ 5,300 ft Same as above. Trash in the pump was a problem.

Eleventh test, gas well, North Louisiana, USA
2.7/8 Slim Hole @ 7,400 ft

LESSONS LEARNED INSTALLING CTRS:

- We feel comfortable to use this pumping system to 7,000 ft. with existing CT. Further test will show new limits, and will depend basically on experience and new CT materials.
- If possible make a trip to clean the bottom of the hole with the pulling unit after pulling rods and pump, or make a preliminary trip with the same CT to be run as permanent installation, to clean the well.
- After well clean out, GIH with CT and subsurface pump.
- There is no need for polished (hollow) rod. The same CT proved the ability to act as polished rod through the stuffing box.
- Only one connector is needed between the hollow pull rod of the subsurface pump, and the CT.
- CT must be new in order to eliminate possible premature fatigue due to notches, internal corrosion or beyond fatigue limits.

- ❑ CT must be straightened as is run in hole, to eliminate or minimize possible buckling and wear.

- ❑ A “roll on” connector as bottom connector could be sufficient. However is preferable to use an external connector (grapple type) to avoid restrictions on the ID.

- ❑ A “Lenz Lock” or similar is acceptable to connect the hose to the flow line on surface.

- ❑ Run the CT previously primed with fluid or water, and be aware that the valve on top of the string is OPEN before start pumping . Otherwise chances are that the string would not go down (resisting a down stroke….it happen before…!!).

- ❑ Avoid the use of CT centralizers or any other unnecessary “gadget” in the CT string.

- ❑ Try to use the larges OD possible on the hollow pull rod of the pump, to increase stiffness and minimize buckling. (*)

- ❑ Retrievable anchors can be an issue if we don’t pay attention to:
- ✓ ability to stay in place once is set
- ✓ flow area around the anchor (*bear in mind that in a Slim Hole gas or even fluid has to go through pass the anchor).*
- ✓ retrievable anchor, if possible, shall be run in the same trip attached to the pump.

- ❑ If CTRS is to be used in a well that has production tubing, try to use the same seating nipple to hold the pump in place.

- ❑ If CTRS is to be used to de-water a gas well, remember that will be producing water, which is the worst lubricant. For that matter check with pump manufacturer to design a pump accordingly. Stuck plunger due to galling not only will ruin the pump but also will force the pump to unseat. Soft plunger might be the solution.

- ❑ If is a new well make a prevision to run a regular pump seating nipple in the string. That will make things much easier if later needs to be pumped with CT.

- ❑ A pumping unit with less PRL and torque capacity can be use provided that the stroke length is compatible with stroke length required. (**)

- ❑ The massive application of CT for artificial lift will depend on availability of “fit for purpose” CTU’s, to replace, not only sucker rods, but also, pulling units.

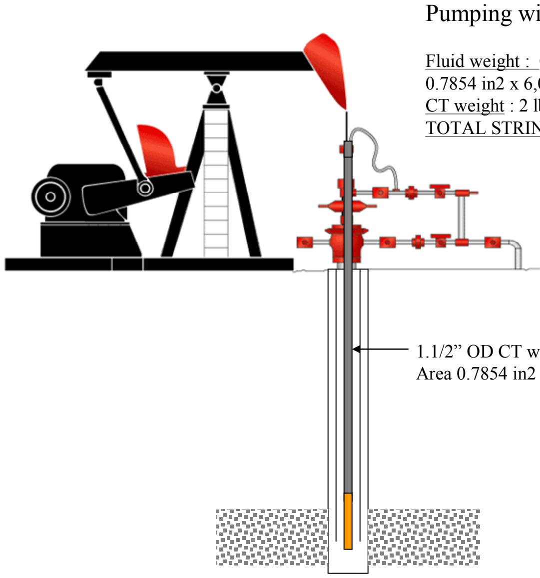
Pumping with coiled tubing

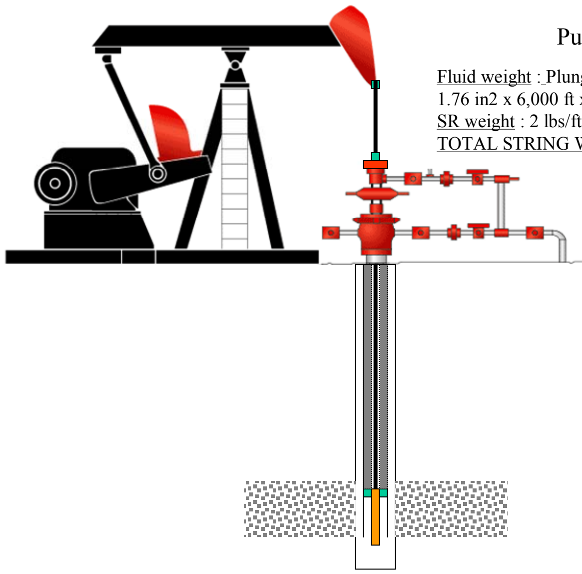
US Patent 6.220.358 & 6.502.639

Comparison of *string weight* and *stiffness* between conventional pumping string with sucker rods and the innovative pumping system with Coiled Tubing.

Pumping with Coiled Tubing

<u>Fluid weight :</u> CT ID area x CT Length x 0.433 psi/ft
0.7854 in2 x 6,000 ft x 0.433 psi/ft = 2.040 lbs
<u>CT weight</u> : 2 lbs/ft x 6,000 ft = 12,000 lbs
<u>TOTAL STRING WEIGHT</u> = 14,400 lbs





Pumping with Sucker Rods

<u>Fluid weight</u> : Plunger OD area x SR Length x 0.433 psi/ft
1.76 in2 x 6,000 ft x 0.433 psi/ft = 4,591lbs
<u>SR weight</u> : 2 lbs/ft x 6,000 ft = 12,000 lbs
<u>TOTAL STRING WEIGHT</u> = 16.591 lbs

Torque comparison

Formulas

Static load = weight of string + weight of fluid
Impulse factor "T" = length of stroke x spm2 / 70.500
Dynamic rod load = 1 + T x weight of string
Peak polished rod load = (1+T) x weight of string + weight of fluid
Minimum load = weight of string x 0.76 - T
Load range = Peak polished rod load – minimum load
Peak torque =Load range x length of stroke / 4

Example with 1.1/4 Coiled Tubing
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Static load = = 12,000 + 2,040 = 14,400 lbs(*)
Impulse factor = 54 x 36 / 70.500 = 0,027
Dynamic load = (1 + 0.027) 14,400 = 14,788 lbs
Peak polished rod load = 1 + 0,027 x 14,788 + 1 = 15,188 lbs(**)
Minimum rod load = 14,788 x 0.76 – 0,027 = 10.839 lbs
Load range = 15,188 – 10,839 = 4,349 lbs
Peak torque = 4,349 x 54 / 4 = 58,711 lbs.inch

(*) Steel + water inside
(**) minimum fluid level, fluid @ pump

Example with Sucker rods and 1.1/2" plunger

Static load= 12,000 + 4,591= 16,591 lbs
Impulse factor "T"= 54x36/70500=0,027
Dynamic load = 1 + 0,027x 12,000 = 12,324 lbs
Peak polished rod load= (1+0.027)x 12,000 + 4,591=17,038lbs
Minimum load =12,000 x 0.76-0.027= 8,796lbs
Load range= 17,038 – 8,796 = 8,242 lbs
Peak torque = 8,242 x 54/4= 111,267 lbs.inch

<u>Steel weight and stiffness</u>

<u>Diameter</u>   <u>Weight</u>   <u>Moment of Inertia</u>

1” CT………..1 lb/ft   ……………..…0.037

1.1/4 CT……. 1.5 lb/ft …………....0.070

1.1/2” CT……2 lb/ft ……………....0.128

¾” Rods……..1.6 lb/ft……………..0.015

7/8” rods……. 2.24 lb/ft……………0.032

1” Rods………2.9 lb/ft…………….0.049