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Riserless Coiled-Tubing Well Intervention

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Abstract
This paper describes a concept for subsea coiled tubing well intervention, without the use of a workover riser system. Coiled tubing analyses and design, surface and subsea equipment design, vessel and operational requirements and limitations are addressed.

The novel steps in the development are the lubricator system, where the lubricator resides on top of the injector, and the use of a tensioned coiled tubing configuration with a heave compensation system and a second coiled tubing injector at surface.

A comparative risk assessment has been performed, and concluded that the overall personell and environmental risk is the same or reduced compared to a workover riser based system.

Introduction
With the increasing number of subsea wells, there is a need for more cost-effective intervention methods. For offshore platform wells, typical recovery factor (for the North Sea) is in the 50 – 60 % range, whereas for subsea wells, this number is significantly lower, typically in the 30% range. One of the main reasons for this is the low intervention frequency in subsea wells. While platform wells are commonly intervened as often as 2-4 times a year, subsea wells are in general only intervened if absolutely necessary, i.e. in case of barrier failure or dramatically reduced production. The main reason for this is the cost and difficulty associated with subsea well intervention.

Intervention in subsea wells traditionally involves mobilizing a drilling rig and running a workover riser system [1]. With this approach several days of operation is required before any productive work in the well can commence due to the time required for positioning and anchoring of the rig and installing the workover riser system. While the use of dynamically positioned (DP) vessels has eliminated the time required for anchor handling, running of jointed workover riser (WOR) is still a time consuming operation [2].

Operators also tend to use contracted drilling rigs for drilling and completing wells rather than intervention operations, where the outcome is in general more uncertain. While production logging and well test data is usually available for platform wells, this type of information is in general not available for subsea wells, making planning of the intervention operation difficult. Usually diagnostic runs, i.e. production logs are included in the intervention campaign, as well as mobilization of equipment for various outcomes of the diagnoses. For a platform or onshore well, the intervention campaign often continues at another well while i.e. production logs are being analysed and additional equipment is mobilized. This is not practical for subsea wells, with the possible exception of templates or other configurations where the wells are in close proximity to each other so the rig may be moved between wells without pulling the workover riser.

Experience from platform wells indicates that well intervention has higher risk of incidents and accidents than drilling and completion operations. When the risk of operating with a workover riser with full well pressure up to the vessel is added to the equation, the risk of incidents and accidents is above operators' comfort level, especially in harsh weather areas such as the North Sea.

All these factors have given a lot of operator interest in well intervention systems that can be used efficiently for subsea wells, and preferably from a DP monohull vessel. Riserless wireline systems have been on the market for a while, and have been used successfully [3-5]. However, while wireline is suitable for well diagnostics such as production logging or sampling tools, remedial operations such as running plugs, straddles, stimulation and perforation is more efficiently performed with coiled tubing, especially in highly deviated and horizontal wells. With the advances in coiled tubing tools and deployment methods in the last decade, most subsea well problems can now be diagnosed and efficiently remedied with coiled tubing or wireline operations, reducing the dependence of drilling rigs if an efficient subsea deployment system was available.

To summarise, the motivations for developing a riserless coiled tubing well intervention systems are:

- Reduced overall risk level
- Operation time and cost saving
- Perform remedial interventions not possible with wireline
- Drilling rig is not required for intervention

This paper describes the conceptual design of a riserless coiled tubing well intervention system, and discuss operational requirements and limitations.

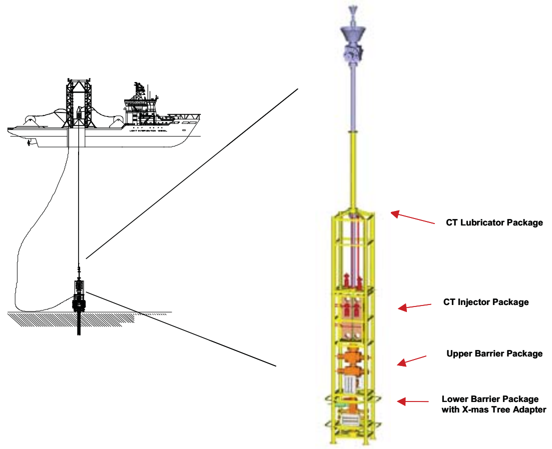


Figure 1 Riserless coiled tubing well intervention system

System Description

The two novel features of the system compared to previous solutions [6] is the use of a tensioned coil and a new lubrication system where the lubricator is placed *above* the coiled tubing injector, Figure 1. The Well Barrier Packages and X-mas tree adapter shown in the figure are conventional. The use of a tensioned coil ensures that the coil behaviour and loads are predictable and may be monitored at all times during operation. By mounting the lubricator above the injector package, the bending moment on the X-mas tree adapter is considerably reduced, and tool string deployment and retrieval is considerably simplified compared to a surface type coiled tubing system where the injector needs to be lifted off when changing toolstrings.

The system has been designed for use in the North Sea in the summer season, and year round in benign waters. The intervention system has 7 3/8" bore, for accomodation of full bore plugs, and is rated to 10.000 psi. For guidance two guidewires has been assumed.

Lubrication system. To avoid excessive bending moment on the X-mas tree, and to simplify toolstring deployment, a new lubricator design has been developed. By using extended retracts on the coiled tubing injector belts, sufficient room is available to lower the lubricator through the injector, and connect to top of the Well Barrier Package. The deployment sequence is illustrated in Figure 2.

After the lubricator is landed on top of the injector, toolstrings up to at least 50 ft may be deployed, limited mainly by the available length of the lubricator and available height of the topside derrick.

Surface System. The surface system consists of the standard coiled tubing equipment such as reel, power packs and control cabin, in addition to the equipment required to maintain a tensioned coil configuration. Furthermore, a derrick is required for safe end efficient handling of the subsea equipment and toolstrings. In Figure 3, the derrick is shown before start of operation. The different equipment packages are stored on the vessel deck and skidded to and from the derrick for installation and disassembly the system. They are

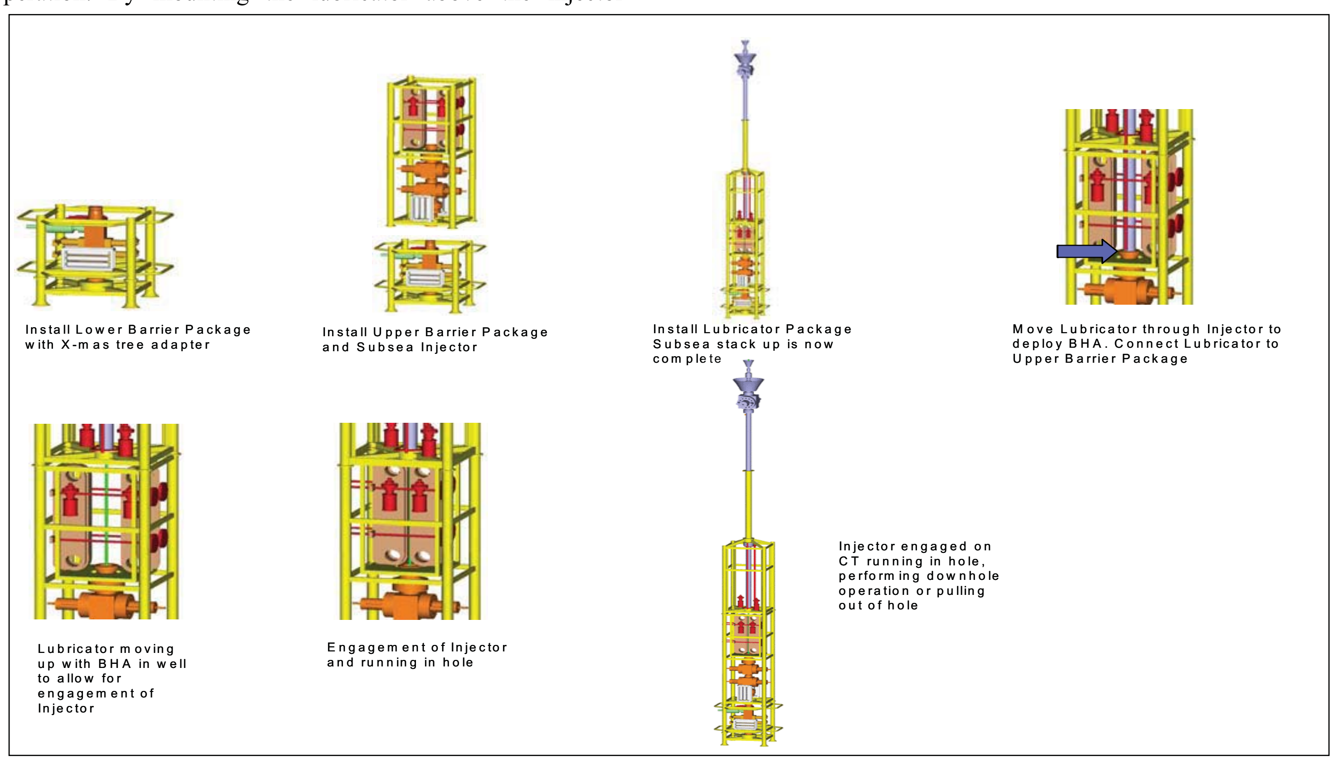


Figure 2 Deployment sequence

installed using a heave compensated main winch, and a cursor system is integrated in the derrick for guidance and handling through the splash zone.

After deployment of the subsea equipment, the toolstring is prepared and hung off in the moonpool secured to the skid plates. The gooseneck and surface injector are then skidded into the moonpool and hung off in the cursor system before the toolstring is made up to the coiled tubing connector. The cursor uses an active heave compensation system when installing the toolstring in the subsea lubricator and in the toolstring deployment and running sequences.

In Figure 3 the umbilical winch is shown fore of the derrick. The coiled tubing reel should be placed as far aft as possible from the derrick to minimize reel winding and unwinding as the gooseneck and injector heaves.

Control System. The control system need to include all necessary equipment for controlling the subsea lubricator system, subsea injector, Xmas tree system and barrier package, the Downhole Safety Valve (DHSV) and the surface coiled tubing equipment system throughout a well intervention operation. While the Xmas tree and well barrier package controls are similar to a standard Workover Control System (WOCS), the integration of the coiled tubing controls is not straightforward. A further challenge is the behaviour of the heave compensation system, particularly for the derrick cursors where the surface injector and gooseneck are hung off during operation.

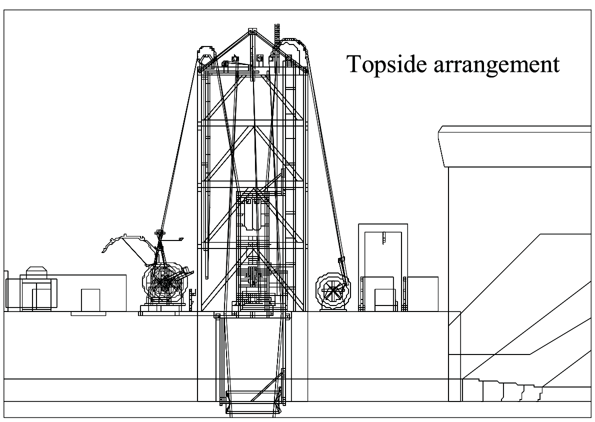


Figure 3 Topside arrangement before start of operation

The subsea injector, operating equivalent to a surface injector for a dry Xmas tree setup, is used for running the coiled tubing. The surface injector is run with a constant tension, and is only used to maintain the tensioned coil configuration. It is also used when lubricating out of the well to pull the toolstring into the lubricator, and then to surface. The surface injector must have sufficient power to pull the coiled tubing out of the well in case of failure of the subsea injector.

With the number of control signals going to and from the subsea system, a multiplexed control system is the most attractive solution. The power sources will be a combination of hydraulic for valves and electrical power to drive the injector motors. In addition, chemicals for subsea use are required, and Emergency Shutdown (ESD) panels will have to be located around the vessel.

Coiled Tubing Analyses

By removing the workover riser the load situation for the coiled tubing changes significantly compared to inside tubing or riser coiled tubing operations. In addition to the loads caused by the internal fluid and toolstring, loads imposed by vessel motion, waves and current are now to be accommodated by the coiled tubing. The coiled tubing is now a riser in function and need to be analyzed and designed as such.

The relevant design codes normally applied for dynamic risers are API RP 2 RD – Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) [7] and Offshore Standard DnV-OS-F201 – Dynamic Risers [8]. DnV-OS-F201 has been used in this work, as it contains explicit capacity criteria suitable for coiled tubing. It is also based on state-of-the-art riser analyses models.

Coiled Tubing Behaviour. Risers and riser-like structures such as coiled tubing suspended between a surface vessel and a wellhead behave non-linearly due to the combination of loads experienced.

Risers carry lateral loads mainly the same way as ropes or wires, i.e. the lateral loads are carried by tension in the structure. Since the axial force in a riser (or rope) always are directed along the tangent to the riser, there will be a change in direction of the axial force along the riser. This change in direction makes it possible for the riser to carry lateral loads, being it distributed, concentrated or a combination. For risers, both top tensioned and more flexible configurations, the major nonlinear behavior is related to establishing the static equilibrium configuration. Any dynamic behavior related to direct or indirect wave loading such as first order vessel motions causing top end motion, can for most practical purposes be regarded as linear about a static equilibrium.

Two different configurations have been evaluated for the coiled tubing suspended from the vessel to the seabed, the tensioned heave compensated configuration and the steep-wave configuration.

Tensioned configuration. The tensioned configuration, Figure 4, is known from traditional top tensioned risers, such as drilling risers, workover risers or marine risers for production tubing. The transverse loads on the coiled tubing such as direct wave and current action, but also transverse top end motions, are carried through utilization of the tensioned string principle. This implies that a tension is applied to the top end of the coiled tubing.

The tension magnitude at vessel level is always kept sufficiently larger than the submerged weight of the coiled tubing including content. This will prevent compression that may induce local buckling in the suspended coiled tubing. Since the coiled tubing itself is kept under a permanent tension it will remain an almost straight line between the termination points. The deformations caused by lateral top end displacements will therefore mainly be concentrated where the coiled tubing enters the lubricator and at the vessel connection respectively. Furthermore, since a straight tensioned steel string has very limited ability to accommodate axial elongation, the vertical motions of the coiled tubing top end need be eliminated. Thus the tension keeping system at the vessel must be heave compensated.

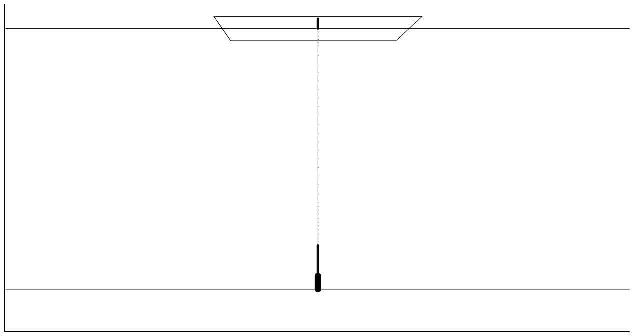


Figure 4 Tensioned riser configuration

Steep-wave configuration. To avoid dependance on the heave compensation system where failures such as a compensator lock may be detrimental to the coiled tubing, a steep wave configuration, as commonly applied for flexible risers seem attractive.

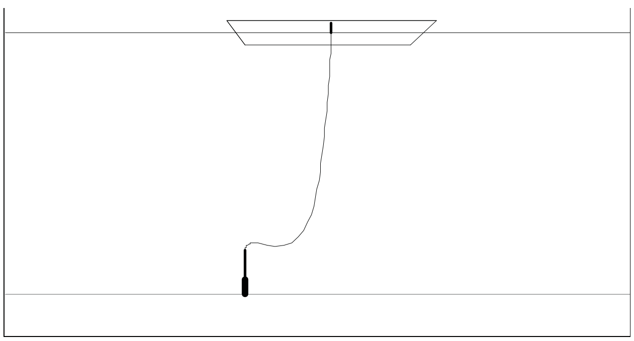


Figure 5 Steep-wave configuration

The generic steep wave configuration shown in Figure 5 is the static equilibrium shape of coiled tubing with a particular length suspended between a vessel and a wellhead. The present configuration is established applying neither current nor waves. The active loads for the shown configuration are only the submerged weight of the coiled tubing and its content, but including current or wave loads will not lead to major changes in the shape. As can be seen large bending deformations will occur close to where the coiled tubing enters the lubricator. Depending on the mechanical and strength properties of the coiled tubing these deformations can be detrimental to the coiled tubing cross section. For the coiled tubing with 2" OD and 0.25" wall thickness, and filled with seawater, the minimum bending radius where the coiled tubing enters the lubricator is calculated to be approximately 12 ft. This is far below the allowable bending radius for this particular coiled tubing. Also, the calculations are performed assuming elastic material behavior, which is not the case for such large deformations. In a real case one should expect the formation of a plastic hinge where the coiled tubing enters the lubricator. Thus the real bending radius would be even smaller than the one calculated and shown above. A bend restrictor is required to avoid the damaging bending deformations at the lower termination point, i.e. where the coiled tubing enters the lubricator.

Coiled Tubing Loads. The coiled tubing need to be checked for structural integrity for the releavant load cases. The following cases are given in [8]

- Burst
- System Hoop Buckling
- Propagating Buckling
- Combined Loading with net Internal Overpressure
- Combined Loading with net External Overpressure

DnV-OS-F201 [8] presents both Load effect and Resistance Factor Design (LRFD) and Working Stress Design (WSD) criteria. The WSD criterion is more convenient and slightly more conservative than the LRFD criteria, and has been used for our calculations.

Coiled tubing subjected to bending moments, effective tension and net *internal* overpressure shall be designed to satisfy the following equation:

$$\frac{|M|}{M_k}\sqrt{1-\left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2}+\left(\frac{T_e}{T_k}\right)^2+\left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2\leq\eta^2 \qquad (1)$$

The failure modes controlled by this Limit State comprise gross plastic deformation, yielding and wrinkling. The design criterion may be viewed as a plastic Von Mises criterion in terms of cross sectional forces and plastic cross sectional resistance.

Coiled tubing subjected to bending moments, effective tension and net *external* overpressure shall be designed to satisfy the following equation:

$$\left[\left(\frac{|M|}{M_k}\right)+\left(\frac{T_e}{T_k}\right)^2\right]^2+\left(\frac{p_e-p_{\min}}{p_c(t_2)}\right)^2\leq\eta^4 \qquad (2)$$

The failure modes controlled by this Limit State comprise yielding and combined local buckling and hoop buckling due to combined bending, axial tension and external overpressure.

A usage factor of 0.83 (DNV safety class Low) has been used. The selection of this safety class is motivated mainly by the low risk of human injury in case of failure. This safety factor ensures that the coiled tubing is in elastic deformation only.

Bending deformations. A key element to success of a riserless coiled tubing system is the ability to avoid excessive bending deformations at the entry into the lubricator and at the support where the coil leaves the vessel. At both positions the bending deformations need be restricted.

The maximum allowable moment and the bending stiffness of the pipe determine the maximum allowable bending deformation of the tubular, e.g. in terms of minimum allowable bending radius

$$\rho_{mbr} = \frac{EI}{|M_a|} \quad (3)$$

The allowable bending radius of the coiled tubing determines the required dimensions of bend limiting devices. Thus the opening diameter of a bell-mouth (or funnel) is given as follows:

$$D = 2 \cdot \rho_{mbr}\left(1 - \cos\theta\right) + D_0 \quad (4)$$

The height of the bell-mouth is given as:

$$h = \rho_{mbr} \sin\theta \quad (5)$$

where θ is the opening angle of the bell-mouth and D_0 is the ID of the pipe connected to the bell-mouth.

The maximum allowable moment $|M|_a$ for coiled tubing can be determined solving equation (1) and (2) for $|M|$. We see that the minimum allowable bending radius for coiled tubing depends on several independent variables, i.e. the chosen usage factor η, the effective tension T_e, the net overpressure and the resistance related variables M_k, T_k, p_b or p_c as follows in equations (6) and (7)

$$|M|_a \le \frac{M_k}{\sqrt{1-\left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2}}\left\{\eta^2 - \left(\frac{T_e}{T_k}\right)^2 - \left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2\right\} \quad (6)$$

or

$$|M|_a \le M_k\left\{\sqrt{\eta^4 - \left(\frac{p_e - p_{\min}}{p_c(t_2)}\right)^2} - \left(\frac{T_e}{T_k}\right)^2\right\} \quad (7)$$

The maximum allowable axial tension for coiled tubing can be determined similarly solving equation (1) or (2) for T_{ea}. We see that the maximum allowable effective tension for coiled tubing depends on three independent variables, i.e. the chosen usage factor η, the bending moment $|M|$, and the net overpressure respectively, and in addition the resistance related variables M_k, T_k, p_b or p_c as follows in equations (8) and (9)

$$T_{ea} \le T_k\sqrt{\eta^2 - \frac{|M|}{M_k}\sqrt{1-\left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2} - \left(\frac{p_{ld}-p_e}{p_b(t_2)}\right)^2} \quad (8)$$

or

$$T_{ea} \le T_k\sqrt{\sqrt{\eta^4 - \left(\frac{p_e - p_{\min}}{p_c(t_2)}\right)^2} - \frac{|M|}{M_k}} \quad (9)$$

The capacity according to [8] for pure axial load, pure bending moment and pure external pressure are given in Table 1 for some relevant coiled tubing dimensions.

Table 1 Coiled tubing bending radius

Nominal external diameter	Nominal wall thickness	Axial tension capacity	Bending moment capacity	Minimum bending radius	Maximum water depth without collapse
[inches]	[inches]	[1000 lbs]	[lbs-ft]	[ft]	[ft]
2"	0.1"	47	2	23	13780
	0.15"	68	4	23	24049
	0.2"	89	4	23	32808
	0.25"	108	5	23	41371
	0.3"	125	6	23	49902
2.375"	0.1"	56	4	30	9350
	0.15"	82	5	30	19652
	0.2"	107	6	30	27329
	0.25"	131	7	26	34613
	0.3"	153	8	26	41831
2.875"	0.1"	68	5	36	5577
	0.15"	100	7	36	14862
	0.2"	132	10	33	22080
	0.25"	161	11	33	28281
	0.3"	190	13	33	34318
3"	0.1"	84	7	43	3150
	0.15"	124	11	43	9777
	0.2"	162	14	43	17192
	0.25"	200	17	43	22769
	0.3"	236	20	43	27854

Analyses of the top-tensioned coiled tubing configuration. The stiffness in rotation at the end of a stretched beam, such as for a coiled tubing configuration is given by

$$\frac{M}{\theta} = \frac{TL}{\frac{KL}{\tanh(KL)} - 1} \quad (10)$$

where M is the moment required to rotate any end an angle θ assuming a pinned end connection, θ is the angle of rotation at any end of the beam caused by static and dynamic loads, T is the tension in the beam close to the end and EI is the cross sectional bending stiffness. $K = \sqrt{T/EI}$ is the flexibility factor and L is the length of the beam. For KL large, which often is the case for coiled tubing, the equation above simplifies

$$\frac{M}{\theta} = \sqrt{T \cdot EI} \tag{11}$$

Even though the system is nonlinear, superposition with respect to angles at the lower and upper end is valid as long as the angles are relatively small, i.e. less than 15° to 20° [1]. This means that one can calculate separately the angles caused by self-weight and top end offset, current loads and dynamic loads, and superpose the results to obtain the final angles. The bending moments at the end terminations of the coiled tubing becomes thus

$$M = \theta\sqrt{T \cdot EI} = \left(\theta_w + \theta_q\right)\cdot\sqrt{T \cdot EI} = M_w + M_q \tag{12}$$

where θ_w is the end angles caused by self-weight for any top end offset, and θ_q is the angles caused by other loads such as e.g. current, waves and vessel motions. θ is the angle that need be accommodated by e.g. a bell-mouth.

Based on [9] the relations between top end offset X_o and end angles caused by self-weight become

$$\theta_{wB} = \frac{X_o}{\dfrac{T_B}{w}\cdot\ln\left(\dfrac{T_T}{T_B}\right)} \tag{13}$$

$$\theta_{wT} = \frac{X_o}{\dfrac{T_T}{w}\cdot\ln\left(\dfrac{T_T}{T_B}\right)} \tag{14}$$

This results in the following relations between end moments, top end offset, tension, weight, length and bending stiffness of the coiled tubing:

$$M_{wB} = \theta_{wB}\cdot\sqrt{T_B \cdot EI} = X_o\sqrt{\frac{w \cdot EI}{L}}\cdot\left(\frac{1}{-\ln(\alpha_T)}\sqrt{\frac{1-\alpha_T}{\alpha_T}}\right) \tag{15}$$

$$M_{wT} = \theta_{wT}\cdot\sqrt{T_T \cdot EI} = X_o\sqrt{\frac{w \cdot EI}{L}}\cdot\left(\frac{\sqrt{1-\alpha_T}}{-\ln(\alpha_T)}\cdot\right) \tag{16}$$

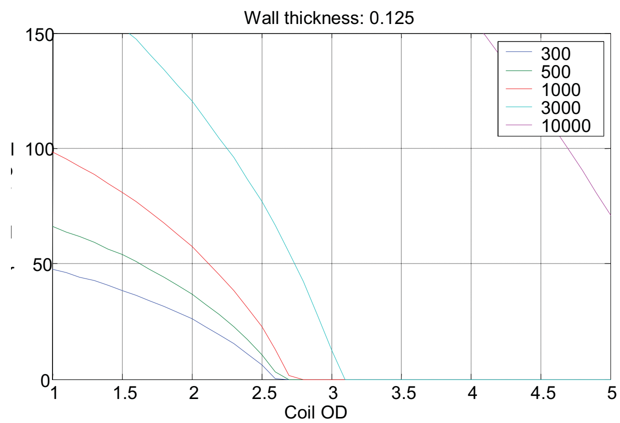
From equation (12) we see

$$M = M_w + M_q \le M_a \quad \Rightarrow \quad M_w \le M_a - M_q \tag{17}$$

That is, the moment capacity left for the self-weight induced moment are the maximum allowable moment capacity of the coiled tubing for the specific combination of pressure and effective tension *reduced* by the apparent moment due to current, wave loads and vessel dynamic motions.
Figure 6 contain some illustrative examples for the allowable offsets with respect to lower end bending without applying any bend limiting devices. The curves are obtained assuming no currents and dynamic loading.

There are also limits on the applicable OD of the coiled tubing. These limits depend on the water depth, the mass density of the content, and the OD and wall thickness of the coiled tubing, i.e. the weight of the suspended tubing. The relations are non-linear. Thus it is not possible to establish simple criteria for the applicability of particular coiled tubing with respect to water depth.

Figure 6 show the maximum offset that can be allowed without any bend-limiting device for different coiled tubing dimensions. Neither dynamic motions nor current action is included. Such loads will reduce the operating envelope, especially with respect to the upper end.



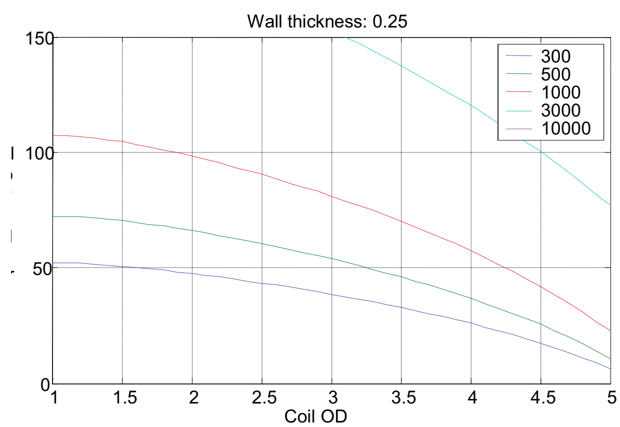


Figure 6 Coiled tubing allowable offset as function of coiled tubing diameter for waterdepths 300-10000 ft.

Figure 7 shows how the diameter of a funnel or bell-mouth at the top of the lubricator influences the allowable vessel offset. We see that for the shallow waters reasonable funnel opening diameters, e.g. 3 ft, impose restrictions on the allowable vessel offset, or the performance requirements to the DP system are narrowed. For the larger water depths, i.e. 3000 ft and below, there is almost no need for a funnel.

The dynamic effects reduce the presented static operational envelopes, which do not account for dynamic effects. The dynamic effects are largest at the upper end. Including dynamics will further increase the criticality of this section. At the lower end the effect of vessel dynamics decreases rapidly as the water depth increases and is almost insignificant below 500 ft water depth. At the upper end it is the vessel pitch and roll motions that may introduce the most severe dynamic loading on the coiled tubing. However, by introducing a gimbaled support for the tensioning device or a bend stiffener, moment loading on the coiled tubing caused by pitch and roll motions may be significantly reduced.

Dynamic analysis shows that as long as the heave compensation system behaves well the coiled tubing will survive for waves with large wave heights, well above 15 ft significant. However, if the heave compensation system fails, the coiled tubing will rupture or buckle even for significant wave heights as low as 2 ft.

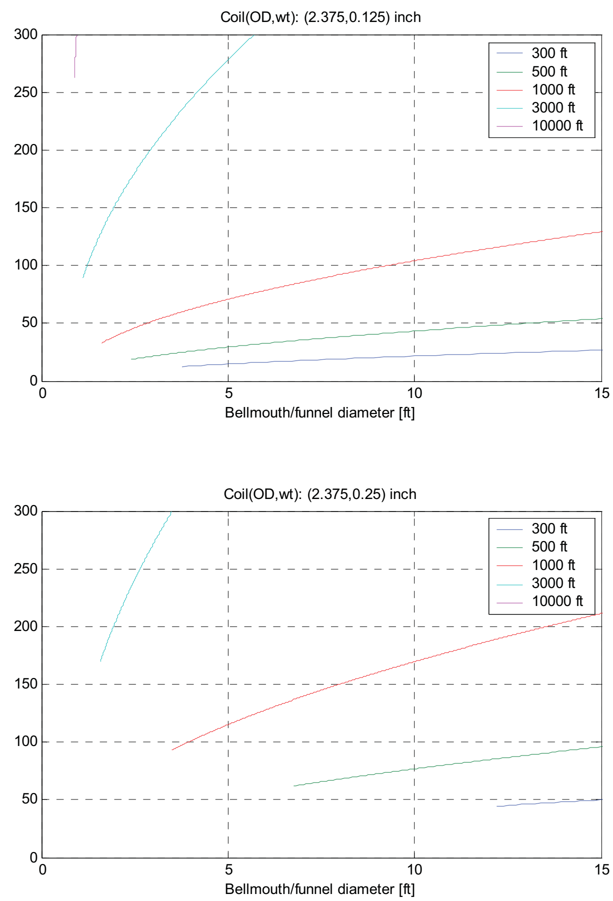


Figure 7 Bell diameter for various coiled tubing sizes

Analyses of the steep wave configuration. The steep wave configuration is a relatively complex and cannot be treated analytically as is the case for the static behavior of the top tensioned configuration. However, approximate models can be used to analyse part of the configuration analytically.

The upper part of the steep wave configuration, from the sag bend to the upper termination, can be approximated by a free-hanging simple catenary. Thus the top tension is given by the submerged weight of the tubing including content. The allowable upper end bending radii can therefore be calculated similarly to what has been done for the top tensioned configuration.

At the lower end the steep-wave configuration need a bend restrictor or a bend stiffener in order not to be damaged by the static loads. Figure 8 can be used to get an idea of the minimum allowable bending radius for the lower part of the coiled tubing in the steep wave configuration with internal pressure and applied tension. Assuming a design net internal overpressure of 7000 psi, we see that the minimum allowable bending radius quickly exceeds 50 ft.

The necessary length of the bend restrictor is given by the actual geometry of the steep wave configuration. This depends on several variables. Especially important are the density of the content and the length of the suspended part of the coiled tubing. Assuming that the angle between the lubricator and the tangent to the coiled tubing at the inflection point between hog bend and sag bend is 135°, the required length of the bend restrictor easily becomes as large as 130 ft. This is the case for tubing with 2 7/8” OD and 0.2” wall thickness, which has a minimum, allowed bending radius of approximately 65 ft for a net internal overpressure of 7000 psi.

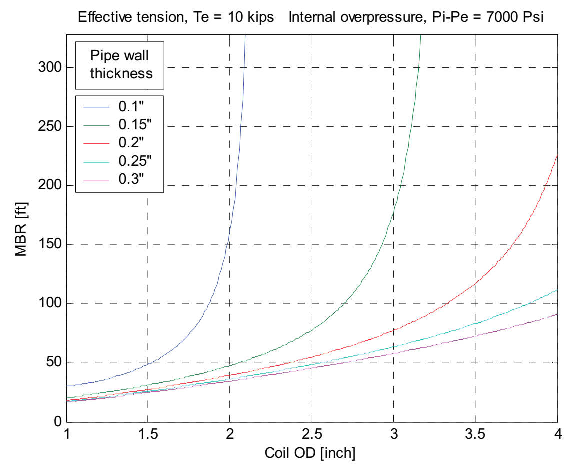


Figure 8 Coiled tubing MBR dependence on OD and wall thickness

Dynamic analysis of the configuration show that provided sufficient bend restrictor devices are applied both at the top of the lubricator and at the vessel connection, the coiled tubing should survive without detrimental damages in sea states with a significant wave height around 13 ft, however the practical implications of a large bend restrictor system, and the requirement for pipe-straigthening below eliminates the steep-wave configuration. A tensioned coil configuration and a heave compensation system are thus required to ensure coil integrity. A coil monitoring system including position and tension measurement subsea is required in addition to the normal wear monitoring

Equipment design and qualification

The system consists mainly of parts that have been used in similar applications such as workover riser systems or surface coiled tubing systems. However, the subsea lubricator, the retractable subsea injector, and the electric drive for the subsea injector are considered new and require a testing and qualification program to be carried out.

Subsea lubricator. The subsea lubricator system consists of the Coiled Tubing Lubricator Package, (Figure 9), the Coiled Tubing Injector Package and the Well Barrier Package. The Injector and Barrier packages are run together, as shown in Figure 2, the Lubricator Package is then installed in a separate run. The toolstring and top section of the lubricator (above the guide funnel) is then run on the coiled tubing. This top section of the lubricator contains a fixed stripper element, a moveable stripper element, and a shear seal BOP that can cut the coiled tubing above the injector in case of a drift-off situation.

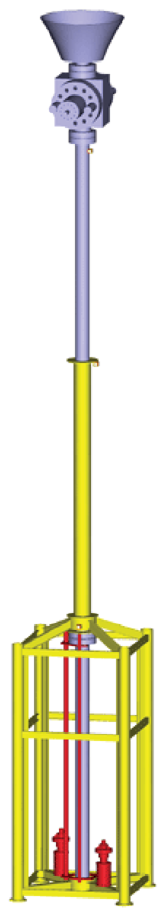


Figure 9 Coiled tubing lubricator

After the toolstring is installed in the lubricator, the coiled tubing injector belts are retracted, and the lubricator pipe is run through the injector and connected to the top of the Well Barrier Package. The lubricator is then flushed and pressure tested against the gate valve in top of the Well Barrier Package and the fixed stripper in the top of the lubricator.

The gate valve in the Well Barrier Package can then be equalized and opened, giving access to the well. The moveable stripper element in top of the lubricator section is then pumped down inside the lubricator, together with the toolstring. The moveable stripper is then locked to the Well Barrier Package and the connection pressure tested through a test port.

After flushing and equalization of the lubricator for any hydrocarbons, the lubricator can now be released from the Well Barrier Package, leaving the moveable stripper element as the topmost item on the Well Barrier Package. After moving the lubricator pipe to its upper position, the injector belts may be engaged, and running into the well can commence. The moveable stripper element is the main stripper that will contain the well pressure. In the well barier package there are back-up stripper elements that can be used in case of failure of the moveable stripper. By using the moveable stripper as the main stripper element in operations, this wear critical item may be inspected and replaced between each run.

The moveable stripper is subject to a qualification program including a full scale prototype testing.

Injector Motors. The main power system for the coiled tubing injector package can be either electrical or hydraulic. Electrical Motors are more power efficient, easier to regulate and have less components and maintenance requirements than hydraulic motors. However, high voltage transfer and connections in a subsea environment is a challenge. The recent success of the Troll Pilot system [10] show that high voltage electrical systems can be used subsea with high reliability.

The major disadvantage of hydraulic motors is the increased dimensions of the umbilical, and a second umbilical would probably required if this option was selected. A qualification program for the subsea electrical motors is ongoing.

Vessel Requirements

Well intervention vessels for North Sea application are mostly modified diving, pipelaying vessels or purpose built intervention vessels. In more benign waters, i.e. frac boats may be a suitable alternative. The main requirements for any vessel would be:

- Sufficient length and deckspace to contain coiled tubing and wireline equipment, in addition minimum one WROV
- Vessel characteristics must be satisfactory regarding heave, roll and pitch for operations in the selected geographical area (for the North Sea this is 13 ft significant waveheight, yelding vessels of minimum 390 ft long)
- DP 3 system with full redundancy in technical and physical design, or an appropriate anchor system.
- The vessel must be equipped with a heave compensation system, both for installation of subsea equipment and running coiled tubing in tension
- The vessel must be equipped with sufficient pumping facilities for the planned operations including contingency
- Moonpool or deployment area bigger than 16 ft x 20 ft. A derrick arrangement above the moonpool is required.
- Deck crane capacity should be minimum of 66000 lbs for loading and unloading equipment.

The vessel must have accommodations for sufficient crew for ROV, coiled tubing and wireline operation simultaneously. In addition service personell for the downhole tools and operator representatives need accommodation. With the number of short term personell onboard, and requirements for quick mobilization of equipment a helideck would also be required to ensure efficient operation.

Safety and Risk Assessment.

A risk assessment of a riserless system compared to a workover riser based system has been performed. It is concluded that the riserless concept represents reduced risk to personnel compared to a conventional coiled tubing system. The two main contributing factors to the reduced personnel risk are:

- Moving the lubrication activities subsea, personnel will not be exposed to risks related to lubricating the toolstring in and out of the well (hydrocarbon leakages, blown seals or nipples, etc.)
- Reduced probability of personnel and environmental damage as a result of compensation system failures. The energy release upon this failure scenario will be significantly reduced compared to a workover riser based system, and will not involve release of hydrocarbons unless combined with failure of the coiled tubing flapper valves.

The main downside of the riserless concept is the increased risk of minor hydrocarbon releases as a result of leakages through the subsea stripper elements, and when flushing the lubricator. The risk of major hydrocarbon releases resulting from potential damage to the Xmas tree and wellhead, i.e. as result of inability to perform an emergency release of the workover riser from the Xmas tree, will be reduced. Although the number of scenarios with risk of minor spills is increased, the total risk of hydrocarbon release is not increased with the riserless concept.

Figure 10 and Figure 11 show the risk level for the different procedure steps in the operation. The figures show the number of risk scenarios, not the total risk level, which is equivalent for both the riserless and workover riser based scenarios.

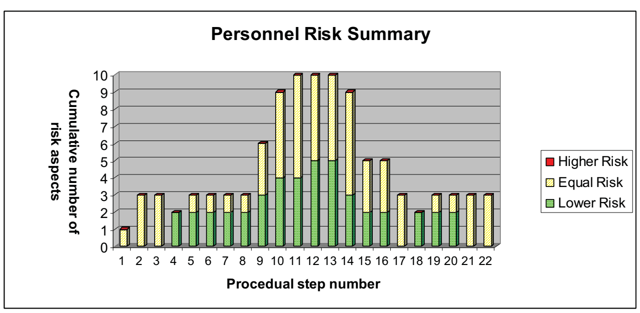


Figure 10 Personell Risk Summary

In addition to a comparative risk assessment, a Hazard and Operability Analysis (HAZOP) was performed. For the HAZOP, detailed operational procedures for normal operations, as well as the conceivable contingency scenarios was prepared, and reviewed in the HAZOP session. While a number of issues were found, this only resulted in minor design modifications or configurations. Implementation of a gate valve on top of the lubricator section was added as a result of the HAZOP review, to be able to cut the coiled tubing with perforation guns inside the Well Barrier Package in a drift-off situation.

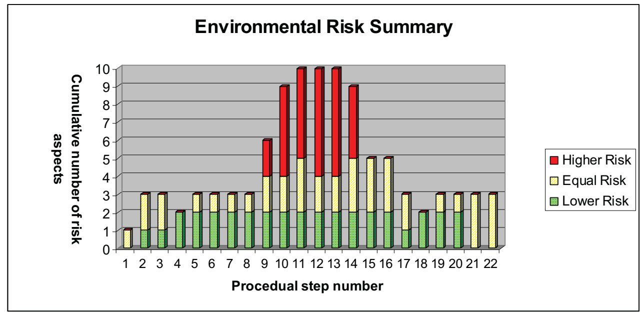


Figure 11 Environmental Risk Summary

The system has been reviewed against NPD requirements and relevant standards such as NORSOK-standards D-002, NORSOK-standard U-007, ISO 13628-1, ISO 13628-7 and ISO 13628-8. The riserless system complies with all the requirements and regulations applicable to the North Sea.

Conclusions

A system for riserless coiled tubing well intervention has been designed. The novel steps in the development are the lubricator system, where the lubricator resides on top of the injector, and the use of a tensioned coiled tubing configuration with a heave compensation system and a second coiled tubing injector at surface. The choice of a tensioned coil configuration has been performed based on state of the art riser analyses methods, which disqualified a steep wave configuration.

A comparative risk assessment has been performed, and concluded that the overall personell and environmental risk is the same or reduced compared to a workover riser based system.

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Nomenclature

M	*Applied bending moment*
M_k	*Plastic bending moment resistance*
T_e	*Effective tension*
T_k	*Plastic axial force resistance*
p_{ld}	*Local internal design pressure*
p_e	*Local external pressure*
$p_{\min}$	*Minimum local internal pressure*
$p_b(t_2)$	*Burst resistance*
$p_c(t_2)$	*Hoop buckling resistance*
η	*Usage factor*

t_2 *Nominal wall thickness*
f_y *Yield stress*
f_u *Tensile strength*
D *Nominal outside diameter*
α_c *Strain hardening parameter*
ρ_{mbr} *Minimum allowable bending radius*
E *Young's modulus*
I *Cross sectional area moment of inertia*
M_a *Maximum allowable moment*
M_{wB} *Lower end momen*
M_{wT} *Top end moment*
θ_{wB} *Lower end angle*
θ_{wT} *Top end angle*
$\alpha_T = \frac{T_B}{T_T}$ *The ratio between lower end and top tension*
w *The submerged weight of the coiled tubing*
L *Length of the coiled tubing from vessel to well head*
EI *The bending stiffness of the coiled tubing*
X_o *The top end offset relative to the lower end*

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Metric Conversion Factors

1 foot = 0.3048 meters
1 inch = 2.54 cm
1 psi = 0.07031 kg/cm^2
1 barrel = 0.1596 m^3
1 ppg = 119.82 kg/m^3