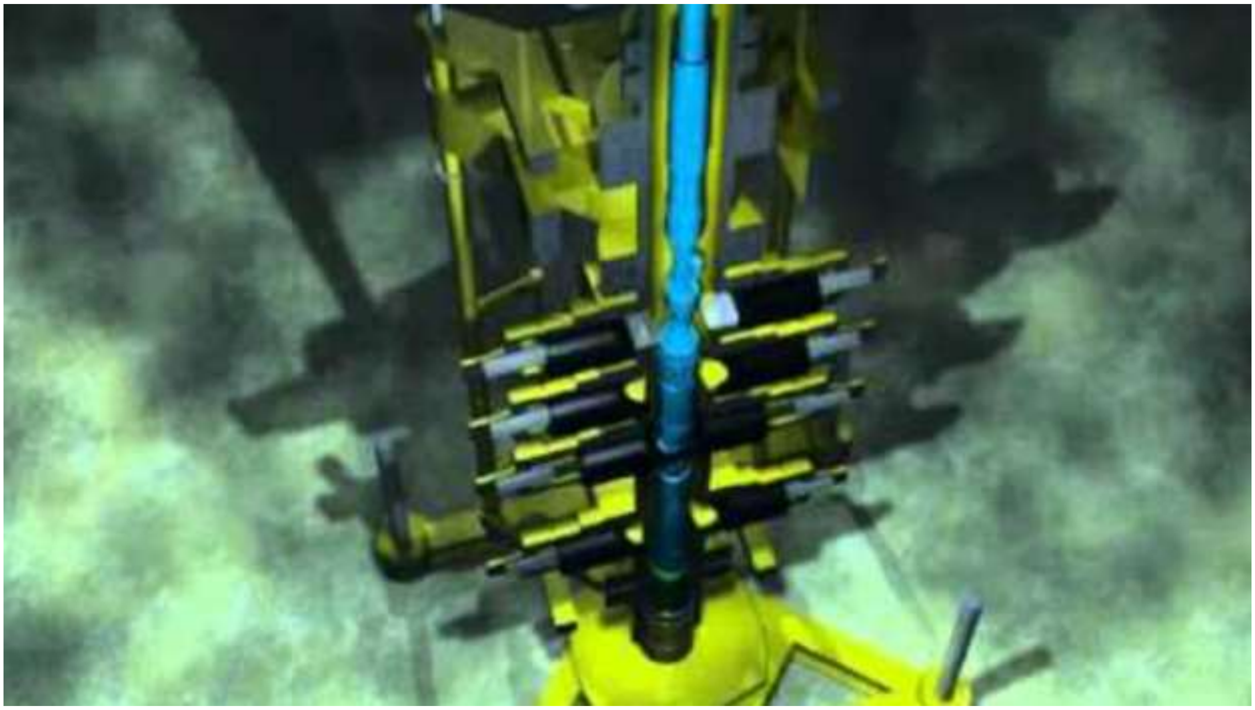
Subsea Hardware Training Exercise - Wellhead, XT, SSTT by Grant Pierce



Some time back I was compiling information (in the form of a refresher/training exercise) with regards to the hardware involved in a subsea well completion.

The following information is taken from multiple trusted sources then compiled into one document. I hope that it's useful here as a technical resource.

1. List the main functions of a subsea wellhead (WH):

• Structural base and pressure containing anchoring point for all the drilling and c completion systems subsea.

• Incorporates internal profiles that support the various casing strings and isolate the annulus.

• Connection and support when drilling and completing the well.

The WH must be able to:

• Support the weight of the BOP stack plus the weight of any drill pipe or tubing string hung from the BOP rams. *If the well is completed with HXT, the WH will need to support the combined weight of the horizontal tree plus the BOP stack.*

• Withstand bending resulting from riser offset.

• Provide a seal for the BOP stack and production tree.

• Support and lock down all casing and tubing strings.

• Provide pressure integrity between casing strings, and between casing and production tubing.

• Contain maximum WH pressure and test pressure.

• Assist with the orientation of the subsea tree.

2. Name the main components in a subsea WH system:

The main components that comprise a subsea WH are: Temporary guide base (TGB), Permanent guide base (PGB), Conductor housing, & Wellhead housing; additionally casing hangers & annulus seals. The high-pressure WH housing is the primary pressure-containing body for a subsea well, which supports and seals the casing hangers. It also transfers external loads to the conductor housing and pipe, which finally are transferred to the seabed.

3. What are the considerations when choosing a subsea WH system?

Axial loads, Hook loads, Pressure cycling, Dynamic bending loads, Thermal induced expansion & contraction, Vibration induced loads, Well Fluid make-up, Light Architecture well, Heavy Architecture well, Temporary Guidebase, Hydrate Remediation of Temporary Guidebase/Permanent Guidebase

4. What is the main purpose of a XT system & its components?

• Vital component in the well integrity barrier envelope.

• Attaches to the WH and directs flow through a series of valves to the flowline.

• Used to isolate flow from the well; Flow is regulated at the choke that is normally attached to the tree downstream of the wing valves.

• Provides access for well intervention operations.

5. Describe the main components of a VXT system:

Conventional dual bore trees have a 5 in. production bore and a 2 in. annulus bore through the body of the tree. Flow from the production bore is isolated using the master valve and/or production wing valve. Most trees have two master valves (upper and lower). A swab provides access to the production bore for intervention purposes. A smaller secondary bore (2 in. nominal ID) is used to access, monitor, and vent the annulus. Most trees have only a single master valve and a swab valve on the annulus side.

Since the introduction of large bore vertical trees most of the advantages of horizontal and vertical trees have been combined. A large through bore allows large tubing (up to 7 in.) to be run without having to reverse taper below the hanger. A dedicated riser system is not required as the tree can be run on drill pipe. Intervention access is possible with a mono-bore riser system which is available as a rental package when required. The riser system allows circulation with fluid returns through a large bore hose in the control umbilical. TH is landed in the WH.

Mono-bore vertical trees do not need to be run on a dedicated riser system. They can be deployed from the rig using drill pipe and a control umbilical (or these days with Optime Subsea ROCS). Some operators choose to run the SS XT from a support vessel after the rig has moved off location, by using the vessel crane and a control umbilical.

To enable this to happen, the well is typically shut in using a formation isolation valve (FIV) and a retrievable plug in the tubing hanger. Once the tree is installed, the tubing hanger plug is removed using rlwi methodology (open water wireline). Pressure cycles are then used to open the FIV; this methodology is equivalent to significant cost savings, as the rig can leave location as soon as the completion has been landed and the well temporarily shut in.

Similar to a horizontal XT system the tubing hanger can be installed either with a simplified landing string or a conventional landing string with subsea test tree. What differentiates the vertical XT system is the guiding system which is required for the tubing hanger to be correctly aligned inside the WH before the Vertical XT is installed. This is usually performed via a tubing hanger orientation joint which interfaces a specific pin in the BOP. The orientation joint can be integral both in the simplified and conventional landing string, giving operators the same choice regarding clean-up philosophy as for horizontal XT systems.

After the tubing hanger is landed and locked in the WH appropriate barriers are required to be installed in the well to be able to install the vertical XT safely. The typical scope of work would be installing a shallow set mechanical plug in conjunction with a deep set remotely operated plug, but this varies and depends on operator preference. Alternatively, the shallow set mechanical plug can be replaced with a remotely operated plug (e.g. glass plug) which can be opened by pressure cycling to avoid having to re-connect an intervention system to the VXT to pull the mechanical plug.

The vertical XT on tubing head spool is in simple terms a combination of both vertical and horizontal XT systems. The tubing hanger is installed inside the tubing head spool while the vertical tree is installed on the re-entry hub of the tubing head spool. Similarly to horizontal trees, this enables the WH provider to be chosen independent of the XT provider, while providing the ability to retrieve the XT without having to pull the tubing hanger.

The tubing hanger is installed like a horizontal XT system where guidance of the tubing hanger is handled by an integral guiding system within the tubing head spool. The choice of landing string (simplified or conventional) for tubing hanger running is normally based on the decided clean-up philosophy or whether other types of interventions are required prior to the installation of the vertical XT. Similar to a horizontal XT system the same choices regarding well isolation prior to XT installation applies where different alternatives are available.

6. Outline the main well construction steps for a subsea well with a VXT:

1. Spud well & drill top hole

2. Run BOP stack on marine riser

3. Drill to TD & install/cement liner

4. Install completion & Tbg hanger

5. Install temporary barriers

6. Recover BOP stack

7. Perform pre-installation tree tests

8. Skid tree to moon-pool

9. Push guide wires into tree guide arms

10. Install lower riser package (LRP) and emergency disconnect package (EDP) on tree at moon-pool area

11. Connect the installation and work-over control system (IWOCS)

12. Lower the tree to the guide base with tubing riser

13. Lock the tree onto the guide base & test the seal gasket

14. Perform tree valve function tests with the IWOCS

15. Retrieve the tree running tool (TRT)

16. Connect flowline jumpers and flying leads

17. Remove temporary barriers

18. Rig up guns

19. Run guns, correlate and perforate well

20. Flow test well

21. Recover intervention package

22. Run the tree cap on the drill pipe with the utility running tool system

23. Lower the tree cap to the subsea tree

24. Land and lock the tree cap onto the tree mandrel

25. Lower the corrosion cap onto the tree cap with a drill pipe (or lifting wires); or run an ROV installed corrosion cap

26. Install protection cover

27. Commission well from platform

7. Describe the main components of a HXT system:

With a horizontal (spool) tree, the tubing hanger sits inside the tree block. The “tree” is in the form of a concentric bore spool with a WH connector below and a second WH connector above. Since the tubing hanger lands inside the tree block, the tree must be installed before the completion tubing is run. A horizontal tree is very different in appearance from a conventional tree.

All the flow control gate valves are attached to the outside of the main bore; there are no valves in the vertical bore. During the landing of the tubing hanger, a production port on the hanger body is aligned with its counterpart in the spool of the tree and is the main flow conduit when the well is producing. Additional ports within the spool provide access to the production (“A”) annulus.

Annulus pressure can be vented to the production flowline through a cross-over loop controlled by gate valves. Tubing hangers for horizontal trees have a single concentric bore and side production outlet.

There are additional penetrations for downhole control and instrument lines. The exact configuration will depend on operator requirements and vendor design.

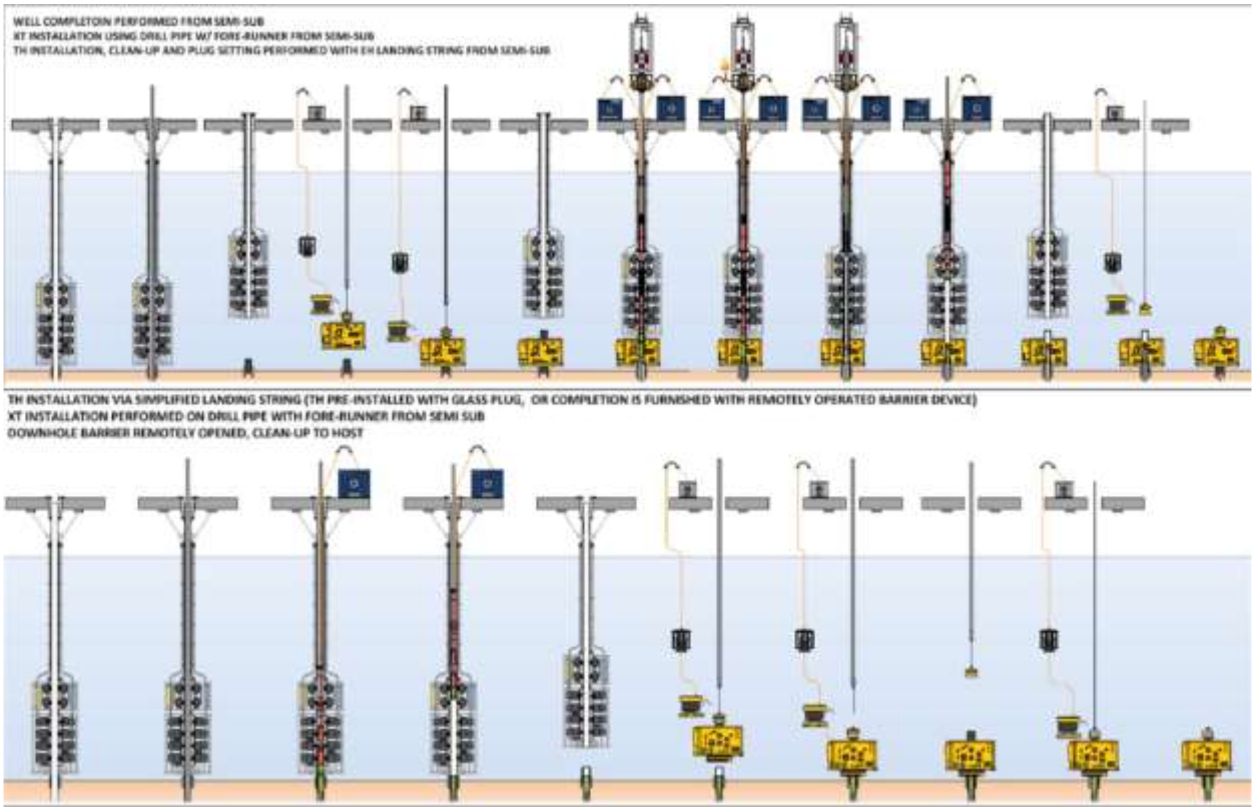
Orientation of the tubing hanger is necessary to align the production outlet in the hanger with the outlet in the spool. Most systems use an orientation helix built into the bottom of the hanger assembly. The helix engages a key slot in the tree spool, giving 180 degree of passive orientation as the hanger is landed. Once landed the hanger is hydraulically locked in place. The main hanger seals are metal-to-metal.

As there are no gate valves in the vertical section of the main production bore, mechanical barriers are needed for isolation of the produced fluids. An external metal-to-metal seal prevents pressure escaping between the hanger body and the internal diameter of the tree spool. A wireline conveyed mechanical bridge plug is set in the top of the tubing hanger assembly above the production off-take port. Set in the upper section of the tree spool (above the hanger), a high-pressure internal tree cap forms a second pressure barrier, ensuring conformance with double barrier isolation policy.

The internal tree cap also has a wireline set plug to isolate the production bore. It is worth noting that these wireline set plugs form an essential component in the well integrity barrier envelope. To reduce the possibility of a leak, they are run without an integral equalizing device. This can make the crown plugs difficult to pull, particularly the lower crown plug.

If a horizontal XT is utilized the well is prepared with a suitable casing program and the lower completion is installed. Due to the location of the tubing hanger in horizontal XT systems the BOP is at this point removed and the XT is deployed and locked to the WH. The BOP is then re-connected to the re-entry hub on the horizontal XT before the tubing hanger is run and installed inside the horizontal XT.

Depending on the clean-up philosophy for the well/ field the tubing hanger can be installed either using an in-riser simplified landing string (i.e. spanner joint with no integrated well control features – utilized on dead well), or a conventional landing string with subsea test tree. Using the simplified landing string allows the operator to swiftly install the tubing hanger and crown plugs to minimize rig time. The downside is its inability to handle hydrocarbons, hence no well clean-up can be performed back to the rig. Utilizing a conventional landing string with subsea test tree allows for tubing hanger installation and subsequent well clean-up back to the rig due to its integral well control barriers, but is slower to run due to the increased equipment complexity.



8. Outline the main well construction steps for a subsea well with a HXT:

1. Spud well & drill top hole

2. Deploy BOP stack on marine riser

3. Drill to TD & install/cement liner

4. Retrieve the drilling riser and BOP stack, move rig off

5. Retrieve drilling guide base with ROV assistance

6. Run the production flow-base and latch onto wellhead housing

7. Run HXT

8. Land the tree, lock the connector, test seal function valves with an ROV, release tree running tool (TRT)

9. Connect flowline jumpers and flying leads

10. Run BOP stack onto HXT, lock connector, run BOP test tool and test, function-test tree

11. Retrieve suspension packer, remove wear bushing from tree, make up SSTT system, rack back.

12. Run completion string, make up tubing hanger tool (THRT) and SSTT system on tubing hanger, Run landing string with umbilical, Make up surface control head to landing string

13. Land hanger in production tree and test seals. Rig up wireline and retrieve straddle sleeve. Run seat protectors. Circulate tubing to potable water for drawdown. Set wireline plug, test string and set packer.

14. Rig up production test package. Rig up guns

15. Run guns, correlate and perforate well

16. Carry out production test, acid stimulation and multi rate test

17. Unlatch THRT and retrieve landing string and SSTT. Rig down production test package and flowhead

18. Run lower and upper crown plugs (2 runs)

19. Run internal tree cap

20. ROV closes tree valves

21. Retrieve BOP stack, retrieve guidewires

22. Install debris cap

23. Suspend well

24. Install protection cover

25. Commission well from platform

9. Explain the technical difference between Vertical (VXT) and Horizontal (HXT) xmas trees?

With HXT TH landed in XT (or the TH Spool) whereas with VXT TH is landed in WH.

10. Outline pros and cons with VXT and HXT:

Type of tree	Advantages	Disadvantages
Horizontal	The tubing can be pulled without having to remove the tree, which is an additional advantage with subsea operations as the need to disconnect flowlines and control umbilical is also eliminated	If the tree needs to be replaced, the completion must be recovered first
	Completion installation, tree deployment, and any subsequent well interventions are performed using standard drilling BOP, marine riser, and (well test) vendor supplied rental equipment—subsea test tree (SSTT)	There are no gate valves in the vertical bore of the tree. Well integrity is reliant on the BOP and SSTT during completion operations and post-completion perforating and well testing. This is arguably less secure than a conventional tree configuration
	The subsea tree provides an integral, precise, and passive hanger orientation system. No BOP modification (orientation pin) is needed	Well interventions are complicated by the need to remove and install the tubing hanger plugs to gain access to the wellbore
	Large bore. Large tubing size if required	The subsea tree must be able to withstand the loading associated with the subsea BOP and marine riser system
	Tree can be installed before drilling the reservoir if desired	Rental costs for SSTT
Vertical (dual bore)	No requirement to recover internal "crown" plugs when re-entering the well for interventions	Tree needs to be recovered when performing a tubing workover. This will mean having to disconnect flow line and control umbilical
		Limited through bore size (5 in. nominal)
		Dedicated LMRP/EDP and riser needed to deploy the tree and reconnect for interventions
Vertical (mono-bore)	Large through bore means large tubing size if required	Restricted flow path for returns if forward circulating—high ECD
	No dedicated riser system required	
	Well control barriers can be configured to allow the tree to be installed after rig departure—potential to save significant amount of rig time	
	No requirement to recover internal "crown" plugs when re-entering well for interventions	

11. What are some points to be aware of when deploying Subsea XMT on Wire:

- Double check lifting gear to confirm up to spec and fit for purpose
- Ensure correct valve configuration prior to deployment to avoid hydraulically locking connector on landing
- Ensure connector is fully unlocked prior to deployment
- Ensure gasket is painted with black/yellow stripes to make sure ROV can see it when installed into WH
- Ensure correct alignment prior to landing out on WH
- Ensure enough slack in wire when landing out XMT on WH taking into account heave
- Ensure 2 x ROV's are in the water set 90 degrees apart for best options to stabilize XMT

12. How does a Workover System differ from a Marine Riser/BOP?

Smaller bore, smaller system, less people to operate, less time to install and allowing safe well access for subsea well installation and completion, diagnostics, maintenance, repairs, enhanced production, and p&a.

13. Describe SSTT in detail:

The SSTT is a vital component in the landing/intervention string for any well equipped with a horizontal tree, as it provides the essential well control barriers until the time the tubing hanger and crown plug are installed.

To perform an intervention on a well equipped with a horizontal tree, the BOP and marine riser are first installed. The THRT is connected to the SSTT and the assembly is run into the riser on production tubing (normally with premium connections). The THRT is hydraulically latched onto a sealing profile in the top of the high-pressure internal tree cap.

Wireline pressure control equipment would then be rigged up on top of the riser and wireline used to pull both crown and tubing hanger plugs. With the plugs removed, valves in the SSTT are used to control flow from the well. They become the primary well control barrier until the wireline plugs are replaced.

The main points to note are:

• The THRT is locked onto the high-pressure internal tree cap. BOP pipe rams are closed around the SSTT slick joint. The closed rams are above the outlet for the kill and choke lines. The closed rams provide a well control barrier when circulating.

• Valves in the tree can be opened to allow communication with the annulus, and to provide a circulation path.

• There are two valves in the production bore of the SSTT. The lower valve is a ball valve with a wire and coiled tubing cutting capability. The upper valve is either a ball valve (ex. Expro) or a flapper (ex. Schlumberger); both are fail-safe.

• Above the two fail-safe valves is the disconnect latch.

• Above the disconnect latch is a shear sub. This must be positioned across the BOP shear ram. In the event of an emergency, or a vessel drive off, the shear rams can be closed to disconnect the landing string. Shearing the SSTT severs all the hydraulic lines, causing the SSTT valves to close (fail safe closure).

• In the lower end of the landing string a retainer valve prevents loss of hydrocarbons in the event of a disconnect.

• Some riser systems will have an additional "lubricator valve" positioned above the retainer valve.

• In addition landing string and surface flow tree (flow head) are part of this package.

The purpose of the subsea test tree (SSTT) is to provide well barriers within the high pressure upper completion string, and to facilitate well control in the event of an emergency disconnection of the rig from the well, without requiring the blowout preventer (BOP) to shear the shear joint.

The lower ball valve should be capable of simultaneous cutting of coiled tubing (23/8 in. x 0.156 w.t.) and 0.438 in. mono conductor wireline. A hydraulic latch mechanism is incorporated above the SSTT valves to provide a remotely disconnectable and reconnectable interface within the marine riser.

The SSTT interfaces with the slick joint at its lower end and with the shear joint at its upper end. The SSTT is spaced out by the slick joint to allow the blind rams to be closed above the latch interface and the shear joint to be positioned across the shear rams.

Externally - the SSTT should have a profile that allows it to be installed within the internal profile of the BOP stack (BOP Stack minimum ID = 18.75 in.). The SSTT should provide internal through porting to allow hydraulic communication to the various SSTT and THRT functions below the latch assembly.

The control umbilical should terminate above the packoff sub, and be through-ported to the top of the shear joint. Synthetic hose sections should be used for hydraulic control spanning the shear joint (metal tubes are not acceptable for this application). The synthetic hoses should terminate at the bottom flange of the shear joint, and hydraulic communication should be provided via internal porting from the shear joint lower flange to each lower control function as required.

Internally - the SSTT should have a bore suitable to enable the passage of wireline tools and tree equipment. All internal bore transitions are to be tapered so as not to interfere with or snag the wireline tools and equipment.

The SSTT should incorporate an anti-rotation feature to permit torque transfer during orientation of the Tubing Hanger (TH) or actuation of downhole completion equipment functions (and to prevent application of torque to the hydraulic couplers in the landing string, etc.). A point of fixation in the tubing string 400 m below the TH, and the requirement to rotate the string a maximum of 180 degrees above that point, should be assumed for the purposes of determining the required torque capacity for the anti-rotation device.

The SSTT should be composed of two major parts:

The lower part (below the emergency disconnect latch) remains attached to THRT and contains a minimum of two barriers in the production fluid conduit capable of containing the anticipated well shut-in pressure from below.

The upper valve is strongly preferred to be a flapper type valve, but a ball type valve in this position will be considered.

The lower valve should be a ball valve capable of cutting wireline and coiled tubing.

The SSTT valves should be fail safe closed. In the failed closed condition the barriers and the cutting device should have "pump through" capability to permit the passage of kill fluid at a suitable flow rate into the well, so that the well can be killed by bullheading in the event of a total failure of the SSTT or its control system.

The upper part of the SSTT (above the emergency disconnect latch) should be capable of disconnection from the lower part of the SSTT and retrieval to the surface, and should be provided with hydraulic connections to suit the attachment of the hydraulic hoses surrounding the shear joint. The unlatch operation should be operable without altering the rig top tension. The unlatch function should be fail-as-is.

Ensure there is a retainer valve to prevent unlatching under tension that may cause the upper SSTT to jump, and may damage the interface when it lands on the lower half.

The Retainer Valve should have the following requirements:

- Fail-safe closed
- No pump-through capability
- Able to retain the contents of the landing string upon unlatch from the SSTT

The connections at the emergency disconnect latch interface between the upper and lower parts of the SSTT should be provided with check valves where appropriate to prevent the ingress of the contents of the marine riser into the control lines.

Some of the lower coupler halves may need to vent to allow the valves to be fail safe closed. Also, the coupler should be separable under full line pressure of the hydraulic functions. Any electrical couplers communicating through the SSTT emergency disconnect latch interface should be wet mate-able and pressure sealing in both the coupled and uncoupled conditions.

The SSTT should incorporate an interlock to prevent release of the SSTT quick disconnect latch prior to closure of the upper (ball or flapper) valve. The structural integrity of the SSTT should be adequate to withstand the combinations of internal and external loading possible under all conditions expected during handling, including both normal and contingency operations. The material from which the SSTT is made should be suitable for the duty required, and for the fluids with which it may come into contact (understanding that there will be limited exposure time to acids used in well stimulation, and to produced fluids).

The SSTT should have a primary mode of operation using hydraulic fluid and controls conveyed via an umbilical. In addition, the SSTT should be provided with a secondary operating means, in the event the primary mode becomes inoperable.

Primary circuit functions:

Open upper SSTT valve

Close upper SSTT valve

Open lower SSTT valve

Close lower SSTT valve

Open retainer valve

Close retainer valve

Lock emergency disconnect latch

Unlock emergency disconnect latch

Injection of hydrate inhibitor (methanol) between lower SSTT valves

Bleed-off valve (for bleed-off below retainer valve)

Secondary circuit functions:

Close lower SSTT valve

Unlock emergency disconnect latch

Unlock Tubing Hanger Running Tool from Tubing Hanger

Retainer Valve

The retainer valve should be incorporated to hold the contents of the upper completion string and/or prevent communication of the upper completion string and marine riser contents after an emergency disconnect of the subsea test tree (SSTT) latch has been performed inside the Blowout Preventer (BOP)/marine riser. In the case where the upper completion string contents are high-pressure gas, the retainer valve prevents the release and expansion of the gas into the marine riser. This would result in the displacement of the marine riser contents to the rig, which in deep water may result in the collapse of the marine riser due to external hydrostatic pressure.

The retainer valve interfaces with the shear joint sub at the lower end, and either a space-out sub or packoff sub at the upper end, depending on BOP geometry. Externally, the retainer valve will have a profile suitable to enable it to be installed within the internal profile of the BOP stack.

Internally, the retainer valve should have a bore suitable to enable the passage of the components required to establish the required production barriers in the subsea horizontal tree. All internal bore transitions are to be tapered so as not to interfere with or snag the wireline tools and tree equipment.

The retainer valve should provide a minimum of one barrier in the production fluid conduit and be capable of retaining pressure from above. In addition, the retainer valve should not be provided with a pump through facility. In the fail closed condition, the barrier(s) should not permit the passage of kill fluid.

This is not seen as a disadvantage in the case of the horizontal subsea tree, as the well can be killed via the choke/kill lines and the tree mounted crossover valve, in the event the retainer valve fails to open. In addition, prior to getting back on the lower SSTT, the landing string can be tripped out of the hole and the retainer valve can be re-configured with pump-through capability if desired, in order to kill the well.

The structural integrity of the retainer valve should be adequate to withstand the combinations of internal and external loading possible under all conditions expected during handling, including both normal and contingency operations. The material from which the retainer valve is made should be suitable for the duty required, and for the fluids with which it may come into contact.

Note: Attention should be paid to the means by which a secondary release of Tubing Hanger Running Tool (THRT) is to be achieved, to ensure that the desired operation occurs if the retainer cannot be opened.

Lubricator Valve

The lubricator valve for the subsea test tree is a surface-operated hydraulic valve that is run from one or two joints below the flowhead. It enables the top of the string to be used as a lubricator during wireline, slick-line, or coiled tubing intervention operations, thereby reducing the amount of lubricator sections needed above the flowhead.

The lubricator valve is connected by a two- or three-line hose bundle to a surface-operating console. The third line may be used for injection of a hydrate inhibitor, such as glycol or methanol, just below the valve. In event of control line pressure failure, the valve will remain in the last position, open or closed, that it was placed in before the pressure loss occurred.

The lubricator valve is a pump-through valve and can be pressure tested from above (with hydraulic pressure maintained in the close line). When it is closed, the lubricator valve seals from either above or below to withstand the well pressure when tools are introduced or removed from the upper section of the test string being used as a lubricator test the flowhead and surface wireline or coiled tubing equipment.

Benefits of Lubricator Valve:

Increases operational efficiency by testing pressure-control equipment without needing to pressure up the entire landing string. Enhances flexibility by reducing the amount of surface equipment necessary in operations that require long wireline, slick-line, or coiled tubing strings.

Applications of Lubricator Valve:

- Subsea completions installation
- Downhole testing and evaluation
- Well cleanup

- Well intervention and abandonment

Other Features of Lubricator Valve:

- Tested and qualified to maximum pressure and temperature
- Holds pressure from above or below
- Enables pump-through to kill well by application of 1000-psi differential pressure from above
- Includes option for chemical injection at valve
- Incorporates a fail-as-is design
- Operates either as a lubricator valve or as a dual-valve system
- Actuates as many times as necessary for well intervention operations

Other considerations:

System layout

The subsea system layout will impact the installation strategy for a field. The most obvious parameter regarding the vertical axis is normally the geographical location of the wells and whether it will be possible to plan for batch completions. Depending on the choice of subsea tree this could for instance be jumping from well to well without having to pull the BOP to surface (i.e. saving trip time), and combinations of rig/ vessel usage.

Clean-up philosophy

Deciding on clean-up philosophy can have a major impact on the installation campaign. 2 choices are available – either well clean-up is performed to the rig through an intervention system (i.e. a conventional landing string with subsea test tree, or a riser based light well intervention system), or well clean-up is produced along the horizontal axis through the subsea production system to the host facility.

The first option allows the operator to perform clean-up without having to have necessary production facilities in place, which relieves schedule dependencies to the permanent production system equipment, but generates more rig time per well.

The latter option enables operator to move rig off location to continue operations on new well, however requires the horizontal production system and topside host to be installed and available. Furthermore, it needs to be evaluated whether the downstream production equipment can handle the expected dirt and debris during clean-up to host facility.

The XT choice will impact the choice of intervention system to be used for clean-up purposes; One example being vertical XTs where some types are non-compatible with landing string systems. In such a case the clean-up can be performed prior to VXT installation using a conventional landing string with subsea test tree (including a tubing hanger orientation joint), or after the vertical XT is installed using a riser based light well intervention system.

Plug setting philosophy

In horizontal XT systems two crown plugs are normally used to isolate the vertical access point due to lack of valves in the vertical main bore. Vertical XTs, however, provides multiple options. In a vertical XT system (whether this is installed directly on the wellhead, or on to a tubing head spool) it is necessary to isolate the well after the tubing hanger is set to be able to disconnect the BOP.

Conventionally this is achieved by using a deep set remotely operated isolation device and a shallow set mechanical barrier. The vertical XT is then installed, and a well intervention system is used to remove the mechanical plug and thus enable flow.

To avoid deploying an intervention system to remove plugs, and hence reduce overall installation cost, alternative strategies can be deployed. This typically involves utilization of a remotely operated shallow set valve, or a "pump-open" glass plugs, which negates the need for an intervention system after the vertical tree is installed.

Water depth

Water depth at field location will in general impact how much time is spent on running and retrieving equipment. The difference between the various intervention systems are not necessarily decisive in shallow waters, however in deep/ultra-deep waters the difference in running time is considerable when comparing BOP systems to light well intervention systems.

Contingency operations

Having a realistic mindset and a pro-active approach regarding contingency/ unplanned operations are vital to mitigate risks throughout the installation campaign. Referring back to the plug setting philosophy and the use of remotely operated shallow set isolation devices as an example, it is important to evaluate the potential scenario where these do not open as intended and whether equipment should be available/ mobilized at an earlier time to handle unforeseen risks.

None of the parameters mentioned above can be evaluated individually – all of them need to be considered and weighted with the specific field development in mind. Having a clear understanding and reasonable strategies related to these topics at an early stage is fundamental to establish an overall field development plan. In such both CAPEX and OPEX can be evaluated along with other corresponding expenditures to get a realistic overview of the complete development and its initial phases.

Heavy intervention system

The heavy intervention system consists of a large bore marine/ drilling riser and subsea BOP with a conventional landing string with subsea test tree inside. The system can perform all necessary operations in a subsea well including installation/ retrieval of tubulars, and intervention activities using standard intervention strings such as coiled tubing, wire line and slick line.

The system is capable of cutting mentioned intervention strings through cutting valves in the lower landing string (i.e. subsea test tree), but can also shear from the "outside" using the shear ram on the BOP should this be needed. The system can disconnect from the subsea well in sequence by firstly disconnecting the landing string above the subsea test tree and subsequently disconnect the top part of the BOP (the Lower Marine Riser Package – LMRP).

The obvious benefit with heavy intervention systems is that the complete tool kit is available, however the immediate drawback is the size and weight of the equipment which requires a rig with high day rates, and leads to less efficient deployment and retrieval compared to lighter intervention solutions.

Riser based light well intervention system

The riser based light well intervention system (also called open water workover system) consists of a small bore riser (typically up to 7-3/8" internal bore) and a subsea well control package. The subsea well control package is divided in to an emergency disconnect package, designed to disconnect from the subsea well and retain hydrocarbons in the riser by the retainer valve, and a lower riser package with cutting valves/rams to make sure sufficient well barriers are in place at all times.

Standard intervention strings like coiled tubing, wireline and slickline can be run, however due to the internal bore size no tubulars can be installed/retrieved from the subsea well. Conversely, due to the internal bore size the equipment can be considerably smaller compared to a heavy intervention system, it can be deployed from smaller vessels, and is faster to deploy and retrieve.

Riserless light well intervention system

The riserless light intervention system is similar to the riser based intervention system, however without the riser back to surface. Instead a short lubricator section is included which is used to lubricate tool strings in to the well by using an intricate sealing and circulation system. Since the riser is not stretching back to the surface there is only need for rapid disconnect functionality on downlines such as control umbilical(s) and circulation line(s).