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Further Developments for Coiled Tubing Floater Operations

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Abstract

The number of new subsea-completed wells is increasing rapidly. At the same time, existing subsea field developments are entering more challenging phases of production with wells demanding a higher intervention frequency in order to maintain production and/or increase recoverable reserves. Consequently the demand for performing coiled tubing (CT) interventions in such wells is increasing. As an indication of this trend, one operator in Norway has seen a doubling of CT interventions in subsea wells in 2003 compared to previous years.

Today the most common installations available to perform CT interventions on subsea wells are semisubmersible rigs that are primarily designed for drilling and completion activities. The challenges of interfacing with and performing CT operations from these "semisubmersibles" are well documented [(1)]. Such challenges relate mainly to restricted access and space around the hoisting systems and, even more importantly, to the relative motion (primarily heave) that exists between the "fixed" wellhead/riser and the moving installation.

This paper describes newly introduced equipment and techniques that are now considered field tested to improve coiled tubing, semisubmersible operations by

- Reducing personnel exposure to safety hazards
- Reducing equipment exposure to damage hazards
- Increasing efficiency and the operational window with respect to heave conditions

Items to be described and discussed in this regard are:

- A latest generation lifting frame with integrated stripper crash frame and stabbing guide
- Revolutionary use of a new slip joint system that effectively cancels out the effect of heave during critical phases of the operations

Introduction

The Norwegian Continental Shelf (NCS) presents one of the most challenging offshore environments in today's oil and gas industry—particularly with respect to the weather and sea conditions experienced.

There are over 420 active subsea completed development wells already in place on the NCS and the number is increasing steadily at approximately 40 new wells per year. These wells are used in satellite activities for existing fixed platform developments and as part of stand-alone subsea field developments, which is where the majority are to be found. Subsea developments predominate the new field developments that are underway and planned.

Fig. 1—The Norwegian Continental Shelf including North Sea and Norwegian Sea areas with the Statoil Åsgard field highlighted.

Figure 1 shows the geographic location and extent of the Åsgard field, where much of the technology developments discussed in this paper has been focused. The field is located in one of the most northerly areas of the world with significant offshore oil and gas drilling activity and challenging weather and sea conditions.

Over 90% of the existing subsea wells on the NCS are located in latitudes of 60º or more, and the trend is moving even further north for future developments. Water depths at the subsea wells completed range from less than 100 m for satellite activity around fixed platforms to 380 m. Upcoming subsea fields will be developed in water depths in excess of 1,000 m.

The average wellbore measured depth is around 4,200 m with maximum depths exceeding 7,000m for some wells. The majority of the wells have horizontal or highly deviated sections. Around 70% of the existing subsea wells are oil producers with the complement made up of gas or gas/condensate producers and water and/or gas injector wells. CT sizes used range from 1 3/4" to 2 3/8" outside diameter. Subsea wellheads installed include both vertical and horizontal designs. Intervention operations from conventional semisubmersible rigs are being conducted using both concentric and in-sea, dual-bore riser systems.

Intervention Activity and Limitations. The need for intervention in the subsea wells on the NCS has been of increasing interest in recent years. This is partly the result of the relatively low reserves recovery from these fields when compared with platform developed fields in the same area. It became clear that a step change in the reliability of the methods being used was required to safely attain the levels of intervention activity demanded. This need was particularly acute for coiled tubing operations—where the extreme sensitivity to sea conditions, which in turn is directly related to safety concerns—is often disruptive to the operations.

Several campaigns of wireline intervention from light well intervention vessels utilizing subsea lubrication systems have been conducted and are likely to increase in frequency. Although there are ongoing initiatives to develop "light" solutions for coiled tubing interventions it is expected that such systems will not be available and suitable for NCS conditions for several years. For the foreseeable future therefore, it is expected that the majority of CT interventions in these wells will be conducted mainly using fixed riser to surface from conventional floating rigs. It is for this reason that solutions, to the limitations of conventional CT interface systems for semisubmersible rigs, have been pursued.

Equipment Developments

The equipment being referred to here are those items used to create the interface between a 'standard' CT unit, the rig/derrick and the subsea riser system. A generic CT unit configuration is typically used. The well control stack from the top of the surface flow tree and up consists of a four-function blowout preventer (BOP), riser quick connect, dual-stripper with the injector head, and goosneck on top.

As is normal with the introduction of new equipment, a number of incremental improvements have been implemented. Whereas some of these are discussed in the paper, the main focus here is on the key features that have allowed "step-change" improvements in the working conditions and work processes for these operations.

The system developments described in this paper are the result of a series of collaborative efforts between the CT service supplier, specialist engineering companies, drilling contractors, and offshore operator companies. In that regard it is not possible to overemphasize the importance of the input from the offshore personnel directly involved in the operations. A proactive and creative approach from key individuals with first-hand experience has been crucial for the success of these projects.

Conventional Equipment. For the purposes of the subsequent discussion a "conventional" interface is defined as one where a simple tension frame (CTF), consisting of two vertical and two horizontal members, is used to create a "window" in the compensated system between the traveling block and the riser. The surface flow tree (SFT) is suspended below the frame on bails. The CT equipment is usually located inside the window of the tension frame. A typical arrangement is illustrated in Fig. 2.

A winch at the top of the frame is used during installation of the BOP and injector head and also to manipulate the injector head during installation and removal of bottom hole assemblies (BHA). Typically this winch is the only means, within the structure of the frame, for manipulating the injector head. Rigging operations inside the frame require direct, and intensive intervention by personnel who must be transferred in and out of the frame and be supported at height when inside the frame. The transport and support is normally achieved using "manrider" winches located in the derrick of the rig.

With this basic system, it is necessary to maintain tension through the frame, SFT, and riser system at all times after the subsea riser has been landed and latched onto the wellhead. For that reason all stages of the subsequent operations with the CT system must take place with relative motion between the working window in the CTF and the rig and other items making up the CT unit—most notably the reel.

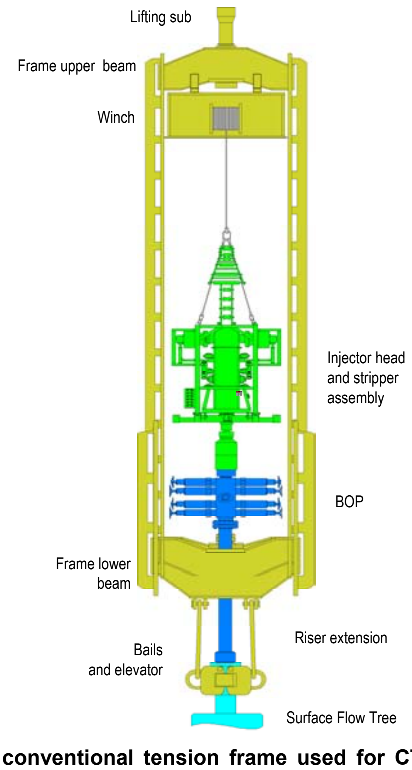

Fig. 2—A conventional tension frame used for CT and wireline interventions on semisubmersible rigs where all items shown are in motion relative to rig, derrick and CT reel

There are key disadvantages to this conventional system

- Once the subsea intervention system has been latched onto the wellhead, all transfers of equipment and personnel between the rig floor to the tension frame must go from one motion frame of reference to another.
- Whenever the injector head is unlatched from the BOP, it has multiple degrees of freedom of movement that represent a safety hazard to any personnel in the vicinity.
- Personnel working with equipment installed inside the tension frame must rely on riding belts for support most of the time. There are few stable work platforms on which to position themselves
- Coupling and uncoupling equipment inside the tension frame is personnel intensive and for most activities requires at least two people.

Figures 3 and 4 highlight the difficult working conditions that can be experienced by personnel during operations using a CTF. The figures show two operators, supported in riding belts, working around the injector head. The CT BOP can be seen towards the bottom of the figures. As can be seen, it is a challenge to find suitable support points to allow free work with the hands.

Fig. 3—CT operators working underneath the suspended injector assembly while changing out the BHA

Fig. 4—CT operators trying to maneuver on a conventional tension frame

Advanced Tension Frame. A modified tension frame (**Fig. 5**) has now been extensively field tested in Norway.

Fig. 5—The advanced tension frame used on Transocean Searcher pictured during yard testing

The Advanced Tension Frame (ATF) serves the same basic function as a conventional frame, but has several key features that provide important benefits for the personnel involved in these operations.

- Remote operated injector support platform with
  - Self-locking lifting screws to raise and lower.
  - Hydraulic side skidding.

- Injector head guide frame.
- Optional remote controlled folding for transport and installation in/out of the derrick

As a result it is possible to install, remove, latch, and unlatch the injector head and displace from the well center without direct personnel intervention. All operations can be controlled remotely. In addition, personnel are not required to work under or adjacent to a suspended load when installing and removing BHAs from the riser. This is a major advantage compared with conventional frames where the heave, roll, and pitch of the rig can cause the suspended injector head to move erratically at the same time personnel are required to work adjacent to it.

- Dedicated personnel work platforms for the injector head and BOP work areas **(Fig. 6)**.

  Consequently personnel performing normal tasks inside the ATF do not rely on riding-belts as working support, only for transfers and as fall arrestors.
- The surface flow tree is installed in the lower horizontal member of the ATF and latched in by means of a hydraulically operated gate.

  In some situations, this makes it possible to install the CT BOP on top of the SFT prior to latching on with the ATF—further reducing personnel exposure to rigging operations inside the frame.

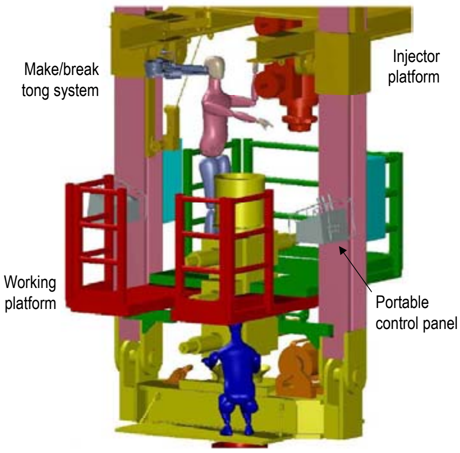

Fig. 6— With the advanced tension frame it is possible to create a much-improved working environment for the personnel changing out the BHA

Additional features of the ATF which further enhance these operations are

- A remote-operated winch with swing boom for handling the BHA that allows it be picked up from the rig floor, centered over and inserted into the riser with only remote operations.
- A portable wireless remote control panel for all ATF functions previously described (**Fig. 7**). With the panel the operator has full flexibility in adopting the best position from which to observe and control the frame functions for any given work task.

Fig. 7—The portable wireless control panel being used to control the advanced tension frame on Transocean Searcher

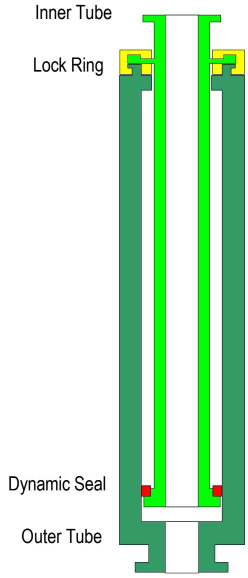

Fig. 8—The main components of the slip-joint are illustrated

Slip Joint. The most recent innovation to deliver a step-change improvement for operations is a pressure sealing slip joint (BLAFRO HEAVE ARRESTOR®) installed as part of the riser system below the surface flow tree. The principal of the slip joint is quite straightforward and follows a concept that has been well known for many years but has only recently become a practical reality.

The slip joint illustrated in **Fig. 8** is effectively a telescopic pipe with an internal pressure rating of 600-bar (60,000-kPa) working pressure at a design load of 400MT. It can operate in heave of up to 4m. It is typically positioned in place of a conventional “slick joint” through the rotary table. The slip joint is not pressure balanced and is only intended to contain pressure when fully extended.

There are three basic operational modes for the slip joint:

1) Locked. The inner tube is mechanically locked to the outer tube during installation in the riser system and hookup to the SFT and tension frame.

2) Stroking. The complete riser assembly, slip joint, SFT, and tension frame is held in the traveling block. The weight of the riser is taken up by the rig riser-tensioning system directly or through a marine riser. The slip joint is now unlocked and the tension frame and SFT can be lowered so that the slip joint is at the “mid-stroke” position. The tension frame is effectively decoupled from the riser with respect to heave motion, and allows rigging operations and personnel transfers to be conducted without the influence of relative motion between the rig structure and the tension frame. The floating function is only enabled when the riser system is depressurised.

3) Tension. Prior to pressuring up the riser system and opening the wellhead, the slip joint is stroked to its maximum extension, and the riser is tensioned using the traveling block.

Figures 9, 10 and 11 illustrate the tool function and its use during the trial operations offshore.

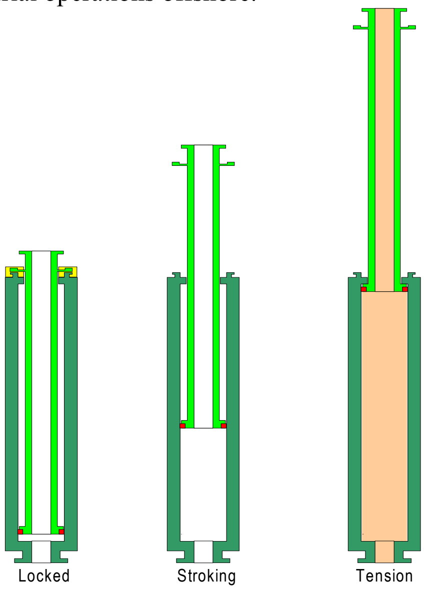

Fig. 9 – The three working positions for the slip joint

Fig. 10—The slip joint is pictured after installation below the surface flow tree on Transocean Searcher

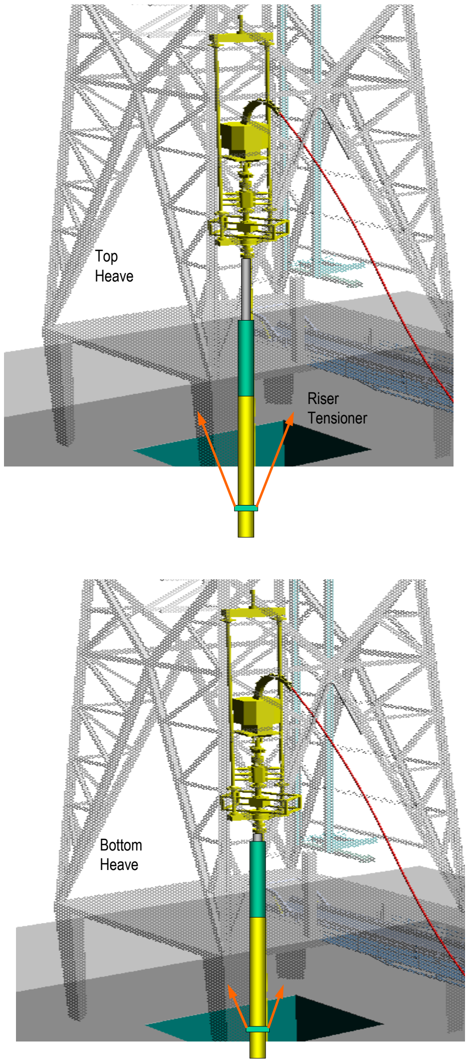

Fig. 11—With the slip joint in the stroking position there is no vertical movement between the tension frame and the rig

An additional benefit of operating with the slip joint is there is no relative motion between the injector head and coiled tubing reel when the coiled tubing is stabbed into the injector head (and not being run in the well). This removes any concern about damage to the pipe at the gooseneck and/or the reel when exposed to prolonged periods of heave. Such problems have been observed on previous operations with conventional frames.

Applicability. To date this new tool has been used with concentric (riser inside riser) systems because of the particular situations at the field-test sites. Development of a dual-bore slip joint system is not anticipated. However on most intervention operations with dual-bore risers (which do not require entry down the annulus bore), it is expected to use the slip joint by implementing a straightforward modification to the uppermost section of a standard dual-bore riser.

The prototype slip joint used for these successful trials is now undergoing certification revision prior to release for general use with the range of rigs and riser systems normally encountered.

Operational Experience Summary

There are three tension frames now in use on the NCS incorporating the advanced features described in this paper. In the past 2 years, more than 15 well operations have been completed for 2 different operators on a number of different rig designs—including a "Ram Rig" configuration. A wide range of coiled tubing applications has been involved including fill cleanout, milling, perforating, tractor assist, and straddle installation.

The high-pressure slip joint has been used on four different coiled tubing well operations, each time in combination with an advanced frame. Three of these jobs were on the Transocean Searcher rig working in the Åsgard field where the system was originally specified and developed. The most recent job was on a different rig and field for the same operator, and was completed in November 2003.

Feedback from the offshore personnel working on these operations has been described as "overwhelmingly positive." The normal challenges with introducing new equipment have been greatly outweighed by the immediate benefits of the new systems.

Impact on Operations

The impact, of the technical developments described previously, is discussed in terms of safety, operating uptime and efficiency.

Safety. The incidence of injury or damage involving personnel or equipment for these operations is extremely low. There have been no occurrences related to heave motion. As a consequence it is, fortunately, not possible to use statistics to describe the impact of the developments discussed here on levels of safety. With this in mind we do consider that it is both possible and important to provide some means of quantifying the impact on reducing hazards for the operations since that was one of the key drivers for the technology developments. Previous discussions have tended to use subjective terms such as "better" and "improved" without attempting to quantify the relative impact of specific initiatives.

A straightforward system is applied that is based on identifying generic actions, or tasks, performed during an operation. Each task has an associated hazard exposure level (HEL). HEL values for specific tasks are assigned as part of the analysis process. Each task being assigned a value between 1 and 10 depending on the assessed level of exposure with 10 being the most severe. The values are derived from a combination of observation, interviews with offshore personnel and consideration of objective factors such as time and energy involved in specific tasks. They are, therefore, ultimately subjective, but for the purpose of comparing alternative operating scenarios, this evaluation is considered superior to a purely "gut feeling" approach. It should be noted that these values are of no meaning in absolute terms of safety. They are only used to provide a comparison of different situations.

The following hazardous tasks are identified with assigned HEL values:

A. Personnel transfer in riding belt between two structures in same motion frame of reference (MFR) (HEL 1)
B. personnel transfer in riding belt between two structures in different MFR (HEL 3)
C. personnel supported by riding belt while working in heaving frame (HEL 6)
D. personnel working adjacent to suspended heavy load in heaving frame (HEL 8)
E. equipment transfer between two structures with different MFR (HEL 2)

The general operational scenario used here to assess the impact of the new equipment is one where a coiled tubing intervention (two runs) is scheduled between wireline runs. As a result, the activities to install and remove the riser system and tension frame are excluded from the analysis. This is considered reasonable, because the details of these activities can vary significantly depending on the wellhead, riser, and rig configuration encountered. The intention is to provide a generic analysis.

Table 1 indicates the operation stages that are to be conducted. These same stages apply equally for all scenarios. For each stage, the sum of the applicable HEL counts is displayed in the columns on the right with the total for each scenario summarized on the bottom row.

Operation stage	Scenario			
	Conven-tional	ATF	Conv. +slip-joint	ATF + slip-joint
Transfer 2 crew up	6	6	2	2
Install BOP + BHA 1	30	30	12	0
Install injector	30	2	12	0
Transfer 2 crew down	6	6	2	2
Transfer 2 crew up	6	6	2	2
Change to BHA 2	30	2	12	0
Transfer 2 crew down	6	6	2	2
Transfer 2 crew up	6	6	2	2
Remove injector head	30	2	12	0
Remove BOP	30	30	12	0
Transfer 2 crew down	6	6	2	2
Total HEL count	**186**	**102**	**72**	**12**

Table 1—A numerical interpretation of the reduction in exposure to hazards associated with heave and working conditions in the tension frame

To reiterate, the interpretation of this data is only relevant in relative terms when comparing the different scenarios for the specific hazards being considered. They have no relevance in absolute terms.

The indications are very clear. Either of the two main technology developments (ATF and slip joint) used individually has a significant impact on reducing the exposure to hazards for the operation. When used together, it can be seen that the majority of the usual hazards, specific to these types of operations, are avoided altogether.

Operating Uptime. One of the most significant factors that can contribute to operational downtime for coiled tubing operations on semisubmersibles are interruptions due to weather/heave conditions moving outside of the accepted working envelope. For conventional coiled tubing operations on semisubmersible rigs in Norway, a maximum limit of 1.5-m heave is normally set for conducting rigging operations and personnel transfers in tension frames. With the introduction of the pressure containing slip joint, this limit is no longer applicable. The relative motion between the rig and riser system below the slip joint is not experienced in the derrick where the rigging work is being conducted. Consequently the maximum rig heave allowable for coiled tubing rigging operations is increased significantly.

It is possible to quantify the impact of this easing of the heave constraints by considering the example of the Transocean Searcher rig used for drilling and well intervention operations in the Åsgard field. While it is noted that the relationship between the wave height statistics and rig heave behavior is specific to a given area and rig design, the general conclusions from this analysis can be equally applicable to other areas and rigs where coiled tubing operations can be adversely affected by weather and the resulting rig motion.

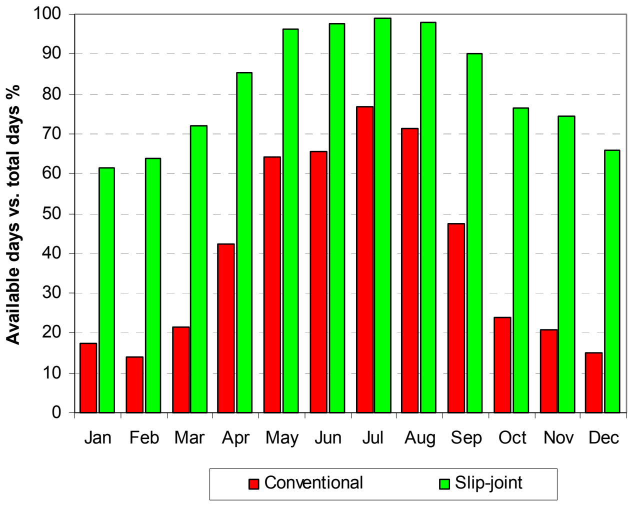

Fig. 12—Comparing the CT operational window for the Transocean Searcher at Åsgard with and without the slip joint

From the information presented in **Fig. 12,** it becomes clear that there is a very significant impact from introducing the slip joint, particularly in the winter months where, on average, the number of available operational days is doubled. Regardless of how the data is analyzed, the practical implications remain straightforward:

- Coiled tubing operations are no longer seen as the "weak-link" in the rig activity schedule and can effectively be conducted within a similar weather and sea conditions envelope as the other rig activities.
- The period of the year where coiled tubing operations can be confidently planned expands from the minority (core summer months) to the majority, including spring and autumn.

Efficiency. As mentioned previously, operational efficiency was not the primary driver for these technology developments. At the same time, it is reasonable to expect that by providing a working environment where personnel can focus more on the job in hand, and less on the challenges of maneuvering and positioning, the work tasks should be more quickly achieved.

There is insufficient data available to make any direct statistical comparisons between operational efficiency with and without the ATF and slip joint developments referred to in this paper. The total job count is not high, and the equipment has been utilized in a variety of configurations and locations as described. The best available data is from the Transocean Searcher operations in the Åsgard field, which has the highest job count for the same rig, riser system, and location. This data is contained in **Table 2**.

Activity	Convent-ional (4)	ATF (2)	ATF + Slip joint (3)
Rig-up frame	17.2	18.8	20.3
Rig-up CT after wireline	23.4	17.7	16.3
Change BHA	11.6	14.8	11.1
Rig-down CT for wireline	11.3	11.2	12.5
Rig-down frame	8.3	5.0	9.2

Table 2—The average number of hours taken per task. The number of jobs is indicated in brackets in row 1.

It may be observed from Table 2 that a considerable length of time has been taken for changing out BHA, particularly on those jobs with the ATF and ATF plus slip joint. It should be noted that a majority of these operations involved insertion and removal of long strings of perforating guns. A great deal of the time taken was associated with safe handling of the explosive systems involved and not associated with operation of the equipment inside the frame. Current evaluation indicates that efficiency gains on specific tasks of up to 20% can be expected once the new equipment is completely integrated and with the offshore crews fully experienced.

Conclusions

1. Field tested technology is available that is capable of providing a step change improvement in safety, reliability, and efficiency for coiled tubing operations on semisubmersible rigs.
2. An advanced tension frame has been developed and extensively field tested. The frame considerably reduces the need for personnel to directly handle heavy equipment in the tension frame. When personnel are required to enter the frame, a significantly improved working environment is available when compared with conventional frames.
3. A pressure-rated slip joint has been field tested on four operations, and is now proven to offer a major reduction in the sensitivity of the coiled tubing operations to adverse weather and rig heave conditions.
4. When the advanced tension frame and slip joint are used together, the majority of the usual hazards specific to coiled tubing semisubmersible operations, is avoided.

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