Coiled Tubing in High-Pressure Wells

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This paper was prepared for presentation at the 67th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Washington, DC, October 4-7, 1992.

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Introduction

The number and types of well services that are performed using coiled tubing (CT) are increasing rapidly. These services have typically been limited to wells with well-head pressures (WHP) below 3,500psi. CT can be used safely in wells with higher WHP. The special considerations involved in the job design for wells with higher WHPs are reviewed in this paper. These special considerations include:

- Well control equipment capable of operating safely with high WHP
- Burst and collapse limits of the CT
- Injector head capable of pushing the CT into the well against the WHP
- The possibility of buckling of the CT between the chains and the stripper

Well Control Considerations

The blowout preventer (BOP) system, stripper, and downhole checkvalves are the major devices used for well control.

BOP Considerations

A typical CT BOP has four sets of rams (Figure 1). These rams perform the following functions:

- Blind rams seal when there is no CT or tools in the BOP body
- Shear rams cut through the CT
- Slip rams hold the CT at forces up to its break strength
- Pipe rams seal around the CT

The configuration of the BOP rams, equalizing valves and side port facility allow well control operations to be conducted under a variety of conditions. It is important to note that all the ram functions require the CT to be stationary before being activated. Operation of the BOP is achieved

References and figures at end of paper.
hydraulically but can be actuated and locked manually. The BOP actuation system must have redundant systems which can operate the BOP in case one system fails.

The general industry standard BOP today is rated for 10,000 psi maximum allowable working pressure ($P_{\text{MW}}$). This rating is only a definition of the BOP's integrity under static conditions. It does not ensure that the BOP will perform all the necessary functions with a 10,000 psi WHP. It is important to understand the limitations of the BOP system under higher WHPs.

The WHP works against the BOP rams, and reduces the force applied by the ram. Special consideration must be given to the BOP's closing ratio. The closing ratio is given by:

$$R = \frac{D^2}{d^2}$$

where

- $R$ = closing ratio
- $D$ = diameter of hydraulic piston
- $d$ = diameter of connecting rod

The hydraulic pressure which is trying to close the ram works against the hydraulic piston diameter while the WHP which is trying to prevent the ram from closing is working against the connecting rod diameter.

In case of a failure in the hydraulic power supply system, accumulators are used to operate the BOP system. Each time a set of rams is either closed or opened the volume of hydraulic fluid in the accumulator decreases and the available operating pressure decreases. Figure 2 shows this pressure decrease after each close-open cycle of a set of rams for systems with different accumulator volumes. To close and open all four rams requires four cycles. The system should be sized so that there is sufficient pressure to perform all BOP functions after all four ram sets have been closed, opened and closed again, considering the required closing pressure under high WHP operations.

It is also necessary to maintain the ability to shear the heaviest section of CT pipe in the string with high WHP. With some BOPs, increasing the hydraulic system pressure to ensure that the shear rams can cut the pipe may cause the slip rams to crush the pipe. It is assumed that in a catastrophic situation where the shear rams were to be actuated, that the procedure to reduce the pressure above the set pipe and slip rams would not be prudent because of the time required and the dependance on the pipe rams. Table 1 gives some typical pressure values required for shearing the CT with various WHPs. Modifications to current industry equipment may be required if the BOP is to maintain its required functionality at high WHP.

Another important consideration for high WHP CT operations is the requirement of a redundant shear/seal capability in the BOP stack. This can be achieved with the use of a shear/seal BOP that performs both functions with a single ram actuation. This should be the first item of equipment flanged to the wellhead, normally on the swab valve, and considerations previously discussed must be reviewed. The shear/seal ram has the advantage of being able to isolate the wellbore with a single actuation, with no injector head movement.

In all CT operations it is recommended that pipe thread connections are not used in the assembly of well control equipment directly exposed to the wellbore fluids or pressures because their structural and sealing capacity is of a lower standard than flanged or intergal pin/collar unions.

**Stripper Considerations**

The stripper (Figures 3) provides a pressure tight seal around the CT as it is being run (stripped) in and out of a well with a WHP. This sealing pressure is caused by WHP and by a hydraulic pressure known as "stripper pressure" which is
controlled by the operator. These pressures force a consumable element against the CT. This element is typically made of Urethane, Nitrile or Viton, depending on the intended service and operating environment.

With high WHP CT operations the following must be considered:

- the frictional force the seal imparts on the CT
- the durability of the sealing element over the duration of the job
- redundancy of the annular sealing system

A rough approximation of the friction force the seal imparts on the CT can be made by assuming that the force is 0.5 lbf for each 1.0 psi of WHP. Thus for a 5,000 psi WHP the friction force would be approximately 2,500 lbf. This estimate may be inaccurate by as much as 100% depending on the type of sealing element, CT size, stripper pressure being applied, and lubrication of the pipe surface.

The sealing element is a consumable item but it must be capable of performing the entire operation without having to be replaced. Two techniques are applied to improve the life of the sealing elements and to reduce the friction force. One technique is to lubricate the pipe as it enters the seal. In some cases this has reduced the friction by as much as 1,500 lbs. This is not difficult when running in the hole (RIH), but is more difficult when pulling out of the hole (POOH) in dry gas wells. The second technique requires special materials for the sealing element. Sealing elements have been built which reduce the friction the wear significantly.

In normal WHP applications, the stripper sealing elements can be replaced by closing the pipe rams to seal the WHP while the elements are replaced. This is not recommended when there is a high WHP because there is only one seal while the elements are being replaced. A backup stripper as shown in Figure 3 is imperative for safety in this case. It is generally accepted that splitting the pressure drop across two strippers decreases the system redundancy, and is therefore not recommended. The lower, backup stripper should only be used in case the primary stripper should start to leak. The lower stripper and the pipe rams of the BOP provide a dual set of annular seals while the primary stripper sealing elements are replaced. Both stripper assemblies should be of the "side access" type which facilitates better access to the replacable sealing elements. Figure 3 shows a standard and a backup side access stripper assembly. Replacing sealing elements in a side access type stripper is faster and hence safer.

Collapsing of the CT

The pressure and tension limits of CT are derived in reference 2. This derivation assumed that the CT was round. Bending the CT on the reel and over the gooseneck of the injector tends to make it oval. This ovality significantly reduces the collapse pressure of the CT. Recently extensive work has been done to understand the collapse pressure of oval tubing. Results from this work for one example CT size are given in Figure 4. Ovality is defined as follows

\[
\text{% Ovality} = \left( \frac{\text{Major Diameter}}{\text{Minor Diameter}} - 1 \right) \times 100
\]

Note from Figure 4 the decrease in collapse pressure with only 5% ovality, compared to 0% ovality for new pipe.

When designing jobs in wells with a high WHP, careful consideration must be given to the possibility of collapsing the CT in the well. There are three possible ways of avoiding collapse:

- Use small-diameter, heavy-wall CT which will not collapse at the WHP even without pressure inside the pipe.
- Maintain pressure inside the CT so that the differential pressure is always above the collapse pressure.
- Run the CT without a checkvalve ("open ended") so that the inside of the CT is pressurized by the well.

Running small, heavy-wall CT is certainly the best of the options given above. However, this will limit the flow rate and depth capability of the CT.

Maintaining pressure inside the CT is the next best solution for avoiding collapse. Care must be taken to ensure that the CT is capable of withstanding the internal pressure without extensive fatigue damage to the CT. Continuous pumping is recommended during the job to ensure that the internal pressure is maintained. If pumping pressure is lost for some reason, and the CT does collapse, well control is still maintained and there are several options available to remove the CT from the well.

Running the CT open ended is potentially dangerous and is not normally recommended. In this case the entire length of the CT, including the CT on the reel at surface, as well as the reel manifold, becomes well-control equipment. A failure in any part of this system would allow well fluids to escape at surface. Using the BOP shear and seal rams would be the only option available to control the well.

**Injector Considerations**

Figure 5 is a sketch of a typical CT injector. The injector chains are driven by hydraulic motors usually located at the top of the injector. Hydraulic, inside tension rams force the chain tension bars, or "skates" against the chains, forcing the chains against the tubing to increase the friction between the chains and the tubing. The hydraulic pressure to these rams, known as "skate pressure," must be high enough to keep the chains from slipping on the tubing. An outside chain tension cylinder keeps the chains in tension.

When pulling CT upwards, the chain sections in contact with the CT are in tension because they are being pulled upward by the motors. When pushing the CT downwards, the chain sections in contact with the CT will be in compression unless the chain tension caused by the outside tensioning rams is high enough. Most injector heads are limited in the amount of downward compressive force they can apply because of limitations in the chain tensioning system. A typical injector head that is capable of pulling 40,000 lbf tension is only capable of pushing with approximately 14,000 lbf of compression.

Figure 6 shows the upward force with which the WHP will try to push the CT out of the well for various sizes of CT and various WHPs. The CT injector must be able to push the CT into the well against both this force and the friction force caused by the stripper. As an example, assume that the injector is able to push with a force of 10,000 lbf after overcoming the stripper friction and including a safety margin. This 10,000 lbf limit limits the WHP to 8,100 psi for 1.25" CT and 5,600 psi for 1.5" CT, for this injector.

The injector head "floats" within the injector head crash frame. It is hinged on one side and rests on the weight indicator load cell on the opposite side. Positive (tensile) forces acting on the CT will cause the injector head to compress the load cell. However, negative (compressive) forces "lift" the injector head off of the load cell. The load cell is able to measure more tension (positive weight) than the injector is capable of pulling. Compression on the CT (negative weight or setdown weight) can be measured until the injector head is lifted off the load cell. When the injector head is off of the load cell there is no weight indication to the operator and he is "running blind", potentially a very dangerous situation. Some operators depend on the hydraulic motor pressure to indicate the weight, but this technique is not recommended because of the poor resolution of this pressure measurement. For a typical injector head, 3,000 lbf to 5,000 lbf of setdown weight can be measured before the injector head is lifted off of the load cell. Obviously this is not sufficient for working in wells with high WHPs.

This problem must be avoided by using a "dual-
acting" load cell. A dual acting load cell attaches to the injector head as well as the injector head crash frame, and is capable of measuring the force on the CT in both directions beyond the capability of the injector to push and pull.

When designing a CT operation in a well with a high WHP the injector setdown force capability must be considered to be certain the CT can be pushed into the well with an adequate margin of safety. A dual acting weight indicator must also be used to accurately measure the forces.

**Buckling of CT at Wellhead**

Between the last point of contact between the chains and the CT and the top of the stripper there is often an exposed length of CT. When a high compressive load is placed on the CT through this section, as is the case in a well with a high WHP, there is a possibility of buckling the CT in this area, as is shown in Figure 7.

When a single-acting load cell is used there is a rotation of the center section of the injector head about the hinge which causes the chains to be misaligned with the stripper. This misalignment causes a bending force on the CT which increases the possibility of buckling. This is not a problem when an electronic "fixed" load cell is used.

The results of calculations to estimate the buckling forces of the CT for a typical injector are 3,000 lbs for 1.0" CT, 6,000 lbs for 1.25" CT and 12,000 lbs for 1.5" CT. Obviously this buckling load varies tremendously with the distance between the chains and the stripper, the misalignment of the chains and the stripper, and the wall thickness of the CT.

When running into a well with a high WHP this problem must be avoided by using a buckling guide around the CT in this area. The buckling guide is simply an extension of the top of the stripper until it almost contacts the chains as is shown in figure 8.

**Conclusions**

CT operations in wells with a WHP greater than 3,500 psi are possible but are limited by the CT pipe burst and collapse limits and the injector limits in compression.

Preparations for existing equipment to be used in high pressure wells should include an injector head chain to stripper pipe guide, dual acting tension/compression load cell (preferably the strain gauge type), lubricated and/or long wear stripper elements, and BOP function testing at WHP conditions. A backup stripper assembly and shear/seal BOP must also be used.

**Acknowledgements**

The authors are grateful to Bruce Adam for his support and the graphic for this paper. Also to Hydra-Rig and Texas Oil Tools for technical support and review of the paper.

**References**


Table 1
BOP Hydraulic System Pressure Required to Shear CT for a Typical 3" BOP

<table>
<thead>
<tr>
<th>CT OD (in)</th>
<th>Wall Thickness (in)</th>
<th>Pressure Required to Shear 0psi WHP</th>
<th>Pressure Required to Shear 5,000psi WHP</th>
<th>Pressure Required to Shear 10,000psi WHP</th>
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</table>
Figure 1
Typical CT BOP

Figure 2
Accumulator pressure after close - open cycles for BOP system
Figure 3
Typical CT strippers - standard and backup side access type

Figure 4
The effect of ovality on collapse pressure
Figure 5
Typical CT Injector

Figure 6
Axial compressive force on CT due to WHP
Buckled tubing in unsupported section.

Figure 7
Buckled CT between the chains and stripper

Figure 8
CT buckling guide